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st. johns river POWER PARK

EV 960604

June 04, 1996

Ms. Janet Stanko
Sierra Club, Northeast Chapter
3417 Hermitage Rd. East
Jacksonville, Florida 32277

Re: St. Johns River Power Park (SJRPP)
Jacksonville Electric Authority (JEA)
Petition on Amendment of Permit PSD-FL-010

Dear Ms. Stanko:

Thank you for the opportunity to provide you with additional information on JEA's proposal to co-fire a blend of petroleum coke and coal at SJRPP. I have attached the information you requested along with an explanation of JEA's actions to assure no emission increases of regulated pollutants from the burning of the petroleum coke and coal blend.

SJRPP operates under the provisions of the Florida Power Plant Siting Act (PPSA) and the Prevention of Significant Deterioration (PSD) permit program. Prior to receiving our original PSD permit (Attached), we had to demonstrate that under maximum operating conditions SJRPP would not significantly impact Air Quality in the Jacksonville Area as well as the Okeefenokee Class I area. In order to remain within the current PSD air emissions limitations, JEA has committed to no increase in regulated air emissions due to the co-firing of petroleum coke and coal blends.

To assist you in preparation for our upcoming meeting I would like to provide the following information in response to your petition.

<u>Statement of material facts disputed by petitioner:</u>

1. JEA proposes to blend petroleum coke and coal by weight. Our test burn was performed on a weight basis. The confusion arises from the fact that our emission limits are based on a heat input basis.. (lbs/MMBTU). Since petroleum coke has a slightly higher heat content per pound, 20% by weight is equal to approximately 24% by heat input. It is noted that petroleum coke resembles and handles like coal.

2. Since petroleum coke is a solid material with the same characteristics of coal, the pollution and safety controls we employ to handle coal will be used for the handling of petroleum coke.

3. It is noted that our test burn was primarily for operational purposes to assure we could burn petroleum coke within operational parameters. For that reason our scrubber removal efficiency during the test was based on our current permit provisions. To assure that our emissions are not increased during the proposed co-firing of petroleum coke and coal, we are agreeing to permit conditions that will require greater scrubber removal efficiency than currently required. This will result in no increase in emissions.

4. The scrubbers at SJRPP are designed to meet the scrubbing requirements of the PSD permit. JEA is accepting a permit revision to increase the required scrubber removal efficiency during the proposed co-firing of petroleum coke and coal. The test burn was conducted under the existing permit conditions which requires a minimum of 70% SO2 removal efficiency as compared to the proposed minimum SO2 removal efficiency of 75.86%.

11201 New Berlin Road (32226) • P.O. Box 26888 • Jacksonville, FL 32218-0888

5. SJRPP was designed and permitted to burn a wide range of coals. Permitted sulfur content of those coals range from 0.5% to 4.0%. The current permit requires JEA to increase scrubber efficiency as sulfur content increases. This efficiency ranges from a minimum 70% to a maximum of 90%. JEA is accepting a permit revision which maintains the maximum sulfur content of the petroleum coke/coke blend to no more than 4.0%. In addition we have agreed to increase the minimum scrubber efficiency to 76% and the maximum to 92% while burning the blend.

6. Prior to our permit revision submittal, carbon monoxide (CO) emissions from burning petroleum/coke blends from several power plants similar to SJRPP were examined. During normal operations the data indicated no difference in CO emissions between the burning of coal and the burning of petroleum coke/coal blends. It felt that similar results will occur during normal operations at SJRPP. It is noted that combustion was not optimized during our test burn. We feel that CO emissions during normal operations will be much lower than the test burn and similar to units currently burning petroleum coke/coal blends.

   It is noted that we maintain continuous CO monitors on the SJRPP units. CO data submitted to the DEP indicates that our CO levels while burning petroleum coke were in the range of those levels observed while burning only coal during 1995. We have agreed to submit quarterly continuous emissions data for CO to the DEP for a period of two years to show the range of CO emissions experienced during each quarter. For added assurance we have agreed to semi-annual CO stack tests for the first two years and annually thereafter.

Statement of precisely the action the petitioner wants the Department to take:

One point which may be causing significant confusion is our test burn results. It should be noted that this test was for operational purposes and was not designed to optimize pollution emissions. Our 10 years of operational experience with our pollution control systems gives us reasonable assurance that we can increase our removal efficiency to meet the proposed permit requirements. We have EPA certified continuous emissions monitors (CEMs) on the SJRPP units. These monitors are used to confirm both our actual SO2 and NOx emissions and well as our scrubber removal efficiency. These monitors are required to be in operation during all boiler operations and can verify compliance with the proposed permit conditions on a instantaneous basis.

Thank-you again for the opportunity to provide this additional information. If you wish any explanation of this material prior to our meeting, please give me a call at 632-6245.

Very truly yours,

Richard Breitmoser
Vice-President
Environmental Health and Safety Group

cc: Buck Oven, FDEP
Jeff Brasswell, FDEP
Al Linero, FDEP

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

4APT-AP/ch OCT 28 1986

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. Richard Breitmoser, P. E.
Division Chief
Research and Environmental Affairs Division
Jacksonville Electric Authority
P. O. Box 53015
233 W. Duval Street
Jacksonville, Florida 32201

RE: St. John's River Power Park PSD-FL-010

Dear Mr. Breitmoser:

This letter is in response to your May 12, 1986, request for coal terminal and blending modifications at the above-referenced facility permitted on March 12, 1982, by EPA Region IV. The Florida Department of Regulation (FDER) published a public notice announcing the proposed coal handling modifications on July 28, 1986. No comments were received and the FDER subsequently recommended that the PSD permit be modified.

In addition to the above, we have reviewed recommendations from The Department of Health, Welfare, and Bio-Environmental Services (City of Jacksonville, Florida) dated July 1, 1986, regarding opacity and control of fugitive emissions from shiploading, and subsequent recommendations from your office dated August 27, 1986, regarding emission limits and testing of non-stack emission points. In response to these recommendations and communications with the FDER, your PSD permit (PSD-FL-010) is hereby modified as follows:

1. The second paragraph of Condition of Approval No. 3 is changed from the existing wording regarding compliance testing of particulate emission points to the following:

   "Opacity tests shall be performed for emission points three (3) through nineteen (19) of revised Table 6 for compliance purposes. If the opacity limits are not met for those sources that exhaust through a stack, permit compliance shall be determined on the basis of mass emission rate tests."

2. Table 2 of the final determination is replaced by revised Table 2 (enclosed).

3. Table 6 of the final determination is replaced by revised Table 6 (enclosed).

4. All reference to Table 2 and Table 6 in Conditions of Approval numbers 2, 3, 4, and 5, as contained in the March 12, 1982 PSD permit, shall be construed to pertain to the enclosed revised Tables 2 and 6.

Please be advised that the modification to your PSD permit herein described shall become a binding part of permit PSD-FL-010. This permit modification shall become effective upon receipt of this letter, unless you notify us of your unacceptance of the conditions contained herein within ten (10) days after receipt of this letter.

If you have any questions regarding this permit modification, please contact Mr. Wayne J. Aronson, Chief, Program Support Section, at (404) 347-4901.

Sincerely yours,

/s/ Lee A. DeHihns, III
Deputy Regional Administrator

Jack E. Ravan
Regional Administrator

Attachments: 2

cc: Mr. Clair H. Fancy
Deputy Bureau Chief
Florida Department of Environmental Regulation

Table 6. Allowable Emission Limits (Revised; From PSD Permit) (lb/hour: lb/MMBtu)

	Emission Unit	SO_2	NO_x	PM (Revised Original)	Opacity (Percent)
1.	Steam Generating Boiler No.1 (6,144 MMBtu/hr maximum heat input)	4,669.; 0.76 (30-day rolling average)	3,686: 0.6	184: 0.03	20
2.	Steam Generating Boiler No. 2 (6,144 MMBtu/hr maximum heat input)	4,669: 0.76 (30-day rolling average)	3,686: 0.6	184: 0.03	20
3.	Auxiliary boilers (254 MMBtu/hr maximum heat input total)	203: 0.8		25.0: 0.1	20
4.	Ship Unloading (2 Grab Buckets)*			1.0	10
5.	Feeders to Conveyor A (2 Wet Suppression points)*			0.13	10
6.	Conveyor Transfers 1 & 2 (2 points)*			0.57	10
7.	Conveyor Transfer 3, 4, 5 & D to D by-pass (4 points)*			2.6	10
8.	Conveyor Transfers 6 & 7 (2 points)*			1.0	10
9.	Traveling Stacker (3 points)*			0.8	10
10.	Bucket Wheel Reclaimer (2 points)*			0.6	10
11.	Ship unloading facility coal storage pile			1.6	10
12.	Coal handling transfer points ship unloading facility coal pile (8 points)*			1.8	10
13.	Rail car unloading (Rotary Dumper)			5	10
14.	Coal handling transfer points (6 wet suppression points)			5(each)	10
15.	Coal handling transfer points (11 dry collection)			0.1(each)	10
16.	Coal storage at plant* (10 acres active)			0.5	10
17.	Coal storage at plant* (2 to 13-acre inactive piles)			0.02	10
18.	Limestone unloading (rail dumper)			0.1	10
19.	Limestone transfer points			0.2(each)	10
20.	Cooling towers			67(each tower)	N/A

* Revised emission unit, May 1986.

Table 2. Fugitive Emissions and Control Summary (Revised; From PSD Permit)

	Process	Type	Amount	Factor	Control	Technique	Emissions (grams/sec)
1	Ship Unloading*	2 Grab Buckets	2,200 Tons/hr	0.0016 lb/Ton-	70.0%	Suppression, Enclosure	0.13
2	Feeders to Conveyor A*	2 Points	2,200 Tons/hr	0.00039 lb/Ton	85.0%	Suppression, Enclosure	0.02
3	Conveyor Transfers, 1 and 2*	2 Points	2,200 Tons/hr	0.00087 lb/Ton**	85.0%	Suppression Enclosure	0.07
4	Conveyor Transfers 3, 4, 5 and D to D by-pass*	4 Points	2,200 Tons/hr	0.00118 lb/Ton**	75.0%	Enclosure, Conditioned Material	0.33
5	Conveyor Transfers 6 and 7*	2 Points	2,000 Tons/hr	0.00106 lb/Ton**	75.0%	Enclosure, Conditioned Material	0.13
6	Traveling Stacker*	3 Points: 1 Point	2,200 Tons/hr	0.00031 lb/Ton	75.0%	Enclosure, Conditioned Material	0.02
		1 Point	2,200 Tons/hr	0.00039 lb/Ton	75.0%	Enclosure, Conditioned Material	0.03
		1 Point	2,200 Tons/hr	0.00017 lb/Ton	0.0%		0.05
7	Bucket Wheel Reclaimer*	2 Points	2,000 Tons/hr	0.00063 lb/Ton**	75.0%	Enclosure, Conditioned Material	0.08
8	Ship-Unloading Facility Coal Surge Pile	Active	30 Acres	13 lb/Acre/day[a]	(90%)[a]	Wetting Agent	0.20
9	Coal Handling Transfer Points Ship Unloading Facility Coal Pile*	8 Points	2,200 Tons/Hr.	0.00041 lbs/Ton**	75.0%	Enclosure, Conditioned Material	0.23
10	Rail Car Unloading	Rotary Dumper	10,000 Tons/Day	0.4 lb/Ton[a]	(97%)[b]	Wet Suppression	0.63
11	Coal Handling Transfer Points	2 Points	10,000 Tons/Day	0.2 lb/Ton[c]	(99.9%)[b]	Dry Collection	0.02
12	Coal Handling Transfer Points	2 Points	3,300 Tons/Day	0.2 lb/Ton[c]	(99.9%)[b]	Dry Collection	0.01
13	Coal Handling Transfer Points	6 Points	3,300 Tons/Day	0.2 lb/Ton[c]	(97%)[b]	Wet Suppression	0.62
14	Coal Handling Transfer Points	7 Points	5,000 Tons/Day	0.2 lb/Ton[c]	(99.9%)[b]	Dry Collection	0.04
15	Coal Storage At Plant*	Active	10 Acres	13 lb/Acre/day[a]	(90%)[a]	Wetting Agent	0.07
16	Coal Storage At Plant*	2 Inactive Piles	13 Acres	3.5 lb/Acre/day[a]	(99%)[a]	Wetting Agent	0.002
17	Limestone Unloading	Rail Dumper	750 Tons/Day	0.4 lb/ton[a]	(97%)[b]	Wet Suppression	0.05
18	Limestone Transfer	1 Point	750 Tons/Day	0.2 lb/Ton[a]	(99.9%)[b]	Dry Collection	0.001
19	Cooling Towers	Drift	2 x 243,500 gal/min	51,450 ppm solids (maximum) (40% < 50 microns diameter)	99.998%	Drift Elimination	12.66
20	Solid Waste Disposal Area	Active	10 Acres	13 lb/Acre/day[a]	(90%)[a]	Wetting Agent	0.07

* Revised process or emissions, May 1986.
\- Weighted average based on 1,500 and 700 STPH ship unloaders.
** Average of emission factors for individual sources.

a. Pedco, 1977.
b. Stoughton, 1980.
c. EPA, 1979.

0400b(050886)PM

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30365

PSD-FL-010

PERMIT TO CONSTRUCT UNDER THE RULES FOR THE
PREVENTION OF SIGNIFICANT DETERIORATION OF AIR QUALITY

Pursuant to and in accordance with the provisions of Part C, Subpart 1 of the Clean Air Act, as amended, 42 U.S.C. §7470 et seq., and the regulations promulgated thereunder at 40 C.F.R. §52.21, as amended at 45 Fed. Reg. 52676, 52735-41 (August 7, 1980),

Jacksonville Electric Authority
P.O. Box 53015
233 W. Duval
Jacksonville, Florida 32201

is hereby authorized to construct/modify a stationary source at the following location:

St. Johns River Power Park
Duval County, Florida

UTM Coordinates: 446.9 Km East - 3366.3 Km North

Upon completion of this authorized construction and commencement of operation/production, this stationary source shall be operated in accordance with the emission limitations, sampling requirements, monitoring requirements and other conditions set forth in the attached Specific Conditions (Part I) and General Conditions (Part II).

This permit shall become effective on MAR 12 1982

If construction does not commence within 18 months after the effective date of this permit, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time this permit shall expire and authorization to construct shall become invalid.

This authorization to construct/modify shall not relieve the owner or operator of the responsibility to comply fully with all applicable provisions of Federal, State, and Local law.

MAR 12 1982
Date Signed

Charles R. Jeter
Regional Administrator

Please be advised that a violation of any condition issued as part of this approval, as well as any construction which proceeds in material variance with information submitted in your application, will be subject to enforcement action.

This final permitting decision is subject to appeal under 40 CFR §124.19 by petitioning the Administrator of the U. S. EPA within 30 days after receipt of this letter of approval to construct. The petitioner must submit a statement of reasons for the appeal and the Administrator must decide on the petition within a reasonable time period. If the petition is denied, the permit becomes immediately effective. The petitioner may then seek judical review.

Authority to modify this facility will take effect on the date specified in the permit. The complete analysis which justifies this approval has been fully documented for future reference, if necessary. Any questions concerning this approval may be directed to Dr. Kent Williams, Chief, New Source Review Section, Air and Waste Management Division at (404) 881-4552.

Sincerely yours,

Charles R. Jeter
Regional Administrator

Enclosures

Table 1. EMISSIONS SUMMARY OF THE PROPOSED JEA POWER GENERATING PLANT

·llutant	Potential Emissions[a] (Tons per Year)	PSD Significance Levels (Tons per Year)
SO_2	41,800	40
PM	1670	25
NO_x	32,700	40
CO	2,870	100
VOC	28[b]	40

[a]Potential emissions calculations are based on a continuous maximum operating capacity.

[b]Applicant estimated 0.0005 lb VOC/MMBtu (27 tons/yr) average emissions rate from the boilers.

Table 2. Fugitive Emi[illegible]ons and Control Summary

Process	Type	Amount	Factor	Control	Technique	Emissions (Grams/Sec)
Ship Unloading	Grab Bucket	10,000 Tons/Day	0.4 lb/Ton[a]	(99.9%)[b]	Dry Collection on Hoppers	0.04
Ship Unloading Transfer Points	6 Points	10,000 Tons/Day	0.2 lb/Ton[c]	(99.9%)[b]	Dry Collection	0.06
Ship Unloading Transfer Points	3 Points	10,000 Tons/Day	0.2 lb/Ton[c]	(97%)[b]	Wet Suppression	0.95
Ship Unloading Facility Train	Loading Shed	10,000 Tons/Day	0.4 lb/Ton[a]	(99.9%)[b]	Dry Collection	0.02
Ship Unloading Facility Coal Surge Pile	Active	30 Acres	13 lb/Acre/Day[a]	(90%)[a]	Wetting Agent	0.20
Rail Car Unloading	Rotary Dumper	10,000 Tons/Day	0.4 lb/Ton[a]	(97%)[b]	Wet Suppression	0.63
Coal Handling Transfer Points	2 Points	10,000 Tons/Day	0.2 lb/Ton[c]	(99.9%)[b]	Dry Collection	0.02
Coal Handling Transfer Points	2 Points	3,300 Tons/Day	0.2 lb/Ton[c]	(99.9%)[b]	Dry Collection	0.01
Coal Handling Transfer Points	6 Points	3,300 Tons/Day	0.2 lb/Ton[c]	(97%)[b]	Wet Suppression	0.62
Coal Handling Transfer Points	7 Points	5,000 Tons/Day	0.2 lb/Ton[c]	(99.9%)[b]	Dry Collection	0.04
Coal Storage at Plant	Active	8 Acres	13 lb/Acre/Day[a]	(90%)[a]	Wetting Agent	0.05
Coal Storage at Plant	2 Inactive Piles	15 Acres	3.5 lb/Acre/Day[a]	(99%)[a]	Wetting Agent	0.01
Limestone Unloading	Rail Dumper	750 Tons/Day	0.4 lb/Ton[a]	(97%)[b]	Wet Suppression	0.05
Limestone Transfer	1 Point	750 Tons/Day	0.2 lb/Ton[a]	(99.9%)[b]	Dry Collection	0.001
Cooling Towers	Drift	2 x 243,500 gal/min	51,450 ppm solids (maximum) (40% < 50 microns diameter)	99.998%	Drift Eliminators	17.66
Solid Waste Disposal Area	Active	10 Acres	13 lb/Acre/Day[a]	(90%)[a]	Wetting Agent	0.07

a Pedco, 1977
b Stoughton, 1980
c USEPA, 1979

Table 3. NAAQS ANALYSIS

Pollutant/ averaging time	Monitored[a] background concentration (ug/m^3)	Maximum[b] projected concentration (ug/m^3)	Total concentration (ug/m^3)	NAAQS (ug/m^3)
SO_2				
3-hour	90	987	1077	1,300
24-hour	21	195	216	365
annual	4	13	17	80
PM				
24-hour	50	30	80	150
annual	27	3	30	75
NO_2				
annual	10	10	20	100
CO				
1-hour	--[c] 5200	108[d]	5308	40,000
8-hour	--[c] 4500	<100[d]	4600	20,000

[a]These values do not include contributions from the JEA Northside Plant and the St. Regis Paper Co.

[b]These concentrations include contributions from the proposed JEA steam electric generating station, the existing JEA Northside Plant and the existing St. Regis Paper Co.

[c]These values were estimated from the projected SO_2 ambient air concentrations based on worst-case operating load and meteorological conditions.

Table 4. CLASS II INCREMENT ANALYSIS

Pollutant/ averaging time	Maximum[a] Class II increment consumption ($\mu g/m^3$)	PSD Class II increment ($\mu g/m^3$)
SO_2		
3-hour	346	512
24-hour	44	91
annual	2	20
PM		
24-hour	10	37
annual	2	19

[a]These values include contributions from all increment consuming sources impacting the ambient air quality within 50 kilometers of the proposed new source, including the proposed JEA steam electric generating station. Five years of meteorological data was used in the analysis; therefore, these values represent the highest, second highest concentrations.

Table 5. CLASS I INCREMENT ANALYSIS

Pollutant/ averaging time	Maximum[a] Class I increment consumption (ug/m^3)	PSD Class I increment (ug/m^3)
SO_2		
3-hour	19	25
24-hour	4	5
annual	<1	2
PM		
24-hour	<1	5
annual	<1	10

[a]These values include contributions from all increment consuming sources within 100 kilometers of the Class I area including the proposed JEA electric steam generating station. Five years of meteorological data was used in the analysis; therefore, these values represent the highest, second highest concentrations.

Table 6. ALLOWABLE EMISSION LIMITS
(lb/hour; lb/MMBtu)

Emission Unit	SO_2	NO_x	PM	Opacity (Percent)
1. Steam generating boiler no. 1 (6,144 MMBtu/hr maximum heat input)	4,669; 0.76 (30 day rolling average)	3,686; 0.6	184; 0.03	20
2. Steam generating boiler no. 2 (6,144 MMBtu/hr maximum heat input)	4,669; 0.76 (30 day rolling average)	3,686; 0.6	184; 0.03	20
3. Auxiliary boilers (254 MMBtu/hr maximum heat input total)	203; 0.8		25.0; 0.1	20
4. Ship unloading (Grab Bucket)			0.32	10
5. Ship unloading transfer points (6 dry collection points)			0.1 (ea.)	10
6. Ship unloading (3 wet suppression points)			7.5	10
7. Ship unloading facility train (loading shed)			0.2	10
8. Ship unloading facility coal storage pile (30 acres)			1.6	10

Table 6. ALLOWABLE EMISSION LIMITS
(lb/hour; lb/MMBtu)
(continued)

Emission Unit	SO_2	NO_x	PM	Opacity (Percent)
9. Rail car unloading (Rotary Dumper)			5	10
10. Coal handling transfer points (6 wet suppression points)			5 (each)	10
11. Coal handling transfer points (11 dry collection)			0.1 (each)	10
12. Coal storage at plant (8 acres active)			0.4	10
13. Coal storage at plant (2-15 acre inactive piles)			0.1	10
14. Limestone unloading (rail dumper)			0.1	10
15. Limestone transfer points			0.4 (each)	10
16. Cooling towers			67 (each tower)	N/A

Final Determination
Jacksonville Electric Authority
PSD-FL-010

I. Applicant

Jacksonville Electric Authority
P.O. Box 53015
233 W. Duval Street
Jacksonville, Florida 32201

II. Location

The Jacksonville Electric Authority (JEA), in cooperation with Florida Power and Light Company (FPL), proposes to construct a new power generating facility consisting of two 600 megawatt (MW) coal-fired steam generating units in Duval County, Florida. The construction site, known as the St. Johns River Power Park, is located adjacent to the existing JEA Northside Generating Station, approximately 15 kilometers northeast of downtown Jacksonville, Florida. The UTM coordinates of the proposed source are 446.9 kilometers east and 3366.3 kilometers north.

III. Project Description

The applicant proposes to construct a new power generating station consisting of two 600 MW turbine-generator units powered by two pulverized coal-fired steam generators (boilers), two auxiliary boilers, and coal, limestone, and fly ash handling facilities. The two proposed steam generators will fire a maximum of 6144 million Btu's per hour (MMBtu/hr) each or approximately 292.6 tons per hour each of a medium bituminous coal having a minimum higher heating value of 10,500 Btu/lb. Of the coals under consideration, the maximum sulfur content coal has 4.0 percent sulfur by weight.

Two 127 MMBtu/hr auxiliary boilers will be utilized to provide start-up and shutdown capability for the two turbine-generating units. The auxiliary boilers will be fired with No. 2 fuel oil having a maximum sulfur content of .76 percent by weight (wt. %) and an approximate heating value of 19,500 Btu/lb.

The cooling system will consist of two counterflow natural draft cooling towers located at the north end of the plant.

The coal handling facility provides for water delivery of coal by ocean-going barge or ship to a marine terminal located on Blount Island, Florida where a 30-acre coal surge pile will be operated. The coal will be transferred from the marine terminal to the proposed plant site. The facility also will be capable of receiving direct rail car coal shipments. The coal handling equipment at the proposed plant site includes a rotary car dumper, yard area coal storage, transfer system, coal silos, and tripper floor distribution system. On the average, less than 10,000 tons per day of coal will be unloaded at the proposed source.

Limestone will be delivered to the proposed source by rail and stored in an open pile or day storage silos.

IV. Source Impact Analysis

PSD regulations amended in the August 7, 1980, Federal Register require that a new fossil fuel-fired steam electric plant with potential emissions of 100 or more tons per year of any pollutant regulated under the Act undergo a PSD review for each pollutant which results in a significant net increase in emissions. Table 1 presents an emissions summary for the proposed new source. The proposed new source has potential emission increases of sulfur dioxide (SO_2) and other pollutants of greater than 100 tons per year and significant increases in particulate matter (PM), nitrogen oxides (NO_x), carbon monoxide (CO) and SO_2. Therefore, a PSD review is required for SO_2, NO_x, PM, and CO. A full PSD review consists of the following:

A. A demonstration that Best Availabile Control Technology (BACT) is being applied to all facilities emitting SO_2, PM, NO_x, and CO;

B. An analysis of existing air quality;

C. A demonstration that the source will not cause or contribute to any NAAQS violations;

D. A PSD increment analysis;

E. A growth analysis;

F. An analysis of impacts on soils, vegetation, and visibility; and

G. A Class I area analysis

The proposed new source will be located in an area considered attainment for all pollutants under review. A non-attainment area for PM is located in the vicinity of Jacksonville, Florida, approximately 9 kilometers from the proposed new source at its closest point. Also Duval County is nonattainment for ozone. The source however, has insignificant emissions of VOC and therefore is not subject to review for this pollutant.

The JEA's application was considered complete prior to August 7, 1980. It should be noted that Table 1 in the Preliminary Determination and the Public Notice misrepresented emissions estimates for SO_2, NO_x, CO, and PM (pounds per hour in place of tons per year). Table 1 of this determination correctly summarizes these emissions rates. A notice of correction was published for public information.

A preliminary determination and public notice were made previously regarding the proposed construction. Subsequent design modifications to the plant necessitated the issuance of revised preliminary determination. Where necessary, additional analysis of emissions, controls, etc., were provided by the applicant. This final determination correctly reflects the design of the proposed power generating station.

A. Best Available Control Technology (BACT)

Paragraph (i)(9) of the August 7, 1980 PSD regulations exempts this source from paragraph (j) of the regulations. Instead, paragraph (j) of the June 19, 1978 PSD regulations applies. Therefore, BACT must be applied to all emission units emitting SO_2, PM, NO_x, and CO because allowable emissions of these pollutants are greater than 50 tons per year.

Sulfur Dioxide

BACT must be applied to the two proposed steam generators (boilers) and the auxiliary boiler to control SO_2 emissions.

The applicant proposes to install a lime/limestone flue gas desulfurization (FGD) system on each of the proposed steam generators as BACT for SO_2. The SO_2 removal efficiency of single FGD system is 90 percent (.76 lb/MM Btu SO_2 emissions determined in a 30-day rolling average). The applicant will maintain a minimum 70 percent control efficiency consistent with the NSPS requirements for steam generating electric plants (40 CFR 60 Subpart Da) when emission rates are below 0.6 lbs/MMBtu.

Two other emissions control systems, a lime/limestone FGD with a 95 percent SO_2 removal efficiency and a lime spray drying FGD with a 90 percent SO_2 removal efficiency, were examined. The incremental cost of the higher efficiency lime/limestone FGD system was determined not to be cost effective with respect to the resulting improvement in air quality. The lime spray drying FGD system also was rejected on the basis of economics and the existence of unfavorable operating experience. The New Source Performance Standard (NSPS) for electric utility steam generation was promulgated June 11, 1979. The NSPS limits SO_2 emissions to 10 percent of potential SO_2 emissions and a maximum emission rate of 1.2 lb/MMBtu heat input except when the emissions are less than 0.6 lb/MMBtu. At the latter emission rate, a minimum of 70 percent reduction (30 percent of potential emitted) in potential SO_2 emissions is required. The percentage reduction in potential SO_2 emissions is dependent upon the sulfur content of the coal. The proposed SO_2 control system meets all requirements of the NSPS for electric utility steam generation stations for the control of SO_2 emissions. A continuous monitor for sulfur dioxide emissions will be installed in the flue of both steam generators in accordance with 40 CFR 60.47a. The above emissions control system represents BACT for SO_2 emissions from the two proposed steam generators.

Auxiliary boilers will be fired with a maximum .76 wt. % sulfur fuel oil. The SO_2 emissions from the auxiliary boilers are small when compared to those of the main units. BACT for SO_2 emissions from the auxiliary boilers has been determined to be the firing of a maximum .76 wt.

Particulate Matter

Application of BACT is required for the emissions of PM from the two steam generators (boilers), auxiliary boilers and coal, fly ash, and limestone handling facilities.

BACT for PM emissions from the two steam generators has been determined to be the installation of an electrostatic precipitator with a PM removal efficiency of 99.78 percent (.03) lb/MMBtu). Two alternative systems, an electrostatic precipitatior with a PM removal efficiency of 99.85 percent (.02 lb/MMBtu) and a fabric filter with a PM removal efficiency of 99.85 percent (.02 lb/MMBtu), were examined in the BACT analysis. The higher efficiency electrostatic precipitator was determined not to be cost effective with respect to the resulting improvement in ambient quality. The fabric filter system also was rejected on the basis of economics and the existence of unfavorable operating experience. The NSPS for electric utility steam generation limits PM emissions to .03 lb/MMBtu heat input. The proposed PM emissions control system meets the NSPS requirements for control of PM emissions. A continuous opacity monitor will be installed in the flue of both steam generators in accordance with 40 CFR 60.47a. The above system has been determined to be BACT for PM emissions from the two steam generators.

Control and collection of particulate matter emissions from the coal handling system will be accomplished by several different methods including totally enclosed conveying systems, water spray dust collection systems, and dust collection systems utilizing fabric filters.

Control of fugitive dust from limestone handling will be accomplished by the use of totally enclosed conveyors, fabric filter dust collectors, and wet suppression systems.

Fugitive fly ash emissions will be controlled at all transfer and discharge locations by fabric filters. The handling system utilized to transfer fly ash to and from ash storage silos is enclosed and exhausted to fabric filters. Transfer from silo storage will be through gravity feed chutes to covered trucks for disposal in landfills or for sale.

Fugitive dissolved and suspended particulate emissions from the cooling tower will be controlled by high efficiency drift eliminators. Table 2 presents a fugitive emissions and control summary.

The above emission control systems represents BACT for fugitive emissions.

BACT for PM emissions from the auxiliary boilers has been determined to be the firing of No. 2 fuel oil with a maximum ash content of 0.01 wt. %. Therefore, no air pollution control equipment for the purpose of PM reduction is warranted.

Nitrogen Oxides and Carbon Monoxide

BACT must be applied to the two steam generators and the auxiliary boilers to control NO_x and CO emissions. Emissions of NO_x and CO resulting from the combustion of coal is dependent on boiler design, the amount of excess air in the combustion chamber, flame temperature, burner spacing and burner design.

The applicant proposes to use combustion controls and modern boiler design for a maximum NO_x emission rate of 0.6 lb/MMBtu and to minimize CO emissions.

B. Analysis of Existing Air Quality

Paragraph (i)(9) of the August 7, 1980 PSD regulations exempts this source from paragraph (m)(1) of the regulations. Instead, paragraph (n) of the June 19, 1978 PSD regulations applies. Therefore, an analysis of existing air quality for SO_2, PM, NO_x, and CO is required as deemed necessary by the Administrator because the allowable emissions increases of these pollutants are greater than 50 tons per year.

An air quality analysis, using meteorological data from the on site monitoring program, determined the maximum pollutant concentrations at the monitoring site when the contributions from large existing sources of pollution were negligible. The sources were the JEA Northside plant and the St. Regis Paper Company. These maximum background pollutant concentrations were determined to be representative of the existing air quality in the region of the proposed source. All monitoring, data collection procedures, and modeling analyses were conducted using EPA-approved techniques. The monitoring data was utilized in the NAAQS analysis in projecting the maximum ambient air concentrations of each pollutant under review. The results are shown in Table 3.

C. NAAQS Analysis

The EPA-approved dispersion models CRSTER (modified for use with multiple point sources of emissions) and ISCST were utilized to assess the total ambient air concentrations of SO_2, PM, NO_x and CO within 50 km of the proposed plant site. Meteorological data for the years 1970 - 1974 were obtained from weather stations located at Jacksonville International Airport (surface date) and Waycross, Georgia (upper air observations). The meteorological data was determined to be representative of the weather conditions at the proposed construction site.

An emissions inventory of all increment consuming and other sources within 50 km of the proposed plant, and new sources within 100 km of the nearest Class I area was compiled. For the purpose of the modeling analysis, the main steam generating units were considered to operate continuously. This is a conservative assumption because the plant capability factor is expected to be no greater than 74 percent.

An initial modeling anlysis determined that the 1973 meteorological data represented the "worst-case" year assuming a 100 percent plant load. Additional modeling at 75 percent and 50 percent load showed that a 100 percent continuous operating load resulted in the highest ground level concentrations. Therefore, the more detailed analyses were conducted using the emission parameters for the 100 percent load level. All modeling was conducted using EPA-approved modeling techniques. All stacks were modeled at Good Engineering Practice (GEP) stack height. No downwash is expected to occur as a result of turbulent building wake effects because all stacks meet GEP stack height.

The maximum ambient air concentrations for the pollutants under review were determined by modeling emissions from the proposed new source along with emissions from the JEA Northside plant and ST. Regis Paper Company. The maximum concentrations obtained from the modeling analysis were added to the maximum background concentrations (which did not include contributions from the St. Regis Paper Company or the JEA Northside plant) to obtain the maximum ambient air concentrations of each pollutant under review. This analysis is considered conservative because both the maximum monitored background and modeled concentration were not located at the same geographical point. The results of the NAAQS analysis are presented in Table 3.

A modeling analysis was conducted to determine the impact of PM emissions (including fugitive PM emissions) from the proposed new source on the PM non-attainment area located in downtown Jacksonville, Florida. The maximum impacts were projected to be below 1 ug/m^3 on an annual average and 5 ug/m^3 on a 24-hr average. These values are below the PSD ambient significance levels as defined in the June 19, 1978 PSD regulations, 43 FR 26358. Therefore, the proposed new source will not significantly impact the PM non-attainment area, in compliance with the August 7, 1980 PSD regulations paragraph (f)(4)(a).

The VOC emissions from the proposed new source are not expected to impact the ozone non-attainment area located near Jacksonville, Florida. Presently, no EPA-approved dispersion models exist with which to model ozone emissions (of which VOC is a precursor). The VOC emission levels from the proposed new source are small and not expected to significantly impact the ozone non-attainment area under any meteorological conditions.

D. Increment Analysis

The models and meteorology for determination of PM and SO_2 increment consumption were the same as those discussed in the NAAQS analysis (above). All increment consuming sources potentially affecting the ambient air quality in the area of the proposed new source were included in the modeling analysis. No violations of the Class II increment standards were predicted. The results are presented in Table 4.

E. Growth Analysis

The proposed new source is expected to directly employ about 400 people. Most of these workers will come from the local work force. No air quality impacts resulting from industrial, commercial, or residential growth associated with the proposed new source are expected.

F. Soils, Vegetation and Visibility Analysis

No soils vegetation or visibility impacts are expected to occur due to emissions from the proposed new source because of the relatively small increase in ambient pollutant concentrations.

G. Class I Area Analysis

The nearest Class I area to the proposed new source is the Okefenokee Swamp whose borders are located between 61 and 73 kilometers in a northwestly direction. The models and meteorology used in the increment and NAAQS analyses were utilized to predict the maximum SO_2 and PM increment consumption at the borders of the Class I area. All increment consuming sources potentially impacting the Class I area were included in the modeling analysis. Five years of meteorological data were modeled. No violations of the Class I increments were predicted. The results are presented in Table 5.

No impacts on Class I area soils, vegetation or visibility are expected due to the low level of ambient air concentrations projected in the Class I area for any pollutant under review. The results of this analysis have been forwarded to the Federal Land Managers responsible for this Class I area for comment.

V. Conclusion

EPA proposes a final determination of approval with conditions for construction of the steam - electric generating station proposed by the Jacksonville Electric Authority. This final determination is based on the application received May 28, 1980 and additional information submittals dated July 8, 1980, November 26, 1980, March 6, 1981, July 30, 1981, July 31, 1981, September 8, 1981, September 21, 1981 and October 21, 1981. The application was determined to be complete as of July 9, 1980.

Approval to construct is contingent upon the following conditions;

1. The proposed steam generating station will be constructed and operated in accordance with the capacities and specifications contained in the application.

2. Emissions will not exceed the allowable emissions listed in Table 6 for SO_2, PM, and NO_x.

3. Compliance with the allowable emission limits for emission point 1 and 2, in Table 6 will be demonstrated with performance tests conducted in accordance with the provisions of 40 CFR 60.46a, 48a and 49a, including applicable test methods, sampling procedures, sample volumes, sampling periods, etc. Compliance with the emission limitations of all emission points in Table 6 will be in accordance with 40 CFR 60, Appendix A; Method 5, Determination of Particulate Emissions from Stationary Sources; Method 7, Determination of Nitrogen Oxide Emissions from Stationary Sources; Method 9, Determination of the Opacity of Emissions from Stationary Sources.

   Emission points 3 thru 13 of Table 6 are exempted from mass emission rate compliance tests unless opacity limits are exceeded or the Administrator (or his representative) otherwise determines that such performance testing is required. All facilities will operate within 10 percent of maximum operating capacity during performance testing.

4. The applicant will install and maintain a continuous monitoring and recording opacity meter, sulfur dioxide, nitrogen oxide and carbon monoxide analyzers for each steam generator (emissions units 1 and 2 Table 6) in accordance with the provisions of 40 CFR 60.47a.

5. Emission points 1 and 2 of Table 6 shall fire coal with an ash content not to exceed 18% and a sulfur content not to exceed 4% by weight. Coal sulfur content shall be determined and recorded in accordance with 40 CFR 60.47a.

Emission point 3 of Table 6 shall fire No. 2 fuel oil with a maximum sulfur content of .76 percent by weight and a maximum ash content of .01 percent by weight. Samples of all fuel oil fired in the boilers shall be taken and analyzed for sulfur and ash content. Accordingly, samples shall be taken of each fuel oil shipment received. Records of the analyses shall be recorded and kept for public inspection for a minimum of two years after the data is recorded.

6. The following requirements will be met to minimize fugitive emissions of particulate matter from the coal storage and handling facilities, the limestone storage and handling facilities, haul roads and general plant operations:

   a. All conveyors and conveyor transfer points will be enclosed to preclude PM emissions (except those directly associated with the coal stacker/reclaimer for which enclosure is operationally infeasible).

   b. Inactive coal storage piles will be shaped, compacted and oriented to minimize wind erosion.

   c. Water sprays or chemical wetting agents and stabilizers will be applied to storage piles, handling equipment, etc., during dry periods and as necessary to all facilities to maintain an opacity of less than or equal to 10 percent.

   d. Limestone handling will be from bottom dump rail car delivery with wet dust suppression, and open storage or day storage silos.

   e. The fly ash handling system (including transfer and silo storage) will be totally enclosed and vented (including pneumatic system exhaust) through fabric filters.

7. The applicant will comply with all requirements and provisions of the New Source Performance Standard for electric utility steam generating units (40 CFR 60 Part Da). In addition, the applicant must comply with the provisions and the requirements of the attached General Conditions.

8. As a requirement of this specific condition, the applicant will comply with all emissions limits and enforceable restrictions required by the State of Florida Department of Environmental Regulation which are more strict operating requirements and equipment specifications than the requirements of specific conditions 1-9 of this permit.

9. This PSD approval to construct shall be valid only in the event that the stacks at the Southside (Unit 1-5) and Kennedy (Units 8, 9, 10) plants are raised to 84 meters as presented in the ambient air quality analysis for this determination; or additional modeling of air quality impacts (considering federally enforceable system operating restrictions) is submitted which demonstrate that the NAAQS will not be violated at the lower stack height under valid worst case conditions. If such modeling is to be used to show compliance with NAAQS it should be submitted prior to construction of the new units at the St. Johns River Power Park.

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OFFICIAL RECORDS

STATE OF FLORIDA DOCUMENTARY STAMP TAX 00.45

Please record and return to
Richard Brietmoser, P.E.
Jacksonville Electric Authority
233 West Duval Street
Jacksonville, Florida 32202

NOTICE OF CERTIFIED CORRIDOR ROUTE
PURSUANT TO THE FLORIDA ELECTRICAL
POWER PLANT SITING ACT

This Notice of Certified Corridor Route Pursuant to the Florida Electrical Power Plant Siting Act is made and given this _______ day of August, 1982 by the Jacksonville Electric Authority, a body politic and corporate existing under the laws of the State of Florida, 233 West Duval Street, Jacksonville, Florida 32202 (the "Electric Utility").

RECITALS

1. The Florida Governor and Cabinet, sitting as the Siting Board pursuant to Part II, Chapter 403, Florida Statutes (the "Florida Electrical Power Plant Siting Act"), issued a Certification Order on June 29, 1982 authorizing the Electric Utility to construct and operate the proposed St. Johns River Power Park electrical power plant, including its associated facilities and its directly associated transmission lines, at a site in Duval County, Florida. The Certification Order has become final without appeal.

2. The Florida Electrical Power Plant Siting Act requires a notice of the route certified by the Siting Board to be recorded in the official records of each county through which the transmission line will pass.

NOW, THEREFORE, the Electric Utility hereby gives notice that the Siting Board has authorized the Electric Utility to construct and operate an electric transmission line directly associated with the proposed St. Johns River Power Park over a certified corridor route located as shown on the maps and aerial photographs attached hereto and made a part hereof. The certification of the above described corridor route will result in the acquisition of rights-of-way within the corridor route. This notice is given pursuant to and as required by state law and shall not constitute a lien, cloud or encumbrance on the real property described herein.

IN WITNESS WHEREOF, the Electric Utility has caused this Notice of Certified Corridor Route Pursuant to the Florida Electrical Plant Siting Act to be executed in its name the day and year first above written.

JACKSONVILLE ELECTRIC AUTHORITY,
a body politic and corporate

(Corporate Seal)

By: [signature]
Walter Williams, Jr., Chairman

By: [signature]
Royce Lyles, Managing Director

STATE OF FLORIDA
COUNTY OF DUVAL

The foregoing instrument was acknowledged before me this 27th day of August, 1982 by Walter Williams, Jr. and Royce Lyles, the Chairman and Managing Director, respectively, of the Jacksonville Electric Authority, a body politic and corporate, on behalf of the Jacksonville Electric Authority.

[signature]
Notary Public State of Florida at Large.
My commission expires:
NOTARY PUBLIC STATE OF FLORIDA AT LARGE
MY COMMISSION EXPIRES JAN. 30 1983
BONDED THRU GENERAL INS. UNDERWRITERS

World markets for petroleum coke

R. E. Dymond, The Pace Consultants, Houston

THE INDUSTRY is poised for another coker expansion larger than 1983/1984 when nearly five million tons of additional capacity was added in the U.S. Current world markets and environmental regulations suggest that the resultant coke production could be absorbed into existing applications, but the threat of more rigid environmental regulations on a worldwide basis is real. Installation of stack gas scrubbers and continued expansion of fluidized bed combustion units would be the panacea.

While still a byproduct, petroleum coke marketing has become more important and has recognition as an incremental revenue source within the oil refining industry. The purpose of this article is to provide a cursory view of the world markets of petroleum coke.

Current refinery conversion economics justify maximizing coker thruput and new coker expansion. Worldwide coke production should increase by 30% by the year 2000 with significant new capacity in the U.S. The new production is projected to be lower in quality—higher sulfur and trace metals contents. It is unlikely that the domestic developments in the commercialization of fluidized bed combustion and "window" created by the Clean Air Act will absorb this amount; thus, export markets will continue to play a pivotal role.

Coke types. When discussing the marketing of petroleum coke it is essential to recognize that there are three different types of coking processes and the byproduct petroleum coke produced from each is distinctly different. These processes—delayed, fluid and Flexicoking—are all effective in converting residual oils to higher value products and concentrating the contaminants (sulfur, metals, etc.) in the coke.

Petroleum coke from the delayed process is described as delayed sponge, shot or needle coke depending on its physical structure. The former is desired from a marketer's viewpoint; shot is most prevalent when running the unit under severe conditions with very sour crude oils; and the latter is produced from selected aromatic feedstocks. Although the chemical properties are most critical, the physical characteristics of each type play a major role in the final market application. For example, sponge coke is more porous and contains greater surface area; shot coke looks like BBs, has much less surface area and is harder; and needle coke's unique structure lends its use for graphitization. Unlike the others, needle coke is a product (versus byproduct) which the refinery intentionally produces from selected feedstocks.

By comparison, fluid coke is spherical in shape, contains less volatile materials and is much harder than sponge coke. Normal size is less than 1/4 in., and it does not tend to agglomerate like shot coke. Flexicoking is an extension of fluid coking in that some (over 60%) of the coke is gasified to low Btu gas for refinery use. The resultant purge coke, Flexicoke, has relatively small particle size (80% passing 200 mesh) and is either very wet (cake) or very dry. Both conditions create difficult problems in subsequent handling/storage/shipping.

TABLE 1—Petroleum coke characteristics by process type.

Process	Type coke	Characteristics
Delayed	Sponge	Sponge-like appearance Higher sulfur area Lower contaminants levels Higher volatiles Higher HGI* (>50) 0 in. x 6 in. typical sizing
	Shot	Spherical appearance Lower surface area Lower volatiles Lower HGI* (<50) Tends to agglomerate
	(Aromatic feed) Needle	Needle-like appearance Low volatiles High carbon content
Fluid	Fluid	Low volatiles Higher contaminants levels Low HGI* (<40) 1/4 in. particle size
Flexicoker	Flexicoke	Highest contaminants levels 80% <200 mesh

*HGI—Hardgrove Grindability Index

The delayed coker is much more prevalent and will be the primary focus of this article. Table 1 illustrates the characteristics of the cokes from these processes.

In world markets, all the different types of petroleum cokes are valued as an industrial carbon or an energy source. The cokes' chemical and physical properties generally dictate the end-use application and competitive products influence the market value. Ignoring logistics' costs, the lower quality cokes compete with coal and high-sulfur fuel oils in the energy sector and represent the lowest market value. As an industrial carbon, petroleum cokes function as a reductant in the manufacture of aluminum, titanium and phosphorus; as a carbon source in steel manufacturing; and as an inert electrical conductor in electric arc steel manufacturing. In the energy (fuel) applications the cokes are sold as is—raw/green—while, in the carbon applications an "added value" step of calcining is often necessary to increase the purity. Calcined petroleum coke is many times more valuable than green coke or fuel grade coke.

A simple hierarchy for the world market applications for petroleum cokes is as follows:

- U.S. calciner feedstock
- European space heating
- Japanese and European steel and coke
- Japanese solid industrial fuel
- European solid industrial fuel
- U.S. solid industrial fuel.

PETROLEUM COKE SUPPLY

Unlike most products, a simple analysis of the supply/demand of petroleum coke is misleading because the supply of green petroleum coke is inelastic with respect to its own price. In other words, refiners seldom change coker operations to produce more or less petroleum coke based on coke market prices. Rather, the overall supply of byproduct petroleum coke is a function of:

- Total crude runs
- Crude oil quality
- Refined products' demand patterns

• Coking capacity.

Current world coking capacity is approximately 115,000 short tons per day (stpd). Of this, about 65% is located in the U.S. (75,000 stpd). When considering World Outside Communist Areas (WOCA), the U.S. produces over 70% of the petroleum coke.

Current production. Production of petroleum coke in the U.S. during 1990 edged to near 92% of capacity, or over 25 million short tons (MMst). U.S. production will not increase significantly until new capacity comes on-line.

Complete and reliable estimates for coke production in the rest of the world are not available, but have been approximated from industry information. Production in other WOCA areas is estimated to average 80% of capacity. This equates to 10 MMst in 1990, bringing the WOCA total to some 36 MMst (33 million metric tons) of petroleum coke production.

U.S. petroleum coke production has quadrupled since 1960. The U.S. position as the world's largest producer of petroleum coke is explained by the following factors:

• The U.S. is the largest producer and consumer of refined petroleum products in the world.

• The U.S. gasoline market is very large, accounting for about one-half of all crude oil refined.

• U.S. heavy fuel oil demand is relatively low, due in part to plentiful coal and natural gas resources.

• Incremental crude oil supplies available to the U.S. refining industry (offshore sources) contain large amounts of "heavy" crude oil fractions which require conversion.

Fig. 1 shows the relative worldwide production capacities by regions and type processes, respectively.

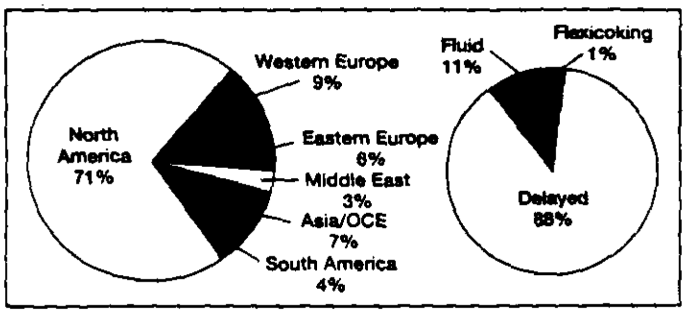

Fig. 1—Worldwide petroleum coke production.

Supply forecast. Annual WOCA coke production should increase approximately 30% to 40 million metric tons by 2000. Two technical indicators which Pace follows with respect to coking economics are the light/heavy spread (coker incentive) and the coker contribution. They define these terms as follows:

• Light/heavy spread (coker incentive)—Average of gasoline and light distillate prices less the price of high-sulfur fuel oil.

• Coker contribution—Difference in margins for high conversion vs. average conversion model refineries with 200,000 bpd capacity; the primary process difference is that *the high conversion model contains a delayed coker.*

As an example, Figs. 2 and 3 present the trend relationships for U.S. Gulf Coast refiners between U.S. green coke production (total) versus Gulf Coast light/heavy spread and Gulf Coast coker contribution versus U.S. green coke production (total). The coker contribution is based on $/bbl of crude oil for the refinery, not coker feed.

Since the total production of green petroleum coke continues to increase and no new cokers have been built in this area within the past few years, Pace would conclude that U.S.

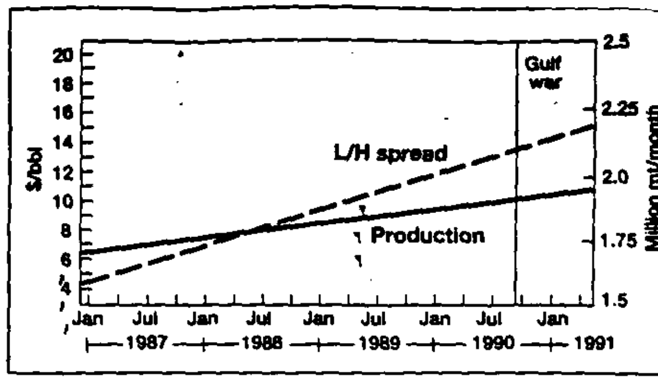

Fig. 2—U.S. green coke production vs. light/heavy spread.

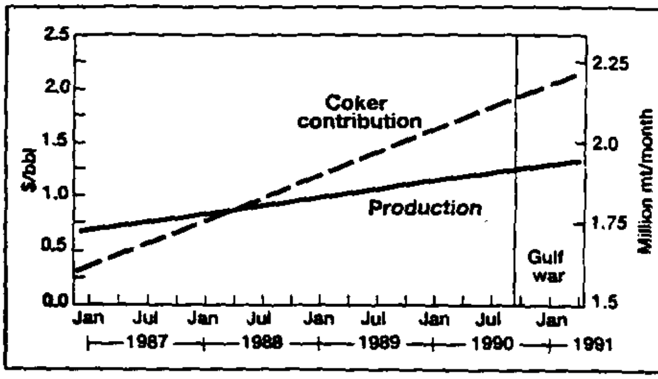

Fig. 3—Coker contribution vs. U.S. green coke production.

refiners are increasing the conversion capacity of the cokers by reducing cycle times and/or increasing the Conradson carbon content of the coker feed. Pace believes these economic

TABLE 2—Announced coker capacity additions (Mbpsd)

Company	Country	Region/ location	Capacity	Completion date
ARCO	U.S.	Cherry Point	3.0	4Q:90
Conoco	U.S.	Billings	13.0	4Q:92
Enichem Anic Sp	Italy	Gela	19.5	3Q:90
Husky	Canada	Lloydminster	7.5	1991
Lagoven	Venezuela	Amuary	9.0	1990
Mobil	U.S.	Beaumont	15.0	1992
Petrobras	Brazil	Betium	20.4	1991
Petrobras	Brazil	Paulina	20.4	1992
Petrobras	Brazil	Paulina	20.4	1994
Petrox	Chile	Tacahuano	9.0	1993
Repsol Petroleo	Spain	Puerto Llano	14.3	2Q:90
Star	U.S.	Port Arthur	40.0	1Q:93
Texaco	U.S.	Los Angeles	10.0	na
	Total		201.5	

indicators justify maximizing the conversion aspects of the coker and appear to justify new/additional coker capacity.

Coking expansions. Approximately 500,000 bpd of refinery conversion capacity, in the form of cokers, is currently being considered in WOCA. This total includes the projects listed in Table 2 which represent some 200,000 bpd of conversion capacity. Additional coking capacity, above that currently being considered, will be required by the end of the century. Most expansions will occur in the U.S. and Europe. Other expansions are possible in the Middle East, Far East and South America.

Petroleum coke quality outlook. Petroleum coke quality is most often judged by the concentration of sulfur and trace metal it contains. A portion of current coke production has sufficiently low sulfur and metals content to be calcined for use in the aluminum industry. This type of coke commands a premium compared to fuel (Btu) applications. Calcinable coke represents less than 30% of current U.S. petroleum coke production. This percentage should decrease with expansion of capacity.

Users of fuel-grade petroleum coke are more tolerant of sulfur, metals and other impurities. Fuel grade coke represents slightly over 70% of current U.S. coke production. Approximately 80% of petroleum coke not calcined in the U.S. is exported. The bulk of this coke is, by most standards, fuel grade.

The degree of contamination from sulfur and metals in petroleum coke is a direct function of the chemical composition of coker feedstock and ultimately the crude oil. Though additional production of light crude oil is expected from areas such as the North Sea and Indonesia, most incremental crude oil added to world supply will be from the Middle East. These crude oils are heavier and tend to contain a higher concentration of sulfur and metals. Therefore, though composite crude oil quality will change little during the next decade, new coking capacity will likely produce largely fuel grade coke.

Pace has surveyed producers of petroleum coke in all regions of the world for several years. Quality information regarding sulfur and vanadium levels was used to develop average specifications for coke produced in WOCA. Table 3 shows the past and anticipated trends in the average sulfur and vanadium content of coke produced in WOCA. These figures reflect the subtle changes in composite crude oil quality that is expected.

TABLE 3—Petroleum coke quality

	1990	1995	2000
Sulfur content (wt %)			
Free world average	3.7	4.2	4.3
Fuel-grade average	4.1	4.7	4.8
Vanadium content (ppm)			
Free world average	530	560	575
Fuel-grade average	670	680	695

PETROLEUM COKE DEMAND

Typical end uses. In the carbon source and Btu applications the chemical and physical quality characteristics play a major role in determining a specific coke's value in the marketplace. Generally, the lower quality cokes are placed into applications of lower value (i.e., the solid fuel markets). The higher quality cokes command higher prices and can be subjected to further added value processing—calcining—to improve their purity. The calcining process is completed at elevated temperatures in a rotary kiln or hearth with the intent of driving off the volatile matter and moisture to yield a purer carbon. Table 4 details significant market applications.

The relative market values for the applications and cokes are approximated by starting at the bottom and proceeding to the top of the list—highest value being at the top. This market value hierarchy generally holds true for all the world markets with actual prices reflecting the competition from alternate products in that specific market. Within the carbon source and one or two of the fuel applications, there are real limits on the demand. Thus, the higher quality cokes fill this requirement with any balance cascading down into the next lower valued application.

For delayed sponge coke, the aluminum anode application is the premium market since there is no practical substitute for the calcined coke; supply and price competition are strictly

TABLE 4—Typical petroleum coke end uses

Application	Type coke	State	End use
Carbon source	Needle	Calcined	Electrodes Synthetic graphite
	Sponge	Calcined	Aluminum anodes TiO_2 pigments Carbon raiser
	Sponge	Green	Silicon carbide Foundries Coke ovens
Fuel use	Sponge	Green lump	Europe/Japan space heating
	Sponge	Green	Industrial boilers
	Shot	Green	Utilities
	Fluid	Green	Cogeneration
	Flexicoke	Green	Lime Cement

from within the petroleum coke industry. The volume of coke consumed is about 0.40 lb for each pound of aluminum made in the entire world. Other high value applications like titanium dioxide, coke ovens and silicon carbide are demand limited, and petroleum coke must compete on a cost-effective basis with other nonpetroleum sourced products.

Similarly, petroleum coke targeted for fuel applications competes with coal, natural gas, high-sulfur fuel oils, waste oils, etc., on a delivered basis. The critical factor is the delivered cost of the petroleum coke and competing materials compared on a $/MMBtu basis with other adjustments to compensate for quality differences.

Two quality factors which are most critical are the relatively high sulfur levels in coke which can contribute to the SO_2 emissions, and low HGI which can reduce crushing/pulverizing capabilities. The price adjustments negotiated are influenced by the end-users' operations and competitive factors.

Historically, the cement/lime industry has been a particularly attractive application for petroleum coke because it represents substantial volumes and can tolerate the high sulfur level in the coke (most of the SO_2 is absorbed in the cement).

PETROLEUM COKE MARKETING

The objective of the marketing function is to move the products (supply) from the refinery to the end-consumer (demand) at the minimum costs and highest sales prices (profit/loss). A variety of business entities such as petroleum refiners, resellers, calciners and numerous end users operating in several allied industries are involved in the marketing. Some refiners have integrated downstream into calcining and/or direct selling to consumers. Resellers, specialized marketing firms involved in bulk trade of petroleum coke, play a pivotal role in the orderly distribution of petroleum coke throughout the world and are constantly seeking/developing new markets. Calcined coke producers add value by calcining raw petroleum coke into essentially pure carbon, a critical input to the aluminum smelting process. The end users receive the product from the refiner, reseller or calciner.

Fig. 4 illustrates the typical flow of U.S. petroleum coke production into the marketplace. Although several refiners have made downstream investments and have started direct marketing, resellers still distribute/market 59% of the U.S. production. Since the resellers developed most of the markets, acquired logistics skills, made capital investments in facilities and staffed accordingly, they are able to guarantee the removal of the coke, regardless of quality. Their historic and continuing role is important to the industry.

U.S. calcining operations are controlled by two major aluminum producers, five oil companies and four independent

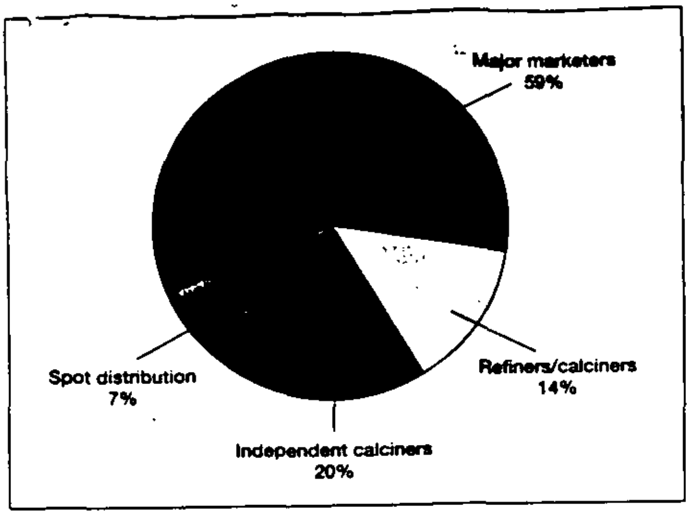

Fig. 4—U.S. green coke trade, 1989.

calciners or specialized producers. The forward integration of large oil refiners has had a lasting effect on this industry.

U.S. consumption. Most of the petroleum coke consumed domestically is for anode manufacture. The U.S. has never been a large consumer of fuel-grade petroleum coke. Although petroleum coke is readily available, most American industries prefer clean-burning natural gas, low-sulfur residual fuel oil or coal. The consumption of fuel-grade petroleum coke within the United States is hampered by costs of logistics. The major refineries are on the coasts, whereas the markets are inland and more accessible to competing products. To some degree, the limitation in coke burning capability is an outfall of years of price-controlled or relatively inexpensive natural gas. Few companies have installed equipment (i.e., bulk handling, blending, scrubbers) to make use of petroleum coke as a fuel. Very little U.S. Gulf Coast-produced petroleum coke (high sulfur, high metals quality) is consumed domestically, thus by necessity more than 50% of the annual green coke production is exported into international markets.

Two factors—the Clean Air Act of 1990 and fluidized bed technology—offer some potential for additional petroleum coke consumption within the U.S. utility and cogeneration industries. Petroleum coke has been the fuel of choice for several commercial cogeneration installations. Conformance to the Clean Air Act has many utilities investigating switching to low sulfur/low Btu Powder River Basin coals; some are realizing a sulfur cushion which allows blending of petroleum coke for the Btu benefit. Table 5 lists these companies. Unless the utilities/industrial boilers install scrubbers to achieve conformance, the "window" provided by the Clean Air Act will close and even threaten historic consumers in this sector.

U.S. export markets. Export markets are different from U.S. markets in that they are generally energy/carbon deficient because of inadequate energy reserves or the infrastructure to develop the same. Thus, they purchase petroleum coke, as well as other products from international sources. The typical market hierarchy exists. Minimum petroleum coke values occur when petroleum coke is used to displace more traditional fuels. Therefore, lower tier petroleum coke markets exist where petroleum coke is used as a low-cost fuel alternative to coal and residual fuel oils. Because lower tier fuel markets are demand limited in the U.S., export markets have become a necessary outlet for expanding U.S. production of high-sulfur, high-metals petroleum coke.

U.S. green petroleum coke exports have almost doubled from 1980 to 1990—6.4 million metric tons versus 12.5 million, respectively. Exports to the major areas for the past several years are shown in Fig. 5.

TABLE 5—Facilities using petroleum coke 1987–1991

Company	Plant	Supplier	Capacity (megawatts)	Coke usage (mt/day)
Central Electric Power Co.	Chamois No. 1	Mobil/Clark	15.0	13
	Chamois No.2	Mobil/Clark	44.0	37
Iowa Southern Utilities	Burlington	Koch	212.0	0
Northern Indiana Public Service	Bailly	Koch	615.6	235
Northern Indiana Public Service	Schahfer	Koch	1,943.4	560
Northern States Power	Black Dog	Koch	81.0	100
Northern States Power	King	Koch	598.4	140
Northern States Power	Riverside	Koch	137.0	50
Pennsylvania Power & Light	Holtwood	Star	75.0	220
Pennsylvania Power & Light	Sunbury No. 1	Mobil	75.0	220
	Sunbury No. 2	Mobil	75.0	220
Dairyland Power Coop.	Alma-Madgett	Koch	387.0	0
Dairyland Power Coop.	Genoa No.3	Koch	345.6	0
Delmarva Power & Light	Delaware City No. 1	Star	27.5	200
Empire District Electric Co.	Asbury Plant	Koch	235.0	10
	Cogeneration facilities			
GWF Power Systems Inc.	Antioch No.1	Tosco/Exxon	20	17
GWF Power Systems Inc.	Antioch No.2	Tosco/Exxon	20	174
GWF Power Systems Inc.	Antioch No.3	Tosco/Exxon	20	174
GWF Power Systems Inc.	Antioch No.4	Tosco/Exxon	20	174
GWF Power Systems Inc.	Antioch No.5	Tosco/Exxon	20	174
AES Deepwater	Houston, TX	Lyondell	150	1,370
Nelson International (NISCO)	Lake Charles, LA	Conoco/Citgo	200	0

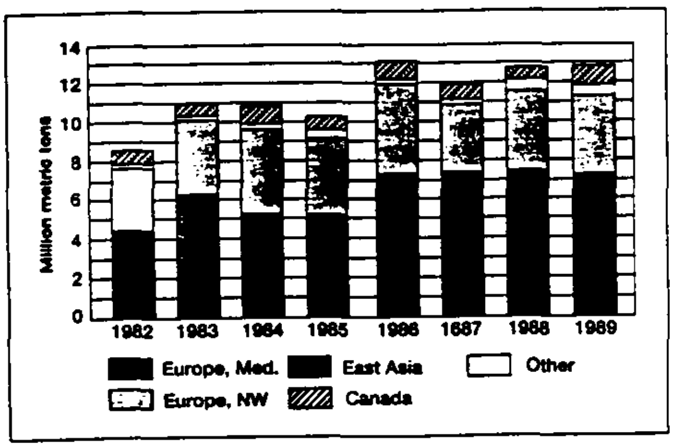

Fig. 5—Green coke exports to selected regions.

Western Europe is the largest regional importer of petroleum coke, regularly importing more petroleum coke than the rest of the world; Japan imports more petroleum coke than any other country. However, petroleum coke remains only a small segment of the total trade of its nearest competitor, coal. Current U.S. petroleum coke exports represent about 5% of the total ocean coal trade. Thus, from a theoretical basis the demand exceeds supply. Figs. 6 and 7 define the petroleum coke uses for these areas.

Most of these countries are facing more strict environmental regulations which could eliminate or certainly limit petroleum coke usage in all fuel boiler applications. The cement industry is a large consuming application in both markets and can

TABLE 6—Petroleum coke price setting mechanisms

Coke type	Sulfur level (wt %)	Mechanism
Fuel grade	Greater than 4	Discount from coal BTU value (sulfur, handling, etc.)
Premium grade	Below 2	Blending with fuel grade to obtain anode grade or other specialty applications
Anode grade	2 to 3	Related to the price of calcined coke
Calcined coke	2 to 3	Complex relationships of supply, calcining costs, demand by the aluminum industry and regional factors

TABLE 7—Theoretical U.S. Gulf Coast petroleum coke FOB price in competition with fuel oil delivered in the Mediterranean

CIF fuel oil price ($/MMBtu)	Discount level (%)	Equivalent U.S. Gulf coast price ($/mt)*
1.66	0	38.00
	10	30.60
	20	25.60
1.51	0	31.30
	10	26.60
	20	21.90

*Based on arbitrary freight rate of $16/metric ton.

accommodate the higher sulfur levels of petroleum coke without excessive capital investment (i.e., scrubbers). During the next decade WOCA cement manufacturing could consume 14.5 MMst annually.

Export fuel market. Price setting mechanisms for green coke grades are shown in Table 6. As an example, petroleum coke exported into Europe and Japan must compete on a delivered cost basis with coal and fuel oil. Coal supplies could originate in Australia, Poland, South Africa, Colombia, Russia, Germany or even the U.S.; fuel oils would be more local to the market area. Petroleum coke is always the lowest price fuel in the Mediterranean area. Reasons are poorer quality, certainty of supply (coal is a product) and handling problems. To illustrate the impact of changing fuel oil prices on petroleum coke prices, FOB U.S. Gulf Coast, Table 7 was prepared assuming an arbitrary bulk freight rate of $16/metric ton U.S. Gulf to Mediterranean. The table shows petroleum coke prices at parity and two discount levels.

The author

Raymond E. Dymond has over 30 years experience in the refining industry, ranging from product research to commercial sales of lubricants, asphalts and fuels. He has been involved in all aspects of petroleum coke markets for over 15 years. He worked at Mobil for 20 years where he managed sales and technical services for petroleum coke, pitch, asphalt and carbon black feedstocks. He also worked for Gulf Oil Chemicals where he was responsible for the company's carbon product sales. In 1982, Mr. Dymond began the Carbon Division of SSM Coal North America and served as president and general manager until 1990, when he assumed responsibilities for managing all aspects of SSM Coal's worldwide petroleum coke supply projects. In 1991, Mr. Dymond joined Pace Consultants Inc. as Director of Petroleum Coke/Residual Upgrading. In that capacity he applies his extensive background in the petroleum coke and bottom-of-the-barrel to individual client projects as well as serving as project manager of the Pace Petroleum Coke Quarterly, the authoritative source of information concerning the petroleum coke industry. He has a BS in chemistry from Muhlenberg College.

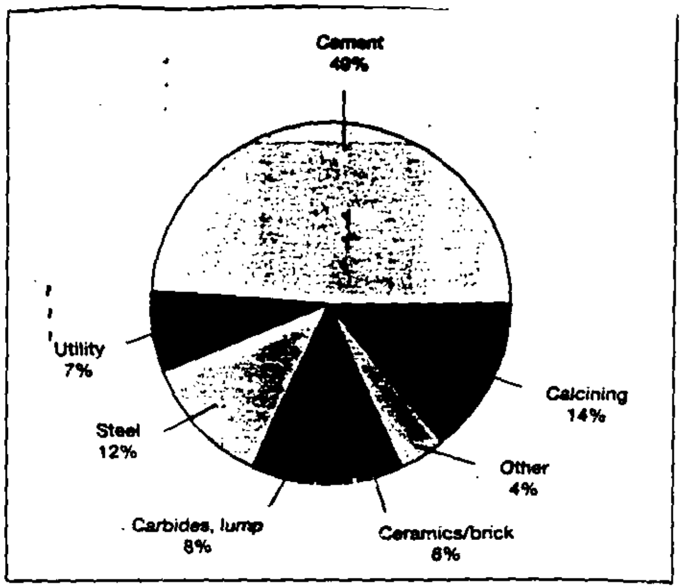

Fig. 6—European petroleum coke demand.

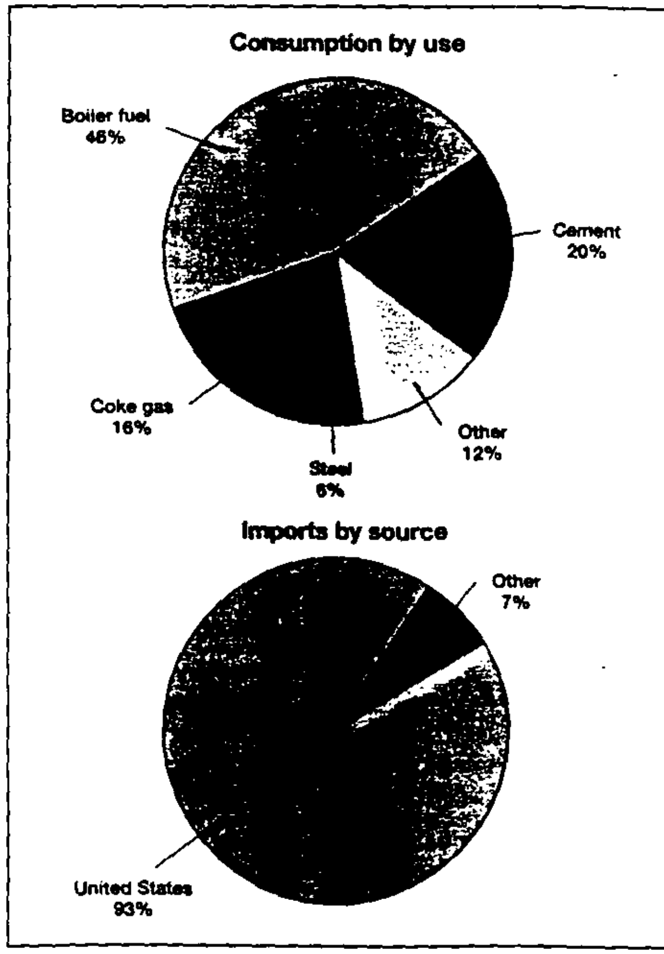

Fig. 7—Japanese green petroleum coke market.

The refinery netback price for a U.S. Gulf Coast refinery with its own loading facility would be the theoretical price less any profits, adjustments, etc. An inland refinery would have to include the logistics costs in getting from the refinery to aboard vessel; these could be an additional $5 to $15/ton.

ACKNOWLEDGMENT

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