FOSTER WHEELER ENVIRONMENTAL CORPORATION

December 10, 1998

RECEIVED

DEC 31 1998

BUREAU OF
AIR REGULATION

Mr. Syed Arif
Florida Department of Environmental Protection
Bureau of Air Regulation
111 South Magnolia Street, Suite 23
Tallahassee, FL 32301

Dear Mr. Arif:

SUBJECT: JEA NORTHSIDE REPOWERING PROJECT
DRAFT PSD APPLICATION (PARTIAL)

Please find enclosed a copy of the Draft PSD Application for the subject Project, minus the ELSA application forms. This is being transmitted to you at JEA's direction in order to provide you with an opportunity for an early review of our working draft. Based on a conversation between Al Linero and Bert Gianazza of JEA, a copy is being provided to Mike Halpin as well. This draft will also be provided to the Jacksonville RESD and other stakeholders for their comments and input during this same time frame. The draft ELSA application forms will be provided to you sometime next week.

Please contact Bert Gianazza of JEA (904-665-6247) with any questions or comments on the draft application. We will be calling you to set up a meeting in the near future to go through the application. We would appreciate your comments as soon as possible, and no later than the end of December, so that we may incorporate them into the actual application which we plan to file in early 1999.

FAX #
850-665-7376

Very truly yours,

Douglas J. Fulle
Lead Scientist, Air quality

Enclosure

cc. Mike Halpin (FDEP)(w/enc.)
Al Linero (FDEP)(w/o enc.)
Bert Gianazza (JEA)(w/o enc.)
Liz Deken (FWENC)(w/o enc.)

TECHNOLOGY PARK, 302 RESEARCH DRIVE, NORCROSS, GA 30092-2925
TEL: 770-825-7100 FAX: 770-825-7261

Copy Cleve
Original to JEA Northside
[illegible]

FOSTER WHEELER ENVIRONMENTAL CORPORATION

October 26, 1998

RECEIVED
OCT 27 1998
BUREAU OF
AIR REGULATION

Mr. Cleve Holladay
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Dear Mr. Holladay:

SUBJECT: NORTHSIDE REPOWERING PROJECT
PARTICULATE MATTER (PM_{10}) MULTI-SOURCE EMISSIONS
INVENTORIES

A listing of PM sources that are proposed for use in the AAQS and PSD analysis modelling (if required) has been prepared for the JEA Northside Repowering Project. The source inventory was prepared based on information contained in the Stone Container PSD Application (7/98) and the Cedar Bay Air Quality Analysis (2/93).

Facilities that have more than one source may be "merged" into a single source, if possible, using the M factor included in the inventory listings provided.

Please review and provide any comments you may have on these draft inventories. This inventory has also been transmitted to Lori Tilley of RESD for review. As always, we would appreciate your prompt review as the modelling analysis is currently being conducted. Should you have any questions please call me at (770) 825-7143.

Sincerely,

Michael A. Bilello
Senior Scientist

cc: D. Fulle
B. Gianazza
C. St. Cin (file)

CC: C. Holladay, BAR

TECHNOLOGY PARK, 302 RESEARCH DRIVE, NORCROSS, GA 30092-2925
TEL: 770-825-7100 FAX: 770-825-7261

Proposed Multi- Source Inventory For JEA Northside Repowereing Project

APIS Number/Facility	Source Description	APIS Source Number	Height (m)	Diameter (m)	Temp (K)	Velocity (m/sec)	M Factor dimensionless	(g/s)	(TPY)	Total TPY	20d	PM PSD Source (EXP/CON)	East	North
31DVL 160202 Celotex	Gypsum Crushing System	1	7.6	0.49	321.9	18.9	14420	0.63	21				446400	3362600
	Calcinizing Kettle #1 - #3	07, 11, 12	22.9	0.91	727.4	4.9	131158	0.42	14				446400	3362600
	Wallboard Drying Kilns	08. 13, 14	15.2	0.94	435.8	7.3	106247	0.32	11				446400	3362600
	Calcinizing Kettle	3	27.4	1	344.2	24.7	36929	4.96	172				446400	3362600
	Material Equipment Storage	4	11.3	0.21	294.2	132.0	23995	0.63	22				446400	3362600
	Wallboard End Trim System	5	18.3	0.49	294.2	26.8	45000	0.63	21				446400	3362600
										261	50			
31DVL 160005 Anchor Hocking Glass	Glass Melt Furnace #1	1	17.4	0.91	511.3	19.5	87129	1.28	45				431500	3357500
	Glass Melt Furnace #2	2	17.4	0.82	522.4	14.0	50814	1.32	46				431500	3357500
	Glass Melt Furnace #3	3	33.2	1.71	429.7	11.6	185591	2.04	71				431500	3357500
	Glass Melt Furnace #4	4	35.7	1.58	510.8	11.9	230699	1.83	64				431500	3357500
										226	339			
31DVL 160039 SCM Glidco Organics	Boiler #3 (Retired)	3	12.2	1.1	658.0	10.1	148084	0.31	18			EXP	435600	3360700
	Boiler #4	4	12.2	1.1	405.2	14.0	54466	1.22	42				435600	3360700
	Boiler #5	5	15.2	1.1	535.8	12.8	78199	1.27	44				435600	3360700
	Boiler #6	6	15.2	1.22	513.6	10.4	63147	1.50	52				435600	3360700
	Boiler #7	11	13.7	1.22	449.7	5.5	137324	0.78	10			CON	435600	3360700
	Dryer	7	12.5	1.22	310.9	2.7	432326	0.12	1				435600	3360700
	Sodium Acetate Dryer #1	8	12.2	1.22	314.2	6.7	94793	0.12	11				435600	3360700
	Sodium Acetate Dryer #2	9	12.5	1.22	310.9	2.4	34999	0.12	11				435600	3360700
										189	238			

APIS Number/Facility	Source Description	APIS Source Number	Height (m)	Diameter (m)	Temp (K)	Velocity (m/sec)	M Factor dimensionless	(g/s)	(TPY)	Total TPY	20d	PM PSD Source (EXP/CON)	East	North
31DVL 160046 JEA - Southside	Steam Generator #1 & #2	01, 02	40.8	2.44	433.0	11.6	80250	9.58	414				437700	3353900
	Steam Generator #3	3	40.8	3.05	406.9	10.4	138550	7.26	315				437700	3353900
	Steam Generator #4	4	43.9	3.35	421.9	11.9	221033	10.03	305				437700	3353900
	Steam Generator #5	5	44.2	3.05	416.9	13.7	78140	18.90	821				437700	3353900
	Auxiliary Boiler	10	6.7	0.49	493.6	17.7	382944	0.04	1				437700	3353900
										1856	287			
31DVL 160047 JEA - Kennedy	Combustion Turbine #4	4	13.7	2.8	651.9	8.8	51792	9.37	326				440000	3359200
	Steam Generator #8	7	45.7	3.2	394.1	7.9	134607	6.82	296			EXP	440000	3359200
	Steam Generator #9	8	45.7	3.2	398.0	7.9	135939	6.82	296				440000	3359200
	Steam Generator #10	9	41.5	2.74	410.8	15.5	74221	16.82	731				440000	3359200
	Auxiliary Boiler	13	10.1	0.49	493.6	17.7	577273	0.04	1			CON	440000	3359200
										1650	178			
31DVL 16003 Jefferson Smurfit	Power Boiler #10	11	61	3.05	341.5	9.7	337333	5.56	152			CON	439900	3359300
	Recover Boiler #9	5	53.3	3.2	409.8	22.9	265155	15.12	526				439900	3359300
	Smelt Dissolving Tank #9	4	53.3	1.65	362.0	4.3	38688	4.59	160				439900	3359300
	Lime Kiln #1	6	15.8	1.45	347.0	6.7	22899	2.65	92			EXP	439900	3359300
	Lime Kiln #2	7	15.8	1.45	347.0	6.7	22653	2.65	93			EXP	439900	3359300
	Lime Kiln #3	23	60.7	1.37	340.2	12.2	140429	2.65	92			CON	439900	3359300
	Coal Bark Boiler #1	12	53.3	1.65	366.5	4.0	35905	4.59	160				439900	3359300
	Coal Bark Boiler #2	13	61	3.05	334.8	10.7	363786	5.56	152				439900	3359300
	Coal Handling Silo #1, #2	21, 22, 20	32.9	0.3	298.1	7.0	42196	0.14	4				439900	3359300
	Line Storage Silo	24	27.4	0.52	338.7	2.1	220912	0.02	0.66				439900	3359300
										1432	178			

APIS Number/Facility	Source Description	APIS Source Number	Height (m)	Diameter (m)	Temp (K)	Velocity (m/sec)	M Factor dimensionless	(g/s)	(TPY)	Total TPY	20d	PM PSD Source (EXP/CON)	East	North
31DVL 160072 U.S. Gypsum	Wallboard Kiln #2	33	13.7	1.07	421.9	29.0	209106	0.77	25				438900	3361200
	Calcinizing Kettles #1 - #7	36	28.3	1.07	505.2	0.9	8833	1.47	46				438900	3361200
	Downtherm Heater	41	20.7	0.91	733.0	6.4	274194	0.23	8				438900	3361200
	Rotary Kiln	48	26.8	0.49	339.1	59.1	586573	0.20	6				438900	3361200
	Combustion Turbine #1 - #2	68, 69	36.6	1.01	346.9	25.0	1471478	0.15	6				438900	3361200
	Ambient Vents #1	5, 36, 40, 73, 78	3	1.06	298.1	11.9	32590	0.34	10				438900	3361200
	Ambient Vents #2	34, 35, 42, 70, 71, 72	6.1	0.7	294.2	8.8	7312	1.40	29				438900	3361200
	Ambient Vents #3	37, 44, 54, 62, 63, 64, 65, 66	0.9	0.61	316.5	8.2	610	1.17	39				438900	3361200
	Stucco Bin No. 3 & No. 4	6, 7	18.3	0.46	344.2	8.5	51688	0.08	6				438900	3361200
	Stucco & Feed Bin	8, 9	21.9	0.3	344.2	19.2	88828	0.07	4				438900	3361200
	Kettles	39, 46, 47, 55	22.9	1.22	363.7	3.1	25784	1.18	40				438900	3361200
	Storage Bins	43, 58	26.5	0.61	310.4	7.9	55104	0.37	12				438900	3361200
	Tube Mill Discharge	45	20.7	0.24	298.7	72.2	701416	0.03**	1				438900	3361200
	#5 Raymond Mill	60	26.8	0.15	331.5	49.7	135445	0.05	2				438900	3361200
	Additive Feed System	61	28.9	0.46	344.2	4.3	122584	0.05	2				438900	3361200
	Calcium Carbonate Storage	67	10.1	0.15	305.4	15.2	144258	$.52 \times 10^3$	0.2				438900	3361200
										236	174			
31DVL 160004 Maxwell House	Agglom Process	1, 10, 30, 31	14.6	1	374.8	15.6	58027	1.14	40				439700	3350000
	Scrap Paper Cyclone	26, 27, 28, 29	21.3	0.03	298.0	0.6	12	0.22	8				439700	3350000
	Thermalo Afterburner	60, 61	27.4	0.49	793.0	19.0	540198	0.14	5				439700	3350000
	Power Airveyor	21, 22, 18, 20, 52	27.4	0.61	298.1	0.9	18861	0.13	4				439700	3350000
	Continuous Roaster	5, D4, 12, 16	27.4	0.61	311.5	19.8	85809	0.58	20				439700	3350000
	Boiler #2	4	45.7	0.43	396.9	68.0	248727	0.72	25				439700	3350000

APIS Number/Facility	Source Description	APIS Source Number	Height (m)	Diameter (m)	Temp (K)	Velocity (m/sec)	M Factor dimensionless	(g/s)	(TPY)	Total TPY	20d	PM PSD Source (EXP/CON)	East	North
	Green Coffee Silo	F0, F1, f2, F3, F4, F5, 53, 55, 56, 57, 58, 59, 23, 24, 25, 54	27.4	0.31	306.5	14.3	22534	0.40	14				439700	3350000
	Cooling Carts	32, 33, 34, 35, 36, 37, 38, 39, 40, 41, 42, 43, 44, 45, 46, 47, 48, 49, 50, 51	30.5	0.18	310.9	18.3	2395	1.84	64				439700	3350000
	Thermalo Roaster #1	7	45.7	0.79	844.2	9.8	246296	0.75	26				439700	3350000
	Roaster Afterburner	D3	27.4	2.29	811.5	3.7	1058301	0.31	11				439700	3350000
	Soluble Coffee Spray Dryer	6, 8, 9	47.2	1.07	383.7	18.6	138350	2.20	76				439700	3350000
	Dryer	D5, D6, D7, D8, E0, E1, D2, 14, 15, 17	23.2	1.49	327.6	7.9	165907	0.64	22				439700	3350000
	Boiler #1	D1, 98, 2, 3	45.7	0.98	606.9	0.6	31659	0.42	14				439700	3350000
	Probat Afterburners	E2, E3, E4, E5, 77, 78, 79, 80, 81, 82, 83, 84, 85, 86	27.4	1	737.6	7.9	101669	1.24	43				439700	3350000
	Thermalo Stoner Cyclone	64, 65, 62, 63, 66, 87, 89, 90, 88, Z9, E6, E7, E8, E9, 97, B1, B2, B3, B4-B9, C1-C9, 67-76, 91-96, D9, F6, A1, A2, A3, A4, A5, A7, A8, A9	27.4	0.61	308.1	7.9	4356	4.46	156				439700	3350000
										528	332			

APIS Number/Facility	Source Description	APIS Source Number	Height (m)	Diameter (m)	Temp (K)	Velocity (m/sec)	M Factor dimensionless	(g/s)	(TPY)	Total TPY	20d	PM PSD Source (EXP/CON)	East	North
CEDAR BAY COGENERATION INC.	1063 MMBTU/HR CIRCULATING FLUIDIZED BED BOILER 1-A		122.9	4.1	327	36.6	8470698	2.24	78			CON	441610	3365540
	1063 MMBTU/HR CIRCULATING FLUIDIZED BED BOILER #1-B		122.9	4.1	327	36.6	8470698	2.24	78			CON	441610	3365540
	1063 MMBTU/HR CIRCULATING FLUIDIZED BED BOILER #1-C		122.9	4.1	327	36.6	8470698	2.24	78			CON	441610	3365540
	LIMESTONE DRYER; #1 FO @ 0.05% SULFUR, BY WT., MAX.;		19.2	1.3	301	28.4	10035990	0.02	1			CON	441610	3365540
	LIMESTONE DRYER; #2 FO @ 0.05% SULFUR, BY WT., MAX.;		19.2	1.3	301	28.4	10035990	0.02	1			CON	441610	3365540
	Cooling Tower							0.68	24			CON	441610	3365540
	Material Handling							0.26	9.2			CON	441610	3365540
										268	102			
STONE CONTAINER CORPORATION	NATURAL GAS/#2 FO FIRED PKG STEAM BOILER (#1 OF 3 BOILERS)		61.0	2.4	439	5.2	1955694	0.37	11.5			CON	442950	3365390
PSD Appl. (7/6/98)	NATURAL GAS/#2 FO FIRED PKG STEAM BOILER (#2 OF 3 BOILERS)		61.0	2.4	439	5.2	1955694	0.37	11.5			CON	442950	3365390
	NATURAL GAS/#2 FO FIRED PKG STEAM BOILER (#3 OF 3 BOILERS)		61.0	2.4	439	5.2	1955694	0.37	11.5			CON	442950	3365390
										35	75			
STONE CONTAINER CORPORATION	Bark Boiler No. 1		41.45	2.46	332	13.01	502624	1.69	58.8			EXP	442950	3365390
	Bark Boiler No. 2		41.45	2.46	332	13.01	665638	1.28	44.4			EXP	442950	3365390
	Power Boiler No. 1		32.31	1.83	455	14.02	184590	2.94	102			EXP	442950	3365390
	Power Boiler No. 2		32.31	2.13	439	14.51	170714	4.30	149.2			EXP	442950	3365390
	Power Boiler No. 3		32.31	2.13	439	14.51	171288	4.28	148.7			EXP	442950	3365390
	Recovery Boiler No. 1		38.4	2.59	341	15.97	250425	4.40	152.8			EXP	442950	3365390
	Recovery Boiler No. 2		38.4	2.74	345	15.61	448160	2.72	94.5			EXP	442950	3365390
	Recovery Boiler No. 3		38.4	2.74	344	14.6	308563	3.69	128			EXP	442950	3365390
	Smelt Dissolving Tank No. 1		36.58	1.07	344	3.96	56797	0.79	27.4			EXP	442950	3365390
	Smelt Dissolving Tank No. 2		37.8	1.22	344	4.27	34681	1.87	65			EXP	442950	3365390
	Smelt Dissolving Tank No. 3		37.8	1.22	344	4.27	35389	1.83	63.7			EXP	442950	3365390
	Lime Kiln No. 1		21.03	1.77	343	3.11	67504	0.82	28.4			EXP	442950	3365390
	Lime Kiln No. 2		22.86	1.42	336	6.52	90909	0.87	30.3			EXP	442950	3365390
	Lime Kiln No. 3		22.86	1.12	336	8.17	66893	0.92	32.1			EXP	442950	3365390
except as noted, data obtained from Cedar Bay AQ Analysis Report (2/93)										1125	75			

AL

Date: 10/23/98 8:35:55 AM
From: Jan Brewer JAX
Subject: Meeting - JEA 29th
To: See Below

I have reserved the van for the meeting ... who will be riding in the van? Thanks!! Jan

To: David Apple JAX
To: Mark Cadenhead JAX
To: Erin Hart JAX
To: Kenneth Kohn JAX
To: Jim Maher JAX
To: Steve Nguyen JAX
To: Richard Rachal JAX
To: Stephen Sabia JAX
To: Russell A. Price JAX
To: Rita Felton-Smith JAX
To: Alvaro Linero TAL
To: Clair Fancy TAL

Date: 10/23/98 8:54:22 AM
From: Jan Brewer JAX
Subject: JEA Participant list
To: See Below

I will update as necessary. Jan

JEA Team Permitting

Participant List

Name	Section	E-mail Address
Department of Environmental Protection		
David Apple	StormW	apple_d@jax1.dep.state.fl.us
Jan Brewer	Admin	brewer_j@jax1.dep.state.fl.us
Mark Cadenhead	IW	cadenhead_m@jax1.dep.state.fl.us
Erin Hart	Admin	hart_e@jax1.dep.state.fl.us
Ken Kohn	IW	kohn_k@jax1.dep.state.fl.us
Jim Maher	IW	maher_j@jax1.dep.state.fl.us
Steve Nguyen	SW	nguyen_s@jax1.dep.state.fl.us
Rick Rachal	WCU	rachal_r@jax1.dep.state.fl.us
Steve Sabia	ERP	sabia_s@jax1.dep.state.fl.us
Rita Felton-Smith	Air	felton_r@jax1.dep.state.fl.us
Jacksonville Electric Authority		
Reece Comer	Pro.Mger	comere@jea.com
Suzanne Bartlett	Environ.	bartsm@jea.com
Bert Gianazza		giannb@jea.com
Susan Hughes	Environ.	hughsn@jea.com
Steve Moser		mosesl@jea.com
Matt McClure		mcclmr@jea.com
Tim Perkins		perkte@jea.com
P.T. Nielsen		nielpt@jea.com

To: David Apple JAX
To: Mark Cadenhead JAX
To: Erin Hart JAX
To: Kenneth Kohn JAX
To: Jim Maher JAX
To: Steve Nguyen JAX
To: Richard Rachal JAX
To: Stephen Sabia JAX
To: Russell A. Price JAX
To: Rita Felton-Smith JAX
To: Alvaro Linero TAL
To: Clair Fancy TAL

AC

Date: 10/22/98 1:18:22 PM
From: Jan Brewer JAX
Subject: Jea Team Permitting Meeting
To: See Below

Remember for your calendars:

JEA Team Permitting Meeting
Thursday, October 29 @9:30
JEA Building, 11th Floor Conference Room

It has been suggested that we order lunch in for that day ... I will get the info on that and a draft agenda soon.

Thanks!!!! Jan

To: David Apple JAX
To: Mark Cadenhead JAX
To: Erin Hart JAX
To: Kenneth Kohn JAX
To: Jim Maher JAX
To: Steve Nguyen JAX
To: Richard Rachal JAX
To: Stephen Sabia JAX
To: Russell A. Price JAX
To: Rita Felton-Smith JAX
To: Alvaro Linero TAL
To: Clair Fancy TAL

. . . .

Date: 10/23/98 2:10:38 PM
From: Jan Brewer JAX
Subject: Pre-meeting
To: See Below

al

Mary just came over and we were discussing the Team Permit. We were finding we had more questions then answers about the project! I think we really need to get together prior to the Thursday meeting to discuss as a group our desires on how this endeavor is to proceed. We need time ... without JEA ... to get our direction as a group. What looks good for everyone? I have Monday morning, Tuesday afternoon or Wednesday morning. Please e-mail me as soon as you can with a time. Thanks!!!!!! Jan

To: David Apple JAX
To: Mark Cadenhead JAX
To: Erin Hart JAX
To: Kenneth Kohn JAX
To: Jim Maher JAX
To: Steve Nguyen JAX
To: Richard Rachal JAX
To: Stephen Sabia JAX
To: Russell A. Price JAX
To: Rita Felton-Smith JAX
To: Alvaro Linero TAL
To: Clair Fancy TAL
To: Mary Nogas JAX

United States Department of the Interior

FISH AND WILDLIFE SERVICE
1875 Century Boulevard
Atlanta, Georgia 30345

IN REPLY REFER TO

June 23, 1998

RECEIVED
JUN 29 1998
BUREAU OF
AIR REGULATION

FWS/R4/ARW

Ms. Lisa K. Hollingsworth
Environmental, Safety, and
Health Division
U.S. Department of Energy
3610 Collins Ferry Road
P.O. Box 880
Morgantown, West Virginia 26507-0880

Dear Ms. Hollingsworth:

Our Air Quality Branch has reviewed the information you provided on the U.S. Department of Energy's proposal to provide Federal funding for cost-shared support to construct and demonstrate utility-scale, circulating fluidized-bed combustion technology at the Jacksonville Electric Authority's Northside Generating Station, Jacksonville, Florida. The project is located 61 km east of Okefenokee Wilderness, 102 km south of Wolf Island Wilderness, and 209 km northeast of Chassahowitzka Wilderness, all Class I air quality areas, administered by the Fish and Wildlife Service. The technical review comments from our Air Quality Branch are enclosed.

Thank you for giving us the opportunity to comment on this project. We appreciate your cooperation in notifying us of proposed projects with the potential to impact the air quality and related resources of our Class I air quality areas. If you have questions, please contact Ms. Ellen Porter of our Air Quality Branch in Denver at 303/969-2617.

Sincerely yours,

Sam D. Hamilton

Sam D. Hamilton
Regional Director

Enclosure

CC: C. Holladay, BAR
S. Arif, BAR
FAX - F. Shelton, C & L

cc:
Mr. C. H. Fancy
Chief, Bureau of Air Regulation
Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road, MS 48
Tallahassee, Florida 32399-2400

Mr. Doug Neeley
Chief, Air and Radiation Branch
U.S. EPA, Region IV
100 Alabama St., SW.
Atlanta, Georgia 30303

Bert Gianazza, P.E.
Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202-3139

Technical Review of Information
For Jacksonville Electric Authority's Northside Generating Station
Jacksonville, Florida
by
Air Quality Branch, Fish and Wildlife Service - Denver
June 18, 1998

The U.S. Department of Energy (DOE) is considering a proposal to provide Federal funding for cost-shared support to construct and demonstrate utility-scale, circulating fluidized-bed combustion technology at the Jacksonville Electric Authority's (JEA) Northside Generating Station, Jacksonville, Florida. The project is located 61 km east of Okefenokee Wilderness, 102 km south of Wolf Island Wilderness, and 209 km northeast of Chassahowitzka Wilderness, all Class I air quality areas administered by the U.S. Fish and Wildlife Service (FWS). DOE is developing an Environmental Impact Statement (EIS) for the project and would like to ensure that project alternatives and potential environmental impacts are properly addressed in the EIS. Therefore, DOE has asked FWS to review and comment on aspects of the project pertaining to air quality, including the proposed emissions control technology, proposed modeling protocol, and potential air quality related values (AQRV) impacts. Our comments follow.

Emissions Control Technology Analysis

JEA proposes to replace two existing boilers with two new Circulating Fluidized Bed (CFB) boilers burning coal and petroleum coke. Sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions will be controlled by a polishing scrubber and Selective Non-catalytic Reduction (SNCR), respectively. Particulates will be controlled by a baghouse.

A review of the RACT/BACT/LAER (Reasonably Available Control Technology/Best Available Control Technology/Lowest Achievable Emission Rate) Clearinghouse (RBLC) found eight coal-fired fluidized-bed boilers permitted since 1991. Particulate (PM) emissions from most were controlled by fabric filters (one had an electrostatic precipitator) and limits ranged from 0.015 to 0.03 pound per million Btu (lb/mmBtu). Although none of the boilers had add-on controls for SO_2, they all relied upon the presence of limestone in the fluidized bed to reduce SO_2 emissions to 0.16-0.6 lb/mmBtu. Half of the boilers added SCNR to control NO_x emissions to 0.07-0.20 lb/mmBtu; those boilers without add-on NO_x controls had limits of 0.20-0.50 lb/mmBtu. (Because a well-operated CFB can achieve NO_x emissions as low as 0.20 lb/mmBtu without add-on controls, and SNCR can reduce remaining emissions by another 60%, a limit of 0.07 lb/mmBtu is feasible.)

As a result of our review of the RBLC, we recommend that emissions from the proposed JEA not exceed 0.15 lb PM/mmBtu, 0.16 lb SO_2/mmBtu, and 0.07 lb NO_x/mmBtu. When we are provided additional information on the proposed equipment and emissions rates, we may have additional comments on the control technology. At that time, we may suggest even lower limits, especially if more efficient controls for NO_x are deemed feasible.

Draft Air Quality Modeling Protocol

Because proposed emission rates have not been provided, and Prevention of Significant Deterioration-significant pollutants have not been identified, only general modeling analysis requirements can be provided at this time.

Air Quality Analysis

JEA should perform a cumulative air quality modeling analysis to predict impacts from all increment consuming sources if the proposed projects predicted impacts are over the Class I significance impact levels proposed by the Environmental Protection Agency.

JEA proposes to use the North Carolina screening method (referred to in "Emission Inventory" of the draft protocol) for emission inventories for the Class I analysis. This screening method may eliminate sources that should be included in a cumulative analysis. An analysis that considers less than all increment-consuming sources would need to be agreed upon by FWS, the State, and the applicant.

Visibility Analysis

JEA proposes to perform a regional haze analysis using the Interagency Workgroup on Air Quality Modeling (IWAQM) protocol. The analysis should provide the predicted change in extinction from the project's emissions to the background condition (65-km of visual range). If the change in extinction is 5% or greater, the applicant will need do a cumulative haze analysis that includes all increment-consuming sources.

Air Quality Related Values (AQRV) Analysis

Again, because the types and amounts of pollutants that will be emitted by this project have not been identified, only general analysis requirements can be provided at this time.

We would like JEA to consider potential impacts from this project to AQRVs, including wildlife, vegetation, soils, and water quality. Impacts to consider include eutrophication or fertilization of ecosystems (coastal, freshwater, and terrestrial) caused by atmospheric nitrogen deposition, and toxicity to wildlife from emissions of trace metals (e.g., mercury and lead) and organic compounds.

Contact: Ellen Porter, Air Quality Branch (303) 969-2617.

Department of Energy Initiates Environmental Impact Statement Process

JEA and DOE kicked off the federal review process for the Northside Repowering Project at a public meeting held at the Northside Station on December 3, 1997. Sponsored by DOE, this public scoping meeting provided the public an opportunity to discuss with DOE issues that should be addressed as part of the environmental impact review. Approximately 50 members of the public attended.

The Environmental Impact Statement (EIS) process includes an extensive review of potential impacts on the environment and the surrounding community. Issues that will be addressed in the EIS include air quality, water resources, aquatic ecology, infrastructure, land use, solid waste, construction, floodplains, wetlands, socioeconomic impacts, and visual impacts.

A team of environmental experts working under the direction of DOE is developing the Draft EIS. The Draft EIS is expected to be complete and available for public review by October 1998. Once the Draft EIS is available, a 45-day public comment period will commence, during which a public hearing will be conducted. The final EIS is scheduled for completion by January 1999, and a written statement that documents DOE's decision whether to fund the project is expected to be issued in February 1999.

There are several opportunities for public input during the EIS process. These consist of the public scoping period including the public scoping meeting, completed as of December 31, 1997, and the Draft EIS public comment period including the public hearing, expected to begin in October 1998.

Issues raised at the December 3rd public scoping meeting included transportation and noise impacts from train traffic through the Northside area and air emissions, including the potential for dioxin emissions. A copy of the scoping meeting transcript is in the Highlands Branch Library at 1826 Dunn Avenue in Jacksonville.

JEA Consults with Neighbors and Interested Groups

In addition to the formal DOE process, the JEA has met with the following groups:

- Florida Department of Environmental Protection (both Tallahassee and the Northeast District)
- City of Jacksonville Environmental Protection Board Air Committee
- Florida Lung Association
- Northside Civic Association
- Heckscher Drive Community Club
- First Coast Manufacturers Association
- Sierra Club
- Jacksonville Certified Public Accountant Association
- Editorial Boards for Florida Times Union, WJXT TV-4, and Jacksonville Business Journal

JEA is committed to earning the public trust through participation in community affairs and is available to present and discuss this project with any community organization. If you are aware of an organization that may be interested in hearing more about the Northside Repowering Project, please call Susan Hughes at 665-6248.

Technology and Fuel Choices Reflect Environmental and Cost Considerations

The technology chosen for the repowering project at Northside is circulating fluidized bed, burning petroleum coke and coal. Circulating fluidized bed technology is an advanced and proven technology which is very fuel flexible and results in low air emissions. For example, 90 percent of the sulfur dioxide emissions from fuel combustion will be eliminated in the boiler. JEA is planning to add a flue gas scrubbing system to capture additional emissions. Overall, more than 98 percent of the sulfur dioxide emissions will be removed.

Fuel is by far the largest single component in the cost of electricity. Given trends toward deregulation and greater competition in the electric utility industry, fuel price is of vital importance in the evaluation of new generation alternatives.

JEA considered a wide range of fuels in its planning process, including petroleum coke, coal, high sulfur fuel oil, natural gas, and low sulfur fuel oil. Petroleum coke, a byproduct of oil refining operations, is projected to have the lowest price over the long term of all the fuels evaluated. JEA completed a successful test burn at the St. Johns River Power Park and has been burning petroleum coke, along with coal, at the Power Park since February, 1997. As a result of the agreement reached with the DOE, the repowering project will include a two-year demonstration of the circulating fluidized bed technology burning coal. Use of a blend of the two fuels is also being considered.

Northside Repowering Project Contacts

Environmental Issues

Mr. Bob Kappelmann
Phone 665-6249

Construction, Labor & Equipment Issues

Mr. Reece Comer
Phone 665-6312

JEA Begins Environmental Studies & Permitting

JEA is assembling the information required to apply for the various permits that will be needed for the Northside Repowering Project. As with the EIS, the permits ensure that impacts to the environment and the community are considered and minimized. They also specify how the project can be constructed and operated. Permits detailing potential impacts to the air, water, and land are required for a project of this type.

A draft of the air permit application will be completed in mid-summer 1998. JEA has committed to make this draft permit application available for review by individuals, community groups, and the local Environmental Protection Board prior to formal submittal.

Environmental Health & Safety Department
Tower 8
Jacksonville Electric Authority
21 West Church Street
Jacksonville, FL 32202-3139

Mr. Al Linero
FDEP Division of Air Resources Management
2600 Blair Stone Road
MS 5505
Tallahassee, Florida 32399-2400

32399/2400

Northside Repowering Project

May, 1998

This newsletter is designed to inform the public of the progress of the Jacksonville Electric Authority's Northside Generating Station Repowering Project.

Visit our web site at www.jea.com

JEA is upgrading two electrical generating units at the Northside Generating Station. This is a significant construction project which will cost $463 million over a five year period and is scheduled to be completed by 2002. JEA is committed to continuous community involvement in the planning and implementation phases of the project. The purpose of this newsletter is to keep the public informed about the status of the project. It will be issued periodically as the project progresses and information becomes available.

Northside Repowering Project Begins

During 1996, the JEA went through a comprehensive planning process to determine how best to meet the growing demand for electricity in Jacksonville. Jacksonville's growth will outstrip the capacity of the City's electric system by 2002 if new generating capacity isn't brought on line. Even considering other sources of power and demand reduction strategies, such as energy conservation programs, new generation will be needed.

In May 1997, the JEA Board decided to proceed with the option to upgrade Units 1 and 2 at the Northside Generating Station (Unit 2 has been out of service since 1983 and the boiler has been dismantled and removed). This option involves changing the type of fuel used at the two units from oil to petroleum coke and coal and using a new type of generating technology called circulating fluidized bed. This technology can burn a wide range of fuels and results in low air emissions. This option, referred to as the Northside Repowering Project, also includes additional equipment to control air emissions such as sulfur dioxide, nitrogen oxides, and particulate matter.

JEA has made a commitment to the Jacksonville community to reduce annual emissions of sulfur dioxide, nitrogen oxides, and particulate matter from the Northside Station by at least 10 percent*. Likewise, groundwater consumption for the facility will also be reduced by at least 10 percent.** These reductions are to be accomplished while increasing the total annual energy output of the Northside Generating Station over 2.5 times.

Subsequent to the JEA Board decision to proceed with this project, the U.S. Department of Energy (DOE) selected JEA to participate in a demonstration project. The DOE plans to contribute nearly $75 million toward the repowering project as part of the federal government's Clean Coal Technology Program. Before the money is provided to JEA, the DOE is required to evaluate the potential environmental impacts expected from the project. This process has several opportunities for public input.

* (JEA will reduce by at least 10% the stack emissions of sulfur dioxide, nitrogen oxides, and particulate matter based on actual emissions as reported in the Annual Operating Report submitted to the Florida Department of Environmental Protection for 1994 and 1995 for Units 1 and 3. Unit 2 did not operate in 1994 or 1995.)

** JEA will reduce groundwater withdrawal quantities by at least 10% based on the 1996 daily average withdrawal quantity.

JACKSONVILLE ELECTRIC AUTHORITY

21 WEST CHURCH STREET • JACKSONVILLE, FL 32202-3139

JEA "POWER TO SERVE"

June 1, 1998

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RECEIVED
JUN 03 1998
BUREAU OF
AIR REGULATION

Dear Mr. Linero:

SUBJECT: JACKSONVILLE ELECTRIC AUTHORITY
NORTHSIDE REPOWERING PROJECT
FINAL MODELLING PROTOCOL

Attached is the Final Modelling Protocol for the subject Project. We have incorporated the comments of Cleve Holladay of your department as well as those of Lori Tilley (RESD) and Bud Rolofson (USFWS).

Please call me at (904) 665-6249 if you have any questions on the Protocol. Your prompt review and approval of the protocol would be appreciated.

Very truly yours,

Robert L. Kappelmann, P.E.
Director, Legislative and
Regulatory Affairs

Attachment

JEA NORTHSIDE REPOWERING PROJECT
AIR QUALITY MODELLING PROTOCOL

Introduction

The development of and agreement on a modelling protocol is suggested by U.S. Environmental Protection (EPA), the Florida Department of Environmental Protection (DEP), and the Jacksonville Regulatory & Environmental Services Department (RESD) prior to embarking on any major air quality modelling exercise. This protocol describes, in some detail, the models (and model options) which will be used, the meteorological and emissions data which will be input to the model, the receptor grids which will be utilized, and the analyses which will use the model results. This protocol has been prepared to address both those analyses which are known at this time to be required (significant impact analysis and monitoring exemption determination and FARC analysis) and those analyses which have not yet been determined to be required (AAQS, PSD increment, additional impacts). This modelling protocol is being submitted for formal DEP approval.

Proposed Project

The Northside Generating Station is approximately 10 miles north of downtown Jacksonville, Florida. The Northside Generating Station is an industrial site encompassing approximately 400 acres, with 200 acres devoted to existing steam generation units, combustion turbine units, and associated infrastructure.

The Northside Repowering Project consists of the replacement of the Unit 1 and Unit 2 boilers at the Northside Generating Station with two new circulating fluidized bed (CFB) combustors which would feed steam to the existing turbine generators. One new CFB combustor would use coal and petroleum coke to generate nearly 300 MWe by repowering the existing Unit 2 steam turbine, a 297.5-MWe unit that has been out of service since 1983. This will be done with the assistance of a DOE Clean Coal Technology Demonstration cost sharing arrangement. In addition, JEA plans to repower the currently operating Unit 1 steam turbine with a CFB combustor which will fire primarily petroleum coke. The Unit 1 steam turbine is essentially identical to the turbine for Unit 2, and is scheduled to be repowered about 6 to 12 months after the Unit 2 repowering.

In a CFB combustor, coal, petroleum coke, and coal/coke blends, air, and limestone are introduced into the lower portion of the combustor, where initial combustion occurs. As the fuel is reduced in size through combustion and breakage, it is transported higher in the combustor where additional air is introduced. Ash and unburned fuel and limestone pass out of the combustor, collect in a particle separator, and recirculate to the lower portion of the combustor. Sulfur reacts with limestone added in the furnace to form ash that can be marketed as a useful by-product such as roadbed material. Although this process has intrinsically low emissions of air pollutants, additional air quality control systems are planned including SNCR for NO_x control, a polishing scrubber for SO_2 control, and either an electrostatic precipitator or a fabric filter for control of particulate emissions.

Netting Analysis

The netting analysis for the determination of PSD applicability will be conducted in accordance with the PSD Workshop Guidance, and Rules 62-213.400(2)(d)4., F.A.C. and 62-213.400(2)(a)3, F.A.C. The applicability of PSD for each pollutant will be determined based upon whether there will be a significant increase in emissions between the actual emissions during the baseline period and future potential emissions after the modification is made. The baseline emissions have been presented in a letter from JEA to DEP dated January 7, 1998 (JEA, 1998) and have been accepted by DEP (DEP, 1998) except from particulate matter. JEA intends to use these approved baseline emissions (including revised values for particulate matter in accordance with DEP's request) together with maximum future potential emissions to determine PSD applicability and therefore the requirement for an air quality impact analysis for each PSD regulated pollutant.

In accordance with DEP desires, PSD applicability will be determined based on the net changes in emissions for Units 1 and 2 at Northside. However, it should be kept in mind that, regardless of PSD applicability, JEA will be seeking federally enforceable permit conditions which will restrict stack emissions of SO_2, NO_x and particulates from Northside Units 1, 2, and 3 combined to 10 percent less than the baseline emissions in 1994 and 1995 as determined from the Annual Operating Reports. Therefore, it is expected ambient air quality will improve for those pollutants as a result of the project and only limited modelling will be necessary.

General Modelling Approach

General Modelling Approach - The air quality impact assessment will consist of a proposed source significant impact area analysis, and if determined necessary, a PSD increment consumption analysis, an ambient air quality standards impact analysis, and an additional impacts analysis. In addition, the need for ambient monitoring will be evaluated. These analyses are discussed in greater detail below. Normally these analyses would be needed for only those pollutants for which PSD is triggered. However, because the construction could influence the dispersion from existing units at Northside which will not be modified and due to a commitment made by JEA to the Jacksonville community, JEA intends to determine whether the modification would cause any significant off-site impacts for all PSD-regulated pollutants with Class II significance values.

The modelling approach will follow EPA and DEP modelling guidelines for determining compliance with applicable PSD increments and ambient air quality standards (AAQS). EPA Modelling Guidance is provided in the Guideline on Air Quality Models (40 CFR 51, Appendix W) as well as the Draft New Source Review Workshop Manual (EPA, 1990). DEP guidance on conducting the analyses is provided in Rule 62-212.400 F.A.C.

Based on current EPA and DEP policies, the highest annual average and highest second-high short-term (i.e., 24 hours or less) predicted concentrations (critical concentrations) will be selected for comparison to applicable AAQS and PSD increments, except for PM_{10} which is discussed below. In accordance with Modelling Guidance, the highest short-term predicted concentrations will be used for comparison to significance levels. The use of a five-year meteorological data base in the modelling analysis, as proposed below, allows a comparison of the predicted highest second-high, short-term concentration to applicable short-term PSD increments and ambient air quality standards. The highest second-high concentration is calculated for a receptor field by:

- Eliminating the highest concentration predicted at each receptor;
- Identifying the second-high concentration predicted at each receptor; and
- Selecting the highest concentration among those second-high concentrations.

This approach is consistent with the air quality standards and PSD increments which permit one short-term average exceedance per year at each receptor.

The general modelling approach for each air quality impact analysis will commence with a significance level impact phase. The proposed Project (both emissions increases and decreases) will be modelled by itself for each of the PSD regulated pollutants with significance levels in Rule 62-210.200(256), F.A.C. If predicted impacts are below the significance levels, then modelling impacts with respect to PSD increments and AAQS is not required. JEA intends to model the impacts of the Northside Generating Station, together with SJRPP, in both before the repowering and after the repowering modes for selected criteria pollutants regardless of insignificance of the impacts.

If predicted impacts are above the significance levels, both screening and refined multi-source modelling phases will be conducted for those pollutants having a significant impact. The major difference between the two latter phases is the receptor grid used when predicting concentrations and the number of meteorological data periods evaluated. In general, concentrations for the screening phase will be predicted using a coarse mesh receptor grid and a five-year meteorological data base. The screening phase will identify the critical receptors associated with the highest and highest second-high short-term concentrations for all applicable pollutants and averaging periods. The predicted concentrations at those critical receptors will be evaluated in greater detail in the refined phase of the analysis.

The refined phase of the analysis will be performed by predicting concentrations using a fine mesh receptor grid centered over each of the critical receptors identified in the screening phase of the modelling analysis. Several critical receptors will be evaluated for each year of meteorological data containing the meteorological conditions which caused the critical concentrations identified in the screening phase analysis. This approach will be used to ensure that valid highest second-highest (critical) short-term concentrations will be obtained for comparison to applicable air quality standards and PSD increments.

Model Selection and Use

The most current version of Industrial Source Complex (ISC) dispersion model will be used to evaluate the emissions from the proposed units. As of the date of this protocol, this is ISC3 (Version 97363). The model and its use are covered in the Users Guide (EPA, 1995a). The ISC3 model was selected primarily for the following reasons:

1. EPA and DEP have approved the general use of the model for air quality dispersion analysis because the model assumptions and methods are consistent with those in the Guideline on Air Quality Models.

2. The ISC3 model is capable of predicting the impacts from stack, area, and volume sources that are spatially distributed over large areas and located in flat or gently rolling terrain.
3. The results from the ISC3 model are appropriate for addressing compliance with AAQS and PSD increments since the model can predict the highest as well as the highest second-high concentration and period of occurrence for 1-hour, 3-hour, 8-hour and 24-hour averaging periods at each receptor for each full year of hourly meteorological data used. The short-term or long-term versions of the ISC3 model can be used for annual averages.
4. The ISC3 model has several options and features that allow it to handle certain situations in a variety of ways. For this analysis, the EPA regulatory default options will be used to predict the maximum impacts from the facility.

Area Classification

The ISC3 model has rural and urban options which affect the wind speed profile exponent law, dispersion rates, and mixing-height formulations used in calculating ground-level concentrations. The criteria used to determine when the rural or urban mode is appropriate are based on land use near the proposed plant's surroundings (Auer, 1978). If the land use is classified as heavy industrial, light-moderate industrial, commercial, or compact residential for more than 50 percent of the area within a 3 km radius circle centered on the proposed source, the urban option should be selected. Otherwise, the rural option is more appropriate.

Based on the use of USGS topographic maps, it has been preliminarily concluded that the land use is consistent with the use of the rural rather than urban options. This will be confirmed in accordance with the Modelling Guidance.

GEP Stack Height/Downwash Considerations

If the stack for the proposed unit or existing units are less than Good Engineering Practice (GEP), then the potential for building downwash based upon the dimensions of nearby buildings must be considered in the modelling analysis. The procedures used for addressing the effects of building downwash are those recommended in the ISC3 Dispersion Model User's Guide and are incorporated into the ISC3 model. The effective height and effective width of structures are input to the model and are used to modify the dispersion parameters. The GEP stack height and the effective widths and heights of the structures will be determined using the EPA Building Profile Input Program (BPIP). The new unit's stacks are planned to be less than or equal to GEP height; the stacks of the existing units are believed to be less than GEP.

The possibility of on-site structures influencing off-site concentrations due to the structures creating a cavity recirculation region will be evaluated. The first level of screening will be performed to determine if a structure is within 3H of the property line (where H = structure height). Structures greater than 3H from the property line are not expected to have an off-site cavity. Structures which are within 3H of the property line will be further evaluated using the method presented in the SCREEN3 Model User's Guide (EPA, 1995b) to determine the cavity height, length and concentration. The results of these calculations will be used in subsequent analyses.

Plant Loads/Ambient Temperatures/Fuels

Operating load can affect emission parameters, and therefore ground-level impacts, because exit temperature and velocity change along with source emission rate. Three operating load cases will be analyzed using ISC3 and one year of meteorological data. These loads will be selected to cover the range of normal plant operations (probably 50%, 75% and 100%). The load case shown in the analysis to cause the highest impacts will be used in the subsequent multi-year analyses. Both coal and petroleum coke will be modelled to determine which is worst case for each pollutant. The worst-case fuel will be used in subsequent analyses.

Meteorological Data

The air quality modelling analysis will use hourly preprocessed National Weather Service (NWS) surface meteorological data from Jacksonville, Florida and concurrent twice-daily mixing heights from Waycross, Georgia for the years 1985 to 1989. The preprocessed hourly meteorological data file for each year of record used in the analysis will be obtained from DEP and will contain randomized wind direction, wind speed, ambient temperature, atmospheric stability using the Turner (1970) stability classification scheme, and mixing heights. The anemometer height of 6.1 meters, to be used in the modelling analysis, was obtained from NWS Local Climatological Data summaries for Jacksonville.

Emission Inventory

Emissions and stack parameters of the proposed project for the significant impact area analysis as well as subsequent analyses will be generated from the most current engineering information available at the time the modelling is performed. Emissions data will be obtained for the PSD regulated pollutants.

For those pollutants for which the project will have a significant impact, it will be necessary to consider other sources in the AAQS and PSD increment consumption analyses. The sources to be considered will be determined in accordance with guidance in EPA's Guideline on Air Quality Models and Draft New Source Review Workshop Manual. Sources located beyond the significant impact area of the proposed source will be screened based on the "Screening Threshold" method (North Carolina DNR, 1985) to determine whether they should be included in the modelling analysis. Source information will be obtained from DEP, RESD and from other recent air quality modelling studies for the area. Maximum allowable emission rates will be used in all modelling analyses involving other sources (including the existing Northside units not affected by the Project). A listing of sources in the inventory will be submitted to DEP for review and concurrence prior to the initiation of any detailed multi-source modelling effort. Existing sources will be categorized as increment consuming PSD sources, PSD increment expanding sources, or non-PSD affecting sources depending upon whether their emissions have increased or decreased from their "baseline" emissions and whether they commenced construction before or after the PSD baseline date for the area, which also will be obtained from DEP.

Stacks which have similar emission parameters will be modelled as co-located sources to simplify the analysis. Further, stacks which have similar stack gas compositions will be modelled using a unit emission rate and the results scaled to get the impacts for each separate pollutant.

Receptor Locations

Receptors will be placed at locations considered to be "ambient air," which EPA has defined as "that portion of the atmosphere, external to buildings, to which the general public has access" [40 CFR 50.1(e)]. All of the site will not be ambient air because access to it is restricted. Therefore, the closest receptors will for the most part be on the site property lines. Since the public has access to the San Carlos Creek which is included within the Northside facility boundaries, the bank of the San Carlos Creek closest to the project site will be used as the site boundary. A plot plan showing the plant boundary and areas where public access is precluded will be provided, as will a description of the measures taken to prohibit public access (e.g., fences, signs along the river). In keeping with EPA Modelling Guidance, the adjacent SJRPP site will not be considered ambient air and no receptors will be included on that site either.

The significant impact area analysis will use a polar receptor grid centered over the proposed source. The polar receptor grid will consist of 36 radials, each separated by 10 degree increments and extending out from the plant boundary line in all 36 directions. The length of the radials will depend upon the distance at which the proposed source impacts reach the significant impact levels as defined for each applicable pollutant in the PSD regulations, but will be no more than 50 km.

The screening phase for the air quality impact analysis will use a coarse mesh polar receptor grid (0.50 km distance between rings with radials spaced 10 degrees apart out to 6 km and then at 1.0 km spacing out to at least 10 km) centered over the proposed source. The receptor grid will begin coverage at the plant boundary line and extend outward in all directions. The receptor grid will provide sufficient receptor coverage to determine the locations of all critical concentration receptors to be evaluated in the refined phase of the analysis.

The refined phase of the air quality impact analysis will use a fine mesh cartesian receptor grid (0.10 km grid resolution) composed of 121 discrete receptors within a 1.0 km square grid centered over each critical receptor.

Background Concentrations

To analyze impacts relative to AAQS, estimates of background pollutant concentrations will be needed. Background concentrations should include contributions from sources not included in the modelling analyses as well as contributions from natural sources. Since it is anticipated that no on-site monitoring program will be required, background concentrations will be obtained from DEP and RESD.

The Guideline on Air Quality Models provides some guidance regarding the determination of background concentrations. The data collected as part of the DEP/RESD monitoring network will be interpreted following this guidance.

Proposed Analyses

Proposed Source Significant Impact Area Analysis - The proposed project will be modelled using the emissions data discussed above. The significant impact area will be defined on a pollutant-specific basis for all applicable averaging periods according to the Class II significant impact levels defined in the PSD Workshop Manual. Highest rather than highest second-high short-term values will be used in this analysis. The greatest significant impact area resulting from an analysis of all applicable averaging periods for a given pollutant will be the significant impact area for that pollutant. The significant impact area will be used to determine the source interaction zone for the screening phase of the air quality impact analysis.

Ambient Air Monitoring Requirements Analysis - The results of the significant impact area analysis will be compared to "de minimis" monitoring concentrations in Table 212.400-3 in Rule 62-212.400 F.A.C. to determine if ambient air monitoring is required or if a monitoring exemption will be granted. While JEA does not anticipate the need for ambient air monitoring, a monitoring plan will be prepared if the modelling results demonstrate a need.

PSD Increment Consumption Analysis (if required)

The Northside Generating Station is in a Class II PSD area. The closest Class I area is the Okefenokee Wilderness Area in Georgia (about 61 km west of the site). The next closest Class I areas are the Wolf Island Wilderness Area in Georgia (about 102 km north of the site) and the Chassahowitzka Wilderness Area in Florida (about 209 km southwest of the site). The Class II PSD increment consumption analysis will consist of modelling the PSD source inventory for those PSD pollutants projected to have a significant off-site impact using the ISC3 model and comparing the highest second-highest short-term average and highest annual average impacts to the appropriate Class II PSD increments. For the Class I PSD increment consumption analysis, the ISC3 model will be used to assess whether the net proposed project impact will be "significant," with significance defined both by the EPA in the recently proposed New Source Review Reform Regulations (61 FR 38,249, dated July 23, 1996) and by the National Park Service/Fish and Wildlife Service.

Ambient Air Quality Standards Impact Analysis (if required)

The area around the Northside Generating Station is attainment or unclassifiable for all of the criteria pollutants. The ambient air quality standards impact analysis will consist of modelling all major existing sources identified on the emissions inventory for each criteria air pollutant (SO_2, NO_2, CO, PM_{10}, and Pb) for which the proposed project will have a significant impact. The highest second-high short-term and highest annual average impacts will be combined with appropriate background concentrations for each applicable air pollutant and averaging time and compared to the appropriate state and federal ambient air quality standards to determine whether the ambient air quality standards are exceeded. The background concentrations for each applicable air pollutant will be determined using the procedures described above. No modelling of proposed project impacts on ozone (O_3) concentrations is planned as it is not considered to be feasible for single source impact analysis.

Even if the proposed Project impacts will not be significant, the impacts of the Northside Generating Station, together with SJRPP, will be modelled, combined with background concentrations and compared with AAQS for these criteria pollutants for two cases: before the proposed repowering and after the proposed repowering.

Additional Impacts Analysis (if required)

Additional impacts analysis will be performed for those criteria and non-criteria PSD regulated air pollutants emitted in significant quantities to determine air pollution impacts on soils and vegetation caused by emissions from the proposed project and emissions resulting from associated growth. Specifically, a growth projection analysis including population growth projection and industrial growth project data will be performed. The impacts of this growth on air quality will be qualitatively estimated. Modelled concentrations and/or deposition will be used to determine if there will be any significant impacts on soils or vegetation. The need for an Air Quality Related Values (AQRV) analysis for the Okefenokee, Wolf Island and Chassahowitzka Wilderness Areas will be determined after further discussions with the DEP and the Federal Land Managers. A screening (level-l) visibility impact analysis will be conducted for the nearest Class I areas using the technical guidance provided in the Workbook for Plume Visual Impact Screening and Analysis (EPA, 1988b) only if emissions of SO_2, NO_x, and/or PM_{10} increase as a result of the Project. A Background Visual Range of 65 km will be used for this analysis. Also, a regional haze analysis conducted in accordance with the Interagency Workgroup Air Quality Modelling (IWAQM) guidance (EPA, 1993) will be conducted only under these same circumstances. As indicated earlier, emissions of SO_2, NO_x and PM_{10} are expected to decrease; hence visibility assessments are not expected to be needed.

FARC Analysis

The analysis of hazardous air pollutants (HAPs) will follow the DEP guidelines. The maximum impacts from the proposed project for those HAPs regulated under the Clean Air Act Amendments and on the DEP Draft FARC list will be predicted and compared with the guidelines.

References

Auer, A.H., Jr. 1978. Correlation of Land Use and Cover with Meteorological Anomalies. Journal of Applied Meteorology. 17:636-643.

Department of Environmental Protection. 1998. Letter from Martin Costello (DEP) to Robert Kappelmann (JEA) dated February 6, 1998 regarding baseline emissions calculations. Tallahassee, FL.

Jacksonville Electric Authority (JEA). 1998. Letter from Robert Kappelmann (JEA) to Al Linero (DEP) dated January 7, 1998 regarding baseline emissions calculations. Jacksonville, FL

North Carolina Department of Natural Resources and Community Development. Screening Threshold Method for PSD Modelling. Letter of approval from Bruce P. Miller, USEPA Region IV.

Turner, D.B. 1970. Workbook of Atmospheric Dispersion Estimates. AP-26. U.S. Environmental Protection Agency. Office of Air Programs. Research Triangle Park, NC.

U.S. Environmental Protection Agency. 1985. Compilation of Air Pollutant Emission Factors. Volume I: Stationary Point and Area Sources. AP-42. Office of Air Quality Planning and Standards. Research Triangle Park, NC.

U.S. Environmental Protection Agency. 1986. Supplement A to Compilation of Air Pollutant Emission Factors. Office of Air Quality Planning and Standards. Research Triangle Park, NC.

U.S. Environmental Protection Agency. 1988a. Supplement B to Compilation of Air Pollutant Emission Factors. Office of Air Quality Planning and Standards. Research Triangle Park, NC.

U.S. Environmental Protection Agency. 1988b. Workbook for Plume Visual Impact Screening and Analysis. Office of Air Quality Planning and Standards. Research Triangle Park, NC.

U.S. Environmental Protection Agency. 1990. Draft New Source Review Workshop Manual. Office of Air Quality Planning and Standards. Research Triangle Park, NC.

U.S. Environmental Protection Agency. 1993. Interagency Workgroup on Air Quality Modelling (IWAQM) Phase I Report: Interim Recommendation for Modelling Long Range Transport and Impacts on Regional Visibility (EPA-454/R-93-015). With the National Park Service, USDA Forest Service and U.S. Fish and Wildlife Service. Triangle Park, N.C.

U.S. Environmental Protection Agency. 1995a. Users Guide for the Industrial Source Complex (ISC3) Dispersion Models. Volume I. EPA - 454/B-95-003a. Office of Air Quality Planning and Standards. Research Triangle Park, NC.

U.S. Environmental Protection Agency. 1995b. SCREEN3 Model Users Guide. EPA- 454/B-95-004. Office of Air Quality Planning and Standards. Research Triangle Park, NC.

U.S. Environmental Protection Agency. 1996. Guideline on Air Quality Models (40 CFR 51 Appendix W).

U.S. Environmental Protection Agency. 1998. Memorandum from William F. Hunt, Jr. (EPA) to EPA modellers dated March 17, 1998. Research Triangle Park, NC.

JACKSONVILLE ELECTRIC AUTHORITY

21 WEST CHURCH STREET • JACKSONVILLE, FL 32202-3139

JEA "POWER TO SERVE"

April 13, 1998

Mr. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RECEIVED

APR 15 1998

BUREAU OF
AIR REGULATION

Dear Mr. Linero:

SUBJECT: JACKSONVILLE ELECTRIC AUTHORITY
NORTHSIDE REPOWERING PROJECT
DRAFT MODELLING PROTOCOL

Attached for your review and comment is a Draft Modelling Protocol for the subject Project. We have based this Protocol on those of recent similar projects and on very preliminary discussions with Mr. Cleve Holladay of the Department. Please review the draft and provide us with any comments at your earliest opportunity.

We would like to schedule a meeting to discuss the Draft Protocol with you, Messrs. Holladay and Costello of the Department; Ms. Lori Tilley (the RESD modelling contact); and, if she has an interest, with the air quality representative of the nearest FLM (the U. S. Fish and Wildlife Service Okefenokee National Wildlife Refuge/Wilderness Area). As we are ready to start modelling this month, we request that such a meeting be scheduled within two weeks either here in Jacksonville (so that you may visit the site) or in Tallahassee (if that would be more convenient for you and the other interested parties).

Please call me at (904) 665-6249 if you have any questions on the Protocol and to schedule the meeting. Your prompt response would be appreciated.

Very truly yours,

Robert L. Kappelmann / Pja

Robert L. Kappelmann, P.E.
Manager, Environmental Affairs

Attachment

DRAFT
JEA NORTHSIDE REPOWERING PROJECT
AIR QUALITY MODELLING PROTOCOL

Introduction

The development of and agreement on a modelling protocol is suggested by U.S. Environmental Protection (EPA), the Florida Department of Environmental Protection (DEP), and the Jacksonville Regulatory & Environmental Services Department (RESD) prior to embarking on any major air quality modelling exercise. This protocol describes, in some detail, the models (and model options) which will be used, the meteorological and emissions data which will be input to the model, the receptor grids which will be utilized, and the analyses which will use the model results. This protocol has been prepared to address both those analyses which are known at this time to be required (significant impact analysis and monitoring exemption determination and FARC analysis) and those analyses which have not yet been determined to be required (AAQS, PSD increment, additional impacts). This modelling protocol is being submitted for formal DEP approval.

Proposed Project

The Northside Generating Station is approximately 10 miles north of downtown Jacksonville, Florida. The Northside Generating Station is an industrial site encompassing approximately 400 acres, with 200 acres devoted to existing steam generation units, combustion turbine units, and associated infrastructure.

The Northside Repowering Project consists of the replacement of the Unit 1 and Unit 2 boilers at the Northside Generating Station with two new circulating fluidized bed (CFB) combustors which would feed steam to the existing turbine generators. One new CFB combustor would use coal and petroleum coke to generate nearly 300 MWe by repowering the existing Unit 2 steam turbine, a 297.5-MWe unit that has been out of service since 1983. This will be done with the assistance of a DOE Clean Coal Technology Demonstration cost sharing arrangement. In addition, JEA plans to repower the currently operating Unit 1 steam turbine with a CFB combustor which will fire primarily petroleum coke. The Unit 1 steam turbine is essentially identical to the turbine for Unit 2, and is scheduled to be repowered about 6 to 12 months after the Unit 2 repowering.

In a CFB combustor, coal, petroleum coke, and coal/coke blends, air, and limestone are introduced into the lower portion of the combustor, where initial combustion occurs. As the fuel is reduced in size through combustion and breakage, it is transported higher in the combustor where additional air is introduced. Ash and unburned fuel and limestone pass out of the combustor, collect in a particle separator, and recirculate to the lower portion of the combustor. Sulfur reacts with limestone added in the furnace to form ash that can be marketed as a useful by-product such as roadbed material. Although this process has intrinsically low emissions of air pollutants, additional air quality control systems are planned including SNCR for NO_x control, a polishing scrubber for SO_2 control, and either an electrostatic precipitator or a fabric filter for control of particulate emissions.

Netting Analysis

The netting analysis for the determination of PSD applicability will be conducted in accordance with the PSD Workshop Guidance, and Rules 62-213.400(2)(d)4., F.A.C. and 62-213.400(2)(a)3, F.A.C. The applicability of PSD for each pollutant will be determined based upon whether there will be a significant increase in emissions between the actual emissions during the baseline period and future potential emissions after the modification is made. The baseline emissions have been presented in a letter from JEA to DEP dated January 7, 1998 (JEA, 1998) and have been accepted by DEP (DEP, 1998) except from particulate matter. JEA intends to use these approved baseline emissions (including revised values for particulate matter in accordance with DEP's request) together with maximum future potential emissions to determine PSD applicability and therefore the requirement for an air quality impact analysis for each PSD regulated pollutant.

General Modelling Approach

General Modelling Approach - The air quality impact assessment will consist of a proposed source significant impact area analysis, and if determined necessary, a PSD increment consumption analysis, an ambient air quality standards impact analysis, and an additional impacts analysis. In addition, the need for ambient monitoring will be evaluated. These analyses are discussed in greater detail below. Normally these analyses would be needed for only those pollutants for which PSD is triggered. However, because the construction could influence the dispersion from existing units at Northside which will not be modified and due to a commitment made by JEA to the Jacksonville community, JEA intends to determine whether the modification would cause any significant off-site impacts for all PSD-regulated pollutants with Class II significance values.

The modelling approach will follow EPA and DEP modelling guidelines for determining compliance with applicable PSD increments and ambient air quality standards (AAQS). EPA Modelling Guidance is provided in the Guideline on Air Quality Models (40 CFR 51, Appendix W) as well as the Draft New Source Review Workshop Manual (EPA, 1990). DEP guidance on conducting the analyses is provided in Rule 62-212.400 F.A.C.

Based on current EPA and DEP policies, the highest annual average and highest second-high short-term (i.e., 24 hours or less) predicted concentrations (critical concentrations) will be selected for comparison to applicable AAQS and PSD increments, except for PM_{10} which is discussed below. In accordance with Modelling Guidance, the highest short-term predicted concentrations will be used for comparison to significance levels. The use of a five-year meteorological data base in the modelling analysis, as proposed below, allows a comparison of the predicted highest second-high, short-term concentration to applicable short-term PSD increments and ambient air quality standards. The highest second-high concentration is calculated for a receptor field by:

- Eliminating the highest concentration predicted at each receptor;
- Identifying the second-high concentration predicted at each receptor; and
- Selecting the highest concentration among those second-high concentrations.

This approach is consistent with the air quality standards and PSD increments which permit one short-term average exceedance per year at each receptor.

Modelling for PM_{10} will be performed using the most recent guidance from EPA (EPA, 1998). The Guidance provides the following procedure:

> The entire 5-year period of meteorological data will be used to calculate, at each receptor, the 5-year average of the annual fourth-high 24-hour estimates and the 5-year average of the annual average estimates. The resulting values will serve as unbiased estimates for the 3-year average 99th percentile and annual concentrations, respectively, for comparison with the NAAQS. To determine whether the entire area is in compliance, the values at the highest receptors will be compared to the revised PM_{10} NAAQS.

The general modelling approach for each air quality impact analysis will commence with a significance level impact phase. The proposed Project (both emissions increases and decreases) will be modelled by itself for each of the PSD regulated pollutants with significance levels in Rule 62-210.200(256), F.A.C. If predicted impacts are below the significance levels, then modelling impacts with respect to PSD increments and AAQS is not required. JEA intends to model the impacts of the Northside Generating Station, together with SJRPP, in both before the repowering and after the repowering modes for selected criteria pollutants regardless of insignificance of the impacts.

If predicted impacts are above the significance levels, both screening and refined multi-source modelling phases will be conducted for those pollutants having a significant impact. The major difference between the two latter phases is the receptor grid used when predicting concentrations and the number of meteorological data periods evaluated. In general, concentrations for the screening phase will be predicted using a coarse mesh receptor grid and a five-year meteorological data base. The screening phase will identify the critical receptors associated with the highest and highest second-high short-term concentrations for all applicable pollutants and averaging periods. The predicted concentrations at those critical receptors will be evaluated in greater detail in the refined phase of the analysis.

The refined phase of the analysis will be performed by predicting concentrations using a fine mesh receptor grid centered over each of the critical receptors identified in the screening phase of the modelling analysis. Several critical receptors will be evaluated for each year of meteorological data containing the meteorological conditions which caused the critical concentrations identified in the screening phase analysis. This approach will be used to ensure that valid highest second-highest (critical) short-term concentrations will be obtained for comparison to applicable air quality standards and PSD increments.

Model Selection and Use

The most current version of Industrial Source Complex (ISC) dispersion model will be used to evaluate the emissions from the proposed units. As of the date of this protocol, this is ISC3 (Version 97363). The model and its use are covered in the Users Guide (EPA, 1995a). The ISC3 model was selected primarily for the following reasons:

1. EPA and DEP have approved the general use of the model for air quality dispersion analysis because the model assumptions and methods are consistent with those in the Guideline on Air Quality Models.

2. The ISC3 model is capable of predicting the impacts from stack, area, and volume sources that are spatially distributed over large areas and located in flat or gently rolling terrain.
3. The results from the ISC3 model are appropriate for addressing compliance with AAQS and PSD increments since the model can predict the highest as well as the highest second-high concentration and period of occurrence for 1-hour, 3-hour, 8-hour and 24-hour averaging periods at each receptor for each full year of hourly meteorological data used. The short-term or long-term versions of the ISC3 model can be used for annual averages.
4. The ISC3 model has several options and features that allow it to handle certain situations in a variety of ways. For this analysis, the EPA regulatory default options will be used to predict the maximum impacts from the facility.

Area Classification

The ISC3 model has rural and urban options which affect the wind speed profile exponent law, dispersion rates, and mixing-height formulations used in calculating ground-level concentrations. The criteria used to determine when the rural or urban mode is appropriate are based on land use near the proposed plant's surroundings (Auer, 1978). If the land use is classified as heavy industrial, light-moderate industrial, commercial, or compact residential for more than 50 percent of the area within a 3 km radius circle centered on the proposed source, the urban option should be selected. Otherwise, the rural option is more appropriate.

Based on the use of USGS topographic maps, it has been preliminarily concluded that the land use is consistent with the use of the rural rather than urban options. This will be confirmed in accordance with the Modelling Guidance.

GEP Stack Height/Downwash Considerations

If the stack for the proposed unit or existing units are less than Good Engineering Practice (GEP), then the potential for building downwash based upon the dimensions of nearby buildings must be considered in the modelling analysis. The procedures used for addressing the effects of building downwash are those recommended in the ISC3 Dispersion Model User's Guide and are incorporated into the ISC3 model. The effective height and effective width of structures are input to the model and are used to modify the dispersion parameters. The GEP stack height and the effective widths and heights of the structures will be determined using the EPA Building Profile Input Program (BPIP). The new unit's stacks are planned to be less than or equal to GEP height; the stacks of the existing units are believed to be less than GEP.

The possibility of on-site structures influencing off-site concentrations due to the structures creating a cavity recirculation region will be evaluated. The first level of screening will be performed to determine if a structure is within 3H of the property line (where H = structure height). Structures greater than 3H from the property line are not expected to have an off-site cavity. Structures which are within 3H of the property line will be further evaluated using the method presented in the SCREEN3 Model User's Guide (EPA, 1995b) to determine the cavity height, length and concentration. The results of these calculations will be used in subsequent analyses.

Plant Loads/Ambient Temperatures/Fuels

Operating load can affect emission parameters, and therefore ground-level impacts, because exit temperature and velocity change along with source emission rate. Three operating load cases will be analyzed using ISC3 and one year of meteorological data. These loads will be selected to cover the range of normal plant operations (probably 50%, 75% and 100%). The load case shown in the analysis to cause the highest impacts will be used in the subsequent multi-year analyses. Both coal and petroleum coke will be modelled to determine which is worst case for each pollutant. The worst-case fuel will be used in subsequent analyses.

Meteorological Data

The air quality modelling analysis will use hourly preprocessed National Weather Service (NWS) surface meteorological data from Jacksonville, Florida and concurrent twice-daily mixing heights from Waycross, Georgia for the years 1985 to 1989. The preprocessed hourly meteorological data file for each year of record used in the analysis will be obtained from DEP and will contain randomized wind direction, wind speed, ambient temperature, atmospheric stability using the Turner (1970) stability classification scheme, and mixing heights. The anemometer height of 6.1 meters, to be used in the modelling analysis, was obtained from NWS Local Climatological Data summaries for Jacksonville.

Emission Inventory

Emissions and stack parameters of the proposed project for the significant impact area analysis as well as subsequent analyses will be generated from the most current engineering information available at the time the modelling is performed. Emissions data will be obtained for the PSD regulated pollutants.

For those pollutants for which the project will have a significant impact, it will be necessary to consider other sources in the AAQS and PSD increment consumption analyses. The sources to be considered will be determined in accordance with guidance in EPA's Guideline on Air Quality Models and Draft New Source Review Workshop Manual. Sources located beyond the significant impact area of the proposed source will be screened based on the "Screening Threshold" method (North Carolina DNR, 1985) to determine whether they should be included in the modelling analysis. Source information will be obtained from DEP, RESD and from other recent air quality modelling studies for the area. Maximum allowable emission rates will be used in all modelling analyses involving other sources (including the existing Northside units not affected by the Project). A listing of sources in the inventory will be submitted to DEP for review and concurrence prior to the initiation of any detailed multi-source modelling effort. Existing sources will be categorized as increment consuming PSD sources, PSD increment expanding sources, or non-PSD affecting sources depending upon whether their emissions have increased or decreased from their "baseline" emissions and whether they commenced construction before or after the PSD baseline date for the area, which also will be obtained from DEP.

Stacks which have similar emission parameters will be modelled as co-located sources to simplify the analysis. Further, stacks which have similar stack gas compositions will be modelled using a unit emission rate and the results scaled to get the impacts for each separate pollutant.

Receptor Locations

Receptors will be placed at locations considered to be "ambient air," which EPA has defined as "that portion of the atmosphere, external to buildings, to which the general public has access" [40 CFR 50.1(e)]. All of the site will not be ambient air because access to it is restricted. Therefore, the closest receptors will be on the site property lines. A plot plan showing the plant boundary and areas where public access is precluded will be provided, as will a description of the measures taken to prohibit public access (e.g., fences, signs along the river). In keeping with EPA Modelling Guidance, the adjacent SJRPP site will not be considered ambient air and no receptors will be included on that site either.

The significant impact area analysis will use a polar receptor grid centered over the proposed source. The polar receptor grid will consist of 36 radials, each separated by 10 degree increments and extending out from the plant boundary line in all 36 directions. The length of the radials will depend upon the distance at which the proposed source impacts reach the significant impact levels as defined for each applicable pollutant in the PSD regulations, but will be no more than 50 km.

The screening phase for the air quality impact analysis will use a coarse mesh polar receptor grid (0.50 km distance between rings with radials spaced 10 degrees apart out to 6 km and then at 1.0 km spacing out to at least 10 km) centered over the proposed source. The receptor grid will begin coverage at the plant boundary line and extend outward in all directions. The receptor grid will provide sufficient receptor coverage to determine the locations of all critical concentration receptors to be evaluated in the refined phase of the analysis.

The refined phase of the air quality impact analysis will use a fine mesh cartesian receptor grid (0.10 km grid resolution) composed of 121 discrete receptors within a 1.0 km square grid centered over each critical receptor.

Background Concentrations

To analyze impacts relative to AAQS, estimates of background pollutant concentrations will be needed. Background concentrations should include contributions from sources not included in the modelling analyses as well as contributions from natural sources. Since it is anticipated that no on-site monitoring program will be required, background concentrations will be obtained from DEP and RESD.

The Guideline on Air Quality Models provides some guidance regarding the determination of background concentrations. The data collected as part of the DEP/RESD monitoring network will be interpreted following this guidance.

Proposed Analyses

Proposed Source Significant Impact Area Analysis - The proposed project will be modelled using the emissions data discussed above. The significant impact area will be defined on a pollutant-specific basis for all applicable averaging periods according to the Class II significant impact levels defined in the PSD Workshop Manual. Highest rather than highest second-high short-term values will be used in this analysis. The greatest significant impact area resulting from an analysis of all applicable averaging periods for a given pollutant will be the significant impact area for that pollutant. The significant impact area will be used to determine the source interaction zone for the screening phase of the air quality impact analysis.

Ambient Air Monitoring Requirements Analysis - The results of the significant impact area analysis will be compared to "de minimis" monitoring concentrations in Table 212.400-3 in Rule 62-212.400 F.A.C. to determine if ambient air monitoring is required or if a monitoring exemption will be granted. While JEA does not anticipate the need for ambient air monitoring, a monitoring plan will be prepared if the modelling results demonstrate a need.

PSD Increment Consumption Analysis (if required)

The Northside Generating Station is in a Class II PSD area. The closest Class I area is the Okefenokee Wilderness Area in Georgia (about 61 km west of the site). The next closest Class I areas are the Wolf Island Wilderness Area in Georgia (about 102 km north of the site) and the Chassahowitzka Wilderness Area in Florida (about 209 km southwest of the site). The Class II PSD increment consumption analysis will consist of modelling the PSD source inventory for those PSD pollutants projected to have a significant off-site impact using the ISC3 model and comparing the highest second-highest short-term average and highest annual average impacts to the appropriate Class II PSD increments. For the Class I PSD increment consumption analysis, the ISC3 model will be used to assess whether the net proposed project impact will be "significant," with significance defined both by the EPA in the recently proposed New Source Review Reform Regulations (61 FR 38,249, dated July 23, 1996) and by the National Park Service/Fish and Wildlife Service.

Ambient Air Quality Standards Impact Analysis (if required)

The area around the Northside Generating Station is attainment or unclassifiable for all of the criteria pollutants. The ambient air quality standards impact analysis will consist of modelling all major existing sources identified on the emissions inventory for each criteria air pollutant (SO_2, NO_2, CO, PM_{10}, and Pb) for which the proposed project will have a significant impact. The highest second-high short-term and highest annual average impacts will be combined with appropriate background concentrations for each applicable air pollutant and averaging time and compared to the appropriate state and federal ambient air quality standards to determine whether the ambient air quality standards are exceeded. The background concentrations for each applicable air pollutant will be determined using the procedures described above. No modelling of proposed project impacts on ozone (O_3) concentrations is planned as it is not considered to be feasible for single source impact analysis.

Even if the proposed Project impacts will not be significant, the impacts of the Northside Generating Station, together with SJRPP, will be modelled, combined with background concentrations and compared with AAQS for these criteria pollutants for two cases: before the proposed repowering and after the proposed repowering.

Additional Impacts Analysis (if required)

Additional impacts analysis will be performed for those criteria and non-criteria PSD regulated air pollutants emitted in significant quantities to determine air pollution impacts on soils and vegetation caused by emissions from the proposed project and emissions resulting from associated growth. Specifically, a growth projection analysis including population growth projection and industrial growth project data will be performed. The impacts of this growth on air quality will be qualitatively estimated. Modelled concentrations and/or deposition will be used to determine if there will be any significant impacts on soils or vegetation. The need for an Air Quality Related Values (AQRV) analysis for the Okefenokee, Wolf Island and Chassahowitzka Wilderness Areas will be determined after further discussions with the DEP and the Federal Land Managers. A screening (level-I) visibility impact analysis will be conducted for the nearest Class I areas using the technical guidance provided in the Workbook for Plume Visual Impact Screening and Analysis (EPA, 1988b) only if emissions of SO_2, NO_x, and/or PM_{10} increase as a result of the Project. A Background Visual Range of 65 km will be used for this analysis.

FARC Analysis

The analysis of hazardous air pollutants (HAPs) will follow the DEP guidelines. The maximum impacts from the proposed project for those HAPs regulated under the Clean Air Act Amendments and on the DEP Draft FARC list will be predicted and compared with the guidelines.

References

Auer, A.H., Jr. 1978. Correlation of Land Use and Cover with Meteorological Anomalies. Journal of Applied Meteorology. 17:636-643.

Department of Environmental Protection. 1998. Letter from Martin Costello (DEP) to Robert Kappelmann (JEA) dated February 6, 1998 regarding baseline emissions calculations. Tallahassee, FL.

Jacksonville Electric Authority (JEA). 1998. Letter from Robert Kappelmann (JEA) to Al Linero (DEP) dated January 7, 1998 regarding baseline emissions calculations. Jacksonville, FL

North Carolina Department of Natural Resources and Community Development. Screening Threshold Method for PSD Modelling. Letter of approval from Bruce P. Miller, USEPA Region IV.

Turner, D.B. 1970. Workbook of Atmospheric Dispersion Estimates. AP-26. U.S. Environmental Protection Agency. Office of Air Programs. Research Triangle Park, NC.

U.S. Environmental Protection Agency. 1985. Compilation of Air Pollutant Emission Factors. Volume I: Stationary Point and Area Sources. AP-42. Office of Air Quality Planning and Standards. Research Triangle Park, NC.

U.S. Environmental Protection Agency. 1986. Supplement A to Compilation of Air Pollutant Emission Factors. Office of Air Quality Planning and Standards. Research Triangle Park, NC.

U.S. Environmental Protection Agency. 1988a. Supplement B to Compilation of Air Pollutant Emission Factors. Office of Air Quality Planning and Standards. Research Triangle Park, NC.

U.S. Environmental Protection Agency. 1988b. Workbook for Plume Visual Impact Screening and Analysis. Office of Air Quality Planning and Standards. Research Triangle Park, NC.

U.S. Environmental Protection Agency. 1990. Draft New Source Review Workshop Manual. Office of Air Quality Planning and Standards. Research Triangle Park, NC.

U.S. Environmental Protection Agency. 1995a. Users Guide for the Industrial Source Complex (ISC3) Dispersion Models. Volume I. EPA - 454/B-95-003a. Office of Air Quality Planning and Standards. Research Triangle Park, NC.

U.S. Environmental Protection Agency. 1995b. SCREEN3 Model Users Guide. EPA- 454/B-95-004. Office of Air Quality Planning and Standards. Research Triangle Park, NC.

U.S. Environmental Protection Agency. 1996. Guideline on Air Quality Models (40 CFR 51 Appendix W).

U.S. Environmental Protection Agency. 1998. Memorandum from William F. Hunt, Jr. (EPA) to EPA modellers dated March 17, 1998. Research Triangle Park, NC.

REGULATORY & ENVIRONMENTAL SERVICES DEPARTMENT

Air and Water Quality Division

CITY OF JACKSONVILLE, FLORIDA

February 23, 1998

RECEIVED

FEB 26 1998

BUREAU OF
AIR REGULATION

MEMORANDUM

TO: Bob Kappleman, P.E.
Manager, Environmental Affairs

FROM: Steve Pace, P.E.
Manager, Air Quality Branch SP

RE: **NS CFBs**
January 7, 1998 letter

A review of the subject letter has raised some initial questions. Please clarify JEA's position on the following items, thank you;

A. Regarding NS #1, JEA has projected the SO2 emissions as 4,328.3 TPY for 1995. JEA has previously submitted as part of their Annual Operating Reports (AOR) that the SO2 emissions from NS #1 were 3558.57 TPY. Please advise as to why there is a difference in the numbers of January 7, 1998, and the 1995 AOR.

B. A similar situation exists for NS #1 SO2 emissions for the year 1994. However, for 1994 the SO2 emissions for the AOR are approximately 400 TPY greater than the emissions projected in the 1998 letter, why the difference?

C. Please confirm that it is still JEA intent to obtain a 10% overall reduction in SO2, NOX, PM, and groundwater based upon the "actual" emission of units #1 and #3. It is still this agency's understanding that unit #2 will not be used in the calculation. Please advise.

D. Since the State has decided to use 1993 stack test data for extablishing the 1994 baseline for particulates, please advise as to the difference this action generates from your earlier submittal.

As always your attention to this request is appreciated.

c: Christi P. Veleta
Richard L. Robinson, P.E.
A. Linero, P.E., FDEP - Tallahassee

cc: Marty Costello, BAR

117 West Duval Street, Suite 225
Jacksonville, Florida 32202
Fax (904) 630-3638

Air Quality	630-3484
Water Quality	630-3461
Ground Water	630-4900
Hazardous Materials	630-3404

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

February 6, 1998

Robert Kapplemann, P.E.
Manager, Environmental Affairs
Jacksonville Electric Authority
21 West Church Street
Jacksonville, FL 32202-3139

Dear Mr. Kapplemann:

The Department has reviewed your letter dated January 7 regarding PSD applicability to the Northside Repowering Project. A letter from the Department of Energy is expected in the near future which describes the repowering of Unit 2 as a Clean Coal Technology Demonstration Project. Based on this information, the Department concludes that Unit 2 qualifies for the exemption contained in Rule 62-212.400(2)(a)3, F.A.C. provided that emissions from repowered Unit 2 do not result in an increase in the potential to emit of any regulated air pollutant.

The letter also describes the method for determining baseline emissions from Unit 1 for the period of 1994 through 1995. The Department concludes that this baseline period is acceptable. The baseline emissions estimates based on continuous monitoring data, stack test data, and AP-42 emission factors is acceptable with one exception. Baseline emissions for particulate matter shall be based on the stack test data for the baseline period since these emission rates are specific to Unit 1. Note that December 1993 test data shall be used for the 1994 baseline year since this test apparently satisfied the test requirement in 62-297.310(7)4, F.A.C. which requires a stack test during each federal fiscal year.

If you have further questions, please contact me at (850) 921-8986 or by using the following e-mail address: costello_m@dep.state.fl.us.

Sincerely,

Martin Costello

Martin Costello, P.E.
Bureau of Air Regulation

CC: Gregg Worley, EPA
Steve Pace, RESD

Is your RETURN ADDRESS completed on the reverse side?

- ... on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "*Return Receipt Requested*" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

... extra ...

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Robert Kapplemann P.E.
Manager, Env. Affairs
Jacksonville Electric A.
21 W Church St.
Jacksonville, Fl
32202-3139

4a. Article Number
P 265 659 290

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
2-12-98

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X

PS Form **3811**, December 1994

Domestic Return Receipt

Thank you for using Return Receipt Service.

P 265 659 290

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to	Robert Kapplemann
Street & Number	JEA
Post Office, State, & ZIP Code	JAX, Fl
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	2-9-98

Form 3800, April 1995

JACKSONVILLE ELECTRIC AUTHORITY

21 WEST CHURCH STREET • JACKSONVILLE, FL 32202-3139

JEA POWER TO SERVE

January 7, 1998

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399 -2400

RECEIVED

JAN 08 1998

BUREAU OF
AIR REGULATION

Dear Mr. Linero

SUBJECT: JACKSONVILLE ELECTRIC AUTHORITY
NORTHSIDE REPOWERING PROJECT
BASELINE EMISSIONS CALCULATIONS

This letter is provided as a follow-up to a meeting which took place in your offices on October 22, 1997, between Messrs. Syed Arif, Martin Costello, and Cleve Holladay of the Department, Mr. Doug Fulle of Foster Wheeler Environmental, and Mr. Bert Gianazza of Jacksonville Electric Authority (JEA). The proposed Repowering Project at the Northside Generating Station was discussed at that meeting with respect to the potential applicability of the PSD permitting requirements at Section 62-212.400, F.A.C. As you recall, the Northside Repowering Project would consist of the modification of existing Units 1 and 2 at Northside to incorporate new circulating fluidized bed boilers with associated air quality control systems and other ancillary equipment. The modified units would fire petroleum coke and/or coal whereas the existing Unit 1 fires No. 6 fuel oil and natural gas (the Unit 2 boiler, which has also fired fuel oil and natural gas, has not operated recently). As a modification of a "major existing source," PSD applicability would generally be triggered if the net change in emissions would exceed the PSD significant emission rates in Table 62-212.400-2 of Ch. 62-212, F.A.C.

Background

At the time of our meeting, our plan was to compare the current actual emissions from existing Unit 1 with the future potential emissions from modified Units 1 and 2 and then compare the net changes with the significant emission rates. However, subsequent to our meeting, we have determined that the Unit 2 modification qualifies for the "Permanent Clean Coal Technology Demonstration Project Exemption" under Section 62-212.400(2)(a)3, F.A.C., as further explained below. As a result, the Unit 2 modification will be subject to PSD review for only those pollutants whose potential emissions will increase above the potential emissions from the existing Unit 2 as a result of the modification. Therefore, for PSD netting purposes, JEA proposes to compare the current actual emissions from existing Unit 1 with the future potential emissions from modified Unit 1 and to compare the current potential emissions from existing

Unit 2 with the future potential emissions from modified Unit 2. The net changes would be compared with the significant emission rates, and PSD applicability will be determined for each pollutant separately for each unit. Although JEA has made commitments to the community regarding stack emission reductions for SO_2, NO_x, and PM for the Northside Generating Station as a whole, we understand that the PSD netting analysis will not include any changes in emissions from existing Unit 3 or the existing combustion turbines and will thus be confined to Units 1 and 2.

As indicated above, JEA believes that the Unit 2 modification qualifies for the "Permanent Clean Coal Technology Demonstration" under FDEP's rules (Section 62-212.400(2)(a)3, F.A.C.). The project meets the definition of a "Clean Coal Technology Demonstration Project" under 40 CFR 52.21(b)(35) (the cross reference under FDEP's rules) because it: (1) uses funds appropriated under the heading "Department of Energy - Clean Coal Technology" (up to $2.5 billion), (2) is a commercial demonstration of clean coal technology, (3) has federal (DOE) funding for at least 20 percent of the total cost, and (4) constitutes "Repowering" under paragraph (ii) of 40 CFR 52.21(b)(37). The project qualifies under the fourth point because the demonstration funding was awarded by DOE on November 30, 1990(prior to the January 1, 1991 deadline) as the project was originally planned for the Arvah B. Hopkins Station Unit 2 site, and subsequently moved to the Northside Unit 2 location. Attachment A is a copy of DOE's Notice of Intent to prepare an EIS on the project; it provides some background on the project and its funding.

Although a BACT analysis and air quality impact modelling would normally be conducted for only PSD-regulated pollutants indicated by the netting analysis, please be advised that JEA's community commitment has been to conduct a BACT analysis and utilize the indicated air quality control systems or methods for SO_2, NO_x, PM_{10}, CO, and VOCs. In addition, we are committed to conduct air quality dispersion modelling of the air quality impacts of the modification by itself for SO_2, NO_x, PM_{10}, and CO regardless of whether PSD is triggered by emission increases. Therefore, our intent in conducting the PSD netting analysis is to clearly determine PSD applicability from a regulatory standpoint rather than to avoid the BACT and air quality modelling requirements.

The purpose of this letter is to explain the approach which we have taken in determining the baseline emissions for Unit 1 and for Unit 2 in preparation for going forward with the netting analysis and to seek your concurrence with the baseline emissions which we propose to use. Included are some revisions to the calculated values provided to FDEP during the meeting of October 22 for Unit 1, which take into account suggestions from FDEP staff, and the support data which were requested in that meeting.

PSD Netting Considerations

As we understand it, there are two important considerations in determining the baseline emissions for PSD netting purposes - the baseline period and the emission factors. As indicated in Section 62-2 10.200(12) F.A.C., the baseline period for Unit 1 consists of a two year period prior to the particular date that is considered to be *representative of normal operation*. However, since the actual modification will not take place for several years, practicality dictates that we use a two-year "representative" period prior to the netting analysis. In addition, in the preamble to the WEPCO rulemaking (57 FR 32314 (July 21, 1992) and 56 FR 27630 (June 24, 1991) (excerpts included as Attachment B)), EPA explained that while it had been its historical practice to use the two-year period immediately preceding the proposed change to establish the baseline, it was not required under the regulations to use this particular period and will presume that *for utilities* <u>any</u> two consecutive years with the five year period prior to the proposed change is representative of normal source operations. EPA explained that because of the fluctuation in operations experienced by utilities in responding to electricity demands that vary due to climatic and economic conditions as well as changes within a particular utility's system affecting the dispatch of a unit, the use of any consecutive two-year period within the last five allows the recent actual emissions to be more realistic and more closely representative of "normal source operation." The preamble also gives source owners the ability to seek approval to use other than a two year period, including a baseline period prior to the last five years, if it is "more representative of normal operations." Based on this information, JEA believes that there is some appropriate flexibility in the determination of the baseline period for Unit 1, and, as more fully explained below, that the years 1994-1995 are the most representative of normal operation. For Unit 2 the baseline period is not considered since the baseline emissions will be based on potential rather than actual emissions.

With respect to emission factors, it is understood that the FDEP preference for emission factors is to use CEMS data when available as a first choice, followed by stack test data when available and representative as a second choice, followed by published emission factors (e.g., AP-42) as a third choice. The remainder of this letter contains discussion of the proposed baseline years for Unit 1 netting purposes as well as the proposed emission factors and resulting actual emissions values for each of the regulated criteria pollutants for Unit 1 and the potential emissions for Unit 2.

Baseline Period

With respect to the baseline period for Unit 1, Attachment C contains complete generation statistics for the Northside Generating Station for calendar years 1992 through 1996. These data were previously provided to FDEP at the October 22 meeting. In addition, partial, preliminary data for 1997 through September are included in response to FDEP's request.

As discussed in the October 22 meeting, 1996 was not a representative year for Unit 1. A major outage occurred between February 6, 1996 and June 12, 1996 and the generation data in Attachment C reflects that fact. As indicated, the gross MWH were only 367,721 in 1996, compared to the 1992-1995 average of 902, 979 MWH. Calendar year 1997 is not yet complete and only partial data through September are available. However, climatological temperature (heating and cooling degree day) data indicate that, through September at least, 1997 is not a representative year either. As indicated in Attachment D, January through September 1997 data are 8.5% below the National Oceanic and Atmospheric Administration (NOAA) 30-year average. As a result, neither of the last two consecutive calendar years are considered representative years. Therefore, JEA proposed to use the next most recent consecutive two years for the netting analysis - 1994 and 1995.

During the October 22 meeting, FDEP suggested that alternate periods, including the most recent year should be considered. JEA believes that the most recent two years are inappropriate for the reasons discussed above, and further believes that 1994 and 1995 are appropriate and representative of normal operations. However, JEA suggests that, if the preferred period is not accepted, an average of a longer period (e.g., 1991-1995 or 1992-1995) would be appropriate. JEA requests that these longer periods be considered as alternatives. However, JEA proposes that 1994-1995 is the most appropriate period, and all of the calculated baseline emissions in this letter and attachments are based on this period.

Baseline Emissions

The remainder of this letter presents proposed baseline emissions for all of the PSD-regulated pollutants for which emissions are expected. These include NO_x, SO_2, PM (TSP and PM_{10}), CO, VOCs, lead, sulfuric acid mist, fluorides, and mercury. It is understood that beryllium, asbestos, and vinyl chloride are in the process of being removed from the list of PSD-regulated pollutants. Emissions of total reduced sulfur, reduced sulfur compounds, and municipal waste related emissions are not expected from gas/oil fired or coal/petroleum coke fired power plants and no emission factors are available; thus, baseline and future potential emissions are proposed as zero for these PSD-regulated pollutants.

Unit 1

For NO_x, emissions data based on CEMS are available beginning January 1, 1995 (we had erroneously indicated January 1, 1996 in the October 22 meeting). Thus, for calendar year 1995, NO_x emissions based on the CEMS data are proposed even though it is believed that these data underestimate actual NO_x emissions (see Attachment E). However, as discussed in the October 22 meeting, the NO_x emission rates vary as a function of plant load and it is therefore appropriate to use a weighted average (see Attachment F) which accounts for the variation of NO_x emission rates with loads. This weighted average consists of the hourly NO_x emission rates multiplied by the corresponding hourly heat inputs and then totaled to produce the annual values (in tons per year), an approach recognized by EPA as appropriate for acid rain purposes. For 1994, CEMS data are not available nor are stack test data for that year. However, it is proposed that the weighted average CEMS emission rate (in lbs/mmBtu) for calendar year 1996 be used as a conservative approximation of the rate which existed in 1994 since the ratio of oil/gas usage in 1996 was closer to that used in 1994 than the rate in 1995, and the low load factor for 1997 (partial) resulted in an unusually low NO_x rate for that year. The resulting NO_x emission estimate is believed to underestimate the true emission rate and therefore total emissions for the period since a NO_x reduction program begun in 1995 is affecting our estimated 1996 emission rate and therefore the total calculated emissions for 1994 when no such program existed. Further, the only stack test data available for NO_x (Attachment G) reflect a higher rate on oil, and reflect steady state operation rather than the actual constantly varying load operation, lending further support to the argument that typical actual NO_x emission rates in 1994 (and prior years) were higher. Nevertheless, JEA proposes to use 1,801.9 tons in 1994 and 1,081.7 tons in 1995 for an average of 1,441.8 tpy for the PSD netting analysis.

For SO_2, CEMS data are available for 1995 but not for 1994. In response to FDEP's preference, JEA proposes to use the CEMS data for 1995 to estimate the actual SO_2 emissions in that year. For 1994, JEA proposes to use the mass balance approach contained within AP-42 and the measured fuel flow (converted to mmBtu/hr) to calculate baseline emissions for this pollutant. The SO_2 emissions calculated on this basis are 7,510.3 tpy in 1994 and 4,328.3 tpy in 1995 for a two year average of 5,919.3 tpy. These data are included in Attachment E for 1995 and Attachment H for 1994.

For PM (TSP and PM_{10}), no CEMS data are available. Some stack test data are available and these are summarized in Attachment G. JEA considers the stack test data for TSP to be inappropriate to be considered alone for estimating annual emissions of this pollutant since the stack tests are conducted only during periods of steady-state operation. Particulate emissions are higher during load changes, soot blowing, startup, and shutdown than during steady-state operation, which is important in determining emissions from Unit 1. As indicated in our meeting, Unit 1's load varies constantly (it is operated as a load-following unit) and, as such, it does not operate in steady-state mode for very long. Further, the unit is subject to numerous startups and shut downs, also resulting in higher TSP emissions. There were 35 startups in 1994 and 37 in 1995. Further, soot blowing occurred on a daily basis when firing fuel oil. For these reasons, JEA proposes that the AP-42 emission factors (which have "A" ratings) be used for TSP and PM_{10}. While the stack tests are consistent with the AP-42 emission factors, the AP-42 emission factors cover the full range of operations and better predict annual emissions. The results of the analysis are presented in Attachment H, a revised version of material presented in our meeting, and reflect averages of 389.9 tpy for TSP for 1994/1995 and 278.5 tpy for PM_{10} for Unit 1.

For CO and VOCs, no CEMS data are available. Similarly, no stack test data are available. As a result, the AP-42 emission factors are the best available information for these pollutants. Data for both pollutants were presented in the October 22 handout, a revised version included here as Attachment H. As indicated, baseline emissions of 153.1 tpy for CO and 17.9 tpy for VOCs are proposed by JEA for Unit 1.

For the other PSD-regulated pollutants with baseline emissions, lead, sulfuric acid mist, fluorides, and mercury, no CEMS data nor stack test data are available. No data for these pollutants were provided in the October 22 meeting. Since that time, calculations of baseline emissions have been made using the 1994 and 1995 fuel consumption and the emission factors in AP-42. These calculations are summarized on Attachment I. As indicated, JEA proposes baseline emission as follows: lead - 0.03265 tpy, sulfuric acid mist - 195.525 tpy, fluorides - 0.79877 tpy, and mercury - 0.0024 tpy for Unit 1.

Unit 2

The baseline emissions estimation for Unit 2 is much simpler than for Unit 1 since the baseline emissions are potential emissions rather than actual emissions. Potential emissions, as defined in Section 62-210.200(225) F.A.C., reflect the maximum capacity under a unit's physical or operational design. In this case, the potential emissions are the permitted emissions or those reflecting full load continuous operation for the entire year. Calculations of potential emissions have been made based on permit limits or AP-42 emission rates, as neither CEMS nor reliable stack test data are available to determine the worst-case (maximum) emissions. These calculations are contained in Attachment J. As indicated, JEA proposed baseline emissions for Unit 2 are as follows: NO_x - 6407 tpy; SO_2 - 20,397 tpy; TSP - 1287 tpy; PM_{10} - 1114 tpy; CO - 466 tpy; VOCs - 60.38 tpy; lead - 0.119974 tpy; sulfuric acid mist - 815 tpy; fluorides - 2.9636 tpy; and mercury - 0.08978 tpy.

Conclusion

JEA requests FDEP concurrence with the baseline emissions and netting approach proposed in this letter, including the applicability of the Clean Coal Technology Demonstration Project exemption. As the establishment of baseline emissions is a necessary first step in the PSD netting analysis, a written decision by FDEP is requested by January 23, 1998. We will call you shortly to set up a meeting with you and your staff to answer any questions you may have on our analysis and the proposed Repowering Project in general. Should you have any immediate questions, please call me at (904) 632-6249.

Very truly yours,

Robert L. Kappelmann, P.E.
Manager, Environmental Affairs

Attachments

cc: C. Fancy (FDEP)
S. Arif (FDEP)
M. Costello (FDEP)
C. Holladay (FDEP)

Attachment A

Rules of Practice and Procedure on October 22, 1997.

H. Public Dialogue.

Dated: November 3, 1997.

Susan M. Weisman,

Secretary.

[FR Doc. 97-29888 Filed 11-12-97; 8:45 am]

BILLING CODE 6386-01-P

DEPARTMENT OF ENERGY

Notice of Intent To Prepare an Environmental Impact Statement and Notice of Floodplain and Wetlands Involvement for the Proposed Jacksonville Electric Authority Circulating Fluidized Bed Combustor Project

AGENCY: Department of Energy.

ACTION: Notice of intent to prepare an Environmental Impact Statement (EIS), and notice of floodplain and wetlands involvement.

SUMMARY: The Department of Energy (DOE) announces its intent to prepare an Environmental Impact Statement (EIS) pursuant to the National Environmental Policy Act (NEPA) of 1969, as amended (42 U.S.C. 4321 *et seq.*), the Council on Environmental Quality NEPA regulations (40 CFR Parts 1500-1508), and the DOE NEPA regulations (10 CFR Part 1021), to assess the potential environmental and human health impacts of the construction and operation of a project proposed by the Jacksonville Electric Authority (JEA) that has been selected by DOE to demonstrate circulating fluidized bed (CFB) technology under the Clean Coal Technology (CCT) Program. The proposed project would involve construction and operation of a CFB combustor fueled by coal and petroleum coke to repower an existing steam turbine at JEA's Northside Generating Station in Jacksonville, Florida, to generate nearly 300 megawatts of electricity (MWe). This EIS will support a DOE decision regarding whether DOE will provide approximately $75 million in cost-shared funding (about 24% of the total cost of approximately $309 million) for the proposed project.

The purpose of this Notice of Intent is to inform the public about the proposed action; present the schedule for the action; announce the plans for a public scoping meeting; invite public participation in the scoping process; and solicit public comments for consideration in establishing the scope and content of the EIS. The EIS will evaluate the potential impacts of the proposed action and reasonable alternatives. Because the proposed project may involve an action in floodplains and wetlands, the EIS will include a floodplain and wetlands assessment and a statement of findings in accordance with DOE regulations for compliance with floodplain and wetlands environmental review requirements (10 CFR Part 1022).

DATES: To ensure that the full range of issues related to this proposal is addressed, DOE invites comments on the scope and content of the EIS from all interested parties. All comments must be received by December 31, 1997, to ensure consideration. Late comments will be considered to the extent practicable. In addition to receiving comments in writing and by telephone, DOE will conduct a public scoping meeting in which agencies, organizations, and the general public are invited to present oral comments or suggestions with regard to the range of actions, alternatives, and impacts to be considered in the EIS. The scoping meeting will be held at the Northside Generating Station, In-Plant Conference Room, 4377 Heckscher Drive, Jacksonville, Florida, on Wednesday, December 3, 1997, at 7 p.m.

ADDRESSES: Written comments and requests to participate in the public scoping process should be addressed to: Dr. Jan Wachter, NEPA Document Manager for the JEA Project, Federal Energy Technology Center, U.S. Department of Energy, 3610 Collins Ferry Road, Morgantown, WV 26507-0880. Individuals who would like to verbally or electronically provide comments should contact Dr. Wachter at direct telephone 304-285-4607; toll free number 1-800-432-8330 (ext. 4607); fax 304-285-4469; or E-mail JWACHT@FETC.DOE.GOV.

FOR FURTHER INFORMATION CONTACT: To obtain additional information about this project or to receive a copy of the draft EIS when it is issued, contact Dr. Jan Wachter at the address provided above. For general information on the DOE NEPA process, contact Ms. Carol M. Borgstrom, Director, Office of NEPA Policy and Assistance (EH-42), U.S. Department of Energy, 1000 Independence Avenue, S.W., Washington, D.C. 20585-0119; telephone 202-586-4600; or leave a message at 1-800-472-2756.

SUPPLEMENTARY INFORMATION:

Background and Need for the Proposed Action

Under Public Law 99-190, Congress provided authorization and funds to DOE to support the construction and operation of demonstration facilities selected for cost-shared financial assistance as part of DOE's CCT Program. In December 1985, Congress made funds available to DOE for conducting the first round of the CCT Program. Congress directed that this first solicitation for federal cost-sharing (1) be open to all market applications of clean coal technologies, (2) apply to any segment of the U.S. coal resource base, and (3) encompass both new and retrofit applications. In response to the solicitation, proposals were received and projects were selected by DOE for negotiation. In addition, a list of alternate candidates was established from which replacement selection could be made should any of the original selections not proceed. JEA's proposed CFB combustor project has evolved through a series of site changes from a project that was selected from the alternate list for demonstration.

The demonstration of JEA's CFB combustor project under the CCT Program would fulfill an existing DOE programmatic need. Coal has the potential to address critical energy supply issues because of its abundant reserves; however, barriers to increased use of coal include concerns about environmental issues, such as acid deposition, global climate change, polyaromatic hydrocarbon emissions, and solid waste. Since the early 1970's, DOE and its predecessor agencies have sponsored long-term programs to develop innovative coal technologies through the proof-of-concept stage to overcome these environmental barriers while improving combustion efficiency and reducing costs.

However, the availability of a technology at the proof-of-concept stage is not sufficient to ensure its continued development and subsequent commercialization. Before any technology can seriously be considered for commercialization, it must be demonstrated at a large enough scale to prove its reliability and to show economically competitive performance. The financial risk associated with such large-scale demonstration is, in general, too high for the private sector to assume in the absence of strong incentives. The congressionally-directed CCT Program provides a mechanism to accelerate the commercialization of innovative technologies to meet the nation's near-term energy and environmental goals, to reduce technological risk to industry to an acceptable level, and to provide private sector incentives required for continued research and development aimed at finding solutions to long-range energy supply problems.

Proposed Action

The proposed action is for DOE to provide, through a cooperative agreement with JEA, cost-shared financial assistance to JEA for the design, construction, and operation of the proposed project, as described below. JEA plans to form an alliance with Foster Wheeler Corporation through its subsidiary, Foster Wheeler Power Systems, Inc., to jointly own and operate the project. Together with other Foster Wheeler affiliates, Foster Wheeler Power Systems, Inc. will provide the CFB combustor and perform the project engineering, procurement, and construction. The demonstration project would last 24 months and cost approximately $309 million, with DOE's share being nearly $75 million (24%). The proposed project would be located at JEA's existing Northside Generating Station in Jacksonville, Florida, which currently consists of 3 heavy oil- and natural gas-fired steam generation units and 4 diesel oil-fired combustion turbine units.

The Northside Generating Station is approximately 10 miles north of downtown Jacksonville, Florida. The Northside Generating Station is an industrial site encompassing approximately 400 acres, with 200 acres devoted to existing steam generation units, combustion turbine units, and associated infrastructure. New construction associated with JEA's proposed CFB combustor project would occupy approximately 60 acres of previously disturbed land. The Northside Generating Station contains a number of wetland areas, especially in the perimeter areas. Preliminary analysis indicates that the site may be in a hurricane storm surge area, in addition to the 100-year floodplain of the St. Johns River. The most significant environmental feature associated with the Northside Generating Station is the nearby presence of estuarine salt marsh backwaters of the St. Johns River. St. Johns River Power Park, an industrial site which consists of two 624 MWe coal- and petroleum coke-burning power plants on 1,656 acres, is adjacent to the Northside Generating Station.

The overall objective of the project is to demonstrate the feasibility of CFB technology at a size that will be attractive for large-scale utility operation. The new CFB combustor would use coal and petroleum coke to generate nearly 300 MWe by repowering the existing Unit 2 steam turbine, a 297.5-MWe unit that has been out of service since 1983. The project is expected to provide JEA with a low-cost, efficient, and environmentally-sound generating resource. In addition, JEA plans to repower the currently operating Unit 1 steam turbine without cost-shared funding from DOE. The Unit 1 steam turbine will be essentially identical to the turbine for Unit 2, and is scheduled to be repowered about 6 to 12 months after the Unit 2 repowering. While the proposed project only consists of the Unit 2 repowering (because DOE would provide no funding for the Unit 1 repowering), the EIS will evaluate the Unit 1 repowering as a related action.

In a CFB combustor, coal and coal/fuel blends, air, and limestone are introduced into the lower portion of the combustor, where initial combustion occurs. As the fuel is reduced in size through combustion and breakage, it is transported higher in the combustor where additional air is introduced. Ash and unburned fuel and limestone pass out of the combustor, collect in a particle separator, and recirculate to the lower portion of the combustor. Sulfur reacts with limestone added in the furnace to form ash that can be marketed as a useful byproduct such as roadbed material.

For the proposed project, the combined installation of the CFB combustor and a flue gas scrubber is expected to remove over 97% of the sulfur dioxide emitted from burning coal that contains up to 4.5% sulfur. The relatively low furnace operating temperature of about 1650°F would result in appreciably lower nitrogen oxide emissions compared to conventional coal-fired power plants.

The project would also include a new selective non-catalytic reduction system to further reduce emissions of nitrogen oxides. Over 99.8% of particulate emissions would be removed by a new baghouse or a new electrostatic precipitator.

In addition to the CFB combustor itself and the air pollution control systems, new equipment for the project would include a new stack and new fuel, limestone, and ash handling systems. The height of the proposed new stack is expected to be approximately 450 feet compared to 300 feet for the existing stack at Unit 2. The project would also require overhaul and/or modifications to existing systems such as the steam turbine, condensate and feedwater systems, circulating water systems, water treatment systems, plant electrical distribution systems, the switchyard, and the control systems.

Options being considered for transport of coal include (1) an extension of conveyors from the nearby St. Johns River Power Park, and (2) construction of new receiving, handling, and storage facilities for solid fuel. Limestone and ash storage and handling facilities also would be required. Wherever possible, existing facilities and infrastructure located at the Northside Generating Station would be used for the proposed project. These include the discharge system for cooling water to the St. Johns River, the wastewater treatment system, and the electric transmission lines and towers.

Because Unit 2 has not operated since 1983, the baseline emissions from that unit are zero. Units 1 and 3 have been operating at annual capacity factors of less than 40%, firing either heavy oil or natural gas. Unit 3 would continue as a 563.7-MWe oil/gas-fired unit. With the exception of low-NO_X (nitrogen oxide) burners on Unit 3, Units 1 and 3 are not currently equipped with emission control systems.

The area is in attainment of the National Ambient Air Quality Standards. However, as part of JEA's commitment to the local community in the implementation of this project, JEA has committed to a 10% reduction in the annual stack emissions for criteria pollutants (i.e., sulfur dioxide, nitrogen oxides, and particulate matter) from the Northside Generating Station (as compared to recent annual emissions). In achieving this objective, the combined emissions from the repowered Units 1 and 2 operating at annual capacity factors of 100% are projected to be less than recent typical annual emissions from Unit 1 alone.

Another part of JEA's community commitment is that groundwater consumption will be reduced by at least 10% from recent levels. This would be accomplished by increased recycling of the treated wastewater produced at the station. Plant wastewater is presently treated with lime, followed by clarification in settling basins. While some recycled water is currently utilized, most of the treated wastewater is discharged to percolation ponds. Should the proposed project be implemented, the discharge of treated wastewater to the ponds would be reduced.

Project activities would include engineering and design, permitting, equipment procurement, construction, startup, and a 24-month demonstration of the commercial feasibility of the technology. DOE plans to complete the EIS and issue a Record of Decision within 15 months of publication of this Notice of Intent, assuming timely delivery of environmental information from JEA for use in developing the EIS. Upon completing its NEPA review, if DOE decides to implement the proposed action, construction would commence in early 1999 and finish in late 2001, startup would occur in early 2002, and demonstration of the technology would begin in April 2002. During the demonstration, Unit 2 would be operated on several different types of coal and coal/fuel blends to demonstrate the flexibility of the technology. Upon completion of the demonstration phase, the facility would continue its commercial operation.

Alternatives

NEPA requires that agencies discuss the reasonable alternatives to the proposed action in an EIS. The purpose for agency action determines the range of reasonable alternatives. Congress established the CCT Program with a specific purpose: to demonstrate the commercial viability of technologies that use coal in more environmentally benign ways than conventional coal technologies. Congress also directed DOE to pursue the goals of the CCT Program by means of partial funding (cost-sharing) of projects owned and controlled by non-federal government sponsors. This statutory requirement places DOE in a much more limited role than if the federal government were the owner and operator of the project. In the latter situation, DOE would be responsible for a comprehensive review of reasonable alternatives. However, in dealing with an applicant, the scope of alternatives is necessarily more restricted. It is appropriate in such cases for DOE to give substantial weight to the applicant's needs in establishing a project's reasonable alternatives.

An overall strategy for compliance with NEPA was developed for the CCT Program that includes consideration of both programmatic and project-specific environmental impacts during and after the process of selecting a project. As part of the NEPA strategy, the EIS for JEA's proposed CFB combustor project will tier off the program's final Programmatic Environmental Impact Statement (PEIS) that was issued by DOE in November 1989 (DOE/EIS-0146). Two alternatives were evaluated in the PEIS: (1) the no action alternative, which assumed that the CCT Program was not continued and that conventional coal-fired technologies, with flue gas desulfurization and nitrogen oxide controls to meet New Source Performance Standards, would continue to be used; and (2) the proposed action, which assumed that the clean coal projects would be selected and funded, and that successfully demonstrated technologies would undergo widespread commercialization by the year 2010.

For JEA's proposed CFB combustor project, the range of reasonable alternatives to be considered in the EIS is also narrowed in accordance with the overall NEPA strategy. The no action alternative will be analyzed in the EIS as a reasonable alternative to the proposed action of providing cost-shared funding support for the proposed project. DOE will consider any other reasonable alternatives that may be suggested during the public scoping period.

Under no action, DOE would not provide partial funding for the design, construction, and operation of the project. In the absence of DOE funding, there are three options that JEA could reasonably pursue. These options will be analyzed under the no action alternative. JEA could construct the proposed project without DOE cost-shared funding. Under this scenario, the potential environmental impacts or benefits at Northside Generating Station are expected to be identical to those of the proposed project. A second option is that JEA could construct a new gas-fired combined cycle facility at Northside Generating Station or at another location. Under this scenario, potential environmental impacts or benefits at Northside Generating Station would vary from those of the proposed project. A third option is that JEA could purchase electricity from other utilities to meet JEA's projected demand. Under this scenario, potential environmental impacts or benefits at Northside Generating Station related to demonstration of the proposed project would not be realized. In addition, the second and third options would not contribute to the objective of the CCT Program, which is to make available to the U.S. energy marketplace advanced, more efficient, economically feasible, and environmentally acceptable coal technologies.

Because of DOE's limited role of providing cost-shared funding for JEA's proposed project and because of the advantages associated with the proposed location, DOE does not plan to evaluate alternative sites for the proposed project. JEA considered additional sites during its site selection process. Site selection was governed primarily by benefits that could be realized by JEA. An existing plant site was preferred because the cost associated with construction of the project at a "greenfield" site in an undisturbed area would be much higher, and the environmental impact likely would be much greater than at an existing facility. The existing Northside Generating Station has several advantages because it is an operating plant with land available for installation of new facilities. Much of the required infrastructure, including the electric transmission lines and towers, is already in place, thereby reducing the level of capital investment and construction impacts. The station has the flexibility to accommodate possible fuel delivery needs with its existing rail and water facilities. Furthermore, most of the operational staffing for the new facility would be accommodated by the existing Northside Generating Station staff.

Preliminary Identification of Environmental Issues

The following issues have been tentatively identified for analysis in the EIS. This list, which was developed partly on the basis of concerns provided by the public in response to JEA's stakeholder outreach program, is not intended to be all inclusive, but is presented to facilitate public comment on the scope of the EIS. Additions to or deletions from this list may occur as a result of the scoping process. The issues include:

(1) Atmospheric Resources: potential air quality impacts resulting from air emissions during current and future operation of Northside Generating Station (e.g., effects of ground-level concentrations of criteria pollutants, and trace metals including mercury, on surrounding residential areas and the Timucuan Preserve (a National Park Service Class II ecological and historic preserve adjacent to the western edge of the Northside Generating Station); potential effects of greenhouse gas emissions on global climate change;

(2) Water Resources and Aquatic Ecology: potential effects on surface water and groundwater resources consumed and discharged; potential effects on estuarine salt marsh ecosystems and aquatic biota resulting from withdrawing and discharging cooling water from the St. Johns River (e.g., thermal discharge, entrainment or impingement of fish and invertebrate species);

(3) Infrastructure and Land Use: potential effects resulting from the transport of coal, petroleum coke, and limestone required for the proposed project, including the development of land for infrastructure, storage, or waste disposal; affected resource areas including land (e.g., existing shoreline and wetlands), utilities, and

transportation routes (e.g., train traffic to supply coal);

(4) Solid Waste: pollution prevention and waste management practices, including solid waste impacts, caused by the generation, treatment, transport, storage, and disposal of solid wastes;

(5) Construction: impacts associated with noise, traffic patterns, and construction-related emissions;

(6) Visual: impacts associated with a new stack that is taller than existing structures at Northside Generating Station;

(7) Floodplains: potential impacts (e.g., impeding floodwaters, re-directing floodwaters, on-site and off-site property damage) of siting new buildings and infrastructure within floodplain and hurricane storm surge areas;

(8) Wetlands: potential reduction of wetlands due to new construction (e.g., construction associated with feedstock transport infrastructure);

(9) Community Impacts: impacts on public safety related to fire and emergency vehicle access to the Northside community of Jacksonville; impacts to local traffic patterns resulting from rail traffic; socioeconomic impacts on public services and infrastructure (e.g., police protection, schools, and utilities); noise associated with project operation; environmental justice with respect to the surrounding community; and

(10) Cumulative effects that result from the incremental impacts of the proposed project when added to other past, present, and reasonably foreseeable future actions (e.g., incremental discharge of cooling water affecting aquatic biota).

Public Scoping Process

To ensure that the full range of issues related to this proposal are addressed, DOE will conduct an open process to define the scope of the EIS. The public scoping period will run until December 31, 1997. Interested agencies, organizations, and the general public are encouraged to submit comments or suggestions concerning the content of the EIS, issues and impacts to be addressed in the EIS, and the alternatives that should be analyzed.

Scoping comments should clearly describe specific issues or topics that the EIS should address in order to assist DOE in identifying significant issues. Written, e-mailed, faxed, or telephoned comments should be communicated by December 31, 1997 (see ADDRESSES).

In addition, a public scoping meeting to be conducted by DOE will be held in the In-Plant Conference Room at the Northside Generating Station on December 3, 1997, at 7 p.m. The address of the Northside Generating Station is 4377 Heckscher Drive, Jacksonville, Florida. DOE requests that anyone who wishes to speak at this public scoping meeting contact Dr. Jan Wachter, either by phone, fax, computer, or in writing (see ADDRESSES in this Notice). Individuals who do not make advance arrangements to speak may register at the meeting and will be given the opportunity to speak after all previously scheduled speakers have made their presentations. Speakers who wish to make presentations longer than five minutes should indicate the length of time desired in their request. Depending on the number of speakers, it may be necessary to limit speakers to five minute presentations initially, with the opportunity for additional presentation as time permits. Speakers can also provide additional written information to supplement their presentations. Oral and written comments will be given equal weight.

DOE will begin the meeting with an overview of the proposed CFB combustor project. A presiding officer will be designated by DOE to chair the meeting. The meeting will not be conducted as an evidentiary hearing, and speakers will not be cross-examined. However, speakers may be asked to clarify their statements to ensure that DOE fully understands the comments or suggestions. The presiding officer will establish the order of speakers and provide, any additional procedures necessary to conduct the meeting.

Issued in Washington, D.C., this 6th day of November, 1997.

Peter N. Brush,

Acting Assistant Secretary, Environment, Safety and Health.

[FR Doc. 97-29890 Filed 11-12-97; 8:45 am]

BILLING CODE 6450-01-P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[FERC-512]

Information Collection Submitted for Review and Request For Comments

November 6, 1997.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of submission for review by the Office of Management and Budget (OMB) and request for comments.

SUMMARY: The Federal Regulatory Commission (Commission) has submitted the energy information collection listed in this notice to Office of Management and Budget (OMB) for review under provisions of Section 3507 of the Paperwork Reduction Act of 1995 (Pub. L. No. 104-13). Any interested person may file comments on the collection of information directly with OMB and should address a copy of those comments to the Commission as explained below. The Commission received no comments in response to an earlier Federal Register notice of May 28, 1997 (62 FR 28844) and has made this notation in its submission to OMB.

DATES: Comments regarding this collection of information are best assured of having their full effect if received within 30 days of this notification.

ADDRESSES: Address comments to Office of Management and Budget, Office of Information and Regulatory Affairs, Attention: Federal Energy Regulatory Commission, Desk Officer, 726 Jackson Place, N.W., Washington, D.C. 20503. A copy of the comments should also be sent to Federal Energy regulatory Commission, Division of Information Services, Attention: Mr. Michael Miller, 888 First Street N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Michael P. Miller may be reached by telephone at (202) 208-1415, by fax at (202) 273-0873, and by e-mail at mmiller@ferc.fed.us.

SUPPLEMENTARY INFORMATION:

Description

The energy information collection submitted to OMB for review contains:

1. *Collection of Information:* FERC-512 "Application for Preliminary Permit"

2. *Sponsor:* Federal Energy Regulatory Commission

3. *Control No.:* OMB No. 1902-0073. The Commission is now requesting that OMB approve a three-year extension of the current expiration date, with no changes to the existing collection. There is a decrease in the reporting burden due to a decrease in the number of applicants filing with the Commission. These are mandatory collection requirements.

4. *Necessity of Collection of Information:* Submission of the information is necessary to enable the Commission to carry out its responsibilities in implementing the provisions of the Federal Power Act (FPA). The information reported under Commission identifier FERC-512 is filed in accordance with Sections 4(f), 5, 7, (FPA). The Part I of the FPA gives the Commission authority to issue licenses

most appropriate policy would be to adopt a potential-to-potential test.

One commenter noted that the actual-to-future-actual test would end what was felt to be the "unlawful and unfair practice" of using the NSR program to "arbitrarily reduce allowable hours of operation or rates of production for existing sources." Countering the argument that the actual-to-future-actual test could create public health problems, two commenters noted that utilities must comply with all Federal, State and local air quality restrictions regardless of the tests used. Also supporting the actual-to-future-actual test, one commenter pointed out that source owners will be motivated by incentives in the CAA, proposed regulations, and market forces to finance and engineer economic and efficient physical and operational changes at plants so as to achieve excellent environmental control. One commenter favored calculating future emissions over a representative 2-year period within a 5-year period after the change.

3. Comments Generally Opposing the EPA Proposal

One opponent of the proposed methods stated that emission increases at power plants would now be fostered since the proposal will allow utilities to choose their own definitions for when emissions have increased.

In general, opponents of the proposal regarding the pre-change baseline noted that the change is arbitrary and capricious and that there is no analysis in the docket suggesting that any 2-year period is more representative of pre-change maximum emissions. Commenters noted that under the proposal, sources could select the years in which they had the highest emissions in an attempt to minimize the appearance of an increase and escape NSR. One commenter noted that the change in baseline calculation methodology would give utilities such flexibility in refurbishing, repowering, and life extension projects as to bias competitive power markets towards the continued use of existing old units rather than the construction of new ones.

Opponents to the use of future actual emissions stated that there is no reasoned basis for an unenforceable representative actual emissions approach, and application of this test to electric utilities is not consistent with EPA's established policy toward other sources. Other comments contended that the future actual test ignores all past precedents and that, in determining whether a change triggers NSR, EPA should compare actual emissions for the current unit to potential emissions from the altered source; the future actual test does not guard against artificially low estimates made by sources to escape NSR, nor does it protect against substantial increases made immediately after the 2-year period; and the future actual emissions calculation procedure amounts to self-regulation and is easily subject to abuse.

State and local air agencies generally opposed the future actual method of calculating post-change emissions. One noted that the appropriate emission increase test should be determined on a case-by-case basis. One agency noted that the actual-to-future actual approach results in a significant relaxation of title I NSR requirements and would allow utilities to upgrade equipment which may have lost significant generating capacity without the equipment being subject to NSR, hampering local air quality attainment and maintenance efforts. There were several comments that future emissions cannot be reasonably determined solely on past operating history. One State noted that direction is needed on how actual versus potential emissions are estimated.

A few commenters addressed the 2-year period after the proposed change which is the basis for calculating the future actual emissions. Opponents of the future actual concept stated that use of such a provision would result in unrealistically low future emissions projections and shield a company against efforts to enforce NSR requirements at a source that increased emissions 3 years after making physical changes.

An environmental group and several State agencies noted that the projected post-change emissions should become an enforceable permit condition in order to commit a source to limit its future emissions to a specific amount and to provide assurance that these projections are reasonable estimates of expected emissions. If a source will not accept such a permit condition, then the source should have to use potential post-change emissions.

4. Comments Suggesting Revisions to the Proposal

Three commenters suggested a more flexible test for ascertaining SO_2 increases for determining applicability of NSR and NSPS requirements, namely a measure of pollution per unit of electrical output.

a. Commenters made the following specific suggestions for changes surrounding the future actual calculation method:

(1) Develop guidelines to assist States in making like-kind determinations;

(2) Require like-kind replacements to use the representative actual annual emissions for calculation of actual emissions;

(3) Define "like-kind replacement" to include complete replacement of an existing emissions unit;

(4) Define "routine repair and replacement;"

(5) Apply the actual-to-actual test to like-kind replacement of an entire emitting unit;

(6) Allow new units or greenfield plants to rely on future actual emissions if they can reliably project future emissions; and

(7) Consider an alternative way to make the NSR accounting system consistent, such as basing it on past allowable to future allowable emissions.

(b) Other suggestions included the following:

(1) Provide guidance on routine repair and replacement and maintenance activities to include placing units on cold reserve and bringing them back on line, and

(2) Use a 2-year period other than immediately after the change only when the EPA cannot clearly demonstrate that the 2-year period immediately following the change is not representative.

5. The EPA Analysis

The EPA has decided to promulgate the proposed "representative actual annual emissions" methodology for calculating emissions changes at electric utility steam generating units where the changes do not involve the construction of a new, "greenfield" unit or the replacement of an existing one. After a thorough review of the comments, EPA concludes that the comparison of "actual emissions before" to a projection of "actual emissions after" a physical or operational change at an existing utility steam generating unit is workable and, with the added safeguard discussed below, is the most suitable method for evaluating emissions changes at such sources.

Many commenters questioned EPA's proposed presumption that sources may use, as the baseline, emissions from any 2 consecutive years within the 5 years prior to the proposed change without regard to normal source operations. As discussed in the proposal, this presumption is consistent with EPA's decision in WEPCO and the 5-year period for "contemporaneous" emissions after the change. Thus, EPA will presume that any increase in emissions levels more than 5 years after the change has occurred is not related to the physical or operational change.

In response to comments regarding "like-kind" replacements, EPA notes that today's regulations recognize no distinction between "like-kind" replacements and other nonroutine physical or operational changes at a utility steam generating unit. The "actual-to-future-actual" methodology promulgated today for calculating emissions changes applies to all types of changes at utility units, including the replacement of "like-kind" components at an existing unit. However, the "like-kind" replacement of a whole unit is for all practical purposes a replacement unit and, therefore, is treated as a new unit.

Although several commenters suggested that EPA should expand the representative actual emissions test to new and reconstructed units, EPA has decided not to do so. Since there is no relevant operating history for new or reconstructed units, it would not be possible to accurately project operations or emissions for these units. Consequently, the EPA has left unchanged the regulations which require that for any unit which has not begun normal operations, actual emissions are considered equal to the unit's potential-to-emit.

A few commenters requested that EPA define or provide guidance on "routine repair, replacement and maintenance" activities. The June 14 proposal did not deal with this aspect of the regulations, nor do the regulatory changes promulgated today. However, the issue has an important bearing on today's rule because a project that is determined to be routine is excluded by EPA regulations from the definition of major modification. For this reason, EPA plans to issue guidance on this subject as part of a NSR regulatory update package which EPA presently intends to propose by early summer. In the meantime, EPA is today clarifying that the determination of whether the repair or replacement of a particular item of equipment is "routine" under the NSR regulations, while made on a case-by-case basis, must be based on the evaluation of whether that type of equipment has been repaired or replaced by sources within the relevant industrial category.

C. The Causation Requirement

1. Background

The NSR regulatory provisions require that the physical or operational change "result in" an increase in actual emissions in order to consider that change to be a modification [see e.g., 40 CFR 52.21(2)(i)]. In other words, NSR will not apply unless EPA finds that there is a causal link between the proposed change and any post-change increase in emissions. The EPA proposed to amend its rules to clarify this provision in the context of modifications at electric utility steam generating units.

Under the proposed regulations, any emissions increase attributable to a physical or operational change, such as a physical or operational change that significantly alters the efficiency of the plant, (see, *Puerto Rican Cement*, 889 F.2d at 297–8), must continue to be included in the post-change emissions calculation. The proposal clarified that where increased operations are in response to independent factors, such as system-wide demand growth, which would have occurred and affected the unit's operations even in the absence of the physical or operational change, such increases do not result from the change and shall be excluded from the projection of future actual emissions. Thus, in assessing whether the proposed change will result in an increase in *actual emissions, utilities need not* include in their projection of post-change utilization that portion of the increased rate of utilization, if any, due to factors unrelated to the physical or operational change, such as an increase in projected capacity utilization due to the rate of electricity demand growth for the utility system (of which that source is a member) as a whole.

Under today's rule, during a representative baseline period (see *supra*), the plant must have been able to *accommodate the projected demand* growth physically and legally even absent the particular change. Increased operations (and resultant increases in *actual emissions) that could not* physically and legally be accommodated during the representative baseline period but for the proposed physical or *operational change should be* considered to result from the change.

2. Comments Generally Favoring the EPA Proposal

Several utility representatives supported the proposed demand growth exclusion and the causation requirement. Many commenters requested clarification of certain points or expansion of certain provisions. One commenter noted that there should be a specific exclusion for emissions increases at a generating station resulting from generation shifts and decreased plant efficiencies caused by operation of pollution control systems. Another noted that the discussion of the criteria for recognizing "factors unrelated to the physical or operational change" should be improved upon because the proposed requirements that a facility must have been physically able to accommodate the projected growth during a "representative baseline period" could have a negative impact in utility capacity planning and investment decisions, depending upon how such a period is determined.

One commenter noted that EPA should specifically recognize an exception for units which have been inactive, because a unit should not have to include all of its emissions due to demand growth merely because it was in need of repair or maintenance while inactive. Commenters asked that EPA better define "independent factors" in the context of the demand growth exclusion. Lastly, one commenter stated that the final rule should reconcile the "demand growth exclusion" with the existing "hours of operation/rate of production" exclusion by confirming that increases attributable to system-wide demand growth are already excluded under the already-existing exclusion and, therefore the "demand growth exclusion" only applies where there is a federally-enforceable permit term limiting hours of operation or production rate.

3. Comments Generally Opposing the EPA Proposal

Opponents of the exclusion of emissions attributable to demand growth contended that there is no rational basis for ignoring such emissions. When increased capacity or utilization is the immediate goal of a project and an increase in emissions occurs, the project must be subject to NSR regardless of the underlying reasons for the increased capacity or utilization and corresponding emission increase. Contrary to the letter and purpose of the statute, the demand growth exclusion could result in major increases in actual emissions going unreviewed and unregulated, would create serious local pollution problems, and would discriminate against companies that were successful in implementing energy efficiency programs. One local agency pointed out that it is virtually impossible to determine with any degree of certainty what portion of a unit's emissions are attributable to an increase in projected capacity utilization.

In addition, commenters noted that the exclusion will have an adverse effect on local agencies' ability to control emissions and that the time of projection of post-change capacity utilization for applicability purposes should be based on a projection of utilization for a period after the physical or operational change. Specifically, EPA today proposes to allow sources to base the projection of utilization on the 2 years after the change, or a different consecutive 2-year period within the 10 years after the change, where the Administrator determines that such period is more representative of normal source operations.

C. The Causation Requirement

The NSR regulatory provisions require that the physical or operational change "result in" an increase in actual emissions in order to consider that change to be a modification. See *e.g.* 40 CFR 52.21(2)(i). In other words, NSR will not apply unless EPA finds that there is a causal link between the proposed change and any post-change increase in emissions. The EPA today proposes to amend its rules to clarify this provision in the context of modifications at electric utility steam generating units.

Under these proposed regulations, any emissions increase attributable to a physical or operational change, such as a physical or operational change that significantly alters the efficiency of the plant, (see, *Puerto Rican Cement*, 889 F.2d at 297–8), must continue to be included in the post-change emissions calculation. Today's proposal makes clear that where increased operations are in response to independent factors, such as system-wide demand growth, which would have occurred and affected the unit's operations even in the absence of the physical or operational change, such increases do not result from the change and shall be excluded from the projection of future actual emissions. Thus, in assessing whether the proposed change will result in an increase in actual emissions, utilities need not include in their projection of post-change utilization that portion of the increased rate of utilization, if any, due to factors unrelated to the physical or operational change, such as an increase in projected capacity utilization due to the rate of electricity demand growth for the utility system (of which that source is a member) as a whole.

Under this proposal, during a representative baseline period (see *supra*), the plant must have been able to accommodate the projected demand growth physically and legally even absent the particular change. Increased operations (and resultant increases in actual emissions) that could not physically and legally be accommodated but for the proposed physical or operational change should be considered to result from the change.

D. Repowering

As previously mentioned, title IV of the 1990 Amendments grants special treatment to utilities that seek to comply with mandated acid rain reductions by repowering a unit with qualifying clean coal technology. 1990 Amendments sections 402(12), 409(a). Specifically, repowering projects that qualify for a Phase II compliance extension will also be exempt from NSPS requirements, so long as the repowering "does not increase actual hourly emissions for any pollutant regulated under the Act." Section 409(d). The EPA interprets the requirement that the repowering not lead to an increase in "actual hourly emissions" as an expression of Congressional intent that will respect to repowering projects, EPA should use the same general approach to determining applicability as it has for other physical or operational changes, discussed above. Accordingly, EPA today proposes rules that provide that a repowering project which results in an increase over baseline in a unit's post-modification hourly emissions will not be eligible for this limited NSPS exemption.

The proposed NSPS exemption applies to repowering of existing units at existing sources, so long as the project qualifies for the Phase II extension and satisfies the "actual hourly emissions" increase test. Because of this provision, the reconstruction limitations specified in 40 CFR 60.15 are not applicable to qualifying repowering projects. However, no special treatment can be afforded to a new unit which is located at a different site than the existing unit it replaces. See CAA section 409(d).

Pursuant to section 409(e), EPA will provide expedited NSR processing for repowering projects and will encourage State permitting authorities to do the same.

E. Clean Coal Technology Demonstration Projects

Today's notice also proposes rules implementing the new CCT exemption created by the 1990 Amendments. For the purposes of this proposal, temporary CCT demonstration projects are defined as those CCT demonstration projects lasting 5 years or less. Title IV gives these projects an exemption from NSPS, PSD and nonattainment requirements. *Id.*, section 415(b)(2). However, the facility would still be subject to any applicable SIP and must comply with any other requirements necessary to attain and maintain NAAQS. This ruling proposes to implement this provision and clarifies that EPA considers the 5-year period as starting on the date of startup (as defined in 40 CFR 60.2). A temporary demonstration project may be converted to a permanent status at any time, provided it meets all the requirements that apply to a permanent CCT project criteria at the time of conversion.

Further, EPA proposes that at the end of a temporary project, the facility must be returned to pre-demonstration conditions and hourly emission rates (or lower). The return of the facility to its pre-demonstration physical and operational condition would not result in the loss of the actual emissions margin between pre-demonstration actual emissions rate and SIP allowable emissions rates for that facility. Rather, the facility would be treated as if the temporary demonstration project had never occurred.[19]

This proposal does not extend to emissions increases that are unrelated to the conduct of temporary demonstration projects. The EPA considers emissions increases (above the predemonstration levels) that are attributable to physical or operational changes, other than those necessary to restore that unit to its pre-demonstration condition, to be beyond the scope of the Congressional exemption.

Today's action also proposes to implement an exemption from NSPS and PSD requirements for repowering projects which are awarded funding from the DOE as permanent CCT demonstration projects (or similar projects funded by EPA) so long as potential emissions (see § 52.21(b)(4)) from the unit do not increase as a result of the project. Section 415(b)(3). However, repowering projects that qualify as pollution control projects will be treated as other pollution control projects for the purposes of the nonattainment provisions of title I of the Act.

Finally, today's proposal would implement the statutory exemptions in section 415(c). In that section, Congress provided an exemption from NSPS and PSD for the reactivation of "very clean units" otherwise in compliance with the Act that had been shut down for at least

[19] This would be the case even if there were small differences in the post-demonstration physical and operational conditions due to a technical inability to restore the unit to its precise pre-demonstration condition, or due to normal variability in the coal used. Thus, EPA would not seek to apply NSPS or NSR because of a post-demonstration emissions increase attributable solely to an increase in the hours of operation or production rate of the unit (subject to the NSPS limitation that the production rate increase must be accomplished without a capital expenditure).

Attachment C
(6 pages)

05:28 PM
03/04/93

NORTHSIDE GENERATING STATION

GENERATION STATISTICS

CALENDAR YEAR, 1992

GENERATION DATA (MWH)	NS-1	NS-3	STM TOT**	NCT3	NCT4	NCT5	NCT6	NCT TOTAL
1. GROSS MWH	1,055,692	1,913,710	2,969,402	1,030	1,367	2,677	1,597	6,671
2. AUX. LOAD	61,872	82,219	147,751	236	365	237	414	1,252
3. NET MWH ONLINE (SYNC)	999,167	1,835,767	2,834,934	1014	1343	2641	1577	6,575
NET MWH OVERALL	993,820	1,831,491	2,821,651	794	1,002	2,440	1,183	5,419
4. NET MWH LST YR	724,529	1,632,386	2,353,265	1,096	585	2,718	981	5,380
5. CUM NET MWH (FSCL)	993,820	1,831,491	2,821,651	794	1,002	2,440	1,183	5,419
6. CUM NET MWH (CAL)	993,820	1,831,491	2,821,651	794	1,002	2,440	1,183	5,419
7. % STATION GROSS GEN	35.5	64.3	99.8	0.0	0.0	0.1	0.1	0.2
* 8. ON-LINE LOAD FACTOR %	60.7	57.6	42.6	47.6	43.1	57.3	62.0	NA
* 9. #6 OIL BURNED ON-LINE	1,063,506	1,147,524	2,211,030	NA	NA	NA	NA	NA
#6 OIL BURNED OVERALL	1,067,058	1,147,609	2,214,667	NA	NA	NA	NA	NA
#2 OIL BURNED ON-LINE	NA	NA	NA	2760	3897	6656	4488	17,801
#2 OIL BURNED OVERALL	NA	NA	NA	3,029	4,141	6,950	4,731	18,851
#2 OIL BURNED (EQ BBL)	NA	NA	NA	2,776	3,795	6,369	4,336	17,276
GAS BURNED ON-LINE	3,584,773	11,339,799	14,924,572	NA	NA	NA	NA	NA
GAS BURNED OVERALL	3,625,996	11,395,593	15,044,662	NA	NA	NA	NA	NA
GAS BURNED (EQ BBL)	596,463	1,872,000	2,471,669	NA	NA	NA	NA	NA
TTL FUEL BURN (EQ BBL)	1,663,521	3,019,609	4,686,336	2,776	3,795	6,369	4,336	17,276
10. AVG BTU / BBL #6 OIL	6,354,105	6,347,839	6,350,858	NA	NA	NA	NA	NA
AVG BTU / BBL #2 OIL	NA	NA	NA	5,820,966	5,820,966	5,820,966	5,820,966	5,820,966
AVG BTU / FT3 GAS	1,045	1,043	1,043	NA	NA	NA	NA	NA
11. GROSS KWH / EQ BBL	635	634	634	371	360	420	368	386
12. NET KWH / EQ BBL	597	607	602	286	264	383	273	314
13. HEATRATE (ON LINE)	10,513	10,409	10,446	15,851	16,895	14,669	16,561	15,759
HEATRATE (OVERALL)	10,636	10,466	10,548	22,196	24,063	16,580	23,280	20,249
14. NUMBER OF STARTS	39	26	65	32	29	35	29	125
15. HOURS OF OPERATION	6320.6	6419.3	12739.9	41.2	60.4	89.0	49.1	239.7

	OIL	GAS	HOURS
16. AUXILIARY BOILER	0	23,073	155

STATION INVENTORIES	# 6 FUEL (bbl)	# 2 FUEL (bbl)	MgO (gal)
17. ON HAND (BOY)	943,202	27,208	3,875
18. RECEIVED	1,741,881	12,462	42,066
19. BARGE IN (INTRA-JEA)	15,920	15,969	0
BARGE OUT (INTRA-JEA)	0	0	0
20. TTL AVAILABLE	2,701,003	55,639	45,941
21. ON HAND (EOY)	486,337	36,787	4,769
22. CONSUMED	2,214,667	18,851	41,172

* NOTES;

(8) ON-LINE LOAD FACTOR FOR UNITS, CAPACITY FACTOR FOR STEAM TOTAL.

(9) AUXILIARY BOILER FUEL INCLUDED IN STATION'S OVERALL FUEL BURNED. OIL MEASUREMENTS CORRECTED TO THE END OF YEAR SOUNDINGS.

LIFETIME TOTALS	NS-1	NS-3
23. GROSS MWH	23,042,577	21,312,050
24. HOURS OF OPERATION	137,890	74,975
25. NUMBER OF STARTS	678	302

** UNIT TOTALS MAY NOT ADD UP TO STATION TOTALS DUE TO ADDITIONAL STATION AUXILIARY REQUIREMENTS.

Attachment C

04:37 PM
02/04/94

NORTHSIDE GENERATING STATION

GENERATION STATISTICS

CALENDAR YEAR, 1993

GENERATION DATA (MWH)	NS-1	NS-3	STM TOT**	NCT3	NCT4	NCT5	NCT6	NCT TOTAL
1. GROSS MWH	609,733	1,704,240	2,313,973	533	1,622	1,216	1,322	4,693
2. AUX. LOAD	39,333	89,658	132,641	209	258	309	354	1,130
3. NET MWH ONLINE (SYNC)	577,767	1,620,319	2,198,087	525	1605	1204	1306	4,640
4. NET MWH OVERALL	570,400	1,614,582	2,181,332	324	1,364	907	968	3,563
5. NET MWH LST YR	993,820	1,831,491	2,821,651	794	1,002	2,440	1,183	5,419
6. % STATION GROSS GEN	26.3	73.5	99.8	0.0	0.1	0.1	0.1	0.2
7. ON-LINE LOAD FACTOR %	65.8	51.6	54.7	53.3	73.3	75.7	63.6	17.0
8. CAPACITY FACTOR %	26.6	37.6	33.9	0.1	0.4	0.3	0.3	0.3
* 9. #6 OIL BURNED ON-LINE	869,649	2,513,484	3,383,134	NA	NA	NA	NA	NA
#6 OIL BURNED OVERALL	871,261	2,515,189	3,386,450	NA	NA	NA	NA	NA
#2 OIL BURNED ON-LINE	NA	NA	NA	1,510	3,883	3,370	3,682	12,444
#2 OIL BURNED OVERALL	NA	NA	NA	1,703	4,018	3,521	3,825	13,066
#2 OIL BURNED (EQ BBL)	NA	NA	NA	1,557	3,673	3,219	3,497	11,945
GAS BURNED ON-LINE	358,006	1,041,067	1,399,072	NA	NA	NA	NA	NA
GAS BURNED OVERALL	386,573	1,066,374	1,454,362	NA	NA	NA	NA	NA
GAS BURNED (EQ BBL)	63,297	174,666	238,193	NA	NA	NA	NA	NA
TTL FUEL BURN (EQ BBL)	934,558	2,689,855	3,624,643	1,557	3,673	3,219	3,497	11,945
10. AVG BTU / BBL #6 OIL	6,358,108	6,362,541	6,361,401	NA	NA	NA	NA	NA
AVG BTU / BBL #2 OIL	NA	NA	NA	5,814,186	5,814,186	5,814,186	5,814,186	5,814,186
AVG BTU / FT3 GAS	1,041	1,042	1,042	NA	NA	NA	NA	NA
11. GROSS KWH / EQ BBL	652	634	638	342	442	378	378	393
12. NET KWH / EQ BBL	610	600	602	208	371	282	277	298
13. HEATRATE (ON LINE)	10,215	10,539	10,454	16,705	14,066	16,276	16,389	15,592
HEATRATE (OVERALL)	10,417	10,600	10,571	30,537	17,128	22,573	22,966	21,320
14. NUMBER OF STARTS	27	17	44	23	16	18	17	74
15. HOURS OF OPERATION	3,538.8	6,373.6	9,912.4	19.0	42.1	30.6	39.6	131.4

	OIL	GAS	HOURS
16. AUXILIARY BOILER	0	1,415	28

STATION INVENTORIES	# 6 FUEL (bbl)	# 2 FUEL (bbl)	MgO (gal)
17. ON HAND (BOY)	486,242	36,787	4,769
18. RECEIVED	3,541,466	68,883	29,292
19. ADJUSTMENT (+ = more)	(1,369)	0	0
20. BARGED IN/OUT	2,415	(2,415)	275
21. TTL AVAILABLE	4,028,754	103,255	34,336
22. ON HAND (EOY)	642,304	90,190	4,773
23. CONSUMED	3,386,450	13,066	29,563

* NOTES;

(2) CORRECTED FOR CIRCULATOR MWH USED FOR SJRPP

(9) AUXILIARY BOILER FUEL INCLUDED IN STATION'S OVERALL FUEL BURNED.

OIL MEASUREMENTS CORRECTED TO THE END OF YEAR SOUNDINGS.

LIFETIME TOTALS	NS-1	NS-3
24. GROSS MWH	23,652,310	23,016,290
25. HOURS OF OPERATION	141,426	81,345
26. NUMBER OF STARTS	705	319

** UNIT TOTALS MAY NOT ADD UP TO STATION TOTALS DUE TO ADDITIONAL STATION AUXILIARY REQUIREMENTS.

Attachment C

09:50 AM
03/10/95

NORTHSIDE GENERATING STATION

GENERATION STATISTICS

CALENDAR YEAR, 1994

GENERATION DATA (MWH)	NS-1	NS-3	STM TOT**	NCT3	NCT4	NCT5	NCT6	NCT TOTAL
1. GROSS MWH	1,018,638	1,414,429	2,433,067	679	178	262	141	1,260
* 2. AUX. LOAD	61,259	78,488	143,182	108	350	343	544	1,345
3. NET MWH ONLINE (SYNC)	960,574	1,339,546	2,300,121	671	175	257	138	1,241
4. NET MWH OVERALL	957,379	1,335,941	2,289,885	571	(172)	(81)	(403)	(85)
5. NET MWH LST YR	570,400	1,614,582	2,181,332	324	1,364	907	968	3,563
6. % STATION GROSS GEN	41.8	58.1	99.9	0.0	0.0	0.0	0.0	0.1
7. ON-LINE LOAD FACTOR %	57.7	45.8	50.1	65.5	36.6	39.9	36.6	12.3
8. CAPACITY FACTOR %	44.4	31.2	35.6	0.1	0.0	0.1	0.0	0.1
* 9. #6 OIL BURNED ON-LINE	1,347,661	2,045,213	3,392,874	NA	NA	NA	NA	NA
#6 OIL BURNED OVERALL	1,347,809	2,045,406	3,393,215	NA	NA	NA	NA	NA
#2 OIL BURNED ON-LINE	NA	NA	NA	3,210	917	2,099	885	7,111
#2 OIL BURNED OVERALL	NA	NA	NA	3,319	984	2,208	978	7,489
#2 OIL BURNED (EQ BBL)	NA	NA	NA	3,031	899	2,016	893	6,839
GAS BURNED ON-LINE	1,387,834	1,400,419	2,788,253	NA	NA	NA	NA	NA
GAS BURNED OVERALL	1,409,508	1,410,109	2,819,616	NA	NA	NA	NA	NA
GAS BURNED (EQ BBL)	232,269	232,861	465,079	NA	NA	NA	NA	NA
TTL FUEL BURN (EQ BBL)	1,580,078	2,278,266	3,858,294	3,031	899	2,016	893	6,839
10. AVG BTU / BBL #6 OIL	6,353,046	6,359,774	6,357,102	NA	NA	NA	NA	NA
AVG BTU / BBL #2 OIL	NA	NA	NA	5,805,869	5,805,869	5,805,869	5,805,869	5,805,869
AVG BTU / FT3 GAS	1,047	1,050	1,049	NA	NA	NA	NA	NA
11. GROSS KWH / EQ BBL	645	621	631	224	NA	NA	NA	NA
12. NET KWH / EQ BBL	606	586	593	188	NA	NA	NA	NA
13. HEATRATE (ON LINE)	10,426	10,808	10,648	27,755	30,493	NA	37,257	33,281
HEATRATE (OVERALL)	10,485	10,846	10,711	33,755	NA	NA	NA	NA
14. NUMBER OF STARTS	35	7	42	13	8	13	11	45
15. HOURS OF OPERATION	6,734.7	5,960.4	12,695.1	19.8	9.3	12.5	7.3	48.9

	OIL	GAS	HOURS
16. AUXILIARY BOILER	0	0	0

STATION INVENTORIES	# 6 FUEL (bbl)	# 2 FUEL (bbl)	MgO (gal)
17. ON HAND (BOY)	642,304	90,190	4,773
18. RECEIVED	3,403,644	0	41,944
19. TRANSFER IN	1,330	0	0
20. TRANSFER OUT	(12,978)	1,330	0
21. TTL AVAILABLE	4,060,206	88,859	46,717
22. ON HAND (EOY)	666,992	81,370	7,302
23. CONSUMED	3,393,215	7,489	39,415

* NOTES;

(2) CORRECTED FOR CIRCULATOR MWH USED FOR SJRPP

(9) AUXILIARY BOILER FUEL INCLUDED IN STATION'S OVERALL FUEL BURNED.

OIL MEASUREMENTS CORRECTED TO THE END OF YEAR SOUNDINGS.

LIFETIME TOTALS	NS-1	NS-3
24. GROSS MWH	24,670,948	24,430,719
25. HOURS OF OPERATION	148,161	87,305
26. NUMBER OF STARTS	740	326

** UNIT TOTALS DO NOT ADD UP TO STATION TOTALS DUE TO ADDITIONAL STATION AUXILIARY REQUIREMENTS.

Attachment C

13:44
04/03/96

NORTHSIDE GENERATING STATION

GENERATION STATISTICS

CALENDAR YEAR 1995

GENERATION DATA (MWH)	NS-1	NS-3	STM TOT**	NCT3	NCT4	NCT5	NCT6	NCT TOT
1. GROSS MWH	768,793	1,700,840	2,469,633	1,294	1,363	1,218	1,622	5,496
*2. AUX. LOAD	52,236	67,597	119,833	293	321	336	442	1,392
3. NET MWH ONLINE (SYNC)	722,934	1,637,895	2,360,829	1,276	1,344	1,203	1,599	5,422
4. NET MWH OVERALL	716,556	1,633,244	2,349,800	1,000	1,043	881	1,180	4,104
5. NET MWH LST YR	957,379	1,335,941	2,289,670	571	(172)	(81)	(404)	(85)
6. % STATION GROSS GEN	31.1	68.7	99.8	0.1	0.1	0.0	0.1	0.2
7. ONLINE LOAD FACTOR %	55.5	51.0	52.3	56.5	54.3	64.2	54.1	14.2
8. CAPACITY FACTOR %	33.5	37.5	36.1	0.3	0.3	0.3	0.4	0.3
*9. #6 OIL BURNED ONLINE	691,391	1,028,765	1,720,155	NA	NA	NA	NA	NA
#6 OIL (BBLS) OVERALL	691,694	1,028,774	1,720,468	NA	NA	NA	NA	NA
#2 OIL BURNED ONLINE	NA	NA	NA	3,883	3,335	3,082	4,381	14,681
#2 OIL (BBLS) OVERALL	NA	NA	NA	4,068	3,520	3,267	4,641	15,496
#2 OIL BURNED (EQ BBL)	NA	NA	NA	3,715	3,215	2,983	4,238	14,151
GAS BURNED ONLINE	3,165,787	10,071,872	13,237,660	NA	NA	NA	NA	NA
GAS (KCF) OVERALL	3,189,963	10,093,968	13,283,931	NA	NA	NA	NA	NA
GAS BURNED (EQ BBL)	526,026	1,660,166	2,186,823	NA	NA	NA	NA	NA
TTL FUEL BURN (EQ BBL)	1,217,720	2,688,940	3,907,291	3,715	3,215	2,983	4,238	14,151
10. AVG BTU / BBL #6 OIL	6,361,571	6,372,944	6,368,372	NA	NA	NA	NA	NA
AVG BTU / BBL #2 OIL	NA	NA	NA	5,815,477	5,815,477	5,815,477	5,815,477	5,815,477
AVG BTU / FT3 GAS	1,049	1,048	1,048	NA	NA	NA	NA	NA
11. GROSS KWH / EQ BBL	631	633	632	348	424	408	383	388
12. NET KWH / EQ BBL	588	607	601	269	324	295	278	383
13. HEAT RATE (ONLINE)	10,678	10,448	10,519	17,696	NA	14,895	15,936	15,746
HEAT RATE (OVERALL)	10,811	10,492	10,589	23,648	19,635	21,553	22,874	21,956
14. NUMBER OF STARTS	37	21	58	22	22	22	31	97
15. HOURS OF OPERATION	5,289.5	6,437.7	11,727.2	43.7	47.9	36.2	57.2	185.0
16. ANNUAL REVENUE ($ 000)	48,878	111,408						

	OIL	GAS	HOURS
17. AUXILIARY BOILER	0	0	0.0

STATION INVENTORIES	#6 FUEL (bbl)	#2 FUEL (bbl)	MgO (gal)
18. ON HAND (BOY)	666,991.60	81,369.92	7,302.0
19. RECEIVED	1,626,796.92	20,012.74	12,919.0
20. ADJUSTMENT (+ = more)	0.00	0.00	0.0
21. BARGED IN/OUT	0.00	0.00	0.0
22. TTL AVAILABLE	2,293,788.52	101,382.66	20,221.0
23. ON HAND (EOY)	573,320.03	85,886.45	4,266.7
24. CONSUMED	1,720,468.49	15,496.21	15,954.3

*NOTES:

(2) CORRECTED FOR CIRCULATOR MWH USED FOR SJRPP

(9) AUXILIARY BOILER FUEL INCLUDED IN STATIONS'S OVERALL GAS BURNED.

OIL MEASUREMENTS CORRECTED TO THE END OF YEAR SOUNDINGS.

LIFETIME TOTALS	NS-1	NS-3
25. GROSS MWH	25,439,741	26,131,559
26. HOURS OF OPERATION	153,451	93,743
27. NUMBER OF STARTS	777	347

** UNIT TOTALS MAY NOT ADD UP TO STATION TOTALS DUE TO ADDITIONAL STATION AUXILIARY REQUIREMENTS.

Attachment C

11:45
02/12/97

NORTHSIDE GENERATING STATION

GENERATION STATISTICS

CALENDAR YEAR 1996

GENERATION DATA (MWH)	NS-1	NS-3	STM TOT**	NCT3	NCT4	NCT5	NCT6	NCT TOT
1. GROSS MWH	367,721	1,200,484	1,568,205	1,223	1,084	788	860	3,955
*2. AUX. LOAD	29,010	59,338	88,348	278	339	358	420	1,395
3. NET MWH ONLINE (SYNC)	345,839	1,146,715	1,492,554	1,201	1,063	772	842	3,878
4. NET MWH OVERALL	338,711	1,141,146	$\boxed{1,479,857}$	945	745	430	441	2,560
5. NET MWH LST YR	716,556	1,633,244	2,349,800	1,000	1,043	881	1,180	4,104
6. % STATION GROSS GEN	23.4	76.4	99.7	0.1	0.1	0.1	0.1	0.3
7. ONLINE LOAD FACTOR %	51.9	37.6	40.2	42.9	40.3	36.4	35.3	9.7
8. CAPACITY FACTOR %	16.0	26.5	23.0	0.3	0.2	0.2	0.2	0.2
*9. #6 OIL BURNED ONLINE	468,939	1,304,664	1,773,603	NA	NA	NA	NA	NA
#6 OIL (BBLS) OVERALL	469,148	1,304,781	1,773,929	NA	NA	NA	NA	NA
#2 OIL BURNED ONLINE	NA	NA	NA	3,667	3,326	2,512	2,913	12,418
#2 OIL (BBLS) OVERALL	NA	NA	NA	3,944	3,578	2,722	3,165	13,409
#2 OIL BURNED (EQ BBL)	NA	NA	NA	3,652	3,313	2,520	2,930	12,415
GAS BURNED ONLINE	550,625	3,946,121	4,496,745	NA	NA	NA	NA	NA
GAS (KCF) OVERALL	573,830	3,978,034	4,551,864	NA	NA	NA	NA	NA
GAS BURNED (EQ BBL)	94,842	655,489	750,713	NA	NA	NA	NA	NA
TTL FUEL BURN (EQ BBL)	563,990	1,960,270	2,524,643	3,652	3,313	2,520	2,930	12,415
10. AVG BTU / BBL #6 OIL	6,355,576	6,379,133	6,372,903	NA	NA	NA	NA	NA
AVG BTU / BBL #2 OIL	NA	NA	NA	5,900,423	5,900,423	5,900,423	5,900,423	5,900,423
AVG BTU / FT3 GAS	1,050	1,051	1,051	NA	NA	NA	NA	NA
11. GROSS KWH / EQ BBL	652	612	621	335	327	313	NA	319
12. NET KWH / EQ BBL	601	582	586	259	225	171	NA	312
13. HEAT RATE (ONLINE)	10,290	10,875	10,740	18,013	NA	19,212	20,420	18,895
HEAT RATE (OVERALL)	10,583	10,958	$\boxed{10,872}$	24,639	28,335	37,352	NA	30,902
14. NUMBER OF STARTS	29	20	49	33	30	25	30	118
15. HOURS OF OPERATION	2,703.1	6,167.0	8,870.0	54.4	51.4	41.3	46.5	193.6
16. ANNUAL REVENUE ($ 000)	23,365	78,720						

	OIL	GAS	HOURS
17. AUXILIARY BOILER	0	0	10.0

STATION INVENTORIES	#6 FUEL (bbl)	#2 FUEL (bbl)	MgO (gal)
18. ON HAND (BOY)	573,320.03	85,886.45	4,266.7
19. RECEIVED	1,782,285.54	0.00	24,823.0
20. ADJUSTMENT (+ = more)	0.00	0.00	0.0
21. BARGED IN/OUT	64.30	(64.30)	0.0
22. TTL AVAILABLE	2,355,669.87	85,822.15	29,089.7
23. ON HAND (EOY)	581,740.78	72,413.10	4,490.7
24. CONSUMED	$\boxed{1,773,929.09}$	$\boxed{13,409.05}$	24,599.0

*NOTES:

(2) CORRECTED FOR CIRCULATOR MWH USED FOR SJRPP

(9) AUXILIARY BOILER FUEL INCLUDED IN STATIONS'S OVERALL GAS BURNED.

OIL MEASUREMENTS CORRECTED TO THE END OF YEAR SOUNDINGS.

LIFETIME TOTALS	NS-1	NS-3
25. GROSS MWH	25,807,462	27,334,291
26. HOURS OF OPERATION	156,154	99,909
27. NUMBER OF STARTS	806	367

** UNIT TOTALS MAY NOT ADD UP TO STATION TOTALS DUE TO ADDITIONAL STATION AUXILIARY REQUIREMENTS.

(Attachment C)

NORTHSIDE GENERATING STATION

GENERATION STATISTICS

January-September 1997

GENERATION DATA (MWH)	Unit 1
1. GROSS MWH	494,373
*2. AUX. LOAD	
3. NET MWH ONLINE (SYNC)	
4. NET MWH OVERALL	
5. NET MWH LST YR	
6. % STATION GROSS GEN	
7. ONLINE LOAD FACTOR %	
8. CAPACITY FACTOR %	
*9. #6 OIL BURNED ONLINE	699,379
#6 OIL (BBLS) OVERALL	
#2 OIL BURNED ONLINE	
#2 OIL (BBLS) OVERALL	
#2 OIL BURNED (EQ BBL)	
GAS BURNED ONLINE	
GAS (KCF) OVERALL	310,846
GAS BURNED (EQ BBL)	
TTL FUEL BURN (EQ BBL)	
10. AVG BTU / BBL #6 OIL	
AVG BTU / BBL #2 OIL	
AVG BTU / FT3 GAS	
11. GROSS KWH / EQ BBL	
12. NET KWH / EQ BBL	
13. HEAT RATE (ONLINE)	
HEAT RATE (OVERALL)	
14. NUMBER OF STARTS	
15. HOURS OF OPERATION	
16. ANNUAL REVENUE ($ 000)	
17. AUXILIARY BOILER	

STATION INVENTORIES

18. ON HAND (BOY)
19. RECEIVED
20. ADJUSTMENT (+ = more)
21. BARGED IN/OUT
22. TTL AVAILABLE
23. ON HAND (EOY)
24. CONSUMED

LIFETIME TOTALS

25. GROSS MWH
26. HOURS OF OPERATION
27. NUMBER OF STARTS

Attachment D

Jacksonville Electric Authority
Statistical Information
for the Twelve Months Ending September 30, 1997
Total Degree Day Comparison

Month	NOAA 30 Year Average	Fiscal Year 1995/96	Fiscal Year 1996/97	Percentage Change 97 vs 96	Percentage Change 97 vs NOAA
October	210	296	198	-33%	-6%
November	205	288	218	-24%	6%
December	356	377	313	-17%	-12%
January	452	405	348	-14%	-23%
February	318	303	221	-27%	-31%
March	217	302	174	-42%	-20%
April	134	180	159	-12%	19%
May	260	350	243	-31%	-7%
June	423	416	365	-12%	-14%
July	515	549	531	-3%	3%
August	502	445	485	9%	-3%
September	393	381	415	9%	6%
Total	3,985	4,292	3,670	-14%	-8%
JAN-SEPT	3214		2941		-8.5%

Firm KWH Sales

	Fiscal Year 1995/96	Fiscal Year 1996/97	Percentage Change 97 vs 96
Total	10,110,464,307	10,023,800,060	-1.0%

Average Number of Territorial Customers

	Fiscal Year to Date 1995/96	Fiscal Year to Date 1996/97	Percentage Change 97 vs 96
Total	328,371	335,463	2.3%

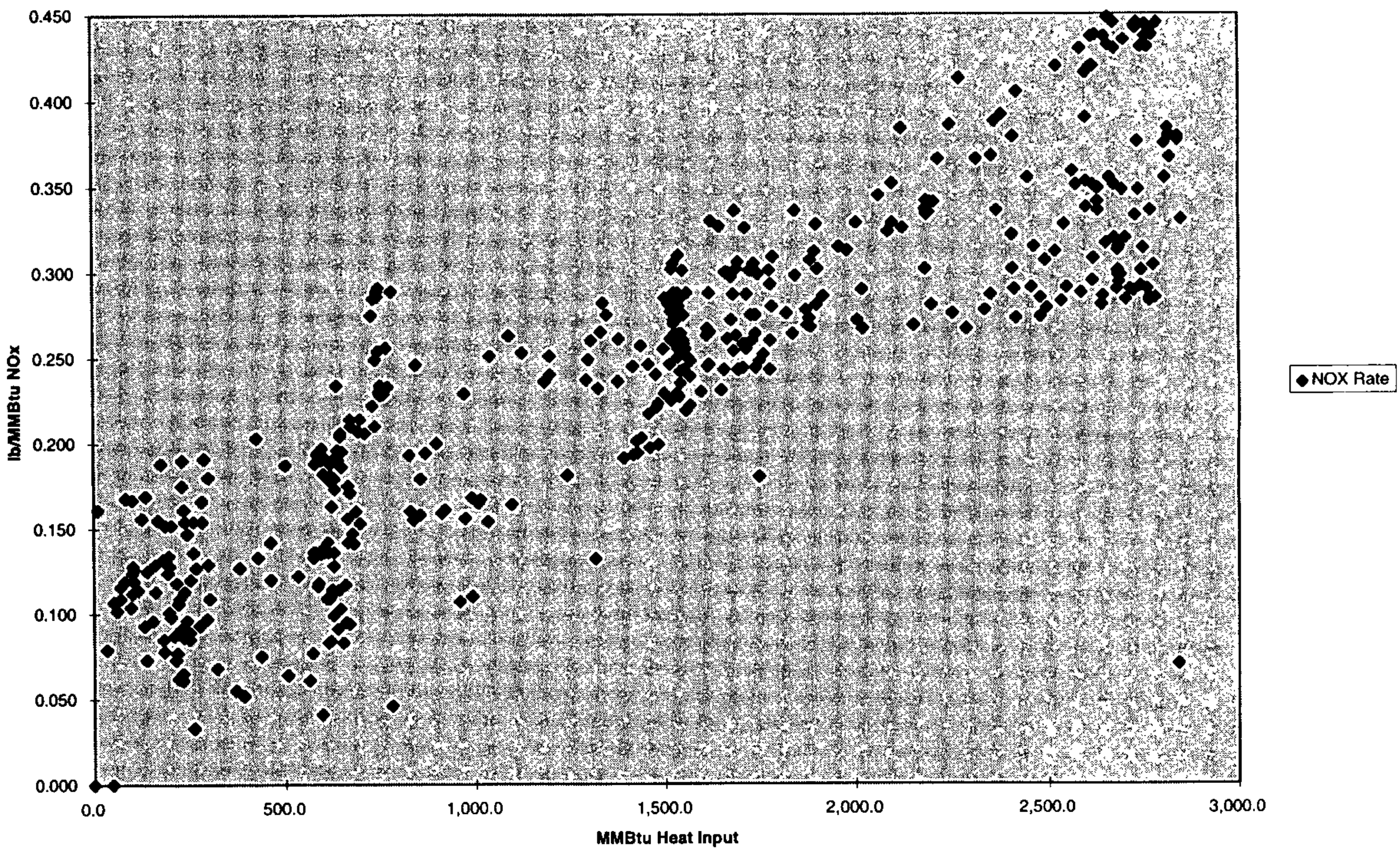
Attachment E

Jacksonville Electric Authority

CEM NS #1 Annual Emission Data

YEAR	1995	1996	1997 (Jan-Sep)
Tons of SO_2	4,328.3	3,674	4,083
Tons of NOx	1,081.7	661	913
NOx Rate	0.284	0.359	0.33
Load Factor	52.85	49.47	47.6
Cap. Factor	31.91	15.22	27.44

NOx Rate vs. Load (NGS Unit 1)



Attachment F

NS # 1Stack Tests for Nox and Particulate Lb/ Million BTU

Date	Soot Blowing	No soot Blow	Nox	MW	Fuel
July 88	0.213	0.097		250	# 6 oil
July 89	0.131	0.058		250	# 6 oil
July 90	0.128	0.075		255	# 6 oil
July 91	0.177	0.062		275	# 6 oil
Feb 92	0.100	0.03	0.38 @ 7.2% O2 0.24 @ 7.1% O2 0.32 @ 6.6% O2	252 252 252	# 6 oil 50/50 gas&oil 100% gas
June 93	0.25	0.08	0.29 @ 4.6% O2		
Aug 93	0.101	0.068		170	oil
Dec 93	0.110	0.072		248	oil
Aug 95	0.103	0.082		240	oil
Aug 96	0.069	0.066		250	oil
Aug 97	0.118	0.055		250	oil

FOSTER WHEELER ENVIRONMENTAL CORPORATION
EXCEL 5.0 CALCULATION SHEET

By: E. Deken, PE
Date: 12/5/97
Ck'd By:
Date:

Cal. No.: 971008ED01
Rev. No.: 1
OFS: 7830.0020.0030

Project: JEA Northside Generating Station Repowering
Subject: Emission Estimates - Unit 1

Operating Data

Calendar Year (Jan - Dec)	1994	1995
Operating Hours	6734.7	5289.5
Nat. Gas Heat Content (Btu/scf)	1047	1049
Nat. Gas Usage (mmCF/yr)	1409.5	3189.963
Nat. Gas Sulfur Cont. (gr/scf)	0.0032	0.0032
No. 6 Heat Content (Btu/gal)	151263	151466
No. 6 Sulfur Content (%wt)	1.69	1.43
Assumed No. 6 Density (lb/gal)	7.88	7.88
No. 6 Usage (kgal/yr)	56608	29051.15

Emission Estimates (tons/year)

	E.F.	Units	Tons/Year	
Oxides of Nitrogen(1994)	0.359	lb/mmbtu	1801.9	Based on CEMS generated emission factor and calculated heat input
Oxides of Nitrogen(1995)	0.284	lb/mmbtu	1081.7	Based on CEMS generated emission factor and CEMS reported heat input
2-year Average			1441.801	

No. 6 Firing

Pollutant	E.F.	Units	1994	E.F.	Units	1995	2-yr Ave.	
Carbon Monoxide	5	lb/kGal	141.5	5	lb/kGal	72.6	107.1	Ref. - AP42, 5th Edition
Volatile Organic Compounds	0.76	lb/kGal	21.5	0.76	lb/kGal	11.0	16.3	Ref. - AP42, 5th Edition
Sulfur Dioxide	265.33	lb/kGal	7510	Cems Data	na	4328.3	5919.1	Ref. - AP42, 5th Edition
Particulate Matter	18.7511	lb/kGal	530.7	16.3617	lb/kGal	237.7	384.2	Ref. - AP42, 5th Edition
Particulate Matter (PM10)	13.31328	lb/kGal	376.8	11.616807	lb/kGal	168.7	272.8	Ref. - AP42, 5th Edition

N.G. Firing

Pollutant	E.F.	Units	1994	1995	2-yr Ave.	
Carbon Monoxide	40	lb/mmCF	28.2	63.8	46.0	Ref. - AP42, 5th Edition
Volatile Organic Compounds	1.41	lb/mmCF	1.0	2.2	1.6	Ref. - AP42, 5th Edition
Sulfur Dioxide	0.6	lb/mmCF	0.4	1.0	0.7	Ref. - AP42, 5th Edition
Particulate Matter	5	lb/mmCF	3.5	8.0	5.7	Ref. - AP42, 5th Edition
Particulate Matter (PM10)	5	lb/mmCF	3.5	8.0	5.7	Ref. - AP42, 5th Edition

Totals

Pollutant	1994	1995	2-yr Ave.
Oxides of Nitrogen	1801.9	1081.7	1441.8
Carbon Monoxide	169.7	136.4	153.1
Total Organic Compounds	22.5	13.3	17.9
Sulfur Dioxide	7510.3	4329.3	5919.8
Particulate Matter	534.3	245.6	389.9
Particulate Matter (PM10)	380.3	176.7	278.5

Attachment I

CA-NGS Unit 1 (noncnteria)

FOSTER WHEELER ENVIRONMENTAL CORPORATION
EXCEL 5.0 CALCULATION SHEET

By: E. Deken, PE
Date: 12/4/97

Cal. No.: 971008ED01
Rev. No.: None
OFS: 7830.0020.0030

Project: JEA Northside Generating Station Repowering
Subject: Emission Estimates - Unit 1 (noncriteria pollutants)

Operating Data

Calendar Year (Jan - Dec)	1994	1995
Operating Hours	6734.7	5289.5
Nat. Gas Heat Content (Btu/scf)	1047	1049
Nat. Gas Usage (mmCF/yr)	1409.5	3189.963
Nat. Gas Sulfur Cont. (gr/scf)	0.0032	0.0032
No. 6 Heat Content (Btu/gal)	151466	151263
No. 6 Sulfur Content (%wt)	1.69	1.43
Assumed No. 6 Density (lb/gal)	7.88	7.88
No. 6 Usage (kgal/yr)	56608	29051.148

Emission Estimates (tons/year)

No. 6 Firing

Pollutant	E.F.	Units	1994	E.F.	Units	1995	2-yr Ave.	
Lead	0.00151	lb/kGal	0.04274	0.00151	lb/kGal	0.02193	0.03234	Ref. - AP42,Section 1.3 (10/96)
Fluorides	0.0373	lb/kGal	1.05574	0.0373	lb/kGal	0.54180	0.79877	Ref. - AP42,Section 1.3 (10/96)
Sulfuric Acid Mist	5.7S	lb/kGal	272.7	5.7S	lb/kGal	118.4	195.525	Ref. - AP42,Section 1.3 (10/96)
Mercury	0.000113	lb/kGal	0.00320	0.000113	lb/kGal	0.00164	0.00242	Ref. - AP42,Section 1.3 (10/96)

N.G. Firing

Pollutant	E.F.	Units	1994	1995	2-yr Ave.	
Lead	0.000271	lb/mmCF	0.000191	0.000432	0.000312	Ref. - AP42, Section 1.4
Fluorides	na	lb/mmCF	0.0	0.0	0.0	Ref. - AP42, Section 1.4
Sulfuric Acid Mist	mass balance	na	0.00000006	0.00000015	0.00000010	Ref. - AP42/Mass Balance
Mercury	0.00078	lb/10^12 btu	0.000003	0.000002	0.000003	Ref. - FCG Factor (EPRI)

Totals

Pollutant	1994	1995	2-yr Ave.
Lead	0.04293	0.02237	0.03265
Fluorides	1.05574	0.54180	0.79877
Sulfuric Acid Mist	272.652	118.3980	195.525
Mercury	0.00320	0.00164	0.00242

"Existing" Unit 2 Potential Emissions*

	NATURAL GAS				FUEL OIL					Permit Limit	Potential Emissions
POLLUTANT	Em. Factor (lb/mm cu. ft.)	Max. Gas Consumed (mm cu.ft./hour)	Hours of Operation (hours/year)	Emissions (tons/year)	Em. Factor (lb/1000 gal)	Max. Oil Consumed (1000 gal/hour)	Hours of Operation (hours/year)	Max. S Content (% Sulfur)	Emissions (tons/year)	(tons/year)	(tons/year)
NOx	550	2.66	8760	6407.94	67	18.14	8760	1.8	5323.364		6407.94
SO2	0.6	2.66	8760	6.99048	157S	18.14	8760	1.8	22453.47	20397	20397
H2SO4		2.66	8760	0	5.7S	18.14	8760	1.8	815.1898		815.1898
PM	5	2.66	8760	58.254	9.19S+3.22	18.14	8760	1.8	1570.154	1287	1287
PM10	5	2.66	8760	58.254	.71(9.19S+3.22	18.14	8760	1.8	1114.809		1114.809
CO	40	2.66	8760	466.032	5	18.14	8760	1.8	397.266		466.032
VOC	1.41	2.66	8760	16.42763	0.76	18.14	8760	1.8	60.38443		60.38443
beryllium		2.66	8760	0	0.0000278	18.14	8760	1.8	0.002209		0.002209
fluorides		2.66	8760	0	0.0373	18.14	8760	1.8	2.963604		2.963604
lead	0.000271	2.66	8760	0.003157	0.00151	18.14	8760	1.8	0.119974		0.119974
mercury		2.66	8760	0	0.000113	18.14	8760	1.8	0.008978		0.008978

* Unit 2 can be fired on oil or gas therefore the potential emissions for both fuels are shown.
Emissions were based on AP-42, maximum hourly fuel consumption, 100% CF, and permit limits. The maximum fuel consumption was obtained from JEA Annual Operating Reports.

Attachment J

Al,

New Combustion Turbine Installation
Kennedy Generating Station

DRAFT
Ambient Air Quality Impact Analysis and Permitting Workplan

Prepared by
Black & Veatch

for
Jacksonville Electric Authority

December 1997

Project No.
29686

Date: 12/11/97 5:42:00 PM
From: Orvis, David P.
Subject: JEA Draft Workplan

B&V Project 29686.030
B&V File 32.0404

Al/Martin,

Attached for your review is a draft air permitting/modeling workplan which has been prepared by Black & Veatch for the Jacksonville Electric Authority (JEA). This workplan addresses the proposed installation of a new combustion turbine at JEA's Kennedy Station. It is my understanding that one or both of you will be involved in FDEP's review of this project.

As you are probably aware, a meeting between JEA, FDEP and Black & Veatch has been scheduled for next week. The purpose of that meeting will be to discuss permitting issues and finalize the draft workplan.

The attached document was prepared in Microsoft Word 6.0. If an alternate format is needed, or if you have any questions concerning this transmittal, feel free to contact me directly at (913) 458-7746. Thank you.

David Orvis

Table of Contents

Table of Contents (cont.)

List of Tables

List of Appendices

1.0 Introduction

The Jacksonville Electric Authority (JEA) proposes to construct a new combustion turbine at the existing Kennedy Generating Station in Jacksonville, Florida. Concurrently, an existing natural gas and #6 fuel oil fired boiler at the facility (hereafter referred to as KE10) will be taken out of service. This document has been developed to propose an air permitting approach and an air quality impact analysis (AQIA) air dispersion modeling methodology for review and approval by the Florida Department of Environmental Protection (FDEP).

Due to the low capacity factor at which the turbine will operate, JEA intends to request permit terms such that the project will not be subject to Prevention of Significant Deterioration (PSD) pre-construction review requirements. Nevertheless, a portion of this document has been directed towards PSD review requirements in order to facilitate discussion of permitting issues.

2.0 Project Characterization

The following sections briefly characterize the project including a general description of the facility, location, and emission units, as well as an overview of the of the local ambient air quality status and air permitting approach.

2.1 Project Description

JEA proposes to construct a 165 megawatt, natural gas and #2 oil fired, simple cycle combustion turbine at the existing Kennedy Generating Station in Jacksonville, Florida. The proposed combustion turbine would replace an aging natural gas and oil fired boiler (KE10), and is expected to be used as a peaking unit. KE10 would be taken out of service once the new combustion turbine becomes operational.

The specific turbine to be installed has yet to be selected. Thus, this document has been prepared using more general information concerning the proposed installation.

2.2 Project Location

The Kennedy Generating Station is located in at 4215 Talleyrand Avenue in Jacksonville, Florida (approximate UTM coordinates 3359100 North and 440000 East, Zone 17), along the St. Johns River. The base elevation for this facility is approximately 10 feet above mean sea level. The surrounding terrain ranges from being essentially flat to gently rolling hills. The five Class I areas nearest the Kennedy facility are outlined in Table 2-1.

2.3 Project Emissions

As stated above, KE10 will be taken out of service following the installation and successful startup of the proposed combustion turbine. Therefore, a netting analysis will be performed to determine the net emissions increase associated with this project. In this analysis, past actual KE10 emissions will be subtracted from the PTE of the new turbine to determine the net emissions increase. The net emission rate of each pollutant will be compared to PSD significant emission rates to determine PSD applicability.

Table 2-1

Class I Areas Nearest to Kennedy Facility

Area	State	Approximate Distance from Kennedy Facility
Wolf Island	Georgia	114 km
Okefenokee	Georgia	56 km
Bradwell Bay	Florida	223 km
Saint Marks	Florida	223 km
Chassahowitzka	Florida	200 km

Representative manufacturer's data will be used to characterize and quantify the potential to emit (PTE) of criteria pollutants from the proposed turbine. In determining the PTE of the turbine, the range of possible fuel types and unit loads will be examined. Any federally enforceable limits on operation which are requested by JEA will be taken into account. For each pollutant, the scenario which produces the highest annual emissions will be assumed in determining the PTE of the pollutant. The average annual temperature for Jacksonville, Florida, will be assumed in calculating the turbine's annual PTE.

Past actual emissions from KE10 will be estimated based on current AP-42 emission factors coupled with the past actual operational data. Pursuant to PSD guidelines, the two most recent consecutive years of operating data should be used, unless these years are shown to be unrepresentative. In this case, the 1995 and 1996 operating years meet the criteria of being the two most recent consecutive years of operating data, and are thought to represent typical KE10 operation. Therefore, it is proposed that 1995 and 1996 operational data will be used to determine past KE10 actual emissions.

In addition to being used in the netting analysis to determine PSD applicability, these emission estimates will also be used to develop representative worst-case emission rates for the air dispersion modeling analysis as described in Section 3.1, if such analysis is required.

2.4 Local Air Quality Attainment/Nonattainment Status

The air quality in a given area is generally designated as being in attainment for a pollutant if the monitored concentrations of that pollutant are less than the applicable National Ambient Air Quality Standards (NAAQS). Likewise, a given area is generally classified as nonattainment for a pollutant if the monitored concentrations of that pollutant in the area are above the NAAQS.

A review of the air quality status in the region reveals that all areas in Florida are currently in attainment or unclassifiable for all pollutants. In Georgia, the nearest nonattainment area to the Kennedy facility is Muscogee County. At its closest point, the Muscogee County nonattainment area is more than 380 km from the proposed facility.

The portion of Duval County, Florida, in which the Kennedy facility is located is designated as an air quality maintenance area for the air pollutants ozone and PM_{10}. Accordingly, the construction permit application submitted for the proposed turbine will address any requirements associated with Duval County's air quality maintenance area status.

2.5 Air Permitting Approach

The air permitting requirements will depend on the net emission increase associated with this project. General air permitting requirements are discussed in Section 2.5.1; these will likely satisfy air permitting requirements for this project. As noted above, it is anticipated that the net emission increases will not exceed the PSD significant emission rates. However, an approach to PSD requirements is presented in Section 2.5.2 for discussion purposes.

2.5.1 State of Florida General Construction Permitting Requirements

A complete application to construct the proposed turbine will be submitted to the FDEP on appropriate forms. This application will be certified by a professional engineer registered in the State of Florida. Supporting documents will be certified by a professional engineer registered in the State of Florida if such certification is required.

All application materials and supporting documents will be filed in quadruplicate.

As required by FDEP regulation, the following two items will accompany the application. First, an engineering report will be provided which covers plant description and operations, types and quantities of air emissions to be generated, design criteria on which controls are based, and other relevant information. Second, the facility owner will provide a written guarantee to meet the design criteria as accepted by the FDEP and to abide by Chapter 403, F.S., and the rules of the FDEP as to the quantities and types of materials to be discharged from the installation. An air toxics review may also be required as part of the application process; this issue is discussed in Section 3.4.

It is proposed that air dispersion modeling of criteria pollutants need not be performed if this project is not subject to PSD requirements. The proposed turbine, with the operational restrictions JEA will be requesting, is a relatively small emission source. The hot plume typical of combustion turbines will result in high dispersion of air pollutants, lowering ground level impacts. Finally, since KE10 will be taken out of service as part of this project, ground level impacts from the turbine are expected to be offset by the elimination of previous impacts from KE10.

2.5.2 Prevention of Significant Deterioration Applicability

The federal Clean Air Act (CAA) NSR provisions are implemented for new major stationary sources and major modifications under two programs; the PSD program outlined in 40 CFR 52.21, and the Nonattainment NSR program outlined in 40 CFR 51 and 52. As noted in Section 2.4, the proposed facility is in an attainment area with respect to all pollutants. As such, the PSD program will apply to the proposed combustion turbine if the net emission increase of at least one pollutant exceeds that PSD significant emission rate for that pollutant.

The PSD regulations are designed to ensure that the air quality in existing attainment areas does not significantly deteriorate or exceed the NAAQS while providing a margin for future industrial and commercial growth. PSD regulations apply to major stationary sources and major modifications at major existing sources undergoing construction in areas designated as attainment or unclassifiable under Section 107 of the CAA for any criteria pollutant.

A major stationary source is defined as any one of the listed major source categories which emits, or has the potential to emit, 100 TPY or more of any regulated pollutant, or 250 TPY or more of any regulated pollutant if the facility is not one of the listed major source categories. The existing Kennedy facility is a listed major source category (fossil fuel fired steam electric plant) and has the potential to emit 100 TPY of at least one regulated pollutant, making it a major source. Thus, once final emission estimates have been prepared for the proposed project, the net emission increase of each pollutant will be compared against the appropriate PSD significant emission rate. If the net emission increase of at least one pollutant exceeds the PSD significant emission rate for the pollutant, the project would be considered a major modification.

As a major modification, PSD applicability would be determined on a pollutant by pollutant basis by comparing the proposed project net emission increases with the PSD significant emission rates. For those pollutants with a net increase greater than the applicable PSD significant emission rates, the PSD Permit Application must contain the following:

- an AQIA
- best available control technology (BACT) analysis
- an assessment of the total project's impact on general commercial, residential, and commercial growth, soils and vegetation, and visibility.

A table of contents for the proposed project's PSD Permit Application is included in Appendix A. The AQIA is discussed in Sections 3.1 and 3.2, while the additional impact analysis is addressed in Section 3.3.

3.0 Air Quality Impact Analysis

The following sections discuss the air dispersion modeling methodology and AQIA that are proposed, should such work be required. Any air dispersion modeling analyses will be conducted in accordance with USEPA's air dispersion modeling guidelines (incorporated as Appendix W of 40 CFR 51), as well as a mutually agreed upon modeling methodology initiated by this work plan.

3.1 Air Dispersion Modeling Methodology

The Industrial Source Complex Short-Term (ISCST3 Version 96113) air dispersion model is proposed for modeling purposes. The ISCST3 model is an USEPA approved, steady-state, straight-line Gaussian plume model, which may be used to assess pollutant concentrations from a wide variety of sources associated with an industrial source complex. In addition, ISCST3, unlike its predecessors, incorporates the COMPLEX1 dispersion algorithm for determining intermediate and complex terrain concentration impacts in accordance with USEPA guidance.

The ISCST3 air dispersion model would be used in two modes. First, the model would be used in a screening mode to determine the worst-case combustion turbine operating scenario based on maximum predicted concentrations, and then in a refined mode (based on the worst-case operating scenario identified in the screening phase) to determine the maximum predicted impact concentrations for the AQIA. The screening and refined ISCST3 modeling methodologies are discussed below.

3.1.1 Screening Level Modeling

The ISCST3 model would first be used in a screening mode to determine the worst-case combination of operating loads, fuel type and ambient temperature that produce the maximum predicted ground level pollutant concentrations.

In the screening mode, the ISCST3 model would use a matrix of worst-case meteorological data derived from USEPA's *SCREEN3 Model User's Guide* to determine worst-case operating scenarios based on 1-hour model predicted concentrations. The turbine operating scenarios producing the highest 1-hour concentration in the ISCST3 screening evaluation for each pollutant would be carried forward into the refined modeling analysis.

3.1.2 Refined Modeling

The worst-case representative operating scenario for the proposed turbine, based on the results of the screening level modeling analysis discussed in Section 3.1.1, would be used in the refined ISCST3 modeling for the PSD AQIA. Here, actual sequential hourly meteorological data would be used in ISCST3 to predict concentrations for each pollutant and applicable averaging period. These data are discussed in Section 3.1.6.

3.1.3 GEP and Building Downwash Evaluation

As part of any modeling effort, buildings and structures of the facility would be analyzed to determine the potential to influence the dispersion of the proposed turbine's emissions. The USEPA's *Guideline for Determination of Good Engineering Practice Stack Height* guidance document would be followed in this evaluation. Structure dimensions and relative locations would be entered into the USEPA's Building Profile Input Program (BPIP) to produce an ISCST3 input file with the proper Huber-Snyder or Schulman-Scire direction specific building downwash parameters. This same program would also determine a good engineering practice (GEP) stack height for the proposed turbine stacks.

3.1.4 Model Options

The following standard USEPA default regulatory modeling options would be invoked in the ISCST3 model during both the screening and refined level modeling runs:

- Final plume rise.
- Stack-tip downwash.
- Buoyancy induced dispersion.
- Default vertical wind profile exponents and vertical potential temperature gradient values.
- Calm processing option.

Terrain elevations would be incorporated provided that the surrounding terrain rises to at least 50% of the stack height. Should the surrounding terrain not meet this criterion, if is proposed that no terrain heights need be utilized.

3.1.5 Receptor Grids and Terrain Considerations

Air dispersion modeling receptor locations would be established at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the area. Specifically, a nested rectangular grid network is proposed that will extend 10 km from the center of proposed facility. The rectangular grid network would consist of 100 m spacing from the proposed fenceline out to 1000 m, 500 m spacing out to 5 km, and then 1,000 m spacing from 5 to 10 km. Receptor spacing at 100 m intervals would be used along the proposed property fenceline. The receptor grid would be extended as necessary to ensure that the significant impact area is defined.

If, based on the criteria discussed in Section 3:1.4, it is deemed necessary to enter terrain elevations into the ISCST3 model, the elevations for the receptor locations would be obtained from 7.5 minute USGS topographic maps. The terrain elevations would be determined by finding the maximum elevation in an area surrounding each receptor. The area considered for each receptor would consist of a "box" with boundaries drawn midway between the particular receptor and the adjacent receptor. This method would ensure that the highest (most conservative) elevations are used for each receptor.

3.1.6 Meteorological Data

The ISCST3 air dispersion model requires hourly input of specific surface and upper-air meteorological data. These data include the wind flow vector, wind speed, ambient temperature, stability category, and the mixing height. Five years of surface and upper air meteorological data from Jacksonville, Florida, and Waycross, Georgia, respectively, are proposed for any required ISCST3 refined air dispersion modeling analysis. Specifically, data from 1985-1988 and 1991 are proposed. These data would be downloaded from USEPA's SCRAM Bulletin Board and processed with PCRAMMET to combine the surface and mixing height data, interpolate hourly mixing heights from the twice-daily mixing heights, and calculate atmospheric stability class. The proposed years represent the most recent sets of surface and mixing height data available from SCRAM.

3.1.7 Land Use Dispersion Coefficients

The USEPA's land use method would be used to determine whether rural or urban dispersion coefficients will be used in the ISCST3 air dispersion model. In this procedure, land circumscribed within a 3 km radius of the site is classified as rural or urban using the Auer land use classification method. If rural land use types are shown to account for more than 50 percent of the land use area within the 3 km radius, then the rural dispersion coefficient option is used. Otherwise, the urban coefficients is used.

Based on a preliminary inspection of USGS 7.5 minute topographic maps of the proposed site location, it appears that over 50 percent of the area surrounding the proposed project is rural. Accordingly, it is anticipated that the rural dispersion modeling option is appropriate.

3.2 Model Predicted Impacts

Based on the air dispersion modeling methodology outlined in the previous sections, the maximum model predicted ground-level concentrations for the worst-case operating scenario associated with the proposed project would be determined for each pollutant and applicable averaging period. From the modeling results, the significant impact area, preconstruction monitoring requirements, and the need for a NAAQS and PSD increment consumption analyses would be determined.

3.2.1 Significant Impact Area

For all PSD significant pollutants, the highest predicted concentrations due to emissions from the proposed turbine will be compared to the applicable PSD significant impact levels. If the model predicted maximum concentrations are less than the PSD significant impact levels for all pollutants and applicable averaging periods, then no further air dispersion modeling analyses will be performed. However, if one or more pollutants and applicable averaging periods are greater than the PSD significant impact levels, then a significant impact area will be determined and interacting source modeling will be performed for those pollutants. Interacting source modeling is described in Section 3.2.3.

3.2.2 Determination of Preconstruction Monitoring Requirements

Preconstruction monitoring issues will be addressed for all PSD significant pollutants. Ambient air quality data will be compared with the PSD significant monitoring concentrations. If examination of existing air quality data in the area shows that the existing ambient pollutant concentrations for each criteria pollutant are less than the applicable significant monitoring concentrations, then an exemption from pre-application monitoring will be requested for that pollutant.

If the existing air quality concentration for a given pollutant is equal to or greater than the applicable PSD significant monitoring concentration, then PSD pre-application monitoring applicability will be determined by comparing the pollutant's maximum model predicted concentration from the proposed turbine emissions to the applicable PSD significant monitoring concentration. If the proposed turbine's maximum model predicted concentration for that pollutant is less than the applicable PSD significant monitoring concentration, then an exemption from pre-application monitoring requirements will be requested for that pollutant.

In the event both the ambient air quality data and maximum model predicted impacts exceed the applicable PSD significant monitoring concentration for a given pollutant, then the existing ambient air quality monitoring network will be evaluated for representativeness of the project area pursuant to requesting a waiver from the pre-application monitoring requirements for that pollutant.

3.2.3 PSD Increment and NAAQS Analyses

If modeling results predict ground level pollutant impacts from the turbine emissions which exceed the applicable significant impact level, additional agency consultation will be requested and an inventory of PSD increment consuming sources and all nearby sources for the NAAQS analysis will be obtained and included as interactive sources in the air dispersion modeling.

For pollutants which have a net emission increase greater than the PSD significant emission rates, Class I air quality and visibility analyses will be conducted for the Okefenokee Class I Area. It is proposed that Class I air quality and visibility analyses are not necessary for the other areas listed in Table 2-1, as they are more than 100 km from the proposed facility.

3.3 Additional Impact Analysis

Federal PSD regulations require the preparation of an analysis of additional impacts due to construction and operation of a new major stationary source. The analysis considers impairment to visibility, soils, and vegetation, as well as projected air quality impacts that may occur as the result of general commercial, residential, industrial, and other growth associated with the proposed modification.

3.3.1 Commercial, Residential, and Industrial Growth

An estimate of the industrial, commercial, and residential growth resulting from the proposed modification will be made if the project is subject to PSD regulations. This estimate will be based on the projected construction schedules, operation work force size estimates, work force source areas (local vs. nonlocal), and projected estimates of new commercial facilities and services which will be added to the area to support the proposed facility and its employees.

These estimates will be used to qualitatively project air emissions associated with such growth. Due to the expected small number of staff that will be required to operate and maintain the proposed turbine, the effects to ambient air quality due to growth are expected to be insignificant. Consequently, an air dispersion modeling analysis of direct growth emissions is not planned.

3.3.2 Vegetation and Soils

If the project becomes subject to PSD requirements, an analysis will be performed to examine the proposed turbine's predicted air quality impacts on local soils and vegetation. The Environmental Impact Statement (EIS) and the secondary NAAQS will serve as a basis for assessing the vegetation and soil impacts.

3.3.3 Visibility

The effects on visibility in the local area where the proposed facility will be constructed will be examined provided that the project is subject to PSD requirements. This analysis will make use of procedures recommended in the EPA's draft *New Source Review Workshop Manual*, 1990, and the EPA document *Workbook for Plume Visual Impact Screening and Analysis*, 1988.

While there may be a net significant increase in CO emissions, these emissions will not affect visibility in the surrounding area. Furthermore, the proposed project is not expected to have a net significant emission increase for NO_2, SO_2, PM_{10}, VOC or Lead. Due to these facts, no visibility impairment is expected.

3.4 Toxic Air Pollutants Impact

Based on recent discussion with FDEP personnel, it was revealed that the FDEP air toxics review process is organized in a tiered fashion. The first tier incorporates projects which emit less than 1000 lb/year of a single hazardous air pollutant (HAP) from a single unit and less than 2500 lb/year of a single HAP facility-wide. Such installations are not required to conduct an air toxics review as part of the construction permit application process.

The second tier includes those projects which do not qualify for the first tier, but are also not major HAP sources. Here, an air toxics review is not automatically required by the FDEP but may be requested from the permit review engineer. In such a case, the most recent copy of FDEP's Air Toxics Permitting Strategy would be followed to assess the impact of HAP emissions from proposed facilities.

Finally, a third tier exists which includes major HAP sources (i.e., those with a potential to emit 10 tons/year of an individual HAP or 25 tons/year of combined HAPs). Such proposed sources are subject to review under Title III of the CAA, and must follow the appropriate review procedures.

It is anticipated that the proposed project will fall under the first or second tier. Should the project qualify for the first tier, no air toxics review will be conducted. If the second tier procedures are applicable, a toxics review will be conducted pursuant to the Florida Air Toxics Permitting Strategy if the review is requested by the FDEP. To determine tier applicability for the proposed turbine, toxic pollutant emission rates will be estimated based on available AP-42 emission factors and worst case operational data.

U. S. Department of Energy
Federal Energy Technology Center
3610 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507-0880

626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236-0940

FETC
We Solve National Energy and Environmental Problems

November 18, 1997

Mr. Al Linero
Florida Department of Environmental
Protection
Division of Air Resources Management
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

Dear Mr. Linero:

Announcement of Public Scoping Meeting for the Jacksonville Electric Authority (JEA) Circulating Fluidized Bed Combustor Project

The U.S. Department of Energy (DOE) is conducting a public scoping meeting in Jacksonville, Florida, on December 3, 1997, as part of the process for developing an Environmental Impact Statement (EIS). The EIS will evaluate the environmental and human health impacts of the proposed construction and operation of a new circulating fluidized bed (CFB) combustor to repower at existing steam turbine at JEA's Northside Generating Station in Jacksonville, Florida. The CFB combustor, fueled by coal and petroleum coke, would generate approximately 300 megawatts of electricity. The project is part of the national Clean Coal Technology Program, a $5 billion effort co-funded by government and industry, that is demonstrating a new generation of clean and efficient technologies in "showcase" facilities across the nation.

As part of the public scoping process to ensure that the full range of issues related to this proposal is addressed, DOE invites your attendance at the public meeting and solicits your oral and written comments. Enclosed are the Notice of Intent, published in the *Federal Register* on November 13, 1997, and a 1-page fact sheet for the project which provide further details on the project and scoping meeting.

Sincerely,

RECEIVED
NOV 24 1997
BUREAU OF
AIR REGULATION

Jan K. Wachter

Jan K. Wachter
Director
Environmental, Safety, and Health Division

Enclosures

cc: S. Arif, BAR

REPLY TO: Morgantown Office
Voice (304)285-4607 • FAX (304)285-4403 • jwacht@fetc.doe.gov • http://www.fetc.doe.gov

UNITED STATES DEPARTMENT OF ENERGY
PUBLIC SCOPING MEETING
JACKSONVILLE ELECTRIC AUTHORITY
CIRCULATING FLUIDIZED BED COMBUSTOR PROJECT
ENVIRONMENTAL IMPACT STATEMENT

On November 13, 1997, the U.S. Department of Energy (DOE) issued a Notice of Intent (NOI) in the *Federal Register* (62 FR 60889-60892) to prepare an Environmental Impact Statement (EIS) and to conduct a public scoping meeting for a proposed circulating fluidized bed combustor at Jacksonville Electric Authority's (JEA's) Northside Generating Station in Jacksonville, Florida. The proposed coal- and petroleum coke-fired combustor would repower an existing steam turbine to generate about 300 megawatts of electricity. JEA has proposed the project and plans to form an alliance with Foster Wheeler Corporation to jointly own and operate the project. The proposed Federal action is to provide cost-shared funding support through the Clean Coal Technology Program. The EIS will assess the potential environmental and human health effects associated with the construction and operation of the project.

DOE will hold a public scoping meeting in which agencies, organizations, and individuals are invited to present oral comments or suggestions with regard to the range of actions, alternatives, and impacts to be considered in the EIS. The public scoping meeting will be held:

DATE:	**Wednesday, December 3, 1997**
TIME:	**7:00 p.m.**
PLACE:	**Northside Generating Station** **In-Plant Conference Room** **4377 Heckscher Drive** **Jacksonville, Florida**

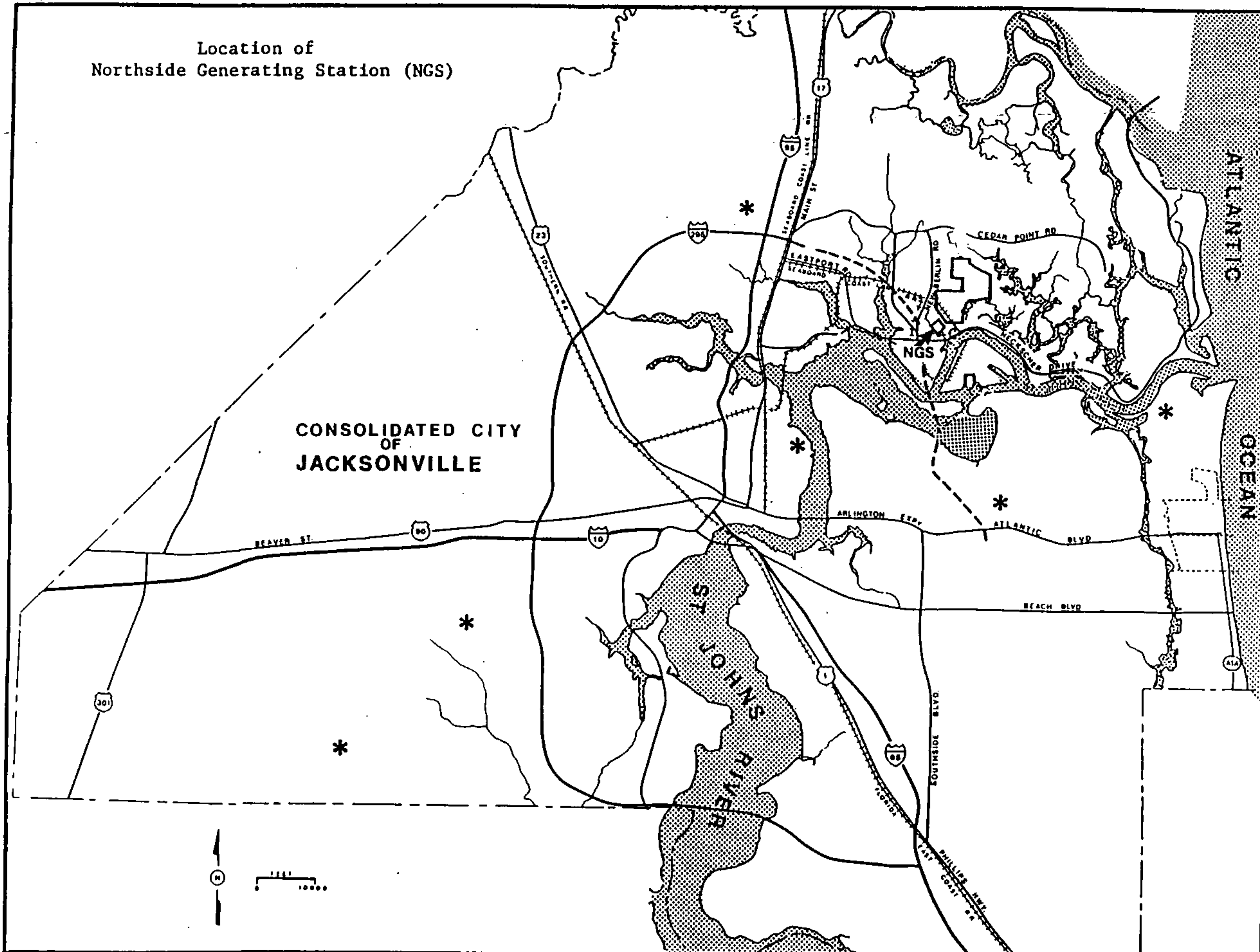
Prior to the meeting, an informal session to discuss the project with DOE and JEA personnel will be held from 5:00 p.m. to 7:00 p.m. Individuals may register in advance to speak at the public scoping meeting by calling Dr. Jan Wachter at direct telephone (304) 285-4607; toll free number 1-800-432-8330 (ext. 4607); fax 304-285-4469; E-mail JWACHT@FETC.DOE.GOV; or in person at the public meeting prior to or during the session.

To ensure that the full range of issues related to this proposed project are addressed, DOE also invites written comments or suggestions on the scope of the EIS, which should be postmarked by December 31, 1997. Written comments, requests to speak at the public scoping meeting, or questions concerning the proposed project should be directed to:

Dr. Jan Wachter
U.S. Department of Energy
Federal Energy Technology Center (FETC)
3610 Collins Ferry Road
Morgantown, West Virginia 26507-0880

Envelopes should be marked "Scoping for JEA EIS."

Location of
Northside Generating Station (NGS)



[6450-01-P]

DEPARTMENT OF ENERGY

Notice of Intent to Prepare an Environmental Impact Statement and Notice of Floodplain and Wetlands Involvement for the Proposed Jacksonville Electric Authority Circulating Fluidized Bed Combustor Project

AGENCY: Department of Energy

ACTION: Notice of Intent to prepare an Environmental Impact Statement (EIS), and Notice of Floodplain and Wetlands Involvement

SUMMARY: The Department of Energy (DOE) announces its intent to prepare an Environmental Impact Statement (EIS) pursuant to the National Environmental Policy Act (NEPA) of 1969, as amended (42 U.S.C. 4321 *et seq.*), the Council on Environmental Quality NEPA regulations (40 CFR Parts 1500-1508), and the DOE NEPA regulations (10 CFR Part 1021), to assess the potential environmental and human health impacts of the construction and operation of a project proposed by the Jacksonville Electric Authority (JEA) that has been selected by DOE to demonstrate circulating fluidized bed (CFB) technology under the Clean Coal Technology (CCT) Program. The proposed project would involve construction and operation of a CFB combustor fueled by coal and petroleum coke to repower an existing steam turbine at JEA's Northside Generating Station in Jacksonville, Florida, to generate nearly 300 megawatts of electricity (MWe). This EIS will support a DOE decision regarding whether DOE will provide approximately $75 million in cost-shared funding (about 24% of the total cost of approximately $309 million) for the proposed project.

The purpose of this Notice of Intent is to inform the public about the proposed action; present the schedule for the action; announce the plans for a public scoping meeting; invite public participation in the scoping process; and solicit public comments for consideration in establishing the scope and content of the EIS. The EIS will evaluate the potential impacts of the proposed action and reasonable alternatives. Because the proposed project may involve an action in floodplains and wetlands, the EIS will include a floodplain and wetlands assessment and a statement of findings in accordance with DOE regulations for compliance with floodplain and wetlands environmental review requirements (10 CFR Part 1022).

DATES: To ensure that the full range of issues related to this proposal is addressed, DOE invites comments on the scope and content of the EIS from all interested parties. All comments must be received by December 31, 1997, to ensure consideration. Late comments will be considered to the extent practicable. In addition to receiving comments in writing and by telephone, DOE will conduct a public scoping meeting in which agencies, organizations, and the general public are invited to present oral comments or suggestions with regard to the range of actions, alternatives, and impacts to be considered in the EIS. The scoping meeting will be held at the Northside Generating Station, In-Plant Conference Room, 4377 Heckscher Drive, Jacksonville, Florida, on Wednesday, December 3, 1997, at 7 p.m.

ADDRESSES: Written comments and requests to participate in the public scoping process should be addressed to: Dr. Jan Wachter, NEPA Document Manager for the JEA Project, Federal Energy Technology Center, U.S. Department of Energy, 3610 Collins Ferry Road, Morgantown, WV 26507-0880. Individuals who would like to verbally or electronically provide comments should contact Dr. Wachter at direct telephone 304-285-4607; toll free number 1-800-432-8330 (ext. 4607); fax 304-285-4469; or E-mail JWACHT@FETC.DOE.GOV.

DOE CONTACTS FOR FURTHER INFORMATION: To obtain additional information about this project or to receive a copy of the draft EIS when it is issued, contact Dr. Jan Wachter at the address provided above. For general information on the DOE NEPA process, contact Ms. Carol M. Borgstrom, Director, Office of NEPA Policy and Assistance (EH-42), U.S. Department of Energy, 1000 Independence Avenue, S.W., Washington, D.C. 20585-0119; telephone 202-586-4600; or leave a message at 1-800-472-2756.

BACKGROUND AND NEED FOR THE PROPOSED ACTION: Under Public Law 99-190, Congress provided authorization and funds to DOE to support the construction and operation of demonstration facilities selected for cost-shared financial assistance as part of DOE's CCT Program. In December 1985, Congress made funds available to DOE for conducting the first round of the CCT Program. Congress directed that this first solicitation for federal cost-sharing (1) be open to all market applications of clean coal technologies, (2) apply to any segment of the U.S. coal resource base, and (3) encompass both new and retrofit applications. In response to the solicitation, proposals were received and projects were selected by DOE for negotiation. In addition, a list of alternate candidates was established from which replacement selection could be made should any of the original selections not proceed. JEA's proposed CFB combustor project has evolved through a series of site changes from a project that was selected from the alternate list for demonstration.

The demonstration of JEA's CFB combustor project under the CCT Program would fulfill an existing DOE programmatic need. Coal has the potential to address critical energy supply issues because of its abundant reserves; however, barriers to increased use of coal include concerns about environmental issues, such as acid deposition, global climate change, polyaromatic hydrocarbon emissions, and solid waste. Since the early 1970s, DOE and its predecessor agencies have sponsored long-term programs to develop innovative coal technologies through the proof-of-concept stage to overcome these environmental barriers while improving combustion efficiency and reducing costs.

However, the availability of a technology at the proof-of-concept stage is not sufficient to ensure its continued development and subsequent commercialization. Before any technology can seriously be considered for commercialization, it must be demonstrated at a large enough scale to prove its reliability and to show economically competitive performance. The financial risk associated with such large-scale demonstration is, in general, too high for the private sector to assume in the absence of strong incentives. The congressionally-directed CCT Program provides a mechanism to accelerate the commercialization of innovative technologies to meet the nation's near-term energy and environmental goals, to reduce technological risk to industry to an acceptable level, and to provide private sector incentives required for continued research and development aimed at finding solutions to long-range energy supply problems.

PROPOSED ACTION: The proposed action is for DOE to provide, through a cooperative agreement with JEA, cost-shared financial assistance to JEA for the design, construction, and operation of the proposed project, as described below. JEA plans to form an alliance with Foster Wheeler Corporation through its subsidiary, Foster Wheeler Power Systems, Inc., to jointly own and operate the project. Together with other Foster Wheeler affiliates, Foster Wheeler Power Systems, Inc. will provide the CFB combustor and perform the project engineering, procurement, and construction. The demonstration project would last 24 months and cost approximately $309 million, with DOE's share being nearly $75 million (24%). The proposed project would be located at JEA's existing Northside Generating Station in Jacksonville, Florida, which currently consists of 3 heavy oil- and natural gas-fired steam generation units and 4 diesel oil-fired combustion turbine units.

The Northside Generating Station is approximately 10 miles north of downtown Jacksonville, Florida. The Northside Generating Station is an industrial site encompassing approximately 400 acres, with 200 acres devoted to existing steam generation units, combustion turbine units, and associated infrastructure. New construction associated with JEA's proposed CFB combustor project would occupy approximately 60 acres of previously disturbed land. The Northside Generating Station contains a number of wetland areas, especially in the perimeter areas. Preliminary analysis indicates that the site may be in a hurricane storm surge area, in addition to the 100-year floodplain of the St. Johns River. The most significant environmental feature associated with the Northside Generating Station is the nearby presence of estuarine salt marsh backwaters of the St. Johns River. St. Johns River Power Park, an industrial site which consists of two 624 MWe coal- and petroleum coke-burning power plants on 1,656 acres, is adjacent to the Northside Generating Station.

The overall objective of the project is to demonstrate the feasibility of CFB technology at a size that will be attractive for large-scale utility operation. The new CFB combustor would use coal and petroleum coke to generate nearly 300 MWe by repowering the existing Unit 2 steam turbine, a 297.5-MWe unit that has been out of service since 1983. The project is expected to provide JEA with a low-cost, efficient, and environmentally-sound generating resource. In addition, JEA plans to repower the currently operating Unit 1 steam turbine without cost-shared funding from DOE. The Unit 1 steam turbine will be essentially identical to the turbine for Unit 2, and is scheduled to be repowered about 6 to 12 months after the Unit 2 repowering. While the proposed project only consists of the Unit 2 repowering (because DOE would provide no funding for the Unit 1 repowering), the EIS will evaluate the Unit 1 repowering as a related action.

In a CFB combustor, coal and coal/fuel blends, air, and limestone are introduced into the lower portion of the combustor, where initial combustion occurs. As the fuel is reduced in size through combustion and breakage, it is transported higher in the combustor where additional air is introduced. Ash and unburned fuel and limestone pass out of the combustor, collect in a particle separator, and recirculate to the lower portion of the combustor. Sulfur reacts with limestone added in the furnace to form ash that can be marketed as a useful byproduct such as roadbed material.

For the proposed project, the combined installation of the CFB combustor and a flue gas scrubber is expected to remove over 97% of the sulfur dioxide emitted from burning coal that contains up to 4.5% sulfur. The relatively low furnace operating temperature of about 1650°F would result in appreciably lower nitrogen oxide emissions compared to conventional coal-fired power plants. The project would also include a new selective non-catalytic reduction system to further reduce emissions of nitrogen oxides. Over 99.8% of particulate emissions would be removed by a new baghouse or a new electrostatic precipitator.

In addition to the CFB combustor itself and the air pollution control systems, new equipment for the project would include a new stack and new fuel, limestone, and ash handling systems. The height of the proposed new stack is expected to be approximately 450 feet compared to 300 feet for the existing stack at Unit 2. The project would also require overhaul and/or modifications to existing systems such as the steam turbine, condensate and feedwater systems, circulating water systems, water treatment systems, plant electrical distribution systems, the switchyard, and the control systems.

Options being considered for transport of coal include (1) an extension of conveyors from the nearby St. Johns River Power Park, and (2) construction of new receiving, handling, and storage facilities for solid fuel. Limestone and ash storage and handling facilities also would be required. Wherever possible, existing facilities and infrastructure located at the Northside Generating Station would be used for the proposed project. These include the discharge system for cooling water to the St. Johns River, the wastewater treatment system, and the electric transmission lines and towers.

Because Unit 2 has not operated since 1983, the baseline emissions from that unit are zero. Units 1 and 3 have been operating at annual capacity factors of less than 40%, firing either heavy oil or natural gas. Unit 3 would continue as a 563.7-MWe oil/gas-fired unit. With the exception of low-NO_x (nitrogen oxide) burners on Unit 3, Units 1 and 3 are not currently equipped with emission control systems.

The area is in attainment of the National Ambient Air Quality Standards. However, as part of JEA's commitment to the local community in the implementation of this project, JEA has committed to a 10% reduction in the annual stack emissions for criteria pollutants (i.e., sulfur dioxide, nitrogen oxides, and particulate matter) from the Northside Generating Station (as compared to recent annual emissions). In achieving this objective, the combined emissions from the repowered Units 1 and 2 operating at annual capacity factors of 100% are projected to be less than recent typical annual emissions from Unit 1 alone.

Another part of JEA's community commitment is that groundwater consumption will be reduced by at least 10% from recent levels. This would be accomplished by increased recycling of the treated wastewater produced at the station. Plant wastewater is presently treated with lime, followed by clarification in settling basins. While some recycled water is currently utilized, most of the treated wastewater is discharged to percolation ponds. Should the proposed project be implemented, the discharge of treated wastewater to the ponds would be reduced.

Project activities would include engineering and design, permitting, equipment procurement, construction, startup, and a 24-month demonstration of the commercial feasibility of the technology. DOE plans to complete the EIS and issue a Record of Decision within 15 months of publication of this Notice of Intent, assuming timely delivery of environmental information from JEA for use in developing the EIS. Upon completing its NEPA review, if DOE decides to implement the proposed action, construction would commence in early 1999 and finish in late 2001, startup would occur in early 2002, and demonstration of the technology would begin in April 2002. During the demonstration, Unit 2 would be operated on several different types of coal and coal/fuel blends to demonstrate the flexibility of the technology. Upon completion of the demonstration phase, the facility would continue its commercial operation.

ALTERNATIVES: NEPA requires that agencies discuss the reasonable alternatives to the proposed action in an EIS. The purpose for agency action determines the range of reasonable alternatives. Congress established the CCT Program with a specific purpose: to demonstrate the commercial viability of technologies that use coal in more environmentally benign ways than conventional coal technologies. Congress also directed DOE to pursue the goals of the CCT Program by means of partial funding (cost-sharing) of projects owned and controlled by non-federal government sponsors. This statutory requirement places DOE in a much more limited role than if the federal government were the owner and operator of the project. In the latter situation, DOE would be responsible for a comprehensive review of reasonable alternatives. However, in dealing with an applicant, the scope of alternatives is necessarily more restricted. It is appropriate in such cases for DOE to give substantial weight to the applicant's needs in establishing a project's reasonable alternatives.

An overall strategy for compliance with NEPA was developed for the CCT Program that includes consideration of both programmatic and project-specific environmental impacts during and after the process of selecting a project. As part of the NEPA strategy, the EIS for JEA's proposed CFB combustor project will tier off the program's final Programmatic Environmental Impact Statement (PEIS) that was issued by DOE in November 1989 (DOE/EIS-0146). Two alternatives were evaluated in the PEIS: (1) the no action alternative, which assumed that the CCT Program was not continued and that conventional coal-fired technologies, with flue gas desulfurization and nitrogen oxide controls to meet New Source Performance Standards, would continue to be used; and (2) the proposed action, which assumed that the clean coal projects would be selected and funded, and that successfully demonstrated technologies would undergo widespread commercialization by the year 2010.

For JEA's proposed CFB combustor project, the range of reasonable alternatives to be considered in the EIS is also narrowed in accordance with the overall NEPA strategy. The no action alternative will be analyzed in the EIS as a reasonable alternative to the proposed action of providing cost-shared funding support for the proposed project. DOE will consider any other reasonable alternatives that may be suggested during the public scoping period.

Under no action, DOE would not provide partial funding for the design, construction, and operation of the project. In the absence of DOE funding, there are three options that JEA could reasonably pursue. These options will be analyzed under the no action alternative. JEA could construct the proposed project without DOE cost-shared funding. Under this scenario, the potential environmental impacts or benefits at Northside Generating Station are expected to be identical to those of the proposed project. A second option is that JEA could construct a new gas-fired combined cycle facility at Northside Generating Station or at another location. Under this scenario, potential environmental impacts or benefits at Northside Generating Station would vary from those of the proposed project. A third option is that JEA could purchase electricity from other utilities to meet JEA's projected demand. Under this scenario, potential environmental impacts or benefits at Northside Generating Station related to demonstration of the proposed project would not be realized. In addition, the second and third options would not contribute to the objective of the CCT Program, which is to make available to the U.S. energy marketplace advanced, more efficient, economically feasible, and environmentally acceptable coal technologies.

Because of DOE's limited role of providing cost-shared funding for JEA's proposed project and because of the advantages associated with the proposed location, DOE does not plan to evaluate alternative sites for the proposed project. JEA considered additional sites during its site selection process. Site selection was governed primarily by benefits that could be realized by JEA. An existing plant site was preferred because the cost associated with construction of the project at a "greenfield" site in an undisturbed area would be much higher, and the environmental impact likely would be much greater than at an existing facility. The existing Northside Generating Station has several advantages because it is an operating plant with land available for installation of new facilities. Much of the required infrastructure, including the electric transmission lines and towers, is already in place, thereby reducing the level of capital investment and construction impacts. The station has the flexibility to accommodate possible fuel delivery needs with its existing rail and water facilities. Furthermore, most of the operational staffing for the new facility would be accommodated by the existing Northside Generating Station staff.

PRELIMINARY IDENTIFICATION OF ENVIRONMENTAL ISSUES: The following issues have been tentatively identified for analysis in the EIS. This list, which was developed partly on the basis of concerns provided by the public in response to JEA's stakeholder outreach program, is not intended to be all inclusive, but is presented to facilitate public comment on the scope of the EIS. Additions to or deletions from this list may occur as a result of the scoping process. The issues include:

(1) Atmospheric Resources: potential air quality impacts resulting from air emissions during current and future operation of Northside Generating Station (e.g., effects of ground-level concentrations of criteria pollutants, and trace metals including mercury, on surrounding residential areas and the Timucuan Preserve (a National Park Service Class II ecological and historic preserve adjacent to the western edge of the Northside Generating Station); potential effects of greenhouse gas emissions on global climate change;

(2) Water Resources and Aquatic Ecology: potential effects on surface water and groundwater resources consumed and discharged; potential effects on estuarine salt marsh ecosystems and aquatic biota resulting from withdrawing and discharging cooling water from the St. Johns River (e.g., thermal discharge, entrainment or impingement of fish and invertebrate species);

(3) Infrastructure and Land Use: potential effects resulting from the transport of coal, petroleum coke, and limestone required for the proposed project, including the development of land for infrastructure, storage, or waste disposal; affected resource areas including land (e.g., existing shoreline and wetlands), utilities, and transportation routes (e.g., train traffic to supply coal);

(4) Solid Waste: pollution prevention and waste management practices, including solid waste impacts, caused by the generation, treatment, transport, storage, and disposal of solid wastes;

(5) Construction: impacts associated with noise, traffic patterns, and construction-related emissions;

(6) Visual: impacts associated with a new stack that is taller than existing structures at Northside Generating Station;
(7) Floodplains: potential impacts (e.g., impeding floodwaters, re-directing floodwaters, on-site and off-site property damage) of siting new buildings and infrastructure within floodplain and hurricane storm surge areas;
(8) Wetlands: potential reduction of wetlands due to new construction (e.g., construction associated with feedstock transport infrastructure);
(9) Community Impacts: impacts on public safety related to fire and emergency vehicle access to the Northside community of Jacksonville; impacts to local traffic patterns resulting from rail traffic; socioeconomic impacts on public services and infrastructure (e.g., police protection, schools, and utilities); noise associated with project operation; environmental justice with respect to the surrounding community; and
(10) Cumulative effects that result from the incremental impacts of the proposed project when added to other past, present, and reasonably foreseeable future actions (e.g., incremental discharge of cooling water affecting aquatic biota).

PUBLIC SCOPING PROCESS: To ensure that the full range of issues related to this proposal are addressed, DOE will conduct an open process to define the scope of the EIS. The public scoping period will run until December 31, 1997. Interested agencies, organizations, and the general public are encouraged to submit comments or suggestions concerning the content of the EIS, issues and impacts to be addressed in the EIS, and the alternatives that should be analyzed.

Scoping comments should clearly describe specific issues or topics that the EIS should address in order to assist DOE in identifying significant issues. Written, e-mailed, faxed, or telephoned comments should be communicated by December 31, 1997 (see "**ADDRESSES**").

In addition, a public scoping meeting to be conducted by DOE will be held in the In-Plant Conference Room at the Northside Generating Station on December 3, 1997, at 7 p.m. The address of the Northside Generating Station is 4377 Heckscher Drive, Jacksonville, Florida. DOE requests that anyone who wishes to speak at this public scoping meeting contact Dr. Jan Wachter, either by phone, fax, computer, or in writing (see "**ADDRESSES** "in this Notice). Individuals who do not make advance arrangements to speak may register at the meeting and will be given the opportunity to speak after all previously scheduled speakers have made their presentations. Speakers who wish to make presentations longer than five minutes should indicate the length of time desired in their request. Depending on the number of speakers, it may be necessary to limit speakers to five minute presentations initially, with the opportunity for additional presentation as time permits. Speakers can also provide additional written information to supplement their presentations. Oral and written comments will be given equal weight.

DOE will begin the meeting with an overview of the proposed CFB combustor project. A presiding officer will be designated by DOE to chair the meeting. The meeting will not be conducted as an evidentiary hearing, and speakers will not be cross-examined. However, speakers may be asked to clarify their statements to ensure that DOE fully understands the comments or suggestions. The presiding officer will establish the order of speakers and provide, any additional procedures necessary to conduct the meeting.

Issued in Washington, D.C., this 6th day of November, 1997.

"Original Signed By Peter N. Brush"
Peter N. Brush
Acting Assistant Secretary
Environment, Safety and Health

JACKSONVILLE ELECTRIC AUTHORITY

21 WEST CHURCH STREET • JACKSONVILLE, FL 32202-3139

JEA "POWER TO SERVE"

October 6, 1997

Mr. Al Linero
Florida Department of Environmental Protection
Division of Air Resources Management
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

RE: Jacksonville Electric Authority
Northside Generating Station
Units 1 and 2 Repowering Project

Dear Mr. Linero:

In an effort to keep you up to date on the most recent developments related to the Repowering project, I have attached a copy of Walt Bussell's announcement of JEA's award of a DOE grant to help fund the project. If you wish more information on this subject, please feel free to call me at 904/632-6249 or Reece Comer at 904/632-6312.

Sincerely,

Robert L. Kappelmann
Manager
Emerging Environmental Issues

/pja

cc: S. Arif, BAR

JEA Receives U. S. Department of Energy Clean Coal Technology Grant

I am pleased to announce that we have signed an agreement with the U. S. Department of Energy (DOE) which will provide JEA a Clean Coal Technology Grant of $74.7 million for the repowering of the 275 megawatt Northside Unit 2.

The grant is in conjunction with the Federal Government's Clean Coal Technology program. Called a "circulating Fluidized Bed Combustor," the new technology is one of the world's most advanced methods for burning coal and blends of petroleum coke, a byproduct of oil refineries. **The agreement with DOE will give JEA the distinction of hosting the largest such combustor in the world as well as the cleanest.** The combustor itself will eliminate more than 90 percent of sulfur dioxide emissions. In addition we will add a further flue gas scrubbing system to capture additional air emissions.

The new technology will be installed on Northside Unit 1, which is also a 275 megawatt unit. The remaining unit at Northside, Unit 3, a 518 megawatt oil and natural gas-fired unit, will continue to operate. **The repowering project, coupled with other operational improvements, will boost the plant's total energy output by 168 percent.** The entire capital cost for both Units 1 and 2 is estimated at $463 million.

We have established a requirement of at least a 10 percent reduction in total annual power plant stack emissions of sulfur dioxide, nitrogen oxide and particulate matter, and at least a 10 percent reduction in groundwater consumption at the Northside station. **In fact, the projected environmental performance of Northside Units 1 and 2 will be even better than the recently proposed EPA air quality standards that are not slated to become effective until 2004.** This project will substantially improve our environmental performance at Northside while producing energy at a substantially lower cost than our current lowest cost generating units.

DRAFT

Northside Repowering Units 1 and 2
Jacksonville Electric Authority
Fact Sheet

Jacksonville's Growth is Expected to Continue

In 1996, the annual update showed continuing load growth in the 3 percent per year range. Based on that forecast, there was a need for new generating capacity to come on line to meet demand by the year 2002, even considering energy conservation, load management and other available resources, such as cogeneration, purchased power and renewables.

Integrated Resource Planning Process Updates Forecasts and Evaluates Alternatives

Following the recommendation of the Energy Policy Act of 1992, the Jacksonville Electric Authority adopted the Integrated Resource Planning Process in 1994 as its standard procedure for determining the need for new facilities. An integrated resource plan evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and renewable energy resources. Based on the results of the planning process, the JEA Board adopted a reference plan in 1995, which is reviewed and updated annually by staff.

JEA Board Approves Plan

On May 21, 1997, the Jacksonville Electric Authority Board approved a plan to move forward with the repowering of Northside Generating Station Units 1 and 2. The project will involve the installation of new circulating fluidized bed boilers, burning petroleum coke as the primary fuel with coal as the back-up fuel. The repowering proposal was identified as the preferred option as a result of an extensive evaluation of energy needs and alternatives for meeting those needs, called the Integrated Resource Planning Process.

Targets Set for Environmental Improvement at the Northside Generating Station

JEA's management has established a target of a 10 percent reduction in total annual emissions of sulfur dioxide (SO_2), nitrogen oxide (NO_x), and particulate matter compared to emissions during the most recent typical two-year operating period at Northside, 1994-1995. Also targeted for a 10 percent reduction is total annual groundwater consumption at Northside. This is to be accomplished while increasing the total annual energy output from 2,320,000 megawatt hours to 6,220,000 megawatt hours.

Based on a conceptual design developed by staff, these reductions appear to be achievable and have been established as a target for the selected engineering firm to meet or exceed.

Formal Regulatory Approval Process to be Preceded by Public Input

Following the Board's approval of the plan, the permitting process and preliminary design are set to begin. A number of environmental issues will need to be addressed. Prior to starting the formal permitting process, JEA officials will be consulting with Northside and other Jacksonville residents, environmental interests, the business

DRAFT

community and others to better understand their views and get their input and address concerns regarding the repowering plan.

During the third quarter of 1997, an engineering firm will be selected to develop the preliminary design which will support the permitting process. Public input will be factored into the design and permitting processes.

Fuel Price Is the Most Important Factor in the Cost of Electricity

The next step in the planning process was to consider fuel prices. Fuel is by far the largest single component of the overall cost of electricity. Given the trends toward deregulation and greater competition in the electric utility industry, fuel price is of paramount importance in the evaluation of capacity additions.

Among the fuel options considered were petroleum coke, coal, high sulfur fuel oil, natural gas and low sulfur fuel oil. Petroleum coke, a byproduct of oil refining operations, is projected to have the best price and best long term price stability of all the alternatives evaluated. JEA recently completed a successful test burn of petroleum coke at the St. Johns River Power Park and has been burning petroleum coke at the Power Park since February 1997.

Circulating Fluidized Bet Technology Is Highly Efficient and Environmentally Friendly

As a final step in the planning process, an optimization model was run to determine the best generation alternative for meeting the demand, considering demand and fuel forecasts, financial factors, the existing generating system, and options for building or purchasing generation. The result of this modeling effort was the proposal to repower Northside Generating Station Units 1 and 2, using petroleum coke as the fuel. The technology selected is circulating fluidized bed, an advanced and proven generating technology that is very efficient and results in low air emissions.

Based on all the options considered in this multi-step planning process, the repowering of the existing units at Northside is the best option to improve the local environment, provide the needed power and maintain JEA's low electric rates.

For Further Information Contact

Anyone interested in obtaining additional information about the plan may contact:

Media -	Clyde Montgomery - 632-7260
Environmental, General Public -	Robert Kappelmann - 632-6249
	Richard Breitmoser - 632-6245
Construction, Labor, Equipment -	Reece Comer - 632-6312

JACKSONVILLE ELECTRIC AUTHORITY

21 WEST CHURCH STREET • JACKSONVILLE, FL 32202-3139

January 7, 1998

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399 -2400

Dear Mr. Linero

SUBJECT: JACKSONVILLE ELECTRIC AUTHORITY
NORTHSIDE REPOWERING PROJECT
BASELINE EMISSIONS CALCULATIONS

This letter is provided as a follow-up to a meeting which took place in your offices on October 22, 1997, between Messrs. Syed Arif, Martin Costello, and Cleve Holladay of the Department, Mr. Doug Fulle of Foster Wheeler Environmental, and Mr. Bert Gianazza of Jacksonville Electric Authority (JEA). The proposed Repowering Project at the Northside Generating Station was discussed at that meeting with respect to the potential applicability of the PSD permitting requirements at Section 62-212.400, F.A.C. As you recall, the Northside Repowering Project would consist of the modification of existing Units 1 and 2 at Northside to incorporate new circulating fluidized bed boilers with associated air quality control systems and other ancillary equipment. The modified units would fire petroleum coke and/or coal whereas the existing Unit 1 fires No. 6 fuel oil and natural gas (the Unit 2 boiler, which has also fired fuel oil and natural gas, has not operated recently). As a modification of a "major existing source," PSD applicability would generally be triggered if the net change in emissions would exceed the PSD significant emission rates in Table 62-212.400-2 of Ch. 62-212, F.A.C.

Background

At the time of our meeting, our plan was to compare the current actual emissions from existing Unit 1 with the future potential emissions from modified Units 1 and 2 and then compare the net changes with the significant emission rates. However, subsequent to our meeting, we have determined that the Unit 2 modification qualifies for the "Permanent Clean Coal Technology Demonstration Project Exemption" under Section 62-212.400(2)(a)3, F.A.C., as further explained below. As a result, the Unit 2 modification will be subject to PSD review for only those pollutants whose potential emissions will increase above the potential emissions from the existing Unit 2 as a result of the modification. Therefore, for PSD netting purposes, JEA proposes to compare the current actual emissions from existing Unit 1 with the future potential emissions from modified Unit 1 and to compare the current potential emissions from existing

Unit 2 with the future potential emissions from modified Unit 2. The net changes would be compared with the significant emission rates, and PSD applicability will be determined for each pollutant separately for each unit. Although JEA has made commitments to the community regarding stack emission reductions for SO_2, NO_x, and PM for the Northside Generating Station as a whole, we understand that the PSD netting analysis will not include any changes in emissions from existing Unit 3 or the existing combustion turbines and will thus be confined to Units 1 and 2.

As indicated above, JEA believes that the Unit 2 modification qualifies for the "Permanent Clean Coal Technology Demonstration" under FDEP's rules (Section 62-212.400(2)(a)3, F.A.C.). The project meets the definition of a "Clean Coal Technology Demonstration Project" under 40 CFR 52.21(b)(35) (the cross reference under FDEP's rules) because it: (1) uses funds appropriated under the heading "Department of Energy - Clean Coal Technology" (up to $2.5 billion), (2) is a commercial demonstration of clean coal technology, (3) has federal (DOE) funding for at least 20 percent of the total cost, and (4) constitutes "Repowering" under paragraph (ii) of 40 CFR 52.21(b)(37). The project qualifies under the fourth point because the demonstration funding was awarded by DOE on November 30, 1990(prior to the January 1, 1991 deadline) as the project was originally planned for the Arvah B. Hopkins Station Unit 2 site, and subsequently moved to the Northside Unit 2 location. Attachment A is a copy of DOE's Notice of Intent to prepare an EIS on the project; it provides some background on the project and its funding.

Although a BACT analysis and air quality impact modelling would normally be conducted for only PSD-regulated pollutants indicated by the netting analysis, please be advised that JEA's community commitment has been to conduct a BACT analysis and utilize the indicated air quality control systems or methods for SO_2, NO_x, PM_{10}, CO, and VOCs. In addition, we are committed to conduct air quality dispersion modelling of the air quality impacts of the modification by itself for SO_2, NO_x, PM_{10}, and CO regardless of whether PSD is triggered by emission increases. Therefore, our intent in conducting the PSD netting analysis is to clearly determine PSD applicability from a regulatory standpoint rather than to avoid the BACT and air quality modelling requirements.

The purpose of this letter is to explain the approach which we have taken in determining the baseline emissions for Unit 1 and for Unit 2 in preparation for going forward with the netting analysis and to seek your concurrence with the baseline emissions which we propose to use. Included are some revisions to the calculated values provided to FDEP during the meeting of October 22 for Unit 1, which take into account suggestions from FDEP staff, and the support data which were requested in that meeting.

PSD Netting Considerations

As we understand it, there are two important considerations in determining the baseline emissions for PSD netting purposes - the baseline period and the emission factors. As indicated in Section 62-2 10.200(12) F.A.C., the baseline period for Unit 1 consists of a two year period prior to the particular date that is considered to be *representative of normal operation*. However, since the actual modification will not take place for several years, practicality dictates that we use a two-year "representative" period prior to the netting analysis. In addition, in the preamble to the WEPCO rulemaking (57 FR 32314 (July 21, 1992) and 56 FR 27630 (June 24, 1991) (excerpts included as Attachment B)), EPA explained that while it had been its historical practice to use the two-year period immediately preceding the proposed change to establish the baseline, it was not required under the regulations to use this particular period and will presume that *for utilities* any two consecutive years with the five year period prior to the proposed change is representative of normal source operations. EPA explained that because of the fluctuation in operations experienced by utilities in responding to electricity demands that vary due to climatic and economic conditions as well as changes within a particular utility's system affecting the dispatch of a unit, the use of any consecutive two-year period within the last five allows the recent actual emissions to be more realistic and more closely representative of "normal source operation." The preamble also gives source owners the ability to seek approval to use other than a two year period, including a baseline period prior to the last five years, if it is "more representative of normal operations." Based on this information, JEA believes that there is some appropriate flexibility in the determination of the baseline period for Unit 1, and, as more fully explained below, that the years 1994-1995 are the most representative of normal operation. For Unit 2 the baseline period is not considered since the baseline emissions will be based on potential rather than actual emissions.

With respect to emission factors, it is understood that the FDEP preference for emission factors is to use CEMS data when available as a first choice, followed by stack test data when available and representative as a second choice, followed by published emission factors (e.g., AP-42) as a third choice. The remainder of this letter contains discussion of the proposed baseline years for Unit 1 netting purposes as well as the proposed emission factors and resulting actual emissions values for each of the regulated criteria pollutants for Unit 1 and the potential emissions for Unit 2.

Baseline Period

With respect to the baseline period for Unit 1, Attachment C contains complete generation statistics for the Northside Generating Station for calendar years 1992 through 1996. These data were previously provided to FDEP at the October 22 meeting. In addition, partial, preliminary data for 1997 through September are included in response to FDEP's request.

As discussed in the October 22 meeting, 1996 was not a representative year for Unit 1. A major outage occurred between February 6, 1996 and June 12, 1996 and the generation data in Attachment C reflects that fact. As indicated, the gross MWH were only 367,721 in 1996, compared to the 1992-1995 average of 902, 979 MWH. Calendar year 1997 is not yet complete and only partial data through September are available. However, climatological temperature (heating and cooling degree day) data indicate that, through September at least, 1997 is not a representative year either. As indicated in Attachment D, January through September 1997 data are 8.5% below the National Oceanic and Atmospheric Administration (NOAA) 30-year average. As a result, neither of the last two consecutive calendar years are considered representative years. Therefore, JEA proposed to use the next most recent consecutive two years for the netting analysis - 1994 and 1995.

During the October 22 meeting, FDEP suggested that alternate periods, including the most recent year should be considered. JEA believes that the most recent two years are inappropriate for the reasons discussed above, and further believes that 1994 and 1995 are appropriate and representative of normal operations. However, JEA suggests that, if the preferred period is not accepted, an average of a longer period (e.g., 1991-1995 or 1992-1995) would be appropriate. JEA requests that these longer periods be considered as alternatives. However, JEA proposes that 1994-1995 is the most appropriate period, and all of the calculated baseline emissions in this letter and attachments are based on this period.

Baseline Emissions

The remainder of this letter presents proposed baseline emissions for all of the PSD-regulated pollutants for which emissions are expected. These include NO_x, SO_2, PM (TSP and PM_{10}), CO, VOCs, lead, sulfuric acid mist, fluorides, and mercury. It is understood that beryllium, asbestos, and vinyl chloride are in the process of being removed from the list of PSD-regulated pollutants. Emissions of total reduced sulfur, reduced sulfur compounds, and municipal waste related emissions are not expected from gas/oil fired or coal/petroleum coke fired power plants and no emission factors are available; thus, baseline and future potential emissions are proposed as zero for these PSD-regulated pollutants.

Unit 1

For NO_x, emissions data based on CEMS are available beginning January 1, 1995 (we had erroneously indicated January 1, 1996 in the October 22 meeting). Thus, for calendar year 1995, NO_x emissions based on the CEMS data are proposed even though it is believed that these data underestimate actual NO_x emissions (see Attachment E). However, as discussed in the October 22 meeting, the NO_x emission rates vary as a function of plant load and it is therefore appropriate to use a weighted average (see Attachment F) which accounts for the variation of NO_x emission rates with loads. This weighted average consists of the hourly NO_x emission rates multiplied by the corresponding hourly heat inputs and then totaled to produce the annual values (in tons per year), an approach recognized by EPA as appropriate for acid rain purposes. For 1994, CEMS data are not available nor are stack test data for that year. However, it is proposed that the weighted average CEMS emission rate (in lbs/mmBtu) for calendar year 1996 be used as a conservative approximation of the rate which existed in 1994 since the ratio of oil/gas usage in 1996 was closer to that used in 1994 than the rate in 1995, and the low load factor for 1997 (partial) resulted in an unusually low NO_x rate for that year. The resulting NO_x emission estimate is believed to underestimate the true emission rate and therefore total emissions for the period since a NO_x reduction program begun in 1995 is affecting our estimated 1996 emission rate and therefore the total calculated emissions for 1994 when no such program existed. Further, the only stack test data available for NO_x (Attachment G) reflect a higher rate on oil, and reflect steady state operation rather than the actual constantly varying load operation, lending further support to the argument that typical actual NO_x emission rates in 1994 (and prior years) were higher. Nevertheless, JEA proposes to use 1,801.9 tons in 1994 and 1,081.7 tons in 1995 for an average of 1,441.8 tpy for the PSD netting analysis.

For SO_2, CEMS data are available for 1995 but not for 1994. In response to FDEP's preference, JEA proposes to use the CEMS data for 1995 to estimate the actual SO_2 emissions in that year. For 1994, JEA proposes to use the mass balance approach contained within AP-42 and the measured fuel flow (converted to mmBtu/hr) to calculate baseline emissions for this pollutant. The SO_2 emissions calculated on this basis are 7,510.3 tpy in 1994 and 4,328.3 tpy in 1995 for a two year average of 5,919.3 tpy. These data are included in Attachment E for 1995 and Attachment H for 1994.

For PM (TSP and PM_{10}), no CEMS data are available. Some stack test data are available and these are summarized in Attachment G. JEA considers the stack test data for TSP to be inappropriate to be considered alone for estimating annual emissions of this pollutant since the stack tests are conducted only during periods of steady-state operation. Particulate emissions are higher during load changes, soot blowing, startup, and shutdown than during steady-state operation, which is important in determining emissions from Unit 1. As indicated in our meeting, Unit 1's load varies constantly (it is operated as a load-following unit) and, as such, it does not operate in steady-state mode for very long. Further, the unit is subject to numerous startups and shut downs, also resulting in higher TSP emissions. There were 35 startups in 1994 and 37 in 1995. Further, soot blowing occurred on a daily basis when firing fuel oil. For these reasons, JEA proposes that the AP-42 emission factors (which have "A" ratings) be used for TSP and PM_{10}. While the stack tests are consistent with the AP-42 emission factors, the AP-42 emission factors cover the full range of operations and better predict annual emissions. The results of the analysis are presented in Attachment H, a revised version of material presented in our meeting, and reflect averages of 389.9 tpy for TSP for 1994/1995 and 278.5 tpy for PM_{10} for Unit 1.

For CO and VOCs, no CEMS data are available. Similarly, no stack test data are available. As a result, the AP-42 emission factors are the best available information for these pollutants. Data for both pollutants were presented in the October 22 handout, a revised version included here as Attachment H. As indicated, baseline emissions of 153.1 tpy for CO and 17.9 tpy for VOCs are proposed by JEA for Unit 1.

For the other PSD-regulated pollutants with baseline emissions, lead, sulfuric acid mist, fluorides, and mercury, no CEMS data nor stack test data are available. No data for these pollutants were provided in the October 22 meeting. Since that time, calculations of baseline emissions have been made using the 1994 and 1995 fuel consumption and the emission factors in AP-42. These calculations are summarized on Attachment I. As indicated, JEA proposes baseline emission as follows: lead - 0.03265 tpy, sulfuric acid mist - 195.525 tpy, fluorides - 0.79877 tpy, and mercury - 0.0024 tpy for Unit 1.

Unit 2

The baseline emissions estimation for Unit 2 is much simpler than for Unit 1 since the baseline emissions are potential emissions rather than actual emissions. Potential emissions, as defined in Section 62-210.200(225) F.A.C., reflect the maximum capacity under a unit's physical or operational design. In this case, the potential emissions are the permitted emissions or those reflecting full load continuous operation for the entire year. Calculations of potential emissions have been made based on permit limits or AP-42 emission rates, as neither CEMS nor reliable stack test data are available to determine the worst-case (maximum) emissions. These calculations are contained in Attachment J. As indicated, JEA proposed baseline emissions for Unit 2 are as follows: NO_x - 6407 tpy; SO_2 - 20,397 tpy; TSP - 1287 tpy; PM_{10} - 1114 tpy; CO - 466 tpy; VOCs - 60.38 tpy; lead - 0.119974 tpy; sulfuric acid mist - 815 tpy; fluorides - 2.9636 tpy; and mercury - 0.08978 tpy.

Conclusion

JEA requests FDEP concurrence with the baseline emissions and netting approach proposed in this letter, including the applicability of the Clean Coal Technology Demonstration Project exemption. As the establishment of baseline emissions is a necessary first step in the PSD netting analysis, a written decision by FDEP is requested by January 23, 1998. We will call you shortly to set up a meeting with you and your staff to answer any questions you may have on our analysis and the proposed Repowering Project in general. Should you have any immediate questions, please call me at (904) 632-6249.

Very truly yours,

Robert L. Kappelmann, P.E.
Manager, Environmental Affairs

Attachments

cc: C. Fancy (FDEP)
S. Arif (FDEP)
M. Costello (FDEP)
C. Holladay (FDEP)

Attachment A

Rules of Practice and Procedure on October 22, 1997.

H. Public Dialogue.

Dated: November 3, 1997.

Susan M. Weisman,

Secretary.

[FR Doc. 97-29868 Filed 11-12-97; 8:45 am]

BILLING CODE 6380-01-P

DEPARTMENT OF ENERGY

Notice of Intent To Prepare an Environmental Impact Statement and Notice of Floodplain and Wetlands Involvement for the Proposed Jacksonville Electric Authority Circulating Fluidized Bed Combustor Project

AGENCY: Department of Energy.

ACTION: Notice of intent to prepare an Environmental Impact Statement (EIS), and notice of floodplain and wetlands involvement.

SUMMARY: The Department of Energy (DOE) announces its intent to prepare an Environmental Impact Statement (EIS) pursuant to the National Environmental Policy Act (NEPA) of 1969, as amended (42 U.S.C. 4321 *et seq.*), the Council on Environmental Quality NEPA regulations (40 CFR Parts 1500–1508), and the DOE NEPA regulations (10 CFR Part 1021), to assess the potential environmental and human health impacts of the construction and operation of a project proposed by the Jacksonville Electric Authority (JEA) that has been selected by DOE to demonstrate circulating fluidized bed (CFB) technology under the Clean Coal Technology (CCT) Program. The proposed project would involve construction and operation of a CFB combustor fueled by coal and petroleum coke to repower an existing steam turbine at JEA's Northside Generating Station in Jacksonville, Florida, to generate nearly 300 megawatts of electricity (MWe). This EIS will support a DOE decision regarding whether DOE will provide approximately $75 million in cost-shared funding (about 24% of the total cost of approximately $309 million) for the proposed project.

The purpose of this Notice of Intent is to inform the public about the proposed action; present the schedule for the action; announce the plans for a public scoping meeting; invite public participation in the scoping process; and solicit public comments for consideration in establishing the scope and content of the EIS. The EIS will evaluate the potential impacts of the proposed action and reasonable alternatives. Because the proposed project may involve an action in floodplains and wetlands, the EIS will include a floodplain and wetlands assessment and a statement of findings in accordance with DOE regulations for compliance with floodplain and wetlands environmental review requirements (10 CFR Part 1022).

DATES: To ensure that the full range of issues related to this proposal is addressed, DOE invites comments on the scope and content of the EIS from all interested parties. All comments must be received by December 31, 1997, to ensure consideration. Late comments will be considered to the extent practicable. In addition to receiving comments in writing and by telephone, DOE will conduct a public scoping meeting in which agencies, organizations, and the general public are invited to present oral comments or suggestions with regard to the range of actions, alternatives, and impacts to be considered in the EIS. The scoping meeting will be held at the Northside Generating Station, In-Plant Conference Room, 4377 Heckscher Drive, Jacksonville, Florida, on Wednesday, December 3, 1997, at 7 p.m.

ADDRESSES: Written comments and requests to participate in the public scoping process should be addressed to: Dr. Jan Wachter, NEPA Document Manager for the JEA Project, Federal Energy Technology Center, U.S. Department of Energy, 3610 Collins Ferry Road, Morgantown, WV 26507-0880. Individuals who would like to verbally or electronically provide comments should contact Dr. Wachter at direct telephone 304-285-4607; toll free number 1-800-432-8330 (ext. 4607); fax 304-285-4469; or E-mail JWACHT@FETC.DOE.GOV.

FOR FURTHER INFORMATION CONTACT: To obtain additional information about this project or to receive a copy of the draft EIS when it is issued, contact Dr. Jan Wachter at the address provided above. For general information on the DOE NEPA process, contact Ms. Carol M. Borgstrom, Director, Office of NEPA Policy and Assistance (EH-42), U.S. Department of Energy, 1000 Independence Avenue, S.W., Washington, D.C. 20585-0119; telephone 202-586-4600; or leave a message at 1-800-472-2756.

SUPPLEMENTARY INFORMATION:

Background and Need for the Proposed Action

Under Public Law 99-190, Congress provided authorization and funds to DOE to support the construction and operation of demonstration facilities selected for cost-shared financial assistance as part of DOE's CCT Program. In December 1985, Congress made funds available to DOE for conducting the first round of the CCT Program. Congress directed that this first solicitation for federal cost-sharing (1) be open to all market applications of clean coal technologies, (2) apply to any segment of the U.S. coal resource base, and (3) encompass both new and retrofit applications. In response to the solicitation, proposals were received and projects were selected by DOE for negotiation. In addition, a list of alternate candidates was established from which replacement selection could be made should any of the original selections not proceed. JEA's proposed CFB combustor project has evolved through a series of site changes from a project that was selected from the alternate list for demonstration.

The demonstration of JEA's CFB combustor project under the CCT Program would fulfill an existing DOE programmatic need. Coal has the potential to address critical energy supply issues because of its abundant reserves; however, barriers to increased use of coal include concerns about environmental issues, such as acid deposition, global climate change, polyaromatic hydrocarbon emissions, and solid waste. Since the early 1970's, DOE and its predecessor agencies have sponsored long-term programs to develop innovative coal technologies through the proof-of-concept stage to overcome these environmental barriers while improving combustion efficiency and reducing costs.

However, the availability of a technology at the proof-of-concept stage is not sufficient to ensure its continued development and subsequent commercialization. Before any technology can seriously be considered for commercialization, it must be demonstrated at a large enough scale to prove its reliability and to show economically competitive performance. The financial risk associated with such large-scale demonstration is, in general, too high for the private sector to assume in the absence of strong incentives. The congressionally-directed CCT Program provides a mechanism to accelerate the commercialization of innovative technologies to meet the nation's near-term energy and environmental goals, to reduce technological risk to industry to an acceptable level, and to provide private sector incentives required for continued research and development aimed at finding solutions to long-range energy supply problems.

Proposed Action

The proposed action is for DOE to provide, through a cooperative agreement with JEA, cost-shared financial assistance to JEA for the design, construction, and operation of the proposed project, as described below. JEA plans to form an alliance with Foster Wheeler Corporation through its subsidiary, Foster Wheeler Power Systems, Inc., to jointly own and operate the project. Together with other Foster Wheeler affiliates, Foster Wheeler Power Systems, Inc. will provide the CFB combustor and perform the project engineering, procurement, and construction. The demonstration project would last 24 months and cost approximately $309 million, with DOE's share being nearly $75 million (24%). The proposed project would be located at JEA's existing Northside Generating Station in Jacksonville, Florida, which currently consists of 3 heavy oil- and natural gas-fired steam generation units and 4 diesel oil-fired combustion turbine units.

The Northside Generating Station is approximately 10 miles north of downtown Jacksonville, Florida. The Northside Generating Station is an industrial site encompassing approximately 400 acres, with 200 acres devoted to existing steam generation units, combustion turbine units, and associated infrastructure. New construction associated with JEA's proposed CFB combustor project would occupy approximately 60 acres of previously disturbed land. The Northside Generating Station contains a number of wetland areas, especially in the perimeter areas. Preliminary analysis indicates that the site may be in a hurricane storm surge area, in addition to the 100-year floodplain of the St. Johns River. The most significant environmental feature associated with the Northside Generating Station is the nearby presence of estuarine salt marsh backwaters of the St. Johns River. St. Johns River Power Park, an industrial site which consists of two 624 MWe coal- and petroleum coke-burning power plants on 1,656 acres, is adjacent to the Northside Generating Station.

The overall objective of the project is to demonstrate the feasibility of CFB technology at a size that will be attractive for large-scale utility operation. The new CFB combustor would use coal and petroleum coke to generate nearly 300 MWe by repowering the existing Unit 2 steam turbine, a 297.5-MWe unit that has been out of service since 1983. The project is expected to provide JEA with a low-cost, efficient, and environmentally-sound generating resource. In addition, JEA plans to repower the currently operating Unit 1 steam turbine without cost-shared funding from DOE. The Unit 1 steam turbine will be essentially identical to the turbine for Unit 2, and is scheduled to be repowered about 6 to 12 months after the Unit 2 repowering. While the proposed project only consists of the Unit 2 repowering (because DOE would provide no funding for the Unit 1 repowering), the EIS will evaluate the Unit 1 repowering as a related action.

In a CFB combustor, coal and coal/fuel blends, air, and limestone are introduced into the lower portion of the combustor, where initial combustion occurs. As the fuel is reduced in size through combustion and breakage, it is transported higher in the combustor where additional air is introduced. Ash and unburned fuel and limestone pass out of the combustor, collect in a particle separator, and recirculate to the lower portion of the combustor. Sulfur reacts with limestone added in the furnace to form ash that can be marketed as a useful byproduct such as roadbed material.

For the proposed project, the combined installation of the CFB combustor and a flue gas scrubber is expected to remove over 97% of the sulfur dioxide emitted from burning coal that contains up to 4.5% sulfur. The relatively low furnace operating temperature of about 1650°F would result in appreciably lower nitrogen oxide emissions compared to conventional coal-fired power plants.

The project would also include a new selective non-catalytic reduction system to further reduce emissions of nitrogen oxides. Over 99.8% of particulate emissions would be removed by a new baghouse or a new electrostatic precipitator.

In addition to the CFB combustor itself and the air pollution control systems, new equipment for the project would include a new stack and new fuel, limestone, and ash handling systems. The height of the proposed new stack is expected to be approximately 450 feet compared to 300 feet for the existing stack at Unit 2. The project would also require overhaul and/or modifications to existing systems such as the steam turbine, condensate and feedwater systems, circulating water systems, water treatment systems, plant electrical distribution systems, the switchyard, and the control systems.

Options being considered for transport of coal include (1) an extension of conveyors from the nearby St. Johns River Power Park, and (2) construction of new receiving, handling, and storage facilities for solid fuel. Limestone and ash storage and handling facilities also would be required. Wherever possible, existing facilities and infrastructure located at the Northside Generating Station would be used for the proposed project. These include the discharge system for cooling water to the St. Johns River, the wastewater treatment system, and the electric transmission lines and towers.

Because Unit 2 has not operated since 1983, the baseline emissions from that unit are zero. Units 1 and 3 have been operating at annual capacity factors of less than 40%, firing either heavy oil or natural gas. Unit 3 would continue as a 563.7-MWe oil/gas-fired unit. With the exception of low-NO_X (nitrogen oxide) burners on Unit 3, Units 1 and 3 are not currently equipped with emission control systems.

The area is in attainment of the National Ambient Air Quality Standards. However, as part of JEA's commitment to the local community in the implementation of this project, JEA has committed to a 10% reduction in the annual stack emissions for criteria pollutants (i.e., sulfur dioxide, nitrogen oxides, and particulate matter) from the Northside Generating Station (as compared to recent annual emissions). In achieving this objective, the combined emissions from the repowered Units 1 and 2 operating at annual capacity factors of 100% are projected to be less than recent typical annual emissions from Unit 1 alone.

Another part of JEA's community commitment is that groundwater consumption will be reduced by at least 10% from recent levels. This would be accomplished by increased recycling of the treated wastewater produced at the station. Plant wastewater is presently treated with lime, followed by clarification in settling basins. While some recycled water is currently utilized, most of the treated wastewater is discharged to percolation ponds. Should the proposed project be implemented, the discharge of treated wastewater to the ponds would be reduced.

Project activities would include engineering and design, permitting, equipment procurement, construction, startup, and a 24-month demonstration of the commercial feasibility of the technology. DOE plans to complete the EIS and issue a Record of Decision within 15 months of publication of this Notice of Intent, assuming timely delivery of environmental information from JEA for use in developing the EIS. Upon completing its NEPA review, if DOE decides to implement the proposed action, construction would commence in early 1999 and finish in late 2001, startup would occur in early 2002, and demonstration of the technology would begin in April 2002. During the demonstration, Unit 2 would be operated on several different types of coal and coal/fuel blends to demonstrate the flexibility of the technology. Upon completion of the demonstration phase, the facility would continue its commercial operation.

Alternatives

NEPA requires that agencies discuss the reasonable alternatives to the proposed action in an EIS. The purpose for agency action determines the range of reasonable alternatives. Congress established the CCT Program with a specific purpose: to demonstrate the commercial viability of technologies that use coal in more environmentally benign ways than conventional coal technologies. Congress also directed DOE to pursue the goals of the CCT Program by means of partial funding (cost-sharing) of projects owned and controlled by non-federal government sponsors. This statutory requirement places DOE in a much more limited role than if the federal government were the owner and operator of the project. In the latter situation, DOE would be responsible for a comprehensive review of reasonable alternatives. However, in dealing with an applicant, the scope of alternatives is necessarily more restricted. It is appropriate in such cases for DOE to give substantial weight to the applicant's needs in establishing a project's reasonable alternatives.

An overall strategy for compliance with NEPA was developed for the CCT Program that includes consideration of both programmatic and project-specific environmental impacts during and after the process of selecting a project. As part of the NEPA strategy, the EIS for JEA's proposed CFB combustor project will tier off the program's final Programmatic Environmental Impact Statement (PEIS) that was issued by DOE in November 1989 (DOE/EIS-0146). Two alternatives were evaluated in the PEIS: (1) the no action alternative, which assumed that the CCT Program was not continued and that conventional coal-fired technologies, with flue gas desulfurization and nitrogen oxide controls to meet New Source Performance Standards, would continue to be used; and (2) the proposed action, which assumed that the clean coal projects would be selected and funded, and that successfully demonstrated technologies would undergo widespread commercialization by the year 2010.

For JEA's proposed CFB combustor project, the range of reasonable alternatives to be considered in the EIS is also narrowed in accordance with the overall NEPA strategy. The no action alternative will be analyzed in the EIS as a reasonable alternative to the proposed action of providing cost-shared funding support for the proposed project. DOE will consider any other reasonable alternatives that may be suggested during the public scoping period.

Under no action, DOE would not provide partial funding for the design, construction, and operation of the project. In the absence of DOE funding, there are three options that JEA could reasonably pursue. These options will be analyzed under the no action alternative. JEA could construct the proposed project without DOE cost-shared funding. Under this scenario, the potential environmental impacts or benefits at Northside Generating Station are expected to be identical to those of the proposed project. A second option is that JEA could construct a new gas-fired combined cycle facility at Northside Generating Station or at another location. Under this scenario, potential environmental impacts or benefits at Northside Generating Station would vary from those of the proposed project. A third option is that JEA could purchase electricity from other utilities to meet JEA's projected demand. Under this scenario, potential environmental impacts or benefits at Northside Generating Station related to demonstration of the proposed project would not be realized. In addition, the second and third options would not contribute to the objective of the CCT Program, which is to make available to the U.S. energy marketplace advanced, more efficient, economically feasible, and environmentally acceptable coal technologies.

Because of DOE's limited role of providing cost-shared funding for JEA's proposed project and because of the advantages associated with the proposed location, DOE does not plan to evaluate alternative sites for the proposed project. JEA considered additional sites during its site selection process. Site selection was governed primarily by benefits that could be realized by JEA. An existing plant site was preferred because the cost associated with construction of the project at a "greenfield" site in an undisturbed area would be much higher, and the environmental impact likely would be much greater than at an existing facility. The existing Northside Generating Station has several advantages because it is an operating plant with land available for installation of new facilities. Much of the required infrastructure, including the electric transmission lines and towers, is already in place, thereby reducing the level of capital investment and construction impacts. The station has the flexibility to accommodate possible fuel delivery needs with its existing rail and water facilities. Furthermore, most of the operational staffing for the new facility would be accommodated by the existing Northside Generating Station staff.

Preliminary Identification of Environmental Issues

The following issues have been tentatively identified for analysis in the EIS. This list, which was developed partly on the basis of concerns provided by the public in response to JEA's stakeholder outreach program, is not intended to be all inclusive, but is presented to facilitate public comment on the scope of the EIS. Additions to or deletions from this list may occur as a result of the scoping process. The issues include:

(1) Atmospheric Resources: potential air quality impacts resulting from air emissions during current and future operation of Northside Generating Station (e.g., effects of ground-level concentrations of criteria pollutants, and trace metals including mercury, on surrounding residential areas and the Timucuan Preserve (a National Park Service Class II ecological and historic preserve adjacent to the western edge of the Northside Generating Station); potential effects of greenhouse gas emissions on global climate change;

(2) Water Resources and Aquatic Ecology: potential effects on surface water and groundwater resources consumed and discharged; potential effects on estuarine salt marsh ecosystems and aquatic biota resulting from withdrawing and discharging cooling water from the St. Johns River (e.g., thermal discharge, entrainment or impingement of fish and invertebrate species);

(3) Infrastructure and Land Use: potential effects resulting from the transport of coal, petroleum coke, and limestone required for the proposed project, including the development of land for infrastructure, storage, or waste disposal; affected resource areas including land (e.g., existing shoreline and wetlands), utilities, and

transportation routes (e.g., train traffic to supply coal);

(4) Solid Waste: pollution prevention and waste management practices, including solid waste impacts, caused by the generation, treatment, transport, storage, and disposal of solid wastes;

(5) Construction: impacts associated with noise, traffic patterns, and construction-related emissions;

(6) Visual: impacts associated with a new stack that is taller than existing structures at Northside Generating Station;

(7) Floodplains: potential impacts (e.g., impeding floodwaters, re-directing floodwaters, on-site and off-site property damage) of siting new buildings and infrastructure within floodplain and hurricane storm surge areas;

(8) Wetlands: potential reduction of wetlands due to new construction (e.g., construction associated with feedstock transport infrastructure);

(9) Community Impacts: impacts on public safety related to fire and emergency vehicle access to the Northside community of Jacksonville; impacts to local traffic patterns resulting from rail traffic; socioeconomic impacts on public services and infrastructure (e.g., police protection, schools, and utilities); noise associated with project operation; environmental justice with respect to the surrounding community; and

(10) Cumulative effects that result from the incremental impacts of the proposed project when added to other past, present, and reasonably foreseeable future actions (e.g., incremental discharge of cooling water affecting aquatic biota).

Public Scoping Process

To ensure that the full range of issues related to this proposal are addressed, DOE will conduct an open process to define the scope of the EIS. The public scoping period will run until December 31, 1997. Interested agencies, organizations, and the general public are encouraged to submit comments or suggestions concerning the content of the EIS, issues and impacts to be addressed in the EIS, and the alternatives that should be analyzed.

Scoping comments should clearly describe specific issues or topics that the EIS should address in order to assist DOE in identifying significant issues. Written, e-mailed, faxed, or telephoned comments should be communicated by December 31, 1997 (see ADDRESSES).

In addition, a public scoping meeting to be conducted by DOE will be held in the In-Plant Conference Room at the Northside Generating Station on December 3, 1997, at 7 p.m. The address of the Northside Generating Station is 4377 Heckscher Drive, Jacksonville, Florida. DOE requests that anyone who wishes to speak at this public scoping meeting contact Dr. Jan Wachter, either by phone, fax, computer, or in writing (see ADDRESSES in this Notice). Individuals who do not make advance arrangements to speak may register at the meeting and will be given the opportunity to speak after all previously scheduled speakers have made their presentations. Speakers who wish to make presentations longer than five minutes should indicate the length of time desired in their request. Depending on the number of speakers, it may be necessary to limit speakers to five minute presentations initially, with the opportunity for additional presentation as time permits. Speakers can also provide additional written information to supplement their presentations. Oral and written comments will be given equal weight.

DOE will begin the meeting with an overview of the proposed CFB combustor project. A presiding officer will be designated by DOE to chair the meeting. The meeting will not be conducted as an evidentiary hearing, and speakers will not be cross-examined. However, speakers may be asked to clarify their statements to ensure that DOE fully understands the comments or suggestions. The presiding officer will establish the order of speakers and provide, any additional procedures necessary to conduct the meeting.

Issued in Washington, D.C., this 6th day of November, 1997.

Peter N. Brush,

Acting Assistant Secretary, Environment, Safety and Health.

[FR Doc. 97-29890 Filed 11-12-97; 8:45 am]

BILLING CODE 6450-01-P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[FERC-512]

Information Collection Submitted for Review and Request For Comments

November 6, 1997.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of submission for review by the Office of Management and Budget (OMB) and request for comments.

SUMMARY: The Federal Regulatory Commission (Commission) has submitted the energy information collection listed in this notice to Office of Management and Budget (OMB) for review under provisions of Section 3507 of the Paperwork Reduction Act of 1995 (Pub. L. No. 104-13). Any interested person may file comments on the collection of information directly with OMB and should address a copy of those comments to the Commission as explained below. The Commission received no comments in response to an earlier Federal Register notice of May 28, 1997 (62 FR 28844) and has made this notation in its submission to OMB.

DATES: Comments regarding this collection of information are best assured of having their full effect if received within 30 days of this notification.

ADDRESSES: Address comments to Office of Management and Budget, Office of Information and Regulatory Affairs, Attention: Federal Energy Regulatory Commission, Desk Officer, 726 Jackson Place, N.W., Washington, D.C. 20503. A copy of the comments should also be sent to Federal Energy regulatory Commission, Division of Information Services, Attention: Mr. Michael Miller, 888 First Street N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Michael P. Miller may be reached by telephone at (202) 208-1415, by fax at (202) 273-0873, and by e-mail at mmiller@ferc.fed.us.

SUPPLEMENTARY INFORMATION:

Description

The energy information collection submitted to OMB for review contains:

1. *Collection of Information:* FERC-512 "Application for Preliminary Permit"

2. *Sponsor:* Federal Energy Regulatory Commission

3. *Control No.:* OMB No. 1902-0073. The Commission is now requesting that OMB approve a three-year extension of the current expiration date, with no changes to the existing collection. There is a decrease in the reporting burden due to a decrease in the number of applicants filing with the Commission. These are mandatory collection requirements.

4. *Necessity of Collection of Information:* Submission of the information is necessary to enable the Commission to carry out its responsibilities in implementing the provisions of the Federal Power Act (FPA). The information reported under Commission identifier FERC-512 is filed in accordance with Sections 4(f), 5, 7, (FPA). The Part I of the FPA gives the Commission authority to issue licenses

whether a utility unit is "less environmentally beneficial" after controls than it was before controls. Accordingly, the final rule allows consideration of all environmental impacts—beneficial and adverse—in making a determination.

B. Representative Actual Annual Emissions

1. Background

The EPA proposed to clarify its methodology for calculating emissions increases at electric utility steam generating sources that had begun normal operations. The EPA proposed to compare actual emissions before and after changes for all physical or operational changes at an existing electric utility steam generating unit other than the addition of a new unit or the replacement of an existing unit. The EPA proposed to consider a unit to be replaced if it would constitute a reconstructed unit within the meaning of 40 CFR 60.15. Since there is no relevant operating history for wholly new units and replaced units, it is not possible to reasonably project post-change utilization for these units, and hence, their future level of "representative annual actual emissions." For other changes, past operating history, and other relevant information, provides a basis for reasonable projections.

As proposed, the "representative actual annual emissions" methodology requires the utility to compare its baseline emissions with its future actual emissions to determine if the proposed change will increase actual emissions. The EPA's existing regulations define baseline emissions as "the average rate, in tpy, at which the unit actually emitted the pollutant during a 2-year period which precedes the particular date and which is representative of normal source operation" (see, e.g., 40 CFR 52.21). The Administrator "shall" allow use of a different time period "upon a determination that it is more representative of normal source operation." *Id.* Although not required by the regulations, EPA has historically used the 2 years immediately preceding the proposed change to establish the baseline [see 45 FR 52676, 52705, 52718 (1980)]. However, in some cases it has allowed the use of earlier periods. For example, in *WEPCO,* EPA found the fourth and fifth years prior to the modification more representative of WEPCO's normal operations since the source's capacity was reduced due to physical problems. The EPA proposed to retain this regulatory language, but to adopt a new presumption regarding its implementation.

Under the proposed action, the Administrator would presume that any 2 consecutive years within the 5 years prior to the proposed change is representative of normal source operations for a utility. This presumption is consistent with the 5-year period for "contemporaneous" emissions increases and decreases in 40 CFR 52.21(b)(3)(i)(b).[17] Source owners or operators desiring to use other than a 2-year period or a baseline period prior to the last 5 years may seek the Administrator's specific determination that such period is more representative of normal operations.[18]

The future actual projection is the product of: (1) The hourly emissions rate, which is based on the unit's physical and operational capabilities following the change and federally-enforceable operational restrictions that would affect the hourly emissions rate following this change; and (2) projected capacity utilization, which is based on (a) the unit's historical annual utilization, and (b) all available information regarding the unit's likely post-change capacity utilization.[19] The projection of post-change capacity utilization for applicability purposes should be based on a projection of utilization for a period after the physical or operational change. Specifically, EPA proposed to allow sources to base the projection of utilization on the 2 years after the change, or a different consecutive 2-year period within the 10 years after the change, where the Administrator determines that such period is more representative of normal source operations.

2. Comments Generally Favoring the EPA Proposal

a. Several commenters favored the expansion of the time period for establishing the pre-change emissions baseline. Suggestions included:

(1) Allow the use of any 2 consecutive years within the last 5 years of operation to allow for a more representative baseline for units that have been shut down;

(2) Allow utilities to request to use periods of representative high utilization outside the 5 year time period;

(3) Add the "any 2 out of the prior 5 year baseline period" discussed in the preamble to 40 CFR parts 51, 52, and 60;

(4) Allow utilities to use the maximum utilization in any 1 year within at least the last 10 years, since 10 years is a more relevant capacity investment planning horizon than 5 years;

(5) Clarify that the source will be able to select the relevant 2-year period with approval of the reviewing authority required only when the pre-change baseline is outside of the 5-year period proceeding the change;

(6) Expand the baseline calculation period from 5 years to 10 years to be consistent with the after-change calculation period and to address a more representative time period;

(7) Allow the use of any 2 years (rather than consecutive years) due to long reserve shutdowns and because maintenance planning requires that utility boilers be operated in "abnormal" conditions for long durations; and

(8) Require sources to back up the choice of which 2 years to use with a short-term standard using an hourly rate, use the same 2-year period for determining the short-term and annual rates, and codify the 2 years used for the limit.

Several comments that recommended expanding the proposal to include industrial sources in the NSR exemption also noted that a "5-year window" is not satisfactory for industrial sources which do not always have representative periods of emissions immediately before a physical change. One industrial commenter suggested the use of any 2-year period be allowed.

Commenters in favor of the future actual emissions calculation method noted that it will alleviate uncertainty, for nonroutine repair, replacement, and maintenance projects while still protecting local air quality; the future-actual method reduces speculation and allows more reliance on factual data; and the actual-to-future-actual emissions comparison is more appropriate to look at the operating history and projected capacity of an existing unit to determine whether a change will increase emissions. One commenter stated that the actual-to-potential method discouraged environmentally beneficial modifications, but suggested that the

[17] This presumption does not apply to past modifications at an emissions unit for the purpose of determining contemporaneous emission changes at a source and cannot be used to extend the 5 year period specified in that provision [see 40 CFR 52.21(b)(3)(1)(b)].

[18] The level of baseline emissions selected must be consistent with current assumptions regarding the source's emissions that are used under the SIP for planning or permitting purposes. Thus, the source may not select a level of baseline emissions higher than that used by the permitting authority in issuing a PSD or other construction permit to a source in the area, if such higher level would result in a NAAQS or increment violation, or violate a visibility limitation.

[19] In projecting future utilization and emissions factors, the permitting authority may consider the company's historical operational data, its own representations, filings with Federal, State or local regulatory authorities, and compliance plans developed under title IV of the 1990 Amendments.

most appropriate policy would be to adopt a potential-to-potential test.

One commenter noted that the actual-to-future-actual test would end what was felt to be the "unlawful and unfair practice" of using the NSR program to "arbitrarily reduce allowable hours of operation or rates of production for existing sources." Countering the argument that the actual-to-future-actual test could create public health problems, two commenters noted that utilities must comply with all Federal, State and local air quality restrictions regardless of the tests used. Also supporting the actual-to-future-actual test, one commenter pointed out that source owners will be motivated by incentives in the CAA, proposed regulations, and market forces to finance and engineer economic and efficient physical and operational changes at plants so as to achieve excellent environmental control. One commenter favored calculating future emissions over a representative 2-year period within a 5-year period after the change.

3. Comments Generally Opposing the EPA Proposal

One opponent of the proposed methods stated that emission increases at power plants would now be fostered since the proposal will allow utilities to choose their own definitions for when emissions have increased.

In general, opponents of the proposal regarding the pre-change baseline noted that the change is arbitrary and capricious and that there is no analysis in the docket suggesting that any 2-year period is more representative of pre-change maximum emissions. Commenters noted that under the proposal, sources could select the years in which they had the highest emissions in an attempt to minimize the appearance of an increase and escape NSR. One commenter noted that the change in baseline calculation methodology would give utilities such flexibility in refurbishing, repowering, and life extension projects as to bias competitive power markets towards the continued use of existing old units rather than the construction of new ones.

Opponents to the use of future actual emissions stated that there is no reasoned basis for an unenforceable representative actual emissions approach, and application of this test to electric utilities is not consistent with EPA's established policy toward other sources. Other comments contended that the future actual test ignores all past precedents and that, in determining whether a change triggers NSR, EPA should compare actual emissions for the current unit to potential emissions from the altered source; the future actual test does not guard against artificially low estimates made by sources to escape NSR, nor does it protect against substantial increases made immediately after the 2-year period; and the future actual emissions calculation procedure amounts to self-regulation and is easily subject to abuse.

State and local air agencies generally opposed the future actual method of calculating post-change emissions. One noted that the appropriate emission increase test should be determined on a case-by-case basis. One agency noted that the actual-to-future actual approach results in a significant relaxation of title I NSR requirements and would allow utilities to upgrade equipment which may have lost significant generating capacity without the equipment being subject to NSR, hampering local air quality attainment and maintenance efforts. There were several comments that future emissions cannot be reasonably determined solely on past operating history. One State noted that direction is needed on how actual versus potential emissions are estimated.

A few commenters addressed the 2-year period after the proposed change which is the basis for calculating the future actual emissions. Opponents of the future actual concept stated that use of such a provision would result in unrealistically low future emissions projections and shield a company against efforts to enforce NSR requirements at a source that increased emissions 3 years after making physical changes.

An environmental group and several State agencies noted that the projected post-change emissions should become an enforceable permit condition in order to commit a source to limit its future emissions to a specific amount and to provide assurance that these projections are reasonable estimates of expected emissions. If a source will not accept such a permit condition, then the source should have to use potential post-change emissions.

4. Comments Suggesting Revisions to the Proposal

Three commenters suggested a more flexible test for ascertaining SO_2 increases for determining applicability of NSR and NSPS requirements, namely a measure of pollution per unit of electrical output.

a. Commenters made the following specific suggestions for changes surrounding the future actual calculation method:

(1) Develop guidelines to assist States in making like-kind determinations;

(2) Require like-kind replacements to use the representative actual annual emissions for calculation of actual emissions;

(3) Define "like-kind replacement" to include complete replacement of an existing emissions unit;

(4) Define "routine repair and replacement;"

(5) Apply the actual-to-actual test to like-kind replacement of an entire emitting unit;

(6) Allow new units or greenfield plants to rely on future actual emissions if they can reliably project future emissions; and

(7) Consider an alternative way to make the NSR accounting system consistent, such as basing it on past allowable to future allowable emissions.

(b) Other suggestions included the following:

(1) Provide guidance on routine repair and replacement and maintenance activities to include placing units on cold reserve and bringing them back on line, and

(2) Use a 2-year period other than immediately after the change only when the EPA cannot clearly demonstrate that the 2-year period immediately following the change is not representative.

5. The EPA Analysis

The EPA has decided to promulgate the proposed "representative actual annual emissions" methodology for calculating emissions changes at electric utility steam generating units where the changes do not involve the construction of a new, "greenfield" unit or the replacement of an existing one. After a thorough review of the comments, EPA concludes that the comparison of "actual emissions before" to a projection of "actual emissions after" a physical or operational change at an existing utility steam generating unit is workable and, with the added safeguard discussed below, is the most suitable method for evaluating emissions changes at such sources.

Many commenters questioned EPA's proposed presumption that sources may use, as the baseline, emissions from any 2 consecutive years within the 5 years prior to the proposed change without regard to normal source operations. As discussed in the proposal, this presumption is consistent with EPA's decision in WEPCO and the 5-year period for "contemporaneous" emissions increases and decreases in 40 CFR 52.21(b)(3)(i)(b).[20]

Moreover, EPA is not reading "normal source operations" out of the regulation as charged. Rather, the presumption recognizes the nature of utility operations without compromising the existing regulatory language which requires that the pre-change 2-year period used in defining baseline emissions be representative of "normal" operations. For example, as a system a utility's "normal" operations means directly responding to a demand for electricity. A cold winter or hot summer will result in high levels of "normal" operations while a relatively mild year will produce lower "normal" operations. By presumably allowing a utility to use any 2 consecutive years within the past 5, the rule better takes into consideration that electricity demand and resultant utility operations fluctuate in response to various factors such as annual variability in climatic or economic conditions that affect demand, or changes at other plants in the utility system that affect the dispatch of a particular plant. By expanding a baseline for a utility to any consecutive 2 in the last 5 years, these types of fluctuations in operations can be more realistically considered, with the result being a presumptive baseline more closely representative of normal source operation.

The EPA disagrees with comments seeking to allow the use of any 2 consecutive years within the last 5 years of a unit's "operation" rather within than the 5 years directly preceding the proposed change. A shifting of the 5-year period would be difficult to harmonize with definitions of contemporaneous contained in the regulations [see, e.g., 40 CFR 52.21(b)(3)(iii)]. This type of open-ended provision would even credit a unit which has been inoperative for 20 or 30 years or longer with a high level of emissions. The EPA notes, however, that as has always been the case under the prior regulations, any source owner or operator may request a determination that another baseline period is more representative of the unit's "normal" operations.

Several commenters opposing today's regulatory changes charged that without appropriate assurances utilities could deliberately underestimate future operations (and thus emissions) for the purpose of avoiding review or that even where a forthright estimate is made, the forecast may prove inaccurate. The EPA is concerned that without appropriate safeguards increases in future actual emissions that in fact resulted from the physical or operational change could go unnoticed and unreviewed. For this reason, EPA has added the safeguard explained below.

The EPA does not, however, agree with comments that post-change emissions estimates must always be made into permanent federally-enforceable permit conditions. To do so would permanently restrict a utility's legally allowable emission limits to its pre-change actual emissions level unless it subsequently underwent NSR, and would fail to account for the very real possibility that emissions might increase over baseline levels in the future for reasons unrelated to the physical or operational change in question. As discussed more fully in the following section, NSR applies only where the emissions increase is caused by the change. Thus the issue should be viewed more as one of tracking and monitoring post-change utilization and/or emissions levels at the unit to confirm that baseline emission levels are not exceeded as a result of the change.

To guard against the possibility that significant increases in actual emissions attributable to the change may occur under this methodology, EPA is clarifying in the final regulations that any utility which utilizes the "representative actual annual emissions" methodology to determine that it is not subject to NSR must submit for 5 years after the change sufficient records to determine if the change results in an increase in representative actual annual emissions.[21] Utilities may use continuous emissions monitoring data, operational levels, fuel usage data, source test results or any other readily available data of sufficient accuracy for the purpose of documenting a unit's post-change actual annual emissions.

Where the change does not increase the unit's emissions factor, i.e., the amount of pollution emitted by a source after control per unit of fuel combusted (such as pounds of SO_2 emitted per ton of coal burned), the utility may submit annual utilization data, rather than emissions data, as a method of tracking post-change emissions. If annual utilization data show that the unit increased utilization above baseline levels, the permitting authority should determine whether the increase resulted from the change. Where a causal link exists between the change and the increase in utilization, the permitting authority should then determine whether emissions have also increased as a result of the change.

Changes that could increase a unit's emissions factor typically involve changes to the boiler itself. (Such changes do not include activities that qualify as pollution control projects under today's rule.) Where these types of changes exist, the utility should submit annual emissions data to the permitting authority. If these data suggests that the utility has increased annual emissions over baseline levels, the permitting authority should inquire whether the increase resulted from the physical or operational change. The utility may demonstrate that any increase was caused by an independent factor, such as demand growth.

Appropriate records are to be submitted to the permitting agency on an annual basis for a period of 5 years from the date the unit begins operations (i.e., post-change operations after an initial shakedown period). A longer period, not to exceed 10 years, may be required by the permitting agency where it has determined that no period within the first 5 years following the change is representative of source operations.

Since it is expected that utilities will submit the same data normally used to report emissions or operational levels under existing Federal, State or local air pollution control agency requirements, EPA does not expect that documentation of post-change actual annual emissions will impose any additional data collection burden on the part of a utility.

The purpose of this provision is to provide a reasonable means of determining whether a significant increase in representative actual annual emissions resulting from a proposed change at an existing utility occurs within the 5 years following the change. Thus the intent is to confirm the utility's initial projections rather than annually revisiting the issue of NSR applicability. If, however, the reviewing authority determines that the source's emissions have in fact increased significantly over baseline levels as a result of the change, the source would become subject to NSR requirements at that time. The EPA has adopted this approach and the time period because it believes that, in most cases, any emissions increase resulting from a physical or operational change at a utility unit would occur within the first 5 years of normal operation of the unit

[20] As discussed, this presumption does not apply to past modifications at an emissions unit for the purpose of determining contemporaneous emission changes at a source and cannot be used to extend the 5-year period specified in that provision (see 40 CFR 52.21(b)(3)(i)(b)).

[21] This is the only substantive change from the regulations as proposed. However, EPA has also made minor changes to the wording of some of the regulations to address problems with clarity and syntax. Since these changes are not intended to alter the meaning of the regulations, they are not individually discussed in this preamble.

after the change. Thus, EPA will presume that any increase in emissions levels more than 5 years after the change has occurred is not related to the physical or operational change.

In response to comments regarding "like-kind" replacements, EPA notes that today's regulations recognize no distinction between "like-kind" replacements and other nonroutine physical or operational changes at a utility steam generating unit. The "actual-to-future-actual" methodology promulgated today for calculating emissions changes applies to all types of changes at utility units, including the replacement of "like-kind" components at an existing unit. However, the "like-kind" replacement of a whole unit is for all practical purposes a replacement unit and, therefore, is treated as a new unit.

Although several commenters suggested that EPA should expand the representative actual emissions test to new and reconstructed units, EPA has decided not to do so. Since there is no relevant operating history for new or reconstructed units, it would not be possible to accurately project operations or emissions for these units. Consequently, the EPA has left unchanged the regulations which require that for any unit which has not begun normal operations, actual emissions are considered equal to the unit's potential-to-emit.

A few commenters requested that EPA define or provide guidance on "routine repair, replacement and maintenance" activities. The June 14 proposal did not deal with this aspect of the regulations, nor do the regulatory changes promulgated today. However, the issue has an important bearing on today's rule because a project that is determined to be routine is excluded by EPA regulations from the definition of major modification. For this reason, EPA plans to issue guidance on this subject as part of a NSR regulatory update package which EPA presently intends to propose by early summer. In the meantime, EPA is today clarifying that the determination of whether the repair or replacement of a particular item of equipment is "routine" under the NSR regulations, while made on a case-by-case basis, must be based on the evaluation of whether that type of equipment has been repaired or replaced by sources within the relevant industrial category.

C. The Causation Requirement

1. Background

The NSR regulatory provisions require that the physical or operational change "result in" an increase in actual emissions in order to consider that change to be a modification [see e.g., 40 CFR 52.21(2)(i)]. In other words, NSR will not apply unless EPA finds that there is a causal link between the proposed change and any post-change increase in emissions. The EPA proposed to amend its rules to clarify this provision in the context of modifications at electric utility steam generating units.

Under the proposed regulations, any emissions increase attributable to a physical or operational change, such as a physical or operational change that significantly alters the efficiency of the plant, (see, *Puerto Rican Cement*, 889 F.2d at 297–8), must continue to be included in the post-change emissions calculation. The proposal clarified that where increased operations are in response to independent factors, such as system-wide demand growth, which would have occurred and affected the unit's operations even in the absence of the physical or operational change, such increases do not result from the change and shall be excluded from the projection of future actual emissions. Thus, in assessing whether the proposed change will result in an increase in actual emissions, utilities need not include in their projection of post-change utilization that portion of the increased rate of utilization, if any, due to factors unrelated to the physical or operational change, such as an increase in projected capacity utilization due to the rate of electricity demand growth for the utility system (of which that source is a member) as a whole.

Under today's rule, during a representative baseline period (see *supra*), the plant must have been able to accommodate the projected demand growth physically and legally even absent the particular change. Increased operations (and resultant increases in actual emissions) that could not physically and legally be accommodated during the representative baseline period but for the proposed physical or operational change should be considered to result from the change.

2. Comments Generally Favoring the EPA Proposal

Several utility representatives supported the proposed demand growth exclusion and the causation requirement. Many commenters requested clarification of certain points or expansion of certain provisions. One commenter noted that there should be a specific exclusion for emissions increases at a generating station resulting from generation shifts and decreased plant efficiencies caused by operation of pollution control systems. Another noted that the discussion of the criteria for recognizing "factors unrelated to the physical or operational change" should be improved upon because the proposed requirements that a facility must have been physically able to accommodate the projected growth during a "representative baseline period" could have a negative impact in utility capacity planning and investment decisions, depending upon how such a period is determined.

One commenter noted that EPA should specifically recognize an exception for units which have been inactive, because a unit should not have to include all of its emissions due to demand growth merely because it was in need of repair or maintenance while inactive. Commenters asked that EPA better define "independent factors" in the context of the demand growth exclusion. Lastly, one commenter stated that the final rule should reconcile the "demand growth exclusion" with the existing "hours of operation/rate of production" exclusion by confirming that increases attributable to system-wide demand growth are already excluded under the already-existing exclusion and, therefore the "demand growth exclusion" only applies where there is a federally-enforceable permit term limiting hours of operation or production rate.

3. Comments Generally Opposing the EPA Proposal

Opponents of the exclusion of emissions attributable to demand growth contended that there is no rational basis for ignoring such emissions. When increased capacity or utilization is the immediate goal of a project and an increase in emissions occurs, the project must be subject to NSR regardless of the underlying reasons for the increased capacity or utilization and corresponding emission increase. Contrary to the letter and purpose of the statute, the demand growth exclusion could result in major increases in actual emissions going unreviewed and unregulated, would create serious local pollution problems, and would discriminate against companies that were successful in implementing energy efficiency programs. One local agency pointed out that it is virtually impossible to determine with any degree of certainty what portion of a unit's emissions are attributable to an increase in projected capacity utilization.

In addition, commenters noted that the exclusion will have an adverse effect on local agencies' ability to control emissions and that the time of levels used for that source in the most recent air quality impact analysis and (2) it has reason to believe that such an increase would cause or contribute to a violation of a NAAQS, increment or visibility limitation. If this modeling indicates that this increase in emissions will cause or contribute to a violation of any ambient standard, PSD increment or visibility limitation, the pollution control exclusion does not apply.

3. The EPA's Existing Policy Regarding Pollution Control Projects

As noted above, generally pollution control projects at existing stationary sources are not major modifications subject to new source review because they do not usually result in an increase in actual emissions, and EPA believes that, in general, pollution control projects were not intended by Congress to be considered physical or operational changes for purposes of NSR.

The EPA currently applies its PSD regulations in harmony with its NSPS regulations, which exclude most pollution control projects. See 40 CFR 60.14(e)(5). In 1977, Congress incorporated the NSPS definition of modification into the PSD and nonattainment statutes. CAA sections 111(a)(4), 169(a)(c), 171(4). In addition, the legislative history reflects that, as a general matter, Congress intended to conform the meaning of "modification" for PSD purposes to the usage under the NSPS program. See 123 Cong. Rec. H11957 (November 1, 1977). The EPA reiterated this view in 1978. See 43 FR 26396, June 19, 1978. Subsequently, EPA interpreted its NSR regulations to incorporate the NSPS pollution control project exclusion.[13] The EPA later voiced concern about incorporating the precise NSPS pollution control language in the NSR context absent explication through notice-and-comment rulemaking largely because of the ambient air quality component of NSR that is absent from the NSPS program.[14] In recent years however, EPA has consistently excluded pollution control projects from NSR provided that the proposed project would be environmentally beneficial, taking into account ambient air quality.[15] In light of the title IV requirements and other provisions of the Clean Air Act Amendments of 1990, EPA confirms that it will continue to consider the overall environmental consequences of pollution control projects for NSR applicability on an interim basis pending final action on the proposed regulatory exclusion for pollution control projects. By its nature, a determination of whether or not a project renders a unit less environmentally beneficial involves case-by-case assessment of its net emissions and overall impact on the environment. In making such assessments, EPA must consider the overall emissions before and after the project, as well as any other relevant environmental factors. As a result, no single factor can be identified in advance for purposes of making this determination.

B. Representative Actual Annual Emissions

As described above, EPA proposes to revise its methodology for calculating emissions increases at electric utility steam generating sources. The EPA proposes to compare actual emissions before and after changes for all physical or operational changes at an existing electric utility steam generating unit other than the addition of a new unit or the replacement of an existing unit. Under today's action, EPA proposes to consider a unit to be replaced if it would constitute a reconstructed unit within the meaning of 40 CFR 60.15. Since there is no relevant operating history for wholly new units and replaced units, it is not possible to reasonably project post-change utilization for these units, and hence, their future level of "representative annual actual emissions." For other changes, past operating history, and other relevant information, provides a basis for reasonable projections.

As proposed today, the "representative actual annual emissions" methodology requires the utility to compare its baseline emissions with its future actual emissions to determine if the proposed change will increase actual emissions. The EPA's existing regulations define baseline emissions as "the average rate, in tons per year, at which the unit actually emitted the pollutant during a 2-year period which precedes the particular date and which is representative of normal source operation." See *e.g.*, 40 CFR 52.21. The Administrator "shall" allow use of a different time period "upon a determination that it is more representative of normal source operation." *Id.* Although not required by the regulations, EPA has historically used the 2 years immediately preceding the proposed change to establish the baseline. (See 45 FR 52676, 52705, 52718 (1980).) However, in some cases it has allowed the use of earlier periods. For example, in *WEPCO*, EPA found the fourth and fifth years prior to the modification more representative of WEPCO's normal operations since the source's capacity was reduced due to physical problems. The EPA proposes today to retain this regulatory language, but to adopt a new presumption regarding its implementation.

Under today's action, the Administrator will presume that any 2 consecutive years within the 5 years prior to the proposed change is representative of normal source operations for a utility. This presumption is consistent with the 5-year period for "contemporaneous" emissions increases and decreases in 40 CFR 52.21(b)(3)(i)(b).[16] Source owners or operators desiring to use other than a 2-year period or a baseline period prior to the last 5 years may seek the Administrator's specific determination that such period is more representative of normal operations.[17]

The future actual projection is the product of: (1) The hourly emissions rate, which is based on the unit's physical and operational capabilities following the change and federally-enforceable operational restrictions that would affect the hourly emissions rate following this change; and (2) projected capacity utilization, which is based on (a) the unit's historical annual utilization, and (b) all available information regarding the unit's likely post-change capacity utilization.[18] The

[13] Memorandum from Edward Reich, Director, Stationary Source Compliance Division and William F. Pedersen, Acting Associate General Counsel, Air, Noise, and Radiation Division to Allyn M. Davis, Region IV (April 21, 1983).

[14] See, Memorandum from Gerald A. Emison, Director, OAQPS, to Regional Division Directors (July 7, 1986).

[15] See, Letter, William G. Rosenberg, Assistant Administrator, EPA, to Andrew Aitken, Vice President, New England Power Service Co., March 26, 1991; Letter, Rosenberg to Patrick M. McCarter, Senior Vice President, Public Service Co. of Colorado, July 23, 1990; Letters, David Kee, Director, Air and Radiation Division, EPA Region V, to Timothy J. Method, Assistant Commissioner, Indiana Dept. of Environmental Management, January 30, 1990 and March 8, 1990.

[16] This presumption does not apply to past modifications at an emissions unit for the purpose of determining contemporaneous emission changes at a source and cannot be used to extend the five year period specified in that provision. See 40 CFR 52.21(b)(3)(i)(b).

[17] The level of baseline emissions selected must be consistent with current assumptions regarding the source's emissions that are used under the state implementation plans (SIP) for planning or permitting purposes. Thus, the source may not select a level of baseline emissions higher than that used by the permitting authority in issuing a PSD or other construction permit to a source in the area, if such higher level would result in a NAAQS or increment violation, or violate a visibility limitation.

[18] In projecting future utilization and emissions factors, the permitting authority may consider the company's historical operational data, its own representations, filings with Federal, State or local regulatory authorities, and compliance plans developed under title IV of the 1990 Amendments.

projection of post-change capacity utilization for applicability purposes should be based on a projection of utilization for a period after the physical or operational change. Specifically, EPA today proposes to allow sources to base the projection of utilization on the 2 years after the change, or a different consecutive 2-year period within the 10 years after the change, where the Administrator determines that such period is more representative of normal source operations.

C. The Causation Requirement

The NSR regulatory provisions require that the physical or operational change "result in" an increase in actual emissions in order to consider that change to be a modification. See *e.g.* 40 CFR 52.21(2)(i). In other words, NSR will not apply unless EPA finds that there is a causal link between the proposed change and any post-change increase in emissions. The EPA today proposes to amend its rules to clarify this provision in the context of modifications at electric utility steam generating units.

Under these proposed regulations, any emissions increase attributable to a physical or operational change, such as a physical or operational change that significantly alters the efficiency of the plant, (see, *Puerto Rican Cement*, 889 F.2d at 297–8), must continue to be included in the post-change emissions calculation. Today's proposal makes clear that where increased operations are in response to independent factors, such as system-wide demand growth, which would have occurred and affected the unit's operations even in the absence of the physical or operational change, such increases do not result from the change and shall be excluded from the projection of future actual emissions. Thus, in assessing whether the proposed change will result in an increase in actual emissions, utilities need not include in their projection of post-change utilization that portion of the increased rate of utilization, if any, due to factors unrelated to the physical or operational change, such as an increase in projected capacity utilization due to the rate of electricity demand growth for the utility system (of which that source is a member) as a whole.

Under this proposal, during a representative baseline period (see *supra*), the plant must have been able to accommodate the projected demand growth physically and legally even absent the particular change. Increased operations (and resultant increases in actual emissions) that could not physically and legally be accommodated but for the proposed physical or operational change should be considered to result from the change.

D. Repowering

As previously mentioned, title IV of the 1990 Amendments grants special treatment to utilities that seek to comply with mandated acid rain reductions by repowering a unit with qualifying clean coal technology. 1990 Amendments sections 402(12), 409(a). Specifically, repowering projects that qualify for a Phase II compliance extension will also be exempt from NSPS requirements, so long as the repowering "does not increase actual hourly emissions for any pollutant regulated under the Act." Section 409(d). The EPA interprets the requirement that the repowering not lead to an increase in "actual hourly emissions" as an expression of Congressional intent that will respect to repowering projects, EPA should use the same general approach to determining applicability as it has for other physical or operational changes, discussed above. Accordingly, EPA today proposes rules that provide that a repowering project which results in an increase over baseline in a unit's post-modification hourly emissions will not be eligible for this limited NSPS exemption.

The proposed NSPS exemption applies to repowering of existing units at existing sources, so long as the project qualifies for the Phase II extension and satisfies the "actual hourly emissions" increase test. Because of this provision, the reconstruction limitations specified in 40 CFR 60.15 are not applicable to qualifying repowering projects. However, no special treatment can be afforded to a new unit which is located at a different site than the existing unit it replaces. See CAA section 409(d).

Pursuant to section 409(e), EPA will provide expedited NSR processing for repowering projects and will encourage State permitting authorities to do the same.

E. Clean Coal Technology Demonstration Projects

Today's notice also proposes rules implementing the new CCT exemption created by the 1990 Amendments. For the purposes of this proposal, temporary CCT demonstration projects are defined as those CCT demonstration projects lasting 5 years or less. Title IV gives these projects an exemption from NSPS, PSD and nonattainment requirements. *Id.*, section 415(b)(2). However, the facility would still be subject to any applicable SIP and must comply with any other requirements necessary to attain and maintain NAAQS. This ruling proposes to implement this provision and clarifies that EPA considers the 5-year period as starting on the date of startup (as defined in 40 CFR 60.2). A temporary demonstration project may be converted to a permanent status at any time, provided it meets all the requirements that apply to a permanent CCT project criteria at the time of conversion.

Further, EPA proposes that at the end of a temporary project, the facility must be returned to pre-demonstration conditions and hourly emission rates (or lower). The return of the facility to its pre-demonstration physical and operational condition would not result in the loss of the actual emissions margin between pre-demonstration actual emissions rate and SIP allowable emissions rates for that facility. Rather, the facility would be treated as if the temporary demonstration project had never occurred.[19]

This proposal does not extend to emissions increases that are unrelated to the conduct of temporary demonstration projects. The EPA considers emissions increases (above the predemonstration levels) that are attributable to physical or operational changes, other than those necessary to restore that unit to its pre-demonstration condition, to be beyond the scope of the Congressional exemption.

Today's action also proposes to implement an exemption from NSPS and PSD requirements for repowering projects which are awarded funding from the DOE as permanent CCT demonstration projects (or similar projects funded by EPA) so long as potential emissions (see § 52.21(b)(4)) from the unit do not increase as a result of the project. Section 415(b)(3). However, repowering projects that qualify as pollution control projects will be treated as other pollution control projects for the purposes of the nonattainment provisions of title I of the Act.

Finally, today's proposal would implement the statutory exemptions in section 415(c). In that section, Congress provided an exemption from NSPS and PSD for the reactivation of "very clean units" otherwise in compliance with the Act that had been shut down for at least

[19] This would be the case even if there were small differences in the post-demonstration physical and operational conditions due to a technical inability to restore the unit to its precise pre-demonstration condition, or due to normal variability in the coal used. Thus, EPA would not seek to apply NSPS or NSR because of a post-demonstration emissions increase attributable solely to an increase in the hours of operation or production rate of the unit (subject to the NSPS limitation that the production rate increase must be accomplished without a capital expenditure).

Attachment C
(6 pages)

05:28 PM
03/04/93

NORTHSIDE GENERATING STATION

GENERATION STATISTICS

CALENDAR YEAR, 1992

GENERATION DATA (MWH)	NS-1	NS-3	STM TOT**	NCT3	NCT4	NCT5	NCT6	NCT TOTAL
1. GROSS MWH	1,055,692	1,913,710	2,969,402	1,030	1,367	2,677	1,597	6,671
2. AUX. LOAD	61,872	82,219	147,751	236	365	237	414	1,252
3. NET MWH ONLINE (SYNC)	999,167	1,835,767	2,834,934	1014	1343	2641	1577	6,575
NET MWH OVERALL	993,820	1,831,491	2,821,651	794	1,002	2,440	1,183	5,419
4. NET MWH LST YR	724,529	1,632,386	2,353,265	1,096	585	2,718	981	5,380
5. CUM NET MWH (FSCL)	993,820	1,831,491	2,821,651	794	1,002	2,440	1,183	5,419
6. CUM NET MWH (CAL)	993,820	1,831,491	2,821,651	794	1,002	2,440	1,183	5,419
7. % STATION GROSS GEN	35.5	64.3	99.8	0.0	0.0	0.1	0.1	0.2
* 8. ON-LINE LOAD FACTOR %	60.7	57.6	42.6	47.6	43.1	57.3	62.0	NA
* 9. #6 OIL BURNED ON-LINE	1,063,506	1,147,524	2,211,030	NA	NA	NA	NA	NA
#6 OIL BURNED OVERALL	1,067,058	1,147,609	2,214,667	NA	NA	NA	NA	NA
#2 OIL BURNED ON-LINE	NA	NA	NA	2760	3897	6656	4488	17,801
#2 OIL BURNED OVERALL	NA	NA	NA	3,029	4,141	6,950	4,731	18,851
#2 OIL BURNED (EQ BBL)	NA	NA	NA	2,776	3,795	6,369	4,336	17,276
GAS BURNED ON-LINE	3,584,773	11,339,799	14,924,572	NA	NA	NA	NA	NA
GAS BURNED OVERALL	3,625,996	11,395,593	15,044,662	NA	NA	NA	NA	NA
GAS BURNED (EQ BBL)	596,463	1,872,000	2,471,669	NA	NA	NA	NA	NA
TTL FUEL BURN (EQ BBL)	1,663,521	3,019,609	4,686,336	2,776	3,795	6,369	4,336	17,276
10. AVG BTU / BBL #6 OIL	6,354,105	6,347,839	6,350,858	NA	NA	NA	NA	NA
AVG BTU / BBL #2 OIL	NA	NA	NA	5,820,966	5,820,966	5,820,966	5,820,966	5,820,966
AVG BTU / FT3 GAS	1,045	1,043	1,043	NA	NA	NA	NA	NA
11. GROSS KWH / EQ BBL	635	634	634	371	360	420	368	386
12. NET KWH / EQ BBL	597	607	602	286	264	383	273	314
13. HEATRATE (ON LINE)	10,513	10,409	10,446	15,851	16,895	14,669	16,561	15,759
HEATRATE (OVERALL)	10,636	10,466	10,548	22,196	24,063	16,580	23,280	20,249
14. NUMBER OF STARTS	39	26	65	32	29	35	29	125
15. HOURS OF OPERATION	6320.6	6419.3	12739.9	41.2	60.4	89.0	49.1	239.7

	OIL	GAS	HOURS
16. AUXILIARY BOILER	0	23,073	155

STATION INVENTORIES	# 6 FUEL (bbl)	# 2 FUEL (bbl)	MgO (gal)
17. ON HAND (BOY)	943,202	27,208	3,875
18. RECEIVED	1,741,881	12,462	42,066
19. BARGE IN (INTRA-JEA)	15,920	15,969	0
BARGE OUT (INTRA-JEA)	0	0	0
20. TTL AVAILABLE	2,701,003	55,639	45,941
21. ON HAND (EOY)	486,337	36,787	4,769
22. CONSUMED	2,214,667	18,851	41,172

* NOTES;

(8) ON-LINE LOAD FACTOR FOR UNITS, CAPACITY FACTOR FOR STEAM TOTAL.

(9) AUXILIARY BOILER FUEL INCLUDED IN STATION'S OVERALL FUEL BURNED. OIL MEASUREMENTS CORRECTED TO THE END OF YEAR SOUNDINGS.

LIFETIME TOTALS	NS-1	NS-3
23. GROSS MWH	23,042,577	21,312,050
24. HOURS OF OPERATION	137,890	74,975
25. NUMBER OF STARTS	678	302

** UNIT TOTALS MAY NOT ADD UP TO STATION TOTALS DUE TO ADDITIONAL STATION AUXILIARY REQUIREMENTS.

Attachment C

04:37 PM
02/04/94

NORTHSIDE GENERATING STATION

GENERATION STATISTICS

CALENDAR YEAR, 1993

GENERATION DATA (MWH)	NS-1	NS-3	STN TOT**	NCT3	NCT4	NCT5	NCT6	NCT TOTAL
1. GROSS MWH	609,733	1,704,240	2,313,973	533	1,622	1,216	1,322	4,693
2. AUX. LOAD	39,333	89,658	132,641	209	258	309	354	1,130
3. NET MWH ONLINE (SYNC)	577,767	1,620,319	2,198,087	525	1605	1204	1306	4,640
4. NET MWH OVERALL	570,400	1,614,582	2,181,332	324	1,364	907	968	3,563
5. NET MWH LST YR	993,820	1,831,491	2,821,651	794	1,002	2,440	1,183	5,419
6. % STATION GROSS GEN	26.3	73.5	99.8	0.0	0.1	0.1	0.1	0.2
7. ON-LINE LOAD FACTOR %	65.8	51.6	54.7	53.3	73.3	75.7	63.6	17.0
8. CAPACITY FACTOR %	26.6	37.6	33.9	0.1	0.4	0.3	0.3	0.3
* 9. #6 OIL BURNED ON-LINE	869,649	2,513,484	3,383,134	NA	NA	NA	NA	NA
#6 OIL BURNED OVERALL	871,261	2,515,189	3,386,450	NA	NA	NA	NA	NA
#2 OIL BURNED ON-LINE	NA	NA	NA	1,510	3,883	3,370	3,682	12,444
#2 OIL BURNED OVERALL	NA	NA	NA	1,703	4,018	3,521	3,825	13,066
#2 OIL BURNED (EQ BBL)	NA	NA	NA	1,557	3,673	3,219	3,497	11,945
GAS BURNED ON-LINE	358,006	1,041,067	1,399,072	NA	NA	NA	NA	NA
GAS BURNED OVERALL	386,573	1,066,374	1,454,362	NA	NA	NA	NA	NA
GAS BURNED (EQ BBL)	63,297	174,666	238,193	NA	NA	NA	NA	NA
TTL FUEL BURN (EQ BBL)	934,558	2,689,855	3,624,643	1,557	3,673	3,219	3,497	11,945
10. AVG BTU / BBL #6 OIL	6,358,108	6,362,541	6,361,401	NA	NA	NA	NA	NA
AVG BTU / BBL #2 OIL	NA	NA	NA	5,814,186	5,814,186	5,814,186	5,814,186	5,814,186
AVG BTU / FT3 GAS	1,041	1,042	1,042	NA	NA	NA	NA	NA
11. GROSS KWH / EQ BBL	652	634	638	342	442	378	378	393
12. NET KWH / EQ BBL	610	600	602	208	371	282	277	298
13. HEATRATE (ON LINE)	10,215	10,539	10,454	16,705	14,066	16,276	16,389	15,592
HEATRATE (OVERALL)	10,417	10,600	10,571	30,537	17,128	22,573	22,966	21,320
14. NUMBER OF STARTS	27	17	44	23	16	18	17	74
15. HOURS OF OPERATION	3,538.8	6,373.6	9,912.4	19.0	42.1	30.6	39.6	131.4

	OIL	GAS	HOURS
16. AUXILIARY BOILER	0	1,415	28

STATION INVENTORIES	# 6 FUEL (bbl)	# 2 FUEL (bbl)	MgO (gal)
17. ON HAND (BOY)	486,242	36,787	4,769
18. RECEIVED	3,541,466	68,883	29,292
19. ADJUSTMENT (+ = more)	(1,369)	0	0
20. BARGED IN/OUT	2,415	(2,415)	275
21. TTL AVAILABLE	4,028,754	103,255	34,336
22. ON HAND (EOY)	642,304	90,190	4,773
23. CONSUMED	3,386,450	13,066	29,563

* NOTES;

(2) CORRECTED FOR CIRCULATOR MWH USED FOR SJRPP

(9) AUXILIARY BOILER FUEL INCLUDED IN STATION'S OVERALL FUEL BURNED.

OIL MEASUREMENTS CORRECTED TO THE END OF YEAR SOUNDINGS.

LIFETIME TOTALS	NS-1	NS-3
24. GROSS MWH	23,652,310	23,016,290
25. HOURS OF OPERATION	141,426	81,345
26. NUMBER OF STARTS	705	319

** UNIT TOTALS MAY NOT ADD UP TO STATION TOTALS DUE TO ADDITIONAL STATION AUXILIARY REQUIREMENTS.

Attachment C

09:50 AM
03/10/95

NORTHSIDE GENERATING STATION

GENERATION STATISTICS

CALENDAR YEAR, 1994

GENERATION DATA (MWH)	NS-1	NS-3	STM TOT**	NCT3	NCT4	NCT5	NCT6	NCT TOTAL
1. GROSS MWH	1,018,638	1,414,429	2,433,067	679	178	262	141	1,260
* 2. AUX. LOAD	61,259	78,488	143,182	108	350	343	544	1,345
3. NET MWH ONLINE (SYNC)	960,574	1,339,546	2,300,121	671	175	257	138	1,241
4. NET MWH OVERALL	957,379	1,335,941	2,289,885	571	(172)	(81)	(403)	(85)
5. NET MWH LST YR	570,400	1,614,582	2,181,332	324	1,364	907	968	3,563
6. % STATION GROSS GEN	41.8	58.1	99.9	0.0	0.0	0.0	0.0	0.1
7. ON-LINE LOAD FACTOR %	57.7	45.8	50.1	65.5	36.6	39.9	36.6	12.3
8. CAPACITY FACTOR %	44.4	31.2	35.6	0.1	0.0	0.1	0.0	0.1
* 9. #6 OIL BURNED ON-LINE	1,347,661	2,045,213	3,392,874	NA	NA	NA	NA	NA
#6 OIL BURNED OVERALL	1,347,809	2,045,406	3,393,215	NA	NA	NA	NA	NA
#2 OIL BURNED ON-LINE	NA	NA	NA	3,210	917	2,099	885	7,111
#2 OIL BURNED OVERALL	NA	NA	NA	3,319	984	2,208	978	7,489
#2 OIL BURNED (EQ BBL)	NA	NA	NA	3,031	899	2,016	893	6,839
GAS BURNED ON-LINE	1,387,834	1,400,419	2,788,253	NA	NA	NA	NA	NA
GAS BURNED OVERALL	1,409,508	1,410,109	2,819,616	NA	NA	NA	NA	NA
GAS BURNED (EQ BBL)	232,269	232,861	465,079	NA	NA	NA	NA	NA
TTL FUEL BURN (EQ BBL)	1,580,078	2,278,266	3,858,294	3,031	899	2,016	893	6,839
10. AVG BTU / BBL #6 OIL	6,353,046	6,359,774	6,357,102	NA	NA	NA	NA	NA
AVG BTU / BBL #2 OIL	NA	NA	NA	5,805,869	5,805,869	5,805,869	5,805,869	5,805,869
AVG BTU / FT3 GAS	1,047	1,050	1,049	NA	NA	NA	NA	NA
11. GROSS KWH / EQ BBL	645	621	631	224	NA	NA	NA	NA
12. NET KWH / EQ BBL	606	586	593	188	NA	NA	NA	NA
13. HEATRATE (ON LINE)	10,426	10,808	10,648	27,755	30,493	NA	37,257	33,281
HEATRATE (OVERALL)	10,485	10,846	10,711	33,755	NA	NA	NA	NA
14. NUMBER OF STARTS	35	7	42	13	8	13	11	45
15. HOURS OF OPERATION	6,734.7	5,960.4	12,695.1	19.8	9.3	12.5	7.3	48.9

	OIL	GAS	HOURS
16. AUXILIARY BOILER	0	0	0

STATION INVENTORIES	# 6 FUEL (bbl)	# 2 FUEL (bbl)	MgO (gal)
17. ON HAND (BOY)	642,304	90,190	4,773
18. RECEIVED	3,403,644	0	41,944
19. TRANSFER IN	1,330	0	0
20. TRANSFER OUT	(12,978)	1,330	0
21. TTL AVAILABLE	4,060,206	88,859	46,717
22. ON HAND (EOY)	666,992	81,370	7,302
23. CONSUMED	3,393,215	7,489	39,415

* NOTES;

(2) CORRECTED FOR CIRCULATOR MWH USED FOR SJRPP

(9) AUXILIARY BOILER FUEL INCLUDED IN STATION'S OVERALL FUEL BURNED.

OIL MEASUREMENTS CORRECTED TO THE END OF YEAR SOUNDINGS.

LIFETIME TOTALS	NS-1	NS-3
24. GROSS MWH	24,670,948	24,430,719
25. HOURS OF OPERATION	148,161	87,305
26. NUMBER OF STARTS	740	326

** UNIT TOTALS DO NOT ADD UP TO STATION TOTALS DUE TO ADDITIONAL STATION AUXILIARY REQUIREMENTS.

Attachment C

13:44
04/03/96

NORTHSIDE GENERATING STATION

GENERATION STATISTICS

CALENDAR YEAR 1995

GENERATION DATA (MWH)	NS-1	NS-3	STM TOT**	NCT3	NCT4	NCT5	NCT6	NCT TOT
1. GROSS MWH	768,793	1,700,840	2,469,633	1,294	1,363	1,218	1,622	5,496
*2. AUX. LOAD	52,236	67,597	119,833	293	321	336	442	1,392
3. NET MWH ONLINE (SYNC)	722,934	1,637,895	2,360,829	1,276	1,344	1,203	1,599	5,422
4. NET MWH OVERALL	716,556	1,633,244	2,349,800	1,000	1,043	881	1,180	4,104
5. NET MWH LST YR	957,379	1,335,941	2,289,670	571	(172)	(81)	(404)	(85)
6. % STATION GROSS GEN	31.1	68.7	99.8	0.1	0.1	0.0	0.1	0.2
7. ONLINE LOAD FACTOR %	55.5	51.0	52.3	56.5	54.3	64.2	54.1	14.2
8. CAPACITY FACTOR %	33.5	37.5	36.1	0.3	0.3	0.3	0.4	0.3
*9. #6 OIL BURNED ONLINE	691,391	1,028,765	1,720,155	NA	NA	NA	NA	NA
#6 OIL (BBLS) OVERALL	691,694	1,028,774	1,720,468	NA	NA	NA	NA	NA
#2 OIL BURNED ONLINE	NA	NA	NA	3,883	3,335	3,082	4,381	14,681
#2 OIL (BBLS) OVERALL	NA	NA	NA	4,068	3,520	3,267	4,641	15,496
#2 OIL BURNED (EQ BBL)	NA	NA	NA	3,715	3,215	2,983	4,238	14,151
GAS BURNED ONLINE	3,165,787	10,071,872	13,237,660	NA	NA	NA	NA	NA
GAS (KCF) OVERALL	3,189,963	10,093,968	13,283,931	NA	NA	NA	NA	NA
GAS BURNED (EQ BBL)	526,026	1,660,166	2,186,823	NA	NA	NA	NA	NA
TTL FUEL BURN (EQ BBL)	1,217,720	2,688,940	3,907,291	3,715	3,215	2,983	4,238	14,151
10. AVG BTU / BBL #6 OIL	6,361,571	6,372,944	6,368,372	NA	NA	NA	NA	NA
AVG BTU / BBL #2 OIL	NA	NA	NA	5,815,477	5,815,477	5,815,477	5,815,477	5,815,477
AVG BTU / FT3 GAS	1,049	1,048	1,048	NA	NA	NA	NA	NA
11. GROSS KWH / EQ BBL	631	633	632	348	424	408	383	388
12. NET KWH / EQ BBL	588	607	601	269	324	295	278	383
13. HEAT RATE (ONLINE)	10,678	10,448	10,519	17,696	NA	14,895	15,936	15,746
HEAT RATE (OVERALL)	10,811	10,492	10,589	23,648	19,635	21,553	22,874	21,956
14. NUMBER OF STARTS	37	21	58	22	22	22	31	97
15. HOURS OF OPERATION	5,289.5	6,437.7	11,727.2	43.7	47.9	36.2	57.2	185.0
16. ANNUAL REVENUE ($ 000)	48,878	111,408						

	OIL	GAS	HOURS
17. AUXILIARY BOILER	0	0	0.0

STATION INVENTORIES	#6 FUEL (bbl)	#2 FUEL (bbl)	MgO (gal)
18. ON HAND (BOY)	666,991.60	81,369.92	7,302.0
19. RECEIVED	1,626,796.92	20,012.74	12,919.0
20. ADJUSTMENT (+ = more)	0.00	0.00	0.0
21. BARGED IN/OUT	0.00	0.00	0.0
22. TTL AVAILABLE	2,293,788.52	101,382.66	20,221.0
23. ON HAND (EOY)	573,320.03	85,886.45	4,266.7
24. CONSUMED	1,720,468.49	15,496.21	15,954.3

*NOTES:

(2) CORRECTED FOR CIRCULATOR MWH USED FOR SJRPP

(9) AUXILIARY BOILER FUEL INCLUDED IN STATIONS'S OVERALL GAS BURNED.

OIL MEASUREMENTS CORRECTED TO THE END OF YEAR SOUNDINGS.

LIFETIME TOTALS	NS-1	NS-3
25. GROSS MWH	25,439,741	26,131,559
26. HOURS OF OPERATION	153,451	93,743
27. NUMBER OF STARTS	777	347

** UNIT TOTALS MAY NOT ADD UP TO STATION TOTALS DUE TO ADDITIONAL STATION AUXILIARY REQUIREMENTS.

Attachment C

11:45
02/12/97

NORTHSIDE GENERATING STATION

GENERATION STATISTICS

CALENDAR YEAR 1996

GENERATION DATA (MWH)	NS-1	NS-3	STM TOT**	NCT3	NCT4	NCT5	NCT6	NCT TOT
1. GROSS MWH	367,721	1,200,484	1,568,205	1,223	1,084	788	860	3,955
*2. AUX. LOAD	29,010	59,338	88,348	278	339	358	420	1,395
3. NET MWH ONLINE (SYNC)	345,839	1,146,715	1,492,554	1,201	1,063	772	842	3,878
4. NET MWH OVERALL	338,711	1,141,146	1,479,857	945	745	430	441	2,560
5. NET MWH LST YR	716,556	1,633,244	2,349,800	1,000	1,043	881	1,180	4,104
6. % STATION GROSS GEN	23.4	76.4	99.7	0.1	0.1	0.1	0.1	0.3
7. ONLINE LOAD FACTOR %	51.9	37.6	40.2	42.9	40.3	36.4	35.3	9.7
8. CAPACITY FACTOR %	16.0	26.5	23.0	0.3	0.2	0.2	0.2	0.2
*9. #6 OIL BURNED ONLINE	468,939	1,304,664	1,773,603	NA	NA	NA	NA	NA
#6 OIL (BBLS) OVERALL	469,148	1,304,781	1,773,929	NA	NA	NA	NA	NA
#2 OIL BURNED ONLINE	NA	NA	NA	3,667	3,326	2,512	2,913	12,418
#2 OIL (BBLS) OVERALL	NA	NA	NA	3,944	3,578	2,722	3,165	13,409
#2 OIL BURNED (EQ BBL)	NA	NA	NA	3,652	3,313	2,520	2,930	12,415
GAS BURNED ONLINE	550,625	3,946,121	4,496,745	NA	NA	NA	NA	NA
GAS (KCF) OVERALL	573,830	3,978,034	4,551,864	NA	NA	NA	NA	NA
GAS BURNED (EQ BBL)	94,842	655,489	750,713	NA	NA	NA	NA	NA
TTL FUEL BURN (EQ BBL)	563,990	1,960,270	2,524,643	3,652	3,313	2,520	2,930	12,415
10. AVG BTU / BBL #6 OIL	6,355,576	6,379,133	6,372,903	NA	NA	NA	NA	NA
AVG BTU / BBL #2 OIL	NA	NA	NA	5,900,423	5,900,423	5,900,423	5,900,423	5,900,423
AVG BTU / FT3 GAS	1,050	1,051	1,051	NA	NA	NA	NA	NA
11. GROSS KWH / EQ BBL	652	612	621	335	327	313	NA	319
12. NET KWH / EQ BBL	601	582	586	259	225	171	NA	312
13. HEAT RATE (ONLINE)	10,290	10,875	10,740	18,013	NA	19,212	20,420	18,895
HEAT RATE (OVERALL)	10,583	10,958	10,872	24,639	28,335	37,352	NA	30,902
14. NUMBER OF STARTS	29	20	49	33	30	25	30	118
15. HOURS OF OPERATION	2,703.1	6,167.0	8,870.0	54.4	51.4	41.3	46.5	193.6
16. ANNUAL REVENUE ($ 000)	23,365	78,720						

	OIL	GAS	HOURS
17. AUXILIARY BOILER	0	0	10.0

STATION INVENTORIES	#6 FUEL (bbl)	#2 FUEL (bbl)	MgO (gal)
18. ON HAND (BOY)	573,320.03	85,886.45	4,266.7
19. RECEIVED	1,782,285.54	0.00	24,823.0
20. ADJUSTMENT (+ = more)	0.00	0.00	0.0
21. BARGED IN/OUT	64.30	(64.30)	0.0
22. TTL AVAILABLE	2,355,669.87	85,822.15	29,089.7
23. ON HAND (EOY)	581,740.78	72,413.10	4,490.7
24. CONSUMED	1,773,929.09	13,409.05	24,599.0

*NOTES:

(2) CORRECTED FOR CIRCULATOR MWH USED FOR SJRPP

(9) AUXILIARY BOILER FUEL INCLUDED IN STATIONS'S OVERALL GAS BURNED.

OIL MEASUREMENTS CORRECTED TO THE END OF YEAR SOUNDINGS.

LIFETIME TOTALS	NS-1	NS-3
25. GROSS MWH	25,807,462	27,334,291
26. HOURS OF OPERATION	156,154	99,909
27. NUMBER OF STARTS	806	367

** UNIT TOTALS MAY NOT ADD UP TO STATION TOTALS DUE TO ADDITIONAL STATION AUXILIARY REQUIREMENTS.

(Attachment C)

NORTHSIDE GENERATING STATION

GENERATION STATISTICS

January-September 1997

GENERATION DATA (MWH)	Unit 1
1. GROSS MWH	494,373
*2. AUX. LOAD	
3. NET MWH ONLINE (SYNC)	
4. NET MWH OVERALL	
5. NET MWH LST YR	
6. % STATION GROSS GEN	
7. ONLINE LOAD FACTOR %	
8. CAPACITY FACTOR %	
*9. #6 OIL BURNED ONLINE	699,379
#6 OIL (BBLS) OVERALL	
#2 OIL BURNED ONLINE	
#2 OIL (BBLS) OVERALL	
#2 OIL BURNED (EQ BBL)	
GAS BURNED ONLINE	
GAS (KCF) OVERALL	310,846
GAS BURNED (EQ BBL)	
TTL FUEL BURN (EQ BBL)	
10. AVG BTU / BBL #6 OIL	
AVG BTU / BBL #2 OIL	
AVG BTU / FT3 GAS	
11. GROSS KWH / EQ BBL	
12. NET KWH / EQ BBL	
13. HEAT RATE (ONLINE)	
HEAT RATE (OVERALL)	
14. NUMBER OF STARTS	
15. HOURS OF OPERATION	
16. ANNUAL REVENUE ($ 000)	
17. AUXILIARY BOILER	

STATION INVENTORIES

18. ON HAND (BOY)
19. RECEIVED
20. ADJUSTMENT (+ = more)
21. BARGED IN/OUT
22. TTL AVAILABLE
23. ON HAND (EOY)
24. CONSUMED

LIFETIME TOTALS

25. GROSS MWH
26. HOURS OF OPERATION
27. NUMBER OF STARTS

Attachment D

Jacksonville Electric Authority
Statistical Information
for the Twelve Months Ending September 30, 1997
Total Degree Day Comparison

Month	NOAA 30 Year Average	Fiscal Year 1995/96	Fiscal Year 1996/97	Percentage Change 97 vs 96	Percentage Change 97 vs NOAA
October	210	296	198	-33%	-6%
November	205	288	218	-24%	6%
December	356	377	313	-17%	-12%
January	452	405	348	-14%	-23%
February	318	303	221	-27%	-31%
March	217	302	174	-42%	-20%
April	134	180	159	-12%	19%
May	260	350	243	-31%	-7%
June	423	416	365	-12%	-14%
July	515	549	531	-3%	3%
August	502	445	485	9%	-3%
September	393	381	415	9%	6%
Total	3,985	4,292	3,670	-14%	-8%
JAN-SEPT	3214		2941		-8.5%

Firm KWH Sales

	Fiscal Year 1995/96	Fiscal Year 1996/97	Percentage Change 97 vs 96
Total	10,110,464,307	10,023,800,060	-1.0%

Average Number of Territorial Customers

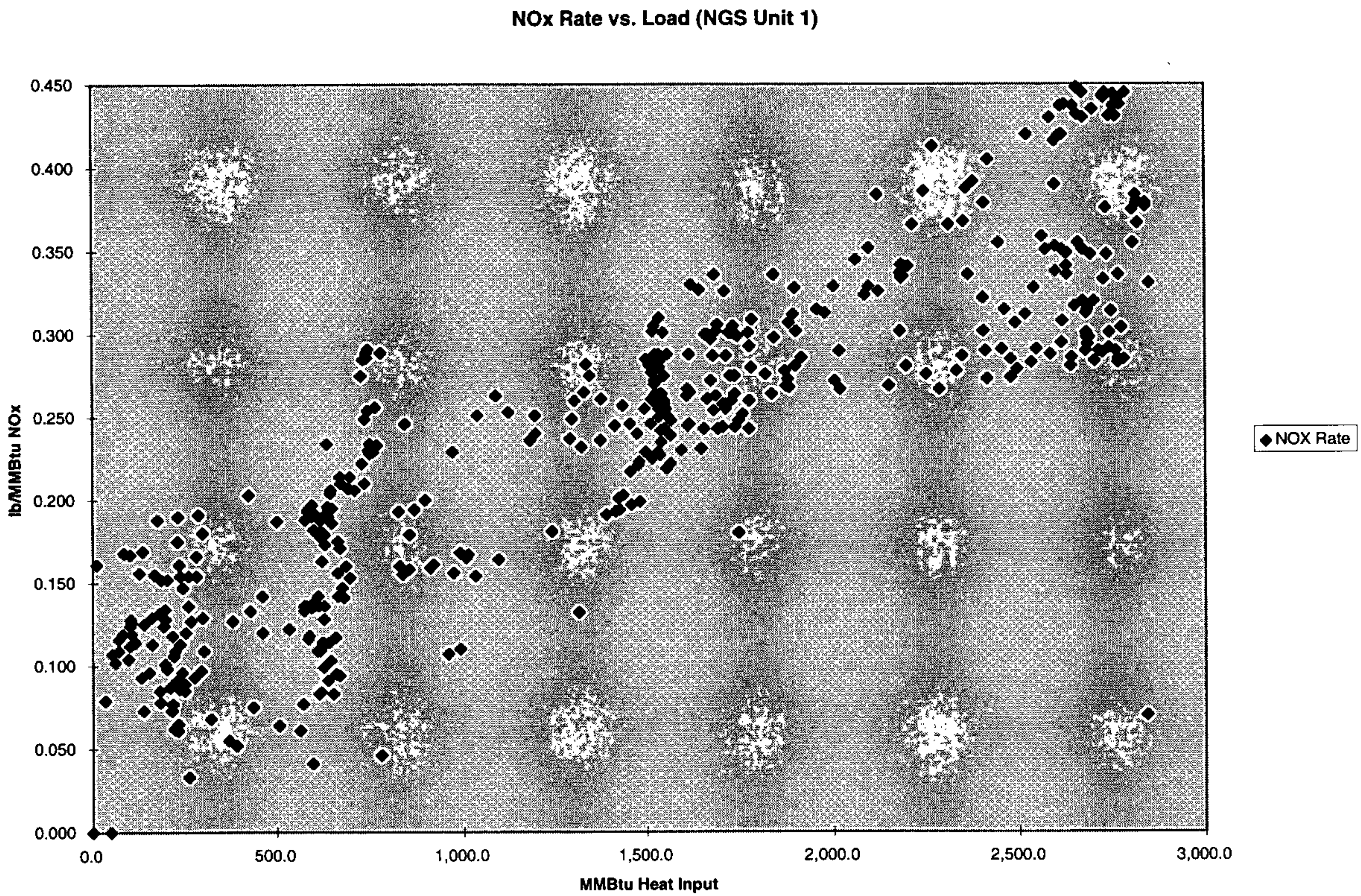
	Fiscal Year to Date 1995/96	Fiscal Year to Date 1996/97	Percentage Change 97 vs 96
Total	328,371	335,463	2.3%

Attachment E

Jacksonville Electric Authority

CEM NS #1 Annual Emission Data

YEAR	1995	1996	1997 (Jan-Sep)
Tons of SO_2	4,328.3	3,674	4,083
Tons of NOx	1,081.7	661	913
NOx Rate	0.284	0.359	0.33
Load Factor	52.85	49.47	47.6
Cap. Factor	31.91	15.22	27.44



Attachment F

NS # 1Stack Tests for Nox and Particulate Lb/ Million BTU

Date	Soot Blowing	No soot Blow	Nox	MW	Fuel
July 88	0.213	0.097		250	# 6 oil
July 89	0.131	0.058		250	# 6 oil
July 90	0.128	0.075		255	# 6 oil
July 91	0.177	0.062		275	# 6 oil
Feb 92	0.100	0.03	0.38 @ 7.2% O_2 0.24 @ 7.1% O_2 0.32 @ 6.6% O_2	252 252 252	# 6 oil 50/50 gas&oil 100% gas
June 93	0.25	0.08	0.29 @ 4.6% O_2		
Aug 93	0.101	0.068		170	oil
Dec 93	0.110	0.072		248	oil
Aug 95	0.103	0.082		240	oil
Aug 96	0.069	0.066		250	oil
Aug 97	0.118	0.055		250	oil

CA-NGS Unit 1 (criteria)

FOSTER WHEELER ENVIRONMENTAL CORPORATION
EXCEL 5.0 CALCULATION SHEET

By: E. Deken, PE
Date: 12/5/97
Ck'd By:
Date:

Cal. No.: 971008ED01
Rev. No.: 1
OFS: 7830.0020.0030

Project: JEA Northside Generating Station Repowering
Subject: Emission Estimates - Unit 1

Operating Data

Calendar Year (Jan - Dec)	1994	1995
Operating Hours	6734.7	5289.5
Nat. Gas Heat Content (Btu/scf)	1047	1049
Nat. Gas Usage (mmCF/yr)	1409.5	3189.963
Nat. Gas Sulfur Cont. (gr/scf)	0.0032	0.0032
No. 6 Heat Content (Btu/gal)	151263	151466
No. 6 Sulfur Content (%wt)	1.69	1.43
Assumed No. 6 Density (lb/gal)	7.88	7.88
No. 6 Usage (kgal/yr)	56608	29051.15

Emission Estimates (tons/year)

	E.F.	Units	Tons/Year	
Oxides of Nitrogen(1994)	0.359	lb/mmbtu	1801.9	Based on CEMS generated emission factor and calculated heat input
Oxides of Nitrogen(1995)	0.284	lb/mmbtu	1081.7	Based on CEMS generated emission factor and CEMS reported heat input
2-year Average			1441.801	

No. 6 Firing

Pollutant	E.F.	Units	1994	E.F.	Units	1995	2-yr Ave.	
Carbon Monoxide	5	lb/kGal	141.5	5	lb/kGal	72.6	107.1	Ref. - AP42, 5th Edition
Volatile Organic Compounds	0.76	lb/kGal	21.5	0.76	lb/kGal	11.0	16.3	Ref. - AP42, 5th Edition
Sulfur Dioxide	265.33	lb/kGal	7510	Cems Data	na	4328.3	5919.1	Ref. - AP42, 5th Edition
Particulate Matter	18.7511	lb/kGal	530.7	16.3617	lb/kGal	237.7	384.2	Ref. - AP42, 5th Edition
Particulate Matter (PM10)	13.31328	lb/kGal	376.8	11.616807	lb/kGal	168.7	272.8	Ref. - AP42, 5th Edition

N.G. Firing

Pollutant	E.F.	Units	1994	1995	2-yr Ave.	
Carbon Monoxide	40	lb/mmCF	28.2	63.8	46.0	Ref. - AP42, 5th Edition
Volatile Organic Compounds	1.41	lb/mmCF	1.0	2.2	1.6	Ref. - AP42, 5th Edition
Sulfur Dioxide	0.6	lb/mmCF	0.4	1.0	0.7	Ref. - AP42, 5th Edition
Particulate Matter	5	lb/mmCF	3.5	8.0	5.7	Ref. - AP42, 5th Edition
Particulate Matter (PM10)	5	lb/mmCF	3.5	8.0	5.7	Ref. - AP42, 5th Edition

Totals

Pollutant	1994	1995	2-yr Ave.
Oxides of Nitrogen	1801.9	1081.7	1441.8
Carbon Monoxide	169.7	136.4	153.1
Total Organic Compounds	22.5	13.3	17.9
Sulfur Dioxide	7510.3	4329.3	5919.8
Particulate Matter	534.3	245.6	389.9
Particulate Matter (PM10)	380.3	176.7	278.5

Attachment I

CA-NGS Unit 1 (noncriteria)

FOSTER WHEELER ENVIRONMENTAL CORPORATION
EXCEL 5.0 CALCULATION SHEET

By: E. Deken, PE
Date: 12/4/97

Cal. No.: 971008ED01
Rev. No.: None
OFS: 7830.0020.0030

Project: JEA Northside Generating Station Repowering
Subject: Emission Estimates - Unit 1 (noncriteria pollutants)

Operating Data

Calendar Year (Jan - Dec)	1994	1995
Operating Hours	6734.7	5289.5
Nat. Gas Heat Content (Btu/scf)	1047	1049
Nat. Gas Usage (mmCF/yr)	1409.5	3189.963
Nat. Gas Sulfur Cont. (gr/scf)	0.0032	0.0032
No. 6 Heat Content (Btu/gal)	151466	151263
No. 6 Sulfur Content (%wt)	1.69	1.43
Assumed No. 6 Density (lb/gal)	7.88	7.88
No. 6 Usage (kgal/yr)	56608	29051.148

Emission Estimates (tons/year)

No. 6 Firing

Pollutant	E.F.	Units	1994	E.F.	Units	1995	2-yr Ave.	
Lead	0.00151	lb/kGal	0.04274	0.00151	lb/kGal	0.02193	0.03234	Ref. - AP42,Section 1.3 (10/96)
Fluorides	0.0373	lb/kGal	1.05574	0.0373	lb/kGal	0.54180	0.79877	Ref. - AP42,Section 1.3 (10/96)
Sulfuric Acid Mist	5.7S	lb/kGal	272.7	5.7S	lb/kGal	118.4	195.525	Ref. - AP42,Section 1.3 (10/96)
Mercury	0.000113	lb/kGal	0.00320	0.000113	lb/kGal	0.00164	0.00242	Ref. - AP42,Section 1.3 (10/96)

N.G. Firing

Pollutant	E.F.	Units	1994	1995	2-yr Ave.	
Lead	0.000271	lb/mmCF	0.000191	0.000432	0.000312	Ref. - AP42, Section 1.4
Fluorides	na	lb/mmCF	0.0	0.0	0.0	Ref. - AP42, Section 1.4
Sulfuric Acid Mist	mass balance	na	0.00000006	0.00000015	0.00000010	Ref. - AP42/Mass Balance
Mercury	0.00078	lb/10^12 btu	0.000003	0.000002	0.000003	Ref. - FCG Factor (EPRI)

Totals

Pollutant	1994	1995	2-yr Ave.
Lead	0.04293	0.02237	0.03265
Fluorides	1.05574	0.54180	0.79877
Sulfuric Acid Mist	272.652	118.3980	195.525
Mercury	0.00320	0.00164	0.00242

"Existing" Unit 2 Potential Emissions*

	NATURAL GAS				FUEL OIL					Permit Limit	Potential Emissions
POLLUTANT	Em. Factor (lb/mm cu. ft.)	Max. Gas Consumed (mm cu.ft./hour)	Hours of Operation (hours/year)	Emissions (tons/year)	Em. Factor (lb/1000 gal)	Max. Oil Consumed (1000 gal/hour)	Hours of Operation (hours/year)	Max. S Content (% Sulfur)	Emissions (tons/year)	(tons/year)	(tons/year)
N0x	550	2.66	8760	6407.94	67	18.14	8760	1.8	5323.364		6407.94
SO2	0.6	2.66	8760	6.99048	157S	18.14	8760	1.8	22453.47	20397	20397
H2SO4		2.66	8760	0	5.7S	18.14	8760	1.8	815.1898		815.1898
PM	5	2.66	8760	58.254	9.19S+3.22	18.14	8760	1.8	1570.154	1287	1287
PM10	5	2.66	8760	58.254	.71(9.19S+3.22	18.14	8760	1.8	1114.809		1114.809
CO	40	2.66	8760	466.032	5	18.14	8760	1.8	397.266		466.032
VOC	1.41	2.66	8760	16.42763	0.76	18.14	8760	1.8	60.38443		60.38443
beryllium		2.66	8760	0	0.0000278	18.14	8760	1.8	0.002209		0.002209
fluorides		2.66	8760	0	0.0373	18.14	8760	1.8	2.963604		2.963604
lead	0.000271	2.66	8760	0.003157	0.00151	18.14	8760	1.8	0.119974		0.119974
mercury		2.66	8760	0	0.000113	18.14	8760	1.8	0.008978		0.008978

* Unit 2 can be fired on oil or gas therefore the potential emissions for both fuels are shown.
Emissions were based on AP-42, maximum hourly fuel consumption, 100% CF, and permit limits. The maximum fuel consumption was obtained from JEA Annual Operating Reports.

Attachment J

Kennedy 10 Historical Test Data

December 1993	125 MW	Oil	NOx 0.312 lb./million Btu
August 1993	124 MW	Oil	Part. 0.026 lb/million Btu nonsoot Part. 0.0623 lb/million Btu soot blow
May 1992	125 MW	Oil	NOx 0.238 lb/million Btu
September 1990	127 MW	Oil	Part 0.0223 lb/million Btu nonsoot Part 0.0377 lb/million Btu soot blow