cc Clair Fancy

Jacksonville Electric Authority

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JEA "POWER TO SERVE"

November 13, 1981

Mr. Kent Williams, Chief
New Source Review Section
Air Facilities Branch
Environmental Protection Agency
Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30308

Dear Mr. Williams:

Subject: JACKSONVILLE ELECTRIC AUTHORITY
ST. JOHNS RIVER POWER PARK UNITS 1 & 2
PSD APPLICATION (PSD-FL-010)
COMMENTS ON REVISED PRELIMINARY DETERMINATION

Attached please find our comments on the Revised Preliminary Determination as it was presented in the Draft Environmental Impact Statement/State Analysis Report, dated October 1981. Although many of our comments are editorial in nature, several are substantive and may require further discussion before an appropriate resolution can be made. Please review these comments as soon as possible and let us know if you feel that a meeting will be necessary to resolve any of the issues identified. If possible, we would like to see these issues resolved prior to the public hearings which are scheduled to begin on 12/1/81.

Thank you for your immediate attention to this matter.

Sincerely,

Richard Breitmoser DTF

Richard Breitmoser
Division Chief
Research and Environmental Affairs

RB/pag
Att.

cc: D. Lucas
D. Fulle
D. A. Moehle
R. Lyles
L. Leskovjan
J. E. Hagan (EPA)
H. Oven (FDER)
File

COMMENTS ON PSD REVISED PRELIMINARY DETERMINAITON (RPD)

Page 1, Section III

Issue: A maximum heating value for the No. 2 fuel oil to be burned in the auxiliary boilers is specified.

Resolution: The words "a maximum higher heating value of 19,567 Btu/lb" should be changed to "an approximate heating value of 19,500 Btu/lb" to allow for fluctuations in oil heating value that are normally expected and to make the condition consistent with a similar condition in FDER's Conditions of Certification.

Page 2, Section III

Issue: "Coal will be transferred from the marine terminal to the proposed plant site by shuttle train."

Resolution: The words "or other means of coal transport" should be added to the above sentence because alternate means of coal transfer are still under investigation and may ultimately be chosen. The method of coal transport chosen should have no measurable effect on air quality.

Page 2, Section III

Issue: "Dry" storage silos for limestone.

Resolution: This should be changed to "day" storage silos.

Page 5, First Paragraph

Issue: Reference to the No. 2 fuel oil which will be used to fire the auxiliary boilers. It is indicated in two places that the oil will have a sulfur content of 0.76% by weight.

Resolution: The words "a maximum" should be inserted before 0.76 wt % sulfur fuel oil in both places to allow for normal fluctuations in fuel oil sulfur content.

Page 5, Third Paragraph

Issue: Typo in third paragraph.

Resolution: The word "fo" should be changed to "to" on the 12th line of that paragraph.

Page 5, Sixth Paragraph

Issue: Reference to sealed trucks for fly ash transport to landfills.

Resolution: Sealed trucks will be used for transport of fly ash for sale. However, since fly ash to be transported to the landfills will be wetted prior to loading into trucks, the use of sealed trucks is unnecessary and is not planned.

Therefore, the sentence should be modified to read: "Transfer of fly ash for sale will be by sealed trucks and of fly ash for disposal by dump trucks."

Page 6, First Paragraph

Issue: A fuel oil ash content of 0.01 wt. % is specified.

Resolution: The words "an ash content of 0.01 wt. %" should be changed to "a maximum ash content of 0.01 wt. %" to allow for normal fluctuations in fuel oil ash content.

Page 6, Third Paragraph

Issue: The requirement for setting a CO emission limitation during NO_x performance testing as well as the requirement for controlling NO_x and CO emissions using a flue gas oxygen meter are unnecessary.

Resolution: As indicated in our comment on Specific Condition 7 on Page 13 of the RPD, a specific emission limit for CO is not feasible. Also, although a flue gas oxygen meter will be used, it will be only one of several means for controlling CO and NO_x emissions and, in practice, can only be used as a guideline. Therefore the second, third, and fourth sentences of the third paragraph on page 6 should be deleted.

Page 6, Section IV-B

Issue: The RPD discusses the analysis of existing air quality based on historical data obtained from the New Berlin monitoring site. The results of the on-site monitoring program are now available.

Resolution: The second paragraph of Section IV-B on Page 6 should be replaced with the following:

"Monitoring data for SO_2, NO_x, CO, O_3 and PM were obtained for a site about 0.5 km north of the northeast boundary of the proposed plant site during the period from December 1979 to December 1980. The results of the monitoring program were presented in four quarterly reports which were submitted to EPA as addenda to the PSD application."

The words "Jacksonville International Airport" in the first paragraph on page 7 of the RPD should be changed to "on-site monitoring program."

The second paragraph on page 7 of the RPD should be eliminated.

These changes are based on information submitted to EPA in a letter from D. Moehle to K. Williams dated 10/21/81.

Page 7, Section IV-C

Issue: Various dispersion models which were used in the NAAQS analysis are referred to in this section. Since reanalyses have been conducted for a variety of reasons, the list of models utilized is no longer correct.

Resolution: The first sentence of the first paragraph of the above referenced section should be modified to begin as follows: "The EPA - approved dispersion models CRSTER (modified for use with multiple sources) and ISC were utilized.." This change was described in a letter from D. Moehle to K. Williams dated 10/21/81, as it relates to a revised fugitive dust analysis.

Page 10

Issue: The conclusion on page 10 of the RPD refers to dates on which information was provided to EPA regarding the application. Additional information has been provided since the dates indicated.

Resolution: The dates of the letters providing additional information to EPA regarding the PSD application should be added. These include July 30, 1981; September 8, 1981; and October 21, 1981.

Page 11, Condition 3

Issue: Performance test requirements refer to emission point 3 (auxiliary boilers) and to CO emission test methods.

Resolution: Condition 3 should be modified to refer to performance tests for only emission points 1 and 2 in Table 6 rather than for emission points 1, 2, and 3. Reference to Method 10 should be deleted since a CO emission limit is infeasible. Also the third paragraph of this condition should be modified to refer to emission points 3 through 13 of Table 6 rather than emission points 4 through 13 of Table 6 since the auxiliary boilers should also be exempted from mass emission rate compliance tests.

Page 11, Condition 4

Issue: Requirement for flue gas oxygen meter, as described in an attachment following the general conditions of the RPD.

Resolution: Although the use of flue gas oxygen meters is planned as one of several methods of controlling CO and NO_x emissions, we feel that the requirement as described in the above referenced attachment is not feasible and is unnecessary as indicated in our response to specific Condition 7 on Page 13 of the RPD. CO and NO_x emissions will be monitored directly in the main units and are very small in the case of the auxiliary boilers.

Therefore, the first paragraph of Condition 4 and the attachment regarding use of the flue gas oxygen meter should be deleted.

Page 12

Issue: Typo in second paragraph.

Resolution: Change .7 to .76 in the second line of that paragraph.

Page 12, Condition 6.d

Issue: Typo in condition 6.d on page 12.

Resolution: Change "Dry" storage silos to "day" storage silos in the second line of that condition.

Page 13, Condition 7

Issue: Carbon monoxide emission limitation.

Resolution: Boilers are designed for optimum combustion efficiency and this design inherently minimizes the production of carbon monoxide. It is in the best interest of the utility to minimize CO emissions for both economic (combustion efficiency) and safety reasons. Therefore, JEA will make every attempt to limit CO emissions. However, since the

boiler vendor cannot and will not guarantee a CO emission level, it is not feasible for JEA to comply with a specific CO emission limitation.

The boiler vendor has indicated that optimum boiler operation can be achieved by maintaining minimum excess O_2 while simultaneously keeping CO emissions as low as practicable. This will also be the condition at which NO_x is minimum for normal boiler operation. However, the parametric relationship between NO_x, O_2 and CO will change with:

- boiler load,
- number of ball mills in service
- coal characteristics (volatility, moisture, grindability, etc.)
- coal nitrogen content and heating value.

Consequently, the excess O_2 range suggested by EPA (between the 0.6 NO_x point and max. CO point) may limit boiler flexibility since this range will change as boiler operating mode changes. Since compliance tests are performed at full load, the O_2 end points thus developed may not be valid during other operating conditions.

The design of the steam generators and their combustion systems is such that the NO_x limit will not be exceeded during normal steam generator operation. But if the EPA recommended method based on a specified O_2 range is to govern boiler operation, JEA's flexibility may be unduly limited.

If, instead, monitoring flue gas O_2 is used only as guideline, we would expect no operational limitations to result. We do not agree that the use of O_2 monitoring alone is BACT for NO_x or CO control.

In light of the above, we request that BACT for CO be expressed as follows:

"JEA will utilize boiler combustion controls and burner settings in order that NO_x emission limits may be observed while maintaining CO emissions at the minimum practicable level."

Page 13, Condition 10

Issue: Typo in Condition 10 on page 13.

Resolution: Change Southside (Units 1-4) to Southside (Units 1-5) in the second line of that condition.

Table 1

Issue: The potential emissions from the project, in tons per year, presented in Table 1 are incorrect.

Resolution: The potential emissions should be as follows:

SO_2	41,800
PM	1,670
NO_x	32,700
CO	2,870
VOC	28

These are based on continuous full load operation of the main units and auxiliary boilers and assume worst case fuel conditions.

Table 2

Issue: The fugitive emission and control summary (Table 2) in the RPD has been updated by information submitted in a letter from D. Moehle to K. Williams dated 10/21/81.

Resolution: Replace Table 2 with the updated information attached to the referenced 10/21/81 letter.

Tables 3,4 and 5

Issue The numbers presented in the NAAQS Analysis Summary (Table 3), the Class II Increment Analysis (Table 4), and the Class I Increment Analysis (Table 5) in the RPD have been updated by information submitted in a letter from D. Moehle to K. Williams dated 10/21/81.

Resolution: Revise Tables 3,4 and 5 based on Exhibits 4,2, and 3, respectively, attached to the referenced 10/21/81 letter. The changes result from (1) use of on-site monitoring data for background instead of historical data from the New Berlin Site, (2) the increase in unit heat input from 5928 to 6144 MMBtu/hr, (3) consideration of the auxiliary boilers, and (4) revisions in the fugitive dust calculations.

Table 6

Issue: Some of the numbers presented in Table 6 (allowable emission limits) of the RPD need to be revised for various reasons.

Resolution: The following revisions to Table 6 should be made for the following reasons:

a. The numerical emission limits for the auxiliary boilers (emission Unit 3) are not appropriate since they are estimated emissions rather than guaranteed values. The

potential boiler vendors have indicated that they do not guarantee specific emission rates. We believe that BACT for the auxiliary boilers is the use of low sulfur, low ash fuel rather than any specific control technology. Hence, given the use of a specific fuel as BACT (as required in Specific Condition 5) and the fact that no control technology is used, there is no need for specific emission limitations, especially if one considers that the auxiliary boilers will only be operated about 5% of the year.

b. The ship unloading facility storage pile emission limit should be 1.6 lbs/hr rather than 1.5 lbs/hr; this difference is apparently due to a rounding error.

c. The emission limits for Emission Units 10 and 11 should be modified so that one refers to points where control is by wet suppression and the other refers to points where control is by dry collection. It is suggested that Emission Unit 11 refer to the 11 dry dust collection points and that the emission limits be 0.1 lbs/hr (each). It is suggested that Emission Unit 10 refer to the six wet dust suppression points and that the emission limits be 5 lbs/hr (each).

d. The emission limit for Emission Point 14 (Limestone Rail Dumper) should be changed to 0.4 lbs/hr from 0.1 lbs/hr in accordance with the information submitted to EPA regarding this system in the 7/30/81 letter from D. Moehle to K. Williams.

RESPONSES TO FDER INTERROGATORIES (APRIL 28, 1981)

Question 1: JEA used tall stacks at Kennedy and Southside Generating stations for modeling, however, at this time (4/20/81) JEA is not taking steps to construct said tall stacks. Please explain.

Response: The only analysis in the Site Certification Application which explicitly included the Kennedy and Southside Generating Stations is the worst-case year analysis, the results of which are presented in Table 5.3-1. Tall stacks were used in the analysis since at that time it was assumed that they would definitely be built. However, in accordance with recommendations from EPA Region IV, the detailed analysis for determination of compliance with ambient standards did not explicitly consider these sources. Kennedy and Southside (at their existing stack heights) were implicitly considered in these analyses through the background air quality concentrations determined from the on-site monitoring program; only the proposed source, Northside, and St. Regis were explicitly modelled.

The JEA has entered into contract with the Southern Company to purchase 600 MW of coal generated electric power. Transmission lines to bring this power into Florida are currently under construction. The first of two 500 kv transmission lines will be in service by August, 1982. The second line will be in service by January, 1983. The effect of this large block of purchased power is to reduce the need for power generation from the Southside and Kennedy Generation Stations. The exact degree of reduced generation, however, is unknown at this time.

If the Kennedy and Southside units are removed from service or greatly reduced in output, the JEA will recommend that tall stacks not be constructed.

A rigorous study of the import power operating mode is currently underway. The results of that study will be made available immediately upon completion.

Question 2: JEA should specifically define the operational state of the Kennedy and Southside Generating Stations, and model accordingly. These operational states should be clearly expressed as permit conditions for the Coal Fired Units.

Response: Suggested by FPL. The operational stations of Kennedy and Southside should not be expressed as permit conditions for SJRPP. They already have approved permits; we do not wish to limit their capabilities and affect system reliability. Please see the response to Question 1.

Question 3: JEA has used differing input data for the modeling efforts presented in this application and their PSD application. Please explain.

Response: The differing input includes differences in background concentrations and emissions inventories. Because the on-site monitoring program was not completed at the time of the May, 1980 PSD application, the background estimates were based on regional air quality monitoring data supplied by the Jacksonville Bio-Environmental Services Division (BESD). The background values presented in the SCA/EID in January, 1981 were based on the results of the on-site monitoring program and were submitted to EPA as an addendum to the PSD application in November, 1980.

The original emissions inventory for PSD increment consuming sources and ambient emissions sources was performed in March, 1980, by canvassing the various DER offices and the BESD. This inventory was included in modeling runs that were used to develop ground-level pollutant concentrations estimates for the May, 1980 PSD submittal. Pursuant to requests by EPA during the initial review of the PSD application, an additional inquiry was made of the regulatory agencies in June of 1980 regarding the inventory of increment consuming sources. This inquiry resulted in some changes to the emission inventory modeling input. The resulting re-analysis was submitted to EPA on July 8, 1980. Correspondence with the Department of Environmental Regulation personnel in November, 1980 regarding the baseline date indicated that an additional PSD increment consuming source existed outside the Jacksonville area which had not been considered in the earlier analyses. The latest inventory was used for modeling input for the SCA/EID submittal in January, 1981. Although the emissions inventories vary somewhat, the resultant differences in ground-level concentrations are not significant.

Question 4: JEA expresses that PAL was used to model fugitive emissions, however, results are not presented. Please provide results.

Response: The following pages present the PAL computer output used to estimate the highest and second highest fugitive emission impacts for comparison to PSD and NAAQS standards. As indicated in Section 5.3.1.2 of the SCA/EID, PAL was run on 18 "worst case" days of meteorological data which were selected based on a CRSTER run using the entire year of 1973 as meteorological input. Because of the relatively large TSP emission rate from the main boilers and the low release heights of the fugitive emissions, the other more distant TSP sources in the emissions inventory were not included in the PAL modeling. The relative impacts from these other sources are very small due to their relatively small emission rates, high release heights and exit velocities, and greater distances from the receptor points which are located in the vicinity of the plant property boundary.

Question 5: In order to better evaluate the isopleths presented throughout the text, please identify the computer run used to generate the specified.

Response: The attached computer printouts were used to generate the air quality isopleths presented in the text:

Figure 5.3-2 - Predicted Annual Average SO_2 PSD Increment Comsumption

Figure 5.3-3 - Predicted Annual Average TSP PSD Increment Consumption

Figure 5.3-4 - Predicted Highest, Second-Highest 24-Hour Average SO_2 PSD Increment Consumption

Figure 5.3-5 - Predicted Highest, Second-Highest 3-Hour Average SO_2 PSD Increment Consumption

Figure 5.3-6 - Predicted Highest, Second-Highest 24-Hour Average TSP PSD Increment Consumption

Figure 5.3-7 - Predicted Annual Average SO_2 Ambient Impacts

Figure 5.3-8 - Predicted Highest, Second-Highest 24-Hour Average SO_2 Ambient Impacts

Figure 5.3-9 - Predicted Highest, Second-Highest 3-Hour Average SO_2 Ambient Impacts

Figure 5.3-10- Predicted Annual Average TSP Ambient Impacts

Figure 5.3-11- Predicted Highest, Second-Highest 24-Hour Average TSP Ambient Impacts

Figure 5.3-12- Predicted Annual Average NO_2 Ambient Impacts

Question 6: The dispersion modeling output needs to be received in order to determine correct use of the models and proper interpretation. Many other questions concerning the modeling can be answered when by looking at this output.

Response: Copies of dispersion modeling output are attached for the following analyses:

a. Worst-Case Load Analysis-Plant by Itself

b. Five-Year Analysis-Major Sources

c. Highest and Second-Highest PSD Class II SO_2 Concentrations

d. Highest and Second-Highest PSD Class II TSP Concentrations

e. Highest and Second-Highest PSD Class I SO_2 Concentrations

f. Highest and Second-Highest Ambient SO_2 Concentrations

g. Highest and Second-Highest Ambient TSP Concentrations

Question 7: The baseline date used, November 25, 1977, is incorrect. The correct dates are December 27, 1977 for particulate matter and July 9, 1980 for SO_2.

Response: After discussing the question of baseline date with L. George of FDER and A. Lee of EPA Region IV, we were directed to Bill Wagner of EPA Region IV on December 9, 1980. Mr. Wagner indicated to us in a telephone conversation on that date that the baseline date was set for both SO_2 and TSP statewide (except for nonattainment areas) on November 25, 1977 when the Occidental Chemical White Springs PSD application was deemed "complete".

However, even if this information is not correct, and the baseline dates are in fact December 27, 1977, and July 9, 1980, for SO_2 and TSP, respectively, the emission inventories modelled are correct since Occidental Chemical would be the only source subject to possible deletion, and it appears to be a "major" source which must be modelled regardless of the baseline date.

Question 8: The JEA conducted a noise survey of the area in and around the project site. Please advise whether the noise meter was operated in the "slow" or "fast" response mode.

Response: It was operated in the "slow" response mode.

Question 9: The JEA noise survey reflects that exceedances of the EPA 55dB(A) guideline will occur. What provisions will JEA use to resolve noise complaints?

Response: Many noise control measures are being taken in the design and construction of the plant to minimize noise levels in plant and off site. Because the EPA guideline of 55dB(A) may be exceeded, does not necessarily mean that complaints will occur at and above that level.

Complaints will be investigated on a case-by-case basis in accordance with existing JEA policy. If the situation warrants, a noise survey will be conducted at the location of the complaint, first to verify the validity of the complaint, and second to determine the exact source of the noise. If feasible, appropriate corrective actions will be taken.

Question 10: Since annoyance and perceived loudness are a function of frequency, did JEA perform any spectrum analysis, and if so, please provide such data.

Response: No spectral analyses of the existing ambient noise were performed, primarily because of the character of the existing noise. The existing noise can be described as "white" noise. That is, the power per-unit of frequency is substantially independent of frequency over the audible range of the human ear. No pure tones were noted by the monitoring personnel. A spectral analysis would be more appropriate after the plant is in operation.

Question 11: In projecting the noise from the construction of the power plant, was the noise contribution from the concurrent construction of the coal handling facility at Blount Island included?

Response: Yes, but its contribution was insignificant because of the spatial separation and the more dominant noise levels from construction of the main plant, which is between the nearest residence and Blount Island.

Question 12: The projected noise levels as shown in Figure 4.1-6 do not agree with noise levels already measured at one mile from the site. Please explain.

Response: The projected ambient levels shown in Figure 4.1-6 show only the contribution of plant construction activities to the noise level at one mile. Existing ambient noise levls are not included. As a rule-of-thumb, if the existing level is equal to the projected plant contribution, the combined level will be three decibels higher than the existing ambient. If the difference in decibel levels is about two decibels, add two decibels to the higher level to obtain the combined noise level. If the difference is six decibels, add one decibel to the higher level, and if the difference is greater than ten decibels, the lower level can be ignored entirely. Thus, as indicated in the text of the SCA/EID, the maximum noise level predicted is 57dB(A) which is a result of combining the existing noise level and the construction impact.

Cooling Tower Drift

Question 1: JEA addresses biological effects of salt deposition, but does not reflect impact as a result of corrosion. JEA should comment on this aspect.

Response: A number of corrosion tests have been performed on a variety of materials. Those materials of particular interest in the area of the proposed plant site include steel, aluminum and aluminum alloys, tin, and concrete.

Cast carbon steels tested at a marine location and an industrial location exhibited a corrosion rate of 0.5 mils per year (mpy) at both locations. (One mil is equivalent to one thousandth of an inch.) Steels alloyed with nickel, chromium, or copper will corrode at a lower rate. The maximum annual average salt deposition rate from the cooling towers outside the site boundary is predicted to be 0.5 $mg/m^2/hr$ in the site vicinity. Combining this with a reported natural deposition rate of 0.42 mg/m^2 yields a total deposition rate of 0.92 $mg/m^2/hr$. This rate is 18.4 percent of that recorded at the shoreline. Thus, the corrosion rate of steel exposed to the 0.92 $mg/m^2/hr$ should be less than the 0.5 mpy observed at the shoreline where a deposition rate approaching 5 $mg/m^2/hr$ was recorded. The exact rate is difficult to predict since it is affected by local weather conditions, proximity of industry, and other factors. The corrosion rate of steel in the vicinity of the proposed site should not increase by more than 0.1 or 0.2 mpy as a result of any increase in salt deposition (0.2-0.5 $mg/m^2/hr$) due to cooling tower operation.

Corrosion tests on various aluminum alloys have shown that the rate of weathering for both wrought and cast aluminum alloys decreases drastically with time. After one or two years, the maximum rate of attack does not exceed 0.11 mpy for the most severe seacoast conditions and may approach 0.03 mpy for less severe atmospheres. The average corrosion rate does not exceed 0.04 mpy for atmospheric exposure. The addition of 0.5 mg/m^2hr or less of salt to the atmosphere would have a negligible effect on the existing aluminum corrosion rate in the vicinity of the proposed plant.

The corrosion rate of tin, based on ten years of exposure tests conducted by ASTM, ranges from 0.02 mpy in rural atmospheres to 0.09 mpy in marine atmospheres. The addition of 0.5 $mg/m^2/hr$ to the background of 0.42 $mg/m^2/hr$ yields a total rate which is only 18.4 percent of the deposition recorded at the seacoast and would therefore not significantly affect the atmospheric corrosion rate of tin in the vicinity of the site. What are commonly referred to as tin roofs are often galvanized steel. Zinc coatings are unaffected by changes in salt content, corroding at the rate of 0.1-0.3 mpy in most atmospheres.

Concrete has widespread use in marine environments, including seawater immersion. This widespread use attests to its excellent resistence to attack by aqueous chlorides (salt). Due to the resistant properties of concrete, the low concentration of salt deposited as a result of cooling tower drift would not pose a problem.

Question 2: JEA should comment on the depostion of other material, other than salt, as a result of the emissions from the cooling tower.

Response: The salt deposition values presented include a number of elements other than the major components, chlorides and sulfates. The salt concentration value used in the dispersion modeling was the total dissolved solids (TDS) as determined by the water quality analyses of the recirculating cooling water source. A water quality analysis was conducted for a number of the elements which comprise the TDS. The selection of elements for analysis was based on engineering, environmental, and human health factors. The predicted deposition of these elements, keeping in mind that they are a fraction of the salt deposition numbers, can be determined by computing a ratio of the elemental concentration in the recirculating water to the TDS concentration used in the dispersion modeling. The element deposition rate is the product of this ratio and the salt deposition isopleths. A list of the elements analyzed for, the corresponding ratios, and the annual deposition vlaues are presented in Table 1.

The background soil concentrations, estimated soil concentration increase, and percent increase are presented in Table 2. It should be noted that the annual deposition values presented in Table 2 are a fraction of the salt deposition numbers and should not be added to the salt deposition numbers presented in the SCA/EID.

None of the elements analyzed for would be deposited in an amount greater than 1 $mg/m^2/yr$, with the exception of bromine. The percent increase of bromine over the 40-year plant life, assuming all the bromine deposited remains in the top 25 cm of the soil, is only 3 percent at the 0.2 $mg/m^2/hr$ isopleth and 7.5 percent at the 0.5 $mg/m^2/hr$ isopleth. In the existing saline environment, these predicted percent increases are considered to be insignificant. Given the small percent increases from the other trace elements analyzed, no significant impact from trace elements in cooling tower drift is anticipated.

Question 3: What impact from the cooling towers emissions and the project site itself, can be expected on the new cars stored at Blount Island?

Response: Cars are typically stored for five to eight days at Blount Island, with five being the typical time, before being shipped to dealers or distributors. Based on the response to Question 1 above (Cooling Tower Emissions) no adverse effects are anticipated on the cars stored at the Blount Island facility due to the low predicted salt deposition rates, the short storage period, and the rust preventative techniques applied to the cars.

Sulfur oxides and particulate matter are two of the projected emissions from the proposed plant with the potential for damaging the new car finishes. Sulfur oxides accelerate the corrosion of metals and the erosion of building stone, while airborne particles soil fibers and structures. Corrosion products were observed on untreated iron surfaces after exposure to 260 ug/m^3 SO_2 for six to eight weeks, while corrosion was evident after a few hours exposure to 4×10^5 ug/m^3 SO_2. For particulates, a concentration of 45 ug/m^3 is thought to be that concentration below which soiling would not increase the cost of cleaning activities.

The predicted SO_2 concentration for the new car storage area on Blount Island ranges from 13-15 ug/m^3 as an annual average. Maximum predicted SO_2 concentration for all sources including the proposed plant is 600-900 ug/m^3 for a 3-hour average. The total suspended particulate (TSP) concentration predicted to occur in the vicinity of the Blount Island car storage area is 31 ug/m^3 on an annual average.

TABLE 1

POTENTIAL DEPOSITION OF TRACE ELEMENTS
FROM COOLING TOWER DRIFT

Element	Maximum Concentration After 1.5 Cycles of Concentration[a] (mg/l)	Element to Total Dissolved Solids Ratio	Annual Deposition ($mg/m^2/yr$)[b]	
			0.2 $mg/m^2/hr$ Salt Deposition Isopleth	0.5 $mg/m^2/hr$ Salt Deposition Isopleth
Arsenic	0.0015	3.1×10^{-8}	5.4×10^{-5}	1.3×10^{-4}
Beryllium	0.00029	5.9×10^{-9}	1.0×10^{-5}	2.5×10^{-5}
Boron	6.9	1.4×10^{-4}	2.4×10^{-1}	6.1×10^{-1}
Bromine	78	1.6×10^{-3}	2.8	7.0
Cadmium	0.0033	6.8×10^{-8}	1.2×10^{-4}	2.9×10^{-4}
Chromium	0.0075	1.5×10^{-7}	2.6×10^{-4}	6.5×10^{-4}
Copper	0.36	7.4×10^{-6}	1.3×10^{-2}	3.2×10^{-2}
Fluorine	0.84	1.7×10^{-5}	2.9×10^{-2}	7.4×10^{-2}
Lead	0.14	2.9×10^{-6}	5.1×10^{-3}	1.3×10^{-2}
Manganese	0.132	2.7×10^{-6}	4.7×10^{-3}	1.2×10^{-2}
Mercury	0.009	1.8×10^{-7}	3.1×10^{-4}	7.8×10^{-4}
Nickel	0.18	3.7×10^{-6}	6.5×10^{-3}	1.6×10^{-2}
Selenium	0.0015	3.1×10^{-8}	5.4×10^{-5}	1.3×10^{-4}
Tin	1.4	2.8×10^{-5}	4.9×10^{-2}	1.2×10^{-1}
Zinc	0.29	5.9×10^{-6}	1.0×10^{-2}	2.6×10^{-2}

[a] Envirosphere Water Quality Analysis

[b] Refer to Figures 5.4-9 Through 5.4-12

TABLE 2
ESTIMATED TRACE ELEMENT CONCENTRATIONS IN THE SOIL
FROM COOLING TOWER DRIFT

Element	Average Background Soil Concentration[a] (ppm)	Estimated Soil Conc. Increase[d] (mg/kg/yr)		Percent Increase Due To Emissions From The Proposed Cooling Towers[e]			
				Per Annum		40 Year Plant Life	
		0.2 $mg/m^2/hr$ Salt Deposition Isopleth	0.5 $mg/m^2/hr$ Salt Deposition Isopleth	0.2 $mg/m^2/hr$ Salt Deposition Isopleth	0.5 $mg/m^2/hr$ Salt Deposition Isopleth	0.2 $mg/m^2/hr$ Salt Deposition Isopleth	0.5 $mg/m^2/hr$ Salt Deposition Isopleth
Arsenic	6	1.44×10^{-7}	3.46×10^{-7}	2.4×10^{-6}	5.76×10^{-6}	9.6×10^{-5}	2.3×10^{-4}
Beryllium	6	2.67×10^{-8}	6.67×10^{-8}	4.4×10^{-7}	1.11×10^{-6}	1.78×10^{-5}	4.4×10^{-5}
Boron	10	6.4×10^{-4}	1.62×10^{-3}	6.4×10^{-3}	1.62×10^{-2}	2.5×10^{-1}	6.5×10^{-1}
Bromine	10[b]	7.47×10^{-3}	1.87×10^{-2}	7.46×10^{-2}	1.86×10^{-1}	2.98	7.5
Cadmium	0.06	3.2×10^{-7}	7.73×10^{-7}	5.3×10^{-4}	1.28×10^{-3}	2.13×10^{-2}	5.15×10^{-2}
Chromium	100	6.93×10^{-7}	1.73×10^{-6}	6.9×10^{-7}	1.73×10^{-6}	2.77×10^{-5}	6.9×10^{-5}
Copper	20	3.46×10^{-5}	8.53×10^{-5}	1.73×10^{-4}	4.26×10^{-4}	6.9×10^{-3}	1.70×10^{-2}
Fluorine	200	7.73×10^{-5}	1.97×10^{-4}	3.86×10^{-5}	9.85×10^{-5}	1.5×10^{-3}	3.93×10^{-3}
Lead	10	1.36×10^{-5}	3.44×10^{-5}	1.35×10^{-4}	3.43×10^{-4}	5.44×10^{-3}	1.37×10^{-2}
Manganese	850	1.25×10^{-5}	3.2×10^{-5}	1.47×10^{-6}	3.76×10^{-6}	5.88×10^{-5}	1.5×10^{-4}
Mercury	0.1	8.26×10^{-7}	2.08×10^{-6}	8.25×10^{-4}	2.08×10^{-3}	3.3×10^{-2}	8.3×10^{-2}
Nickel	40	1.73×10^{-5}	4.26×10^{-5}	4.32×10^{-5}	1.06×10^{-4}	1.72×10^{-3}	4.25×10^{-3}
Selenium	0.5	1.44×10^{-7}	3.46×10^{-7}	2.88×10^{-5}	6.92×10^{-5}	1.15×10^{-3}	2.76×10^{-3}
Tin	200[c]	1.31×10^{-4}	3.2×10^{-4}	6.5×10^{-5}	1.59×10^{-4}	2.6×10^{-3}	6.4×10^{-3}
Zinc	50	2.67×10^{-5}	6.9×10^{-5}	5.3×10^{-5}	1.38×10^{-4}	2.14×10^{-3}	5.5×10^{-3}

[a] U.S. Fish and Wildlife Service, 1978
[b] Horton et al., 1977
[c] Environmental Research and Technology, 1978
[d] Refer to Appendix A - Table A-30 for soil concentration increase formula
[e] Refer to Table 5.3-18

Since the predicted long-term SO_2 concentration (13-15 ug/m^3) is below that where corrosion products were observed (260 ug/m^3) and the maximum short-term concentration of 600-900 ug/m^3 is below that where corrosion products were observed (4×10^5 ug/m^3), and considering the short time period that the cars would be exposed to these low SO_2 concentrations, no adverse effects to the car finishes due to SO_2 are anticipated.

The predicted TSP concentration (31 ug/m^3) is below the concentration reported as the threshold above which additional cleaning costs due to soiling would be incurred. However, the highest 24-hour TSP concentration observed during the on-site monitoring (61 ug/m^3 exceeds this 45 ug/m^3 threshold), which suggests that a soiling problem may exist. However, no problems with car finishes were reported by representatives of the companies operating the car unloading facilities at Blount Island. Thus, it is not anticipated that any adverse soiling effects would occur due to the small increment to be added by the proposed project.

Coal Unloading Facility Blount Island

Question 1: Does JEA recognize the potential problems from locating their coal unloading facility immediately next to a new car storage facility?

Response: The potential for damage to new car finishes exists at the Blount Island coal unloading facility as it would at or near any industrialized area.

It has been reported that iron particles from industrial operations resulted in the staining and pitting of auto finishes. Cars parked near brick buildings being demolished have been damaged by alkali mortar dust during humid weather. A sticky material emitted from oil-fired power plants, termed acid smut, has also been linked to the damage of automotive finishes.

The only atmospheric emission from the coal unloading facility with the potential to damage automotive finishes is the coal dust. Without knowing the chemical composition of the coal, it is difficult to predict what the actual effect of coal dust will be on automotive finishes. However, there have been no reports of coal dust affecting new car finishes from the auto manufacturing representatives questioned.

Coal Blending

Question 1: Will coal blending be utilized at this project to reduce potential SO_2 emissions? If so, what type of blending system will be used?

Response: Coal blending has been considered for the SJRPP project. Plans are now being made to incorporate the capability to readily retrofit coal blending at the Blount Island coal unloading facility for water-borne transport. Retrofit of coal blending capability would be implemented should it be shown to be cost-effective in the future. Currently, the capability of the boiler and AQCS to use a wide range of coal from the eastern U.S. makes blending unnecessary, and current economics do not justify its incorporation.

Plans are currently being made to provide the capability to retrofit a blending system capability based on a bucket-wheel reclaimer and a slewing stacker, mounted on common rail system.

Coal Piles

Question 1: What means will be used, or available to prevent or fight fires within the coal pile?

Response: Fires within the coal may occur due to spontaneous combustion of loose coal left undisturbed for extended periods. The coal stored in the active storage system will be cycled in and out over a relatively short period (one to three days) and should not present a serious problem. The coal in inactive storage will be compacted carefully to control spontaneous combustion. Recommendations in the Coal Handling System Study call for two bulldozers and a front-end loader to support coal operations. Should a coal fire occur, this equipment may be used to dig it out and extinguish it. Once the burning coal is dug out and the fire extinguished, the smoldering coals may be quenched using the fireplugs and hoses provided with Fire Protection System. Fireplugs are located every 500 ft. around the periphery of the coal storage area.

FGD

Questions 1 & 2: Does JEA intend to effect HCL removal ahead of the SO_2 removal system in order to minimize chemical consumption and purge requirements?

Has JEA defined the parameters of the purge system necessary to prevent the accumulation of chlorides and magnesium in the circulating solution?

Response: The conceptual arrangement of the FGDS uses a purge flow of water to maintain the chloride level below 3,500 ppm. This purge flow will also produce low magnesium concentrations. Use of a separate chloride stripper ahead of the FGDS was considered. The design of such a stripper leads to a situation where extremely corrosive conditions (pH less than or equal to 1.0, chloride in excess of 100,000 ppm) would exist. To date, we know of no FGDS chloride stripper operating under such severe conditions. We feel that the chloride stripper would produce a considerably less reliable system than our current FGDS conceptual arrangement.

RESPONSES TO BESD INTERROGATORIES (MARCH 25, 1981)
TRANSMITTED THROUGH FDER (MARCH 30, 1981)

Question A: ESP - which of the following instruments will be provided with the ESP?

1. Primary voltage
2. Primary current
3. Secondary current
4. Secondary voltage
5. Gas temperature (outlet)
6. Fan motor current
7. Fan inlet and outlet static pressure taps
8. Hopper level indicator
9. Rapper activation indicator board

What is the size and slope of the hopper?
What type discharge equipment is on the hopper?
What provisions for gas distribution through the ESP has been made?
What explosion and fire protection in the ESP is provided?
What type of rappers will be used?
What degree of accessibility to the ESP is provided? i.e., number, size and location of hatches?
What type of hatch gaskets are proposed?
What construction materials will be used for the ESP?
What type of electrodes are proposed?
What will be the plate spacing?
Show assumptions and calculations used in sizing the ESP, including particle resistivity, particle size distribution, etc.

Response: The control system for the electrostatic precipitator utilizes a microprocessor to monitor primary voltage and current, secondary voltage and current, hopper level, the status of the rapping system and the flue gas temperature in the precipitator. Additional instrumentation such as induced draft fan motor current, and inlet and outlet static pressures will be monitored by other plant systems.

The hoppers are sized for a 12 hour storage capacity when firing coal with maximum ash and minimum heating value, at full load. The hoppers will have a minimum of a 60 degree slope. Fly ash removal from the hoppers will be effected using a pressurized pneumatic conveying system which will be controlled by a micropressor. This system would be capable of removing fly ash on an hourly basis from each hopper.

To assure that proper flue gas distribution to the precipitator is established, the precipitator manufacturer will conduct a model study to determine the type, size and location of such distribution devices as required. In addition, the manufacturer will conduct air flow tests on the installed precipitator to assure that proper gas distribution can be achieved. Furthermore, emergency flue gas balancing dampers are provided to correct gross deviations in gas flow distribution and would be employed until such time that the manufacturer can make corrections to gas distribution devices.

A fire protection system is provided for the precipitator control room and electrical power supplies.

Precipitator rappers can either be the mechanical drive type or the electromagnetic impluse type depending upon the precipitator manufacturer selected.

Access to the precipitator and associated ductwork will be provided to facilitate inspection and maintenance. Since the location, type and size of the access hatches is dependent upon a particular manufacturers design, the exact nature of these facilities cannot be determined until a manufacturer is selected. However, design specifications do require the use of four precipitator casings for each steam generator. Further, each casing will be provided with man-safe isolation devices to facilitate on-line maintenance.

The precipitator casing and hoppers along with associated ductwork will be constructed of ASTM A-242 material. Collecting and discharge electrodes will be constructed of mild steel.

The centerline to centerline distance between electrodes will be 12 inches on a nominal basis.

Rigid type discharge electrodes will be the only type considered for this project.

Due to the broad range of fuels to be fired and the lack of coal specific data, a conservative sizing approach based on field experience of various precipitator manufacturers was used to develop a minimum precipitator size based on 0.5 percent sulfur content coal. Further, the selected manufacturer will have to demonstrate using the EPA precipitator computer program, that the sizing is sufficient. Further, a design margin of 20 percent will be added to the base precipitator size.

Question B: FGD Scrubber - which of the following instruments are provided on the FGD, and where will they be located?

1. Static pressure taps/meters
2. Gas temperature
3. pH of absorber
4. Liquid pressure to nozzle header
5. Fan motor current
6. Liquid temperature
7. Liquid flow rates
8. Other

What is the schematic flow configuration of the FGD?
What construction materials are to be used?
What is the recycle tank capacity?
What is the size, type and location of nozzles?
What type mist eliminator is proposed?
What provisions are made for accessibility to the FGD System?
What method is proposed for solids removal?
Will a thickener tank be employed?
If a thickener is to be used, what are the dimensions and the detention time?

Response: The conceptual flow diagrams (SK-ACE-FGD-3, 4, 5 and 6) are attached hereto. These diagrams also show all required process control instrumentation labeled (AECNTRL). The nature of these diagrams is such that minor modifications will be required to reflect the experience and technology of the selected FGDS manufacturer.

FGDS materials of construction will consist of high nickel alloys such as 904L alloy, Hastelloy G and C-276 and Inconel 625. Specific material selection will be dependent upon the type of service, pH and chloride concentrations.

The absorber recycle tank will have a minimum retention time of ten minutes to allow for chemical reactions to equilibrate.

FGDS nozzles will be constructed of silicon carbide and located as appropriate to provide for uniform flow patterns, complete and intimate mixing and contact between the flue gas and slurry droplets.

Mist eliminators will be of the open, multipass type located horizontally. Accessibility to the FGDS will be provided via access hatches with the use of man-safe isolation devices to permit on-line maintenance. A spare module will be provided to permit full load operation while maintaining any module.

Calcium sulfate solids will be removed from the FGDS through the use of hydrocyclones and vacuum filters to produce a stable material in cake form. It is not planned to use thickeners.

Question C: Fabric Filters for Coal Handling System

What are the sizes and configurations, including gas flows, A/C ratios, number of bags, bag materials to be utilized?
What type of bag cleaning will be used?
Which of the following instruments will be used?

1. Baghouse inlet and outlet static pressure taps/meters
2. Fan inlet and outlet static pressure taps/meters
3. Temperature
4. Fan motor current

What is the size and shape of hoppers?
What type discharge equipment will be used on the hoppers?
What is the ultimate means of dust disposal?
What fire and explosion protection is provided?
What construction materials will be used?
What is the number, size and shape of blast plates?
What type of bag hanger and thimble arrangements are proposed?

Response: Dust collection shall be provided for the following facilities (see attached flow diagrams, M-022260-01/02):

COLLECTOR

I.	a -	Plant coal storage silos
	b -	Belt conveyors C-7/C-9 transfer
	c -	Belt conveyors C-8/C-10 transfer
II.	d -	Crusher CR-A to Belt Conveyor C-7 transfer including crusher discharge
	e -	Crusher CR-B to Belt Conveyor C-8 transfer including crusher discharge
III.	f -	Surge Bins (for ventilation)
	g -	Belt Conveyors C-2 and C-4 Coal Handling Building discharges and C-4 loading chutes and skirt
	h -	Belt Conveyor C-3 discharge chute
IV.	i -	Belt Conveyor C-1/C-2 transfer
V.	j -	Belt Feeder F-CD to Belt Conveyor C-1 transfer
	k -	Bin CD Hoppers to Belt Feeder F-CD
VI.	l -	Bin LD hoppers to belt Feeder F-LD
	m -	Belt Feeder F-LD to Belt Conveyor L-1

VII. n - Belt Conveyor L-1/L-2 transfer

VIII. o - Main Coal Handling Systems control and electrical equipment room HVAC unit - separate collector for outdoor air intake

* All points under a given Roman Numeral are collected by that collector.

The requested information for each installation if available, is given below according to the respective collector for the above designated facilities.

Item	Resolution
1. Bag House Size	Not available - to be determined by Vendor per spec. 20-80-JEA criteria
2. Total Air Flow	50,800 CFM for Collector 1 Resolution for remaining collectors same as for Item No. 1
3. Air to Cloth Ratio	G to 1
4. No. of Bags	Per Item 1 resolution
5. Bag Material	16 oz. polypropylene or Dacron, fire resistant, grounded
6. Bag Cleaning Method	Reverse air pulse
7. Instrumentation	Dust level switch with remote indication and alarm Differential pressure across the collecto-gage and switch for alarm
8. Hopper Size	10 hours dust holding capacity, 60^{o} slopes, Item 1 resolution applicable
9. Hopper Shape	Conical or Pyramid per Item 1 resolution

	Discharge Equipment	Rotary Discharge valve with antispark end seals, cast iron casing. Totally enclosed dust and ignition proof motor. Valve designed for 150% expected maximum load
	Ultimate Disposal	Discharged material is pneumatically conveyed to coal silos from Collector 1 Discharged material is gravity chuted back into process from remaining collectors. The process fires the coal dust into the boilers. The lime dust is discharged into the FGDS solution.
10.	Protection	
	Fire	Automatic shutdown when process fire protection system is activated, except for underground service where the collector is bypassed, but the fans kept running
	Explosion	Blast doors on housings. Electrical equipment designed for NFPA Std. 70, Class II, Div. 1, Group F Application
11.	Construction Material	Housings, Hoppers, and tube sheets are of 10 gage ASTM A570 material, suitably reinforced to assure parallel bag alignment and (-) 20 in. hg. internal pressure
12.	Blast Gates	1 sq.ft. of gate per 30 to 40 ft^3 of collector volume
13.	Bag Hanger and Thimble Arrangement	Item No. 1 Resolution is applicable

Question D: Continuous Emission Monitors

Regarding the Ebasco memo of October 27, 1980: Is this the total number of Continuous Monitoring Devices (CMD) or the monitors per generating unit?

What is the degree of accessibility of each CMD location for servicing and calibration, inspection, and provision of data acquisition in case of instrument outage?

Response: The information in Ebasco memo dated October 27, 1980, (JEA-IC-147) has been revised. The following are the number of CMDs which will now be provided for each generating unit. The locations and services of the CMDs are given in Figure 1, attached.

1. Two (2) combination NO_x and CO_2 control monitors will be located in the ducts between the air heaters and each pair of precipitators (one in each duct). Performance test ports will be provided for manual measurement of NO_x in each duct between the precipitator and air heater outlet.

2. Eight control transmissometers will be located in the ducts between the precipitators and the induced draft fans. Each of the four precipitator outlet ducts will have two transmissometers. Both transmissometers will be used in conjunction with the precipitator control system. One will be used for backup, but they both will be operating continuously. The Operator selectable signal of each pair of transmissometers will be used in the precipitator control system to optimize control of the precipitator and to provide an alarm to the AQCS Control Room Operator.

3. One EPA approved transmissometer will be located in the duct between the induced draft fan discharge header and the scrubber system inlet header. This transmissometer will be used to monitor opacity for EPA reporting and to provide an alarm to the AQCS Control Room Operator.

4. One combination SO_2/CO_2 EPA approved analyzer and two (2) SO_2 control analyzers will be located in the duct between the induced draft fan discharge header and the scrubber system inlet header.

The combination SO_2/CO_2 analyzer will be used for EPA reporting and to provide an alarm to the AQCS Control Room Operator. The two SO_2 analyzers will be used for scrubber control. One control analyzer will be used as a backup but both control analyzers will be operating continuously. The Operator selectable signal from the two control analyzers will be used for the following:

a. Control of the limestone slurry feed.

b. Calculation of the percentage removal of SO_2.

c. Calculation of inlet pounds SO_2 /MBtu.

Performance test ports will be provided for manual measurement of SO_2 in the duct between the induced draft fan discharge header and the scrubber system inlet header.

5. Eight SO_2 control analyzers will be located in the absorber tower outlet ducts. Each of the four absorber tower outlet ducts will have two control analyzers; one will be used as backup but both will be operating continuously. The Operator selectable signal from each pair of control analyzers will be used for the following:

a. Absorber tower diagnostic.

b. Alarm to AQCS Control Room Operator.

c. Calculation of the percentage SO_2 removed.

d. Calculation of outlet pounds SO_2 /MBtu.

e. Fine tune control on limestone slurry feed.

6. The chimney liner will contain one combination $SO_2/NO_x/CO_2$ EPA approved monitor. Its signals will be used for EPA reporting and to provide alarms to the AQCS Control Room Operator. A diagram of the chimney cross-section at the measurement point is given in Figure 2, attached.

Performance test ports will be provided in the chimney liner for manual measurement of stack emissions.

The chimney is provided with an inside elevator and platforms for access to the CMDs and the performance test ports. The CMDs and performance test ports located on the flue gas ducts will also be provided with access platforms for servicing and calibration purposes.

In the event of an instrument outage, data may be collected manually through performance test ports which will be located near all EPA monitoring ports. Another alternative which may be used for data acquisition is the microprocessor based control system. On an extraordinary basis, the control system may be used as a backup to gather, store and print emissions data. The control system will be designed with the ability to calculate this data using various correlation factors.

Question E: NO_x and CO Emissions

What are the specific contract arrangements with the boiler manufacturer to guarantee that the coal fired units and the auxilliary boiler will meet NO_x and CO emission limits? More specifically, what contractural assurances are there that a repeat of the Northside Unit #3 problems with NO_x and subsequent extensive and expensive boiler reconfiguration will be avoided?

Resonse: Coal-Fired Boilers

Foster Wheeler has guaranteed that NO_x emissions will not exceed 0.6 lb/MBtu at economizer outlet when firing performance fuel. The boiler will have special Low NO_x burners. The only other contractual obligations are expressed in paragraphs 3.1.2.4 and 3.1.2.5 of the Steam Generator contract which is attached.

Auxiliary Boilers

It is our understanding that boilers with maximum inputs of less than 250 MBtu/HR do not have to comply with the NO_x limits of the Clean Air Act. However, the boiler manufacturers will be encouraged to guarantee maximum NO_x emissions of .3 lb/MKB and maximum CO emissions of.05 lbs/MBtu through the specifications in the Bid Package. We understand that these guarantees were recommended by you.

Comparison of this case to Northside No. 3 is not valid because the boiler configuration, boiler manufacturers, and boiler fuel are different.

FDER (3/30) Question B

FDER (3/30) Question D

BLUEPRINT

JEA ST. JOHNS RIVER
POWER PARK

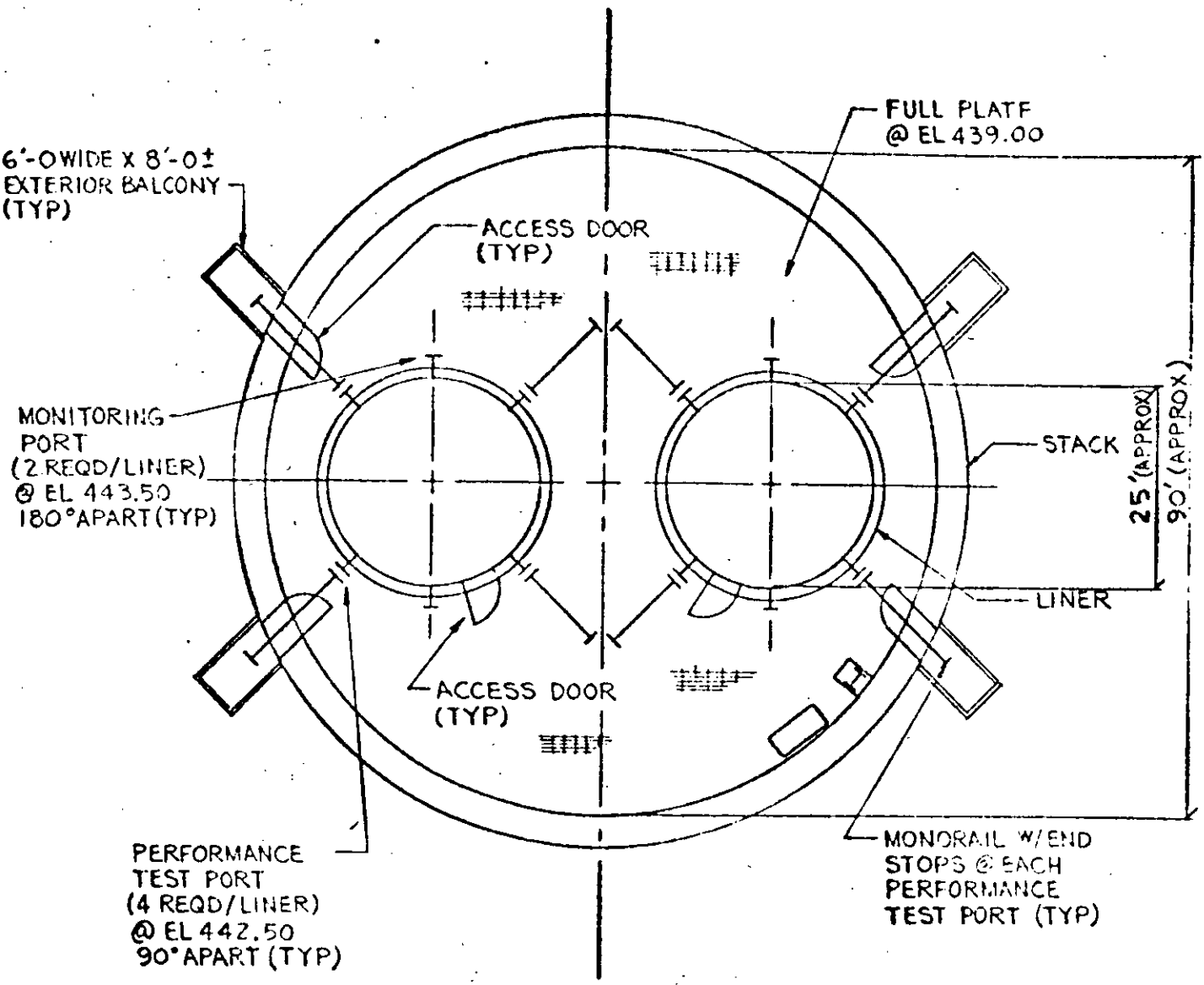
2-600 MW COAL FIRED UNITS
1985-1987

UNIT NO 1

QUESTION D - FIGURE 1

AVAILABLE UPON REQUEST

DER 3/30 # D



INCHES CM.

EBASCO SERVICES INCORPORATED	JACKSONVILLE ELECTRIC AUTHORITY 600MW COAL FIRE PLANT EMISSION MONITORING AND TESTING EQUIPMENT LOCATIONS	Question D FIGURE 2
DIV. I & C DR. EK DATE ____ CH. ____ SCALE ~	APPROVED	

FDER (3/30) Question E

DEL 3/30
Question E

b - Expected sound pressure level measured under "free field" conditions at a distance of 5 ft. from the outline of equipment shown in decibels at the octave band center frequencies ranging from 31.5 to 16,000 Hz, either eight or ten bands, or:

c - Calculated sound power level of the equipment shown in decibels at eight or ten octave band center frequencies ranging from 31.5 to 16,000 Hz and referred to a base of 10^{-12} watts.

3.1.2.1.2 Sound level data shall be provided at maximum capacity rating and at start-up operating conditions of the steam generating unit(s) and all Seller furnished auxiliary equipment.

3.1.2.1.3 In the event that the normal sound level of equipment exceeds the allowable level, at a distance of 5 ft, acoustical treatment features, subject to Purchaser review and acceptance, shall be utilized to achieve the sound level limit specified.

3.1.2.2 No asbestos or asbestos bearing material shall be used as part of the Seller furnished equipment covered by this Specification.

3.1.2.3 No PCB compounds shall be used as part of the Seller furnished equipment covered by this Specification.

3.1.2.4 The equipment furnished under this specification shall, under all normal operating conditions, including start-up, shutdown, load changes and soot blower operation, comply with the New Source Performance Standards for nitrogen oxides as adopted by the United States Environmental Protection Agency in 40CFR Part 60, Subpart Da, Paragraph 60.44a and published in the Federal Register, Volume 44, Number 113, on June 11, 1979. Further, performance testing shall be in accordance with Paragraph 7.1.3.7.

3.1.2.5 Emissions of nitrogen oxides as well as emissions of all other air pollutants regulated under the Clean Air Act (such as, but not limited to, hydrocarbons and carbon monoxide) shall be limited using "Best Available Control Technology" of Contractor's design and manufacture for items of equipment within Contractor's scope.

3.1.3 Guaranteed Performance

3.1.3.1 Guarantee shall be as stated in Bid Item 3: Technical Data, Category 2.0 of the Technical Proposal Form.

3.1.4 Seismic Design Requirements

EBASCO SERVICES INCORPORATED

2/20/81

SPEED LETTER

STRUCTIONS: Originator – Send White and Yellow copies intact to Addressee. Retain Pink copy and destroy when White copy is returned.
Addressee – Prepare reply in duplicate, retain Yellow copy for file, return White copy to Originator.
NOTE: Window envelope (E21201 or E21202) may be used by Originator for Postal mailing.

MESSAGE

TO
Buck Oven
EPA
Tallahassee, Florida

FROM
Doug Fulle
Envirosphere
Norcross, Georgia

SUBJECT

DATE February 18 19 81

For your discussion with Don Lucas of this date, attached please find one copy of the Preliminary Determination regarding JEA's PSD application which was transmitted from DSA on January 14, 1981.

cc D. Lucas

SIGNED Doug Fulle

REPLY

DATE 19

SIGNED

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

RECEIVED
JAN 20 1981
DIVISION CHIEF
NEW FOSSIL GENERATION
EXPANSION PROJECTS

JAN 14 1981

REF: 4AH-AF

Mr. Dale A. Moehle
Division Chief
Jacksonville Electric Authority
Post Office Box 53015
Jacksonville, Florida 32201

RE: New Power Generating Station
PSD-FL-010

Dear Mr. Moehle:

EPA Region IV has reviewed your application to construct the reference source under the provisions of Prevention of Significant Deterioration Regulations (40 CFR 52.21) and has made a preliminary determination of approval with conditions. Please find enclosed two copies of the Preliminary Determination.

A public notice will be run in the near future in a local newspaper, Florida Times Journal. A copy of the summary and your application will be open to public review and comment for a period of 30 days. The public can also request a public hearing to review and discuss specific issues. At the end of this period, EPA will evaluate the comments received and make a final determination regarding the proposed construction.

Should you have questions regarding this information, please contact Mr. Kent Williams, Chief, New Source Review, at 404/881-4552 or Mr. Jeffrey Shumaker of TRW Inc. at 919/541-9100. TRW is under contract to EPA, and its personnel are acting as authorized representatives of the Agency in providing aid to the Region IV PSD program.

Sincerely yours,

Tommie A. Gibbs

Tommie A. Gibbs, Chief
Air Facilities Branch

TAG:JLS:cg

Enclosure

cc. D FOLLE
J JACKSON
C ALTIN
R HARTMAN
WD RETAC
R. [illegible]
D PIKE
FILE 9.7.4

1/31/81

ENVIROPSHERE COMPANY
ATLANTA OFFICE
781 JAN 30 1981
RECEIVED
JEA PROJECT
9.2.2
9.5.1
9.7.4

PUBLIC NOTICE

A new air pollution source is proposed for construction by the Jacksonville Electric Authority near the town of Jacksonville in Duval County, Florida. The source is a new power generating complex that will increase emissions of air pollutants by the following amounts in tons per year:

Sulfur Dioxide	Particulate Matter	Nitrogen Oxides	Carbon Monoxide	Volatile Organic Compounds
9015	377	7117	593	29

The maximum increment consumed by the proposed new source is as follows:

	Annual	24-Hour	3-Hour
Sulfur Dioxide			
Class I	50%	80%	72%
Class II	10%	46%	65%
Particulate Matter			
Class I	10%	20%	--
Class II	12%	46%	--

Note that no allowable 3-hour increments have been established for particulate matter.

The proposed construction has been reviewed by the U.S. Environmental Protection Agency (EPA) under Federal Prevention of Significant Deterioration (PSD) Regulations (40 CFR 52.21), and EPA has made a preliminary determination that the construction can be approved provided certain conditions are met. A summary of the basis for this determination and the application for a permit submitted by the Jacksonville Electric Authority are available for public review in the Information Services Division, City Hall, 200 E. Bay Street, Jacksonville, Florida.

Any person may submit written comments to EPA regarding the proposed modification. All comments, postmarked not later than 30 days from the date of this notice, will be considered by EPA in making a final determination regarding approval for construction of this source. These comments will be made available for public review at the above location. Furthermore, a public hearing can be requested by any person. Such requests should be submitted within 15 days of the date of this notice. Letters should be addressed to:

Mr. Tommie A. Gibbs, Chief
Air Facilities Branch
U.S. Environmental Protection Agency
345 Courtland Street, NE
Atlanta, Georgia 30365

Preliminary 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 the 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 Eastport site, 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 north and 366.3 kilometers east.

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), an auxiliary boiler, and coal, limestone, and fly ash handling facilities. The two proposed steam generators will fire a maximum of 5928 million Btus per hour (MM Btu/hr) each or approximately 282.3 tons per hour each of a medium bituminous coal having a maximum 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.

A 200 MMBtu/hr auxiliary boiler will be utilized to provide start-up and shut-down capability for the two turbine-generating units. The auxiliary boiler will be fired with No. 2 fuel oil having a maximum sulfur content of .76 percent by weight (wt. %) and a maximum higher heating value of 19,000 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 by a shuttle train. 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. Approximately 10,000 tons per day of coal will be unloaded at the proposed source.

Limestone will be delivered to the proposed source by truck and stored in long-term silos 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 regulated under the Act 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 Available 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. Non-attainment areas for PM and ozone are located in the vicinity of Jacksonville, Florida, approximately 10 to 15 kilometers from the proposed new source.

The JEA's application was considered complete prior to August 7, 1980.

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 a single FGD system is 90 percent (.76 lb/MM Btu SO_2 emissions).

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 was determined to be neither reliable nor cost effective. These alternate control systems were rejected based upon the above economic and potential environmental impact considerations. 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 later 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.

The auxiliary boiler will be fired with .76 wt.% sulfur fuel oil. The SO_2 emissions from the auxiliary boiler are small when compared to those from the main units. Also, the auxiliary boiler will be operated on an intermittent basis (annual capacity factor of 5 percent) and will not operate simultaneously with the main power generating boilers. Therefore, the air quality impacts due to operation of the auxiliary boiler will be much less than those resulting from the operation of the main boilers. Based on the above analysis, BACT for SO_2 emissions from auxiliary boiler has been determined to be the firing of .76 wt.% sulfur fuel oil.

Particulate Matter

Application of BACT is required for the emissions of PM from the two steam generators (boilers), auxiliary boiler and coal, flyash, 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/MM Btu). Two alternative systems, a electrostatic precipitator with a PM removal efficiency of 99.85 percent (.02 lb/MM Btu) and a fabric filter with a PM removal efficiency of 99.78 percent (.03 lb/MM Btu), 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 air quality. The fabric filter system was considered neither reliable nor cost effective. These alternative control systems were rejected on the basis of the above economic and environmental impact considerations. The NSPS for electric utility steam generation limits PM emissions to .03 lb/MM Btu heat input. The proposed PM emissions control system meets the NSPS requirements for control of PM emissions. A continuous monitor for opacity emissions will be installed in the flue of both stream 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 and fabric filter dust collectors.

Fugitive fly ash emissions will be controlled at all transfer and discharge locations by fabric filters. Pneumatic conveyors are

utilized to transfer fly ash to and from ash storage silos, and to mixers which prepare the fly ash and FGD wastes for disposal.

Fugitive dissolved and suspended particulate emissions from the cooling tower will be controlled by high efficiency drift eliminators. Additionally, a circumferential drift eliminator wall will be provided at the base of the hyperbolic shell to mitigate the potential effects of blow-through. Table 2 presents a fugitive emissions and controls summary.

The above emission control systems represent BACT for fugitive emissions.

BACT for PM emissions from the auxiliary boiler has been determined to be the firing of No. 2 fuel oil with an ash content of 0.1 wt.%. The auxiliary boiler will not operate simultaneously with the main steam generating unit and the air quality impact from the auxiliary boiler is small when compared to the emissions from the main units. 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 boiler to control NO_x and CO emissions. Emissions of NO_x and CO resulting from the combustion of coal is dependent on such factors of boiler design as 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 to guarantee a maximum NO_x emission rate of 0.6 lb/MM Btu and CO emission rate of 0.05 lb/MM Btu in the two steam generators (boilers). This is in agreement with the NO_x emission limit required in the NSPS for steam electric generating stations. Control of NO_x and CO emissions will be accomplished by a flue gas oxygen monitoring system to control the air/fuel ratio in accordance with the attached "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls." In addition, a continuous nitrogen oxides meter will be installed in the flue at both steam generators in accordance with 40 CFR 60.47a.

BACT for NO_x and CO emissions from the auxiliary boiler will be accomplished by a flue gas oxygen monitoring system in accordance with the attached "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls."

The above emissions control system represents BACT for NO_x and CO emissions from the two steam generators and the auxiliary boiler.

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 apply. 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.

Monitoring data for SO_2, NO_x, and PM were obtained from the New Berlin monitoring site near Jacksonville, Florida for the year 1977. Monitoring data for CO was not available; however, the area surrounding the proposed new source has been classifed attainment or unclassified for CO and therefore no NAAQS violations for CO are expected.

An air quality analysis using meterological data from the Jacksonville International Airport was used to determine the maximum pollutant concentrations at the monitoring site when the contributions from large existing sources of pollution were negligible. These 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) PTMPT and PAL 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 data) 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 analysis 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 effects on the projected ambient air concentrations of pollutants were expected to occur as a result of turbulent building wake effects (downwash) because all stacks met 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 monitored 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 and modeled concentrations 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 the downtown Jacksonville, Florida area. The maximum impacts were projected to be below 1 ug/m^3 on a 24-hr average. These values are below the PSD modeling significance levels as defined in the June 19, 1978 PSD regulations, 43FR26358. Therefore, the proposed new source will not significantly impact the PM non-attainment area which is 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 therefore are 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 200 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 will be forwarded to the Federal Land Managers responsible for this Class I area for comment on the significance of the Class I impacts.

V. Conclusion

EPA proposes a preliminary determination of approval with conditions for construction of the steam electric generating station proposed by the Jacksonville Electric Authority. This determination is based upon the application received May 28, 1980 and additional information dated July 8, 1980 and November 26, 1980 (application determined complete as of July 9, 1980). The determination of approval is contingent upon the following specific conditions:

1. The proposed steam generating station will be constructed and operated in accordance with the capabilities and specifications of the application including the 600 megawatt generating capacity and the 5928 MMBtu/hr heat input rate for each steam generator.

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

3. Compliance with the allowable emission limits for emission points 1, 2, and 3 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 6, Determination of Sulfur Dioxide 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; and Method 10, Determination of Carbon Monoxide Emissions from Stationary Sources.

   Emission points 4 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 opacity during performance testing.

4. A flue gas oxygen meter shall be installed in emission points 1, 2, and 3 of Table 6 to continuously monitor a representative sample of the flue gas. The oxygen monitor shall be used with automatic feedback or manual controls to continuously maintain low excess air (LEA) air/fuel ratio parameters. Performance tests shall be conducted and operating procedures established in accordance with the attached "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls."

   The applicant will install and maintain a continuous monitoring and recording opacity meter, as well as sulfur dioxide and nitrogen oxide analyzers for each steam generator (emissions units 1 and 2 of 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 .7 percent by weight and a maximum ash content of .01 percent by weight. Samples of fuel oil shall be taken and analyzed for sulfur and ash content once per day or whenever new supplies are received, whichever time period is shortest. 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 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.

   b. Coal storage piles will be shaped, compacted and oriented to minimize wind erosion;

   c. Water sprays for storage piles, handling equipment etc., will be applied during dry periods and as necessary to all facilities to maintain an opacity of "no visible emissions";

   d. The limestone handlng receiving hopper, transfer conveyors and day silos will be maintained at negative pressures with the exhaust vented to a control system; and

   e. The fly ash handling system (including transfer and silo storage) will be maintained at negative pressures and vented to the control system.

7. Within 90 days of commencement of operations, the applicant will determine and submit to EPA the pH level in the scrubber effluent that will ensure 90% removal of the SO_2 in the flue gas. Moreover, the applicant is required to operate a continuous pH meter equipped with an upset alarm to ensure that the pH level of the scrubber effluent does not fall below this level. The minimum value pH may be revised at a later date provided notification to EPA is made demonstrating the minimum percent removal will be achieved on a continuous basis. Further, if compliance data show that higher FGD performance is necessary to maintain an overall system reduction of greater than or equal to 90%, a higher minimum pH value will be determined and maintained consistent with the required more stringent removal efficiency.

8. Emission point 3 of Table 6 shall not operate simultaneously with emission point 1 or 2 of Table 6.

9. 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.

10. 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 restrictive, that is lower emissions limits or more strict operating requirements and equipment specifications, than the requirements of specific conditions 1- 9 of this permit.

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

Pollutant	Potential emissions[a]	PSD significance levels
SO_2	9,015	40
PM	377	25
NO_x	7,117	40
CO	593	100
VOC	29	40

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

Table 2. FUGITIVE EMISSIONS AND CONTROL SUMMARY

Process	Type	Amount	Factor	Control	Technique	Emissions (Grams/Sec)
Ship Unloading	Grab Bucket	10,000 Tons/Day	.4LB/Ton[a]	(99.9%)[b]	Dry Collection on Hoppers	.04
Ship Unloading Transfer Points	6 Points	10,000 Tons/Day	.2LB/Ton[a]	(99.9%)[b]	Dry Collection	.06
Ship Unloading Transfer Points	3 Points	10,000 Tons/Day	.2LB/Ton[a]	(97%)[b]	Wet Suppression	.95
Ship Unloading Facility Train	Loading Shed	10,000 Tons/Day	.4LB/Ton[a]	(99.9%)[b]	Dry Collection	.02
Ship Unloading Facility Coal Surge Pile	Active	30 Acres	13LB/Acre/Day[a]	(90%)[a]	Wetting Agents	.20
Rail Car Unloading	Rotary Dumper	10,000 Tons/Day	.4LB/Ton[a]	(97%)[b]	Wet Suppression	.63
Coal Handling Transfer Points	2 Points	10,000 Tons/Day	.2LB/Ton[a]	(99.9%)[b]	Dry Collection	.02
Coal Handling Transfer Points	2 Points	3,300 Tons/Day	.2LB/Ton[a]	(99.9%)[b]	Dry Collection	.01
Coal Handling Transfer Points	6 Points	3,300 Tons/Day	.2LB/Ton[a]	(97%)[b]	Wet Suppression	.62
Coal Handling Transfer Points	7 Points	5,000 Tons/Day	.2LB/Ton[a]	(99.9%)[b]	Dry Collection	.04
Coal Storage at Plant	Active	8 Acres	13LB/Acre/Day[a]	(90%)[a]	Wetting Agents	.05
Coal Storage at Plant	2 Inactive Piles	15 Acres Each	3.5LB/Acre/Day[a]	(99%)[b]	Wetting Agents	.01
Limestone Unloading	Rail Dumper	750 Tons/Day	.4LB/Ton[a]	(99.9%)[b]	Dry Collection	.002
Limestone Tranfer Point	1 Point	750 Tons/Day	.2LB/Ton[a]	(99.9%)[b]	Dry Collection	.001
Cooling Towers	Drift	2x603 Grams/Sec	32,963 ppm Solids	21%<50 Microns	Drift Eliminators	8.4

a (Pedco, 1977)
b (Stoughton, 1980)

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	123	987	1,110	1,300
24-hour	45	187	232	365
annual	11	13	24	80
PM				
24-hour	79	27	106	150
annual	37	3	40	75
NO_2				
annual	15	10	25	100
CO				
1-hour	--[c]	108[d]		40,000
8-hour	--[c]	<100[d]		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] CO monitoring data was not available. However, because of the low ambient air concentrations of CO projected, no violations of the NAAQS for CO is expected.

[d] 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 (ug/m^3)	PSD Class II increment (ug/m^3)
SO_2		
3-hour	334	512
24-hour	42	91
annual	2	20
PM		
24-hour	17	37
annual	2.3	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	18	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/MM Btu)

Emission unit	SO_2	NO_x	PM	CO	Opacity (Percent)
1. Steam generating boiler no. 1 (5,928 MM Btu/hr maximum heat input)	4,502; 0.76 (30 day rolling average)	3,559; 0.6	178; 0.03	296; 0.05	20
2. Steam generating boiler no. 2 (5,928 MM Btu/hr maximum heat input)	4,502; 0.76 (30 day rolling average)	3,559; 0.6	178; 0.03	296; 0.05	20
3. Auxiliary boiler (200 MM Btu/hr maximum heat input)	160; 0.8	60; 0.3	2; 0.01	1; 0.005	10
4. Ship unloading			0.32		no visible emissions
5. Ship unloading transfer points			0.5 (each)		no visible emissions
6. Ship unloading facility train			0.2		no visible emissions
7. Ship unloading facility coal storage pile			1.5		no visible emissions

(continued)

Table 6. (continued)

Emission unit	SO_2	NO_x	PM	CO	Opacity (Percent)
8. Rail car unloading			5		no visible emissions
9. All coal handling transfer points			5 (each)		no visible emissions
10. Coal storage at plant			0.4 (each pile)		no visible emissions
11. Limestone unloading			0.1		no visible emissions
12. Limestone transfer points			0.1 (each)		no visible emissions
13. Cooling towers			67 (each tower)		20

Within the time limits specified in General Condition 3 of this permit, the permittee shall determine the emissions of nitrogen oxides and carbon monoxide from the permitted combustion device in accordance with test methods and procedures set out in 40 CFR Part 60, Appendix A, Methods 7 and 10, respectively. These emission determinations shall be made at:

1) Maximum design capacity; and

2) Normal operational load.

The permittee shall install a continuous oxygen monitor in the flue of the permitted combustion device which meets the requirements of 40 CFR Part 60, Appendix B, Performance Specification 3. Results of emission determinations shall be correlated to the flue gas oxygen content to define:

1) The point at which Nitrogen Oxides (NO_x) emissions (lb/MMBtu) equals the allowable NO_x emission rate contained in the permit.
2) The point at which carbon monoxide (CO) emissions exceed the allowable CO emission rate contained in the permit.

The flue gas oxygen content shall be maintained between these points and alarms shall be set to sound when flue gas oxygen levels exceed either side of this range. Any operation outside of this range will constitute noncompliance with this specific condition, shall be recorded in accordance with General Condition 4 of this permit, and will be reported quarterly along with excess emissions in accordance with 40 CFR 60.7 (c).

Should any combustion equipment modifications be made such as different type burners, combustion air relocation, fuel conversion, tube removal or addition, etc., emissions correlations as described above shall be conducted within 90 days of attaining full operation after such modification. Results of all emission determinations shall be sent to the permitting authority within 90 days after completion of the tests.

GENERAL CONDITIONS

1. The permittee shall notify the permitting authority in writing of the beginning of construction of the permitted source within 30 days of such action and the estimated date of start-up of operation.

2. The permittee shall notify the permitting authority in writing of the actual start-up of the permitted source within 30 days of such action and the estimated date of demonstration of compliance as required in the specific conditions.

3. Each emission point for which an emission test method is established in this permit shall be tested in order to determine compliance with the emission limitations contained herein within sixty (60) days of achieving the maximum production rate, but in no event later than 180 days after initial start-up of the permitted source. The permittee shall notify the permitting authority of the scheduled date of compliance testing at least thirty (30) days in advance of such test. Compliance test results shall be submitted to the permitting authority within forty-five (45) days after the complete testing. The permittee shall provide (1) sampling ports adequate for test methods applicable to such facility, (2) safe sampling platforms, (3) safe access to sampling platforms, and (4) utilities for sampling and testing equipment.

4. The permittee shall retain records of all information resulting from monitoring activities and information indicating operating parameters as specified in the specific conditions of this permit for a minimum of two (2) years from the date of recording.

5. If, for any reason, the permittee does not comply with or will not be able to comply with the emission limitations specified in this permit, the permittee shall provide the permitting authority with the following information in writing within five (5) days of such conditions:

   (a) description of noncomplying emission(s),

   (b) cause of noncompliance,

   (c) anticipated time the noncompliance is expected to continue or, if corrected, the duration of the period of noncompliance,

   (d) steps taken by the permittee to reduce and eliminate the noncomplying emission,

   and

   (e) steps taken by the permittee to prevent recurrence of the noncomplying emission.

   Failure to provide the above information when appropriate shall constitute a violation of the terms and conditions of this permit. Submittal of this report does not constitute a waiver of the emission limitations contained within this permit.

6. Any change in the information submitted in the application regarding facility emissions or changes in the quantity or quality of materials processed that will result in new or increased emissions must be reported to the permitting authority. If appropriate, modifications to the permit may then be made by the permitting authority to reflect any necessary changes in the permit conditions. In no case are any new or increased emissions allowed that will cause violation of the emission limitations specified herein.

7. In the event of any change in control or ownership of the source described in the permit, the permittee shall notify the succeeding owner of the existence of this permit by letter and forward a copy of such letter to the permitting authority.

8. The permittee shall allow representatives of the State environmental control agency and/or representatives of the Environmental Protection Agency, upon the the presentation of credentials:

   (a) to enter upon the permittee's premises, or other premises under the control of the permittee, where an air pollutant source is located or in which any records are required to be kept under the terms and conditions of the permit;

   (b) to have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit, or the Act;

   (c) to inspect at reasonable times any monitoring equipment or monitoring method required in this permit;

   (d) to sample at reasonable times any emission of pollutants;

   and

   (e) to perform at reasonable times an operation and maintenance inspection of the permitted source.

9. All correspondence required to be submitted by this permit to the permitting agency shall be mailed to the:

   Chief, Air Facilities Branch
   Air and Hazardous Materials Division
   U.S. Environmental Protection Agency
   Region IV
   345 Courtland Street
   Atlanta, Georgia 30365

10. The conditions of this permit are severable, and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

The emission of any pollutant more frequently or at a level in excess of that authorized by this permit shall constitute a violation of the terms and conditions of this permit.