ENV 122101

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DEC 26 2001

BUREAU OF AIR REGULATION

st. johns river POWER PARK

December 21, 2001

Al Linero, P.E.
Division of Air Resources Management
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

RE: St. Johns River Power Park (SJRPP), Site Certification No. PA-81-13
PSD Permit No. PSD-FL-010; Title V Permit No. 0310045-002-AV
Burner Component Replacement Project

Dear Mr. Linero:

In an effort to reduce nitrogen oxides (NOx) emissions from the St. Johns River Power Park's two steam generating units, SJRPP plans to replace some of the existing burner components with new ones using state-of-the-art designs. With the burner component replacements, both NOx and carbon monoxide (CO) emissions will be reduced. The first phase of this project is planned for the first quarter of 2002, followed by a second phase in 2003 and the final phase in 2004. Because this is a replacement project resulting in reduced emissions, no permit or permit revision is necessary.

The two 660 MW coal-fired steam generating units began operating in 1986 and 1988 respectively. The Prevention of Significant Deterioration permit and Conditions of Certification limited NOx emissions to 0.60 pounds per million British thermal units (lb/mmBtu) on a 30-day rolling average basis while firing solid fuel. Through an early election under the federal Acid Rain Program, the units' annual average NOx emissions were subsequently limited to 0.50 lb/mmBtu beginning on January 1, 1997. This limit will remain in effect only through January 1, 2008, at which time a much lower annual average NOx limit will be imposed. In anticipation of the lower NOx limit, SJRPP is planning the above-mentioned burner component replacements starting early next year.

Initially SJRPP will replace components on eight of Unit No. 2's twenty-eight existing burners during the Spring 2002 outage to ensure that the equipment operates as efficiently and as effectively as planned before making a further investment in this technology. Assuming that the NOx and CO reductions are as expected, and based on scheduled unit outages, the components on all of the Unit No. 1 burners would be replaced in 2003, followed by completion of the Unit No. 2 component replacements in 2004.

If you need any additional information or have any questions, please contact me at (904) 751-8729

904/665-8729

Sincerely,

Jay Worley

Jay Worley
Group Leader

cc: Hamilton S. Oven, DEP Siting
Chris Kirts, DEP NE District
Jim Manning, RESD

11201 New Berlin Road • Jacksonville, FL 32226

RECEIVED
SEP 24 '01
Bureau of Air Monitoring
& Mobile Sources

September 19, 2001

JEA

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics Management Division
U.S. Environmental Protection Agency
Region IV
61 Forsyth Street
Atlanta, GA 30303-8960

RE: Northside Generating Station Repowered Units 1 and 2
Alternate Monitoring Proposal for % SO2 Removal

Dear Mr. Neeley:

We are in receipt of your letter dated August 21, 2001 regarding the above subject, and accept the modification to our proposal as written.

If you have any questions or need additional information, please call me at 904-665-6247.

Sincerely,

N. Bert Gianazza, P.E.
Environmental Permitting
& Compliance Group

cc: David McNeal, EPA, Region IV
Howard Rhodes, DEP
Joe Kahn, P.E., DEP
Richard Banks, DEP, NE District
Robert S. Pace, P.E., RESD

BEST AVAILABLE COPY

orig - Dotty
x.c. - Clair

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

From: Howard 8/27

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AUG 27 2001

DIVISION OF AIR RESOURCES MANAGEMENT

AUG 21 2001

Joe

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AUG 2 2001
Bureau of Air Monitoring & Mobile Sources

0710002-011-AC
FPL Ft. Myers
Scanned + RUN 7/17/06

4APT-ARB

Howard L. Rhodes, Director
Division of Air Resource Management
FL Department of Environmental Protection
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Rhodes:

The purpose of this letter is to provide you with written comments regarding an alternative sulfur dioxide (SO_2) monitoring proposal that the Jacksonville Electric Authority (JEA) submitted for Units 1 and 2 at its Northside Generating Station in Jacksonville, Florida. These circulating fluidized bed (CFB) coal- and petroleum coke-fired units are subject to 40 C.F.R. Part 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction Commenced After September 18, 1978. Based upon our review of a July 2, 2001, letter that JEA sent to the U.S. Environmental Protection Agency (EPA) Region 4 and to your agency, we have determined that the proposed alternative monitoring method cannot be approved as it is currently written. Details regarding changes that would have to be made in order for it to be approved and comments regarding the requirement for an initial 30-day performance test are provided in the remainder of this letter.

Alternative monitoring proposal

The applicable SO_2 standard in Subpart Da limits emissions to 1.2 pounds per million British thermal units (lb/mmBTU) and requires a minimum SO_2 removal efficiency of 70 percent for units that have an emission rate of less than 0.60 lb/mmBTU. In addition, construction permits for Units 1 and 2 contain SO_2 limits of 0.15 lb/mmBTU (30-day rolling average) and 0.20 lb/mmBTU (24-hour block average). The alternative monitoring proposal from JEA involves the procedures for calculating SO_2 removal efficiencies. According to 40 C.F.R. §60.47a(b), SO_2 removal efficiencies are determined by measuring the SO_2 emission rate at the inlet and outlet of the control device. Under these provisions, emission rates at the outlet of the control device are measured with a continuous emission monitoring system (CEMS), and pre-control emission rates are measured with either a CEMS or through daily as-fired fuel sampling and analysis. The monitoring required under the rule is used to determine compliance with both the 1.2 lb/mmBTU and the 70 percent removal efficiency standards on a 30-day rolling average basis.

Units 1 and 2 are CFB units and because the limestone used to control SO_2 emissions is mixed with coal and petroleum coke in the combustion chamber, a CEMS cannot be used to measure the pre-control SO_2 emission rate. As an alternative to using daily as-fired sampling and analysis to determine the pre-control SO_2 emission rate, JEA proposed to use the results of fuel vendor analyses and monthly on-site sampling and analysis to determine the inlet sulfur loading for its Subpart Da units. In its July 2 letter, JEA proposed to use the lowest inlet sulfur content ever measured by EPA Method 6B, EPA Method 19, as-fired coal sampling, or fuel supplier analyses in the SO_2 removal efficiency calculations. Using the lowest measured pre-control SO_2 emission rate to calculate removal efficiencies is a conservative approach since the reported efficiencies will drop as the inlet concentration used in the calculation decreases. In addition, JEA proposed to temporarily discontinue the use of the alternative monitoring approach and conduct daily as-fired sampling and analysis in accordance with Subpart Da in the event that the calculated removal efficiency using the lowest inlet SO_2 loading drops below 75 percent.

The alternative monitoring approach proposed by JEA is less stringent than one approved by EPA in 1994 for in a source in Region 2, and in order to obtain approval for its proposal, JEA will have to modify it so the terms are consistent with those in EPA's previous approval. The enclosed April 21, 1994, memorandum from EPA's Office of Air Quality Planning and Standards provides details regarding this previous alternative monitoring approval for a unit operated by the Chambers Cogeneration Limited Partnership (Chambers) in Carney's Point, New Jersey. The proposed alternative monitoring approach from JEA is less stringent than the one approved for Chambers since the required minimum removal efficiency that must be maintained under the JEA alternative (75 percent) is lower than it was for Chambers (80 percent).

Making the approval of the alternative monitoring approach contingent upon the maintenance of a removal efficiency higher than the 70 percent level required under Subpart Da will increase the level of compliance assurance under the alternative. Region 4 was involved in discussions that preceded the approval of the monitoring alternative for Chambers, and the added degree of compliance assurance achieved by requiring that the 30-day rolling average removal efficiency be maintained at 80 percent or above was a key factor that made approval of the alternative acceptable to EPA. Therefore, one condition for approval on the proposed JEA alternative monitoring approach would be that daily as-fired fuel sampling and analysis must be initiated in accordance with 40 C.F.R. §60.47a(b)(3) and EPA Method 19 in the event that the 30-day rolling average removal efficiency calculated using the lowest measured uncontrolled SO_2 emission rate ever drops below 80 percent.

Another issue that needs to be addressed regarding JEA's proposal is the provision to temporarily discontinue the use of the alternative in the event the 30-day rolling average removal efficiency drops below 75 percent. According to the final condition in the enclosed memorandum approving the Chambers alternative, monitoring in accordance with the specified procedures in Subpart Da would have to begin immediately if the average removal efficiency ever drops below 80 percent, and these monitoring procedures would have to be followed as long as the facility operates. Therefore, in addition to using 80 percent as a threshold for suspending the use of the alternative, the suspension would have to be permanent in order for the alternative monitoring approach at JEA to be stringent as the one approved for Chambers.

In addition to concerns about the consistency of the alternative monitoring approaches at the JEA and Chambers, there is also a practical reason for permanently discontinuing the use of the alternative monitoring approach once the average removal efficiency drops below 80 percent. One of the mostly likely causes for the average removal efficiency dropping below 80 percent would be the use of a very low pre-control SO_2 emission rate in the efficiency calculations. Since the proposed alternative is based upon the use of the lowest measured pre-control SO_2 emission rate in all subsequent removal efficiency calculations, it is likely that the average SO_2 removal efficiency will be less than 80 percent on a recurring basis once the pre-control SO_2 emission rate is low enough that the average removal efficiency drops below 80 percent for the first time. Based upon the expectation that the average removal efficiency will be less than 80 percent on a recurring basis once it goes below this level for the first time, a permanent, suspension of the alternative monitoring approach would be more practical than a temporary suspension in the event that average efficiency ever drops below 80 percent.

Initial performance testing

The focus of JEA's proposal was SO_2 removal efficiency monitoring, and initial performance testing was not addressed in its July 2, 2001, letter. Subpart Da requires that an initial 30-day performance test be conducted, and under the terms of the previous alternative monitoring approval for Chambers, the company had the following options for obtaining the pre-control SO_2 emission rate data used in the removal efficiency calculations for the initial test:

- Daily as-fired coal sampling and analysis in accordance with EPA Method 19,

- An SO_2 continuous emission monitoring system, or

- EPA Method 6B

Based upon the approval conditions for the alternative monitoring approach approved at Chambers, it will also be necessary for JEA to use one of the procedures above to monitor the pre-control SO_2 emission rate for Northside Generating Station Units 1 and 2 on a daily basis for 30 consecutive boiler operating days in order to collect the data needed to satisfy the Subpart Da requirement for an initial performance test. In addition, the 30 days of data collected during this initial performance test must be considered when determining the lowest measured pre-control SO_2 emission rate used in subsequent removal efficiency calculations.

Summary

Although the basic concept behind JEA's alternative monitoring proposal is acceptable, the following changes will have to be made in it before final approval can be granted:

1. The removal efficiency used as a trigger for discontinuing the use of the alternative must be increased from 75 percent to 80 percent.

2. In the event that the 30-day average removal efficiency drops below 80 percent, the use of the alternative must be discontinued permanently, rather than temporarily.

3. JEA must conduct an initial 30-day performance test during which one of the three methods identified in this letter is used to measure the pre-control SO_2 emission rate on a daily basis.

If you have any questions about the determination provided in this letter, please contact Mr. David McNeal of my staff at 404/562-9102.

Sincerely,

Edward M Lancaster

for R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

Enclosure

(1) April 21, 1994, EPA memorandum outlining approval conditions for alternative monitoring approach at Chambers

cc: A.A. Linero, FL DEP

Syed Arif, FL DEP

Walter P Bussells
Managing Director & Chief Executive Officer

21 West Church Street
Jacksonville, Florida 32202-3139

July 17, 2001

JEA

ELECTRIC - WATER - SEWER

JUL 19 2001
AIR AND RADIATION ... BRANCH
EPA - REGION 4
ATLANTA, GA

David McNeal
U.S. Environmental Protection Agency
Region IV
61 Forsyth Street SW
Atlanta, GA 30303

RE: JEA Brandy Branch Unit 1 (0310485-003-AC, PSD-FL-310)
Request for Extension of Time for Completion of Stack Testing

Dear Mr. McNeal:

On May 20, 2001 Brandy Branch Unit 1 was fired on #2 fuel oil and base loaded. This was the first time the unit ran on liquid fuel with the load greater than 90%. The unit has since experienced problems burning #2 oil.

Per our conversation of this date, we request that an extension of the 60-day window for completing stack testing be granted to allow an additional 720 hours of oil burning within which to complete oil stack testing.

If you have any questions or need additional information, please call me at 904-665-6247.

Sincerely,

N. Bert Gianazza, P.E.
Environmental Permitting
& Compliance Group

cc: A. A. Linero, DEP, BAR
Joe Kahn, DEP, BAR
Richard Banks, DEP, NE District
Robert S. Pace, RESD

DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF ADMINISTRATIVE PERMIT CORRECTION

In the Matter of an Application for Administrative Permit Correction:

Mr. Paul M. Smith
Plant Manager
11201 New Berlin Road
Jacksonville, Florida 32226

DEP File No. 0310045-014-AC, PSD-FL-010
JEA – St. Johns River Power Park

The Department has determined that a minor correction to information contained in Permit Number 0310045-014-AC is required. This correction is related to a typographical error and is minor in nature and does not alter, modify or revise any permit requirement. The correction is related to the compliance procedure for Carbon Monoxide monitoring shown on Page BD-8 of the Technical Evaluation and Final Determination for "Increased Co-Firing of Petroleum Coke" dated March 30, 2005 and revised March 30, 2006. The Compliance Procedure should read:

Five years of annual reporting by CEMS ~~stack test~~ proving annual emissions do not exceed 13776.5 TPY

This permit correction corrects and is a part of Permit Number 0310045-014-AC. This permit correction is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit correction) has the right to seek judicial review of it under section 120.68 of the Florida Statutes, by filing a notice of appeal under rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Administrative Permit Correction was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 4/28/06 to the person(s) listed:

James M. Chansler, JEA *
Jay A. Worley, JEA
Gregg Worley, EPA
John Bunyak, NPS
Chris Kirts, NED
Richard Robinson, P.E. ERMD
Mr. Hamilton S. Oven, DEP-Siting

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Barbara J. Friday 4/28/06
(Clerk) (Date)

from the date the units resume regular operation, information demonstrating that the change did not result in a significant emissions increase. If SJRPP fails to comply with the reporting requirements of the WEPCO rule or if the submitted information indicates that emissions have increased above PSD thresholds as a consequence of the change, it will be required to obtain a PSD permit for petcoke co-firing (meaning that a BACT Review would then be applicable). Finally, even though a PSD review is not triggered due to the co-firing project, SJRPP must meet all other applicable federal, state, and local air pollution requirements.

7. ADDITIONAL COMPLIANCE PROCEDURES (AVERAGE PER EMISSION UNIT)

Pollutant	Compliance Procedures
NO_X	Five years of annual reporting by CEMS proving annual emissions do not exceed 26598.7 TPY
CO	Five years of annual reporting by CEMS ~~stack test~~ proving annual emissions do not exceed *13776.5* TPY
VOC	Five years of annual reporting by historical AOR methods, proving annual emissions do not exceed 158.5 TPY
SO_2	Five years of annual reporting by CEMS proving annual emissions do not exceed 21758.7 TPY
SAM	Five years of annual reporting by stack test proving annual emissions do not exceed 1323.8 TPY
PM	Five years of annual reporting by stack test proving annual facility emissions do not exceed 346.7 TPY

Specific permit conditions shall further describe these limitations. The reporting procedures are to begin during the first calendar year in which petcoke is fired.

8. CONCLUSION

Based on the foregoing technical evaluation of the application, additional information submitted by the applicant and other available information, the Department has made a final determination that the proposed project will comply with all applicable state and federal air pollution regulations.

Michael P. Halpin, P.E. Review Engineer
Department of Environmental Protection, Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

9. 2006 REVISION

The tables within Section 4.1 and 7 herein are revised as of March of 2006 in order to more accurately reflect historical carbon monoxide emissions, since the related permit references these tables. The data reflected within this revision is based upon historical CEMS data which the Department considers more accurate than AP-42 emission factors (see 62-210.370, F.A.C.).

st. johns river power park

EV 961108

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NOV 14 1996

BUREAU OF AIR REGULATION

November 08, 1996

Mr. Hamilton Oven
Florida Dept. of Environmental Protection
2600 Blair Stone Road
Mail Station 48
Tallahassee, FL 32399-2400

RE: St. Johns River Power Park (SJRPP) Units 1 & 2
Power Plant Certification No. PA 81-13
Flue Gas Conditioning
Ammonia Injection -Disclosure

Dear Mr. Oven:

Flue gas conditioning utilizing ammonia injection may be tested and applied in the SJRPP units to control potential sulfuric acid development during the use of higher sulfur fuels. The process involves spraying vaporized anhydrous (NH_3) ammonia into the flue gas prior to the pollution control equipment.

Pursuant to our telephone conversation of November 05, 1996, you requested this letter disclosing the possible use of ammonia injection since a modification of the above referenced Certification was not required. In addition, Mr. Al Linero of the Florida Department of Environmental Protection (FDEP) Bureau of Air Regulation was contacted regarding the utilization of ammonia injection. He stated that permitting was not required for this type of application.

Please contact me at (904) 751-7729 if you have any questions or comments regarding this disclosure.

Sincerely,

Jay Worley
Director, Environmental & Safety

xc: A. Linero, FDEP

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In Re: Jacksonville Electric Authority St. Johns Power Park Power Plant Plant Certificaation Modification Request No. PA 81-13 Duval County, Florida	))))))	OGC NO. 85-0353

FINAL ORDER
MODIFYING CONDITIONS OF CERTIFICATION

The Department of Environmental Protection after notice and opportunity for hearing modifies the Conditions of Certification for the Jacksonville Electric Authority St. Johns River Power Park pursuant to the Florida Electrical Power Plant Siting Act Section 403.516(1) Florida Statutes (F.S.), and Condition XXV, Modification of Conditions, which delegates authority to modify conditions to the Department.

On June 8, 1994, Jacksonville Electric Authority (JEA) submitted petitions to the Department requesting certain modifications to conform the Conditions of Certification for the above referenced facility to the revised NPDES permit by deleting a reference to monitoring for metals at the sump pump, and to conform cooling tower chlorination requirements. On January 24, 1995, JEA requested deletion of references to auxiliary boilers that have been deleted from the site.

Copies of JEA's request were distributed to all parties to the certification proceeding and made available for public review. On March 17, 1995, Notice of Proposed Modification of Power Plant Certification was published in the Florida Administrative Weekly. Copies of the request to modify were sent to all parties to the original proceeding. As of March 14, 1995, all of the parties to the original proceeding had received copies of the intent to issue. The notice specified that a hearing would be held if a party to the original certification hearing objects within 45 days from receipt of the proposed modification or if a person whose substantial interests will be affected by the proposed modification objects in writing within 30 days after issuance of the public notice. No written objection to the proposed modifications was received by the Department.

Accordingly, in the absence of any timely objection,

IT IS ORDERED:

The proposed changes to the conditions of certification for the JEA St. Johns River Power Park described in the June 8, 1994, and January 24, 1995, requests for modification, are APPROVED. The Department hereby approves the requested modifications, and, pursuant to section 403.516(1)(b), F.S., the Department hereby MODIFIES the conditions of certification for the JEA St. Johns River Power Park (SJRPP) as follows:

I.A.11 During start-up and low load operation, Units 1 & 2 may ~~The two auxiliary boilers shall~~ fire No. 2 fuel oil with a maximum sulfur content of 0.76 percent by weight, a maximum ash content of 0.01 percent by weight, an approximate heating value of 19,500 Btu per pound and a maximum viscosity of 3.6 centistokes at 100°F. Samples of all fuel oil fired in the boilers shall be taken and analyzed for sulfur content, ash content, heating value and viscosity. Accordingly, samples shall be taken of each fuel oil shipment received. Records of the analyses shall be kept a minimum of two years to be available for FDEP's ~~FDER's~~ inspection.

~~12. The same quality No. 2 fuel oil, used for the auxiliary boilers, shall be used for the main boilers Units 1 and 2 during start up and low load operation.~~

~~13. Maximum emission from either of the auxiliary boilers shall be limited to 0.8 lb/MMBT for SO_2, 0.1 lb/MMBTU for P.M., and 20% opacity for visible emissions.~~

12. ~~14.~~ Coal fired in Units 1 and 2 shall have an ash content not to exceed 18% and a sulfur content shall be determined and recorded in accordance with 40 CFR 60.47a.

13.~~15.~~ No fraction of flue gas shall be allowed to bypass the FGD system to reheat the gases exiting ~~existing~~ from the FGD system, if the bypass will cause overall SO_2, removal efficiency less than 90 percent or otherwise provided in 40 CFR Part 60, Subpart D~~d~~a. The percentage and amount of flue gas bypassing the FGD system shall be documented and records kept a minimum of two years available for FDEP'S ~~FDER's~~ inspection.

~~16. JEA shall keep records of the frequency, duration, load and manner of operation of the auxiliary boilers. During normal operation of the plant the boilers shall not operate more than seven (7%) percent of the time on an annual basis without prior approval of the Department. However, prior to commercial operation and during boiler start up, shutdown of the main plant or plant upset, the auxiliary boilers may be operated more frequently.~~

II. A. Chlorine

The concentration of total residual chlorine discharged from Units 1 & 2 and/or Northside Generating Station shall not exceed 0.1 mg/1 at the POD nor 0.01 mg/1 beyond an instantaneous mixing zone of 17.0 acres. Neither Free Available Oxidants (FAO) or Total Residual Oxidants (TRO) may be discharged from either cooling tower for more than two hours in one day and not more than one cooling tower may discharge FAO or TRO at the same time. ~~Chlorine resulting from chlorination of either unit at SJRPP shall not be discharged more than two hours per day and no unit shall be chlorinated simultaneously with any other unity at SJRPP or at Northside Generating Station~~. Levels of free available chlorine shall not exceed 0.5 mg/1 for an instantaneous maximum nor 0.2 mg/l on a two hour average from the blowdown of either cooling tower. In the event that 40 CFR, Part 423 is revised with respect to chlorine limitations, such discharge limitations shall apply to cooling tower blowdown. TRO ~~Chlorine~~ shall not be discharged from the SJRPP during periods when TRO ~~chlorine~~ is being discharged from any unit at NGS except if due to cooling tower makeup (from ambient or from chlorination of NGS.)

II.B.1. Chemical Monitoring

The following parameters shall be monitored during discharge as shown. Commencing with the start of commercial operation of SJRPP and reported monthly to the Department's Northeast District Office:

Parameter	Location	Sample Type	Frequency
Metals (Total Recoverable)	Intake and Sump Pump	24 Hour composite	Monthly
Aluminum	"	"	"
Arsenic**	"	"	"
Chromium**	"	"	"
Copper*	"	"	"
Cyanide**	"	"	"
Iron	"	"	"
Lead**	"	"	"
Mercury	"	"	"
Nickel**	"	"	"
Selenium**	"	"	"
Silver	"	"	"
Zinc**	"	"	"

Once per quarter at POD also

** At Intake only

*** At Sump Pump only

Any party to this Order has a right to seek judicial review of this Order pursuant to Section 120.68, Florida Statutes by the Filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the clerk of the Department of Environmental Protection in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date this Order is filed with the clerk of the Department.

DONE AND ORDERED this 17th day of May 1995, in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Kirby B. Green III for
Virginia B. Wetherell
Secretary

3900 Commonwealth Blvd.
Tallahassee, FL 32399-3000
(904) 488-4805

FILING AND ACKNOWLEDGEMENT
FILED, on this date, pursuant to S120.52 Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

[signature] 5/18/95
Clerk Date

5/30

Al,
How do I handle this? K– 1) ~~Send to~~ SA ~~Syed as F.Y.I.~~
~~1) Syed Info~~
2) He should then send to Kinani to update File PA 81-13.
No further actions necessary.

Certificate of Service

I hereby certify that a copy of the Final Order Modifying Conditions of Certification of the JEA St. Johns River Power Park, Power Plant Site Certification was sent to the following parties by Unitied States mail on May 18th, 1995.

Clare Gray, Esquire
St. Johns River Water Management District
Post Office Box 1429
Palatka, Florida 32178-1429

Karen Brodeen, Esquire
Department of Community Affairs
2740 Center View Drive
Tallahassee, FL 32399-2100

Michael Palecki, Esquire
Florida Public Service Commission
Fletcher Building
101 East Gaines Street
Tallahassee, FL 32399-0863

Gary P. Sams, Esquire
Hopping Green Sams & Smith
P. O. Box 6526
Tallahassee, FL 32314

Theresa Matchett, Esquire
Edward Tannen, Esquire
Office of General Counsel
Room 1300 - City Hall
220 West Bay Street
Jacksonville, FL 32202

W.O. Birchfield, Esquire
Martin, Ade, Birchfield & Johnson
3000 Independent Square
Jacksonville, FL 32202

FLORIDA DEPARTMENT OF
ENVIRONMENTAL PROTECTION

Charles T. "Chip" Collette
Assistant General Counsel

2600 Blair Stone Road
Tallahassee, FL 32399-2400
(904) 488-9314

DEPARTMENT OF ENVIRONMENTAL REGULATION

ROUTING AND TRANSMITTAL SLIP

1. TO: (NAME, OFFICE, LOCATION) ~~Bill Thomas~~	Initial / Date
2. Buck Oven DER	Initial / Date
3. MAY 1 1987	Initial / Date
4. BAQM	Initial / Date

ACTION NO

ACTION DUE DATE

REMARKS:

Has your section reviewed + commented on the attached?

From past investigations of self-unloaders (Gen. Portland) they appear to be a preferable alternative to grab buckets — reduce chances of spillage & emissions from drop-transfer.

BT 5/4/87

INFORMATION

- Review & Return
- Review & File
- Initial & Forward

DISPOSITION

- Review & Respond
- Prepare Response
- For My Signature
- For Your Signature
- Let's Discuss
- Set Up Meeting
- Investigate & Report
- Initial & Forward
- Distribute
- Concurrence
- For Processing
- Initial & Return

FROM: ~~Buck Oven~~

DATE

PHONE

TO: Bill T

FROM: Clin

DATE: 4/7

SUBJ: St John River Coal Terminal

DATE DUE: 4/20/87

DATE COMPLETED: ____________

Please accomplish the following job assignment by the date due.

please check with ~~Garrison~~ Aronson at EPA on this. What do we have to do - if anything

Bill Thomas told Buck Owen that BAQM had no objection to this. (5/4/87 - see attached routing slip)

JACKSONVILLE ELECTRIC AUTHORITY
P. O. BOX 53015
233 W. DUVAL STREET
JACKSONVILLE, FL 32201

st. johns river POWER PARK

SJRCTENV 87-6

March 13, 1987

Mr. Bruce Miller
Branch Chief
Air Programs Branch
US EPA - Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30365

Dear Mr. Miller:

Re: St. Johns River Coal Terminal (SJRCT)
Intended Use of Self-Unloading Coal Ships

PSD Permit No. PSD-FL-010 was issued on March 12, 1982 and modified on October 28, 1986 for the St. Johns River Power Park and the St. Johns River Coal Terminal (SJRCT). The purpose of this letter is to inform the U.S. Environmental Protection Agency (EPA) that JEA proposes to use self-unloading ships at SJRCT, as well as conventional coal carriers. Self-unloaders (see attached photograph) are equipped with a mechanical system that reclaims coal from the ship's holds and places it on a boom that swivels from a fixed point toward the stern of the ship. The boom can be swung away from the centerline of the ship, with the discharge end placed over the receiving hopper of the ship unloader gantry crane. Coal is discharged in a continuous stream into the ship unloader hopper, flows through the ship unloader and is placed on the dock conveyor as before. Thus, the self-unloader ship operation involves unloading of coal into the ship unloader hopper by the ship's boom, in lieu of utilizing the grab bucket. Once in the hopper, the flow of the coal is identical for both operations.

Coal unloading from the vessel by means of the self-unloading system described above is not expected to result in a change in dust emissions from the case currently licensed, which involves conventional ship unloading by means of grab bucket. All of the dust control measures to be deployed for grab bucket unloading will be utilized during self-unloading. In addition, the vessels under consideration in most cases have means of applying moisture to the coal, as necessary, by means of ship-mounted sprays. Therefore, coal entering the ship unloader hopper would essentially be "pre-conditioned" for dust control. Dust emission calculations demonstrating equivalent emissions between the two unloading methods are attached. Because of the insignificant change associated with the use of self-unloading vessels, we believe that no permit modification is necessary.

In addition, we would like to inform EPA that the ship unloader will be equipped with a dust collection system in addition to the

(CONT.)

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wet suppression system specified in our May 12, 1986 letter. Both the dry collection system and the wet suppression system will be designed to meet the 10 percent opacity permit requirement. The systems will be used interchangeably, depending on the coal characteristics and operating conditions. Also, wet suppression systems have been added to Transfer Station Nos. 3, 4, 6 and 7, the stacker and the reclaimer. Dry collection has been added to Transfer Station No. 5. These systems will also be utilized as necessary to comply with the 10 percent opacity limit.

If you have any questions or require additional information, please contact Athena Tsengas at (904) 633-4517.

Very truly yours,

Richard Breitmoser, P.E.
Division Chief
Research & Environmental
Affairs Division

RB/AJT/lwr

cc: T. Bisterfeld, EPA
M. Brandon, EPA
H. Oven, FDER

Attachments: 1) Dust Emission Calculations for Self-Unloading Vessel
2) Photograph of Self-Unloading Vessel

ATTACHMENT 1

JACKSONVILLE ELECTRIC AUTHORITY - ST. JOHNS RIVER COAL TERMINAL

DUST EMISSION CALCULATIONS
FOR
SELF-UNLOADING VESSEL
(FEBRUARY, 1987)

Emission Factor (continuous drop):

$$E(\text{lbs/ton}) = k(0.0018)\frac{\left(\frac{S}{5}\right)\left(\frac{U}{5}\right)\left(\frac{H}{10}\right)}{\left(\frac{M}{2}\right)^2}$$

Reference: AP-42, Section 11.2.3, Aggregate Handling and Storage Piles

Where:
k = particle size correction = 1.0
S = silt content (percent) = 5
M = surface moisture content (percent) = 5.5 (see below)
U = wind speed (mph) = 8.4
H = drop height (ft) = 40

Surface moisture content:

In "Estimate of Particulate Emissions: St. Johns River Coal Terminal and Blending Additions at St. Johns River Power Park", May, 1986, a "worst-case" M of 5% was used. The self-unloaders currently contemplated have sprays mounted on the ship and can raise the surface moisture content of the coal and suppress dust when necessary. Therefore, assuming usage of the ship-mounted sprays on coal with a low surface moisture, the previous M has been revised upwards to value of 5.5%.

Substituting for variables:

$$E(\text{lbs/ton}) = 1\ (0.0018)\frac{\left(\frac{5}{5}\right)\left(\frac{8.4}{5}\right)\left(\frac{40}{10}\right)}{\left(\frac{5.5}{2}\right)^2}$$

$$= 0.0016$$

ATTACHMENT 1

JACKSONVILLE ELECTRIC AUTHORITY - ST. JOHNS RIVER COAL TERMINAL

DUST EMISSION CALCULATIONS
FOR
SELF-UNLOADING VESSEL
(FEBRUARY, 1987)

Process Rate: Limited by SJRCT conveyor belt capacity = 2200 STPH

Control: dust suppression sprays and wind guards, composite control efficiency = 70%

(Reference: "Estimate of Particulate Emissions: St. Johns River Coal Terminal and Blending Additions at St. Johns River Power Park", May, 1986)

Total controlled emissions (lbs/hr) =

$$\text{emission factor} \left(\frac{\text{lbs dust}}{\text{ton coal}}\right) \times \text{process rate} \left(\frac{\text{tons coal}}{\text{hr}}\right)$$

$$\times \; 1 - \left(\frac{\text{efficiency (\%)}}{100}\right)$$

= 0.0016 x 2200 x 0.3

= 1.056

Total controlled emissions (gms/sec)

$$= \text{total controlled emissions} \left(\frac{\text{lbs}}{\text{hr}}\right) \times \left(\frac{\text{hr}}{3600 \text{ sec}}\right) \times \left(\frac{453.6 \text{ gms}}{\text{lb}}\right)$$

= 0.13 gms/sec

ATTACHMENT 1

JACKSONVILLE ELECTRIC AUTHORITY - ST. JOHNS RIVER COAL TERMINAL

DUST EMISSION CALCULATIONS
FOR
SELF-UNLOADING VESSEL
(FEBRUARY, 1987)

Summary and Conclusion:

Operation	Pounds/ Hour	Gms/ Sec
Grab bucket unloading	1.0 (1)	0.13 (2)
Self-unloading vessels	1.056	0.13

NOTES: (1) Currently licensed emission limit, rounded from a calculated value of 1.06

(2) from Table 2, existing PSD permit

No significant difference in consideration of rounding error, accuracy of emission factor, accuracy of monitoring, and other factors.

BEST AVAILABLE COPY

John Brown
JACKSONVILLE ELECTRIC AUTHORITY
P. O. BOX 53015
233 W. DUVAL STREET
JACKSONVILLE, FL 32201

st. johns river POWER PARK

CERTIFIED MAIL

Received DER

DEC 22 1986

EPS

SJRENV 86-43

December 18, 1986

Mr. Hamilton S. Oven, Jr., P.E.
Administrator, Power Plant Siting
Fla. Dept. of Env. Regulation
2600 Blair Stone Road
Tallahassee, Florida 32301

DER

DEC 24 1986

BAQM

Dear Mr. Oven:

Subject: St. Johns River Power Park Unit 1
Notification of Initial Startup

The notification of the actual date of initial startup of an affected facility is required as specified in 40 CFR 60.7(3). The date of initial startup for the above referenced facility was December 15, 1986.

Notification of the anticipated date of initial startup as required in 40 CFR 60.7(2) was submitted to your agency November 15, 1986.

Please advise if you have any questions regarding this notification.

Very truly yours,

Richard Breitmoser, P.E.
Division Chief
Research & Environmental
Affairs Division

RB/AJT/lwr

cc: E. Frey (FDER)
D. Bayly (BES)

DEPARTMENT OF ENVIRONMENTAL REGULATION

ROUTING AND TRANSMITTAL SLIP

ACTION NO

ACTION DUE DATE

1. TO: (NAME, OFFICE, LOCATION)

CLAIR ~~FANCY~~

2. ~~Bill T~~ DER

DEC 24 1986

cc: 4/2/87 BBM

3. ~~Pradeep~~ BAQM

4.

Initial	
Date	
Initial	
Date	
Initial	
Date	
Initial	
Date	

REMARKS: fyi / file

INFORMATION

- Review & Return
- Review & File
- Initial & Forward

DISPOSITION

- Review & Respond
- Prepare Response
- For My Signature
- For Your Signature
- Let's Discuss
- Set Up Meeting
- Investigate & Report
- Initial & Forward
- Distribute
- Concurrence
- For Processing
- Initial & Return

FROM: BUCK OVEN

DATE 12-23

PHONE 8-0130

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30365

4APT-AP/ch

OCT 28 1986

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

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

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

Dear Mr. Breitmoser:

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

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

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

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

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

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

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

DER

NOV 17 1986

BAQM

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

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

Sincerely yours,

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

Jack E. Ravan
Regional Administrator

Attachments: 2

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

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

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

* Revised emission unit, May 1986.

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

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

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

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

0400b(050886)PM

SJRENV 86-3

Received DER

SEP 30 1986

B P S

St. Johns River Power Park

September 29, 1986

Mr. Hamilton S. Oven, Jr., P.E.
Administrator, Power Plant Siting
Fla. Dept. of Env. Regulation
2600 Blair Stone Road
Tallahassee, Florida 32301

Dear Mr. Oven:

Re: St. Johns River Power Park
Operating Restrictions

This is to provide the Florida Department of Environmental Regulation with an operating plan and supporting justification that the JEA will follow to permanently eliminate emissions from steam generating units equivalent to the impact of the emissions from Southside Units 1 and 2 (pursuant to Condition of Certification I.E. Operating Restrictions).

The JEA currently has five steam generating units in extended cold storage (ECS). Two of these units are Southside Units 1 and 2. The units were placed into ECS in February, 1983. The sister units are the oldest and smallest of the group of steam generators in ECS. Having these statistics, the units are not scheduled for reactivation until the larger and newer units in ECS are returned to service. Although it cannot be stated with absolute certainty that the units will not be returned to service within the next five year period, it is highly probable that they will not operate.

It is proposed, therefore, that the extended cold storage of Southside Units 1 and 2 be considered to satisfy fully the intent of Condition of Certification I.E. Further, the JEA will commit to a 180 day advance notification of the planned start-up of Southside Units 1 and/or 2. An operating plan to offset these emissions would accompany the advance notification.

With regard to operation of SJRPP during an air pollution episode pursuant to 17-2.320(3), FAC, it is proposed that the SJRPP facility continue to operate normally during any episode level, i.e., alert warning or emergency.

This proposed operating plan during an air episode period is recommended because of the advanced degree of pollution control equipment installed at SJRPP. The control devices include boiler design to minimize nitrogen oxides, electrostatic precipitators and flue gas desulfurization. The flue gas from the facility then exits through a 640 foot stack.

(CONT.)

It should be recognized that the balance of the JEA system (Northside, Southside and Kennedy generating stations) would remain under an episode plan on file with the FDER and the Jacksonville Bio-Environmental Services Division. The operation of SJRPP would enhance the ability of load shift and unit shutdown required, under certain episode conditions, of JEA's existing steam generating units.

Your consideration of the above information to satisfy the requirements of Condition of Certification I.E. is most appreciated. Please contact me (904-633-4517) if there are any questions concerning the operating plan.

Very truly yours,

Richard Breitmoser (ags)

Richard Breitmoser, P.E.
Division Chief
Research & Environmental
Affairs Division

RB/lwr

cc: E. Frey (FDER)
D. Bayly (BES)

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32301-8241

DEPARTMENT OF ENVIRONMENTAL REGULATION STATE OF FLORIDA

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

September 26, 1986

Mr. Mike Brandon
Air Progress Branch
U.S. EPA - Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30365

Dear Mr. Brandon:

Re: Revision of PSD-FL-010, JEA Coal Conveyor

The Jacksonville Electric Authority (JEA) published the public notice for the above referenced project on July 28, 1986, in the Florida Times Union. The only comments received during the public comment period were from JEA. I have enclosed copies of the public notice and comments for your review.

If you have any questions or need additional information, please call me at (904)488-1344.

Sincerely,

Edward J. Svec

Edward J. Svec
Senior Compliance Engineer
Bureau of Air Quality
Management

ES/ks

cc: Richard Breitmoser, P.E.

SJRCTENV 86-30

JACKSONVILLE ELECTRIC AUTHORITY
P. O. BOX 53015
233 W. DUVAL STREET
JACKSONVILLE, FL 32201

August 27, 1986

DER
AUG 28 1986
BAQM

st. johns river POWER PARK

Mr. Ed Svec
Bureau of Air Quality Management
Fla. Dept. of Env. Regulation
2600 Blair Stone Road
Tallahassee, Florida 32301

Dear Mr. Svec:

Re: Jacksonville Electric Authority
St. Johns River Coal Terminal
Revision of PSD Permit PSD-FL-010

Please consider the following comments during the review of the permit modifications requested. Public notice of our permit modification request was published on July 28, 1986, initiating a 30 day comment period. These comments are being submitted within the 30 day comment period.

1. <u>Please review existing PSD permit language contained in Section V, Conclusion, Item 3 (page 10) which states:</u>

"Emission points 3 through 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."

We believe this language should be modified based on the following points:

a) Many of emission points 3 through 13 of Table 6 are fugitive-type sources. Therefore, mass emission rate compliance tests are extremely difficult, if not impossible, to perform accurately. In practice, permit compliance will consequently be determined in reference to the opacity standard. Emission points 14 and 15 are also fugitive-type sources which should also have been included under the mass emission rate compliance test exemption. This omission appears to have been an oversight in the original permit.

b) The function of Table 6 is to present "allowable emission limits". For emission points 3 through 15, particulate emission limits are expressed as both an opacity and a pound per hour limitation. The relationship between the mass emission and opacity limits for a given source on Table 6 are not clear, especially in reference to fugitive-type emission sources. At best, the relationship

(CONT.)

between mass emissions and opacity is theoretical. In practice, there are many variables that prevent a clear relationship. Therefore, the provision of both an opacity and a mass emission rate standard establishes 2 separate, conflicting limits.

c) A 10% opacity standard is the applicable emission limit intended by both EPA and FDER (Conditions of Certification) at the time of permit issuance.

A revision of Table 6 of our PSD permit was requested in our modification submittal dated May 12, 1986. As a bookkeeping matter emission sources 3 through 15 in the existing permit would become sources 3 through 19 in the proposed modification of Table 6.

To summarize, Table 6 references two types of particulate standards which are related in a variable fashion which is imperfectly understood in actual practice, especially for fugitive sources. Therefore, the values specified for the two types of standards are contradictory. One type of standard (mass emissions) is difficult or impossible to measure accurately for fugitive sources. The other standard (10% opacity) is reinforced as EPA and FDER intent by textual citations elsewhere. In light of these considerations, and the proposed renumbering of emission sources in Table 6, we request that the aforementioned permit language be replaced by:

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

2. <u>Please delete mass emission rate limits for Table 6 for emission points 4 through 15 (emission points 4 through 19 in the proposed revision of Table 6)</u>.

In light of the previous discussion and presuming agency acceptance of request (1), the presence of mass emission rate limits for fugitive sources on a table entitled "Allowable Emission Limits" is confusing. The mass emission rate values that appear in both the existing permit and in the proposed revision are estimates only, based on AP-42 emission factors and estimates of control efficiency. The numbers are helpful to indicate the approximate significance of various emission points, but in any given instance an AP-42 emission factor may not precisely predict emission levels, specially with regard to

(CONT.)

fugitive sources. EPA acknowledges the variation in reliability among the AP-42 emission factors by assigning reliability ratings. The reliability ratings assigned to factors that estimate fugitive dust emissions tend toward the bottom.

The mass emission rate estimates contained in our PSD permit modification request were developed to be used in a emission offset procedure to determine whether the emissions associated with a design change would be greater or less than the emissions associated with the original design.

Therefore, we request that numbers presented as mass emission rate estimates only, should not be cited in a table entitled "Allowable Emission Limits", and that therefore mass emission rate limits for sources 4 through 15 (4 through 19 in the proposed revision of Table 6) should not appear in Table 6.

If you would like to discuss this matter further, please call Ms. Athena Tsengas at (904) 633-4517.

Very truly yours,

Richard Breitmoser (ajt)

Richard Breitmoser, P.E.
Division Chief
Research & Environmental
Affairs Division

RB/AJT/lwr

cc: Clair Fancy

JACKSONVILLE ELECTRIC AUTHORITY
P. O. BOX 53015
233 W. DUVAL STREET
JACKSONVILLE, FL 32201

SJRCT 86-33

DER

AUG 6 1986

BAQM

st. johns river POWER PARK

August 1, 1986

Mr. Edward Svec
Review Engineer
Bureau of Air Quality Management
Fla. Dept. of Env. Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32301-8241

Dear Mr. Svec:

Subject: Jacksonville Electric Authority
St. Johns River Power Park and
St. Johns River Coal Terminal
Certification of Public Notice

Enclosed is a copy of the Public Notice which was printed in the Florida Times Union on July 28, 1986. The Public Notice is for the proposed revision of our federal permit PSD-FL-010.

If you have any questions, please feel free to call Athena Tsengas at (904) 633-4517.

Very truly yours,

Richard Breitmoser, P.E.
Division Chief
Research & Environmental
Affairs Division

ajt
RB/AJT/RLS/lwr

Enclosure: As Noted

The Florida Times-Union   Jacksonville Journal

FLORIDA PUBLISHING COMPANY

Publishers

JACKSONVILLE, DUVAL COUNTY, FLORIDA

STATE OF FLORIDA
COUNTY OF DUVAL

Before the undersigned authority personally appeared George A. Dan who on oath says that he is Retail Advertising Manager of The Florida Times-Union, and Jacksonville Journal, daily newspapers published at Jacksonville in Duval County, Florida; that the attached copy of advertisement, being a Legal Notice in the matter of Public Notice

in the ______ Court,

was published in The Florida Times Union

in the issues of July 28, 1986

Affiant further says that the said The Florida Times-Union and Jacksonville Journal are each newspapers published at Jacksonville, in said Duval County, Florida, and that the said newspapers have each heretofore been continuously published in said Duval County, Florida, The Florida Times-Union each day, and Jacksonville Journal each day except Sundays, and each has been entered as second class mail matter at the postoffice in Jacksonville, in said Duval County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in said newspaper.

Sworn to and subscribed before me this 28th day of July A.D. 1986

[signature]

Notary Public,
State of Florida at Large.

[signature] George A Dan

My Commission Expires NOTARY PUBLIC, STATE OF FLORIDA
My commission expires Feb. 19, 1989

DA 444

Public Notice

On May 12, 1986, the Jacksonville Electric Authority requested that their Prevention of Significant Deterioration permit (PSD-FL-010) for two coal-fired steam generating units adjacent to the existing JEA Northside Generation Station near Jacksonville, Florida, be revised. This permit was based on rail delivery of coal from the St. Johns River Coal Terminal to the St. Johns River Power Park. The requested revision to the permit will replace the railcar system with a 3.2 mile overland, fully enclosed conveyor system to transfer coal to the Power Park and additional coal blending capability within the existing Power Park coal stockyard. The requested revision will result in a projected decrease of 0.10 pound per hour of particulate matter.

Any person may submit written comments regarding this proposed permit revision. All comments must be received not later than 30 days from the date of this notice in order to be considered. A public hearing may be held if sufficient justification is provided, as determined by the Administrator. Letters should be addressed to:

Mr. C. H. Fancy, P.E.
State of Florida Department of Environmental Regulation
Bureau of Air Quality Management
2600 Blair Stone Road
Tallahassee, Florida 32301

C. Fancy

JACKSONVILLE ELECTRIC AUTHORITY
P. O. BOX 53015
233 W. DUVAL STREET
JACKSONVILLE, FL 32201

SJRCTENV 86-32

st. johns river POWER PARK

July 17, 1986

Mr. Hamilton S. Oven, Jr., P.E.
Administrator
Siting Coordination Section
Fla. Dept. of Env. Regulation
2600 Blair Stone Road
Tallahassee, Florida 32301

DER
JUL 21 1986
BAQM

Dear Mr. Oven:

Subject: Jacksonville Electric Authority
St. Johns River Coal Terminal
Response to BESD Letter

The Jacksonville Electric Authority (JEA) has received a copy of the Bio-Environmental Services Division (BESD) letter dated July 1, 1986, concerning the modification of the St. Johns River Coal Terminal's PSD permit. The purpose of this letter is to discuss BESD's comments, many of which JEA feels are based on information which has been taken out of context and are therefore not representative of expected operating conditions at the coal unloader and conveyor system. Listed below are JEA's responses to BESD's comments.

1. <u>BESD supports the design change from rail coal conveying to an enclosed belt conveyor.</u>

   JEA appreciates BESD's support of the conveyor design. JEA maintains that the transport of coal by an enclosed conveyor represents an improved design, resulting in reduced environmental impacts over the original rail transport design.

2. <u>Dust control on the ship unloader</u>

   JEA shares BESD's concern for potential deposition on the import car facilities; however, BESD's statement that emissions at the ship unloading point would be over 330% of the original value is based on an analysis taken out of context. It is true that the emissions from the ship unloading point will increase; however, in absolute terms, BESD has compared two very small numbers. The increase at the ship unloading point is from approximately 0.3 lb/hr to 1.0 lb/hr. In addition, a major point which seems to have been overlooked by BESD is that the current design modification will in fact result in a significant decrease in particulate emissions on Blount Island of approximately 5.1 lb/hr, not a "substantial increase" as indicated by BESD.

(CONT.)

JEA proposes to use wet dust suppression in addition to containment to meet the emission limits presented in the PSD modification. The vendor supplying the ship unloader (which will include the particulate control equipment) will be required per his contract to guarantee that the 10% opacity standard will be met.

3. <u>Separate BACT determinations</u>

The total emissions resulting from the modification of the PSD permit results in a net decrease in particulate emissions. Thus, re-addressing BACT (Best Available Control Technology) is not warranted by the proposed PSD modification.

4. <u>Lower the visible emission standard</u>

BESD asserts without supporting information that the visible emission standard should be reduced from 10% to 5% opacity. The initial licensing process for the Power Park and the coal unloading facility established a 10% standard. During this licensing process, analyses were conducted to determine the effect on ambient air quality and appropriate standards were set by the agencies. Since that time, ambient particulate levels have improved in Duval County resulting in a reduction in the size of the particulate non-attainment area. For this reason, there has been an increase in the distance between the non-attainment area boundary and the project site. This improvement along with the fact that the total emissions are slightly less than the original PSD permit levels would seem to justify the current 10% opacity level.

5. <u>Installation and operation of deposition monitoring station</u>

BESD has recommended that JEA install a particulate deposition monitor on Blount Island. In light of the proposed impact reduction in particulate emissions, JEA does not feel that a deposition monitoring program is necessary as part of the PSD permit. If this program is deemed necessary for some other regulatory purpose, JEA would be willing to discuss this matter further.

(CONT.)

If you have any questions or require any additional information, please feel free to contact me at (904) 633-4517.

Very truly yours,

Richard Breitmoser, P.E.
Division Chief
Research & Environmental
Affairs Division

RB/AJT/lwr

cc: Royce Lyles, JEA
Bill Stewart, DER
Clair Fancy, DER
Henry Colson, JPA
Paul deMariano, JPA
Bruce Miller, EPA
Ted Bisterfeld, EPA
Mike Branden, EPA
Ed Svec, FDER

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32301-8241

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

July 16, 1986

Mr. Mike Brandon
Air Programs Branch
U.S. EPA - Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30365

Dear Mr. Brandon:

Re: Revision of PSD-FL-010, JEA Coal Conveyor

In response to our telephone conversation, I am sending you a copy of the public notice that the Jacksonville Electric Authority will be publishing for their proposed revision to the coal handling facility at the St. Johns River Power Park. I will forward a copy of the proof of publication when we receive it.

I also have enclosed a copy of a letter from JEA concerning when the wet suppression system would be utilized. We recommended that this information be incorporated into your review and be included as a permit specific condition.

If you have any questions or need additional information, please call me at (904)488-1344.

Sincerely,

Edward J. Svec
Review Engineer
Bureau of Air Quality
Management

ES/ks

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32301-8241

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

July 16, 1986

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Athena Tsengas
Research and Environmental
Affairs Division
Jacksonville Electrical Authority
Post Office Box 53015
Jacksonville, Florida 32201

Dear Ms. Tsengas:

Attached is a public notice for the proposed revision to your federal permit PSD-FL-010. The notice must be published one time in a newspaper of general circulation servicing the area near the St. Johns River Coal terminal. When the notice appears in the newspaper, please forward a copy to me so we may continue to process your request.

If you have any questions, please feel free to call me at (904)488-1344 or write to me at the above address.

Sincerely,

Edward Svec
Review Engineer
Bureau of Air Quality
Management

ES/ks

Protecting Florida and Your Quality of Life

SENDER: Complete items 1, 2, 3 and 4.

Put your address in the "RETURN TO" space on the reverse side. Failure to do this will prevent this card from being returned to you. The return receipt fee will provide you the name of the person delivered to and the date of delivery. For additional fees the following services are available. Consult postmaster for fees and check box(es) for service(s) requested.

1. ☑ Show to whom, date and address of delivery.
2. ☐ Restricted Delivery.

3. Article Addressed to:
Athena Tsengas
JEA
P.O. Box 53015
Jacksonville, Fl 32201

4. Type of Service:
☐ Registered ☐ Insured
☑ Certified ☐ COD
☐ Express Mail

Article Number
P408 532 108

Always obtain signature of addressee or agent and DATE DELIVERED.

5. Signature – Addressee
X

6. Signature – Agent
X [signature]

7. Date of Delivery
7-22-86

8. Addressee's Address (ONLY if requested and fee paid)

PS Form 3811, July 1983 447-845

DOMESTIC RETURN RECEIPT

P 408 532 108

RECEIPT FOR CERTIFIED MAIL

NO INSURANCE COVERAGE PROVIDED—
NOT FOR INTERNATIONAL MAIL

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Sent to Athena Tsengas	
Street and No. Jea - P.O. Box 53015	
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Postage	$
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Special Delivery Fee	
Restricted Delivery Fee	
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Return Receipt Showing to whom, Date, and Address of Delivery	
TOTAL Postage and Fees	$
Postmark or Date	

PS Form 3800, Feb. 1982

SJRCTENV 86-30

June 27, 1986

JACKSONVILLE ELECTRIC AUTHORITY
P. O. BOX 53015
233 W. DUVAL STREET
JACKSONVILLE, FL 32201

DER

JUL 3 1986

BAQM

Mr. Ed Svec
Environmental Specialist
Stationary Source Control Group
Fla. Dept. of Env. Regulation
2600 Blair Stone Road
Tallahassee, Florida 32301-8241

Dear Mr. Svec:

Re: Jacksonville Electric Authority (JEA)
St. Johns River Coal Terminal
Operation of Wet Suppression System

On June 6, 1986 a meeting was held with you, Mr. David Atkin (Soros Associates) and Ms. Athena Tsengas (JEA) to discuss the air emission aspects of the St. Johns River Coal Terminal (SJRCT). During the discussions you brought out that the PSD permit condition for the type of emission presently in this project would require that the wet suppression system be utilized whenever coal is handled. However, it was discussed that some coal may arrive wet and would not generate dust during handling. Thus, adding water to the already wet coal would only reduce the heating value of the coal without any effect on emissions. Therefore, it was recommended that JEA propose some type of operational procedure which would ensure that the 10% opacity limit would be met while enabling JEA to determine whether or not wet suppression should be utilized.

The following operational procedure was discussed with you in a telephone conversation with D. Atkin and A. Tsengas on June 20, 1986:

> "An observation will be conducted by the unloading facility shift supervisor at the beginning of the vessel unloading consisting of 2 or 3 lifts of coal to determine if wet suppression is required. The shift supervisor will be responsible for monitoring dust emissions during the entire unloading process. If visible emissions are observed at the bucket discharge to the ship unloader hopper, the shift supervisor will direct the wet suppression system, including sprays at conveyor transfers, to be activated. Activation of the system shall result in compliance with the 10% opacity standard."

Please note that we are not proposing any change to the 10% opacity standard for the emmision sources.

The job description for the SJRCT shift supervisor will include the language stated above.

(CONT.)

JEA therefore proposes this operating procedure, in lieu of a permit requirement which would require the activation of the wet suppression system at all times when coal is being handled, regardless of the presence or absence of dust emissions.

If you have any questions or require further information, please contact Ms. Athena Tsengas at (904) 633-4517.

Very truly yours,

Richard Breitmoser, P.E.
Division Chief
Research & Environmental
Affairs Division

RB/AJT/lwr

cc: H.S. Oven (FDER)

DEPARTMENT OF HEALTH, WELFARE
& BIO-ENVIRONMENTAL SERVICES
Bio-Environmental Services Division
Air and Water Pollution Control

July 1, 1986

DER
JUL 3 1986
BAQM

Mr. Hamilton S. Oven, Jr., P.E.
Administrator
Siting Coordination Section
Department of Environmental Regulation
2600 Blair Stone Road
Twin Towers Office Bldg.
Tallahassee, Florida 32301

Re: Jacksonville Electric Authority
St. John River Power Park
Coal Unloading Facility
Coal Conveyor System
PSD Permit No. PSD FL-10

Dear Mr. Oven:

The Bio-Environmental Services Division (BESD) provides the following comments on the proposed revision to the coal unloading operation at the referenced facility:

(1) BESD supports the design change from rail coal conveying to an enclosed belt conveyor.

(2) The proposed controlled emission rate at the ship unloading point (two grab buckets) is over 330% of the original value. This increase of particulate emissions at this point of the coal handling process is of particular concern to this agency, from the standpoint of particulate deposition. Blount Island, the site of the coal unloading operation, is the terminal where thousands of vehicles are imported into the country on an annual basis. During the past few years numerous episodes of material deposition affecting these vehicles have occurred, resulting in damage worth thousands of dollars to the importers and the possible consequence of relocation of the import operation itself to another area.

The proposed changes do not result in a net significant emission increase from the entire coal handling process; however, substantial increase is being proposed at the ship unloading area and this may result in adverse deposition rates at the import car facilities.

The BESD has therefore concluded that BACT for the ship unloading area is not the wet suppression method of control (as proposed) but is in fact the dry dust control method (i.e. capture and evacuation to a bag house) which is in the current certification and PSD permit.

ALL-AMERICA CITY
AREA CODE 904 / AIR POLLUTION — 633-3033 OR 633-3303 / WATER POLLUTION — 633-3415
515 WEST 6TH STREET / JACKSONVILLE, FLORIDA 32206—4397

(3) It is noted that the ship unloading operation is approximately 5000 feet from the coal storage areas at the power park. BACT determination should therefore be made separately for each of the following areas:

(A) Ship unloading operation
(B) Coal conveyor system
(C) Coal handling and storage at the power park.

(4) The visible emission standard of 10% opacity (DER Condition of Certification 1.A) should be changed to 5% opacity.

(5) The permit should require the installation and continuous operation of a particulate deposition monitor at Blount Island in the close vicinity of the unloading operation.

Your consideration of the above is appreciated.

If BESD may be of further assistance, please advise.

Very truly yours,

Khurshid K. Mehta, P.E.
Pollution Control Engineer

KKM/ecr

cc: Mr. Bill Stewart, P.E., DER
Mr. Clair Fancy, P.E., DER
Mr. Richard Breitmoser, P.E., JEA
Mr. Henry Colson, JPA
Mr. Bruce Miller, EPA
Nissan
World Cars
Hobelmann
BESD File 1710 A

State of Florida

DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices And/Or To Other Than The Addressee	
To: Clair Fancy	Loctn.: BAQM
To:	Loctn.:
To:	Loctn.:
From:	Date:

Ed Svec 5/5
please review, with Barry, I would like to sign off before going to Buck. (I know you are busy)
Cl

DER
MAY 1 1986
BAQM

TO: Power Plant Siting Review Committee

FROM: H.S. Oven, Jr HSO

DATE April 30, 1986

SUBJECT: JEA St Johns River Power Park Coal Conveyor PA 81-13.

Please review the attached amendment to the JEA Power Plant Siting Application. Please send me any request for addition information by May 23, 1986. I will need final comment, field report and recommendation by July 10, 1986.

HSOjr/dh

Call Mike Brandon
when decision is made
(404) 347 - ~~7704~~
4253

H6 - Rev 7/76

Public Notice

On May 12, 1986, the Jacksonville Electric Authority requested that their Prevention of Significant Deterioration permit (PSD-FL-010) for two coal-fired steam generating units adjacent to the existing JEA Northside Generation Station near Jacksonville, Florida, be revised. This permit was based on rail delivery of coal from the St. Johns River Coal Terminal to the St. Johns River Power Park. The requested revision to the permit will replace the railcar system with a 3.2 mile overland, fully enclosed conveyor system to transfer coal to the Power Park and additional coal blending capability within the existing Power Park coal stockyard. The requested revision will result in a projected decrease of 0.10 pound per hour of particulate matter.

Any person may submit written comments regarding this proposed permit revision. All comments must be received not later than 30 days from the date of this notice in order to be considered. A public hearing may be held if sufficient justification is provided, as determined by the Administrator. Letters should be addressed to:

Mr. C. H. Fancy, P.E.
State of Florida Department of Environmental Regulation
Bureau of Air Quality Management
2600 Blair Stone Road
Tallahassee, Florida 32301

JACKSONVILLE ELECTRIC AUTHORITY
P. O. BOX 53015
233 W. DUVAL STREET
JACKSONVILLE, FL 32201

st. johns river POWER PARK

SJRCTENV-86-20

May 15, 1986

Mr. Hamilton S. Oven, Jr., P.E.
Administrator of Power Plant Siting
Fla. Dept. of Env. Regulation
2600 Blair Stone Road
Tallahassee, Florida 32301-8241

Dear Mr. Oven:

Subject: SJRPP/SJRCT, Amendment to SCA/EID Table 3.8-3
Fugitive Emission & Control Summary

In accordance with the Florida Power Plant Siting Act, Part II, Chapter 403, Florida Statutes, the Jacksonville Electric Authority (JEA) has previously been granted certification for the location, construction, and operation of the St. Johns River Power Park Units 1 and 2, and its associated facilities including a coal unloading facility and transmision lines.

The present design of the St. Johns River Coal Terminal, includes a 3.2 mile overland, fully enclosed conveyor system to transport coal to the Power Park, and the addition of equipment for coal blending capability within the existing Power Park coal stockyard. Thus, it has become necessary to amend Table 3.8-3 of the Site Certification Application/Environmental Information Document (SCA/EID). Table 3.8-3 provides the fugitive dust control techniques and the expected fugitive emission rates from the various sources associated with the Power Park and St. Johns River Coal Terminal.

This submittal request is being made in accordance with Condition of Certification XXVII, which requires JEA to notify the Department of such SCA/EID amendments. It is our understanding that notice of the SCA/EID amendment must be provided to all parties to the certification proceeding and will be handled by the Department's counsel. We request that copies of all such noticing documents be sent to Mr. William Preston (Hopping Boyd Green & Sams), JEA's counsel. Please let me know if I or Mr Preston can be of any assistance in giving the required notices.

If you have any questions or require additional information, please contact Athena Tsengas at (904) 633-4517.

Sincerely,

Richard Breitmoser (ajt)

Richard Breitmoser
Division Chief
Research & Environmental
Affairs Division

RB:AT:mm ajt lc

cc: w. Preston (HBG&S) w/Attachment

Attachment: Figure 3.8-3 (Revision 2) - Fugitive Emission & Control Summary

Table 3.8-3 (Revision 2)
Fugitive Emissions and Control Summary

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

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

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

0400b(050886)PM

ag-S

JACKSONVILLE ELECTRIC AUTHORITY
P. O. BOX 53015
233 W. DUVAL STREET
JACKSONVILLE, FL 32201

st. johns river POWER PARK

SJRCTENV 86-18

May 12, 1986

Mr. Bruce Miller
Acting Chief
Air Programs Branch
U.S. EPA - Region IV
345 Courtland Street, N. E.
Atlanta, Georgia 30365

Dear Mr. Miller:

Subject: Jacksonville Electric Authority
PSD Permit No. PSD-FL-010 Revision Request
St. Johns River Power Park and the
St. Johns River Coal Terminal

In accordance with the Florida Power Plant Siting Act, Part II, Chapter 403, Florida Statutes, the Jacksonville Electric Authority (JEA) has previously been granted certification for the location, construction, and operation of the St. Johns River Power Park Units 1 and 2, and its associated facilities including a coal unloading facility.

This Certification Order, issued on June 29, 1986 also addresses the construction and operation of a conveyor system to transport coal from the coal unloading facility, the St. Johns River Coal Terminal, on the south side of Blount Island to the main plant site.

On March 12, 1982, the United States Environmental Protection Agency, Region IV, issued permit number PSD-FL-010 to the JEA for the construction of the St. Johns River Power Park and St. Johns River Coal Terminal under the rules for the Prevention of Significant Deterioration of Air Quality. This permit was based on rail delivery of coal from St. Johns River Coal Terminal to the St. Johns River Power Park. The present coal unloading facility design includes a 3.2 mile overland, fully enclosed conveyor system to transport coal to the Power Park, in lieu of a railcar system. In addition, additional equipment for coal blending capability within the existing Power Park coal stockyard has been included in the design. JEA is requesting a revision of the existing PSD permit to incorporate these design changes.

Enclosed is a copy of the report containing particulate emission estimates for the coal terminal modifications, and additions to the Power Park coal handling system to enhance coal blending.

Appendix C of the report contains requested revisions to Tables 2 and 6 of the existing PSD permit. Emission estimates have only been revised for those sources which have been changed by the coal terminal design modifications and blending additions.

(CONT.)

Please contact Ms. Athena Tsengas at (904) 633-4517 if you have any questions or require additional information.

Very truly yours,

Richard Breitmoser, P.E.
Division Chief
Research & Environmental
Affairs Division

RB/AJT/lwr

cc: H. S. Oven, Jr. (FDER)
T. Bisterfeld (EPA) - w/o atta.

Attachment: Estimation of Particulate Emissions: St. Johns River Coal Terminal and Blending Additions at the St. Johns River Power Park

ESTIMATION OF PARTICULATE EMISSIONS:
ST. JOHNS RIVER COAL TERMINAL
AND BLENDING ADDITIONS AT
ST. JOHNS RIVER POWER PARK

Jacksonville Electric Authority

May, 1986

0357b, 5786AM

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0357b, 5786AM

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LIST OF TABLES

0357b, 5786AM

LIST OF FIGURES

1.0 INTRODUCTION

This analysis has been prepared by Soros Associates to support the request for a modification of the existing Prevention of Significant Deterioration (PSD) Permit (PSD-FL-010) issued by EPA on March 12, 1982 for the St. Johns River Power Park (SJRPP) and its ancillary facilities. These modifications are necessary because of design changes since the issuance of the existing permit. These design changes affect the St. Johns River Coal Terminal (SJRCT) and the coal handling system at the Power Park. These changes have resulted from the following two design modifications: a conveyor belt system to transport coal from the SJRCT to the Power Park in lieu of rail car conveyance of coal, and enhancement of coal blending capability within the boundaries of the Power Park.

In this report, particulate emissions are estimated for the coal terminal and additions to the Power Park coal handling system to enhance coal blending. These estimates are based on the design and control equipment for those emission sources which have changed from those described in the original PSD permit. Emissions are estimated using the latest available emission factors accepted and recommended by the U.S. Environmental Protection Agency (EPA). This analysis only includes particulate emission estimates for sources which are being modified.

2.0 OVERVIEW OF THE EQUIPMENT AND DUST CONTROL MEASURES

2.1 BACKGROUND

At the time that the existing PSD permit was reviewed and issued, the proposed means of conveying coal from the St. Johns River Coal Terminal (SJRCT) to the Power Park was a shuttle train service. The present SJRCT design includes a fully enclosed conveyor system to transport the coal, in lieu of the shuttle train. In addition, the interface between the overland conveyor system and the existing coal handling system at the Power Park has been designed to enhance coal blending capability within the existing coal stockyard.

Drawing 94120-02B provides a plan view of the overland conveyor system. Drawing 94120-08B shows design details of the interface between the overland conveyor system and the existing coal handling system to enhance coal blending. Drawing 94120-11B is the schematic material flow diagram, and Drawing 94120-12B shows the proposed dust control measures schematically.

The air pollutant which will be generated by the St. Johns River Coal Terminal (SJRCT) and the additions to the Power Park's coal handling system to enhance coal blending capability, is particulate matter (PM). Fugitive emissions are defined by EPA as those emissions which do not pass through a stack, chimney, vent, or other functionally equivalent opening. Therefore, the emissions from the sources in this project are considered "fugitive". This material becomes airborne when air is mixed with small particles of coal during handling operations. The particulate material is denser than air, and larger particulates quickly settle out of the atmosphere over time and distance. However, dust must still be controlled before it becomes an environmental nuisance. In this case, the dust is to be controlled by means of containment and suppression. These two technologies will result in controlled emission levels fully consistent with the existing PSD Permit.

The equipment applicable to the facilities above are:

- o Ship Unloaders
- o Conveyors
- o Conveyor Transfers
- o Traveling Stacker
- o Bucket Wheel Reclaimer

Some of this equipment represents a modification to the design which is licensed in the existing PSD permit.

2.2 SHIP UNLOADERS

The ultimate phase of the project will require two ship unloaders. During the initial phase, one ship unloader having the free digging capacity of unloading coal at 1,500 short tons per hour (STPH) will be used; the second phase will require a ship unloader with a free digging capacity of unloading coal at 700 STPH. Thus, a maximum of approximately 2,200 STPH of coal could be unloaded by the two ship unloaders. As indicated in the existing PSD Permit, this report is based on two grab bucket unloaders.

Dust emissions from the ship unloaders are to be controlled by means of (1) a drip plate to catch material which may fall from the grab bucket before discharge, (2) wind guards at the receiving hopper to form an enclosure, (3) spray headers around the hopper opening to suppress any escaping dust, and (4) spray headers at the belt feeder transfers below the receiving hopper. These sprays, as well as the other sprays throughout the facility, will be fed a mixture of water and a chemical additive "wetting agent." The "wetting agent" enhances the control provided by the sprays.

In Appendix C, the emissions from ship unloaders and associated coal transfer operations are included in the tables as follows:

Table 2:
- o Process No. 1--Ship Unloading (2 Grab Buckets).
- o Process No. 2--Feeders to Conveyor A (2 points).

Table 6:
- o Emission Unit No. 4--Ship Unloading (2 Grab Buckets).
- o Emission Unit No. 5--Feeders to Conveyor A (2 points).

2.3 CONVEYORS

The overland conveyor system consists of Conveyors A, B, C and D. Conveyors E and F have been added to the existing coal handling system at the Power Park to enhance coal blending.

The belt conveyors will be provided with continuous hood covers (except as noted in the following paragraph) which will extend below the return side of the conveyor belt and enclose it in all directions, i.e., "total enclosure." Belts will be scraped and/or plowed at the ends of the runs to remove residual dust from the return belt strand.

Where the tops of Conveyors A and D must remain open to receive or discharge material, such as along the ship unloader travel and the segments along which the stacker and reclaimer travel, there will be wind guards on each side of the belt. Where Conveyor C crosses Blount Island Boulevard and Heckscher Drive, it will be enclosed within a full gallery structure so that any equipment dropped by personnel on the walkways does not fall onto the road below.

The return strands on Conveyors B and C will be turned over at the terminals so that the dirty side of the return strand is turned up, to minimize material drop-off along the return run and reduce maintenance cleanup within the total enclosure.

2.4 CONVEYOR TRANSFERS

Coal dust emissions at conveyor transfers are to be controlled by fully enclosing the transfers and spraying at selected transfers. Enclosures at conveyor transfers will be chutes with skirtboards, dust curtains, and other dust seals that fully enclose the material transfers.

Sprays will be located within the chutes at the following transfers:

1. Transfer Station No. 1 (Conveyor A to Conveyor B)
2. Transfer Station No. 2 (Conveyor B to Conveyor C)

Sprays will not be provided at the remaining transfer stations because the water and "wetting agent" provided at the spray points upstream will increase the moisture content and condition the coal sufficiently to control dust generation at the downstream transfers not equipped with sprays, which will be fully enclosed in any case.

All conveyor transfers and enclosures along conveyor belts will be cleaned regularly with the vacuum system described in Section 2.7.

In Appendix C, the remaining conveyor transfers are identified in the tables as follows:

Table 2:
- o Process No. 3--Conveyor Transfers 1 and 2 (2 points).
- o Process No. 4--Conveyor Transfers 3, 4, 5 and D to D by-pass (4 points).
- o Process No. 5 -- Conveyor Transfers 6 and 7 (2 points).

Table 6:
- o Emission Unit No. 6--Conveyor Transfers 1 and 2 (2 points).
- o Emission Unit No. 7--Conveyor Transfers 3, 4, 5 and D to D by-pass (4 points).
- o Emission Unit No. 8--Conveyor Transfers 6 and 7 (2 points).

2.5 TRAVELING STACKER

Coal arriving at the Power Park from the overland conveyor system may be placed into storage at the Power Park with a travelling stacker. Alternatively, coal can by-pass the stacker and be placed directly on the existing coal handling system at the Power Park, via conveyors D and E.

Internal transfers within the stacker will be enclosed, and the boom conveyor on the stacker will be provided with a hood cover. The machine has a luffing capability so that the drop height from the head pulley of the boom conveyor to the stockpile will be minimized at all times.

In Appendix C, the traveling stacker is included in the tables as follows:

Table 2: o Process No. 6--Traveling Stacker (3 points).

Table 6: o Emission Unit No. 9--Traveling Stacker (3 points).

2.6 BUCKET WHEEL RECLAIMER

To enhance blending capability, a bucket wheel reclaimer will be provided. Coal reclaimed by the bucket wheel reclaimer will discharge to Conveyor D. The boom conveyor on the reclaimer will be provided with a hood cover, and internal transfers will be enclosed.

In Appendix C, the emission from the bucket wheel reclaimer is included in the tables as follows:

Table 2: o Process No. 7--Bucket Wheel Reclaimer (2 points).

Table 6: o Emission Unit No. 10--Bucket Wheel Reclaimer (2 points).

2.7 VACUUM CLEANUP SYSTEM

A vacuum cleanup system will be provided at transfer stations and along belt runs. The system will be powered by a mobile vacuum unit which would also be available for general cleanup purposes.

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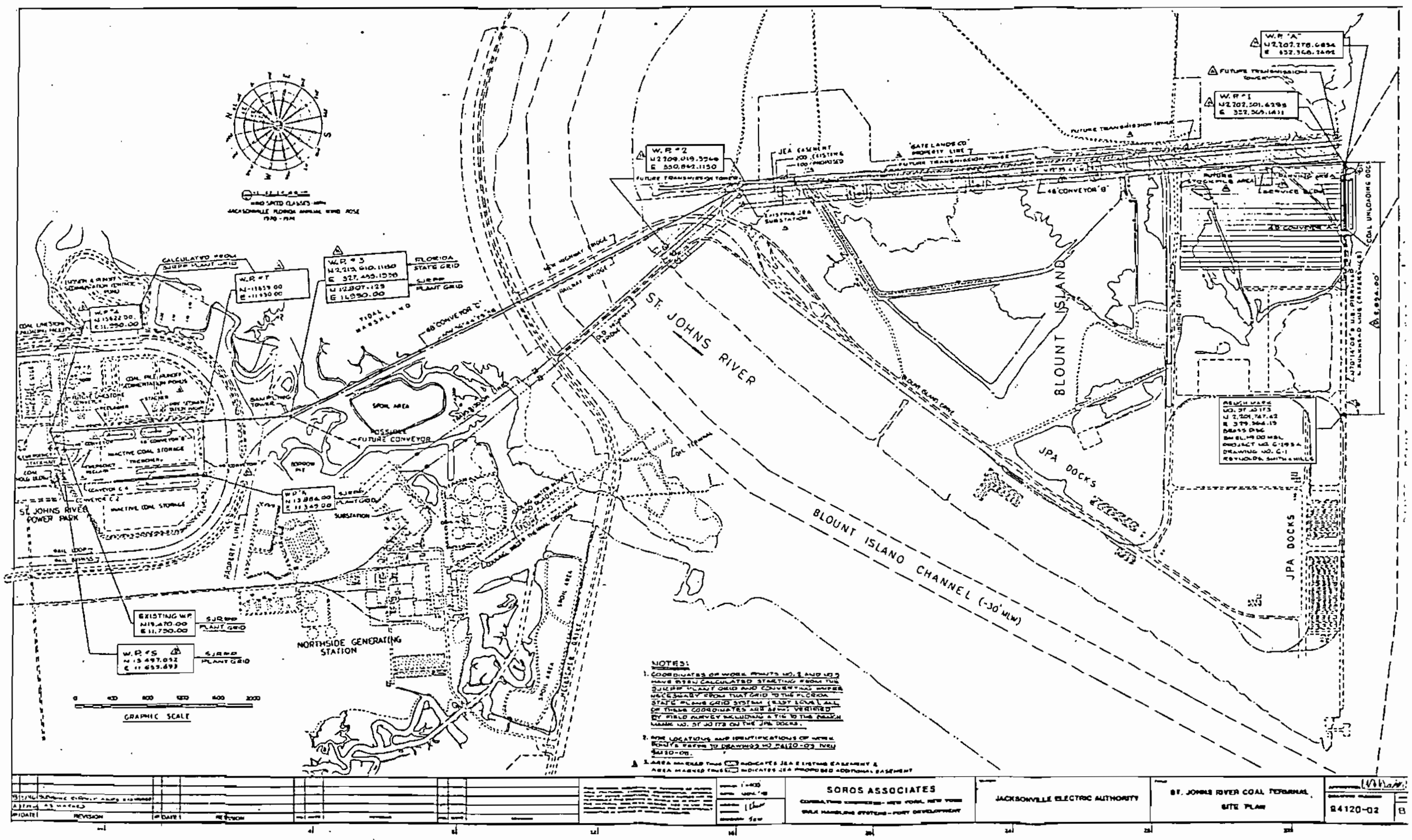

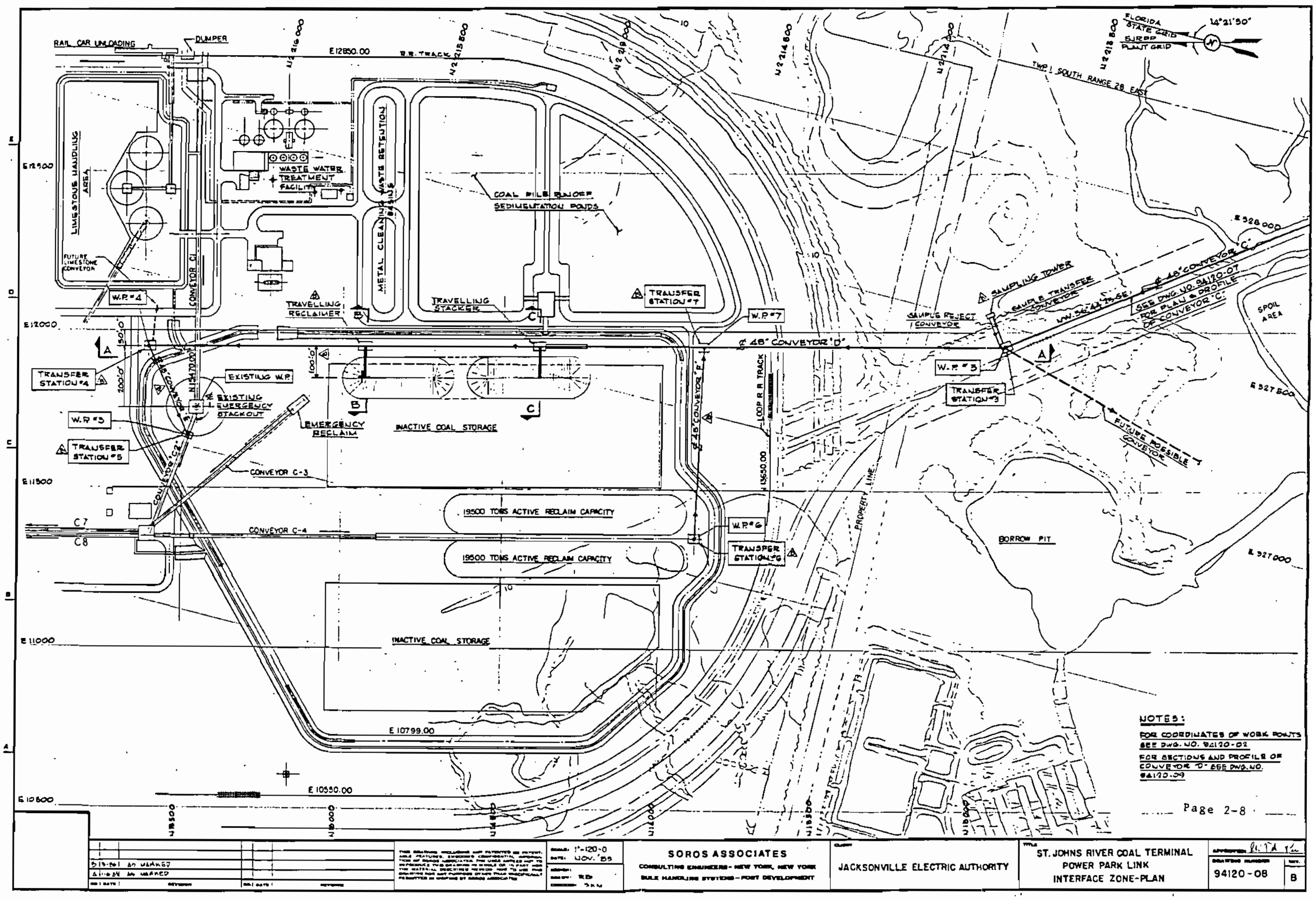
RAIL CAR UNLOADING
DUMPER
E 12850.00
R.R. TRACK
LIMESTONE HANDLING AREA
FUTURE LIMESTONE CONVEYOR
WASTE WATER TREATMENT FACILITY
METAL CLEANING WASTE RETENTION BASINS
COAL PILE RUNOFF SEDIMENTATION PONDS
TWP 1 SOUTH RANGE 28 EAST
FLORIDA STATE GRID
PLANT GRID
14°21'50"
E 12000
E 11500
E 11000
E 10800
E 10799.00
E 10550.00
E 528 000
E 527 500
E 527 000
W.P. #4
W.P. #3
W.P. #5
W.P. #6
W.P. #7
TRAVELLING RECLAIMER
TRAVELLING STACKER
TRANSFER STATION #7
TRANSFER STATION #4
TRANSFER STATION #5
TRANSFER STATION #6
TRANSFER STATION #3
EXISTING W.P.
EXISTING EMERGENCY STACKOUT
EMERGENCY RECLAIM
INACTIVE COAL STORAGE
CONVEYOR C1
CONVEYOR C-3
CONVEYOR C-4
C7
C8
℄ 48" CONVEYOR 'D'
℄ 48" CONVEYOR 'E'
LOOP R R TRACK
19500 TONS ACTIVE RECLAIM CAPACITY
19500 TONS ACTIVE RECLAIM CAPACITY
PROPERTY LINE
BORROW PIT
SPOIL AREA
SAMPLING TOWER
SAMPLE TRANSFER CONVEYOR
SAMPLE REJECT CONVEYOR
℄ 48" CONVEYOR 'C'
SEE DWG. NO. 94120-07 FOR PLAN & PROFILE OF CONVEYOR 'C'
FUTURE POSSIBLE CONVEYOR
NOTES:
FOR COORDINATES OF WORK POINTS SEE DWG. NO. 94120-02
FOR SECTIONS AND PROFILE OF CONVEYOR "D" SEE DWG. NO. 94120-09
SOROS ASSOCIATES
CONSULTING ENGINEERS - NEW YORK, NEW YORK
BULK HANDLING SYSTEMS - PORT DEVELOPMENT
JACKSONVILLE ELECTRIC AUTHORITY
ST. JOHNS RIVER COAL TERMINAL
POWER PARK LINK
INTERFACE ZONE-PLAN
1"=120-0
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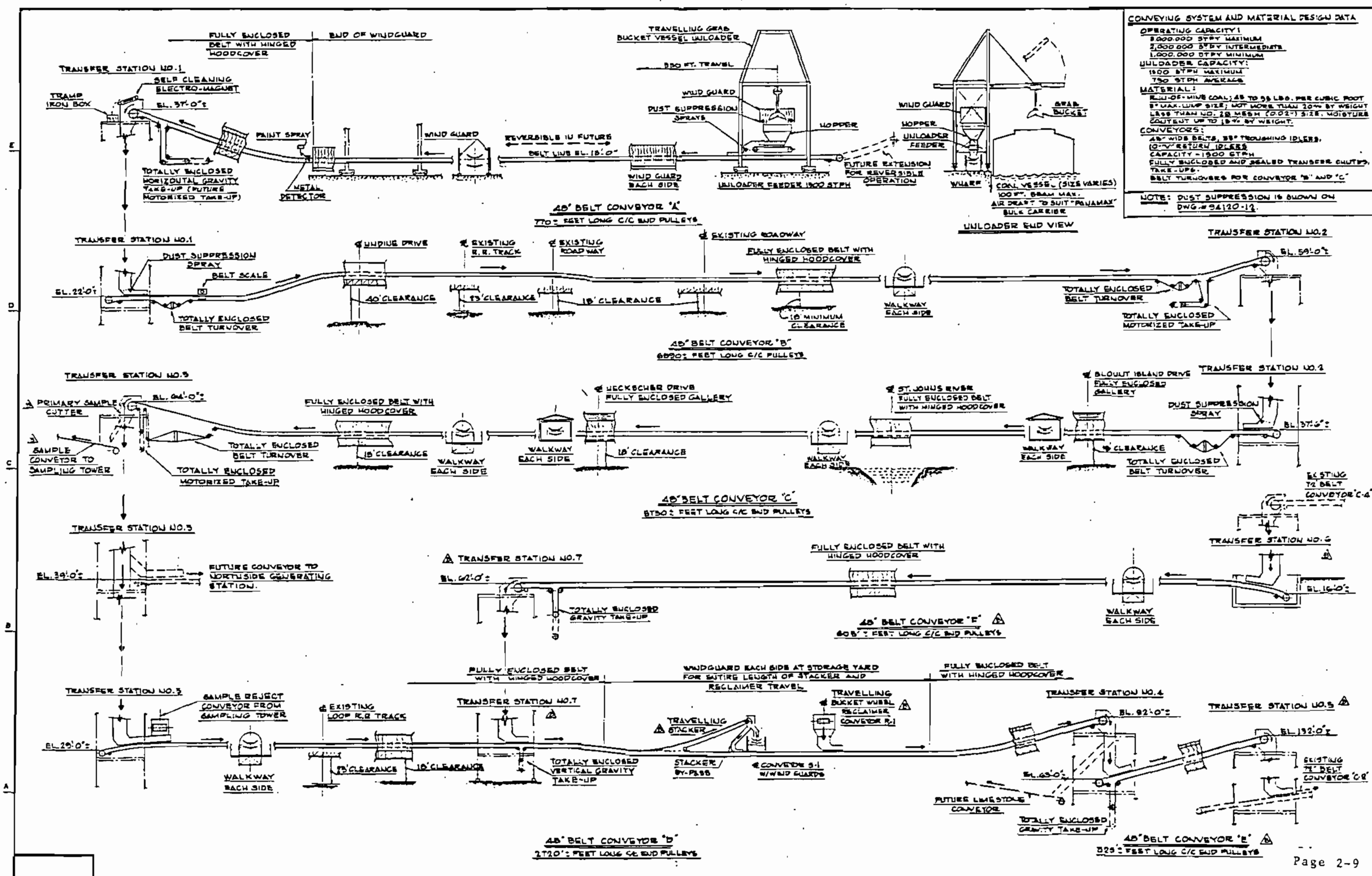

B 12/86 BENDING CIRCUIT CONV. B & C ADDED A As marked	SCALE: NONE DATE: NOV. '85 W.A.C. RCB S.K.U.	SOROS ASSOCIATES CONSULTING ENGINEERS - NEW YORK, NEW YORK BULK HANDLING SYSTEMS - PORT DEVELOPMENT	JACKSONVILLE ELECTRIC AUTHORITY	ST. JOHNS RIVER COAL TERMINAL SYSTEM FLOW DIAGRAM MATERIAL HANDLING	94120-11 B

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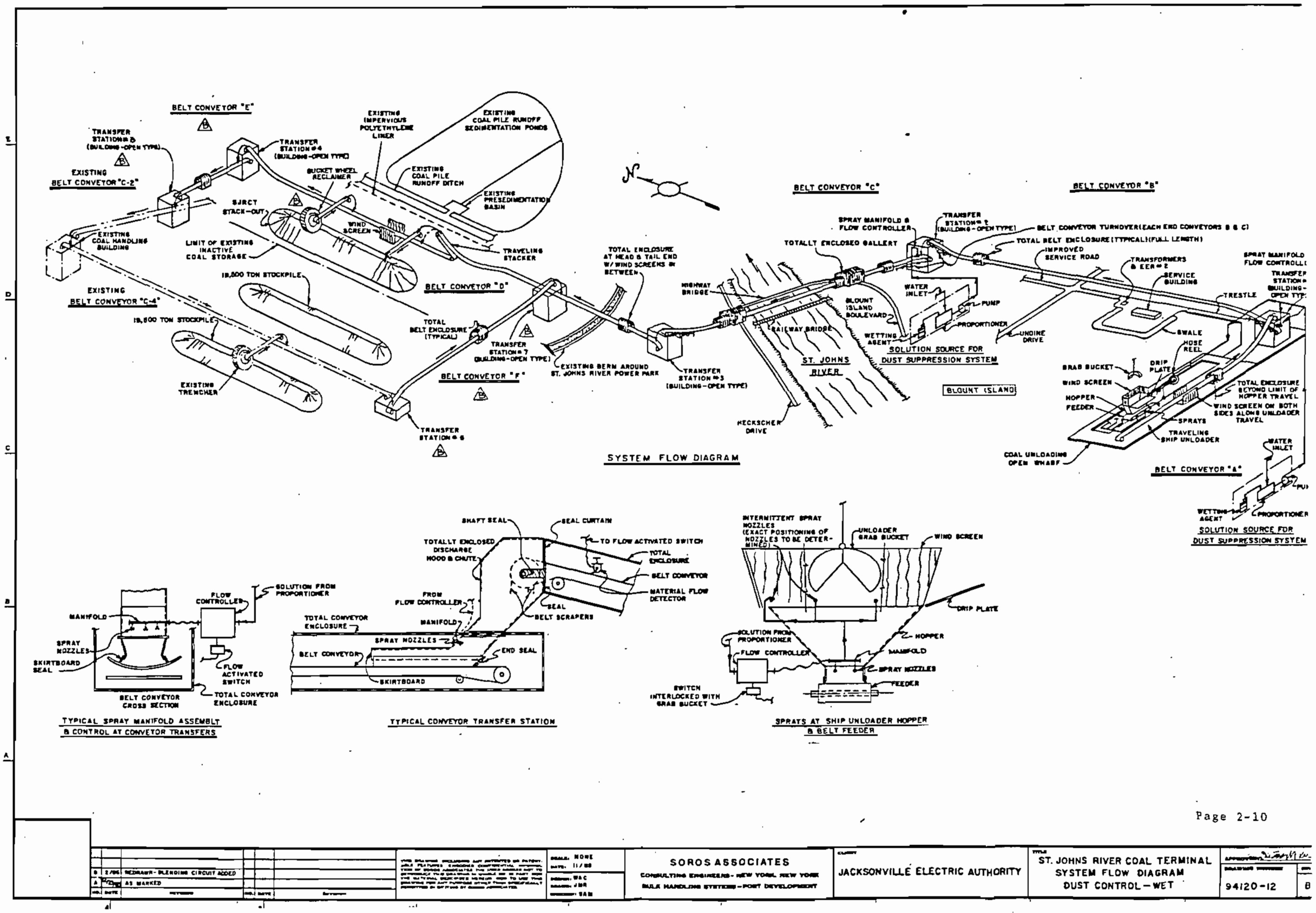

3.0 ESTIMATION OF PARTICULATE EMISSIONS

The equations and parameters used in developing the suspended particulate emission factors for the coal terminal and blending additions are presented in Table 3-1. These equations were obtained from EPA "Compilation of Air Pollutant Emission Factors", Supplements 1-15, commonly known as AP-42 (see Appendix A for excerpts from AP-42).

These emission factors were used since they are the most recent factors that are acceptable to and recommended by EPA for quantifying fugitive dust emissions for the sources that are proposed in this project. For those sources which are not affected by the design modifications, the emission factors used for estimating the fugitive dust emissions were not changed.

The estimated emissions of suspended particulates from the coal terminal and blending additions are presented in Table 3-2. The batch drop equation applies to the batch transfer of material from the grab bucket to the ship unloader receiving hopper. The continuous drop equation applies to the other affected operations in which coal is transferred to or from the conveyors or from one conveyor to another in a continuous flow.

Not shown in Table 3-2 is the change in emissions from the coal storage area at the Power Park. Because of the way that the conveyor linkage system from the SJRCT is tied into the Power Park coal handling system, the allocation of total coal storage at the Power Park between "active" and "inactive" zones changes. This change is due to the addition of a stacker and reclaimer along the eastern edge of the coal storage area, converting the zone within the reach of these machines from "inactive" to "active". The revised areas are used in conjunction with the emission factors in the existing permit to estimate new emission levels from the entire coal storage area. The results are presented in Section 5 and Appendix C. It should be noted that the size of the total coal storage area has not changed.

The emission estimates are assumed to reflect particulate matter (PM) that would be measured by a high-volume air sampler as specified in the reference sampling method for total suspended particulates (TSP). As a result, no particle size correction factors were applied (i.e., k = 1.0). This approach will lead to estimating maximum emissions since a value of k that is less than 1.0 will produce lower emission estimates.

The batch drop and continuous drop emission factor equations of AP-42 include a wind speed term. The emission factor is based on the annual average wind speed of 8.4 miles per hour (mph) obtained from the National Weather Service (NWS) station in Jacksonville (see Appendix B for an excerpt from the local climatological data summary). These data are the same as those referenced in the original PSD permit application.

The emission factors include a term that can account for the surface moisture of material being handled. A surface moisture content of 5 percent is used for coal handling.

Wetting with water and a chemical "wetting agent" will be performed at selected coal handling operations. The spray points are:

- ship unloader hoppers
- feeders below ship unloader hoppers
- Transfer Station 1
- Transfer Station 2

The amount of water and wetting agent to be applied at all spray points is expected to fully condition the coal (i.e. sufficiently sprayed to eliminate dust generation) before it arrives at Transfer Station 3 and subsequent transfers downstream. The water spray system shall be operated during unloading or transfer operations.

In accordance with the Power Park's Certification Order, the coal stream will be enclosed to the maximum extent practicable. The enclosure systems are described in Chapter 2.

The control efficiencies estimated for enclosure and suppression are shown in Table 3-2. The control efficiencies are based on a review of the literature and discussed in AP-42. The resulting particulate emission estimates are shown in Table 3-2. Throughput rates are based upon the maximum operating capacity of the equipment.

Table 3-1 Suspended Particulate Emission Factors and Parameters for Batch and Continuous Operations

---

1. Batch Drop Operations (AP-42 Section 11.2.3, Aggregate Handling and Storage Piles)

$$E = k\ (0.0018) \frac{\left(\frac{s}{5}\right) \left(\frac{U}{5}\right) \left(\frac{H}{5}\right)}{\left(\frac{M}{2}\right)^{2} \left(\frac{Y}{6}\right)^{(0.33)}} \text{ (lbs/ton)}$$

2. Continuous Drop Operations (AP-42 Section 11.2.3)

$$E = k(0.0018) \frac{\left(\frac{s}{5}\right) \left(\frac{U}{5}\right) \left(\frac{H}{5}\right)}{\left(\frac{M}{2}\right)^{2}} \text{ (lbs/ton)}$$

where:

E = emission factor, lb/ton
k = particle size correction (= 1.0)
s = silt content (percent) (= 5)
M = surface moisture content (percent) (= 5)
U = wind speed (mph) (= 8.4)
H = drop height [feet (ft)] (varies with each transfer)
Y = dumping device capacity (cubic yards (yd^3)) (varies with the machine)

TABLE 3-2: EMISSION ESTIMATES AND CONTROL EFFICIENCIES FOR ST. JOHNS RIVER COAL TERMINAL AND BLENDING ADDITIONS.

CONTINUOUS TRANSFER OPERATIONS

EMISSION SOURCE	k	S (%)	U (MPH)	H (FT)	M (%)	EFF. (%)	TONS/HOUR	UNCONTROLLED EMISSION RATE LBS/TON	CONTROLLED EMISSION RATE LBS/TON	TOTAL UNCONTROLLED EMISSION, LBS/HR	TOTAL CONTROLLED EMISSION, LBS/HR	TOTAL CONTROLLED EMISSION, GMS/SEC
FEEDERS TO CONVEYOR A	1	5	8.4	8	5	85	2200	0.000387072	0.0000580608	0.8515584	0.12773376	0.0160944538
CONVEYOR A TO CONVEYOR B	1	5	8.4	14	5	85	2200	0.000677376	0.0001016064	1.4902272	0.22353408	0.0281652941
CONVEYOR B TO CONVEYOR C	1	5	8.4	22	5	85	2200	0.001064448	0.0001596672	2.3417856	0.35126784	0.0442597478
CONVEYOR C TO CONVEYOR D	1	5	8.4	37	5	75	2200	0.001790208	0.000447552	3.9384576	0.9846144	0.1240614144
CONVEYOR D TO CONVEYOR E	1	5	8.4	29	5	75	2200	0.001403136	0.000350784	3.0868992	0.7717248	0.0972373248
CONVEYOR E TO CONVEYOR C2	1	5	8.4	22	5	75	2200	0.001064448	0.000266112	2.3417856	0.5854464	0.0737662464
CONVEYOR D TO CONVEYOR D THROUGH BY PASS	1	5	8.4	9.5	5	75	2200	0.000459648	0.000114912	1.0112256	0.2528064	0.0318536064
CONVEYOR F TO CONVEYOR D	1	5	8.4	33	5	75	2000	0.001596672	0.000399168	3.193344	0.798336	0.100590336
CONVEYOR C4 TO CONVEYOR F	1	5	8.4	11	5	75	2000	0.000532224	0.000133056	1.064448	0.266112	0.033530112
TRAVELLING STACKER												
a. CONVEYOR D TO TRAILER CONVEYOR	1	5	8.4	6.5	5	75	2200	0.000314496	0.000078624	0.6918912	0.1729728	0.0217945728
b. TRAILER CONVEYOR TO BOOM CONVEYOR	1	5	8.4	8	5	75	2200	0.000387072	0.000096768	0.8515584	0.2128896	0.0268240896
c. BOOM CONVEYOR TO COAL STOCKPILE	1	5	8.4	3.5	5	0	2200	0.000169344	0.000169344	0.3725568	0.3725568	0.0469421568
BUCKET WHEEL RECLAIMER												
a. BUCKET WHEEL TO BOOM CONVEYOR	1	5	8.4	9	5	75	2000	0.000435456	0.000108864	0.870912	0.217728	0.027433728
b. BOOM CONVEYOR TO CONVEYOR D	1	5	8.4	17	5	75	2000	0.000822528	0.000205632	1.645056	0.411264	0.051819264

BATCH TRANSFER OPERATIONS

EMISSION SOURCE	k	S(%)	U(MPH)	H (FT)	M(%)	EFF. (%)	Y(YD^3)	TONS/HR	UNCONTROLLED EMISSION RATE LBS/TON	CONTROLLED EMISSION RATE LBS/TON	TOTAL UNCONTROLLED EMISSION, LBS/HR	TOTAL CONTROLLED EMISSION, LBS/HR	TOTAL CONTROLLED EMISSION, GMS/SEC
GRAB BUCKET TO HOPPER													
a. #1 SHIP UNLOADER	1	5	8.4	26	5	70	29.6	1500	0.0014858288	0.0004457486	2.2287431437	0.6686229431	0.0842464908
b. #2 SHIP UNLOADER	1	5	8.4	26	5	70	14.8	700	0.0018677066	0.000560312	1.3073946386	0.3922183916	0.0494195173
COMBINED WEIGHTED AVERAGE EMISSION FACTOR UNLOADERS	1	5	8.4	26	5	70	---	2200	0.0016073353	0.0004822005	3.53613766	1.060841298	0.133666003

4.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT) SELECTION

Many techniques can be used to control fugitive emissions. Selection of controls employed depends largely on the ability to meet Ambient Air Quality Standards (AAQS) and PSD increments at the plant boundary, and economics. The selected controls must be able to comply with the Florida Department of Environmental Regulation Condition of Certification 1.A., Visible Emission Standard of 10-percent opacity, and the Standard for Unconfined Emissions of Particulate Matter (Chapter 17-2.610, Florida Administrative Code) which requires that "reasonable precautions" be taken to control fugitive emissions.

The fugitive emission controls to be used are presented in Appendix C, Table 2 . The combination of control technologies selected as BACT represents enclosures suitable for each application, and dust suppression systems applying water proportioned with "wetting agent". The selected technologies will ensure that AAQS and allowable PSD increments are met due to the proposed modifications because:

1. The emissions from the modified design for the SJRCT and the blending additions will be less than those emissions estimated from the existing permit for those sources affected by the modifications (see Section 5).

2. The air quality impacts from the new design will be less than those predicted in the existing permit (since emissions are less). As a result, since the air quality impacts predicted in the original permit complied with TSP, AAQS and PSD increments, impacts from the new design will also comply with these air quality standards.

3. The control methods proposed represent the most advanced controls known to exist at this time, considering economics and environmental benefits.

5.0 REVISIONS TO EXISTING PERMIT

Appendix C contains requested revisions to Tables 2 and 6 of the existing PSD permit for the St. Johns River Power Park (SJRPP). These revisions are based on the design and emission controls for the coal terminal and the blending additions and future coal handling transfers associated with the ship unloading facility coal storage pile (Table 2, Process No. 9 and Table 6, Emission Unit 12). Emission estimates have not been revised for those sources which are not changed by the proposed coal terminal and blending additions.

The only change made to these tables that can not be directly related to the deletion or addition of sources is a change in the allocation of total coal storage among "active" and "inactive" zones, as discussed in Chapter 3. With the design changes, 10 of the total 23 acres should now be considered "active".

A comparison of the estimated fugitive emissions from the coal terminal and coal blending additions with the estimated emissions for the original design is presented in Table 5-1. The design with emission controls will produce maximum total fugitive emissions of 9.02 pounds per hour (lb/hr). This emission estimate is based on the worst-case assumption that all new sources will be operating simultaneously at their peak design capacity.

The total emission estimate for existing permitted sources that will be modified is 9.12 lb/hr. Therefore, the fugitive emissions resulting from the design changes and controls (9.02 lbs/hr) are not expected to exceed either the emissions or air quality impacts presently approved in the existing PSD permit.

Table 5-1 Comparison of Fugitive Emission Estimates for the Proposed Coal Terminal and Coal Blending Additions with Existing Permitted Sources

Emission Source	Control	(lb/hr)
Proposed Design		
1. Ship Unloading (2 Grab Buckets)	Supression, Enclosure	1.0
2. Feeder to Conveyor A (2 Wet Suppression points)	Suppression, Enclosure	0.13
3. Conveyor Transfers 1 & 2 (2 points)	Enclosure, Conditioned Material	0.57
4. Conveyor Transfers 3, 4, 5 and D to D by pass (4 points)	Enclosure, Conditioned Material	2.6
5. Conveyor Transfers 6 & 7 (2 points)	Enclosure, Conditioned Material	1.0
6. Traveling Stacker (3 points)	Enclosure, Conditioned Material	0.8
7. Bucket Wheel Reclaimer (2 points)	Enclosure, Conditioned Material	0.6
8. Coal Storage at Plant (10 acres active)	Wetting Agent	0.5
9. Coal Storage at Plant (2 to 13-acre inactive piles)	Wetting Agent	0.02
10. Coal Handling Transfer Points Ship Unloading facility coal pile (8 points)	Enclosure, Conditioned Material	1.8
	TOTAL	9.02
Existing Permitted Sources to be Modified		
1. Ship Unloading (2 Grab Buckets)	Dry Collection	0.32
2. Ship Unloading (6 transfer points)	Dry Collection	0.6
3. Ship Unloading (3 points)	Wet Suppression	7.5
4. Ship Unloading Facility Train, Loading Shed	Dry Collection	0.2

Table 5-1 (continued)

Emission Source	Control	(lb/hr)
5. Coal Storage at Plant (8 acres active)	Wetting Agent	0.4
6. Coal Storage at Plant (2-15-acre inactive piles)	Wetting Agent	0.1
	TOTAL	9.12

APPENDICES

0357b, 5786AM

APPENDIX A

EXCERPTS FROM AP-42

0357b, 5786AM

11.2.3 AGGREGATE HANDLING AND STORAGE PILES

11.2.3.1 General

Inherent in operations that use minerals in aggregate form is the maintenance of outdoor storage piles. Storage piles are usually left uncovered, partially because of the need for frequent material transfer into or out of storage.

Dust emissions occur at several points in the storage cycle, during material loading onto the pile, during disturbances by strong wind currents, and during loadout from the pile. The movement of trucks and loading equipment in the storage pile area is also a substantial source of dust.

11.2.3.2 Emissions and Correction Parameters

The quantity of dust emissions from aggregate storage operations varies with the volume of aggregate passing through the storage cycle. Also, emissions depend on three correction parameters that characterize the condition of a particular storage pile: age of the pile, moisture content and proportion of aggregate fines.

When freshly processed aggregate is loaded onto a storage pile, its potential for dust emissions is at a maximum. Fines are easily disaggregated and released to the atmosphere upon exposure to air currents from aggregate transfer itself or high winds. As the aggregate weathers, however, potential for dust emissions is greatly reduced. Moisture causes aggregation and cementation of fines to the surfaces of larger particles. Any significant rainfall soaks the interior of the pile, and the drying process is very slow.

Field investigations have shown that emissions from aggregate storage operations vary in direct proportion to the percentage of silt (particles $< 75\ \mu m$ in diameter) in the aggregate material.[1-3] The silt content is determined by measuring the proportion of dry aggregate material that passes through a 200 mesh screen, using ASTM-C-136 method. Table 11.2.3-1 summarizes measured silt and moisture values for industrial aggregate materials.

11.2.3.3 Predictive Emission Factor Equations

Total dust emissions from aggregate storage piles are contributions of several distinct source activities within the storage cycle:

1. Loading of aggregate onto storage piles (batch or continuous drop operations).
2. Equipment traffic in storage area.
3. Wind erosion of pile surfaces and ground areas around piles.
4. Loadout of aggregate for shipment or for return to the process stream (batch or continuous drop operations).

TABLE 11.2.3-1. TYPICAL SILT AND MOISTURE CONTENT VALUES OF MATERIALS AT VARIOUS INDUSTRIES

Industry	Material	Silt (%)			Moisture (%)		
		No. of test samples	Range	Mean	No. of test samples	Range	Mean
Iron and steel production[a]	Pellet ore	10	1.4 - 13	4.9	8	0.64 - 3.5	2.1
	Lump ore	9	2.8 - 19	9.5	6	1.6 - 8.1	5.4
	Coal	7	2 - 7.7	5	6	2.8 - 11	4.8
	Slag	3	3 - 7.3	5.3	3	0.25 - 2.2	0.92
	Flue dust	2	14 - 23	18.0	0	NA	NA
	Coke breeze	1		5.4	1		6.4
	Blended ore	1		15.0	1		6.6
	Sinter	1		0.7	0	NA	NA
	Limestone	1		0.4	0	NA	NA
Stone quarrying and processing[b]	Crushed limestone	2	1.3 - 1.9	1.6	2	0.3 - 1.1	0.7
Taconite mining and processing[c]	Pellets	9	2.2 - 5.4	3.4	7	0.05 - 2.3	0.96
	Tailings	2	NA	11.0	1		0.35
Western surface coal mining[d]	Coal	15	3.4 - 16	6.2	7	2.8 - 20	6.9
	Overburden	15	3.8 - 15	7.5	0	NA	NA
	Exposed ground	3	5.1 - 21	15.0	3	0.8 - 6.4	3.4

[a] References 2-5. NA = not applicable.
[b] Reference 1.
[c] Reference 6.
[d] Reference 7.

Adding aggregate material to a storage pile or removing it usually involves dropping the material onto a receiving surface. Truck dumping on the pile or loading out from the pile to a truck with a front end loader are examples of batch drop operations. Adding material to the pile by a conveyor stacker is an example of a continuous drop operation.

The quantity of particulate emissions generated by a batch drop operation, per ton of material transferred, may be estimated, with a rating of C, using the following empirical expression[2]:

$$E = k(0.00090)\ \frac{\left(\frac{s}{5}\right)\left(\frac{U}{2.2}\right)\left(\frac{H}{1.5}\right)}{\left(\frac{M}{2}\right)^{2}\left(\frac{Y}{4.6}\right)^{0.33}} \quad (\text{kg/Mg})$$

$$E = k(0.0018)\ \frac{\left(\frac{s}{5}\right)\left(\frac{U}{5}\right)\left(\frac{H}{5}\right)}{\left(\frac{M}{2}\right)^{2}\left(\frac{Y}{6}\right)^{0.33}} \quad (\text{lb/ton})$$

where: E = emission factor
k = particle size multipler (dimensionless)
s = material silt content (%)
U = mean wind speed, m/s (mph)
H = drop height, m (ft)
M = material moisture content (%)
Y = dumping device capacity, m^3 (yd^3)

The particle size multipler (k) for Equation 1 varies with aerodynamic particle size, shown in Table 11.2.3-2.

TABLE 11.2.3-2. AERODYNAMIC PARTICLE SIZE MULTIPLIER (k) FOR EQUATIONS 1 AND 2

Equation	< 30 µm	< 15 µm	< 10 µm	< 5 µm	< 2.5 µm
Batch drop	0.73	0.48	0.36	0.23	0.13
Continuous drop	0.77	0.49	0.37	0.21	0.11

The quantity of particulate emissions generated by a continuous drop operation, per ton of material transferred, may be estimated, with a rating of C, using the following empirical expression[3]:

$$E = k(0.00090)\ \frac{\left(\frac{s}{5}\right)\left(\frac{U}{2.2}\right)\left(\frac{H}{3.0}\right)}{\left(\frac{M}{2}\right)^2}\ \ (\text{kg/Mg}) \qquad (2)$$

$$E = k(0.0018)\ \frac{\left(\frac{s}{5}\right)\left(\frac{U}{5}\right)\left(\frac{H}{10}\right)}{\left(\frac{M}{2}\right)^2}\ \ (\text{lb/ton})$$

where: E = emission factor
k = particle size multiplier (dimensionless)
s = material silt content (%)
U = mean wind speed, m/s (mph)
H = drop height, m (ft)
M = material moisture content (%)

The particle size multiplier (k) for Equation 2 varies with aerodynamic particle size, as shown in Table 11.2.3-2.

Equations 1 and 2 retain the assigned quality rating if applied within the ranges of source conditions that were tested in developing the equations, as given in Table 11.2.3-3. Also, to retain the quality ratings of Equations 1 or 2 applied to a specific facility, it is necessary that reliable correction parameters be determined for the specific sources of interest. The field and laboratory procedures for aggregate sampling are given in Reference 3. In the event that site specific values for correction parameters cannot be obtained, the appropriate mean values from Table 11.2.3-1 may be used, but in that case, the quality ratings of the equations are reduced by one level.

TABLE 11.2.3-3. RANGES OF SOURCE CONDITIONS FOR EQUATIONS 1 AND 2[a]

Equation	Silt content (%)	Moisture content (%)	Dumping capacity m^3	Dumping capacity yd^3	Drop height m	Drop height ft
Batch drop	1.3 - 7.3	0.25 - 0.70	2.10 - 7.6	2.75 - 10	NA	NA
Continuous drop	1.4 - 19	0.64 - 4.8	NA	NA	1.5 - 12	4.8 - 39

[a] NA = not applicable.

For emissions from equipment traffic (trucks, front end loaders, dozers, etc.) traveling between or on piles, it is recommended that the equations for vehicle traffic on unpaved surfaces be used (see Section 11.2.1). For vehicle travel between storage piles, the silt value(s) for the areas among the piles (which may differ from the silt values for the stored materials) should be used.

For emissions from wind erosion of active storage piles, the following total suspended particulate (TSP) emission factor equation is recommended:

$$E = 1.9 \left(\frac{s}{1.5}\right) \left(\frac{365-p}{235}\right) \left(\frac{f}{15}\right) \quad \text{(kg/day/hectare)} \qquad (3)$$

$$E = 1.7 \left(\frac{s}{1.5}\right) \left(\frac{365-p}{235}\right) \left(\frac{f}{15}\right) \quad \text{(lb/day/acre)}$$

where: E = total suspended particulate emission factor
s = silt content of aggregate (%)
p = number of days with $\geq$ 0.25 mm (0.01 in.) of precipitation per year
f = percentage of time that the unobstructed wind speed exceeds 5.4 m/s (12 mph) at the mean pile height

The coefficient in Equation 3 is taken from Reference 1, based on sampling of emissions from a sand and gravel storage pile area during periods when transfer and maintenance equipment was not operating. The factor from Test Report 1, expressed in mass per unit area per day, is more reliable than the factor expressed in mass per unit mass of material placed in storage, for reasons stated in that report. Note that the coefficient has been halved to adjust for the estimate that the wind speed through the emission layer at the test site was one half of the value measured above the top of the piles. The other terms in this equation were added to correct for silt, precipitation and frequency of high winds, as discussed in Reference 2. Equation 3 is rated C for application in the sand and gravel industry and D for other industries.

Worst case emissions from storage pile areas occur under dry windy conditions. Worst case emissions from materials handling (batch and continuous drop) operations may be calculated by substituting into Equations 1 and 2 appropriate values for aggregate material moisture content and for anticipated wind speeds during the worst case averaging period, usually 24 hours. The treatment of dry conditions for vehicle traffic (Section 11.2.1) and for wind erosion (Equation 3), centering around parameter p, follows the methodology described in Section 11.2.1. Also, a separate set of nonclimatic correction parameters and source extent values corresponding to higher than normal storage pile activity may be justified for the worst case averaging period.

11.2.3.4 Control Methods

Watering and chemical wetting agents are the principal means for control of aggregate storage pile emissions. Enclosure or covering of inactive piles to reduce wind erosion can also reduce emissions. Watering is useful mainly to reduce emissions from vehicle traffic in the storage pile area. Watering of the storage piles themselves typically has only a very temporary slight effect on total emissions. A much more effective technique is to apply chemical wetting agents for better wetting of fines and longer retention of the moisture film. Continuous chemical treatment of material loaded onto piles, coupled with watering or treatment of roadways, can reduce total particulate emissions from aggregate storage operations by up to 90 percent.[8]

References for Section 11.2.3

1. C. Cowherd, Jr., et al., Development of Emission Factors for Fugitive Dust Sources, EPA-450/3-74-037, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1974.

2. R. Bohn, et al., Fugitive Emissions from Integrated Iron and Steel Plants, EPA-600/2-78-050, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1978.

3. C. Cowherd, Jr., et al., Iron and Steel Plant Open Dust Source Fugitive Emission Evaluation, EPA-600/2-79-103, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1979.

4. R. Bohn, Evaluation of Open Dust Sources in the Vicinity of Buffalo, New York, U. S. Environmental Protection Agency, New York, NY, March 1979.

5. C. Cowherd, Jr., and T. Cuscino, Jr., Fugitive Emissions Evaluation, Equitable Environmental Health, Inc., Elmhurst, IL, February 1977.

6. T. Cuscino, et al., Taconite Mining Fugitive Emissions Study, Minnesota Pollution Control Agency, Roseville, MN, June 1979.

7. K. Axetell and C. Cowherd, Jr., Improved Emission Factors for Fugitive Dust from Western Surface Coal Mining Sources, 2 Volumes, EPA Contract No. 68-03-2924, PEDCo Environmental, Inc., Kansas City, MO, July 1981.

8. G. A. Jutze, et al., Investigation of Fugitive Dust Sources Emissions and Control, EPA-450/3-74-036a, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1974.

APPENDIX B

JACKSONVILLE, FLORIDA

LOCAL CLIMATOLOGICAL DATA

EXCERPT FROM EXISTING PSD PERMIT APPLICATION

TABLE 2-5
JACKSONVILLE, FLORIDA
NORMALS, MEANS, AND EXTREMES

Station: JACKSONVILLE, FLORIDA # 13889 INTERNATIONAL AIRPORT Standard time used: EASTERN Latitude: 30° 30' N Longitude: 81° 42' W Elevation (ground): 26 feet

Month	Temperatures °F: Normal: Daily maximum	Daily minimum	Monthly	Extremes: Record highest	Year	Record lowest	Year	Normal Degree days Base 65 °F: Heating	Cooling
(a)				37		37			
J	64.6	44.5	54.6	85	1947	19	1977	348	23
F	66.9	45.7	56.3	88	1962	19	1943	282	38
M	72.4	50.1	61.2	91	1974	25	1943	176	98
A	79.0	57.1	68.1	95	1968	35	1975	24	117
M	84.6	63.9	74.3	100	1967	45	1973	0	288
J	88.3	70.0	79.2	103	1954	54	1966	0	426
J	90.0	72.0	81.0	105	1942	61	1972	0	496
A	89.7	72.3	81.0	102	1954	64	1950	0	494
S	86.0	70.4	78.2	100	1944	50	1967	0	396
O	79.4	61.7	70.5	96	1951	36	1977	19	190
N	71.5	51.0	61.2	88	1961	21	1970	161	47
D	65.8	45.1	55.4	84	1956	12	1962	317	19
YR	78.1	58.7	68.4	105	JUL 1942	12	DEC 1962	1327	2596

Month	Precipitation in inches: Water equivalent: Normal	Maximum monthly	Year	Minimum monthly	Year	Maximum in 24 hrs.	Year	Snow, Ice pellets: Maximum monthly	Year	Maximum in 24 hrs.	Year
(a)		37		37		37		37		37	
J	2.78	7.29	1964	0.06	1950	3.02	1963	T	1978	T	1978
F	3.58	8.85	1970	0.32	1962	6.22	1970	1.5	1958	1.5	1958
M	3.56	10.18	1973	0.18	1945	7.12	1970	T	1975	T	1975
A	3.07	11.61	1974	0.17	1942	8.25	1973	0.0		0.0	
M	3.22	10.43	1960	0.61	1953	5.40	1975	0.0		0.0	
J	6.27	12.90	1967	2.19	1950	5.93	1968	0.0		0.0	
J	7.35	16.21	1960	1.97	1977	10.08	1966	0.0		0.0	
A	7.89	16.24	1968	1.92	1942	7.93	1968	0.0		0.0	
S	7.83	19.36	1949	1.02	1961	10.17	1950	0.0		0.0	
O	4.54	13.44	1956	0.16	1942	6.66	1956	0.0		0.0	
N	1.79	7.85	1947	T	1970	5.44	1969	0.0		0.0	
D	2.59	7.09	1965	0.04	1956	3.70	1971	T	1962	T	1962
YR	54.47	19.36	SEP 1949	T	NOV 1970	10.17	SEP 1950	1.5	FEB 1958	1.5	FEB 1958

Month	Relative humidity pct. Hour 01 (Local time)	Hour 07	Hour 13	Hour 19	Wind: Mean speed m.p.h.	Prevailing direction	Fastest mile: Speed m.p.h.	Direction	Year	Pct. of possible sunshine	Mean sky cover, tenths, sunrise to sunset	Mean number of days: Sunrise to sunset: Clear	Partly cloudy	Cloudy	Precipitation .01 inch or more	Snow, Ice pellets 1.0 inch or more	Thunderstorms	Heavy fog, visibility ¼ mile or less	Temperatures °F Max. (b) 90° and above	Max. 32° and below	Min. 32° and below	Min. 0° and below	Average station pressure mb. Elev. 31 feet m.s.l.
(a)	42	42	42	42	29	14	29	29		28	29	30	30	30	37	37	37	34	37	37	37	37	6
J	85	87	57	74	8.4	NW	41	NW	1971	57	6.0	9	8	14	8	0	1	6	0	0	5	0	1020.1
F	82	85	52	68	9.4	WSW	52	NE	1963	61	5.7	9	7	12	8	*	1	4	0	0	3	0	1019.0
M	82	85	49	65	9.4	NW	64	SW	1971	66	5.8	9	10	12	8	0	3	3	*	0	1	0	1017.4
A	83	85	47	64	9.1	SE	48	W	1973	72	5.2	11	10	9	6	0	3	3	2	0	0	0	1017.7
M	85	84	50	66	8.6	WSW	62	N	1975	69	5.5	9	12	10	8	0	7	3	9	0	0	0	1014.9
J	87	86	56	77	8.3	SW	76	NE	1967	62	6.2	6	13	11	12	0	10	1	16	0	0	0	1015.8
J	88	87	58	75	7.5	SW	49	SW	1950	60	6.4	5	14	12	15	0	16	1	23	0	0	0	1016.8
A	90	90	60	78	7.2	SW	52	NE	1969	59	6.2	5	15	11	15	0	13	2	21	0	0	0	1017.4
S	89	91	62	79	8.1	NE	82	N	1964	54	6.5	5	12	13	13	0	7	2	10	0	0	0	1015.6
O	88	90	58	78	8.6	NE	72	E	1950	57	5.5	10	9	12	9	0	2	3	1	0	0	0	1017.6
N	87	89	55	78	8.1	NW	60	S	1950	60	5.2	11	9	10	6	0	1	5	0	0	1	0	1019.3
D	86	88	58	77	8.2	NW	62	N	1963	56	5.9	10	8	13	8	0	1	5	0	0	4	0	1019.4
YR	86	87	55	73	8.4	NW	82	N	SEP 1964	61	5.8	99	127	139	116	*	64	37	82	0	14	0	1017.8

Means and extremes above are from existing and comparable exposures. Annual extremes have been exceeded at other sites in the locality as follows: Lowest temperature 10 in February 1899; maximum monthly precipitation 23.32 in June 1932; maximum monthly snowfall 1.9 in February 1899; maximum snowfall in 24 hours 1.5 in February 1899.

(a) Length of record, years, through the current year unless otherwise noted, based on January data.
(b) 70° and above at Alaskan stations.
* Less than one half.
T Trace.

NORMALS - Based on record for the 1941-1970 period.
DATE OF AN EXTREME - The most recent in cases of multiple occurrence.
PREVAILING WIND DIRECTION - Record through 1963.
WIND DIRECTION - Numerals indicate tens of degrees clockwise from true north. 00 indicates calm.
FASTEST MILE WIND - Speed is fastest observed 1-minute value when the direction is in tens of degrees.

Source: (USDC, 1978)

APPENDIX C

REVISED TABLES 2 and 6 FROM

EXISTING PSD PERMIT AND APPLICATION

0357b, 5786AM

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

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

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

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

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

	Emission Unit	SO_2	NO_x	PM (Revised Original)	Opacity (Percent)
1.	Steam Generating Boiler No.1 (6,144 MMBtu/hr maximum heat input)	4,669.; 0.76 (30-day rolling average)	3,686; 0.6	184; 0.03	20
2.	Steam Generating Boiler No. 2 (6,144 MMBtu/hr maximum heat input)	4,669; 0.76 (30-day rolling average)	3,686; 0.6	184; 0.03	20
3.	Auxiliary boilers (254 MMBtu/hr maximum heat input total)	203; 0.8		25.0; 0.1	20
4.	Ship Unloading (2 Grab Buckets)*			1.0	10
5.	Feeders to Conveyor A (2 Wet Suppression points)*			0.13	10
6.	Conveyor Transfers 1 & 2 (2 points)*			0.57	10
7.	Conveyor Transfer 3, 4, 5 & D to D by-pass (4 points)*			2.6	10
8.	Conveyor Transfers 6 & 7 (2 points)*			1.0	10
9.	Traveling Stacker (3 points)*			0.8	10
10.	Bucket Wheel Reclaimer (2 points)*			0.6	10
11.	Ship unloading facility coal storage pile			1.6	10
12.	Coal handling transfer points ship unloading facility coal pile (8 points)*			1.8	10
13.	Rail car unloading (Rotary Dumper)			5	10
14.	Coal handling transfer points (6 wet suppression points)			5(each)	10
15.	Coal handling transfer points (11 dry collection)			0.1(each)	10
16.	Coal storage at plant* (10 acres active)			0.5	10
17.	Coal storage at plant* (2 to 13-acre inactive piles)			0.02	10
18.	Limestone unloading (rail dumper)			0.1	10
19.	Limestone transfer points			0.4(each)	10
20.	Cooling towers			67(each tower)	N/A

* Revised emission unit, May 1986.

JACKSONVILLE ELECTRIC AUTHORITY
P. O. BOX 53015
233 W. DUVAL STREET
JACKSONVILLE, FL 32201

SJRCTENV 86-13

April 25, 1986

Received DER

APR 28 1986

PPS

st. johns river POWER PARK

Mr. Hamilton S. Oven, Jr. P.E.
Administrator of Power Plant Siting
Fla. Dept. of Env. Regulation
2600 Blair Stone Road
Tallahassee, Florida 32301-8241

Dear Mr. Oven:

Subject: Jacksonville Electric Authority
St. Johns River Coal Terminal
Condition of Certification XXXII
Conveyor Details
Power Plant Siting Application No. PA 81-13

In accordance with the Florida Power Plant Siting Act, Part II, Chapter 403 Florida Statutes, the Jacksonville Electric Authority (JEA) has previously been granted certification for the location, construction, and operation of the St. Johns River Power Park Units 1 and 2, and its associated facilities including a coal unloading facility and transmission lines. This Certification Order, issued on June 29, 1982, also addresses the future construction and operation of a conveyor system to transport coal from the unloading facility on the south side of Blount Island to the Power Park. Condition XXXII of the Certification Order specifically requires that JEA submit information concerning location, design, construction and operation of the coal conveyor system from Blount Island to the main plant site at least 120 days prior to construction.

In accordance with this Condition, we are submitting a description of the coal conveyor system linkage between St. Johns River Coal Terminal and Power Park. This material is provided in Attachment 1 and includes the following:

- Background Information
- System Location
- System Description
- Environmental Aspects

Condition XXXII states that the Secretary of the Department of Environmental Regulation (DER) should issue DER's response within 90 days of receipt.

In addition, JEA requests that DER also issue the Water Quality Certification for the conveyor system linking the coal terminal and the Power Park pursuant to Section 401 of the Federal Water Pollution Control Act, Public Law 92-500, as amended. This certification has been requested by the United States Coast Guard for JEA's Bridge Permit Application for the conveyor crossing of

(CONT.)

the St. Johns River Back Channel. It should be noted that the Water Quality Certification for the Power Park and the coal terminal facility on Blount Island was previously granted as part of the 1982 Site Certification. JEA will forward this certification to the Coast Guard upon receipt.

In addition, please find enclosed a Coastal Zone Management Consistency Certification, prepared as specified in 15 CFR 930.57. State concurrence with this Consistency Certification is required by the Coast Guard for issuance of the Bridge Permit.

Section 380.23, Florida Statutes, suggests that the issuance of the Power Park Certification on June 29, 1982, and satisfaction of Condition of Certification XXXII demonstrates the consistency of the St. Johns River Coal Terminal and the conveyor system linking it to the Power Park with Florida's Coastal Management Plan. Therefore, in accordance with 15 CFR 930.63, please provide the Coast Guard with state concurrence with the attached consistency statement. The contact at the Coast Guard for this matter is Lieutenant Commander J. V. O'Shea (Seventh Coast Guard District, Federal Building, 51 S.W. 1ST Avenue, Miami, Florida, 33130-1681). We would also appreciate receiving a copy of the concurrence statement.

It is our understanding that notice of the submittal of Condition XXXII will be provided to all parties to the certification proceeding and will be handled by DER's counsel. We have provided you with 20 copies of the submittal. If you need the assistance of JEA's counsel, Mr. William Preston (Hopping Boyd Green & Sams), please contact me. We request that Mr. Preston also be copied on all noticing documents.

If you have any questions or require additional information, please contact Athena Tsengas at (904) 633-4517.

Very truly yours,

Richard Breitmoser, P.E.
Division Chief
Research & Environmental
Affairs Division

RB/AJT/lwr
cc: J. V. O'Shea (USCG)
W. Preston (HBG&S)

Attachments:
1. Description of the Coal Conveyor Linkage System Between the St. Johns River Coal Terminal and the St. Johns River Power Park.
2. CZM Statement of Consistency

Attachment 1

DESCRIPTION OF THE COAL CONVEYOR LINKAGE SYSTEM
BETWEEN
THE ST. JOHNS RIVER COAL TERMINAL
AND
THE ST. JOHNS RIVER POWER PARK

JACKSONVILLE ELECTRIC AUTHORITY

April 1986

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(Continued, Page 2 of 2)

LIST OF DRAWINGS

LIST OF FIGURES

I BACKGROUND INFORMATION

On June 29, 1982, the Florida Governor and Cabinet issued a Certification Order (DOAH Case No. 81-357) and Conditions of Certification approving the construction of the St. Johns River Power Park (SJRPP) Units 1 and 2 and their associated facilities. The SJRPP is a joint venture effort of the Jacksonville Electric Authority (JEA) and Florida Power and Light Company (FPL). The Certification Order also approves the construction of a coal unloading facility (the St. Johns River Coal Terminal, or SJRCT) on the south shore of Blount Island adjacent to the Fulton-Dames Point Cutoff of the St. Johns River. The present design is to deliver coal from the SJRCT to the Power Park by a 3.2-mile-long conveyor system.

Condition of Certification XXXII contained in the Certification Order addresses the coal conveyor system as follows:

<u>XXXII Coal Conveyor System</u>

> "JEA shall submit to DER information concerning location, design, construction and operation of any coal conveyor system from Blount Island to the main plant site as least 120 days prior to construction of the coal conveyor system. The Secretary of DER shall indicate DER's approval or disapproval within 90 days of receipt. DER may also impose reasonable conditions on the construction and operation of this conveyor system. These conditions may impose appropriate restrictions on construction, operation and maintenance of the coal conveyor system in order to comply with applicable nonprocedural standards of any agency. DER's decision shall be final unless further review is timely sought by any party pursuant to Section 120.57 or Section 403.516, Florida Statutes..."

The existing Certification Order specifically approves and licenses the SJRCT at the proposed site. It approves the construction of a 1,200-foot wharf along the southwestern portion of the site and requires the submission of additional information about the design of the linkage system between the Power Park and the SJRCT. The purpose of this submission is to present the information required by Condition of Certification XXXII.

II LOCATION OF THE ST. JOHNS RIVER COAL TERMINAL AND CONVEYOR LINKAGE SYSTEM

The coal unloading terminal is located on the southern shore of Blount Island adjacent the Fulton-Dames Point Cutoff of the St. Johns River. The wharf structure of the SJRCT is oriented toward the southeast corner of the project site. This location places the terminal close to the north-south alignment of the transmission line right-of-way as it crosses Blount Island. The conveyor system is located within this right-of-way to a large extent as it crosses Blount Island. Drawing Nos. 94120-01 and 94120-02 show the site location and the site plan for the terminal and the conveyor linkage to the Power Park.

The ship unloader's grab bucket will discharge into a hopper carried in the unloader main frame. A short Belt Conveyor A serves as the initial link connecting the unloader to the first transfer point at the southeast corner of the site (see Drawing Nos. 94120-03 and 94120-04), from where Conveyor Belt B will run northward. Conveyor B will generally follow the existing JEA transmission line easements across Blount Island to a transfer point near the apex of the island (see Drawing Nos. 94120-04 and 94120-05). Belt Conveyor C crosses Blount Island Channel and Heckscher Drive (SR 105) and continues northward within an easement which will be obtained from the Jacksonville Port Authority (see Drawing Nos. 94120-06 and 94120-07). Belt Conveyor D is oriented northward into the Power Park coal storage area (see Drawing No. 94120-08), where it transfers to Belt Conveyor E or to the Power Park coal storage area via the stacker (see Drawing No. 94120-09). Belt Conveyor E transfers to existing Conveyor C-2 of the Power Park's coal handling system.

The interface between Belt Conveyor D and the Power Park's coal handling system has been designed to enable coal mixing. All mechanical components used to achieve coal mixing are located within the property boundary of the Power Park.

III COAL CONVEYOR LINKAGE DESCRIPTION

The St. Johns River Coal Terminal is a facility for receiving waterborne coal and transporting it by an overland conveyor system to the Power Park. Annual quantities may reach approximately 3 million tons, delivered in consignments up to 45,000 tons.

III.1 THE CONVEYOR LINKAGE SYSTEM

III.1.1 General

The belt conveyor system between the SJRCT and the Power Park comprises four 48-inch-wide conveyors, designated A, B, C, and D, in series. Initially, the belts will be able to handle coal at a maximum rate of 1,500 tons per hour. However, the belts have been sized to allow for the future capability of handling 2,200 tons per hour. The system will be of heavy duty design and construction to operate continuously, 24 hours a day, and up to 4,000 hours per year. Drawing No. 94120-11 shows a flow diagram for the conveyor system material handling.

III.1.2 Design Standards

The conveyor system will be designed and constructed in accordance with Conveyor Equipment Manufacturers Association (CEMA) standards. Materials and equipment will be of modern design and workmanship and will follow the best, modern trade practices. Structures will have clean lines free of ledges, pockets, crevices and the like which can contain dirt and moisture leading to accelerated rates of corrosion. Spaces between members which are inaccessible or difficult to reach will be avoided or sealed.

III.1.3 Idlers

The 48-inch-wide conveyor belts will be carried on idler rolls and pulleys.

III.1.4 Pulley Assemblies

Pulleys will have diameters to suit the belting.

III.1.5 Drive Units

Conveyor drive arrangements will consist of gear reducers directly coupled to the drive pulley assemblies. They will be driven by motors with torque control characteristics. Brakes and flywheels will be employed, as necessary, for control of conveyor drift and holdbacks to prevent rollback. Drive units will be arranged so as to have the driving pulley in contact with the clean side of the belt. Drives may either be of parallel shaft or right angle orientation.

III.1.6 Belt Tensioning Devices

Each conveyor will have a belt tensioning arrangement to suit the purpose. Belt tensioning mechanisms will have a length of travel adequate for taking up belt movement and stretch, plus a length of belt sufficient for making a vulcanized splice.

III.1.7 Conveyor Belting

Conveyor belting will be of fabric or steel cord construction. Covers will be abrasion-resistant, of thickness to suit the service conditions, and in balance with their operating life expectancies. Conveyors B andC will have return belt inversion arrangements to keep the carrying side of the belt uppermost over the return run.

III.1.8 Belt Cleaners

Each conveyor will be equipped with belt scrapers and return belt plows, as required.

III.1.9 Chutes and Skirtboards

Conveyors will be fitted with feed and discharge chutes and with skirt-boards to contain and center the coal flow. They will be enclosed to contain dust, and Transfer Stations 1 and 2 will be equipped with spray systems for dust suppression. Abrasion-resistant liners will be provided on impingement and sliding surfaces. Access to liners and spray bars will be available through dust-tight inspection doors.

Dust curtains will be provided at the head chute and loading skirts. Bifurcated chutes will contain flop gates, operated by activators remotely controlled from the main control room.

III.1.10 Framework

Except for the length of Conveyor A, over which the ship unloader will operate, and the length of Conveyor D, corresponding to the stacker and reclaimer traverse distance, conveyors will be carried in a steel truss framework. Eighteen feet minimum headroom will be provided under the framework over the major part of the conveyor lengths. A 23-foot clearance will be provided at rail crossings; a minimum of 18 feet over highways.

The truss framework will carry a main walkway on one side and an access way on the other side. Walkways will be made of grating. Access ladders from grade and conveyor crossovers will be provided at intervals. The conveyor-carrying side will be enclosed with hinged hood covers locked in place with quickly detachable latches. The return strand of belting will be fully enclosed by hinged side panels and a fixed dust pan. The hinged hood and side panels will provide ready access for cleanup with a mobile vacuum system. Over Heckscher Drive and Blount Island Boulevard, conveyors will be housed in totally enclosed galleries. Galleries and truss framework will be supported on bents or towers carried on piled foundations.

The head end of Conveyor A and the tail end of Conveyor B will be carried on a trestle, from landside to the wharf, over tidal water. The trestle will also carry a wharf access road.

Conveyors A and D, wharf and stacker/reclaimer conveyors, will have a stringer framework for the horizontal runs over which the ship unloader and the stacker and reclaimer operate. Wind screens will be provided instead of hood covers along those lengths, since belt loading occurs over that length, in the case of Conveyor A, and belt loading and unloading occurs in the case of Conveyor D. These functions require unobstructed access to the carrying strand of belt, which would not be feasible if hood covers were provided.

III.1.11 Transfer Stations

Machinery floors in conveyor transfer stations will be metal grating. Stairways, walkways, platforms, and ladders will be provided for access to equipment requiring periodic attention.

III.1.12 Belt Turnovers

The return belt runs of Conveyors B and C will be inverted at head and tail ends so that the carrying surface will be uppermost. Therefore, coal particles adhering to the carrying surface will not be deposited along the return runs.

III.1.13 Belt Weigh Scale and Sampling

Near the tail end of Conveyor B, a weigh scale will be located to monitor tonnage passing.

At Transfer Station Number 3, a sample cutter will be installed to obtain primary samples from the coal stream. An adjacent building will house the remainder of the sampling system.

III.1.14 Tramp Metal Detection and Removal

Upstream of Transfer Station Number 1, a metal detector will be installed to detect magnetic and nonmagnetic tramp metal. The metallic object will be removed, if identified as nonmagnetic, by an attendent stationed there. At the head end of Conveyor A, a magnet will be stationed to remove magnetic metallic objects.

The attendant will give an all-clear signal to the ship unloader operator when ready to restart.

III.2 DUST CONTROL

III.2.1 Wet System (See Drawing No. 94120-12)

Dust control will be by means of containment and suppression methods. Containment will be provided by enclosing the coal stream to the maximum extent possible. The containment systems are presented in Sections III.1.9 and III.1.10.

There will be two suppression systems: one for the ship unloader and another for two of the conveyor transfer stations. The ship unloader will have windshields at the hopper. Around the periphery of the hopper will be a spray header with nozzles directed across the hopper mouth. The spray headers will be protected from damage by the bucket and falling coal. The sprays will operate intermittently in phase with the bucket dump cycle.

Sprays will also be located around the feeder under the hopper. Hopper outlet feeder sprays will be actuated by coal flow. To reduce droplet surface tension and improve the affinity of droplets for dust particles, a wetting agent will be added by means of a proportioning pump to the spray water.

Because of intermittent spray water usage corresponding to the batch nature of the coal unloading, the average flow rate is appreciably smaller than the peak. A hose and reel arrangement with a ship-unloader-mounted water surge tank can therefore be used. The water spray pump and surfactant proportioner will all be mounted on the ship unloader.

Transfer station dust control will be by means of totally enclosed chutes and skirtboards, with the first two transfer stations also equipped with water-surfactant solution sprays. Water sprays at the third, fourth, and fifth transfers are not necessary since the earlier spray points will condition the coal sufficiently to control dust. Sprays will be activated by the coal flow.

III.2.2 Dry System (See Drawing No. 94120-13)
Dry dust control is for clean-up of accumulated dust in enclosed spaces to prevent conditions that could result in an explosion hazard.

Vacuum headers will run in segments along the enclosed conveyor framework, with branch connections at regular intervals, for plug-in of hand-held suction nozzles. Each branch will have a valve; all would normally be closed. Each header segment will have a hose connection to a mobile vacuum suction unit.

The high-power mobile vacuum unit(s) will be for use over the length of the entire system.

III.3 WATER DISTRIBUTION
Water for fire protection on Blount Island will be supplied from the JPA well system through an extension of the JPA fire mains (see Drawing No. 94120-16).

Potable water for the service building, located in the vicinity of the ship unloader wharf, will be supplied from the JPA system. Consumption will be approximately 400 gallons per day (based upon 30 to 40 gallons per person per day). Water for dust suppression on Blount Island will come from one new well to supply the ship unloader and the two Transfer Stations 1 and 2. The well will be approximately 750 feet deep. Submersible pumps will be used to pump water through a filter bed into a storage tank. Annual water consumption could reach approximately 9 million gallons.

III.4 SERVICE BUILDING
The service building will be a masonry structure with insulated metal roofing or a prefabricated building. In plan, overall dimensions will

be about 40 x 100 feet. Its location will be onshore close to the land-side end of the trestle and dock access road (see Drawing No. 94120-10). The floor slab will be located above the 100-year flood elevation.

Enclosed spaces will be force ventilated or air conditioned. Windows and electric lighting will be provided. Communications by telephone, intercom, and radio will be installed. The service building will be surrounded by a paved area for open storage and vehicle parking. A security fence will surround the area and restrict access to the wharf. Precipitation runoff will be drained into a nearby swale.

Potable water will be provided from the JPA system, and sewage will be pumped to the JPA treatment plant.

III.5 ELECTRICAL SYSTEM

III.5.1 Conveyors

Conveyors will be provided with several safety devices for personnel and equipment protection:

- o Pull-cord switches for the full length,
- o Underspeed switches,
- o Misalignment sensors.
- o Tramp metal detector, and
- o Tramp metal magnet.

III.5.2 Lighting

The ship unloader will carry its own floodlighting to illuminate unloading operations. The dock will be floodlit from lights mounted on poles aligned on the rear of the wharf clear of the ship unloader clearance envelope. The conveyors will be illuminated by lights mounted along the main walkway.

III.6 CONVEYOR SYSTEM CONSTRUCTION SCHEDULE

The present projected date for beginning the site earthwork is approximately February 1987. Construction of the service building would begin around May 1987, and the erection of the belt conveyor system would begin around September 1987. It is anticipated that the SJRCT would be ready for service approximately October 1988.

IV ENVIRONMENTAL ASPECTS

The following section describes the environmentally significant features of the proposed coal conveyor system. The environmental issues concerning the construction/operation of a coal unloading terminal and the concept of coal conveyance to the Power Park have been previously addressed in both the Site Certification Application and the Environmental Impact Statement/State Analysis Report prepared in 1981 and the public hearing process completed in 1982.

The proposed coal handling system between the SJRCT and the Power Park is a totally enclosed traveling belt conveyor in lieu of a rail linkage system.

IV.1 CONSTRUCTION

IV.1.1 Trestle/Blount Island Conveyor

The major environmental impacts of the trestle and conveyor construction onto and across Blount Island will be due to pile driving activity and the movement of construction equipment on the island. All construction activities in waters of the State will be conducted in accordance with Condition of Certification XI. Turbidity screens will be used, as necessary, to prevent turbidity in excess of 50 JTUs above background beyond 150 meters from the construction activity. However, any turbidity related to the pile driving is expected to be highly localized.

The piling structures will change the benthic substrate in the immediate area of the trestle, but the substrate surface area will be increased and afford new opportunities for colonization by benthic organisms once piling structures are erected.

Pile driving will normally be conducted during daylight hours only, thereby mitigating the noise effects of the pile-driving equipment.

IV.1.2 St. Johns River Back Channel Crossing

The environmental impacts from the proposed conveyor crossing will be limited to the placement of support pilings. No dredging activity will be required. Any impacts to water quality and/or biological resources will be minimal and short-term. The support structures will be installed at 110-foot intervals, aligned with every fifth support of the existing railroad bridge. The above-water vertical clearance for the proposed conveyor Back Channel Crossing will exceed that of the existing railroad bridge, allowing continued safe navigation of watercraft (see Figures IV-1 and IV-2).

The Back Channel construction will be accomplished primarily from the existing railroad bridge with some activities staged from barges. Construction activities will be scheduled around the normal operating routine of the railroad which serves Blount Island for the Jacksonville Port Authority. The construction of the conveyor crossing structure will be accomplished within the existing railroad dedication, granted to the Jacksonville Port Authority by the State of Florida in 1967.

IV.1.3 Heckscher Drive Crossing

The construction of the Heckscher Drive (SR 105) crossing will cause some occasional, temporary traffic constriction. This will be due to construction machinery and conveyor equipment being carried across or put in place above the highway right-of-way. The proposed crossing plans provide for supporting structures to completely span the highway right-of-way, with the conveyor aligned immediately eastward and parallel to the existing railroad crossing. The minimum vertical clearance will be 18 feet above the road surface (see Figure IV-3).

IV.1.4 Heckscher Drive to Power Park

From Heckscher Drive north to the Power Park, the conveyor structure will basically follow along the existing Jacksonville Port Authority railroad tracks on the existing embankment across the wetlands. The centerline-to-centerline separation between the railroad tracks and the conveyor structure will be approximately 21 feet. Portions of the existing railroad berm through the wetlands north of Heckscher Drive are seriously eroded. Use of the service road along the railroad and placement of the westerly support pilings along this berm require that its eastern shoulder be widened approximately 4 feet eastward beyond the original berm perimeter. This would require the placement of approximately 2,500 cubic yards of fill in an area that appears to have been previously excavated during the original construction of the railroad berm. The easterly conveyor support structures will be pilings driven partly into the wetland substrate (see Drawing No. 94120-07, Section A-A). Although filling activity to widen the berm will impact the benthic community immediate to the construction area, no significant change to the benthic community is expected. It is anticipated that no construction mats will be required in the tidal marsh since construction activities can be staged from the railroad and the adjacent service road atop the embankment.

IV.1.5 Service Building

The construction of the 4,000-square-foot service building will require the simple clearing and grading of the site (a previously disturbed spoil disposal area). Vegetation, consisting of shrubs and grasses, will be removed from this area. Construction will also include an adjacent parking lot, swale system for stormwater management, and an unpaved service road. Runoff from the onsite construction area will be contained and controlled to minimize turbidity increases in waters of the state.

IV.1.6 Ground Water Well

Water usage of the dust suppression system requires the construction of one ground water well on Blount Island (see Drawing No. 94120-16). Information concerning the construction of this well has been submitted under separate cover to FDER for review and approval.

IV.2 OPERATION

IV.2.1 Emissions

The primary operational impact of this coal conveyance system will be the emission of particulates (coal dust). The existing PSD permit will be modified to reflect the totally enclosed, continuous belt conveyor system to transport coal from the unloading facility to the Power Park. Total enclosure, belt inversions, and belt cleaning will eliminate possible coal dust dribble to the water and ground surface along the route of the conveyor system.

The routine use of a dust suppression system and the use "as needed" of a vacuum system for cleanup of accumulated dust will greatly enhance the control of particulate emissions.

There will be some noise emission from the electric motors driving the conveyor belts. However, operational noise levels outside the conveyor right-of-way will not exceed the 75 A-weighted decibels (dBA) limit permitted for lands zoned industrial, waterfront (IW), and the 65 dBA limit at any point where the IW district adjoins a residential district.

IV.2.2 Traffic

There will be a negligible increase in the traffic on/off Blount Island due to the presence of operating personnel for the waterfront operations. Coal can be continuously delivered across Heckscher Drive and Blount Island Boulevard with the belt conveyor system with no inconvenience to vehicular traffic.

It should be noted that the conveyor structure crossing Heckscher Drive and Blount Island Boulevard is itself totally enclosed, including access walkways, to prevent any items such as maintenance tools from dropping onto the highway below.

IV.2.3 Stormwater Management

A stormwater management plan has been submitted under separate cover to the FDER subdistrict office and the St. Johns River Water Management District for review and approval in accordance with Condition of Certification IV.A.

IV.2.4 Ground Water Well

Information concerning the operation of a new ground water well on Blount Island has been submitted under separate cover to FDER for review and approval.

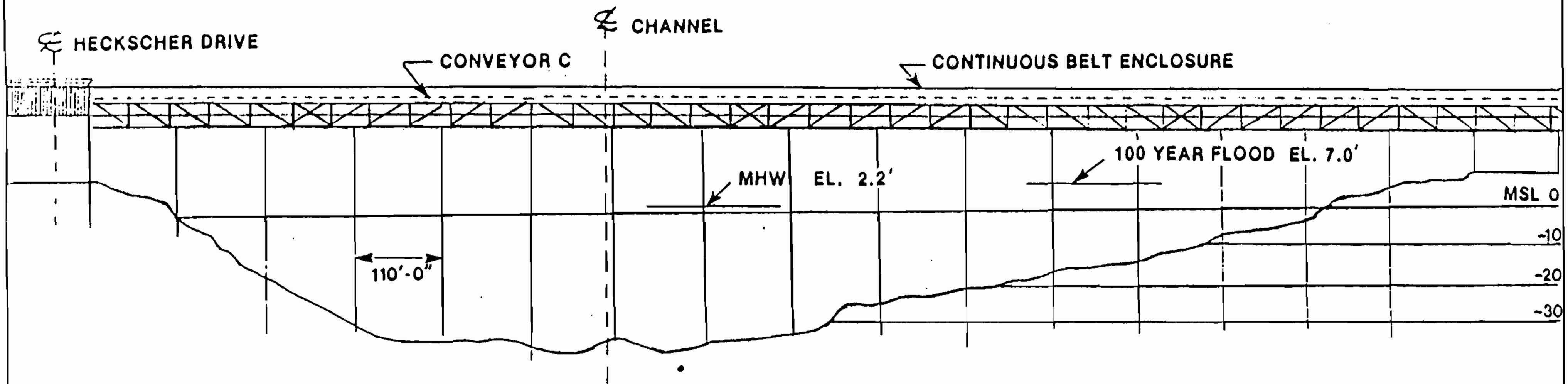
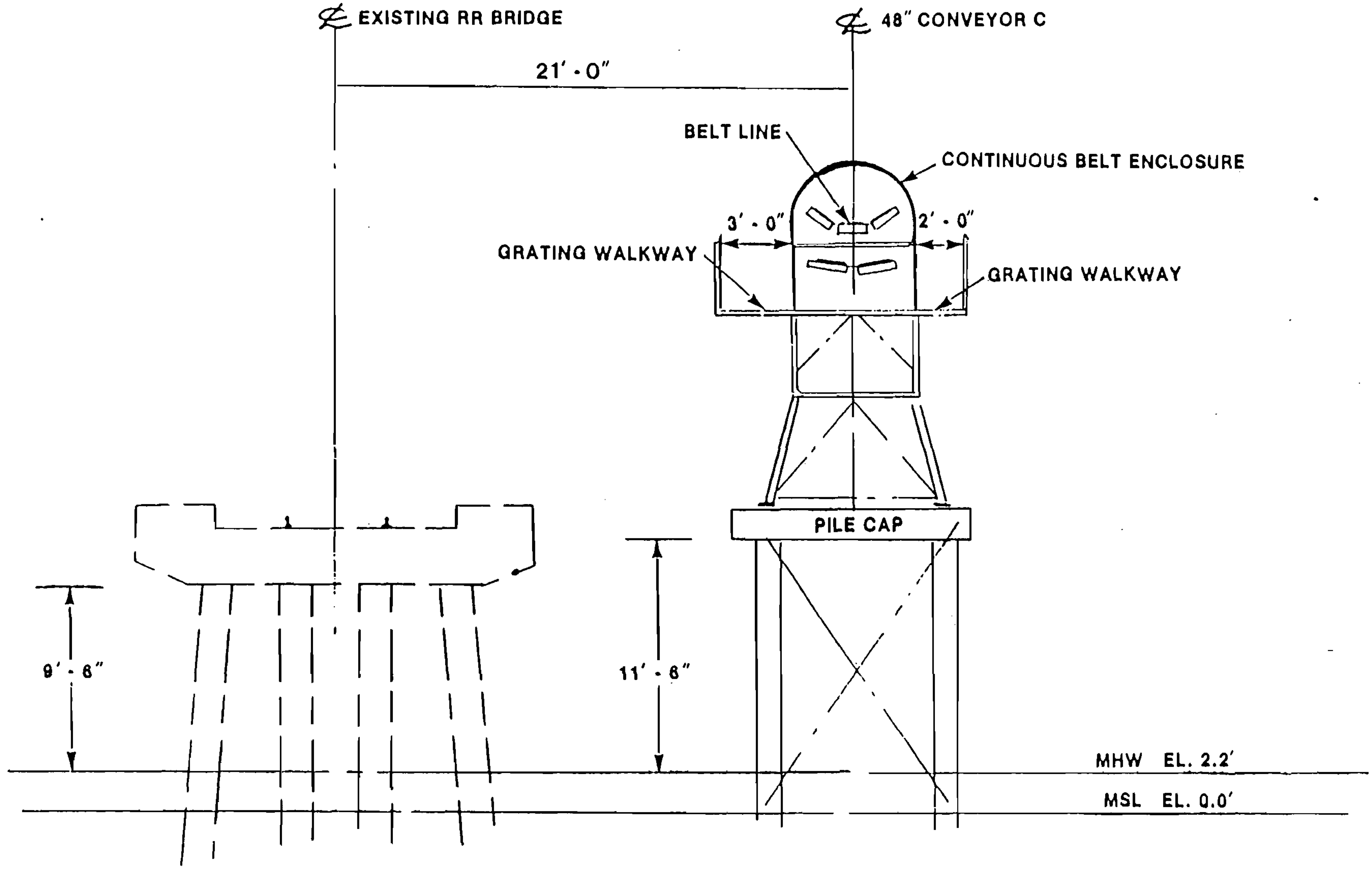


Figure IV-1 ST. JOHNS RIVER COAL TERMINAL: CONVEYOR CROSSING OF ST. JOHNS RIVER BACK CHANNEL/PROFILE

JACKSONVILLE ELECTRIC AUTHORITY(JEA)



SECTION A - A

Figure IV-2	ST. JOHNS RIVER COAL TERMINAL: CONVEYOR CROSSING OF ST. JOHNS RIVER BACK CHANNEL/CROSS SECTION	JACKSONVILLE ELECTRIC AUTHORITY (JEA)

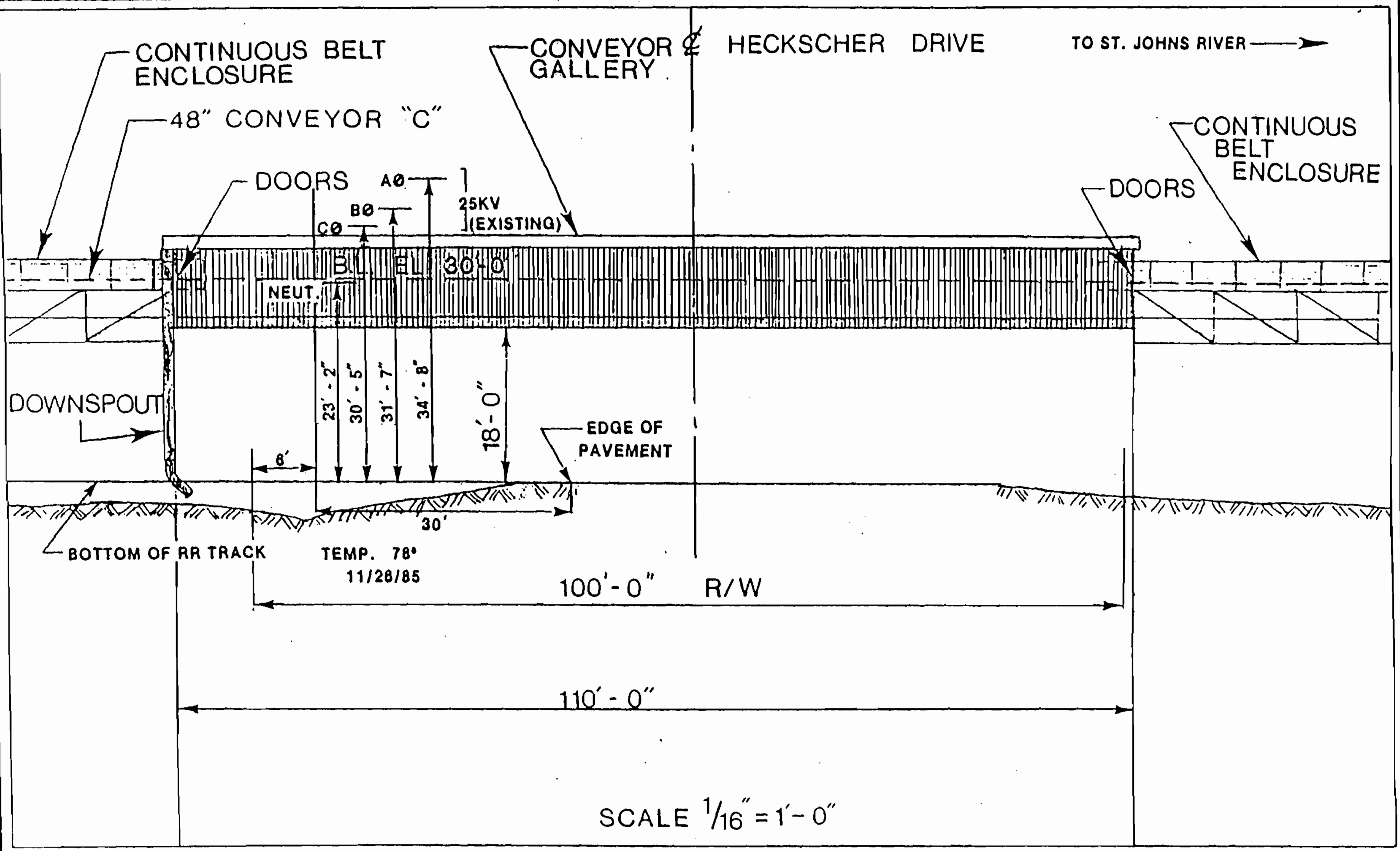
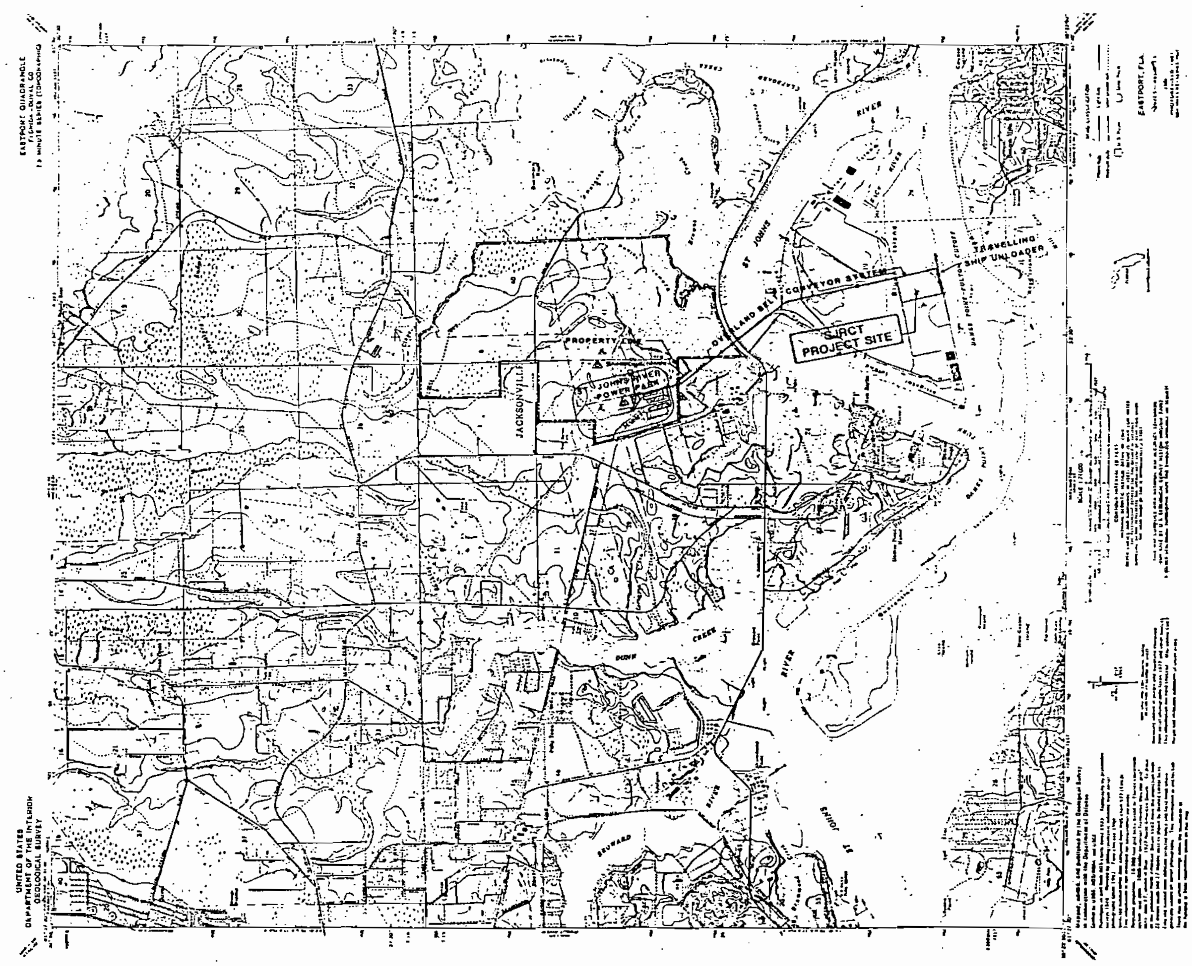


Figure IV-3 ST. JOHNS RIVER COAL TERMINAL: PROFILE OF HECKSCHER DRIVE CROSSING

JACKSONVILLE ELECTRIC AUTHORITY (JEA)



B		BLENDING CIRCUIT ADDED	
A		AS MARKED	

SCALE: 1"=2000'-0"
DATE: NOV. '85
CHECKED: SKM

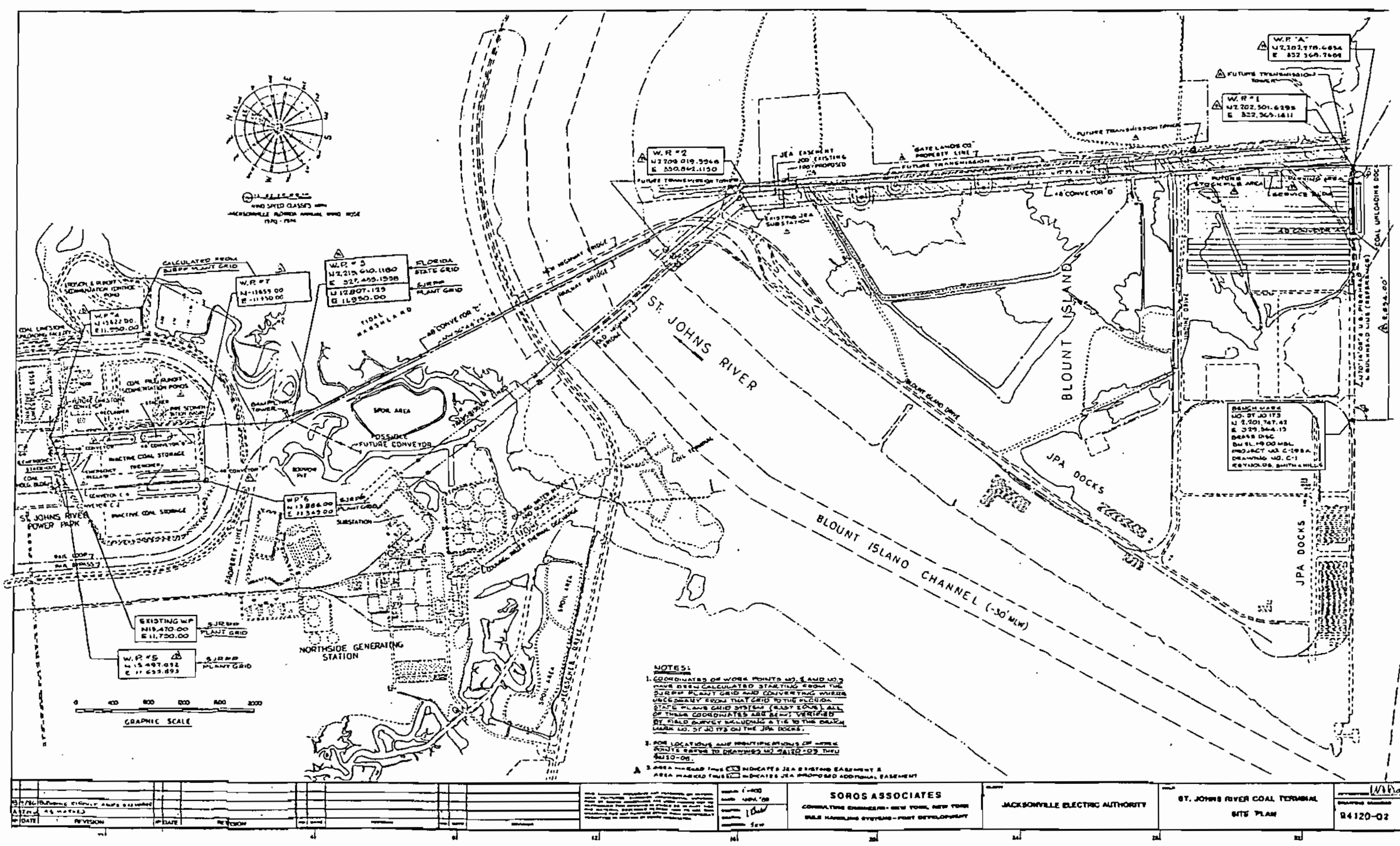
SOROS ASSOCIATES
CONSULTING ENGINEERS - NEW YORK, NEW YORK
BULK HANDLING SYSTEMS - PORT DEVELOPMENT

JACKSONVILLE ELECTRIC AUTHORITY

ST. JOHNS RIVER COAL TERMINAL
SITE IDENTIFICATION

94120-01 | B

BEST AVAILABLE COPY



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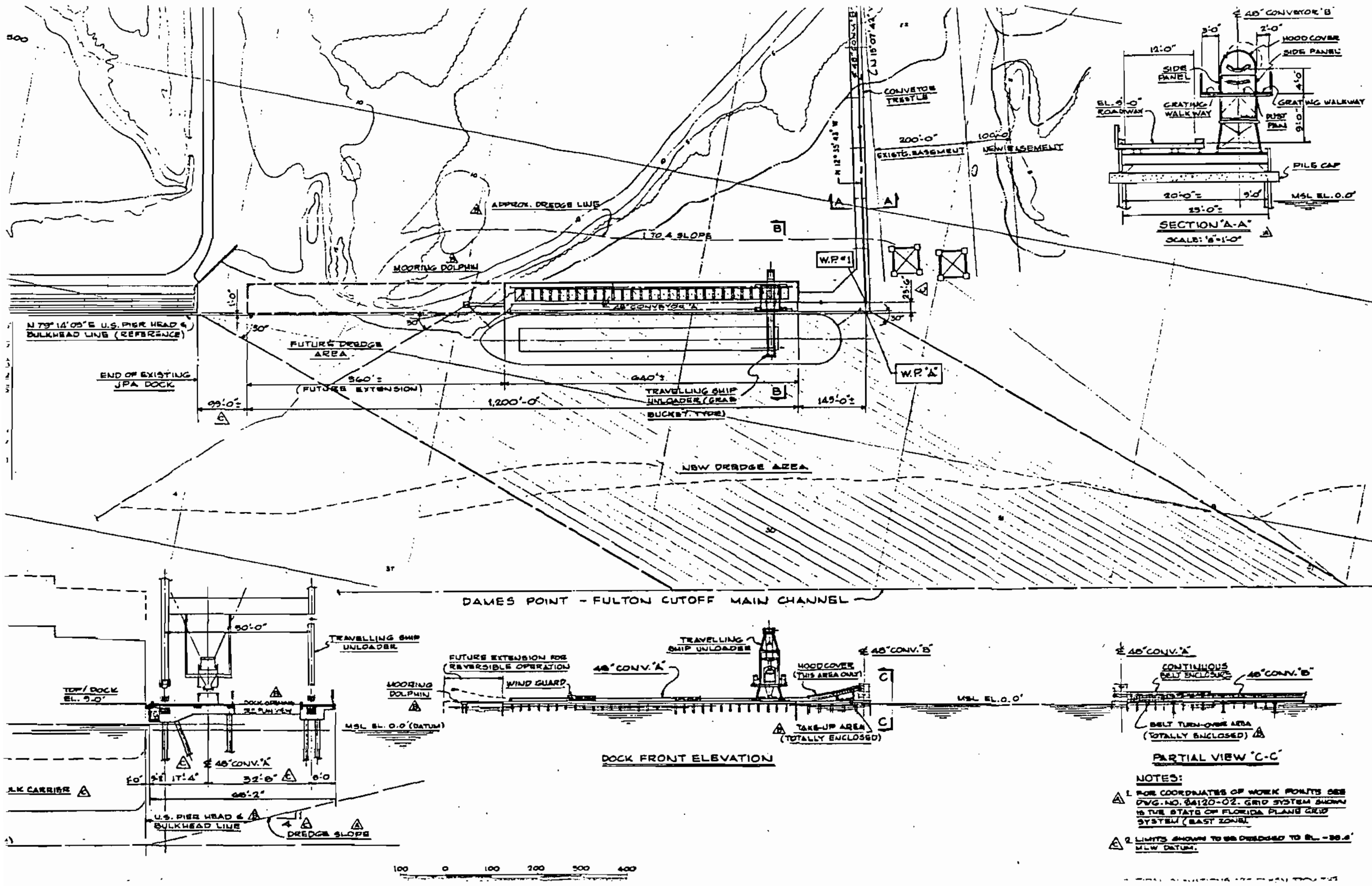
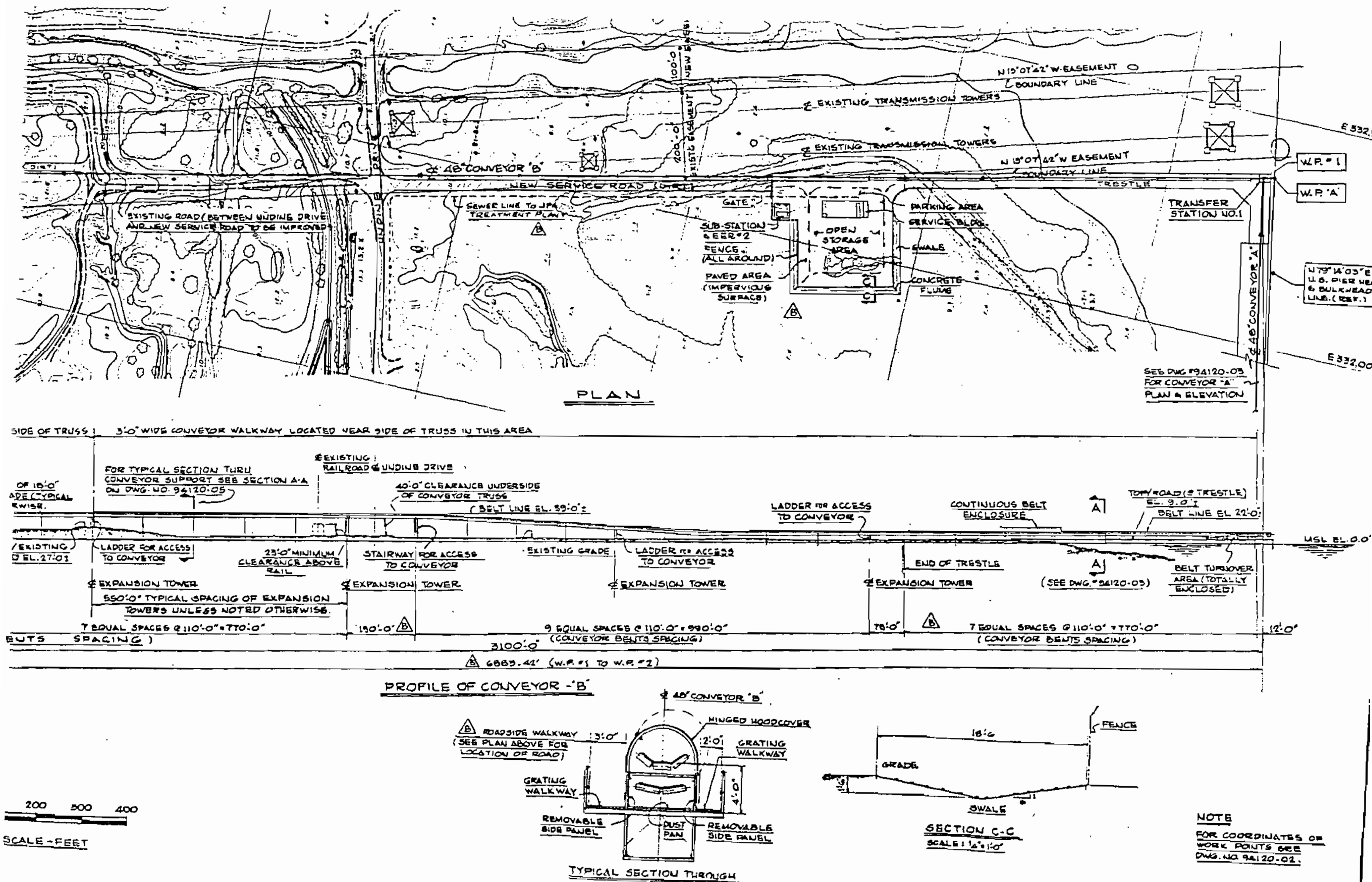
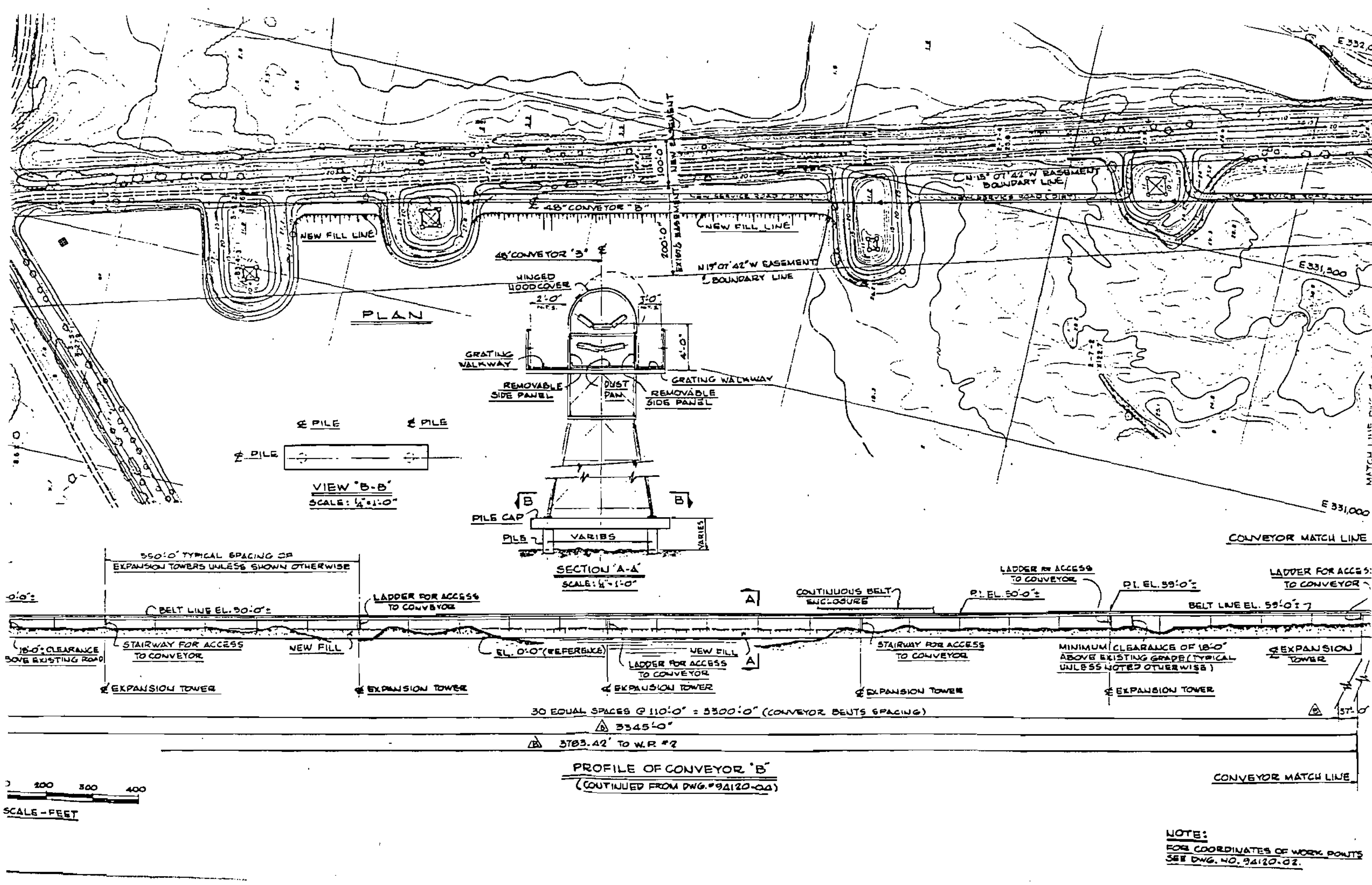




PLAN
N 13°07'42" W EASEMENT BOUNDARY LINE
℄ EXISTING TRANSMISSION TOWERS
℄ 48" CONVEYOR 'B'
NEW SERVICE ROAD
W.P. #1
W.P. 'A'
TRANSFER STATION NO. 1
EXISTING ROAD (BETWEEN UNDINE DRIVE AND NEW SERVICE ROAD TO BE IMPROVED)
SEWER LINE TO JPA TREATMENT PLANT
GATE
SUB-STATION
FENCE (ALL AROUND)
PAVED AREA (IMPERVIOUS SURFACE)
PARKING AREA
SERVICE BLDG.
OPEN STORAGE AREA
SWALE
CONCRETE FLUME
℄ 48" CONVEYOR 'A'
SEE DWG #94120-03 FOR CONVEYOR 'A' PLAN & ELEVATION
PROFILE OF CONVEYOR -'B'
3'-0" WIDE CONVEYOR WALKWAY LOCATED NEAR SIDE OF TRUSS IN THIS AREA
FOR TYPICAL SECTION THRU CONVEYOR SUPPORT SEE SECTION A-A ON DWG. NO. 94120-05
℄ EXISTING RAILROAD ℄ UNDINE DRIVE
40'-0" CLEARANCE UNDERSIDE OF CONVEYOR TRUSS
BELT LINE EL. 59'-0"
LADDER FOR ACCESS TO CONVEYOR
CONTINUOUS BELT ENCLOSURE
TOP ROAD (℄ TRESTLE) EL. 9.0'
BELT LINE EL 22'-0"
MSL EL. 0.0'
23'-0" MINIMUM CLEARANCE ABOVE RAIL
STAIRWAY FOR ACCESS TO CONVEYOR
EXISTING GRADE
END OF TRESTLE
BELT TURNOVER AREA (TOTALLY ENCLOSED)
(SEE DWG. #94120-05)
℄ EXPANSION TOWER
550'-0" TYPICAL SPACING OF EXPANSION TOWERS UNLESS NOTED OTHERWISE
7 EQUAL SPACES @ 110'-0" = 770'-0"
190'-0"
9 EQUAL SPACES @ 110'-0" = 990'-0" (CONVEYOR BENTS SPACING)
78'-0"
7 EQUAL SPACES @ 110'-0" = 770'-0" (CONVEYOR BENTS SPACING)
12'-0"
3100'-0"
6865.41' (W.P. #1 TO W.P. #2)
℄ 48" CONVEYOR 'B'
HINGED HOODCOVER
ROADSIDE WALKWAY (SEE PLAN ABOVE FOR LOCATION OF ROAD)
3'-0"
2'-0"
GRATING WALKWAY
4'-0"
REMOVABLE SIDE PANEL
DUST PAN
TYPICAL SECTION THROUGH
FENCE
GRADE
SWALE
SECTION C-C
200 300 400
SCALE-FEET
NOTE
FOR COORDINATES OF WORK POINTS SEE DWG. NO. 94120-02.

BEST AVAILABLE COPY



NOTE:
FOR COORDINATES OF WORK POINTS SEE DWG. NO. 94120-02.

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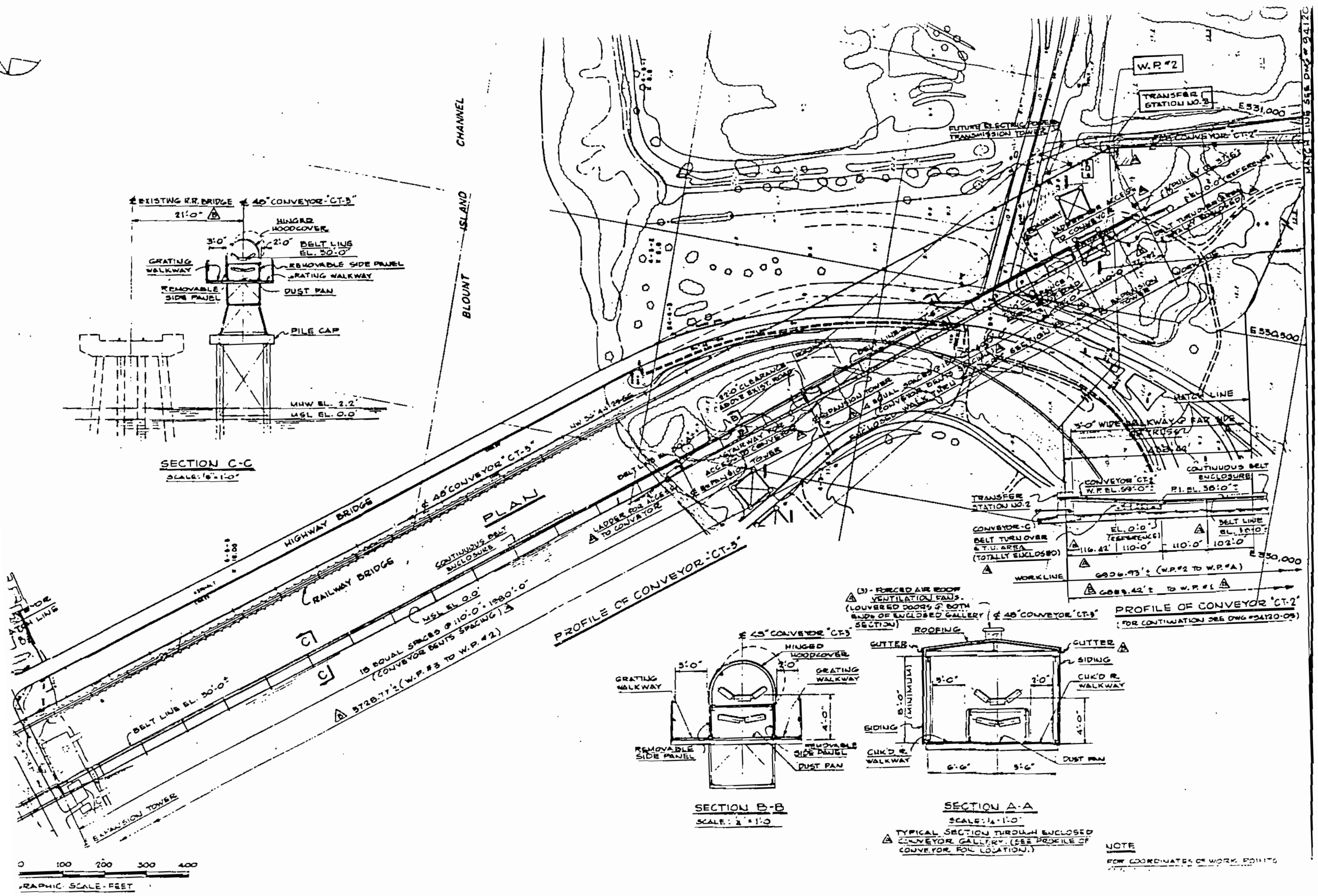

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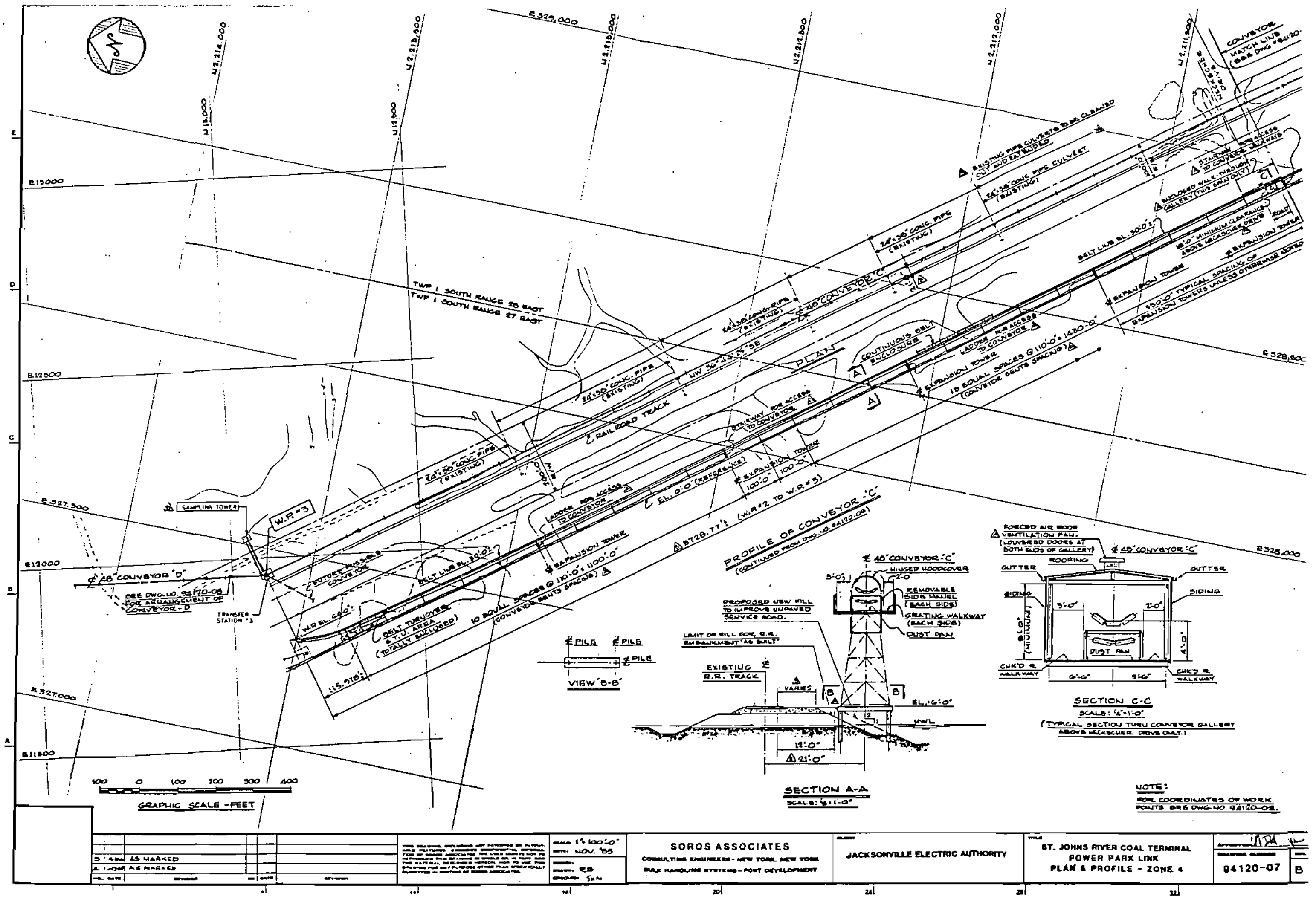

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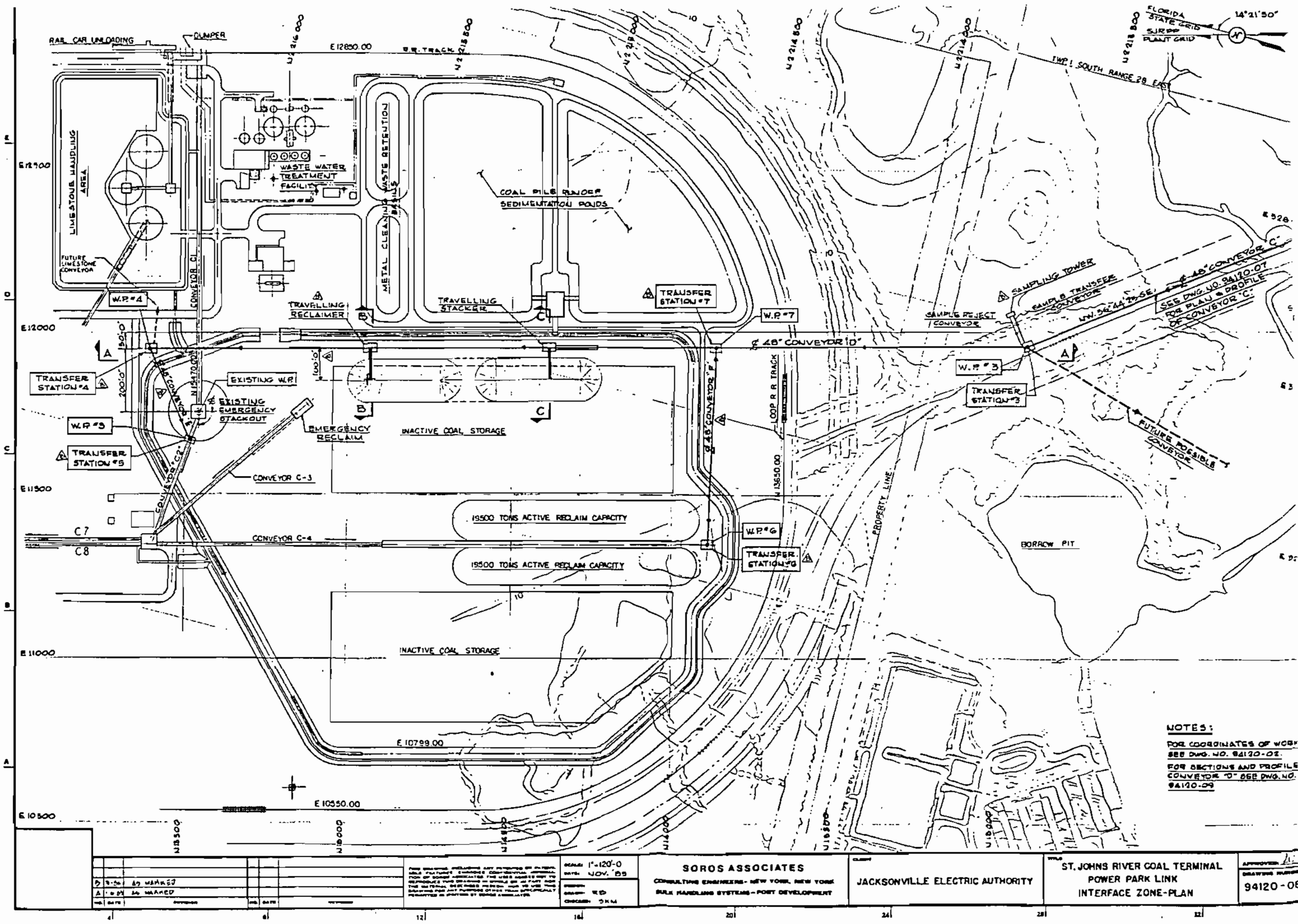

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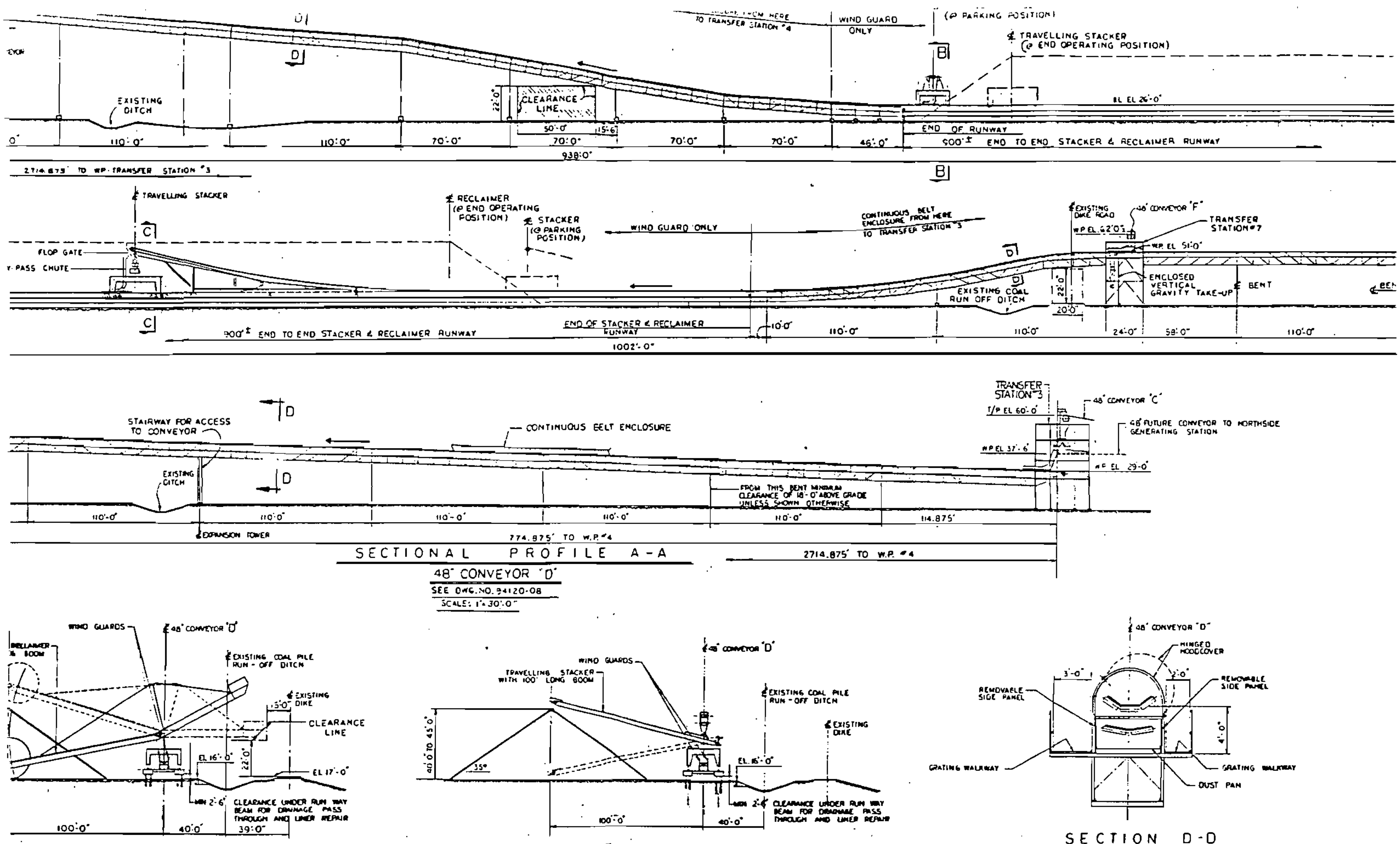


SECTIONAL PROFILE A-A

48" CONVEYOR "D"

SEE DWG. NO. 94120-08

SCALE: 1" = 30'-0"

SECTION B-B

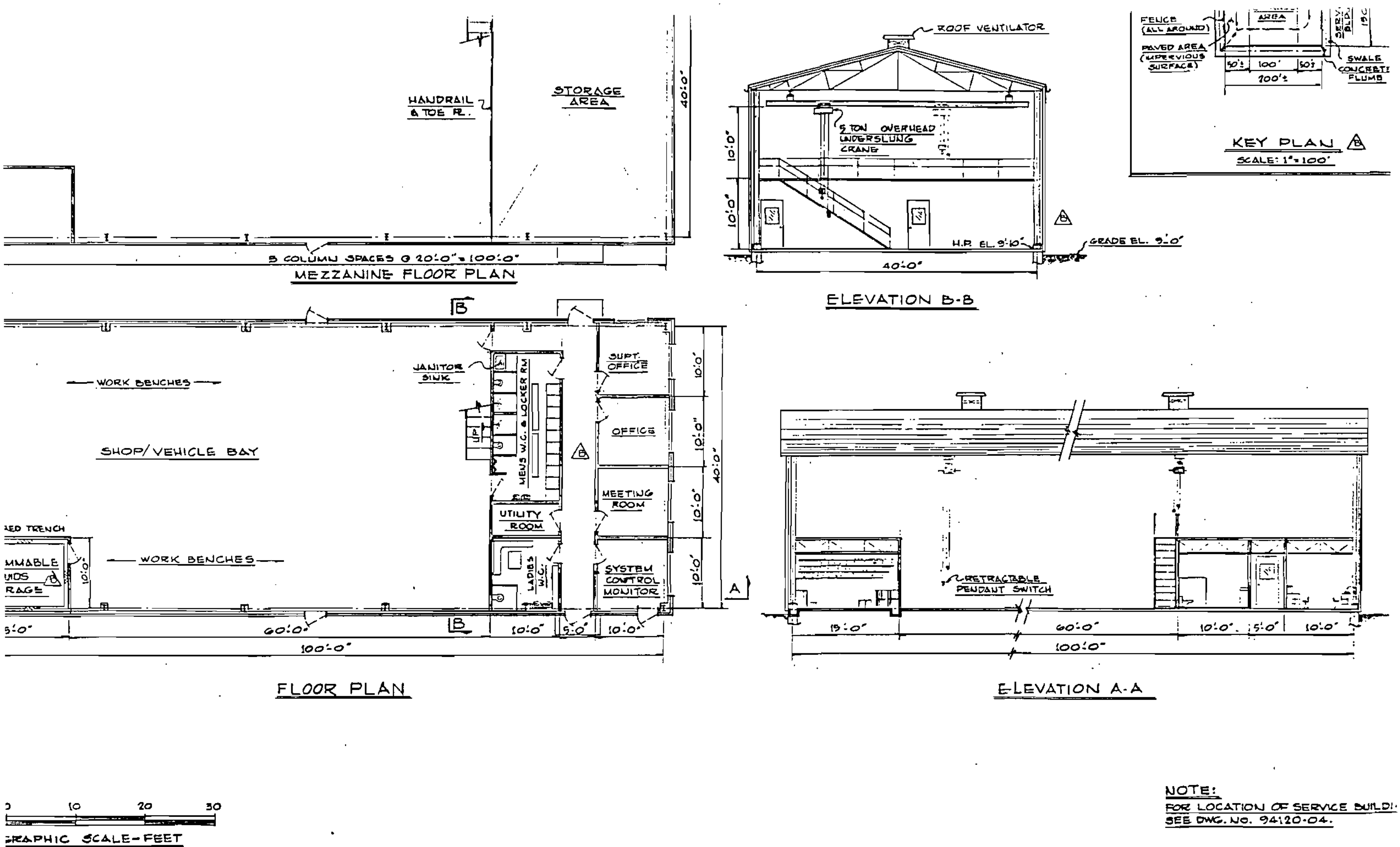
SCALE 1" = 30'-0"

SECTION C-C

SCALE 1" = 30'-0"

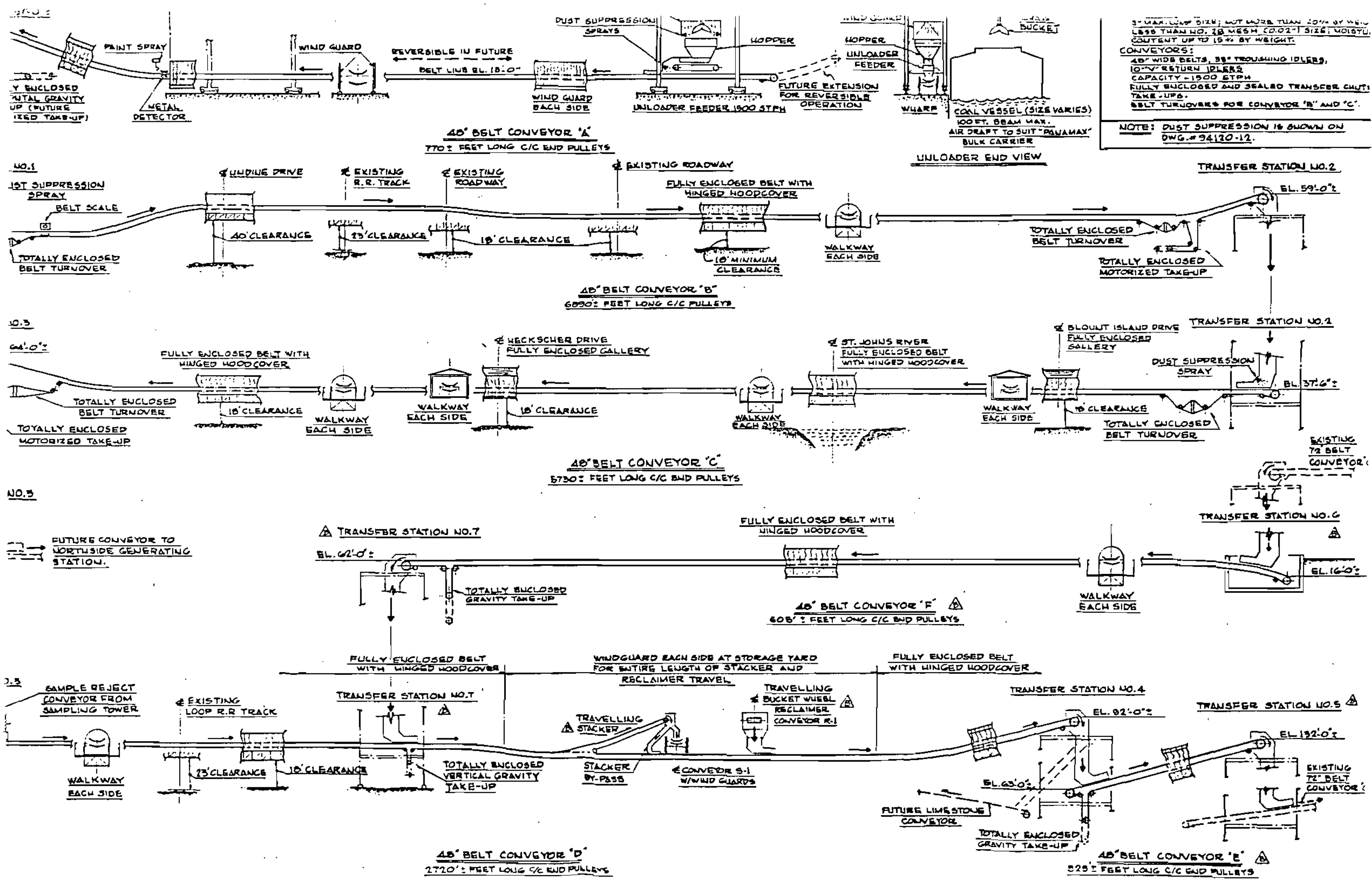
SECTION D-D

SCALE 3/4" = 1'-0"



NOTE:
FOR LOCATION OF SERVICE BUILDI-
SEE DWG. NO. 94120-04.

BEST AVAILABLE COPY



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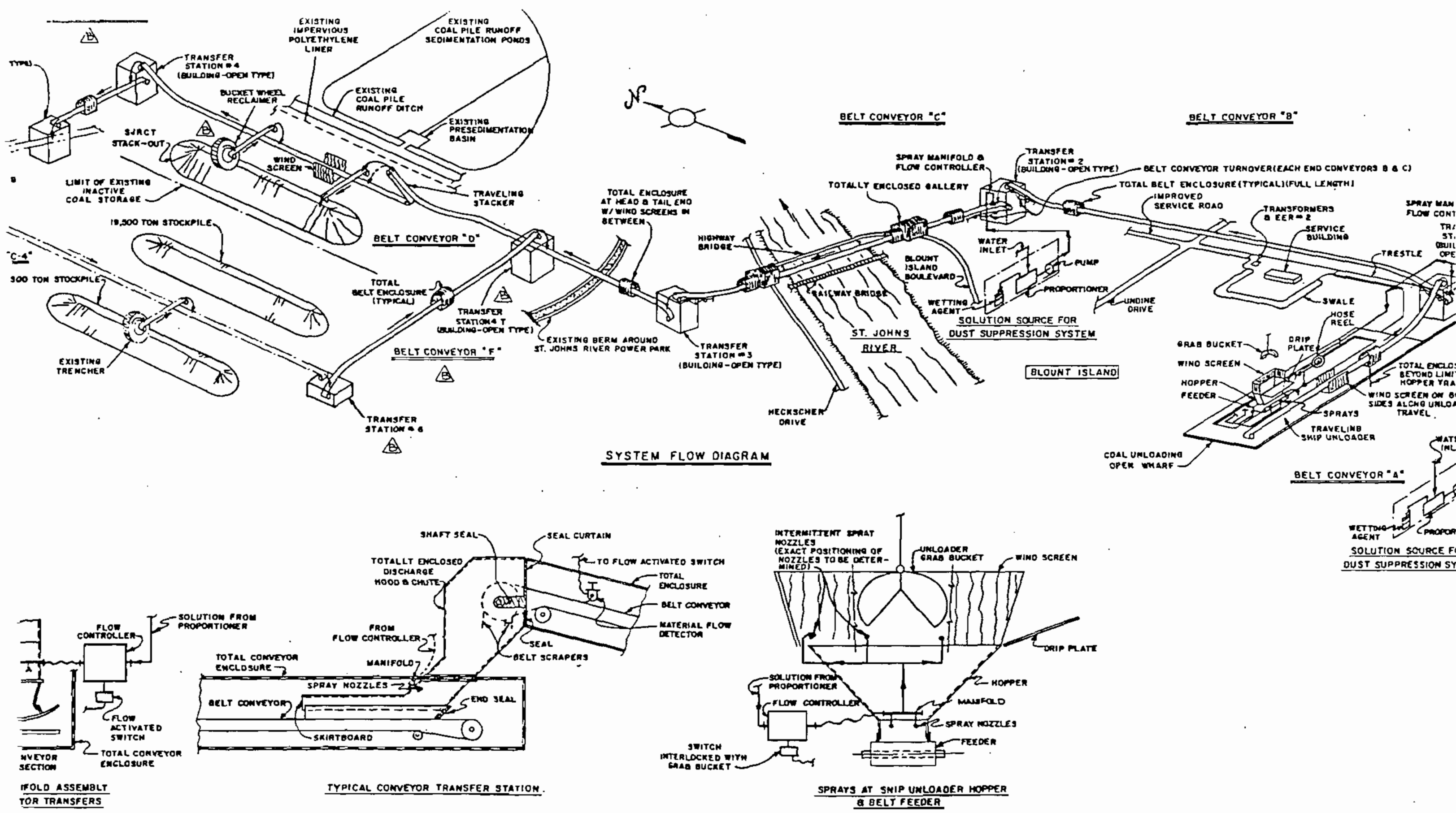
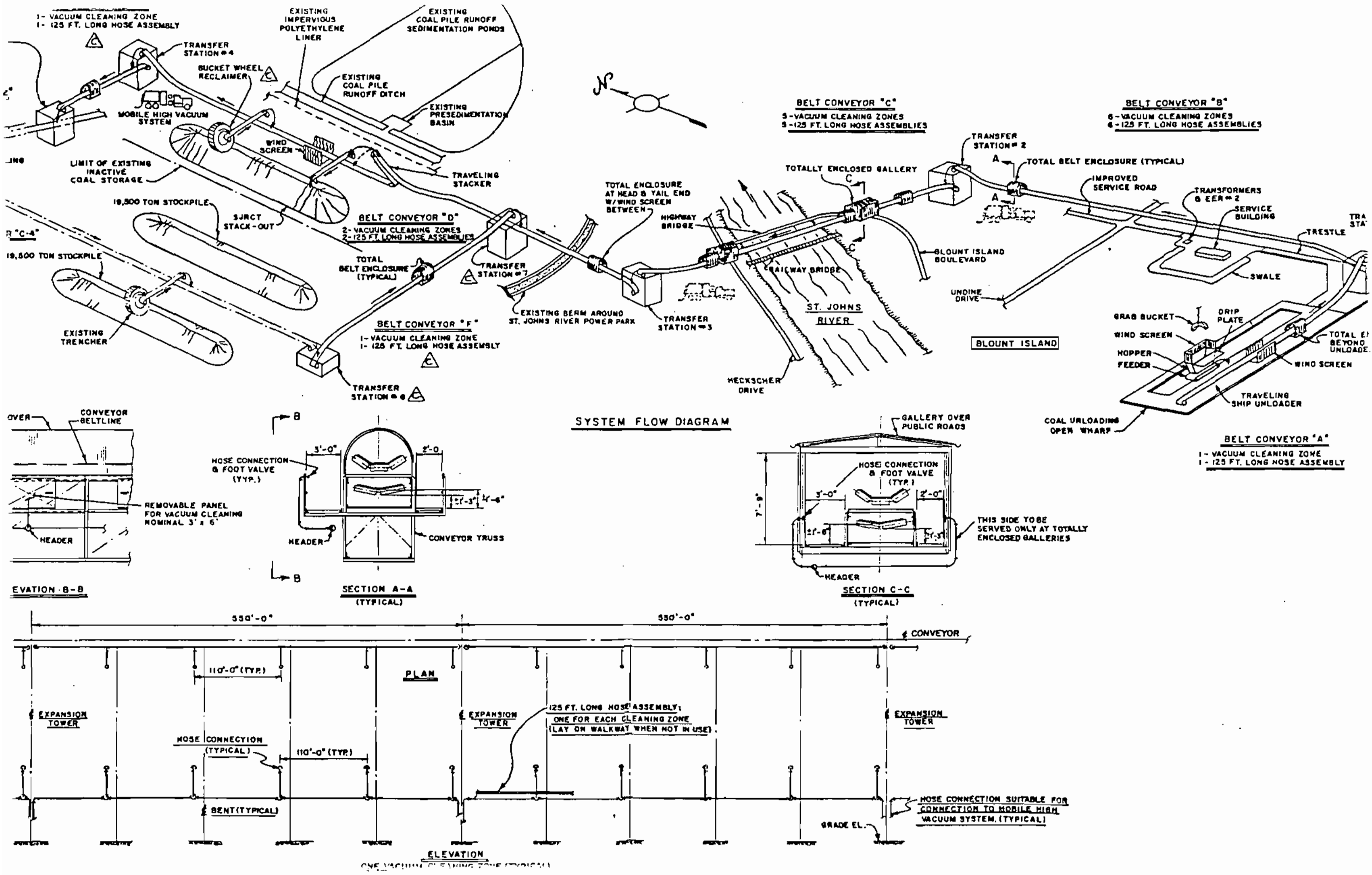
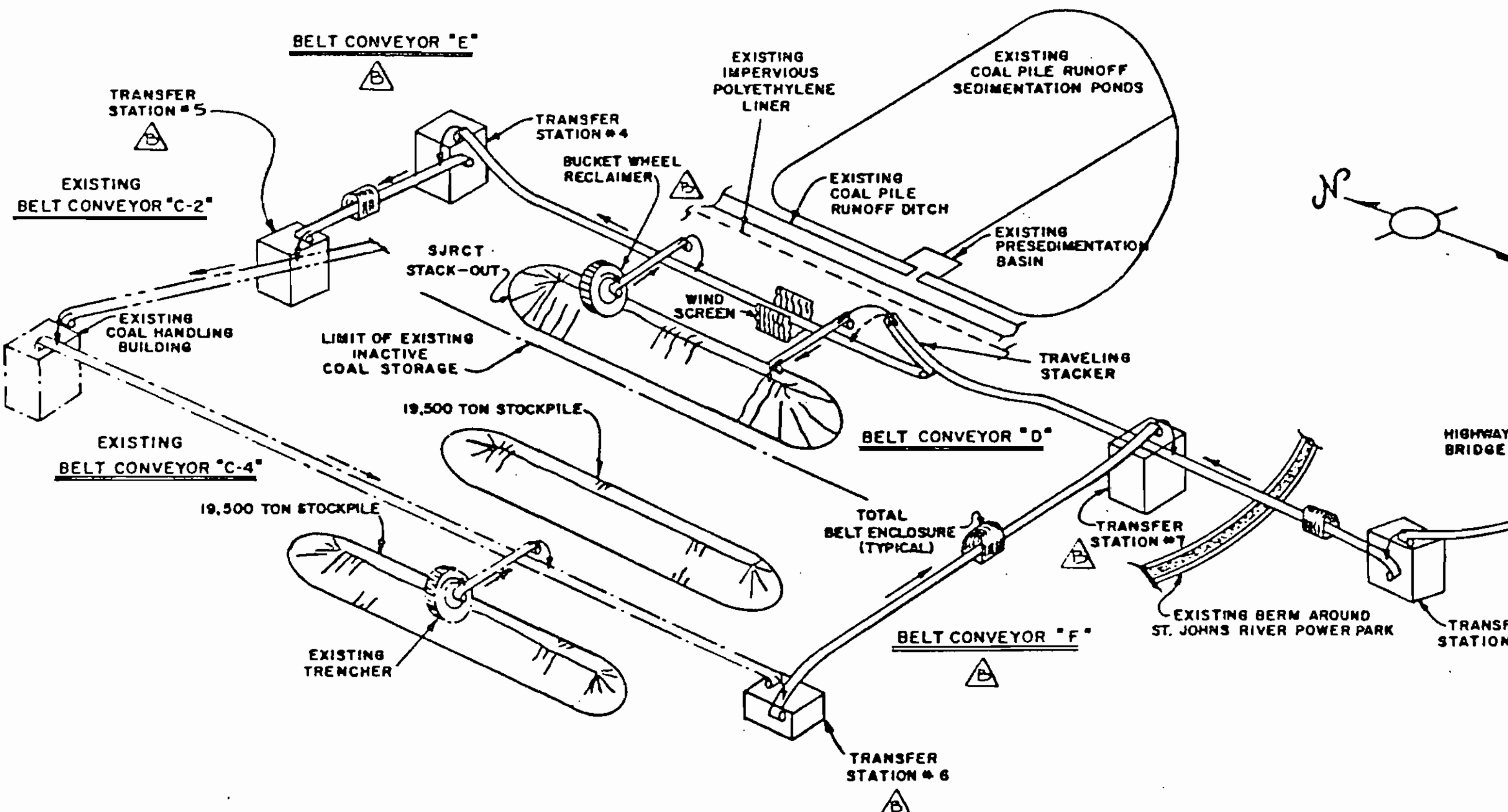
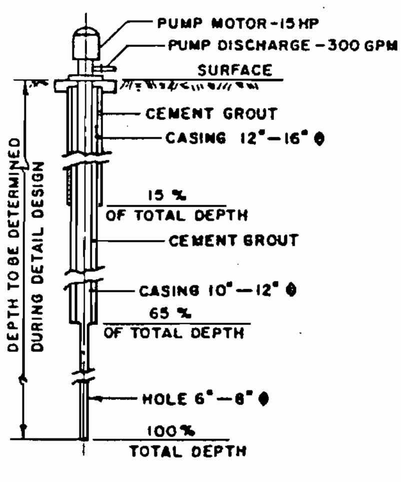


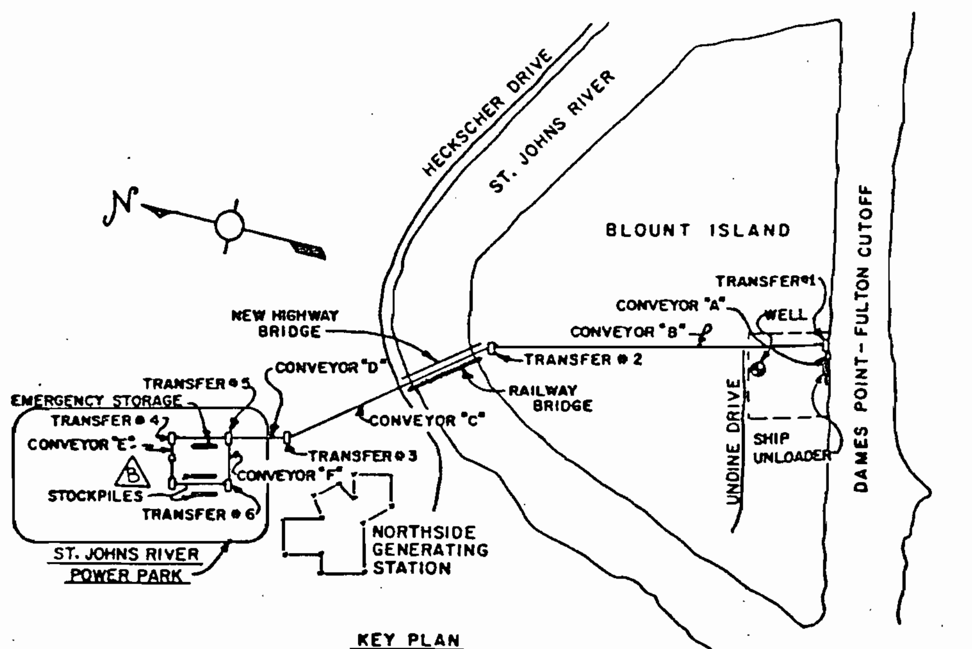

1- VACUUM CLEANING ZONE
1- 125 FT. LONG HOSE ASSEMBLY
TRANSFER STATION # 4
BUCKET WHEEL RECLAIMER
EXISTING IMPERVIOUS POLYETHYLENE LINER
EXISTING COAL PILE RUNOFF SEDIMENTATION PONDS
EXISTING COAL PILE RUNOFF DITCH
EXISTING PRESEDIMENTATION BASIN
MOBILE HIGH VACUUM SYSTEM
WIND SCREEN
LIMIT OF EXISTING INACTIVE COAL STORAGE
TRAVELING STACKER
19,500 TON STOCKPILE
STACK-OUT
19,500 TON STOCKPILE
EXISTING TRENCHER
BELT CONVEYOR "D"
2- VACUUM CLEANING ZONES
2-125 FT. LONG HOSE ASSEMBLIES
TOTAL BELT ENCLOSURE (TYPICAL)
TRANSFER STATION # 7
BELT CONVEYOR "F"
1- VACUUM CLEANING ZONE
1- 125 FT. LONG HOSE ASSEMBLY
TRANSFER STATION # 6
TOTAL ENCLOSURE AT HEAD & TAIL END W/WIND SCREEN BETWEEN
EXISTING BERM AROUND ST. JOHNS RIVER POWER PARK
TRANSFER STATION # 3
HIGHWAY BRIDGE
RAILWAY BRIDGE
ST. JOHNS RIVER
HECKSCHER DRIVE
TOTALLY ENCLOSED GALLERY
BELT CONVEYOR "C"
3- VACUUM CLEANING ZONES
3-125 FT. LONG HOSE ASSEMBLIES
BLOUNT ISLAND BOULEVARD
TRANSFER STATION # 2
TOTAL BELT ENCLOSURE (TYPICAL)
IMPROVED SERVICE ROAD
BELT CONVEYOR "B"
6- VACUUM CLEANING ZONES
6-125 FT. LONG HOSE ASSEMBLIES
TRANSFORMERS & EER # 2
SERVICE BUILDING
TRESTLE
SWALE
UNDINE DRIVE
BLOUNT ISLAND
GRAB BUCKET
DRIP PLATE
WIND SCREEN
HOPPER
FEEDER
WIND SCREEN
TRAVELING SHIP UNLOADER
COAL UNLOADING OPEN WHARF
BELT CONVEYOR "A"
1- VACUUM CLEANING ZONE
1- 125 FT. LONG HOSE ASSEMBLY
SYSTEM FLOW DIAGRAM
CONVEYOR BELTLINE
REMOVABLE PANEL FOR VACUUM CLEANING NOMINAL 3' x 6'
HEADER
ELEVATION B-B
HOSE CONNECTION & FOOT VALVE (TYP.)
3'-0"
2'-0"
HEADER
CONVEYOR TRUSS
SECTION A-A
(TYPICAL)
GALLERY OVER PUBLIC ROADS
HOSE CONNECTION & FOOT VALVE (TYP.)
7'-9"
THIS SIDE TO BE SERVED ONLY AT TOTALLY ENCLOSED GALLERIES
HEADER
SECTION C-C
(TYPICAL)
550'-0"
550'-0"
℄ CONVEYOR
110'-0" (TYP.)
PLAN
℄ EXPANSION TOWER
℄ EXPANSION TOWER
℄ EXPANSION TOWER
125 FT. LONG HOSE ASSEMBLY; ONE FOR EACH CLEANING ZONE (LAY ON WALKWAY WHEN NOT IN USE)
HOSE CONNECTION (TYPICAL)
110'-0" (TYP.)
℄ BENT (TYPICAL)
HOSE CONNECTION SUITABLE FOR CONNECTION TO MOBILE HIGH VACUUM SYSTEM. (TYPICAL)
GRADE EL.
ELEVATION



SYSTEM FLOW DIA



DRILLED WELL



KEY PLAN
NTS

B	2/86	REDRAWN-BLENDING CIRCUIT ADDED				
A	1/6/86	AS MARKED				

SCALE: NONE
DATE: 11/85
DESIGN: WAC
DRAWN: JBR

SOROS
CONSULTING ENGI
BULK HANDLING

Attachment 2

JACKSONVILLE ELECTRIC AUTHORITY
P. O. BOX 53015
233 W. DUVAL STREET
JACKSONVILLE, FL 32201

st. johns river POWER PARK

COASTAL ZONE MANAGEMENT CONSISTENCY CERTIFICATION

The proposed activity complies with Florida's approved coastal management program and will be conducted in a manner consistent with such program.

Richard Breitmoser, P.E.
Division Chief
Research & Environmental
Affairs Division

April 25, 1986

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices And/Or To Other Than The Addressee		
To:	Loctn.:	
To:	Loctn.:	
To:	Loctn.:	
From:	Date:	
Reply Optional [ ]	Reply Required [ ]	Info. Only [ ]
Date Due:	Date Due:	

TO: Buck Oven, Power Plant Siting Section

THRU: Clair Fancy, Deputy Chief, BAQM CHF

FROM: Bob King, BAQM BK

DATE: November 18, 1981

SUBJ: Response to the JEA's Comments on Draft Conditions of Certification

1. The Bureau feels that most comments from JEA on the draft conditions are acceptable except for these comments on Condition Nos. 5, 13, and 15.

2. We disagree on JEA's resolution on draft Condition No. 5. The draft condition is not inconsistent with the conditions in the revised federal PSD preliminary determination. Therefore, we believe that the condition should be retained without any change.

3. JEA's resolution on draft Condition 13 did not point out the reason why they object to the limits addressed for the auxiliary boilers. The condition should not be changed if there is not good reason for it.

4. The SO_2 emission limit is 0.76 lb/MMBTU for the proposed main units, which requires 90% SO_2 reduction based on the federal NSPS. The Bureau cannot agree with the JEA's resolution on draft Condition 15. Bypass reheat is continuous process. The quantity of flue gas bypassed ~~is~~ 25% or more. The Bureau does not believe that JEA can meet the NSPS limit on SO_2 emissions with the amount of bypassing flue gas. The attached document will give good reasons why bypass reheat should not be used in the proposed project.

BK:caa

It should be noted that the higher water vapor content in the gas offsets to some extent the adverse effects of gas cooling. Since the water vapor has a lower density than do other constituents of the gas, it makes the plume more buoyant. The effect is small, however, and has been omitted in developing the curves.

It is concluded that for the high efficiencies of SO_2 removal (85 - 95%), reheating is not likely to be economically justified except in marginal situations where the inlet SO_2 to the scrubber is so high that even with high SO_2 removal ambient concentration is still close to exceeding the standard.

There are some considerations, however, that may make the situation worse than it appears. If there is no reheat, then the gas leaving the stack can already have a load of mist, in which case evaporation of the droplets as the plume becomes mixed with air can cool the plume and further reduce its buoyancy. A high degree of mist elimination should be achieved if no reheat is used. Moreover, very little NO_x (probably less than 15 percent) is removed in SO_2 scrubbing. Thus NO_x ambient concentration will be greatly increased unless the gas is reheated.

4.11.7 Analysis of Bypass Reheat

Bypass reheat should be analyzed to determine its applicability from the standpoint of the emission limitations for sulfur dioxide. Bypass reheat offers the advantages of low capital investment and simple operation. The maximum quantity of reheat that can be obtained, however, is limited by the constraints of pollutant emission standards. As mentioned earlier, a regulation requiring 90 percent SO_2 removal efficiency would completely rule out the bypass reheat option. The limitation of sulfur emission to meet the emission standard for sulfur dioxide of 1.2 lb/mill Btu can be written as:

$$X - 1 - \frac{1}{E} + \frac{1.2}{2WSE} \qquad \text{(Eq. 4.11-11)}$$

where,

W = amount of fuel required to generate one million Btu/lb

S = weight fraction of sulfur in the fuel

X = fraction of bypass flue gas stream

E = Fractional sulfur removal efficiency of the wet scrubbing system

For details of the heat balance around the reheat system, refer to Reference (1).

4.11.8 No Reheat

As mentioned previously, stack gas reheat is not required by law. Some power plants have selected, at least temporarily, a "no-reheat" design and accepted the possible consequences--condensation in the ID fan and the stack.

Wash water can be sprayed periodically on the ID fan blades to prevent solid deposits, and a wet stack can be installed to protect the stack from acid attack.

Some advocate "no-reheat" by utilizing a "slow" stack (gas velocity of 30 ft/s [9 m/s]) rather than a conventional stack (gas velocity of 90 ft/s [30 m/s]). The slow stack allows mist droplets (acid rain) to settle out in the stack bottom. This requires special duct and stack material and handling equipment. It also requires larger stacks, which increase opacity problems.

Another alternative for prevention of ground concentration of pollutants is to build a taller stack. A tall stack may be more economial than reheating, even though it involves a high capital cost. There is, by comparison, no energy cost. Under certain circumstances, however, a stack of the required height might not achieve the objective of dispersion for a particular location. Meteorological modeling is a useful tool for determining the validity of such an alternative, but most dispersion models have not been developed for wet plumes.

To limit corrosion in no-reheat operation, one may either select materials that are inherently resistant to corrosion, or use coatings to cover corrodible materials. Discussion of this issue is included elsewhere in this Data Book. If the purpose of reheat is to protect a downstream fan, an obvious alternative is to place a fan upstream from the scrubber. This solution is only feasible with an upstream collector or ESP to remove abrasive particulate. Most installations with wet stack operation have stack lining problems. The lining usually blisters and eventually

STACK GAS REHEAT FOR WET FLUE GAS DESULFURIZATION SYSTEMS

EPRI FP-361
(Research Project 209-2)

Final Report

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ABSTRACT

A major problem in operating wet flue gas desulfurization systems is the need for stack gas reheat. Reheat is required to avoid downstream condensation and corrosion, to avoid a visible plume, and to enhance plume rise and dispersion of residual pollutants. Reheat methods currently in use include in-line reheat, indirect hot air reheat, and direct combustion reheat. Bypass reheat is not currently in use but has been considered and tested.

In-line reheaters using steam, in general, encounter a severe corrosion problem, due mainly to stress corrosion caused by chloride. Neither carbon nor stainless steel is adequate to resist this corrosion. In-line carbon steel reheaters using hot water have less severe corrosion problems compared to steam in-line reheaters. The use of hot water may not be the reason for less corrosion. More likely, one of the reasons may be that the boiler systems incorporate a limestone injection process which may eliminate chloride and sulfate ions from the flue gas. Because of extended fins on the tubes, however, a heater of this type has more severe pluggage and soot-blowing problems.

Indirect hot air reheaters are free of corrosion and plugging problems. This type of reheater, also providing reduced moisture content in the stack gas, reduces the probability of fog formation in the plume.

The major problems associated with direct combustion reheaters are corrosion and flame instability. An external combustion chamber is desirable. The initial capital investment is low but the utility cost is high due to high cost of fuel.

Bypass reheat has the advantages of low capital investment and simple operation, but the maximum degree of reheat attainable is limited by pollutant standards.

CONCLUSIONS

Based on the results of the unit study on stack gas reheat for wet scrubbing, the following conclusions can be drawn.

(1) Power plant stack gases from wet scrubbers need to be reheated in order to avoid downstream condensation in the I.D. fan and stack, and to avoid a visible plume. A secondary reason for stack gas reheat is to improve plume rise and dispersion. The types of reheat systems currently being employed at power plants include in-line reheat, indirect hot air reheat, and direct combustion reheat.

(2) To minimize the heat requirement for a fixed degree of reheat, the mist carryover from the scrubber should be minimized. The efficiency of the scrubber mist eliminator should, therefore, be high and the time of operation of the top wash sprayer, if used, should be minimized. A high-efficiency mist eliminator also is necessary to avoid severe pluggage problems in in-line reheaters.

(3) The lowest heat requirement to avoid downstream condensation can be obtained by an in-line reheater. The lowest heat requirement to avoid a visible plume can be obtained by an indirect hot air reheater. An indirect hot air reheater also results in a higher plume rise and generally a lower ground-level pollutant concentration for a fixed degree of reheat because of the effect of stack gas dilution with air. However, in general, the effect of reheat on the effective control of ground-level sulfur dioxide concentration is small in the temperature ranges beyond the dewpoint of the stack gas.

(4) Bypass reheat has the advantages of low capital investment and simple operation. However, the maximum degree of reheat which can be obtained is limited by the constraints of pollutant emission standards. The applicability of bypass reheat, for example, based on the limitation for sulfur dioxide emission depends on the sulfur content of the fuel, the removal efficiency of the scrubbing system, the temperature of the bypassed flue gas, and the degree of reheat required.

(5) The general consensus for reheat requirement is to increase the stack gas temperature from the wet scrubber and mist eliminator (about 125 F) by 25 F to 50 F. The energy need for reheat ranges between 1 to 5 percent of the total energy input to the boiler system. The energy need has a wide range because of variations in mode of operation, extent of duct insulation, arrangement of ductwork, and type of reheat.

(6) In-line reheaters using steam, in general, have a severe corrosion problem. The corrosion is mainly due to stress corrosion caused by chloride. Neither carbon steel nor stainless steel is deemed adequate to resist the corrosion. The solids deposited on the tubes should be blown off about once every 4 to 8 hours using either steam or compressed air. The soot blowing equipment is one of the high maintenance items.

(7) In-line, carbon steel reheaters using hot water have less corrosion problems compared with those for steam in-line reheaters during the first 6 to 7 years of operation. The tube temperature in general is low (about 230 to 350 F). Because of

extended fins, a reheater of this type has more severe pluggage and soot blowing problems. An efficient mist eliminator prior to the reheater is essential.

(8) In-line reheaters, either steam or hot water, have the advantages of being simple in design and low in capital investment. However, the reheaters require a large amount of maintenance for successful operation.

(9) Direct combustion reheaters with burners in-line have corrosion and flame stability problems. An external combustion chamber is desirable to cope with the problems. This type of reheat system is not deemed adequate for ducts with combustible linings since ineffective mixing of stack gas and combustion gas would cause downstream hot spots and damage the linings. In addition, the preheating time for the combustion chamber is high (about 8 to 15 hours) in order to prevent the refractory lining from cracking, and the temperature control is difficult. The initial investment is low, but the annual utility cost is very high compared with those for other reheat systems.

(10) Indirect hot air reheaters are free of corrosion and pluggage problems. This type of reheater also provides a decrease in moisture content per unit weight of dry gas, which will reduce the probability of fog formation in the plume. The initial capital investment is relatively high compared with that for other types of reheaters. However, the maintenance cost will probably be lower due to the absence of corrosion and pluggage problems.

(11) Startup and shutdown should be carried out with more attention to proper procedures. The procedures vary with the type of reheater, type of duct lining material, type of mist eliminator material, distance from the mist eliminator, and the type of materials used in

construction of the FGD system. Two important points to consider in the procedures are the prevention of corrosion in the reheater and the protection of structures from thermal damage.

(12) Stack gas that has not been reheated has a very dense, visible plume. The condensate in the stack has a pH of 2 to 4 according to the survey data and causes some deleterious effect on masonry linings. Operation without reheat requires washing I.D. fans to protect the fan blades from solid deposits, and an acid-resistant lining in the stack to protect the stack structure from deterioration.

RECOMMENDATIONS FOR FUTURE STUDY

(1) A detailed economic analysis of alternative reheat systems is recommended to analyze initial investment cost and cost for operation and maintenance. There has been a lack of systematically analyzed information on stack gas reheat, and thus, the selection of stack gas reheat in the scrubber installation has been mainly dependent upon the vendors supplying the scrubbing system. This occurs because the reheat system is usually included as a part of the scrubber package. However, this need not be the case and a utility should be free to select the optimal reheat system for its specific situation. In the proposed study, a representative case will be selected to use as a basis for the comparative analysis. Technical evaluations will be carried out for various reheat alternatives as well as the economic analysis. The results would provide the Electric Power Research Institute and its membership with a better basis for economic and technical analysis of various types of reheat systems.

(2) A study on plume rise and pollutant dispersion is also recommended for a wet plume to examine the effect of various parameters. In the present report, the effect of reheat was studied only for a specific case. The

State of Florida Department of Environmental Regulation
Jacksonville Electric Authority
SJRPP Units 1 & 2
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CONDITIONS OF CERTIFICATION

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State of Florida Department of Environmental Regulation
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CONDITIONS OF CERTIFICATION

I. Air

The construction and operation of SJRPP Units 1 & 2 at the Jacksonville steam electric power plant site shall be in accordance with all applicable provisions of Chapters 17-2, 17-4, 17-5 and 17-7, Florida Administrative Code. In addition to the foregoing, the permittee shall comply with the following conditions of certification:

A. Emission Limitations

1. Based on a maximum heat input of 6,144 million BTU per hour, stack emissions from SJRPP Unit 1 & 2 shall not exceed the following when burning coal:

   a. SO_2 - 1.2 lb. per million BTU heat input, maximum two hour average, 0.76 lb/MMBtu on a 30-day rolling average.

   b. NO_x - 0.60 lb. per million BTU heat input.

   c. Particulates - 0.03 lb. per million BTU heat input.

   d. Visible emissions - 20% (6-minute average), except one 6-minute period per hour of not more than 27% opacity.

2. The height of the boiler exhaust stack for SJRPP Unit 1 & 2 shall not be less than 640 ft. above grade.

3. Particulate emissions from the coal handling facilities:

   a. The permittee shall not cause to be discharged into the atmosphere from any coal processing or conveying equipment, coal storage system or coal transfer and loading system processing coal, visible emissions which exceed 10 percent opacity. Particulate emissions shall be controlled by use of control devices.

   b. The permittee must submit to the Department within thirty (30) days after it becomes available, copies of technical data pertaining to the selected particulate emissions control for the coal handling facility. These data should include, but not be limited to, guaranteed efficiency and emission rates, and major design parameters such as air/-cloth ratio and flow rate. The Department may, upon review of these data, disapprove the use of any such device if the Department determines the selected control device to be inadequate to meet the emission limits specified in 3(a) above. Such disapproval shall be issued within 30 days of receipt of the technical data.

4. Particulate emissions from limestone and flyash handling shall not exceed the following:

    a. Limestone silos - 0.050 lb/hr.

    b. Limestone hopper/transfer conveyors - 0.65 lb/hr.

    c. Flyash handling system - 0.2 lb/hr.

5. Visible emissions from the following facilities shall be limited to 5% opacity: (a) limestone and flyash handling system, (b) limestone day silos and (c) flyash silos.

6. Compliance with opacity limits of the facilities listed in Condition 5 will be determined by EPA reference method 9 (Appendix A, 40 CFR 60).

7. Construction shall reasonably conform to the plans and schedule given in the application.

8. The permittee shall report any delays in construction and completion of the project which would delay commercial operation by more than 90 days to the Department's St. Johns River Subdistrict Office.

9. Reasonable precautions to prevent fugitive particulate emissions during construction, such as coating of roads and construction sites used by contractors regrassing or watering areas of disturbed soils, will be taken by the permittee.

10. Coal shall not be burned in the units unless both electrostatic precipitator and limestone scrubber are operating properly except as provided under 40 CRF Part 60 Subpart Da.

11. The two auxiliary boilers shall fire No. 2 fuel oil with a maximum sulfur content of 0.76 percent by weight, a maximum ash content of 0.01 percent by weight, a minimum

heating value of 19,170 Btu per pound and a maximum viscosity of 3.0 centistokes at 100^{o} F. Samples of all fuel oil fired in the boilers shall be taken and analyzed for sulfur content, ash content, heating value and viscosity. Accordingly, samples shall be taken of each fuel oil shipment received. Records of the analyses shall be kept a minimum of the two years to be available for FDER's inspection.

12. The same quality No. 2 fuel oil, used for the auxiliary boilers, shall be used for the main boilers Units 1 and 2 during start-up and low load operation.

13. Maximum emissions from either of the auxiliary boilers shall be limited to 0.8 lb/MMBTU for SO_2, 0.3 lb/MMBTU for NO_x, 0.01 lb/MMBTU for PM, and 10 percent opacity for visible emissions.

14. Coal fired in Units 1 and 2 shall have 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 CRF 60.47a.

15. No fraction of flue gas shall be allowed to bypass the FGD system to reheat the gases existing from the FGD system, if the bypass will cause overall SO_2 removal efficiency less than 90 percent. The percentage and amount of flue gas bypassing the FGD system shall be documented and records kept a minimum of two years available for FDER's inspection.

16. Neither of the auxiliary boilers shall be allowed to operate while the boiler Units 1 and 2 are operating collectively at greater than 6,144 million Btu per hour heat input.

B. Air Monitoring Program

1. The permittee shall install and operate continuously monitoring devices for each main boiler exhaust for sulfur dioxide, nitrogen oxide, carbon monoxide, carbon dioxide and opacity. The monitoring devices shall meet

the applicable requirements of Section 17-2.710, FAC, and 40 CFR 60.47a. The opacity monitor may be placed in the duct work between the electrostatic precipitator and the FGD scrubber.

2. The permittee or Jacksonville Bio-Environmental Services Division shall operate two ambient monitoring devices for sulfur dioxide in accordance with EPA reference methods in 40 CFR, Part 53, and two ambient monitoring devices for suspended particulates. The monitoring devices shall be specifically located at a location approved by the Department. The frequency of operation shall be every six days commencing as specified by the Department.

3. The permittee shall maintain a daily log of the amounts and types of fuel used and copies of fuel analyses containing information on sulfur content, ash content and heating values.

4. The permittee shall provide stack sampling facilities as required by Rule 17-2.700(4) FAC. The sampling probe liner shall be fabricated of material which can withstand flexing.

5. The ambient monitoring program may be reviewed by the Department and the permittee annually after start-up of Unit 1. The monitoring program may be expanded or modified as deemed necessary by the Department.

6. Prior to operation of the source, the permittee shall submit to the Department a standardized plan or procedure that will allow the permittee to monitor emission control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible.

C. Stack Testing

1. Within 60 calendar days after achieving the maximum capacity at which each unit will be operated, but no later than 180 operating days after initial start-up, the permittee shall conduct performance tests for particulates SO_2, NO_x, and visible emissions during normal operations near (±10%) 6144 MMBtu/hr heat input and furnish the Department a written report of the results of such performance tests within 30 days of completion of the tests. The performance tests will be conducted in accordance with the provisions of 40 CFR 60.46a, 48a, and 49a.

E. Operating Restrictions

1. The permittee shall not operate its Southside, Northside, or Kennedy Generating Station in such a manner as to cause violation of ambient air quality standards for SO_2 when SJRPP is operating.

2. The permittee shall file with the Department, St. Johns River Subdistrict Office and the Jacksonville Bio-Environmental Services by June 1, 1984, the SJRPP proposed operating plan and supporting justification that will include the procedures JEA will follow to permanently eliminate emissions from steam generating units equivalent to the impact of the emissions of Southside Units 1 and 2. The Secretary of the Department shall indicate the Department's approval or disapproval within 90 days of receipt. The proposed operating plan shall also contain proposals for operating during air pollution episodes pursuant to 17-2.320(3), FAC, including use of such alternatives as washed coal.

3. The operating plan shall include retirement of Southside Units 1 and 2, or equivalent units, cold storage, construction of tall stacks or other equivalent programs.

4. The schedule for implementation of the plant shall by consistent with the start-up of SJRPP.

II. Water Discharges

Any discharges into any waters of the State during construction and operation of SJRPP Units 1 and 2 shall be in accordance with all applicable provisions of Chapter 17-3, Florida Administrative Code, and 40 CFR, Part 423, Effluent Guidelines and Standards for Steam Electric Power Generating Point Source Category, except as provided herein. Also, the permittee shall comply with the following conditions of certification:

A. Plant Effluents and Receiving Body of Water

For discharges made from the power plant the following conditions shall apply:

1. Receiving Body of Water (RBW)

The receiving body of water has been determined by the Department to be those waters of the St. John's River and any other waters affected which are considered to be waters of the State within the definition of Chapter 403, Florida Statutes.

2. Point of Discharge (P.O.D.)

The point of discharge has been determined by the Department to be where the effluent physically enters the waters of the State in the St. Johns River or Browns Creek.

3. Thermal Mixing Zone

The instantaneous zone of thermal mixing for the cooling system shall not exceed an area of 9.5 acres. The temperature at the point of discharge into the St. John's River shall not be greater than 105 degrees F. The temperature of the water at the edge of the mixing zone shall not exceed the limitations of Paragraph 17-3.05(1)(d). Cooling tower blowdown shall not exceed 93^{o} F as a 24 hour average.

4. Chemical Wastes

All discharges of low volume wastes (demineralizer regeneration, floor drainage, labs drains, FGD blowdown and similar wastes) and metal cleaning wastes shall comply with Chapter 17-3. If violations of Chapter 17-3 occur, corrective action shall be taken. These wasteswaters shall be directed to an adequately sized and constructed treatment facility.

During periods when treated wastewater does not comply with pH discharge limitations, the treated wastewater may be recycled to the coal pile runoff sedimentation pond, except when the sedimentation pond has insufficient capacity to retain the recycled wastewater and the runoff from a rainfall event equal to or less than a ten year, 24 hour storm.

5. Coal Pile

Coal pile runoff shall be directed in the central wastewater treatment system and shall not be directly discharged to surface waters, except that discharge of stormwater runoff from the coal pile is allowed only during periods of high rainfall in excess of the ten year, 24 hour storm.

6. Chlorine

The concentration of total residual chlorine discharged from Units 1 & 2 and/or Northside Generating Station shall not exceed 0.1 mg/l at the POD nor 0.01 mg/l beyond an instantaneous mixing zone of 1.0 acre. Chlorine from either unit at SJRPP shall not be discharged more than two hours per day and no unit shall be chlorinated simultaneously with any other unit at SJRPP or at Northside Generating Station. Levels of free available chlorine shall not exceed 0.5 mg/l for an instantaneous maximum nor 0.2 mg/l on a daily average from the blowdown of either cooling tower. In the event that 40 CFR, Part 423 is revised with respect to chlorine limitations, such discharge limitations shall apply to cooling tower blowdown.

7. pH

The pH of the combined discharges shall be such that the pH will fall within the range of 6.0 to 9.0.

8. Polychlorinated Biphenyl Compounds

There shall be no net discharge of polychlorinated biphenyl compounds.

9. Combined Low Volume Wastes and Coal Pile Runoff

The combined low volume wastes and coal pile runoff shall be treated to control pH, total suspended solids and toxic metals prior to being discharged. The following effluent limitations will apply:

Effluent	Daily Maximum	Maximum 30-Day Daily Average
TSS	50 mg/l	30 mg/l
Oil and Grease	15 mg/l	10 mg/l
pH	6-9	6-9

The design plans and specifications of the treatment system shall be submitted to the Department for review and approval prior to construction. The Department will indicate approval or disapproval within 45 days.

10. Metal Cleaning and Bottom Ash Sluice System Blowdown

Blowdown from the metal cleaning wastes and from the bottom ash sluice system shall be treated as appropriate prior to discharge to the cooling water system. The following effluent limitations shall apply:

Effluent	Daily Maximum	Maxmimum 30-Day Daily Average
TSS	100 mg/l	30 mg/l
Oil and Grease	20 mg/l	15 mg/l
pH	6-9	
Iron	1 mg/l	
Copper	1 mg/l	
PO_4	1 mg/l	
COD	100 mg/l	

11. Solid Waste and Limestone Storage Areas

There shall be no direct discharge of stormwater runoff to surface waters from the solid waste and limestone storage areas prior to treatment.

12. Storm Water Runoff

During plant operation, necessary measures shall be used to settle, filter, treat or absorb silt-containing or pollutant-laden stormwater runoff to limit the suspended solids to 50 mg/l or less at the POD during rainfall periods less than the 10-year, 24-hour rainfall, and to prevent an increase in turbidity of more than 50 Jackson Turbidity Units above background in waters of the State.

Control measures shall consist at the minimum of filters, sediment traps, barriers, berms or vegetative planting. Exposed or disturbed soil shall be protected as soon as possible to minimize silt - and sediment-laden runoff. The pH shall be kept within the range of 6.0 to 8.5 at the POD.

13. Coal Unloading Facility Percolation Pond Overflow

There shall be no direct discharge to surface waters from the coal unloading facility wastewater treatment system percolation pond. Any discharge from the facility shall be reported to the Department and the Environmental Protection Agency. The quantity of flow and duration of flow shall be estimated.

14. Mixing Zones

The discharge of the following pollutants shall not violate the Water Quality Standards of Chapter 17-3, FAC, beyond the edge of the designated instantaneous mixing zones as described herein.

Pollutants	Mixing Zone	
Aluminum	$125,600^2$	31 Acres
Copper	$125,600^2$	31 Acres
Cyanide	$125,600^2$	31 Acres
Iron	$125,600^2$	31 Acres
Mercury	$125,600^2$	31 Acres
Silver	$125,600^2$	31 Acres

Oil and Grease	125,600[2]	31 Acres
Selenium	80[2]	0.02 Acres
Chlorides	80[2]	0.02 Acres

15. Variances to Water Quality Standards

In accordance with the provisions of Sections 403.201 and 403.511(2), F.S., Jacksonville Electric Authority is hereby granted variances to the water Quality Standards of Chapter 17-3, F.A.C., for Aluminum, Copper, Iron and Mercury and 17-4.244(4) for Copper but only at such times as the natural background levels of the St. Johns River approach or exceed those standards. In any event, the discharge from the SJRPP shall comply with the effluent limitations set forth in paragraph II.A.16. The variances for mercury and copper shall only be for two years, but may be extended by the Secretary pending results of monitoring data on wastewater treatment plant efficiency and ambient water quality data and bioassays performed for copper and mercury.

16. Effluent Limitations

The following effluent limitations shall apply for Aluminum, Copper, Iron, Mercury, Silver, and Oil and Grease at the locations specified:

a. Cooling Tower Blowdown - Daily average concentrations shall not exceed 1.5 times the concentrations present in the intake of the applicant's Northside Generating Station.

b. Wastewater Treatment Facility Discharge - Instantaneous maximum concentrations shall not exceed:

Aluminum	0.15 mg/l
Copper	1.0 mg/l
Iron	1.0 mg/l
Mercury	41.1 ug/l
Silver	6.4 ug/l
Oil and Grease	20 mg/l

B. Water Monitoring Programs

The permittee shall monitor and report to the Department the listed parameters on the basis specified herein. The methods and procedures utilized shall receive written approval by the Department. The monitoring program may be reviewed annually by the Department, and a determination may be made as to the necessity and extent of continuation, and may be modified in accordance with Condition No. XXV.

1. Chemical Monitoring

The following parameters shall be monitored during discharge as shown, commencing with the start of commercial operation of SJRPP and reported quarterly to the Department's St. Johns River Subdistrict Office:

Parameter	Location	Sample Type	Frequency
Flow, Groundwater	Wellfield Pipeline	Recorder	Continuous
Flow, Cooling Water Make-up	Intake	Pump Logs	Daily
Flow, Cooling Tower Blowdown	Cooling Towers	Pump Logs	Daily
Flow, CWTF*	Prior to Pump Sump	Recorder	Continuous
Flow, Oily Waste-Water collection Basin	Prior to Pump Sump	Pump Logs	Daily
pH	Pump Sump Outfall to NGS	Recorder Grab	Continuous One/per week
Temperature	Outfall to NGS	Recorder	Continuous
TSS	Oily Waste Basin, Metal Cleaning Waste Retention Basin CWTF and Sewage Treatment Facility	Grab 24 Hour Composite " " "	Two/per week Two/per week " " " Monthly
Chlorine,Total Residual	Cooling Tower Blowdown Discharge to Browns Creek (During construction only)	Multiple Grab	Weekly

*CWTF = Central Wastewater Treatment Facility

Oil and Grease	Oily Wastewater Collection	3 Grab Composite	Two/week
	Metal Cleaning Waste Retention Basin CWTF	24 Hour Composite	One/day
		3 Grab Composite	Two/week
Metals	Intake and Sump Pump	24 Hour Composite	Once/week for first six months, two/month for the next six months, then monthly thereafter
Aluminum	"		"
Copper	"		"
Cyanide	"		"
Iron	"		"
Mercury	"		"
Nickel	"		"
Selenium	"		"
Silver	"		"
Zinc	"		"
BOD	STP Influent and effluent	8 Hour Composite	Monthly
	Metal Cleaning Waste Facility	24 Hour Composite	Daily
PO_4	Metal Cleaning Facility	24 Hour Composite	Daily
Copper	" " "	" " "	"
Iron	" " "	" " "	"
Cycles-of-concentration	Cooling tower	Calculation	"

2. Groundwater Monitoring

The groundwater levels shall be monitored continuously at selected wells as approved by the St. Johns River Water Management District. Chemical analyses shall be made on samples from all monitored wells identified in Condition III. F. below. The location, frequency and selected chemical analyses shall be as given in Condition III.F.

The groundwater monitoring program shall be implemented at least one year prior to operation of SJRPP Unit 1. The chemical analyses shall be in accord with the latest edition of Standard Methods for the Analysis of Water and Wastewater. The data shall be submitted within 30 days of collection/-analysis to the St. Johns River Water Management District and to the DER St. Johns River Subdistrict Office.

Conductivity shall be monitored in wells around all lined solid waste disposal sites, coal piles, and wastewater treatment and sedimentation ponds.

III. <u>Groundwater</u>

A. General

The use of groundwater from the wellfield for plant service water for SJRPP shall be minimized to the greatest extent practicable, but in no case shall exceed 7.6 mgd on a maximum daily basis from any new wells or 5.1 mgd on an average annual basis.

B. Well Criteria

The submission of well logs and test results and location, design and construction of wells to provide plant service water shall be in accordance with applicable rules of the Department of Evironmental Regulation and the St. Johns River Water Management District(SJRWMD). Total water use per month shall be reported quarterly to SJRWMD commencing with the start of construction.

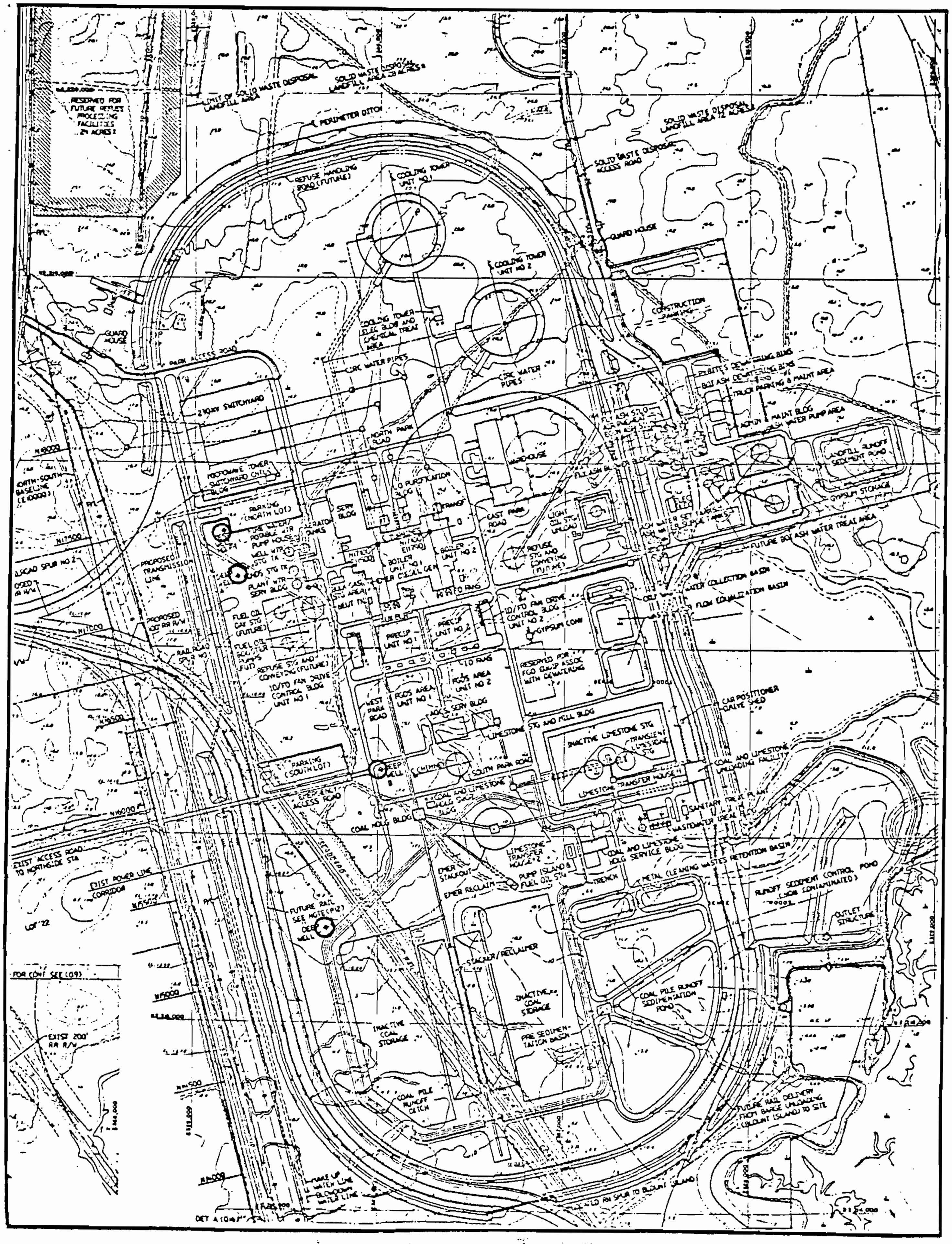
C. Well Withdrawal Limits

JEA is authorized to make a combined average annual withdrawal of 5.1 million gallons of water per day with a maximum combined withdrawal rate not to exceed 7.6 million gallons during a single day. Withdrawals may be made from a wellfield consisting of up to four (4) wells whose approximate locations are described in Figure 1.

After wells have been constructed, St. Johns River Water Management District may evaluate the individual wells and may recommend to the Department authorization of different withdrawals based upon hydrologic characteristics for the individual wells. The Department pursuant to Section 403.516, F.S. may modify the above withdrawal limitations with the concurrence of SJRWMD and the permittee.

D. Water Use Restriction

Said water is restricted to uses other than main stream condensing. Any change in the use of said water will require a modification of this condition.



RESERVED FOR FUTURE REFUSE PROCESSING FACILITIES 24 ACRES±
LIMIT OF SOLID WASTE DISPOSAL LANDFILL AREA
SOLID WASTE DISPOSAL LANDFILL AREA 29 ACRES±
PERIMETER DITCH
SOLID WASTE DISPOSAL LANDFILL AREA 12 ACRES±
SOLID WASTE DISPOSAL ACCESS ROAD
REFUSE HANDLING ROAD (FUTURE)
COOLING TOWER UNIT NO 1
COOLING TOWER UNIT NO 2
GUARD HOUSE
CONSTRUCTION PARKING
COOLING TOWER ELEC BLDG AND CHEMICAL TREAT AREA
CIRC WATER PIPES
PARK ACCESS ROAD
230KV SWITCHYARD
NORTH PARK ROAD
WAREHOUSE
BOT ASH DEWATERING BINS
TRUCK PARKING & MAINT AREA
ADMIN & MAINT BLDG
LANDFILL RUNOFF SEDIMENT POND
GYPSUM STORAGE
FUTURE BOT ASH WATER TREAT AREA
PARKING (NORTH LOT)
PROPOSED TRANSMISSION LINE
BOILER UNIT NO 1
BOILER UNIT NO 2
EAST PARK ROAD
WATER COLLECTION BASIN
FLOW EQUALIZATION BASIN
FUEL OIL DAY STG (FUTURE)
PRECIP UNIT NO 1
PRECIP UNIT NO 2
RESERVED FOR FGD EQUIP ASSOC WITH DEWATERING
FGDS AREA UNIT NO 1
FGDS AREA UNIT NO 2
WEST PARK ROAD
LIMESTONE STG AND MILL BLDG
INACTIVE LIMESTONE STG
CAR POSITIONER
PARKING (SOUTH LOT)
SOUTH PARK ROAD
LIMESTONE TRANSFER HOUSE
COAL AND LIMESTONE UNLOADING FACILITY
EMERGENCY ACCESS ROAD
COAL HDLG BLDG
WASTEWATER TREAT BLDG
EXIST ACCESS ROAD TO NORTHSIDE STA
EXIST POWER LINE CORRIDOR
EMER STACKOUT
EMER RECLAIM
PUMP ISLAND & FUEL OIL STG
RUNOFF SEDIMENT CONTROL POND
OUTLET STRUCTURE
FUTURE RAIL SEE NOTE
STACKER/RECLAIMER
INACTIVE COAL STORAGE
COAL PILE RUNOFF SEDIMENTATION POND
PRE SEDIMENTATION BASIN
COAL PILE RUNOFF DITCH
FUTURE RAIL DELIVERY FROM BARGE UNLOADING (BLOUNT ISLAND) TO SITE
MAKE UP WATER LINE
BLOWDOWN WATER LINE
EXIST 200' RR R/W

FIGURE 1

E. Emergency Shortages

In the event an emergency water shortage should be declared pursuant to Section 373.175 or 373.246, F.S., by St. Johns River Water Management District for an area including the location of these withdrawal points, the Department pursuant to Section 403.516, F.S., may alter, modify, or declare to be inactive, all or parts of Condition III. A.-G. An authorized Water Management District Representative, at any reasonable time, may enter the property to inspect the facilities.

F. Monitoring and Reporting

JEA shall, within the time limits hereinafter set forth, complete the following items.

1. JEA shall install flow meters in compliance with SJRWMD specifications on all production wells.

2. JEA shall submit to SJRWMD, on forms available from the District, a record of pumpage for each meter installed in F.1. above. Said pumpage shall be provided on a monthly basis, and shall be submitted by April 15, July 15, October 15, and January 15 for each preceding calendar quarter.

3. JEA shall maintain and operate a continuous water level recorder on the standby production well located at the test site in Duval County, Florida. Detailed hydrographs of water level fluctuations shall be constructed with the data collected from the water level recorder and shall be submitted to SJRWMD by April 15, July 15, October 15, and January 15 for each preceding calendar quarter.

4. Water quality analysis shall be performed on water withdrawn from each production well. The water samples collected from each of the wells shall be collected immediately after removal by pumping of a quantity of water equal to two casing volumes. The JEA and staff of SJRWMD may determine and adjust the intervals to be monitored in accordance with hydrologic conditions determined from drilling logs. The water quality analyses shall be performed monthly during the first year of operation, quarterly during the second year and twice each year (May and September) thereafter. Results shall be submitted to SJRWMD within 45 days after following such analyses were performed. Testing for the following parameters is required:

Calcium	Magnesium	Sodium
Potassium	Bicarbonate	Sulfate
Chloride	Nitrate	Total Dissolved Solids
Specific conductance	Gross Alpha	Total Phosphate
Radium 226 (only if gross Alpha is greater than 15 pci/l)	Radiation	

5. In the event that SJRWMD determines there is a significant change in the water quality (substantially caused by SJRPP and causing a potentially significant effect on water use), the Department may propose pursuant to Section 403.516, F.S., that the permittee be required to reduce or cease withdrawal from these groundwater sources.

6. Minimum Water Level Restrictions

If the Department and SJRWMD at a future date establish a minimum water level of general applicability to all users in the aquifer or aquifers hydrologically associated with these withdrawals, they may propose pursuant to Section 403.516, F.S. that JEA reduce or cease withdrawal from these groundwater sources at times when water levels fall below these minimums.

G. Shallow Aquifer Monitoring Wells

After consulation with the DER and SJRWMD, JEA shall install a monitoring well network to monitor groundwater quality horizontally and vertically through to the top of the Hawthorne Formation's first clayey lithologic Unit. Groundwater quantity and flow directions will be determined seasonally at the site through the preparation of seasonal watertable contour maps. From these maps the water quality monitoring well network will be located. Monitoring well locations and designs shall be submitted to the Department and SJRWMD for review. Approval or disapproval of the locations and design shall be granted within 60 days. Monitoring wells shall be installed upgradient and downgradient from each solid waste disposal area, each liquid waste pond and each coal pile storage area. An additional monitoring well will be placed immediately downgradient of the first section of each solid waste landfill to be utilized. The water samples collected from each of the monitor wells shall be collected immediately after removal by pumping of a quantity of water equal to two casing volumes. The water quality analyses shall be performed monthly during the year prior to commercial operation and quarterly thereafter. Results shall be submitted to the Department and the SJRWMD by the fifteenth (15th) day of the month following the month during which such analyses were performed. Testing for the following constituents is required:

TDS	Cadmium
Conductance	Zinc
pH	Copper
Redox	Nickel
Sulfate	Selenium
Sulfite	Chromium
Color	Arsenic
	Beryllium
Chloride	Mercury
Iron	Lead
Aluminum	Gross Alpha

H. Leachate

1. Zone of Discharge

Leachate from the solid waste landfills, sludge disposal test cells, coal storage piles, wastewater treatment ponds, or sedimentation ponds shall not contaminate waters of the State (including both surface and groundwaters) in excess of the limitations of Chapter 17-3, FAC., beyond the boundary of a zone of discharge extending 50 feet below the waste and 200 feet from the edge of the landfill or ponds.

2. Corrective Action

When the groundwater monitoring system shows a violation of the groundwater water quality standards of Chapter 17-3, FAC., the appropriate ponds, FGD landfill, or coal pile shall be bottom sealed, relocated, or the operation of the affected facility shall be altered in such a manner as to assure the Department that no violation of the groundwater standards will occur beyond the boundary of the zone of discharge.

IV. Control Measures During Construction

A. Stormwater Runoff

During construction, appropriate measures shall be used to settle, filter, treat or absorb silt-containing or pollutant-laden stormwater runoff to limit the suspended solids to 50 mg/l or less at the POD during rainfall periods less than the 10-year, 24 hour rainfall, and to prevent an increase in turbidity of more than 50 Jackson Turbidity Units above background in waters of the State beyond 50 meters from the POD to Browns Creek. Oil and grease shall not exceed 5 mg/l at the discharge from the runoff sediment control pond.

Control measures shall consist at the minimum of sediment traps, barriers, berms or vegetative planting. Exposed or disturbed soil shall be protected as soon as possible to minimize silt- and sediment-laden runoff. The pH shall be kept within the range of 6.0 to 8.5 at the POD.

Final drainage plans illustrating all stormwater treatment facilities and conveyances for construction phases and ultimate operations for both the entire St. Johns River Power Park site and the Blount Island coal site shall be submitted to the St. Johns River Subdistrict Manager and the St. Johns River Water Management District for review and approval prior to construction of any such conveyance or facility. The Department shall indicate its approval or disapproval within 60 days of the submittal.

Stormwater drainage to Brown's Creek and Brown's Creek proper shall be monitored as indicated below beginning twelve (12) months prior to the commencement of construction and continuing throughout construction:

Monitoring Point	Parameters	Frequency	Sample Type
*Stormwater drainage to Brown's Creek from existing borrow pit in southeast portion of site	BOD5, TOC, suspended solids, turbidity, dissolved oxygen, pH, TKN, Total phosphorus, Fecal Coliform, Total Coliform	Twice Monthly	Grab
	Oil and Grease	Once/Week	Grab
*West Fork of Brown's Creek at Point Downstream from entry of	BOD5, TOC, suspended solids, turbidity, dis-	Twice Monthly	Grab

of stormwater from Power Park site by way of a borrow pit	solved oxygen, pH, TKN, Total phosphorus, fecal coliform, Total coliform

*Monitoring shall be conducted at suitable points for allowing a comparision of the characteristics of pre-construction and construction phase drainage and receiving waters.

B. Sanitary Wastes

Disposal of sanitary wastes from construction toilet facilities shall be in accordance with applicable regulations of the Department and appropriate local health agency. The sewage treatment plant shall be operated in accordance with Chapters 17-3, 17-6, 17-16, and 17-19, FAC. The discharge of total residual chlorine to Brown's creek shall not exceed 0.01 mg/l.

C. Environmental Control Program

An environmental control program shall be established under the supervision of a qualified person to assure that all construction activities conform to good environmental practices and the applicable conditions of certification.

The permittee shall notify the Department by telephone if unexpected harmful effects or evidence of irreversible environmental damage are detected during construction, shall immediately report in writing to the Department and shall within two weeks provide an analysis of the problem and a plan to eliminate or significantly reduce the harmful effects or damage and a plan to prevent reoccurrence.

D. Construction Dewatering Effluent

Construction dewatering effluent shall be treated when appropriate to limit surface water discharges of suspended solids to no more than 50 mg/l. The discharge of construction dewatering liquids shall not cause turbidity in excess of 50 Jackson Turbidity Units above ambient beyond a 20 meter radius from the point of discharge. Weekly grab samples will be collected and analyzed for suspended solids.

A program for controlling the groundwater impacts of construction dewatering shall be submitted to the Department and the St. Johns River Water Management District for review prior to implementation.

V. Solid Wastes

Solid wastes resulting from construction or operation shall be disposed of in accordance with the applicable regulations of Chapter 17-7, FAC. The permittee shall submit a program for approval outlining the methods to be used in handling and disposal of solid wastes. Such program shall indicate at the least methods for erosion control, covering, vegetation and quality control.

Open burning in connection with land clearing shall be in accordance with Chapter 17-5, FAC. No additional permits shall be required, but the Division of Forestry shall be notified prior to burning. Open burning shall not occur if the Division of Forestry has issued a ban on burning due to fire hazard conditions.

VI. Operation Safeguards

The overall design, layout, and operation of the facilities shall be such as to minimize hazards to humans and the environment. Security control measures shall be utilized to prevent exposure of the public to hazardous conditions. The Federal Occupational Safety and Health Standards will be complied with during construction and operation. The Safety Standards specified under Section 440.56, F.S., by the Industrial Safety Section of the Florida Department of Commerce will also be complied with.

VII. Screening

The permittee shall provide screening of the site through the use of aesthetically acceptable structures, vegetated earthen walls and/or existing or planted vegetation.

VIII. Potable Water Supply System

The potable water supply system shall be designed and operated in conformance with Chapter 17-22, FAC. Information as required in 17-22.108 shall be submitted to the Department prior to construction and operation. The operator of the potable water supply system shall be certified in accordance with Chapter 17-16, FAC.

IX. Transformer and Electric Switching Gear

The foundations for transformers, capacitors, and switching gear necessary to connect SJRPP Units 1 & 2 to the existing distribution system shall be constructed in such a manner as to allow complete collection and recovery of any spills or leakage of oily, toxic, or hazardous substances.

X. <u>Toxic, Deleterious, or Hazardous Materials</u>

The spill of any toxic, deleterious, or hazardous materials shall be reported in the manner specified by Condition XV.

XI. <u>Construction in Waters of the State</u>

A. No construction on sovereign submerged lands shall commence without obtaining lease easement or title from the Department of Natural Resources and/or Trustees of the Internal Improvement Trust Fund.

B. Construction of intake and discharge structures, coal unloading wharf, and transmission towers shall be done in a manner to minimize turbidity. Turbidity screens should be used to prevent turbidity in excess of 50 JTUs above background beyond 150 meters from the dredging, pile driving, or construction site.

All spoil from connecting the SJRPP intake/discharge system to the NGS, and the coal unloading wharf shall be piped hydraulically or tucked to an upland disposal site of sufficient capacity to retain all material. Spoil from construction access canals shall be side cast and used for restoring natural bottom contours upon completion of construction.

C. Variances

1. A variances to the provisions of Section 17-3.061(h) for lead and Section 17-3.121(27) for silver for a period no to exceed a cumulative total of twelve months commencin on the start of dredging activities are granted in accordance with Sections 403.201(1)(c) and 403.511(2) F.S. at the coal unloading facility wharf site on Bl Island. Concentrations of at the boundary of a 150 radius mixing zone shall not exceed the following:

Lead	62 µg/l
Silver	6.1 µg/l

2. Variances to the provisions of Sections 17-3. cadmium, 17-3.061(h) for lead, 17-3.121(18) and Section 17-3.121(27) and Section 17-4.2 silver are granted pursuant to the provisi 403.201(1)(c) and 403.511(2), F.S. at the overflow for a period not to exceed a cu of twelve months starting with commence activities concentrations at the bound ius mixing zone shall not exceed t

Cadmium	8.2 μg/l
Mercury	0.2 μg/l
Lead	62 μg/l
Silver	6.1 μg/l

D. Mixing Zones

During dredging activities mixing zone radii are designated for the following parameters:

Parameter	Distance to Edge of Mixing Zone[3] (m)
Aluminum	150
Antimony	18
Cadmium	150
Copper	150
Cyanide	19
Iron	150
Lead	150
Mercury	150
Oil and Grease	25
Silver	150

XII. Solid Waste Landfill

A. The proposed solid waste landfill area shall be monitored and studied pursuant to a detailed groundwater testing and monitoring Program as defined in Condition III, F.G. The results of the program will be used by the Department in determining whether JEA has affirmatively demonstrated that Florida Water Criteria (Chapter 17-3, F.A.C.) will not be violated.

B. JEA shall either provide an impermeable liner under the solid waste disposal areas or shall utilize a chemical fixation process, stablization or other approved methods to control leachate from the solid waste. JEA may implement a test program to demonstrate the quality and quantity of leachate from an unlined or uncontrolled waste facility. Upon an affirmative showing that an uncontrolled solid waste facility will not cause violation of groundwater quality criteria, the Department may approve use of non-lined or uncontrolled landfill cells.

C. JEA shall utilize solid waste disposal area "B", north of Island Drive or the area previously designated for the bottom ash pond, prior to using disposal area "A".

D. Construction of perimeter berms shall be in conformance with the provisions of Chapter 17-9, F.A.C., regarding earthen dams.

E. Prior to the commencement of operation of solid waste disposal areas the following shall be submitted to the St. Johns River Subdistrict Manager for review and approval:

(1) Plot plan - should be drawn on a scale not greater than 200 ft. to the inch showing the following:

a. Dimensions and legal description of the site.

b. Location and depth corrected to MSL of soil borings.

c. Proposed trenching plan.

d. Cover stock piles.

e. Fencing or other measures to restrict access.

f. Cross sections showing both original and proposed fill elevation.

g. Location, depth corrected to MSL and construction details of monitoring wells.

(2) Design Drawings and Maps - may be combined with plot plan and should be drawn on a scale not greater than 200 ft. to the inch showing the following:

a. Topographic map with five foot contour intervals.

b. Proposed fill area.

c. Borrow area.

d. Access roads.

e. Grades required for proper drainage.

f. Typical cross sections of disposal site including lifts, borrow areas and drainage controls.

g. Special drainage devices.

(3) Soil map, Interpretive Guide Sheets, and a report giving the suitability of the site for such an operation.

(4) Contingency plan, including waste handling and disposal

methods, in case of an emergency such as equipment failure, natural disaster or fire.

(5) Operation plans to direct and control the use of the site.

(6) An indication by discussion or drawings or both of how the site is designed to meet water quality standards of Chapter 17-3 and 17-4 FAC at the waste site boundary or the boundary of the zone of discharge.

Based on the Department's reviews of the above, additions to or modifications of the overall monitoring program may be required for monitoring of runoff, groundwaters, and surface waters which may be affected by the various landfilling operations.

The Department shall indicate its approval or disapproval of the submitted plans, drawings, maps, analyses and contingency plans within 60 days.

XIII. Transmission Lines

A. General

1. Filling and construction in water of the State shall be minimized to the extent practicable. No such activities shall take place without obtaining lease, title or title from the Department of Natural Resources and/or TIITF where required. Construction and access roads should avoid wetlands and be located in surrounding uplands.

2. Placement of fill in wetland areas shall be minimized by spanning such areas with the maximum span practicable.

3. The Department may determine that any fill required in wetlands for construction but not required for maintenance purposes shall be removed and the ground restored to its original contours after transmission line placement.

4. Where fill in wetlands is necessary for access, keyhole fills from upland areas should be oriented as nearly parallel to surface water flow lines as possible.

5. Sufficient size and number of culverts or other structures shall be placed through fill causeways to maintain substantially unimpaired sheet flow.

6. Turbidity control measures, including but not limited to hay bales, turbidity curtains, sodding, mulching and seeding, shall be employed to prevent violation of water quality standards.

7. The Right-of-Way shall be located so as to minimize impacts in or on stream beds such as the removal of vegetation, to the extent practicable. Within 25 feet of the banks of any streams, rivers, or lakes, vegetation shall be left undisturbed, except for selective topping of trees or removal of trees which topping would kill. If it is necessary to remove such trees within 25 feet of the banks of streams, rivers, or lakes, the root mat shall be left undisturbed.

8. Any necessary water quality certifications which must be made to the Corps of Engineers shall be made at the time of a finding of compliance for specific work at specific locations.

9. Construction activities should proceed as much as practicable during the dry season.

B. Other Construction Activities

1. Maintenance roads under control of the permittee shall be planted with native species to prevent erosion and subsequent water quality degradation where drainage from such roads would impact waters of the State significantly.

2. Good environmental practices such as described in Environmental Criteria for Electric Transmission Systems as published by the U.S. Department of Interior and the U.S. Department of Agriculture shall be followed to the extent practicable.

3. Compliance with the most recent version of the National Electric Safety Code adopted by the Public Service Commission is required.

4. Fences running parallel to the transmission line which may become conductive shall be grounded at appropriate intervals; fences running perpendicular to the line shall be grounded at the edge of the right-of-way.

5. Field reconnaissance of rare and endangered species shall be performed in order to minimize impacts on these species.

6. Open burning in connection with land clearing shall be in accordance with the applicable rules of the Department of

Agriculture and Consumer Services. No additional permits shall be required, but the Division of Forestry shall be notified prior to burning. Open burning shall not occur if the Division of Forestry has issued a ban on burning due to fire hazard conditions.

C. Maintenance

1. Vegetative clearing operations for maintenance purposes to be carried out within the corridor shall follow the general standards for clearing right-of-way for overhead transmission lines as referenced in Sections XIII. A.7. and XIII.B.2. Selective clearing of vegetation is preferred over clearing and grubbing or clear cutting.

2. If chemicals or herbicides are to be used for vegetation control, the name, type, proposed use, locations, and manner of application shall be provided to the Department prior to their application for assessment of compliance with applicable regulations.

D. Archaeological Sites

Any archaeological sites discovered during construction of the transmission lines shall be disturbed as little as possible and such discovery shall be communicated to the Department of State, Division of Archives, History and Record Management (DAHRM). Potentially affected areas will be surveyed, and if a significant site is located, the site shall be avoided, protected, or excavated as directed by DAHRM.

E. Road Crossing

For all locations where the transmission line will cross State highways, the applicant will submit materials pursuant to the Department of Transportion's (DOT) "Utility Accomodation Guide" to DOT's district office for review and approval. All applicable regulations pertaining to roadway crossings by transmission lines shall be complied with.

F. Emergency Reporting

Emergency replacement of previously existing right-of-way or transmission lines shall not be considered a modification pursuant to Section 403.516, F.S. A verbal report of the emergency shall be made to the Department as soon as possible. Within fourteen (14) calendar days after correction of the emergency, a report to the Department shall be made outlining the details of the emergency and the steps taken for its temporary relief. The report shall be a written description of all of the work performed and shall set forth any pollution control measures or mitigative measures which were utilized or are being utilized to prevent pollution of waters, harm to sensitive areas or alteration of archaeological or historical resources.

G. Final Right-of-Way Location

A map of 1:24000 scale showing final location of the right-of-way shall be submitted to the Department upon completion of acquisition.

H. Compliance

Construction and maintenance shall comply with the applicable rules and regulations of the Department and those agencies specified in 17-17.54(2)(a) and (b), FAC.

XIV. Change in Discharge

All discharges or emissions authorized herein shall be consistent with the terms and conditions of this certification. The discharge of any pollutant not identified in the application or any discharge more frequent than, or at a level in excess of, that authorized herein shall constitute a violation of the certification. Any anticipated facility expansions, production increases, or process modification which will result in new, different or increased discharges or expansion in steam generating capacity will require a submission of new or supplemental application pursuant to Chapter 403, F.S.

XV. Non-Compliance Notification

If, for any reason, the permittee does not comply with or will be unable to comply with any limitation specified in this certification, the permittee shall notify the manager of DER's St. Johns River subdistrict office by telephone during the working day in which permittee becomes aware of said non-compliance and shall confirm this situation in writing within seventy-two (72) hours supplying the following information:

a. A description and cause of non-compliance; and

b. The period of non-compliance, including exact dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate and prevent recurrence of the non-complying event.

XVI. Facilities Operation

The permittee shall at all times maintain in good working order and operate as efficiently as possible all treatment or control facilities or systems installed or used by the permittee to achieve compliance with the terms and conditions of this certification. Such systems are not to be bypassed without prior Department approval. The one exception is that during periods when light oil is used for ignition, the FGD system may be bypassed.

XVII. Adverse Impact

The permittee shall take all reasonable steps to minimize any adverse impact resulting from non-compliance with any limitation specified in this certification, including, but not limited to, such accelerated or additional monitoring as necessary to determine the nature and impact of the non-complying event.

XVIII. Right of Entry

The permittee shall allow the Secretary of the Florida Department of Environmental Regulation and/or authorized representatives, upon the presentation of credentials:

a. To enter upon the permittee's premises where an effluent source is located or in which records are required to be kept under the terms and conditions of this permit; and

b. to have access to and copy all records required to be kept under the conditions of this certification; and

c. to inspect and test any monitoring equipment or monitoring method required in this certification and to sample any discharge or pollutants; and

d. to assess any damage to the environment or violation of ambient standards.

XIX. Revocation or Suspension

This certification may be suspended or revoked pursuant to Section 403.512, Florida Statutes, or for violations of any Condition of Certification.

XX. Civil and Criminal Liability

This certification does not relieve the permittee from civil or criminal responsibility or liability for non-compliance with any conditions of this certifiation, applicable rules or regulations of the Department, or Chapter 403, Florida Statutes, or regulations thereunder.

Subject to Section 403.511, Florida Statutes, this certification shall not preclude the institution of any legal action or relieve the permittee from any responsibilities or penalties established pursuant to any other applicable State Statutes or regulations.

XXI. Property Rights

The issuance of this certification does not convey any property rights in either real or personal property, tangible or intangible, nor any exclusive privileges, nor does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of Federal, State or local laws or regulations. The applicant will obtain title, lease or right of use to any sovereign submerged lands occupied by the plant, transmission line structures, or appurtenant facilities from the State of Florida.

XXII. Severability

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

XXIII. Definitions

The meaning of terms used herein shall be governed by the definitions contained in Chapter 403, Florida Statutes, and any regulation adopted pursuant thereto. In the event of any dispute over the meaning of a term used in these general or special conditions which is not defined in such statutes or regulations, such dispute shall be resolved by reference to the most relevant definitions contained in any other state or federal statute or regulation or, in the alternative, by the use of the commonly accepted meaning as determined by the Department.

XXIV. Review of Site Certification

The certification shall be final unless revised, revoked or suspended pursuant to law. At least every five years from the date of issuance of this certification or any National Pollutant Discharge Elimination System Permit issued pursuant to the Federal Water Pollution Control Act Amendments of 1972 for the plant units, the Department shall review all monitoring data that has been submitted to it during the proceeding five-year period for the purpose of determining the extent of the permittee's compliance with the conditions of this certification of the environmental impact of this facility. The Department shall submit the results of its review and recommendations to the permittee. Such review will be repeated at least every five years thereafter.

XXV. Modification of Conditions

The conditions of this certification may be modified in the following manner:

A. The Board hereby delegates to the Secretary the authority to modify, after notice and opportunity for hearing, any conditions pertaining to consumptive use of water, monitoring, sampling, groundwater, mixing zones, zones of discharge, leachate control programs, effluent limitations or variances to water quality standards.

B. All other modifications shall be made in accordance with Sections 403.516, Florida Statutes.

XXVI. Flood Control Protection

The plant and associated facilities shall be constructed in such a manner as to comply with the Duval County flood protection requirements.

XXVII. Effect of Certification

Certification and conditions of certification are predicated upon design and performance criteria indicated in the application. Thus, conformance to those criteria, unless specifically amended, modified, or as the Department and parties are otherwise notified, is binding upon the applicant in the preparation, construction and maintenance of the certified project. In those instances where a conflict occurs between the application's design criteria and the conditions of certification, the conditions shall prevail.

XXVIII. Noise

To mitigate the effects of noise produced by the steam blowout of steam boiler tubes, JEA shall conduct public awareness campaigns prior to such activities to forewarn the public of the estimated time and duration of the noise.

XXIX. Archaeological Sites

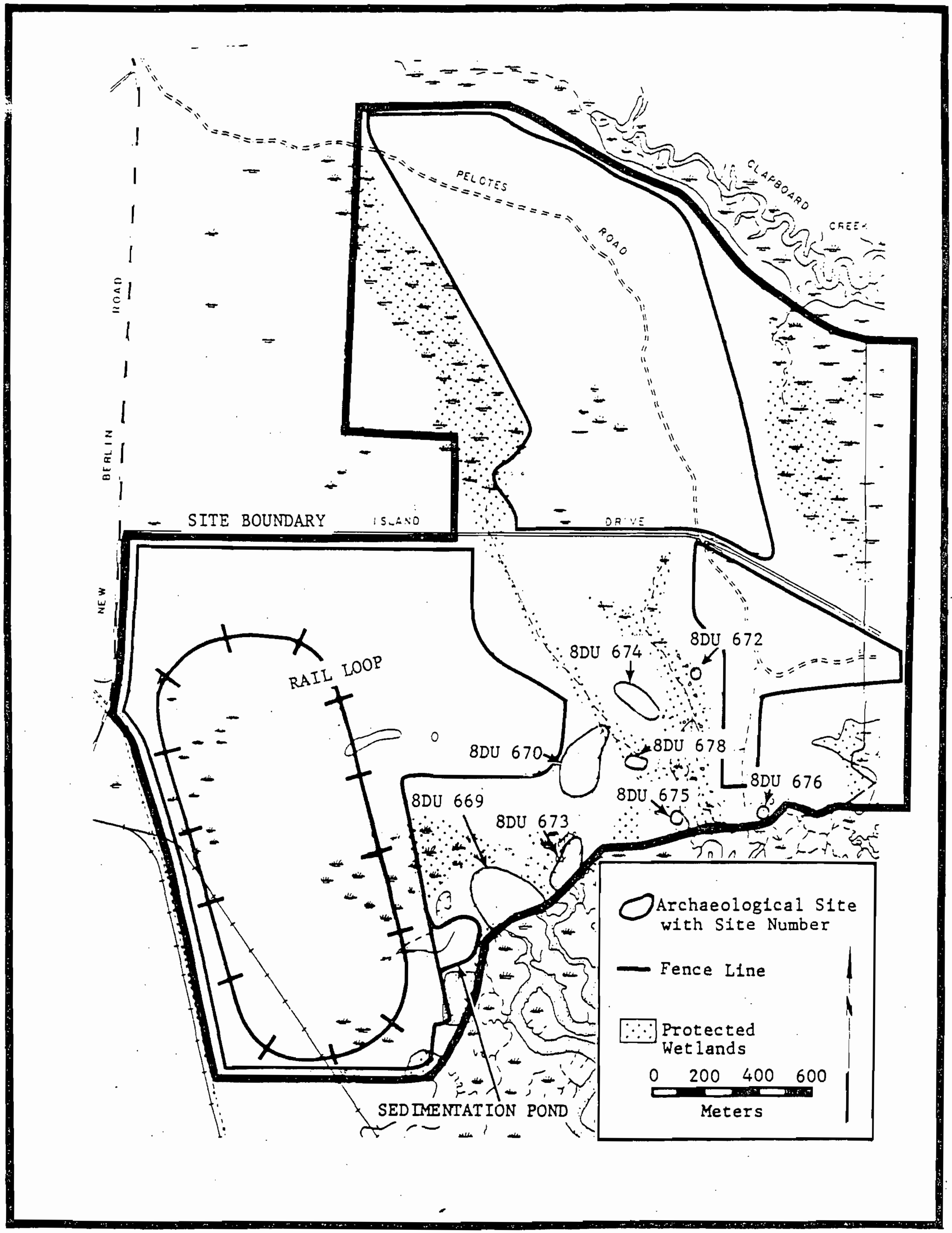
The following archaeological sites shown in Figure 2 shall be preserved whenever practical. If they must be altered by construction, then archaeological salvage excavation shall be performed prior to construction under the supervision of the Florida Department of State, Division of Archives, History and Records Management.

Site -	8Du669	8Du670
	8Du671	8Du673
	8Du674	8Du675
	8Du677	8Du678

XXX. <u>Blount Island Coal Unloading Facility</u>

Area drainage and rainfall runoff from the lined coal pile on Blount Island shall be directed to a lined treatment system designed to process the runoff from the 24-hour, ten-year storm. Wastewater treatment shall consist of as a minimum: removal of solids and metals by precipitation and sedimentation followed by pH adjustment to no less than 8.0 and final disposal by percolation. Sufficient capacity shall be provided to allow for accumulation of settled solids of up to 20 percent of the total pond volume. Solids removed from the sedimentation pond shall be disposed in a properly designed landfill.

The sedimentation pond liner shall be impervious and designed for the life of the facility. The liner shall be installed in such a manner as to prevent rupture during cleaning or removal of solids.



CLAPBOARD
CREEK
PELOTES
ROAD
NEW BERLIN ROAD
SITE BOUNDARY
ISLAND
DRIVE
RAIL LOOP
8DU 674
8DU 672
8DU 670
8DU 678
8DU 676
8DU 675
8DU 669
8DU 673
SEDIMENTATION POND
Archaeological Site with Site Number
Fence Line
Protected Wetlands
0 200 400 600
Meters

FIGURE 2

activities in the area. When current and future JEA spoil disposal activities are completed, Least terns could resume nesting in the spoil areas provided that dredge spoils are not deleterious to this species.

Nesting Least terns and their eggs were observed at three remote sites on Blount Island in areas characterized by sparse vegetation. A decline in suitable tern nesting sites has prompted the Florida Game and Fresh Water Fish Commission to list the Least tern as threatened. Man-made spoil banks are now important nesting areas for this bird and help offset the loss of much of the tern's natural nesting habitat. Several studies have indicated that birds nesting in areas containing toxic constituents suffer from lower reproductive rates than avifauna inhabiting "cleaner" areas. It has also been reported that biomagnification of potentially toxic trace elements occurs in avian food webs. However, it is not known how the toxic compounds (which are present in St. John's River dredge spoil) will affect reproductive and feeding activities of tern and other avian species and future studies could be required.

Of the species found on Blount Island only the Endangered wood stork is seen as possessing unique ecological value. None of the island's fauna are considered to be commercially or recreationally important.

VI. FACILITY SPECIFIC CONCERNS

A. Air Quality

1. Selected Fuel

The units are planned for coal-fired operation; however, provisions are being made in the design to allow for possible conversion to oil, gas or refuse firing. Based on a study of availability of coal, east of the Mississippi River, there are practical sources of coal adequate to meet the plant's needs over the anticipated life of the project (approximately 3,500,000 tons per year). The JEA coal availability study has identified coal supplies in Tennessee, Kentucky, and Ohio as the most likely sources. In addition, partial supplies could be obtained from several foreign sources.

The plant is designed to retain the flexibility to change its coal supply (to insure against disruptions in supply, local market upsets and to maintain competitive prices) with minimum reduction in efficiency and without violating air quality standards. Analyses of potential coal supplies were therefore necessary so that the plant could be designed to accomodate coals with a variety of characteristics. Coals from the above sources were analyzed to determine the ranges of characteristics and chemical constituents.

The air quality control system is designed on a "worst case" basis assuming the maximum sulfur (4 percent) and ash (18 percent) in the coal and a minimum heating value (10,500 Btu/lb). This approach assumes the sulfur and ash contents of the coal are 3.8 lb/MMBtu (Million Btu) and 17.1 lb/MMBtu, respectively. The ash remaining after the coal is burned is assumed to be 80 percent fly ash and 20 percent bottom ash. The above values were used to develop collection equipment efficiencies, investment estimates and long and short-term ground level ambient air quality concentrations. This approach requires a more sophisticated, complex, efficient and costly air quality control system than would be required on the basis of average coal characteristics.

It is proposed that the steam generator will burn No. 2 fuel oil for light-off and flame stabilization during start-up and low load operation. This light oil will be stored on site and pumped to the steam generator as required. Approximately 1,000,000 gal/yr will be utilized on an intermittent basis, which represents less than 2 percent (by heat input) of the steam generator annual fuel consumption. The fuel oil is expected to have a maximum sulfur content of 0.76 percent by weight, a maximum ash content of 0.01 percent by weight, and a heating value of 19,000 Btu/lb. Since the pollutant contents are so low and the utilization of oil so limited, the emissions of particulates and SO_2 from oil burning are considered by JEA to be insignificant when compared to those from coal burning.

The coal handling system will provide for delivery of coal by ocean vessel to a marine terminal on Blount Island with shuttle train delivery to the plant, as well as rail delivery directly to the plant by unit train or in trainload lots. A rotary car dumper will be used to unload coal from the trains on the power plant site proper. The system will also include the yard area coal storage, transfer system, coal silos, and the tripper floor distribution system.

2. Air Quality Impacts

The air quality in the area of the JEA site is currently affected by emissions from the St. Regis and Alton Box Board paper mills, the Celotex wall board plant and JEA's existing power plants. The air quality in the area will also be impacted by the construction and operation of the JEA SJRPP.

The emission of air pollutants from the JEA site are limited by Chapter 17-2, FAC, and by the New Source Performance Standards as imposed by the U.S. Environmental Protection Agency. In order to comply with these regulations, JEA plans to utilize washed coal with electrostatic precipitators to control emission of fly ash and a wet limestone scrubber to control emission of sulfur oxides. Nitrogen oxides emissions will be controlled by boiler design.

When both of the units are operating at 100% of rated capacity, the plant will consume 1129 tons per hour of coal and will emit 9034 pounds per hour of SO_2, 356 pounds per hour of particulates, and 7114 pounds per hour of nitrogen oxides.

The stack height of 640 feet will assist the control equipment in reducing ambient air quality impacts. Only during rate meteorological conditions will stack emissions reach the ground close to the plant. The stack height insures dispersion and dilution of air pollutants before the pollutants reach ground level at some distance from the site.

Air quality impacts are shown on Table 1. The computerized dispersion models used by JEA to predict ambient air quality impacts indicate no violations of ambient air quality standards.

The department has reviewed the models JEA used to predict air quality impacts and the inputs to those models. In verifying the JEA results the department has found a predicted violation of the Florida Ambient Air Quality Standard (FAAQS) for SO_2 on a 24-hour average. We have also found certain discrepancies in the modeling assumptions input data (e.g., emission rates and mixing heights) used in the analysis but are satisfied that all other FAAQS's and PDS increments will be complied with.

The violation of the State SO_2 standard is associated with the three other JEA power plants, Northside, Kennedy, and Southside. These three plants, along with the proposed new plant, are geographically aligned along a roughly northeast to southwest orientation. This causes a maximum interaction of emissions from these facilities to occur when winds blow parallel to this direction. The predicted violation occurs downwind (i.e., southwest) of the Southside facility.

JEA has addressed this case of alignment of the four power plants and has concluded that no violation will occur. This conclusion is based on modeling in which the stack heights at the Kennedy and Southside facilities are raised to 84 m. Pursuant to Executive Order No. 79-67, signed by Governor Bob Graham on August 31, 1979, JEA is required to raise the stacks of the Kennedy and Southside facilities. However, JEA is now asking the Department to reexamine (and rescind) the stack height requirements of the Governor's Executive Order due to significant changes in the utility's future operating plans.

Because the actual stack heights at the Southside and Kennedy plants are considerably lower than those used by JEA in their air quality analysis, we remodeled this case. The results show a predicted 24-hour ground level SO_2 concentration of 263.3 ug/m^3 occurring approximately 2.5 kilometers to the southwest of the Southside facility. (The FAAQS is 260 ug/m^3). The proposed SJRPP facility contributes 8.7 ug/m^3 to the predicted violation. It should be noted that only the four JEA power plants were modeled, and the addition of a background value for SO_2 would further increase the magnitude of the violation.

Unless an alternative proposal for the use of the Kennedy and/or Southside facilities is submitted, taller stacks at those facilities may have to be made a condition of certification of the SJRPP facility. Until these issues are resolved, we are unable to approve the air quality analysis portion of the SJRPP application.

TABLE 1

Maximum Predicted Ambient Air Quality Impacts

($\mu g/m^3$)

Prevention of Significant Deterioration

Pollutant and Source	Annual Avg.	24 Hour Avg.	3 Hour Avg.
SO_2: Plant Only	13	207	1298
Plant & Existing Sources	2	52	410
(Ambient Standards)	60	260	1300
(PSD Increment)	20	91	512
Particulates: Plant Only	3	33	N/A
Plant & Existing Sources	2	28	N/A
(Ambient Standards)	60	150	N/A
(PSD Increment)	19	37	N/A
NO_x: Plant Only	10		N/A
Plant & Existing Sources			
(Ambient Standards)	100		N/A

3. Prevention of Significant Deterioration

Pursuant to Chapter 17-2, FAC, and 40 CFR 52.21, the SJRPP Units 1 and 2 are subject to a review for the Prevention of Significant Deterioration (PSD) of air quality. The Clean Air Act Amendments of 1977 prescribe incremental limitations on the air quality impacts of a new source. Table 1 summarized maximum air quality impacts from the proposed construction of Unit 1 and 2 and all other increment consuming sources in the vicinity of the SSJRPP Site. The Department of Environmental Regulation has reviewed the PSD analysis submitted by JEA and has found that the construction of Units 1 and 2 should not violate state PSD regulations as contained in Section 17-204, FAC.

Additionally, the U. S. Environmental Protection Agency Preliminary Determination for JEA SJRPP Units 1 & 2 was completed in December 1980. Federal regulations on PSD (40 CFR 52.21) require the following air quality impacts to be addressed:

1. National Ambient Air Quality Standards
2. PSD increment impact
3. Visibility, soils and vegetation impacts
4. Impacts due to growth caused by the proposed source
5. Best Available Control Technology (BACT)
6. Class I area impacts

After their review, EPA has made a preliminary determination that the construction can be approved provided certain conditions are met.

The predicted impact of the SJRPP on the Okefenokee Wilderness Area Class I Area increments is presented in the following table:

TABLE 2

Increment	Pollutant	
	Particulate	SO_2
Annual	20%	50%
24 Hour	10%	80%
3 Hour		72%

It appears that the SJRPP would not violate the Class I PSD increments in the Okefenokee.

The percent consumption of the applicable Class II PSD increments caused by the JEA Plant and other new sources are present in the following table:

TABLE 3

Increment	Pollutant	
	Particulate	SO_2
Annual	12%	12%
24 hour	46%	46%
3 hour	N/A	65%

The plant should not violate the increments or cause significant deterioration in the Jacksonville area.

Nonattainment Areas

The extent of the contribution of the proposed plant to the formation of ozone and, therefore, its impact on the Jacksonville ozone nonattainment areas cannot be estimated through modelling. However, because of the plant's low emission levels of oxidants and hydrocarbons (the primary precursors of ozone), it was assumed by JEA that the impacts of the proposed plant on ozone concentrations in the Jacksonville area will not be significant.

The impact of the plant on the Jacksonville particulate nonattainment area was estimated through modelling and compared with the USEPA "significance levels" which are $1\mu g/m^3$ for an annual average and $5\mu g/m^3$ for a 24-hour average. The TSP nonattainment area basically covers the central downtown area and is at its closest point 9.4 km from the proposed plant.

The annual average impact was calculated using the total TSP emissions from the operation of the proposed plant including fugitive dust emissions from the coal handling facilities, coal unloading facility, limestone handling, waste disposal and cooling towers. The results of the analysis indicate that the annual average TSP impact on the nonattainment area would be less than one $\mu g/m^3$ the EPA significance level. The maximum 24 hour TSP impact would be $4\mu g/m^3$, which is less than the $5\ \mu g/m^3$ EPA significance level.

It, therefore, appears that the proposed SJRPP will not have a significant adverse effect on the downtown Jacksonville area.

Impacts on Visibility

The proposed power plant may have an impact on visibility in the area.

Visibility is defined as the greatest distance at which it is just possible to see and identify with the unaided eye a prominent dark object against the sky at the horizon in the daytime or a known unfocused moderately intense light source at night. Visibility is diminished by four major processes: light scattering by gas molecules, light scattering by particles, light absorption by gases not naturally occurring in the atmosphere, and light absorption by particles.

Coal-fired power plants affect visibility through the three major combustion related pollutants: particulates, sulfur dioxide, and nitrogen dioxide. Visibility is decreased by particulates primarily through light scattering; by nitrogen dioxide through absorption and later by scattering due to conversion of gaseous nitrogen dioxide to particulate nitrates and nitrites; and by sulfur dioxide when it converts to particulate sulfates.

The frequency distribution of the visibility observed at Jacksonville Imeson Airport over a five-year period is summarized in the application. The average quarterly background visibility at Jacksonville Airport is seldom greater than 12 miles or less than two miles. Visibility conditions greater than or equal to those measured at Jacksonville can be expected at St. Augustine (70 km southeast) and the Okefenokee Class I area (60-70 km northwest). Using equations, the background conditions may be calculated and the SO_4 (sulfate) and TSP impacts at the Okefenokee Class I and St. Augustine historical areas may be estimated so that the visibility impacts at these areas may also be estimated. For purposes of this simplified analysis, it was necessary to assume that SO_4 and TSP are the only pollutants contributing to visibility reduction. It was also assumed that the background visibility is 12 miles. The calculated new visibility due to the SJRPP was 10.8 miles.

This corresponds to a reduction of approximately 10 percent in the visual range at the Okefenokee Class I area during worst-case conditions. A similar calculation shows that the visual range at St. Augustine is estimated to be 11.1 miles, or a worst-case reduction of approximately 8 percent. It should be noted that these visibility reductions resulting from the TSP, and SO_4 transformation from SO_2 are estimated based on Gaussian Plume modelling at large distances and empirical extinction coefficients and transformation rates. Therefore, the estimates from such calculations cannot be considered precise.

An analysis was made of 5 years (1964-1968) of Jacksonville surface wind data that is resolved to 22.5 degree sectors to determine the percent of time during which the winds would carry the proposed plant plume in the directions of the Okefenokee Class I area and the St. Augustine area. The 5-year average percent occurrence of winds toward St. Augustine is only 5.6 percent. The 5-year average percent occurrence of winds toward the Okefenokee Class I area is 11.2 percent. The visibility reductions previously discussed do not represent full-time visibility impairment, only the estimated maximum visibility impairment during these periods when the winds blow in the critical directions.

4. Best Available Control Technology

Section 17-2.03 Florida Administrative Code (FAC) and Section 169, 424SC 7401 require evaluation of proposed air pollutant emission control equipment and a determination as to whether or not an applicant will utilize the Best Available Control Technology (BACT) for each pollutant.

The installation of high efficiency electrostatic precipitators to control particulate emission from the boilers, bag filters to control particulate emissions from fly ash handling, and liquid spray and bag filter systems to control particulate emissions from coal handling and lime and limestone handling all represent BACT.

The use of washed coal and the installation of limestone scrubbers will achieve a 90% reduction of the potential sulfur oxide emissions and would comply with EPA's requirements under 40 CFR Part 60, Federal New Source Performance Standards.

The use of boiler design controls which limit flame temperature and oxygen availability in order to control the formation of nitrogen oxides in the boiler to 0.6 pounds per million BTU is considered by EPA to be BACT. Likewise, the use of boiler controls to limit the emission of carbon monoxide is also considered BACT.

The Department of Environmental Regulation, having considered (a) all available scientific, engineering and technical material, (b) existing emission control standards of other states, and (c) the social and economic impact of the application of such technology, also finds the emission control technology to be used by JEA to be the Best Available Control Technology, as shown in the following:

The proposed facility will consist of two 600 megawatt coal-fired electric utility steam generating units to be located in Jacksonville, Florida. The units will be designed for possible conversion to oil, gas or refuse firing. There will be an oil fired auxiliary boiler rated at 200 million Btu/hr estimated to have an annual capacity factor of 5 percent compared to 74 percent for the two units.

The plant will be located in Duval County which is classified nonattainment for the pollutant Ozone (17-2.16(1)(c) F.A.C.). It will be located in the area of influence of the Jacksonville particulate nonattainment area (17-2.13(1)(b) F.A.C.), however, the plant will not significantly impact the nonattainment area and is, therefore, exempt from the requirements of Section 17-2, 17 & 18 & 19 with respect to particulate emissions. The facility must comply with the provisions of 17-2.04 F.A.C. (Prevention of Significant Deterioration).

BACT Determination Requested by the Applicant:

Pollutant	Emission Limit
Particulates	0.03 lb/million Btu input
SO_2	0.76 lb/million Btu input
NO_x	0.60 lb/million Btu input
CO	0.05 lb/million Btu input

Particulate emissions are to be controlled using an electrostatic precipitator (ESP). SO_2 emissions are to be controlled with a limestone wet scrubbing system. There is no specific control technology for control of NO_x and CO emissions. BACT is to be manufacturer's guarantee for state-of-the-art burner design parameters to minimize emissions.

Flyash emissions are to be controlled using a pneumatic transfer system and bottom ash using a wet transfer system. Emissions from coal and limestone handling are to be controlled by use of enclosed conveying systems with baghouses rated at 99.9 percent efficiency. Water suppression to control dust is to be used as required.

Bio-Environmental Services recommended a 65% reduction in NO_x emissions or 0.5 lb/million Btu heat input. This was the only exception to unanimous acceptance of the NSPS emission limits as BACT.

BACT Determination by DER:

Pollutant	Emission Limit
Particulates	0.03 lb/million Btu input
SO_2	0.76 lb/million Btu input
NO_x	0.60 lb/million Btu input
CO	0.05 lb/million Btu input

NSPS, Subpart Da, standards of performance for electric utility steam generating units for which construction is commenced after September 18, 1978, is determined as BACT for the proposed project. The proposed control equipment is state-of-the-art and determined as BACT.

Emissions from the auxiliary boiler are minor compared to the main units. The auxiliary boiler will operate only when one of the main units is not in operation. Limited operation of the auxiliary boiler is determined as BACT.

The emission rates proposed by JEA are equal to or better than the New Source Performance Standards. The emission rates adopted by the U.S. EPA are based on extensive recent evaluations of technology employed by the electric power industry in the United States. The emission rates requested by JEA are more restrictive than Florida's emission limiting standards for new coal fired fossil fuel steam generators with a heat input greater than 250 MMBTU/hour.

A determination of Best Available Control Technology for visible emissions from the unit was not requested by the applicant. Specific emission rates were not requested for the limestone and coal handling systems.

The applicant's requested emission rate of 0.76 lbs/MMBTU with 90% removal of SO_2 constitutes Best Available Control Technology for this pollutant. Provision of SO_2 removal efficiency of greater than 90% would not markedly improve the ambient air quality in the area, therefore the increased cost of additional removal efficiency would neither be cost effective nor warranted. The additional waste of large quantities of fuel energy and the use of greater land areas required to meet SO_2 removal rates more efficient than 90% are not justified by the degree of air quality improvement projected.

To achieve the 90% SO_2 reduction, JEA analyzed two control processes, the lime/limestone system selected and a lime spray dryer system. The preferred lime/limestone system utilizes an aqueous lime/-limestone solution to absorb SO_2 and convert the gas to calcium sulfate or gypsum. The alternative system utilizes a spray of an aqueous lime solution to absorb SO_2. The solution is evaporated leaving a calcium sulfite/ sulfate particulate which is collected as a powder. The waste powder is not marketable and cannot be landfilled without treatment. Consequently, the comparative costs over the limestone system will be greater.

The applicant's requested emission rate of 0.03 lbs/MMBTU for particulate is 70% lower than the emission rate currently allowed by Florida's emission limiting standards for new coal fired fossil fuel steam generators. The applicant reviewed assessments of the particulate control alternatives which concluded that fabric filter system and precipitators would be roughly equivalent in terms of the degree of control achieved and that wet scrubbers would not be suitable. Wet scrubbers are not considered suitable for the following reasons:

- The wet scrubber would be intergral with the FGD system, thus preventing emergency bypassing of the FGD system while maintaining particulate matter emission limits.
- The wet scrubber approach requires the use of wet and semi-wet induced draft fans. Wet and semi-wet fans have traditionally experienced corrosion and imbalance problems.
- The flue gas pressure loss across the scrubber is very high, on the order of 25 inches of water. This requires the application of extra energy to maintain the required gas flow through the system.
- Fly ash would have to be handled in a wet mode, thus limiting its marketability as a valuable resource.
- Since the fly ash would enter into the FGD liquid circuitry, contamination of the FGD system by-product would occur thus making it unsuitable for the manufacture of wallboard.

In comparing the practicality of the other two modes, the electrostatic precipitator constitutes proven technology on units of the size proposed by JEA. However, while the U.S. EPA has published studies on two facilities of 39MW and 175MW capacity which are utilizing fabric filters, the application of this technology to a 600 MW unit with flue gas desulfurization could produce scale up difficulties. Further, an analysis conducted by the Seminole Electric Cooperative on 640 MW units indicated the cost of fabric filters to be an additional $5 million in capital and $2 million/year in maintenance. JEA found that a fabric filter could cost as much as $38.7 million more on a capitalized annual basis. Therefore, although the U.S. EPA finds that the New Source Performance Standard of 0.03 lbs/MMBTU is achievable with either baghouse or electrostatic precipitator as Best Available Control Technology for particulates, JEA chose to use electrostatic precipitators.

The applicant requested that an emission rate of 0.60 lbs/MMBTU be declared Best Available Control Technology for nitrogen oxides (NO_x). This is consistent with the proposed federal New Source Performance Standards. Reductions in nitrogen oxide emissions would be accomplished through boiler design.

Equipment designers have guaranteed that NO_x emissions from units will not exceed 0.6 lbs/MMBTU at loads ranging from 20% to 100%. Since loads of less than 20% are only due to startup or operation as spinning reserve, guarantees for that range are recognized as acceptable practice, particularly on base load units. Based on presently available information, an emission rate of 0.6 lbs/MMBTU constitutes Best Available Control Technology for nitrogen oxides from JEA's proposed boilers.

The use of boiler controls and oxygen monitors to limit carbon monoxide to 0.05 lbs/MMBTU (296 lbs/hr) is considered to be BACT.

The applicant did not request a visible emission limit for the proposed facility. The U.S. EPA's new Source Performance Standards specify a visible emission limit of 20% opacity with an allowable opacity of not more than 27% for six minutes in any hour. The Florida Standards for new coal fired fossil fuel steam generators limits the visible emissions to 20% opacity except that 40% opacity may not be exceeded more than two minutes in any hour. Because the proposed federal standards have been based on a review of the best control technology available, the Best Control Technology Available constitutes 20% opacity except that an opacity of 27% may not be exceeded more than six minutes in any hour.

Fugitive Dust

Fugitive dust is produced by a number of sources associated with the project. These include the coal handling system, lime and limestone handling system, fly ash handling system, and FGD waste handling and disposal systems. Also since brackish water cooling towers will be used, EPA has indicated that dissolved and suspended solids in the small droplets fraction (less than 50 microns diameter) of cooling tower drift would be considered fugitive dust in the impact assessment. The following paragraphs describe the control systems and/or methods proposed as BACT for these fugitive dust sources.

Coal Handling Fugitive Dust Collection

Control and collection of fugitive particulates in the coal handling system will be accomplished by several different methods, including totally enclosed conveying systems, water spray dust suppression systems, and dust collection systems utilizing fabric filters.

The ship unloading facility will have dry dust collection systems capable of 99.9 percent control efficiency on the unloader receiving hoppers. All conveyors will be totally enclosed and each transfer point fitted with dry dust collection systems, with the exception of the stacker-reclaimer which will be fitted with a water spray dust suppression system capable of 97 percent efficiency. The rail car loading facility will be enclosed in a building and fitted with a dry dust collection system. The coal surge pile in the ship unloading area will be treated by wetting agents to achieve a 90 percent control efficiency.

Coal will be unloaded at the plant site by a rotary car dumper which will be housed in an unloading building with a wet dust suppression system. This is expected to have a dust control efficiency of 97 percent. From the delivery point, totally enclosed belt conveyors will be used to transport the coal to the coal handling building. Surge bins in the coal handling building will be vented with fabric filter dust collectors (efficiency of 99.9 percent), and similar collectors will be located at all conveyor discharge points. Conveyors between the coal handling building and the stacker-reclaimer will not be enclosed, but coal dust associated with these conveyors will be controlled by a water spray dust suppression system. Dust releases in the stacker-reclaimer area (active coal pile) will be controlled by wetting agents for an efficiency of 90 percent. Dust releases from the inactive coal pile will also be controlled by wetting agents.

All conveyors from the coal handling building to the power house will be enclosed, and fabric filter dust collectors will be utilized to vent the storage silos in the power house and all conveyor transfer points. Tripper conveyors will be enclosed in a gallery.

Lime and Limestone Fugitive Dust Collection

Control and collection of fugitive dust particulates from the limestone and/or lime addition system for the FGD equipment will be accomplished by appropriate types of fabric filter dust collectors.

Lime will be the "pebble" type and will be transported at the site by pneumatic conveyors and stored in silos. The pneumatic conveyors and silos will be vented to fabric filters in order to assure that the fugitive lime dust particles are collected in an efficient manner.

Limestone will be transported at the site by totally enclosed belt conveyors. All silos and hoppers utilized by the limestone system will be vented to fabric filter dust collectors. Similar collectors will be located at all conveyor discharge points.

All fabric filter dust collectors in the lime or limestone additive system will have an efficiency of 99.9 percent.

Control and Collection of Fugitive Fly Ash Particulates

In the fly ash handling system, fugitive fly ash particulate will be controlled at all transfer and discharge locations by fabric filters. The fly ash handling system consists essentially of ash hoppers located beneath the flue gas particulate collection equipment. Pneumatic conveyors are utilized to transfer fly ash to and from ash storage silos, and to mixers which prepare the ash and FGD wastes for disposal. Pneumatic conveyors are by their nature enclosed. Discharge for the conveyor's blower(s) will be equipped with fabric filters with greater than 99 percent collection efficiency.

Cooling Tower Drift

The dissolved and suspended solids in the small droplet size fraction of brackish water cooling tower drift is considered by EPA to contribute to total suspended particulates. This contribution is minimized by using high efficiency drift eliminators in the two natural draft towers (which limit drift to approximately .005 percent of circulating water flow) and by maintaining the cycles of concentration of the circulating water to a low level such as a maximum of 1.5. Additionally, a circumferential drift eliminator wall will be provided at the base of the hyperbolic shell to mitigate the potential effects of blow-through.

Upon reviewing the preceeding information, the Department also finds that the SJRPP Units 1 and 2 will not contribute to significant deterioration of air quality, although it appears that salt drift could have a significant negative impact on some of the dairy-pasture-lands in the area. Pasture grasses such as *Pensacola bahia* are highly intolerant of excessive concentrations of NaCl.

5. Acid Rain

In recent years the increase of rainfall acidity levels across Florida and other parts of the country has been ascribed in part to the air emissions from coal-fired power plants. Hence the requirement for emission controls on these plants, designed to reduce the potential acid causing factors. Generally, sulfur dioxide and oxides of nitrogen are believed to be the primary anthropogenic agents contributing to rainfall acidification. However, a great deal remains unknown about the amount that these two gases contribute to the problem, as well as how and where the acidification takes place.

It should be noted that rainfall under unpolluted conditions tends to be somewhat acidic, on the order of pH 5.6-5.7. This is due to the absorption of carbon dioxide in water in the atmosphere. Also, neither sulfur dioxide nor nitrogen dioxide in and of themselves are acidic. It appears that after a certain amount of time, estimated to be on the order of 3-4 days, these gases interact with sunlight, water vapor, ammonia, and many other chemical compounds in the atmosphere, which converts them to sulfuric acid and nitric acid. Scientists around the world are studying the rate of these reactions, which catalytic aids (sunlight, water, etc.) have the most effect driving the conversion, ways to prevent the end acidic product from affecting the environment, where the end product eventually makes its impacts, and numerous other questions relating to the conversion reactions. It is universally agreed that the entire cause-effect-control relationship is very complex.

There are three issues relevant to the licensing of SJRPP Units 1 & 2 as an emission source in relation to acidic rainfall. These are: (1) why is the problem of concern, (2) what will be the Unit's contribution to the regional, state and country wide problem, and (3) what controls are required to mitigate the problem?

First, the following effects have been ascribed to above-normal acidic rainfall. Acid rain is listed as a cause for destabilization of clay minerals, reduction of soil cation exchange capacity, promotion of chemical denudation of soils, and promotion of runoff. Vegetational effects tend to be quite varied, ranging from a few cases of reported beneficial effects, to the more prevalent harmful effects. The harmful effects include foliage damage, alteration of reponses to pathogens, symbionts and saprophytes, leaching of essential materials from plant surfaces, and destruction of the protective waxy leaf coatings. Impacts to wildlife are generally indirect, but nonetheless potentially significant via habitat alteration. Effects on aquatic ecosystems begin with changes in water quality. The water quality changes are brought about by acidification via direct input of rainfall (or snow melting in the northern states), indirect changes from erosion and previously impacted soil contributions, as well as a cascading effect wherein the addition of acid components and soil-based catalytic materials frees up often-times toxic metals or other wastes which were previously chemically bound. These problems then effect population balances of aquatic organisms by interfering with breeding and reproduction, poisoning, or elimination of food supplies, which frequently result in termination of particular species within those aquatic ecosystems. These population shifts also occur in the aquatic vegetation, further compounding the problem.

Second, the pH levels in Florida lakes, primarily those in the northern part of the state, have been dropping, e.g., becoming more acidic, over the past two decades. Many of Florida's perched sand lakes have little or no buffering capacity and are therefore very susceptible to acid rain.

Trends in data seem to indicate that most of the acidity is derived from sulfur dioxide sources in the northeastern United States. Conversion from sulfur dioxide into sulfuric acid appears to start affecting the environment more than 50 km from the source, and the acid is susceptible to long range transport. Florida is subject to frequent cold fronts moving into the state in the winter months, which are suspected of bringing in northern-based pollutants.

Florida itself has relatively few coal-fired industries at this time, but combustion of oil and gas as well as emissions from heavy industries such as pulp mills and the phosphate industry make significant contributions to SO_x and NO_x loadings. Normal sources of atmospheric sulfur in this state are derived from sea-salt, a non-polluting source, which tends to obscure the acidic sulfur components. Hence, in terms of Florida's impact on other parts of the country, this state tends to be the recipient rather than the donor. As more coal-fired industry is utilized, this balance may begin to shift. The impact from a source such as the SJRPP would be to contribute slightly to the problem, but would not be registered until some distance from the plant, perhaps 100 km or so. The degree of impact, as implied earlier, is extremely hard to quantify. Some studies indicate that the majority of acidic fallout impacts may occur 200-300 kilometers from the source.

One feature that will mitigate some of the impact of SJRPP Units 1 & 2 is that stringent sulfur emission controls will be required prior to Unit operation. These units will thus have less impact than that of other units which do not employ those emission controls. The SJRPP Units 1 & 2 will utilize flue gas desulfurization scrubbers to limit sulfur emissions. Oxides of nitrogen will be controlled by boiler design. Such control will also help mitigate the rainfall acidification problem. The primary source of nitrogen oxides appears to be automobile emissions.

In balancing the need for power with the environmental impacts from the operation of the plant, at this time, the required use of scrubbers and boiler controls seems to be the most relevant and effective way of addressing the unit's contribution to rainfall acidification. In regards to the whole issue of rainfall acidification in the State of Florida, the state, utilities, universities and other industries as well as similar entities throughout the world have been researching the problem.

Construction of new coal fired units may have a slightly positive effect on the acid rain problem in Florida. Data collected during the Florida Sulfur Oxides Study indicated that the conversion of sulfur dioxide to sulfuric acid forms two to three times faster in the exhaust plume from an oil fired power plant than from a coal fired power plant. Oil fired power plants in Florida do not have emission controls for sulfur oxides or nitrogen oxides in most instances. As new coal fired power plants are built with pollution control devices, and as these new coal plants replace the oil plants that emit greater quantities of SO_x and NO_x, then air pollution levels and acidic rainfall may decrease.

6. Radioactivity

The fact that there are radioactive emissions from the combustion of coal has been recognized for some time. Recent articles have disclosed the fact that the amount of such emissions can be greater from a coal-fired power plant than from a normally operating nuclear reactor. The question then becomes how much greater are these emissions and do these pose significant health impacts.

The Department of Veteran and Community Affairs appended to their report on TECO Big Bend Unit 4 a report made by the Radiological Health Services Section of the Department of Health and Rehabilitative Services (HRS) focusing on this issue. Also, TECO briefly addressed radioactivity in their application.

The following discussion has been compiled from exerpts from the HRS report which is oriented to country-wide coal sources and potential impacts thereof, from a section of the TECO Big Bend 4 application which contains data more specific to the type of coals expected to be used, and an article in the 8 December 1978 issue of "Science", titled "Radiological Impact of Airborne Effluents of Coal and Nuclear Plants", by McBride, Moore, Witherspoon, and Blanco.

Coal contains at least 50 percent carbon by weight, as well as sulfur, iron, moisture, and trace quantities of naturally occurring radioactive materials such as Uranium, (U-235, U-238), Thorium (TH-232), their decay products, and potassium-40. When coal is burned, the mineral content of the coal is converted to ash and slag. These waste materials contain most of the radionuclides originally present in the coal. A fraction of the ash is released to the atmosphere, and the remainder is collected and either re-utilized or landfilled.

Various factors affect particulate emission of radionuclides from coal-fired power plants. These include the type of coal and its source, the type of furnace used for combustion, and the equipment type and efficiency of the air emission control equipment.

Radionuclide concentrations in the released particulates may be enriched relative to those in the mineral content of the fuel as a result of the combustion and emission control processes. Enrichment factors for uranium as great as 2.0 are reported while enrichment factors as great as 5.0 are reported for lead and polonium. The actual exposure of humans and the environment to coal emitted radioactivity depends on the emission rate, the stack height and local meteorological conditions.

The Oak Ridge National Laboratory at the request of the U. S. Environmental Protection Agency has made preliminary projections of the health impact of radionuclide emissions from coal-fired power plants. They used a model for new plants based on 550 MW unit burning a western coal with a higher radionuclide content than coals under consideration for the SJRPP.

The Oak Ridge/EPA assessment was initially based on a 1% ash emission rate. It considered dispersion based on stack height and the general atmospheric or meteorological conditions in the region. Also considered was the average distance from the source to potentially exposed population centers. Certain assumptions were also made about the primary mode of exposure to radioactivity i.e. that this could be by ingestion of food grown in the region impacted by the plant. Some exposure could also come by inhalation of fine particles and by contamination of water supplies.

The following table summarizes the doses which could be received from the 550 MW plant in a suburban area, based on the Oak Ridge assumptions.

TABLE 4

Annual Radiation Doses from Radioactive Particulate Emissions From the Model "New" Coal Fired Station (550 MW Plant Burning Western Coal).

Organ	Maximum Individual Dose (mrem/yr)
Lung	1.1
Bone	2.1
Kidney	1.0
Liver	0.9
Thyroid	1.1
G. I. Tract	0.8
Other Soft Tissue	1.1

As a point of reference the following table indicates human dose rate comparisions between emissions from a 1000 MW coal fired plant and natural background radiation, as well as the allowed amounts from a nuclear reactor:

TABLE 5

Dose Commitments from Airborne Radioactivity Released At 1000 MW Power Plants.

Types, Units	Coal Fired Plants	Pressurized Water Reactor	Background	Federal Allowances
Maximum Individual (mrem/yr)				
Whole Body	1.9	1.8	80	5
Bone	18.2	2.7	120	15) iodine
Thyroid	1.9	3.8	—	15) iodine

The maximum individual dose commitments from the 1000 MW plant were estimated at the plant boundary at 500 meters from the release points. Dose commitments would be less at greater distances. The ingestion component of the dose commitment was based on the assumption that all food is grown and consumed at the site boundary. The initial calulations were based on a release height of 20 meters with no plume rise. As a result the doses listed above are extremely conservative.

If SJRPP Units 1 & 2 are built, total plant electric output will use around 1200 MW, or possibly 1.2 times the amount listed in Table 4. For whole body doses from airborne emissions, if the SJRPP site output is comparative to the emissions from the 1000 MW plant used above, then roughly 2.9 mrems/yr exposure might be received, or about 3/5 of what is allowed for light water reactors. Comparision with the Pressurized Water Reactor (PWR) statistics for bone dosages indicates a potential problem for persons whose lifestyle matches the assumptions listed above.

The following table summarizes the risks associated with dose projected for the 550 MW model plant previously described:

TABLE 6

Individual Lifetime Risks and Number of Fatal Cancers Due to Radioactive Particulate Emissions From the Model "New" Coal Fired Station (550 mw Plant Burning Western Coal) for Suburban Site.

	Risk
Individual Lifetime Risks	
Maximum Individual	1.4×10^{-5}
Average Individual	4.8×10^{-7}
Expected Fatal Cancers per Year of Operation	1.7×10^{-2}

The JEA SJRPP Units 1 & 2 impact could be approximately twice as much.

Impacts from the radioactivity retained in the ash and slag are expected to be minimal for several reasons. Ash stored on JEA's site will be landfilled, which should provide a natural earthen buffer to radioactivity. These landfill areas are not the sort of areas frequented by the public, although some slight unquantified level of radioactive component of the ash should be low.

Contamination of drinking water supplies via leaching of radioactive materials could be of some concern. However, JEA will be required to construct the ash landfills to deter infiltration by rainwater, reducing the potential for leaching. Also, the depth to the Floridan aquifer and the buffer provided by the clays of the Hawthorn Formation will help minimize this potential problem.

In Section VI.D.2., the Department has expressed concern over the potential for groundwater contamination from leaching of various chemicals and metals into the surficial aquifer and thence to the marsh or river. This may also be of concern regarding radioactive leachates, if the radiation levels are somewhat high. However, since the radioactivity of the ash is unknown and the leaching rate is unknown, it is impossible to determine whether or not the radiation levels in the groundwater leachate will be significant. Contamination of water supplies can be directly quantified by monitoring of groundwater quality. Comparison of monitoring well data from the site with state groundwater quality criteria for radioactivity will be made. Should problems be directly indicated, rectification will be required.

7. Coal Dust from Trains

The movement of coal supply trains to the proposed plant from coal mines outside the state will result in increased fugitive dust levels in areas near the railroad tracks. These increases in fugitive dust levels will be primarily the result of road bed dust emissions and coal dust blowing from the exposed coal contained within each hopper car. The only other quantifiable emissions associated with the coal trains result from the diesel locomotive emissions, which are relatively minor.

For an impact analysis of the coal trains as they move through Jacksonville, it was assumed that trains will travel 500 miles from the mines and that there will be a maximum of three trains per day with 72 cars per train, and a maximum of 106 tons of coal per car. An estimated one percent of coal by weight will be lost as fugitive dust over a journey of about 500 miles with an estimated 90 percent of the total losses escaping during the first few hours of train transit. This implies that only 0.1 percent of the original coal weight will be dispersed as fugitive dust during the rest of the trip, and only a small fraction of the 0.1 percent will be dispersed in the Jacksonville area.

The fugitive dust emissions from agitated road bed dust in the Jacksonville area were estimated using USEPA Publication AP-42 (1979), assuming that the road bed dust emissions are conservatively approximated by emissions from motor vehicles traveling on unpaved roads and that each train will travel at an average speed of 10 miles per hour.

The 24-hour average TSP level in the Jacksonville area resulting from the operation of three coal trains per day (a conservative estimate) was calculated to be 22 $\mu g/m^3$ at a distance of 100 meters downwind of the railroad tracks under light wind conditions. When added to the Jacksonville area background level of 50 $\mu g/m^3$, this total is relatively small compared to the National Ambient Air Quality secondary standard and Florida standard of 150 $\mu g/m^3$. It is noteworthy that the amount of the fugitive coal dust which was estimated to blow off the coal cars is about half of the expected emissions resulting from agitation of roadbed dust. This is primarily because of the very conservative method that was employed to estimate roadbed dust emissions.

8. Trace Elements

Eighteen trace elements were selected for review on the basis of reported high concentrations in coal, capability for volatilization during combustion, potential for toxicity, and existence of regulatory guidelines. Since a coal source has not been selected, trace element concentrations in coal were obtained from a report on trace elements in coal samples from the eastern United States.

The predicted deposition rates were determined on the basis of coal consumption, trace element concentration, and SO_2 emission rates. Elements considered to be volatile were assumed to exit the stack in an uncontrolled manner. Those trace elements typically occurring as particulates or absorbed on particulates were also assumed to exit in an uncontrolled state. These assumptions were utilized due to the lack of information on the behavior of trace elements passing through an FGD system. In addition, the use of these assumptions introduced a degree of conservatism to the assessment.

Studies of model power plants in most cases predicted increases in soil trace element levels of less than 10 percent of the total endogenous concentrations over the life of the model plant. It was concluded that uptake by vegetation could not increase dramatically unless the forms of deposited trace elements were considerably more available than the endogenous forms.

The estimated increases ranged from 1.5×10^{-5} to 1.2×1 percent, using average soil background concentrations. The estimated increases over the 40 year life of the plant, assuming that the elements remained concentrated in the top 25 cm of soil over this period ranged from 5.9×10^{-4} to 4.7×10^{-1}. The assessment of these estimated increases was based on a number of worst case conditions. Under these conditions there should not be a perceptible increase on an annual basis. Over the 40 year plant life, those elements exhibiting a higher percent increase relative to the others studied included: arsenic, boron, cadmium, lead, mercury, and molybdenum.

The estimated soil concentration increase for arsenic would be 1.48 x 10^{-2} mg per kg of soil over the 40 year plant life. Naturally occurring arsenic levels in soils average about 6 ppm. Soil arsenic concentrations greater than 2 ppm, soluble form, have been shown to produce injury symptoms on alfalfa and barley and as such no effect could be expected under worst case conditions.

The estimated soil concentration increase for boron would be 2.5 x 10^{-2} mg per kg of soil over the 40 year plant life under worst case conditions. Naturally occurring boron concentrations range from 2-100 ppm with the highest levels found in saline and alkaline soils. The average value is considered to be about 10 ppm. Using a toxicity level of 0.5-10 ppm for plants sensitive to boron as a means for comparision, no adverse effects to sensitive species such as citrus would be expected under worst case operating conditions.

The estimated soil concentration increase for cadmium would be 1.43 x 10^{-4} mg per kg of soil over the 40 year plant life. This represents a 2.4 x 10^{-1} percent increase in soil concentration over the average background level of 0.06 ppm, which is high in comparison with the other elements addressed. Toxicity to plants is reported to occur when cadmium concentration in plant tissues reaches about 3 ppm and it is unlikely that the estimated soil concentration will be high enough for the accumulation of 2 ppm in leaf tissue within the vicinity of the proposed plant.

The estimated soil increase for lead would be 3.49×10^{-2} mg per kg of soil over the 40 year plant life. Naturally occurring lead concentrations in soil averages about 10 ppm. Based on reported threshold concentrations of 10 ppm lead in solution culture, the addition of 3.49 $\times 10^{-2}$ mg lead per kg of soil to soils containing as much as 5 ppm lead should not result in any adverse effects. It is thought that lead enters the plant primarily through the leaf surface. However, the effect of such accumulations cannot be predicted due to the lack of information concerning the concentration of lead in plants due to leaf deposition.

The estimated soil increase for mercury would be 1.19×10^{-4} mg per kg of soil. Naturally occurring mercury concentrations in soil average 0.1 ppm. Most higher vascular plants are resistant to toxicity from high mercury concentrations even though high concentrations are present in plant tissue. Concentrations of 0.5-50 ppm are found to inhibit the growth of cauliflower, lettuce, potato, and carrots. The addition of 1.19×10^{-4} mg per kg of soil is not considered to result in any adverse effect.

The estimated soil increase for molybdenum would be 2.73×10^{-3} mg per kg of soil over the 40 year life. Naturally occurring background concentrations average about 2 ppm. Molybdenum toxicity is rarely observed in the field since most plants seem to be able to tolerate high tissue concentration. A Mo concentration of 5 ppm in nutrient solution was found to be toxic to clover and lettuce. It would appear to be unlikely that the contribution of Mo from the proposed plant would result in adverse effects.

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32301

DEPARTMENT OF ENVIRONMENTAL REGULATION
STATE OF FLORIDA

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

November 3, 1981

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

Dear Mr. Gibbs:

Attached is a letter from the Jacksonville Bio-Environmental Services Division that you should be able to answer more easily than this department.

Sincerely,

Hamilton S. Oven Jr.

Hamilton S. Oven, Jr., P.E.
Administrator
Power Plant Siting

cc: Robert S. Pace
Steve Smallwood

BEST AVAILABLE COPY

DEPARTMENT OF HEALTH, WELFARE
& BIO-ENVIRONMENTAL SERVICES
Bio-Environmental Services Division
Air and Water Pollution Control

RECEIVED
NOV 9 1981
DIV. ENVIRONMENTAL PERMITTING

CITY OF JACKSONVILLE, FLORIDA

October 30, 1981

Mr. Hamilton S. Oven, Jr., P.E.
Administrator - Power Plant Siting Section
Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, Florida 32301

Re: St. Johns River Power Park (SJRPP)

Dear Mr. Oven:

In reviewing the recent drafts of the FDER site certification for the SJRPP, several questions have arisen which we wish to convey for your consideration.

1) In January 1981, EPA issued a preliminary determination of approval, with specific conditions, under authority of PSD. Has EPA yet made any final determination under PSD? BES files have no record of such.

2) With reference to PSD approval above, a public notice was published in the Florida Times Union. The information concerning emissions from SJRPP contained in the copy of the public notice sent to this office (copy attached) was grossly in error. Emissions increases resulting from construction of SJRPP will be approximately four times greater than reported in the notice. What legal problems may arise because of the inaccurate notice?

3) The above mentioned notice also indicates maximum PSD increment consumption from the SJRPP. Was the low emissions data referenced above used in the increment consumption modelling, or was correct data used?

4) Recent conversations with JEA personnel revealed that the chimney for the two main power boilers will be a single outer wall, with twin interior stacks, one for each boiler, as opposed to a single common stack. What stack geometry was used in PSD and NAAQS modelling?

Your consideration and response to these matters will be appreciated.

Very truly yours,

Robert Steven Pace

Robert S. Pace, P.E.
Pollution Control Engineer

RSP/vj
Enclosure

cc: D. Dutton with enclosure
R. Breitmoser - JEA with enclosure

BEST AVAILABLE COPY

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30365

JAN 14 1981

RECEIVED
NOV 3 1981
DIV. ENVIRONMENTAL PERMITTING

REF: 4AH-AF

Ms. Marion Degroves
Duval County Bio-Environmental
Services Department
515 West 6th Street
Jacksonville, Florida . 32206

RE: Jacksonville Electric Authority
New Power Generating Station
PSD-FL-010

Dear Ms. Degroves:

I wish to bring to your attention that the Jacksonville Electric Authority proposes to construct a new power generating complex near the city of Jacksonville, Florida, and that emissions of air pollutants will thereby be increased. The U.S. Environmental Protection Agency (EPA) has reviewed the proposed modification under the authority of Federal Prevention of Significant Deterioration Regulations (40 CFR 52.21) and reached a preliminary determination of approval with conditions for this construction. This approval applies only to federal regulatory requirements and has no bearing on State or local functions.

Please also be aware that the attached public notice announcing the Agency's preliminary determination, the availability of pertinent information for public scrutiny and the opportunity for public comment will be published in a local newspaper, Florida Times Journal, in the near future. This notice has been mailed to you for your information and in accordance with regulatory requirements. You need take no action unless you wish to comment on the proposed construction.

If you have questions, please feel free to call 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 review program.

Sincerely yours,

Tommie A. Gibbs

Tommie A. Gibbs, Chief
Air Facilities Branch

Attachment

TAG:JLS:cg

PUBLIC NOTICE

BEST AVAILABLE COPY

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

For Routing To District Offices And/Or To Other Than The Addressee	
To:	Loctn.:
To:	Loctn.:
To:	Loctn.:
From:	Date:
Reply Optional [ ] Date Due:	Reply Required [ ] Date Due: Info. Only [ ]

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

TO: Buck Oven, Power Plant Siting Section

THRU: Steve Smallwood, Bureau of Air Quality Management

THRU: Clair Fancy, Central Air Permitting, BAQM

FROM: Bob King, Central Air Permitting, BAQM B/K

DATE: October 9, 1981

SUBJ: Jacksonville Electric Authority, SJRPP Units 1 and 2 Comments on Conditions of Draft Certification

1. The Bureau believes that the following conditions should be added to the Section 1.A. Emission Limitations:

   (a) The two auxiliary boilers shall fire No. 2 fuel oil with a maximum sulfur content of 0.76 percent by weight, a maximum ash content of 0.01 percent by weight, a minimum heating value of 19,170 Btu per pound and a maximum viscosity of 3.0 centistokes at 100 ^{o}F. Samples of all fuel oil fired in the boilers shall be taken and analyzed for sulfur content, ash content, heating value and viscosity. Accordingly, samples shall be taken of each fuel oil shipment received. Records of the analyses shall be kept a minimum of the two years to be available for FDER's inspection.

   (b) The same quality No. 2 fuel oil, used for the auxiliary boilers, shall be used for the main boilers Units 1 and 2 during start-up and low load operation.

   (c) Maximum emissions from either of the auxiliary boilers shall be limited to 0.8 lb/MMBTU for SO_2, 0.3 lb/MMBTU for NO_x, 0.01 lb/MMBTU for PM, and 10 percent opacity for visible emissions.

   (d) Coal fired in Units 1 and 2 shall have 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.

(e) No fraction of flue gas shall be allowed to bypass the FGD system to reheat the gases existing from the FGD system, if the bypass will cause overall SO_2 removal efficiency less than 90 percent. The percentage and amount of flue gas bypassing the FGD system shall be documented and records kept a minimum of two years available for FDER's inspection.

(f) Neither of the auxiliary boilers shall be allowed to operate while the boiler Units 1 and 2 are operating collectively at greater than 6,144 million Btu per hour heat input.

2. The Bureau objects to using 20% opacity in Subsection I.A.3.a. for coal handling facilities. The 20% opacity limit for visible emissions from coal handling facilities is too lenient in comparison with the visible emission limits addressed in EPA's PSD permit. The Bureau proposes using 10% opacity limit for controlling visible emissions from the coal handling facilities.

3. The heat input values of 4,330 and 4,458 MMBTU/hr addressed in Subsections I.A.1 and I.C.1, respectively, are questionable. Based on our understanding, each main unit has 6,144 MMBTU/hr maximum heat input rate. Please check latest information from the applicant on this matter.

BK:caa

given in Fig. 7 for converting known volumes at other temperatures to the 60F standard base. This correction is also dependent on the API (American Petroleum Institute) gravity range as illustrated by the three parametric curves of Fig. 7.

Since handling and especially burning equipment is usually designed for a maximum oil viscosity, it is necessary to know the viscosity characteristics of the fuel oil to be used. If the viscosities of heavy oils are known at two temperatures, viscosities at other temperatures can be closely predicted with negligible error by a linear interpolation between these two values located on the standard ASTM chart of Fig. 8. Viscosity variations with temperature for certain light oils can also be found with the aid of the ASTM chart but in this case knowledge of the viscosity at only one temperature is required. Viscosities of light oils at various temperatures within the region designated as No. 2 fuel oil can be found by drawing a line parallel to the No. 2 boundary lines through the point of known viscosity and temperature. Copies of the chart may be obtained from the ASTM.

Compared with coal, fuel oils are relatively easy to handle and burn. Heating is not required for the lighter oils, and even the heavier oils are relatively simple to handle. There is not as much ash-in-bulk disposal problem as there is with coal, and the amount of ash discharged from the stack is correspondingly small. In most oil burners the oil is atomized to a mist of small particles that mix with combustion air. In the atomized state, the characteristics of oil approaches those of a gas, with consequent similar explosion hazards (*see Safety Precautions, Chapter 7*).

Because of its relatively low cost compared with that of lighter oils, No. 6 fuel oil is the most widely used for steam generation. It can be considered a by-product of the refining process. Its ash content ranges from about 0.01 to 0.5%, which is very low compared with coal. However, despite this low percentage content, ash containing compounds of vanadium, sodium and sulfur can be responsible for a number of serious operating problems (Chapter 15).

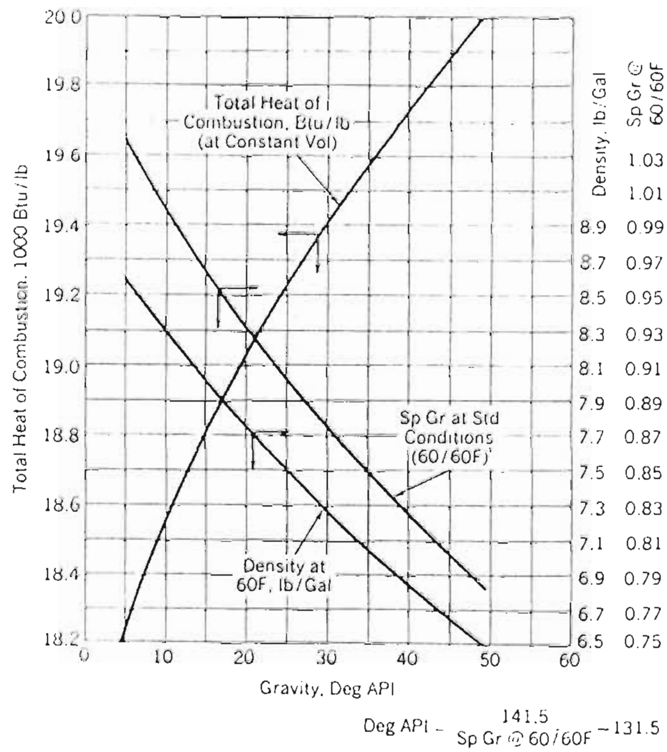


Fig. 6 Heating value, weight (lb per gal), and specific gravity of fuel oil for a range of API gravities.

Table 26
Range of analyses of fuel oils

Grade of Fuel Oil	No. 1	No. 2	No. 4	No. 5	No. 6
Weight, percent					
Sulfur	0.01-0.5	0.05-1.0	0.2-2.0	0.5-3.0	0.7-3.5
Hydrogen	13.3-14.1	11.8-13.9	(10.6-13.0)*	(10.5-12.0)*	(9.5-12.0)*
Carbon	85.9-86.7	86.1-88.2	(86.5-89.2)*	(86.5-89.2)*	(86.5-90.2)*
Nitrogen	Nil-0.1	Nil-0.1	—	—	—
Oxygen	—	—	—	—	—
Ash	—	—	0-0.1	0-0.1	0.01-0.5
Gravity					
Deg API	40-44	28-40	15-30	14-22	7-22
Specific	0.825-0.806	0.887-0.825	0.966-0.876	0.972-0.922	1.022-0.922
Lb per gal	6.87-6.71	7.39-6.87	8.04-7.30	8.10-7.68	8.51-7.68
Pour point, F	0 to −50	0 to −40	−10 to +50	−10 to +80	+15 to +85
Viscosity					
Centistokes @ 100F	1.4-2.2	1.9-3.0	10.5-65	65-200	260-750
SUS @ 100F	—	32-38	60-300	—	—
SSF @ 122F	—	—	—	20-40	45-300
Water & sediment, vol %	—	0-0.1	tr to 1.0	0.05-1.0	0.05-2.0
Heating value					
Btu per lb, gross (calculated)	19,670-19,860	19,170-19,750	18,280-19,400	18,100-19,020	17,410-18,990

* Estimated.

DEPARTMENT OF ENVIRONMENTAL REGULATION

ROUTING AND TRANSMITTAL SLIP

ACTION NO X

ACTION DUE DATE ASAP

KAHEL		FANCY		STARNES	
BLOMMEL		THOMAS		MARY CLARK	
BARKER		GEORGE		HODGES	
J. ROGERS		PALAGYI		MARSHALL MOTT-SMITH	

REMARKS

Do you - ~~but~~ OK BT
larry concur on this?

P.P. Certification

I have been over this with Bob in some detail & feel satisfied. No modeling is involved so if Larry ~~is not available it should not be held up~~ If you agree - lets get it to Buck
BT

Larry has seen this -

INFORMATION: REVIEW & RETURN; REVIEW & FILE; INITIAL & FORWARD

DISPOSITION: REVIEW & RESPOND; PREPARE RESPONSE; FOR MY SIGNATURE; FOR YOUR SIGNATURE; LET'S DISCUSS; SET UP MEETING; INVESTIGATE & REPT; INITIAL & FORWARD; DISTRIBUTE; CONCURRENCE; FOR PROCESSING; INITIAL & RETURN

STEVE SMALLWOOD S Sm

DATE 10-9

PHONE

DEPARTMENT OF ENVIRONMENTAL REGULATION

ROUTING AND TRANSMITTAL SLIP

ACTION NO.

ACTION DUE DATE

1. TO: (NAME, OFFICE, LOCATION) ~~Clair Fancy~~ — INITIAL / DATE
2. Steve Smallwood — INITIAL / DATE
3. — INITIAL / DATE
4. — INITIAL / DATE

REMARKS:

1. Please review and comment.
2. Comments should be sent to Buck Oven ASAP.

INFORMATION: REVIEW & RETURN; REVIEW & FILE; INITIAL & FORWARD

DISPOSITION: REVIEW & RESPOND; PREPARE RESPONSE; FOR MY SIGNATURE; FOR YOUR SIGNATURE; LET'S DISCUSS; SET UP MEETING; INVESTIGATE & REPT; INITIAL & FORWARD; DISTRIBUTE; CONCURRENCE; FOR PROCESSING; INITIAL & RETURN

FROM: Bob King

DATE 10/9/81

PHONE

DEPARTMENT OF ENVIRONMENTAL REGULATION

ROUTING AND TRANSMITTAL SLIP

ACTION NO 10/9/81

ACTION DUE DATE ASAP ? Thursday 8/8

KAHEL	TAFT	STARNES
BLOMMEL	THOMAS	MARY CLARK
BARKER	GEORGE	HODGES
J. ROGERS	PALAGYI	MARSHALL MOTT-SMITH

REMARKS:

- Call Buck
- when does he need comments
- Let me see draft response before it is sent to PPS.

draft response from me

INFORMATION
REVIEW & RETURN
REVIEW & FILE
INITIAL & FORWARD

	DISPOSITION
✓	REVIEW & RESPOND
	PREPARE RESPONSE
	FOR MY SIGNATURE
✓	FOR YOUR SIGNATURE
✓	LET'S DISCUSS
	SET UP MEETING
	INVESTIGATE & REPT
	INITIAL & FORWARD
	DISTRIBUTE
	CONCURRENCE
	FOR PROCESSING
	INITIAL & RETURN

FROM: STEVE SMALLWOOD SS

DATE 9-30

PHONE

DEPARTMENT OF ENVIRONMENTAL REGULATION

ROUTING AND TRANSMITTAL SLIP

ACTION NO.

ACTION DUE DATE

TO: (NAME, OFFICE, LOCATION)	
1. Steve Smallwood	INITIAL / DATE
2.	INITIAL / DATE
3.	INITIAL / DATE
4.	INITIAL / DATE

REMARKS:

Please have your staff review + comment. I know we are missing a section on control of Southside + Kennedy with respect to SJRPP

SEP 1981 L U AOM

INFORMATION
REVIEW & RETURN
REVIEW & FILE
INITIAL & FORWARD

DISPOSITION
REVIEW & RESPOND
PREPARE RESPONSE
FOR MY SIGNATURE
FOR YOUR SIGNATURE
LET'S DISCUSS
SET UP MEETING
INVESTIGATE & REPT
INITIAL & FORWARD
DISTRIBUTE
CONCURRENCE
FOR PROCESSING
INITIAL & RETURN

FROM: Buck Oven

DATE

PHONE

1:00 meeting
@ room C

can't finalize until modeling

has to file response
with hearing office on 10/16

9th October

DRAFT COPY

9/21/81

SEP 1981
BUREAU
A Q M

State of Florida Department of Environmental Regulation
Jacksonville Electric Authority
SJRPP Units 1 & 2
PA 81-13

CONDITIONS OF CERTIFICATION

I. Air

The construction and operation of SJRPP Units 1 & 2 at the Jacksonville steam electric power plant site shall be in accordance with all applicable provisions of Chapters 17-2, 17-4, 17-5 and 17-7, Florida Administrative Code. In addition to the foregoing, the permittee shall comply with the following conditions of certification:

A. Emission Limitations

6144 ?

1. Based on a maximum heat input of 4,330 million BTU per hour, stack emissions from SJRPP Unit 1 & 2 shall not exceed the following when burning coal:

   a. SO_2 - 1.2 lb. per million BTU heat input, maximum two hour average, 0.76 lb/MMBtu on a 30-day rolling average.

   b. NO_x - 0.60 lb. per million BTU heat input.

   Particulate matter

   ✓c. Particulates - 0.03 lb. per million BTU heat input.

   d. Visible emissions - 20% (6-minute average), except one 6-minute period per hour of not more than 27% opacity.

2. The height of the boiler exhaust stack for SJRPP Unit 1 & 2 shall not be less than 640 ft. above grade.

3. Particulate emissions from the coal handling facilities:

   a. The permittee shall not cause to be discharged into the atmosphere from any coal processing or conveying equipment, coal storage system or coal transfer and loading system processing coal, visible emissions which exceed 20 percent opacity. Particulate emissions shall be controlled by use of control devices.

   too high - 10% ok.

   b. The permittee must submit to the Department within ten (10) working days after it becomes available, copies of technical data pertaining to the selected particulate emissions control for the coal handling facility. These data should include, but not be limited to, guaranteed efficiency and emission rates, and major design parameters such as air/-cloth ratio and flow rate. The Department may, upon review of these data, disapprove the use of such device if the Department determines the selected control device to be inadequate to meet the emission limits specified in 3(a) above. Such disapproval shall be issued within 30 days of receipt of the technical data.

4. Particulate emissions from limestone and flyash handling shall not exceed the following:

   a. Limestone silos - 0.050 lb/hr.

   b. Limestone hopper/transfer conveyors - 0.65 lb/hr.

   c. Flyash handling system - 0.2 lb/hr.

5. Visible emissions from the following facilities shall be limited to 5% opacity: (a) limestone and flyash handling system, (b) limestone day silos and (c) flyash silos.

6. Compliance with opacity limits of the facilities listed in Condition 5 will be determined by EPA reference method 9 (Appendix A, 40 CFR 60).

7. Construction shall reasonably conform to the plans and schedule given in the application.

8. The permittee shall report any delays in construction and completion of the project to the Department's Southwest District Office.

9. Reasonable precautions to prevent fugitive particulate emissions during construction, such as coating of roads and construction sites used by contractors, will be taken by the permittee.

10. Coal should not be burned in the unit unless both electrostatic precipitator and limestone scrubber are operating properly.

11. Coal burned in the unit should be washed before it is transported to the plant site.

B. <u>Air Monitoring Program</u>

1. The permittee shall install and operate continuously monitoring devices for each boiler exhaust for sulfur dioxide, nitrogen dioxide, oxygen and opacity. The

monitoring devices shall meet the applicable requirements of Section 17-2.08, FAC, and 40 CFR 60.47a. The opacity monitor may be placed in the duct work between the electrostatic precipitator and the FGD scrubber.

2. The permittee or Jacksonville Bio-Environmental Services Division shall operate the two ambient monitoring devices for sulfur dioxide in accordance with EPA reference methods in 40 CFR, Part 53, and two ambient monitoring devices for suspended particulates. The monitoring devices shall be specifically located at a location approved by the Department. The frequency of operation shall be every six days commencing as specified by the Department.

3. The permittee shall maintain a daily log of the amounts and types of fuel used and copies of fuel analyses containing information on sulfur content, ash content and heating values.

4. The permittee shall provide stack sampling facilities as required by Rule 17-2.23(4) FAC and shall explicitly provide a safe and reliable elevator to the platform. The sampling probe liner shall be fabricated of material which can withstand flexing.

5. The ambient monitoring program may be reviewed by the Department and the permittee annually beginning two years after start-up of Unit 2.

6. Prior to operation of the source, the permittee shall submit to the Department a standardized plan or procedure that will allow the permittee to monitor emission control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible.

C. Stack Testing

6144 MMBtu/hr

1. Within 60 calendar days after achieving the maximum capacity at which each unit will be operated, but no later than 180 operating days after initial start-up, the permittee shall conduct performance tests for particulates SO_2, NO_x, and visible emissions during normal operations near 4458 MMBtu/hr heat input and furnish the Department a written report of the results of such performance tests within 30 days. The performance tests will be conducted in accordance with the provisions of 40 CFR 60.46a, 48a, and 49a.

2. Performance tests shall be conducted and data reduced in accordance with methods and procedures in accordance with <u>DER's Standard Sampling Techniques and Methods of Analysis for Determination of Air Pollutants From Point Sources</u>, July 1975.

3. Performance tests shall be conducted under such conditions as the Department shall specify based on representative performance of the facility. The permittee shall make available to the Department such records as may be necessary to determine the conditions of the performance tests.

4. The permittee shall provide 30 days prior notice of the performance tests to afford the Department the opportunity to have an observer present.

particulate matter

5. Stack tests for particulates and SO_2 shall be performed annually in accordance with conditions C. 2, 3, and 4 above.

D. <u>Reporting</u>

1. For SJRPP, stack monitoring, fuel usage and fuel analysis data shall be reported to the Department's St. John's River Subdistrict Office on a quarterly basis commencing with the start of commercial operation in accordance with 40 CFR, Part 60, Section 60.7., and in accordance with Section 17-2.08, FAC.

2. Utilizing the SAROAD or other format approved in writing by the Department, ambient air monitoring data shall be reported to the Bureau of Air Quality Management of the Department quarterly. Commencing on the date of certification, such reports shall be due by the last day of the month following the quarterly reporting period.

3. Beginning one month after certification, the permittee shall submit to the Department a quarterly status report briefly outlining porgress made on engineering design and purchase of major pieces of equipment (including control equipment). All reports and information required to be submitted under this condition shall be submitted to the Administrator of Power Plant Siting, Department of Environmental Regulation, 2600 Blair Stone Road, Tallahassee, Florida, 32301.

II. Water Discharges

Any discharges into any waters of the State during construction and operation of SJRPP Units 1 & 2 shall be in accordance with all applicable provisions of Chapter 17-3, Florida Administrative Code, and 40 CFR, 423, Effluent Guidelines and Standards for Steam Electric Power Generating Point Source Category, except as provided herein. Also, the permittee shall comply with the following conditions of certification:

A. Plant Effluents and Receiving Body of Water

For discharges made from the power plant the following conditions shall apply:

1. Receiving Boby of Water (RBW)

The receiving body of water has been determined by the Department to be those waters of the St. John's River and any other waters affected which are considered to be waters of the State within the definition of Chapter 403, Florida Statutes.

2. Point of Dishcarge (P.O.D.)

The point of discharge will be determined by the Department to be where the effluent physically enters the waters of the State.

3. Thermal Mixing Zone

The instantaneous zone of thermal mixing for the cooling system shall not exceed an area of 9.5 acres. The temperature at the point of discharge into the St. John's River shall not be greater than 105 degrees F. The temperature of the water at the edge of the mixing zone shall not exceed the limitations of Paragraph 17-3.05(1)(d).

4. Chemical Wastes

All discharges of FGD blowdown and low volume wastes (demineralizer regeneration, floor drainage, lab drains and similar wastes) shall comply with Chapter 17-3. If violations of Chapter 17-3 occur, corrective action shall be taken. These wasteswaters shall be discharged to an adequately sized and constructed treatment facility. Low volume wastes, boiler preoperational and operational metal cleaning wastes, preheater wash, and stack wash shall be disposed of in an adequately sized treatment facility.

During periods when treated wastewater does not comply with pH discharge limitations, the treated wastewater may be recycled to the coal pile runoff sedimentation basin, except when the sedimentation basin has insufficient capacity to retain the recycled wastewater and the runoff from a rainfall event equal to or less than a ten year, 24 hour storm.

5. Coal Pile

Coal pile runoff shall be disposed of in the wastewater treatment system and shall not be directly discharged to surface waters. Discharge of stormwater runoff from the coal pile is allowed only during periods of high rainfall in excess of the ten year, 24 hour storm.

6. Chlorine

The concentration of total residual chlorine discharged from Units 1 & 2 shall not exceed 0.1 mg/l at the POD nor 0.01 mg/l beyond an instantaneous mixing zone of 1.0 acre. Chlorine from either unit at SJRPP shall not be discharged more than two hours per day and no unit shall be chlorinated simultaneously with any other unit at SJRPP or at Northside Generating Station. Levels of free available chlorine shall not exceed 0.5 mg/l for an instantaneous maximum nor 0.2 mg/l on a daily average in either cooling tower blowdown.

7. pH

The pH of the combined discharges shall be such that the pH be within the range of 6.0 to 9.0.

8. Polychlorinated Biphenyl Compounds

There shall be no net discharge of polychlorinated biphenyl compounds.

9. Combined Low Volume Wastes and Coal Pile Runoff

The low volume wastes and coal pile runoff shall be treated to control pH, turbidity, solids and toxic metals prior to discharge into the cooling water system. The following effluent limitations will apply:

Effluent	Daily Maximum	Maximum 30-Day Daily Average
TSS	50 mg/l	30 mg/l
Oil and Grease	15 mg/l	10 mg/l
pH	6-9	6-9

The design plans and specifications of the treatment system shall be submitted to the Department for review and approval prior to construction.

10. Metal Cleaning and Bottom Ash Sluice System Blowdown

Blowdown from the metal cleaning wastes and from the bottom ash sluice system shall be treated as appropriate prior to discharge to the cooling water system. The following effluent limitations shall apply:

Effluent	Daily Maximum	Maxmimum 30-Day Daily Average
TSS	100 mg/l	30 mg/l
Oil and Grease	20 mg/l	15 mg/l
pH	6-9	
Iron	1 mg/l	
Copper	1 mg/l	
PO_4	1 mg/l	
COD	100 mg/l	

11. Solid Waste and Limestone Storage Areas

There shall be no direct discharge of stormwater runoff to surface waters from the solid waste and limestone storage areas prior to treatment.

12. Storm Water Runoff

During plant operation, necessary measures shall be used to settle, filter, treat or absorb silt-containing or pollutant-laden stormwater runoff to limit the suspended solids to 50 mg/l or less at the POD during rainfall periods less than the 10-year, 24-hour rainfall, and to prevent an increase in turbidity of more than 50 Jackson Turbidity Units above background in waters of the State beyond 50 meters from the POD at Station E 4500 and N 3712.

Control measures shall consist at the minimum of filters, sediment traps, barriers, berms or vegetative planting.

Exposed or disturbed soil shall be protected as soon as possible to minimize silt - and sediment-laden runoff. The pH shall be kept within the range of 6.0 to 8.5 at the POD.

13. Coal Unloading Facility Percolation Pond Overflow

There shall be no direct discharge to surface waters from the coal unloading facility wastewater treatment system percolation pond. Any discharge from the facility shall be reported to the Department and the Environmental Protection Agency. The quantity of flow and duration of flow shall be estimated.

14. Mixing Zones

The discharge of the following pollutants shall not violate the Water Quality Standards of Chapter 17-3, FAC, beyond the edge of the designated instantaneous mixing zones as described herein.

Pollutants	Mixing Zone	
Aluminum	125,600^2	31 Acres
Copper	125,600^2	31 Acres
Cyanide	125,600^2	31 Acres
Iron	125,600^2	31 Acres
Mercury	125,600^2	31 Acres
Silver	125,600^2	31 Acres
Oil and Grease	125,600^2	31 Acres
Selenium	12,000^2	3 Acres

15. Variances to Water Quality Standards

In accordance with the provisions of Sections 403.201 and 403.511(2), F.S., Jacksonville Electric Authority is hereby granted variances to the water Quality Standards of Chapter 17-3, F.A.C., for Aluminum, Copper, ~~Cyanide,~~ Iron and Mercury, ~~Silver, and Oil and Grease,~~ but only at such times as the natural background levels of the St. Johns River approach or exceed those standards. In any event, the discharge from the SJRPP shall comply with the effluent limitations set forth in paragraph II.A.16. The variance for mercury shall only be for two years, but may be extended by the Secretary pending results of monitoring data on wastewater treatment plant efficiency and ambient data

16. <u>Effluent Limitations</u>

The following instantaneous maximum effluent limitations shall apply for Aluminum, Copper, Cyanide, Mercury, Silver, and Oil and Grease at the locations specified:

a. Cooling Tower Blowdown - Concentrations shall not exceed 1.5 times the concentrations present in the intake of the applicant's Northside Generating Station.

b. Wastewater Treatment Facility Discharge - Concentrations shall not exceed:

Aluminum	0.15 mg/l
Copper	1.0 mg/l
Cyanide	5. ug/l
Iron	1.0 mg/l
Mercury	41.1 ug/l
Silver	6.4 ug/l
Oil and Grease	20 mg/l

B. <u>Water Monitoring Programs</u>

The permittee shall monitor and report to the Department the listed parameters on the basis specified herein. The methods and procedures utilized shall receive written approval by the Department. The monitoring program may be reviewed annually by the Department, and a determination may be made as to the necessity and extent of continuation, and may be modified in accordance with Condition No. XXV.

1. <u>Chemical Monitoring</u>

The following parameters shall be monitored during discharge as shown, discharge commencing with the start of commercial operation of SJRPP and reported quarterly to the Department's St. Johns River Subdistrict Office:

Parameter	Location	Sample Type	Frequency
Flow, Groundwater	Wellfield Pipeline	Recorder	Continuous
Flow, Cooling	Intake	Pump Logs	Continuous
Flow, Cooling Tower Blowdown	Cooling Towers	Recorders	Continuous
Wastewater Flow	Prior to Pump Sump	Recorder	Continuous
Oily Wastewater Flow	Prior to Pump Sump	Recorder	Continuous
pH	Pump Sump Outfall to NGS	Recorder Grab	Continuous Two/per week
Temperature	Outfall to NGS	Recorder	Continuous
TSS	Oily Waste Basin, Metal Cleaning Waste Facility, and Sewage Treatment Facility	Grab 24 Hour Composite " " "	Two/per week Two/per week " " " Monthly
Chlorine,Total Residual	Cooling Tower Blowdown Discharge to Browns Creek (During construction only)	Multiple Grab	Weekly
Oil and Grease	Oily Waste Basin Metal Cleaning Waste Facility Wastewater Treatment Facility	3 Grab Composite 24 Hour Composite 3 Grab Composite	Two/week One/day Two/week
Metals	Intake and Sump Pump	24 Hour Composite	Once/week for first six months, two/month for the next six months, then monthly thereafter
Aluminum	"		"
Copper	"		"
Cyanide	"		"
Iron	"		"
Mercury	"		"

Nickel	"		"
Selenium	"		"
Silver	"		"
Zinc	"		"
BOD	STP Influent and effluent	8 Hour Composite	Monthly
	Metal Clean- ing Waste Facility	24 Hour Composite	Daily
PO_4	Metal Cleaning Facility	24 Hour Composite	Daily
Copper	" " "	" " "	"
Iron	" " "	" " "	"
Cycles-of-con- centration	Cooling tower	Calcuation	"

2. Groundwater Monitoring

The groundwater levels shall be monitored continuously at wells as approved by the St. Johns River Water Management District. Chemical analyses shall be made on samples from all monitored wells identified in Condition III. F. below. The location, frequency and selected chemical analyses shall be as given in Condition III.F.

The groundwater monitoring program shall be implemented at least one year prior to operation of SJRPP Unit 1. The chemical analyses shall be in accord with the latest edition of Standard Methods for the Analysis of Water and Wastewater. The data shall be submitted within 30 days of collection/-analysis to the St. Johns River Water Management District and to the DER St. Johns River Subdistrict Office.

Conductivity and heavy metals shall be monitored in wells around all solid waste disposal sites, coal piles, and wastewater treatment and sedimentation ponds.

III. Groundwater

A. General

The use of groundwater from the wellfield for plant service water for SJRPP shall be minimized to the greatest extent practicable, but in no case shall exceed 7.6 mgd on a maximum daily basis from any new wells or 5.1 mgd on an average annual basis.

B. Well Criteria

The submission of well logs and test results and location, design and construction of wells to provide plant service water shall be in accordance with applicable rules of the Department of Evironmental Regulation and the St. Johns River Water Management District(SJRWMD). Total water use per month shall be reported quarterly to SJRWMD commencing with the start of construction.

C. Well Withdrawal Limits

JEA is authorized to make a combined average annual withdrawal of 5.1 million gallons of water per day with a maximum combined withdrawal rate not to exceed 7.6 million gallons during a single day. Withdrawals may be made from a wellfield consisting of up to four (4) wells whose locations are described in Figure __.

After wells have been constructed, St. Johns River Water Management District may evaluate the individual wells and may recommend to the Department authorization of different withdrawals based upon hydrologic characteristics for the individual wells. The Department pursuant to Section 403.516, F.S. may modify the above withdrawal limitations with the concurrence of SJRWMD.

D. Water Use Restriction

Said water is restricted to uses other than main stream condensing. Any change in the use of said water will require a modification of this condition.

E. Emergency Shortages

In the event an emergency water shortage should be declared pursuant to Section 373.175 or 373.246, F.S., by St. Johns River Water Management District for an area including the location of these withdrawal points, the Department pursuant to Section 403.516, F.S., may alter, modify, or declare to be inactive, all or parts of Condition III. A.-G. An authorized Water Management District Representative, at any reasonable time, may enter the property to inspect the facilities.

F. Monitoring and Reporting

JEA shall, within the time limits hereinafter set forth, complete the following items, and if it fails to complete them by the specified time, the Condition III. A.-G. shall automatically become null and void.

1. FPC shall install flow meters in compliance with SJRWMD specifications on all production wells.

2. JEA shall submit to SJRWMD, on forms available from the District, a record of pumpage for each meter installed in F.1. above. Said pumpage shall be provided on a monthly basis, and shall be submitted by April 15, July 15, October 15, and January 15 for each preceding calendar quarter.

3. JEA shall maintain and operate a continuous water level recorder on the standby production well located at the test site in Duval County, Florida. Detailed hydrographs of water level fluctuations shall be constructed with the data collected from the water level recorder and shall be submitted to SJRWMD by April 15, July 15, October 15, and January 15 for each preceding calendar quarter.

4. Water quality analysis shall be performed on water withdrawn from each production well. The water samples collected from each of the wells shall be collected immediately after removal by pumping of a quantity of water equal to two casing volumes. The JEA and staff of SJRWMD may determine and adjust the intervals to be monitored in accordance with hydrologic conditions determined from drilling logs. The water quality analyses shall be performed monthly during the first year of operation, four times (January, May, September, and December) during the second year and twice each year (May and September) thereafter. Results shall be submitted to SJRWMD by the fifteenth (15th) day of the month following the month during which such analyses were performed. Testing for the following constituents is required:

Calcium	Magnesium	Sodium
Potassium	Bicarbonate	Sulfate
Chloride	Nitrate	Total Dissolved Solids
Specific conductance	Gross Alpha	Total Phosphate
Radium 226 (only if gross Alpha is greater than 15 pci/l)	Radiation	

The design and location of monitoring wells shall be as indicated by the attached Figure or as modified by the staff of SJRWMD.

5. In the event that SJRWMD determines there is a significant change in the water quality, the Department pursuant to Section 403.516, F.S., may require the permittee to reduce or cease withdrawal from these groundwater sources.

6. After consulation with the DER and SJRWMD, JEA shall install a monitoring well system as generally shown on Figure 3 to monitor groundwater quality in the top 55 feet of surficial aquifer. One well shall be installed to a depth greater than 55 feet, but less than 150 feet, to monitor vertical dispersion or groundwater contaminants. Monitoring well locations and designs shall be submitted to the Department and SJRWMD for review. Monitoring wells shall be installed upgradient and downgradient from each solid waste disposal area, each liquid waste pond and each coal pile storage area. An additional monitoring well will be placed immediately downgradient of the first section of each solid waste landfill to be utilized. Approval or disapproval of the locations and design shall be granted within 60 days. The water samples collected from each of the monitor wells shall be collected immediately after removal by pumping of a quantity of water equal to two casing volumes. The water quality analyses shall be performed monthly during the year prior to commercial operation and two years after operation and quarterly thereafter. Results shall be submitted to the Department and the SJRWMD by the fifteenth (15th) day of the month following the month during which such analyses were performed. Testing for the following constituents is required:

TDS	Cadmium
Conductance	Zinc
pH	Copper
Redox	Nickel
Dissolved Oxygen	Selenium
Temperature	Chromium
Color	Arsenic

Turbidity	Beryllium
Chloride	Mercury
Iron	Lead
Aluminum	Gross Alpha

G. Minimum Water Level Restrictions

The Department and SJRWMD may, at a future date pursuant to Section 403.516, F.S., establish a minimum water level in the aquifer or aquifers hydrologically associated with these withdrawals, which may require JEA to reduce or cease withdrawal from these groundwater sources at times when water levels fall below these minimums.

H. Leachate

1. Zone of Discharge

Leachate from the solid waste landfills, sludge disposal test cells, coal storage piles, bottom ash pond, wastewater treatment ponds, and sedimentation shall not contaminate waters of the State (including both surface and groundwaters) in excess of the limitations of Chapter 17-3, FAC., beyond the boundary of the site.

2. Corrective Action

When the groundwater monitoring system shows a violation of the groundwater water quality standards of Chapter 17-3, FAC., the appropriate ponds, FGD landfill, or coal pile shall be sealed, relocated or closed, or the operation of the affected facility shall be altered in such a manner as to assure the Department that no violation of the groundwater standards will occur beyond the boundary of the site.

IV. Control Measures During Construction

A. Stormwater Runoff

During construction, necessary measures shall be used to settle, filter, treat or absorb silt-containing or pollutant-laden stormwater runoff to limit the suspended solids to 50 mg/l or less at the POD during rainfall periods less than the 10-year, 24 hour rainfall, and to prevent an increase in turbidity of more than 50 Jackson Turbidity Units above background in waters of the State beyond 50 meters from the POD to Browns Creek.

Control measures shall consist at the minimum of filters, sediment traps, barriers, berms or vegetative planting. Exposed or disturbed soil shall be protected as soon as possible to minimize silt- and sediment-laden runoff. The pH shall be kept within the range of 6.0 to 8.5 at the POD.

Final drainage plans illustrating all stormwater treatment facilities and conveyances for construction phases and ultimate operations for both the entire St. Johns River Power Park site and the Blount Island coal site shall be submitted to the St. Johns River Subdistrict Manager and the St. Johns River Water Management District for review and approval prior to construction.

Stormwater drainage to Brown's Creek and Brown's Creek shall be monitored as indicated below beginning twelve (12) months prior to the commencement of construction and continuing throughout construction:

Monitoring Point	Parameters	Frequency	Sample Type
*Stormwater drainage to Brown's Creek from existing borrow pit in southeast portion of site	BOD5, COD, suspended solids, turbidity, dissolved oxygen, pH, TKN, Total phosphorus, Fecal Coliform, Total Coliform	Twice Monthly	Grab
*West Fork of Brown's Creek at Point Downstream from entry of of stormwater from Power Park site by way of a borrow pit	BOD5, COD, suspended solids, turbidity, dissolved oxygen, pH, TKN, Total phosphorus, fecal coliform, total coliform	Twice Monthly	Grab

*Monitoring shall be conducted at suitable points for allowing a compparision of the characteristics of pre-construction and construction phase drainage and receiving waters.

B. Sanitary Wastes

Disposal of sanitary wastes from construction toilet facilities shall be in accordance with applicable regulations of the Department and appropriate local health agency. The sewage treatment plant shall be operated in accordance with Chapters 17-3, 17-6, 17-16, and 17-19, FAC. The discharge of total residual chlorine to Brown's creek shall not exceed 0.1 mg/l.

C. Environmental Control Program

An environmental control program shall be established under the supervision of a qualified person to assure that all construction activities conform to good environmental practices and the applicable conditions of certification.

The permittee shall notify the Department by telephone if unexpected harmful effects or evidence of irreversible environmental damage are detected during construction, shall immediately report in writing to the Department and shall within two weeks provide an analyses of the problem and a plan to eliminate or significantly reduce the harmful effects or damage and a plan to prevent reoccurrence.

D. Construction Dewatering Effluent

Construction dewatering effluent shall be treated as appropriate to limit suspended solids to no more than 50 mg/l. The discharge of construction dewatering liquids shall not cause turbidity in excess of 50 Jackson Turbidity Units above ambient beyond a 20 meter radius from the point of discharge. Weekly grab samples will be collected and analyzed for suspended solids.

A program for controlling the groundwater impacts of construction dewatering shall be submitted to the Department and the St. Johns River Water Management District for review prior to implementation.

V. Solid Wastes

Solid wastes resulting from construction or operation shall be disposed of in accordance with the applicable regulations of Chapter 17-7, FAC. The permittee shall submit a program for approval outlining the methods to be used in handling and disposal of solid wastes. Such program shall indicate at the least methods for erosion control, covering, vegetation and quality control.

Open burning in connection with land clearing shall be in accordance with Chapter 17-5, FAC. No additional permits shall be required, but the Division of Forestry shall be notified prior to burning. Open burning shall not occur if the Division of Forestry has issued a ban on burning due to fire hazard conditions.

VI. Operation Safeguards

The overall design, layout, and operation of the facilities shall be such as to minimize hazards to humans and the environment. Security control measures shall be utilized to prevent exposure of the public to hazardous conditions. The Federal Occupational Safety and Health Standards will be complied with during construction and operation. The Safety Standards specified under Section 440.56, F.S., by the Industrial Safety Section of the Florida Department of Commerce will also be complied with.

VII. Screening

The permittee shall provide screening of the site through the use of aesthetically acceptable structures, vegetated earthen walls and/or existing or planted vegetation.

VIII. Potable Water Supply System

The potable water supply system shall be designed and operated in conformance with Chapter 17-22, FAC. Information as required in 17-22.108 shall be submitted to the Department prior to construction and operation. The operator of the potable water supply system shall be certified in accordance with Chapter 17-16, FAC.

IX. Transformer and Electric Switching Gear

The foundations for transformers, capacitors, and switching gear necessary to connect SJRPP Units 1 & 2 to the existing distribution system shall be constructed of an impervious material and shall be constructed in such a manner as to allow complete collection and recovery of any spills or leakage of oily, toxic, or hazardous substances.

X. Toxic, Deleterious, or Hazardous Materials

The spill of any toxic, deleterious, or hazardous materials shall be reported in the manner specified by Condition XV.

XI. Construction in Waters of the State

A. No construction on sovereign submerged lands shall commence without obtaining lease or title from the Department of Natural Resources.

B. Construction of intake and discharge structures, coal unloading wharf, and transmission towers should be done in a manner to minimize turbidity. Turbidity screens should be used to prevent turbidity in excess of 50 JTUs above background beyond 150 meters from the dredging, pile driving, or construction site.

All spoil from connecting the SJRPP intake/discharge system to the NGS, and the coal unloading wharf shall be piped hydraulically or tucked to an upland disposal site of sufficient capacity to retain all material. Spoil from construction access canals shall be side cast and used for restoring natural bottom contours upon completion of construction.

C. Variances

XII. Solid Waste Landfill

A. The proposed solid waste landfill area shall be monitored and studied pursuant to a detailed groundwater testing and monitoring Program as defined in Condition III, F.G. The results of the program will be used by the Department in determining whether JEA has affirmatively demonstrated that Florida Water Criteria (Chapter 17-3, F.A.C.) will not be violated.

B. JEA shall either provide an impermeable liner under the solid waste disposal areas or shall utilize a chemical fixation process to control leachate from the solid waste. JEA may implement a test program to demonstrate the quality and quantity of leachate from an unlined or untreated waste. Upon an affirmative showing that an uncontrolled solid waste facility will not cause violation of groundwater quality criteria, the Department may approve use of non-lined or non-chemically fixed landfill cells.

C. JEA shall utilize solid waste disposal area "B", north of Island Drive, prior to using disposal area "A".

D. Construction of perimeter berms shall be in conformance with the provisions of Chapter 17-9, F.A.C., regarding earthen dams.

E. Prior to the commencement of operation of solid waste disposal areas the following shall be submitted to the St. Johns River Subdistrict Manager for review and approval:

(1) Plot plan - should be drawn on a scale not greater than 200 ft. to the inch showing the following:

a. Dimensions and legal description of the site.

b. Location and depth corrected to MSL of soil borings.

c. Proposed trenching plan.

d. Cover stock piles.

e. Fencing or other measures to restrict access.

f. Cross sections showing both original and proposed fill elevation.

g. Location, depth corrected to MSL and construction details of monitoring wells.

(2) Design Drawings and Maps - may be combined with plot plan and should be drawn on a scale not greater than 200 ft. to the inch showing the following:

a. Topographic map with five foot contour intervals.

b. Proposed fill area.

c. Borrow area.

d. Access roads.

e. Grades required for proper drainage.

f. Typical cross sections of disposal site including lifts, borrow areas and drainage controls.

g. Special drainage devices.

(3) Soil map, Interpretive Guide Sheets, and a report giving the suitability of the site for such an operation.

(4) Contingency plan, including waste handling and disposal methods, in case of an emergency such as equipment failure, natural disaster or fire.

(5) Operation plans to direct and control the use of the site.

(6) An indication by discussion or drawings or both of how the site is designed to meet water quality standards of Chapter 17-3 and 17-4 FAC at the waste site boundary.

Based on the Department's reviews of the above, additions to or modifications of the overall monitoring program may be required for monitoring of runoff, groundwaters, and surface waters which may be affected by the various landfilling operations.

XIII. Transmission Lines

A. General

1. Filling and construction in water of the State shall be minimized to the extent practicable. No such activities shall take place without obtaining lease or title from the Department of Natural Resources where required. Construction and access roads should avoid wetlands and be located in surrounding uplands.

2. Placement of fill in wetland areas shall be minimized by spanning such areas with the maximum span practicable.

3. Any fill required in wetlands for construction but not required for maintenance purposes shall be removed and the ground restored to its original contours after transmission line placement.

4. Where fill in wetlands is necessary for access, keyhole fills from upland areas should be oriented as nearly parallel to surface water flow lines as possible.

5. Sufficient size and number of culverts or other structures shall be placed through fill causeways to maintain sheet flow substantially unimpaired.

6. Turbidity control measures, including but not limited to hay bales, turbidity curtains, sodding, mulching and seeding, shall be employed to prevent violation of water quality standards.

7. The Right-of-Way shall be located so as to minimize impacts in or on stream beds such as the removal of vegetation, to the extent practicable. Within 25 feet of the banks of any streams, rivers, or lakes, vegetation shall be left undisturbed, except for selective topping of trees or removal of trees such as pines. If it is necessary to remove such trees within 25 feet of the banks of streams, rivers, or lakes, the root mat shall be left undisturbed.

8. For all construction activities in waters of the state to their landward extent as defined in 17-4.28 which are also within the jurisdiction of the Corps of Engineers, the permittee shall file a copy of its Dredge/Fill application with the Corps of Engineers and with the DER, Bureau of Permitting, Power Plant Siting Section. For construction activities in waters of the State which are not also subject to the Corps, the permittee shall file substantially similar information. In either case, within 45 days of filing DER shall determine whether or not a probable violation of the conditions of certification would occur if the plans were executed as filed. If DER determines that a probable violation would occur, it shall so notify the permittee. Construction shall not commence without a written statement of compliance. Since certification is the only form of permit required by the State, it is understood that the permittee and DER shall strive to resolve such matters by

mutual agreement. If mutual agreement cannot be reached, as determined by the permittee, then the matter shall be referred to a Hearing Officer for disposition in accordance with the provisions of Chapter 120, Florida Statutes, within 60 days. Referral of an issue to a Hearing Officer pursuant to this condition shall not affect other conditions, nor shall it operate as a stay on any other portion of the line.

9. Any necessary water quality certifications which must be made to the Corps of Engineers shall be made at the time of a finding of compliance for specific work at specific locations.

10. Construction activities should proceed as much as practicable during the dry season.

B. Other Construction Activities

1. Maintenance roads under control of the permittee shall be planted with native species to prevent erosion and subsequent water quality degradation where drainage from such roads would impact waters of the State significantly.

2. Good environmental practices such as described in Environmental Criteria for Electric Transmission Systems as published by the U.S. Department of Interior and the U.S. Department of Agriculture shall be followied to the extent practicable.

3. Compliance with the most recent version of the National Electric Safety Code adopted by the Public Service Commission is required.

4. Fences running parallel to the transmission line which may become conductive shall be grounded at appropriate intervals; fences running perpendicular to the line shall be grounded at the edge of the right-of-way.

5. Field reconnaissance of rare and endangered species should be performed in order to maximize avoidance of impact on these species.

6. Open burning in connection with land clearing shall be in accordance with the applicable rules of the Department of Agriculture and Consumer Services. No additional permits shall be required, but the Division of Forestry shall be notified prior to burning. Open burning shall not occur if the Division of Forestry has issued a ban on burning due to fire hazard conditions.

C. Maintenance

1. Vegetative clearing operations for maintenance purposes to be carried out within the corridor shall follow the general standards for clearing right-of-way for overhead transmission lines as referenced in Sections XIII. A.7. and XIII.B.2. Selective clearing of vegetation is preferred over clearing and grubbing or clear cutting.

2. If chemicals or herbicides are to be used for vegetation control, the name, type, proposed use, locations, and manner of application shall be provided to the Department for assessment of compliance with applicable regulations.

D. Archaeological Sites

Any archaeological sites discovered during construction of the transmission lines shall be disturbed as little as possible and such discovery shall be communicated to the Department of State, Division of Archives, History and Record Management (DAHRM). Potentitally affected areas will be surveyed, and if a significant site is located, the site shall be avoided, protected, or excavated as directed by DAHRM.

E. Road Crossing

For all locations where the transmission line will cross State highways, the applicant will submit materials pursuant to the Department of Transportion's (DOT) "Utility Accomodation Guide" to DOT's district office for review and approval. All applicable regulations pertaining to roadway crossings by transmission lines shall be complied with.

F. Emergency Reporting

Emergency replacement of previously existing right-of-way or transmission lines shall not be considered a modification prusuant to Section 403.5315, F.S. A verbal report of the emergency shall be made to the Department as soon as possible. Within fourteen (14) calendar days after correction of the emergency, a report to the Department shall be made outlining the details of the emergency and the steps taken for its temporary relief. The report shall be a written description of all of the work performed and shall set forth any pollution control measures or mitigative measures which were utilized or are being utilized to prevent pollution of waters, harm to sensitive areas or alteration of archaeological or historical resources.

G. Final Right-of-Way Location

A map of 1:24000 scale showing final location of the right-of-way shall be submitted to the Department upon completion of acquisition.

H. Compliance

Construction and maintenance shall comply with the applicable rules and regulations of the Department and those agencies specified in 17-17.54(2)(a) and (b), FAC.

XIV. Change in Discharge

All discharges or emissions authorized herein shall be consistent with the terms and conditions of this certification. The discharge of any pollutant not identified in the application or any discharge more frequent than, or at a level in excess of, that authorized herein shall constitute a violation of the certification. Any anticipated facility expansions, production increases, or process modification which will result in new, different or increased discharges or expansion in steam generating capacity will require a submission of new or supplemental application pursuant to Chapter 403, F.S.

XV. Non-Compliance Notification

If, for any reason, the permittee does not comply with or will be unable to comply with any limitation specified in this certification, the permittee shall notify the manager of DER's St. Johns River subdistrict office by telephone during the working day in which permittee becomes aware of said non-compliance and shall confirm this situation in writing within seventy-two (72) hours supplying the following information:

a. A description and cause of non-compliance; and

b. The period of non-compliance, including exact dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate and prevent recurrence of the non-complying event.

XVI. Facilities Operation

The permittee shall at all times maintain in good working order and operate as efficiently as possible all treatment or control facilities or systems installed or used by the permittee to achieve compliance with the terms and conditions of this certification. Such systems are not to be bypassed without prior Department approval. The one exception is that during periods when light oil is used for ignition, the FGD system may be bypassed.

XVII. Adverse Impact

The permittee shall take all reasonable steps to minimize any adverse impact resulting from non-compliance with any limitation specified in this certification, including, but not limited to, such accelerated or additional monitoring as necessary to determine the nature and impact of the non-complying event.

XVIII. Right of Entry

The permittee shall allow the Secretary of the Florida Department of Environmental Regulation and/or authorized representatives, upon the presentation of credentials:

a. To enter upon the permittee's premises where an effluent source is located or in which records are required to be kept under the terms and conditions of this permit; and

b. to have access to and copy all records required to be kept under the conditions of this certification; and

c. to inspect and test any monitoring equipment or monitoring method required in this certification and to sample any discharge or pollutants; and

d. to assess any damage to the environment or violation of ambient standards.

XIX. Revocation or Suspension

This certification may be suspended or revoked pursuant to Section 403.512, Florida Statutes, or for violations of any Condition of Certification.

XX. Civil and Criminal Liability

This certification does not relieve the permittee from civil or criminal responsibility or liability for non-compliance with any conditions of this certifiation, applicable rules or regulations of the Department, or Chapter 403, Florida Statutes, or regulations thereunder.

Subject to Section 403.511, Florida Statutes, this certification shall not preclude the institution of any legal action or relieve the permittee from any responsibilities or penalties established pursuant to any other applicable State Statutes or regulations.

XXI. Property Rights

The issuance of this certification does not convey any property rights in either real or personal property, tangible or intangible, nor any exclusive privileges, nor does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of Federal, State or local laws or regulations. The applicant will obtain title, lease or right of use to any sovereign submerged lands occupied by the plant, transmission line structures, or appurtenant facilities from the State of Florida.

XXII. Severability

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

XXIII. Definitions

The meaning of terms used herein shall be governed by the definitions contained in Chapter 403, Florida Statutes, and any regulation adopted pursuant thereto. In the event of any dispute over the meaning of a term used in these general or special conditions which is not defined in such statutes or regulations, such dispute shall be resolved by reference to the most relevant definitions contained in any other state or federal statute or regulation or, in the alternative, by the use of the commonly accepted meaning as determined by the Department.

XXIV. Review of Site Certification

The certification shall be final unless revised, revoked or suspended pursuant to law. At least every five years from the date of issuance of this certification or any National Pollutant Discharge Elimination System Permit issued pursuant to the Federal Water Pollution Control Act Amendments of 1972 for the plant units, the Department shall review all monitoring data that has been submitted to it during the proceeding five-year period for the purpose of determining the extent of the permittee's compliance with the conditions of this certification of the environmental impact of this facility. The Department shall submit the results of its review and recommendations to the permittee. Such review will be repeated at least every five years thereafter.

XXV. Modification of Conditions

The conditions of this certification may be modified in the following manner:

A. The Board hereby delegates to the Secretary the authority to modify, after notice and opportunity for hearing, any conditions pertaining to consumptive use of water, monitoring, sampling, groundwater, mixing zones, zones of discharge, leachate control programs or variances to water quality standards.

B. All other modifications shall be made in accordance with Sections 403.516, Florida Statutes.

XXVI. Flood Control Protection

The plant and associated facilities shall be constructed in such a manner as to comply with the Duval County flood protection requirements.

XXVII. Effect of Certification

Certification and conditions of certification are predicated upon design and performance criteria indicated in the application. Thus, conformance to those criteria, unless specifically amended, modified, or as the Department and parties are otherwise notified, is binding upon the applicant in the preparation, construction and maintenance of the certified project. In those instances where a conflict occurs between the application's design criteria and the conditions of certification, the conditions shall prevail.

XXVIII. Noise

To mitigate the effects of noise produced by the steam blowout of steam boiler tubes, JEA shall conduct public awareness campaigns prior to such activities to forewarn the public of the estimated time and duration of the noise.

XIX. Archaeological Sites

The following archaeological sites shall be preserved whenever possible. If they must be altered by construction, then archaeological salvage excavation shall be performed prior to construction under the supervision of the Florida Department of State, Division of Archives, History and Records Management.

Site -	8Du669	8Du670
	8Du671	8Du673
	8Du674	8Du675
	8Du677	8Du678

XXXI. Blount Island Coal Unloading Facility

Area drainage and rainfall runoff from the lined coal pile on Blount Island shall be directed to a lined treatment system designed to process the runoff from the 24-hour, ten-year storm. Wastewater treatment shall consist of as a minimum: removal of solids and metals by precipitation and sedimentation followed by pH adjustment to no less than 8.0 and final disposal by percolation. Sufficient capacity shall be provided to allow for accumulation of settled solids of up to 20 percent of the total pond volume. Solids removed from the sedimentation pond shall be disposed in a properly designed landfill.

The sedimentation pond liner shall be impervious and designed for the life of the facility. The liner shall be installed in such a manner as to prevent rupture during cleaning or removal of solids.

State of Florida

DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices And/Or To Other Than The Addressee	
To: Bob King	Loctn.:
To:	Loctn.:
To:	Loctn.:
From:	Date:

TO: District, Subdistrict and Local Program Air Engineers

FROM: Edward Palagyi, BACT Coordinator

DATE: May 11, 1981

SUBJ: BACT as determined for Jacksonville Electric Authority

Attached please find one copy of the BACT as determined by the Florida Department of Environmental Regulation for the subject applicant.

Should you have any questions regarding this BACT, please contact me at (904) 488-1344 or Suncom 278-1344.

EP:dav

Best Available Control Technology (BACT) Determination

Jacksonville Electric Authority

Duval County

The proposed facility is the construction of two 600 megawatt coal-fired electric utility steam generating units to be located in Jacksonville, Florida. The units will be designed for possible conversion to oil, gas or refuse firing. There will be an oil fired auxiliary boiler rated at 200 million Btu/hr estimated to have an annual capacity factor of 5 percent compared to 74 percent for the two units.

The plant will be located in Duval County which is classified nonattainment for the pollutant Ozone (17-2.16(1)(c) F.A.C.). It will be located in the area of influence of the Jacksonville particulate nonattainment area (17-2.13(1)(b) F.A.C.), however, the plant will not significantly impact the nonattainment area and is therefore exempt from the requirements of Section 17-2, 17 & 18 & 19 with respect to particulate emissions. The facility must comply with the provisions of 17-2.04 F.A.C. (Prevention of Significant Deterioration).

BACT Determination Requested by the Applicant:

Pollutant	Emission Limit
Particulates	0.03 lb/million Btu input
SO_2	0.76 lb/million Btu input
NO_x	0.60 lb/million Btu input
CO	0.05 lb/million Btu input

Particulate emissions to be controlled using an Electrostatic Precipitator (ESP). SO_2 emissions to be controlled with a limestone wet scrubbing system. There is no specific control technology for control of NO_x and CO emissions. BACT to be manufacturer's guarantee for state-of-the-art burner design parameters to minimize emissions.

Flyash emissions to be controlled using a pneumatic transfer system and bottom ash using a wet transfer system. Emissions from coal and limestone handling to be controlled by use of enclosed conveying systems with baghouses rated at 99.9 percent efficiency. Water suppression to control dust to be used as required.

Date of Receipt of a Complete BACT Application:

February 27, 1981

Date of Publication in the Florida Administrative Weekly:

March 27, 1981

Review Group Members:

Steve Pace, Jacksonville Bio-Environmental Services
Johnny Cole, DER, St. Johns River Subdistrict
Buck Oven Power Plant Siting Section
Bob King, DER, Bureau of Air Quality Management
Tom Rogers, DER, Air Modeling Section

Bio-Environmental Services recommended a 65% reduction in NO_x emissions, or 0.5 lb/million Btu heat input. This was the only exception to unanimous acceptance of the NSPS emission limits as BACT.

BACT Determination by DER:

Pollutant	Emission Limit
Particulates	0.03 lb/million Btu input
SO_2	0.76 lb/million Btu input
NO_x	0.60 lb/million Btu input
CO	0.05 lb/million Btu input

Justification of DER Determination:

NSPS, Subpart Da, Standards of performance for electric utility steam generating units for which construction is commenced after September 18, 1978, is determined as BACT for the proposed project. The proposed control equipment is state-of-the-art and determined as BACT.

Emissions from the auxiliary boiler are minor compared to the main units. The auxiliary boiler will operate only when one of the main units is not in operation. Limited operation of the auxiliary boiler is determined as BACT.

Details of the Analysis May be Obtained by Contacting:

Edward Palagyi, BACT Coordinator
Department of Environmental Regulation
Bureau of Air Quality Management
2600 Blair Stone Road
Tallahassee, Florida 32301

Recommended By:

C H Tavey

for Steve Smallwood, Chief, BAQM

Date:

5/6/81

Approved:

Victoria Tschinkel

Victoria Tschinkel, Secretary

Date:

5/7/81

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

INTERοFFICE MEMORANDUM

For Routing To District Offices And/Or To Other Than The Addressee		
To:	Loctn.:	
To:	Loctn.:	
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Reply Optional [ ]	Reply Required [ ]	Info. Only [ ]
Date Due:	Date Due:	

TO: Buck Oven, Power Plant Siting Section

THRU: Bill Thomas BT, Bureau of Air Quality Management

THRU: Willard Hanks wmh

FROM: Bob King BK

DATE: April 17, 1981

SUBJ: Comments on Sufficiency Review - JEA's St. Johns River Power Park Unit 1 and Unit 2.

1. Did JEA conduct any on-site monitoring program at Northside Site before or after the construction of Northside Unit 3? If JEA did, send us the results of the monitoring program.

2. According to the application (page 2.7-7), EPA Region IV approved the use of on-site monitoring data for baseline/background determination. We need confirmation of this approval.

3. What are the maximum sulfur dioxide and particulate matter emission rates when burning No. 2 fuel oil during start-up and low load operation of Unit 1 and 2?

4. According to the application (page 3.8-6), a small fraction of flue gas will bypass the absorbers to reheat the gases exiting the absorbers. What is maximum flow rate of the bypassing flue gas? What is the overall SO_2 removal efficiency including bypassed flue gas of the system?

5. Cooling towers are subject to both BACT and PSD requirements. Ambient particulate concentrations and drift impacts must be included in the application.

6. If maximum cooling tower drift is 1.5 percent of the circulating water, what is the particulate matter emission rate for each tower?

7. What is maximum particulate matter emission rate in lb/hr and tons/yr from auxiliary boiler?

BK:BT:WH:dav

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices And/Or To Other Than The Addressee			
To: Bill Thomas	Loctn.:		
To:	Loctn.:		
To:	Loctn.:		
From:	Date:		
Reply Optional [ ]	Reply Required [ ]	Info. Only [ ]	
Date Due:	Date Due:		

TO: Power Plant Siting Review Committee

FROM: Hamilton S. Oven, Jr. HSO

DATE: April 14, 1981

SUBJECT: JEA Power Plant

Attached for your review and comment is a partial response from JEA to our questions on sufficiency.

HSOjr:my

Jacksonville Electric Authority

233 WEST DUVAL STREET • P. O. BOX 53015 • JACKSONVILLE, FLORIDA 32201

JEA "POWER TO SERVE"

April 9, 1981

Mr. Hamilton S. Oven, Jr.
Administrator - Power Plant Siting Section
Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32301

Dear Mr. Oven:

In response to your letter dated March 19, 1981, we are forwarding the attached set of responses to sixteen of your fourty initial questions concerning the application for the St. Johns River Power Park Units 1 & 2 (PA 81-13). We are continuing to address the remaining questions and will provide those responses as soon as possible.

Sincerely,

Dale Moehle

Dale Moehle
Division Chief
New Fossil Generation

DAM:DHL:cb

xc: R. Howard, EPA
T. Bisterfield, EPA
R. Lyles
R. Breitmoser
D. Lucas
J. Walden
L. Leskovjan
B.M. Wirz
D.J. Pike, Ebasco

File: 3.3.4.1.1.9.

RESPONSES TO FDER INTERROGATORIES (MARCH 19, 1981)
SET 1

Question 16: Does JEA/FPL have any programs for aiding the impacted residents other than monetary recompense for the property and moving expenses?

Response: According to Mr. Jack H. Weitzel, Right-of-Way Agent for JEA, there are no other programs to aid residents who may have to relocate due to property aquisition associated with the routing of a transmission line.

Question 17: Elaborate on the apparent discrepancy regarding the groundwater requirements. Page 5.2-6 indicates a 3400 GPM continuous demand, while page 3.3-1 indicates an annual average of 1000 GPM.

Response: The major groundwater demand will be for makeup to the flue gas desulfurization system (FGDS). As noted on page 3.3-5, groundwater requirements for the FGDS system could vary from 800 to 3,150 gallons per minute (gpm). For an FGDS groundwater requirement of 3,150 gpm, the total groundwater requirement for all uses would be 3,380 (approximately 3,400) gpm average and 4,020 (approximately 4000) gpm maximum. The annual average groundwater demand of approximately 1,000 gpm noted on page 3.3-1 refers to conditions of minimum groundwater demand (800 gpm) for the FGDS system. The actual groundwater demand will be more accurately defined when the specific FGDS is selected.

Question 18: Has any consideration been given to the construction of an overpass for either the trains or the auto traffic in the plant vicinity?

Response: Consideration has been given to the construction of an overpass for trains or auto traffic at crossing points on Heckscher Drive, Eastport Road, and Main Street. Delay times as presented in the SCA/EID document for "worst case" conditions were evaluated for probability of coal train crossings during peak traffic hours. Given the low expected frequency of a "worst case" occurrence, the savings in social costs that could be realized by construction of an overpass would not likely outweigh the costs of overpass construction and maintenance over the life of the plant.

Question 19: Discuss any variances that may be sought from water quality standards for leachates from the coal pile runoff.

Response: A petition for variance from groundwater standards or a separate petition for chemicals present in coal pile drainage discharged into the St. Johns River via the existing Northside Generating Station (NGS) is not anticipated. However, in filing for any variances at the proposed point of discharge (through the NGS), the contribution of chemicals present in the coal pile drainage will be addressed. Chapter 5.1.3 (Table 5.1-9) and in Appendix C.6, (Table C-38, C-39, C-40 and C-41 and Figures C-40 through C-49) address the predicted influence of plant discharges which include coal pile drainage.

A separate petition for variance may be sought, however, for chemicals present in coal pile drainage discharge into the percolation pond at the Blount Island coal unloading facility. At present no direct discharge to the St. Johns River from this facility exists; however, as a practical matter the possibility for filing a petition for variance is retained as an option.

Question 21: Will sludges from the chemical wastewater treatment facility require acceptable hazardous waste disposal?

Response: Where the spent cleaning solutions and rinse waters generated during the boiler cleaning procedure prove to be a hazardous, corrosive waste under RCRA (i.e., pH less than 2.0 or greater than 12.5), the associated sludges resulting from treatment of this waste will require appropriate hazardous waste disposal. Disposal of these sludges is planned to be off-site of the SJRPP property in an EPA RCRA permitted facility.

Question 24: Why is the chemical quality of leachate based on mean values and not on worst-case values?

Response: Appendix D.5, pages D-46 through D-55, presents a discussion of the sensitivity of calculated quality and quantity of leachate to variations in a variety of hydrologic and engineering parameters. Within the context of that parametric sensitivity analysis, it is noted on page D-53 that some Florida Class I-B water quality standards could be exceeded for worst-case leachate quality. However, it is also noted that the parametric sensitivity analysis is inherently based on several conservative assumptions, one of which is that the leachate generated by solid-waste disposal areas at the SJRPP site could exhibit worst-case concentrations of dissolved constituents.

The analysis of the groundwater effects of solid-waste leachate presented on page 5.1-13 is based on a relaxation of some of the extremely conservative assumptions made for the worst-case analysis. Specifically, it was assumed that the rate of infiltration of precipitation can be reduced by appropriate engineering of the solid-waste landfill as described in Section 3.5.2.2. Furthermore, the solid-waste leachate data summarized on Table D-21, Appendix D, indicate that observed fly ash leachate can exhibit ranges of concentrations varying over as much as four orders of magnitude between minimum and maximum values for several parameters. Similarly, the reported data for FGD sludge liquors exhibit ranges of concentrations varying over one to two orders of magnitude between median and maximum values. Consequently, it was assumed that the chemical quality of leachate will not continuously approach the worst-case values reported in the literature. This latter assumption was quantified by using median rather than maximum reported values of concentrations of dissolved constituents in solid-waste leachate.

<u>Question 25</u>: Has monitoring been performed to determine whether contaminated leachate emanates from the site currently? If so, what plans are there for site rehabilitation?

<u>Response</u>: The site is currently in an undisturbed natural state, containing no facilities which could generate a leachate. Baseline groundwater quality monitoring has been conducted on a quarterly basis since the summer of 1980. Results of the first two quarters of monitoring of site wells and piezometers are given on Table D-20, sheets 1 through 11, Appendix D. These results indicate that the shallow groundwater beneath the site is generally of good to excellent quality, with the exception of high iron concentrations. Consequently, site rehabilitation relative to pre-existing groundwater contamination is not required.

<u>Question 26</u>: JEA's NGS has applied for a Part "A" permit, No. FL0000735860. Is this for existing or proposed chemical waste disposal sites? Will this interact with the SJRPP site?

<u>Response</u>: The RCRA permit application for JEA NGS is for wastes generated at the NGS alone. A separate RCRA permit application has been submitted for wastes generated, treated and stored at the SJRPP facility.

The hazardous wastes from the two power plants will not interact with each other.

Question 27: Has any research been done on the recycling or reclamation of hazardous wastes as an option to disposal?

Response: No disposal of hazardous wastes will take place at the proposed plant. As identified in the facility's RCRA Part A application, all hazardous wastes will be handled through either treatment or storage. Additionally, the demineralizer regeneration wastes, which may be hazardous because of corrosivity, will be addressed for storage and treatment under the proposed permit-by-rule regulations for an elementary neutralization unit (45 FR 76076-76083). Since disposal, on-site, of the anticipated hazardous wastes is not proposed, the option of treatment was selected over possible recycling or reclamation.

Question 28: Will the hazardous wastes listed in the facility's Part A application be generated at the proposed facility? If so, what disposal plans have been made?

Response: The wastes listed in the NGS RCRA Part A application are not the same as those listed in the SJRPP RCRA Part A application (see Appendix O). Hazardous wastes anticipated to be generated at the proposed facility include wastes from demineralizer regeneration, boiler cleaning, and equipment cleaning and maintenance. Those wastes listed in the Part A application are the corrosive wastes produced by the chemicals used for boiler cleaning, and the spent solvents from equipment degreasing activities. A separate permit-by-rule will be requested for the demineralizer regeneration wastes, which are hazardous solely because of their corrosive nature and will be neutralized in a tank prior to treatment in the power plant's wastewater treatment facility.

Question 29: Will proposed dredge materials be classified as a hazardous waste?

Response: The results of elutriate tests taken in the proposed dredge area demonstrate that the dredged materials will not be hazardous wastes under RCRA.

Question 34: Has consideration been given to using fly ash and gypsum as road base material as well as low strength building blocks?

Response: JEA/FPL are keenly aware and are considering the many proven and commercially acceptable uses for fly ash, particularly in the construction industry, which include: (1) highway construction, (2) cement manufacturing, (3) brick manufacturing, (4) block manufacturing, and (5) lightweight aggregate production. With recent publication of the U.S. EPA's Proposed Guidelines for Federal Procurement of Cement and Concrete Containing Fly Ash (45 FR 76906-76921) the use of fly ash should continue to expand. Also, the Federal Highway Administration, various state highway departments, the Transportation Research Board and the National Ash Association have acknowledged that coal ash has a variety of highway construction applications.

Utilization of fly ash mixed with gypsum produced by FGD processes is still in the conceptual stage of development. Although some field experience has been obtained with road bases (e.g., Dulles Airport, Washington, D.C.) and block (e.g., underwater reef in the Atlantic Ocean off the coast of Long Island), no established markets exist to allow a demand forecast. The volumes of fly ash and flue gas desulfurization sludge being generated nationally should increase the amount of research of utilization of these materials as recoverable resources.

Question 37: What is the expected loading of heavy metals from the Blount Island coal pile leachate/runoff percolation pond on the St. Johns River?

Response: Assuming the present proposed location of the percolation pond, a net groundwater flow into the St. Johns River of 61,000 gpd, as discussed in Section 5.6.1.2 of the SCA/EID, and groundwater chemical characteristics as described in Table 5.6-10 of the SCA/EID, loading rates can be estimated for the following referenced heavy metals:

Metal	Loading (lb/day)
Chromium, total	0.002
Copper	0.33
Iron	71.38
Magnanese	0.015
Nickel	0.92
Zinc	2.34

Question 38: What are the safeguards that will be used to protect against oil spills from the handling and storage of No. 2 fuel oil?

Response: Standard oil spill prevention methods will be used at SJRPP, including construction of dikes or berms in oil storage areas; installation of curbine and drainage systems in oil handling areas; and, provisions for booms, weirs, and sorbent materials as required on-site to contain any oil spill and prevent its discharge into waterways. Details of oil containment systems will be included in the Spill Prevention Control and Countermeasure Plan which will be prepared for the proposed facility in accordance with EPA regulation 40 CFR Part 112.

Question 39: What are the expected air quality impacts in downtown Jacksonville if operation of SJRPP 1 and 2 causes Kennedy and Southside to be shut down?

Response: The ambient air quality impacts resulting from the current operation of the JEA Kennedy and Southside units are presently larger than the incremental impacts which will result from the operation of SJRPP Units 1 and 2. This is because of: a) lower stack heights at Southside and Kennedy, b) the absence of SO_2 and TSP removal equipment, and c) adjacent building down wash effects. Therefore, should Kennedy and Southside be shut down following SJRPP 1 & 2 startup, the local air quality would improve. The extent of this improvement in the air quality is not quantifiable, however, without verification by additional numerical modelling. Presently no plan has been adopted to prematurely retire the Southside and Kennedy stations.

Table 5.3-6 of the SCA/EID presents the results of modelling the ambient air quality impacts of SJRPP 1 and 2 along with background concentrations and other major sources in Jacksonville. Because the effects of the Southside and Kennedy units were thus indirectly factored into these predicted concentrations, the maximum ambient levels without Southside and Kennedy would necessarily become less than the concentrations presented in Table 5.3-6.

Question 40: Where can one obtain a copy of FPL's Energy Management Plan for the 80's referred to on Page 1.1-18?

Response: A copy for your use will be provided at our meeting on 4/9/81 in Jacksonville. Additional copies can be obtained from the Florida Public Service Commission.

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices And/Or To Other Than The Addressee	
To: Bob King	Loctn.: 600
To:	Loctn.:
To:	Loctn.:
From:	Date:

RECEIVED MAR 1981 BUREAU AQM

TO: Power Plant Siting Review Committee

FROM: Karen Anthony, Power Plant Siting Section KWA

DATE: March 13, 1981

SUBJECT: JEA/FPL St. Johns River Power Park Units 1 & 2

We will have another PPS review committee meeting (1) to update you on the new timelines we are working on with EPA and JEA for this review, (2) regarding interactions with EPA and their consultants, Wapora, Inc., for the joint EIS/State analysis, and (3) regarding your progress on making a sufficiency determination.

The meeting will be held at 9:00 a.m. on April 2nd in 4th floor conference room B.

KA/bh

Applical - 80 mons.
public hearing - 10 mons.
200 days
EIS Oct 1 - 15
mini size 50 MW.

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32301

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GOVERNOR

JACOB D. VARN
SECRETARY

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

MAR 1981
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February 27, 1981

Mr. Chris H. Bentley, Director
Division of Administrative Hearings
The Oakland Building
2009 Apalachee Parkway
Tallahassee, Florida 32301

Dear Mr. Bentley:

Re: Jacksonville Electric Authority
St. Johns River Power Park
Power Plant Site Certification
Application Case No. 81357,
PA 81-13

Pursuant to Section 403.5065, Florida Statutes the Department of Environmental Regulation finds the above referenced application complete. During the initial review, the department staff and other agencies have noted that the JEA and their consultant will need to clarify or supplement certain areas of the application. A request for that additional information will be forthcoming as soon as a detailed review can be completed.

Sincerely,

Hamilton S. Oven, Jr.

Hamilton S. Oven, Jr., P.E.
Administrator
Power Plant Siting Section

HSOjr:my

cc: Lou Hubener
Dale Moehle
Gary Sams
Don Lucas ✓
Larry Keesey
Joe McGlothlin
Joe Jenkins ✓
Jim Dean ✓
Sonny Vergara
Barney Capehart ✓
Ted Bisterfeld ✓

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices And/Or To Other Than The Addressee		
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From:	Date:	
Reply Optional [ ]	Reply Required [ ]	Info. Only [ ]
Date Due:	Date Due:	

TO: Karen Anthony, Power Plant Siting Section

THRU: Bill Thomas, Air Quality Management BT

FROM: Bob King BK

DATE: February 27, 1981

SUBJ: Jacksonville Electric Authority/Florida Power & Light Power Plant Site Certification Application for St. Johns River Power Park Units 1 and 2 (PA 81-13)

The following information is needed to complete the subject application:

1. Section 4.1, Site Preparation and Plant Construction.

(a). The discussions on the effects of site preparation and plant construction on air quality along with control measures used.

(b). A description of how construction activities may disturb the exising terrain and wildlife habitat.

2. Section 3.8, Air Emissions.

Completed Best Available Control Technology Data.

BK:BT:dav

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices And/Or To Other Than The Addressee	
To: Bill Thomas	Loctn.:
To:	Loctn.:
To:	Loctn.:
From:	Date:

TO: Power Plant Siting Review Committee

FROM: Karen Anthony, KWA Power Plant Siting Section

DATE: February 19, 1981

SUBJECT: Jacksonville Electric Athority/Florida Power & Light Power PLant Site Certification Application for ST. Johns River Power Park Units 1 and 2 (PA81-13)

DER received the attached application on February 18, 1981. Please review the application for completeness (and sufficiency, if obvious on first reading). Completeness basically means whether the applicant has addressed all appropriate sections of the DER application form in at least a cursory fashion. We do not at this time expect the application to have major gaps since JEA has kept in close contact with this agency regarding such matters, but oversights may have occurred. We are required by law to make a determination of completeness by 10 days after receipt.

In regards to determining sufficiency, Ch. 17-17 FAC allows us 75 (include 10 days) days to ascertain whether or not sufficient information has been provided to allow us to properly evaluate the application. If not, then that is the time period within which we can request additional information. It should be noted that in practice, there is a low level exchange of information throughout the entire review process; however, technically, if there are large gaps in the information supplied it should be called to the utility's attention within the alloted time period. Thus, we recommend that you perform a sufficiency type review as soon as possible.

We will hold a meeting on February 27th at 1:30 p.m. in the 4th floor conference Room A to discuss completeness, procedures, the application in general, as well as sufficiency concerns if you have them.

Please have written comments if possible, but verbal ones will be most helpful as well. Please refer to I.M.M. 5.8.1 regarding Departmental processing. A copy of the I.M.M. was distributed with the TECo application, but if you need another, please let me know.

Each application we receive is assigned a specific module number. All time spent on the JEA/FPL application review should be allocated to module 8183. Any expenses incurred should be billed from module 8183/ RCC 0340. Buck Oven will need to sign travel vouchers billed to that number. Also, please indicate on any travel forms that such travel pertains to PA81-13, the trust fund account number for this particular application.

KWA:my

Distribution: Lou Hubener - General Counsel
Bill Thomas - Air Quality
Steve Palmer - Water Quality
Larry Olsen - Biology
Marvin Collins - Dredge/Fill
Ralph Baker (with routing through Groundwater, Hazardous Waste, Solid Waste, and Drinking Water)
Bill Hinkley (shared with Bureau of Water Resources)

cc: Suzanne Walker

Attachment (4 Volume Set of Application)

next meeting: End of March

69 PAGES
4 Copies

THE JACKSONVILLE ELECTRIC AUTHORITY
600 MW COAL-FIRED POWER PLANTS
REFUSE CO-FIRING SYSTEM STUDY

TASK NO. 001225

Ebasco Services Incorporated
145 Technology Park/Atlanta
Norcross, Georgia 30092

June, 1980

THE JACKSONVILLE ELECTRIC AUTHORITY
600 MW COAL-FIRED POWER PLANTS
REFUSE CO-FIRING SYSTEM STUDY

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THE JACKSONVILLE ELECTRIC AUTHORITY
600 MW COAL-FIRED POWER PLANTS
REFUSE CO-FIRING SYSTEM STUDY

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JACKSONVILLE ELECTRIC AUTHORITY
600 MW COAL-FIRED POWER PLANTS
REFUSE CO-FIRING SYSTEM STUDY

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LIST OF FIGURES (Continued)

JACKSONVILLE ELECTRIC AUTHORITY
600 MW UNITS
REFUSE CO-FIRING SYSTEM STUDY

I EXECUTIVE SUMMARY

1.0 PURPOSE

The purpose of this study was to assess the technical and environmental feasibility of co-firing refuse-derived solid fuel (RDSF) with coal in the new Jacksonville Electric Authority 600 MW Coal Fired Power Plants. The study did not consider the feasibility of collection of the refuse, delivery to the plant site, nor the separation of combustible and noncombustible materials, as these considerations are beyond the contractual scope of this investigation.

2.0 SCOPE

This study is concerned with the co-combustion of small percentages of refuse derived solid fuel (RDSF) with coal. This solid fuel is derived from raw garbage by (1) removing the majority of the noncombustible material and (2) shredding the remaining combustible material to a maximum particle size of about 1-1/2 inches. This version of RDSF is designated RDSF-3 in accordance with ASTM Interim Procedure E38.

To provide the basis for the study, the results of a number of previously operational, currently operational, and proposed utility power plants co-firing RDSF were reviewed. A preliminary fuel specification was developed based on this experience. Information was obtained on current refuse collection in the Jacksonville area.

The above information was used to assess the potential impacts of co-firing RDSF on boiler and Air Quality Control System (AQCS) performance and operations. The equipment required for RDSF handling and storage was sized and priced as were the required boiler and AQCS modifications. Anticipated operating costs and fuel savings associated with co-firing RDSF were projected and gross and net fuel fees were calculated.

3.0 RESULTS

3.1 Design Parameters for RDSF System

RDSF normally has a heating value from 4500 to 6500 Btu/lb. and is relatively high in chlorides, ash, and moisture but relatively low in sulfur when compared to coal. However, through proper processing, employing technology which has been developed only in recent years, it should be possible to achieve a fairly high grade of RDSF at Jacksonville.
Table 3.1-1 compares the anticipated range of certain RDSF properties against those of the range of coals to be burned at the new JEA plants.

Table 3.1-1 Coal and RDSF Properties

Properties	Coal Max.	Coal Perf.	Coal Min.	RDSF Max.	RDSF Avg.	RDSF Min.
Heating Value (BTU/LB)	13,250	12,500	10,500	6500	6100	5100
Moisture %	15.0	8.0	4.0	25.0	18.4	18.0
Ash %	18.0	9.0	6.0	15.0	9.6	6.0
Sulfur %	4.0	0.6	0.5	0.2	0.2	0.1
Chlorides %	0.3	0.1	0.1	0.5	0.2	0.2
Ash Fusion Temp.(Soft)°F	-	2300	-	-	2150	-
Ash Fusion Temp.(Fluid)°F	-	2350	-	-	2220	-

The amount of raw refuse that will be available for conversion to RDSF for co-firing at the new power plant is 1950 tpd. This will convert to 1460 tpd of RDSF at a conversion ratio of 75 percent and would result in an average firing rate on two boilers of approximately 50 tph, each, when normal load factors are considered. Although boiler manufacturers normally permit a maximum RDSF firing rate in coal fired boilers of 30 percent of the total heat input, it is recommended that the firing rate be conservatively limited to 20 percent of the total heat input, which is equivalent to a maximum firing rate for RDSF of approximately 99.9 tph per boiler at 100 percent load. For design purposes, a nominal capacity of approximately 100 tph has been selected for the RDSF feed system to each boiler. This will permit greater flexibility in operations, and allow for future growth in the waste stream.

Since it will not be possible to burn RDSF continuously due to factors such as low boiler load or equipment maintenance, there will be days when it will be necessary to fire the RDSF at maximum rates to catch up with the processing operation. Therefore, all assessments of the impact of co-firing RDSF on boiler operations are based on RDSF supplying a maximum of 20 percent of the heat input.

3.2 Impact of Co-firing RDSF on Boiler Design and Operations

In order to burn RDSF in a semi-suspension firing mode,it will be necessary to modify the boiler to incorporate nozzles for the RDSF and to install a dump grate in the bottom ash hopper. The dump grate has been found to be necessary to catch particles that fall out of suspension. These particles will then complete their combustion on the grate. The grate is left open when burning only coal.

Some boiler thermal efficiency is sacrificed when burning RDSF. Efficiency reductions as high as 3 percent have occurred when firing 20 percent RDSF. Higher excess air is not necessarily required to burn RDSF.

Experience indicates that the amount of bottom ash produced may increase by a factor of as much as 6 to 8 times when up to 20 percent of inadequately prepared RDSF is co-fired. This may require pulling bottom ash 3 to 4 times more frequently with a substantial increase in load on the ash settling pond.

The high glass content which is often present in inadequately processed RDSF has contributed to increased slagging problems in those older, higher heat release boilers which have been retrofitted with RDSF co-firing capability. The slagging tendency can be reduced by proper processing to remove as much glass as possible from the RDSF. In the opinion of at least one boiler manufacturer, the limitations placed on heat release in modern coal-fired boilers should minimize, if not preclude the slagging problem if the boiler is designed with RDSF co-firing in mind (Ref. 11).

Induced draft fan and forced draft fan power requirements may increase by as much as 17 percent when burning RDSF. This is a result of the increased mass flow of flue gases and the increased pressure drop due to the higher flue gas velocities. The net increase in fan power could be as much as 2650 horsepower per boiler at full boiler load when firing 20 percent RDSF.

3.3 Impact of Co-firing RDSF on Air and Water Quality Control Systems

There is very little directly applicable data available to support a quantitative assessment of the effects of co-firing RDSF on precipitators. Based on the limited data available, however, precipitator efficiency generally deteriorates when RDSF is burned. This effect may be attributed primarily to the higher resistivity of the ash which is believed to follow from the lower sulfur content of the RDSF and the greater difficulty in collecting carbon particles from the combustion of paper, etc. Efficiency losses up to 2 percentage points have been reported when firing 20 percent RDSF. This much efficiency loss could not be tolerated due to the low allowable particulate emission rate of 0.03 $lb/10^6$ Btu. To avoid this potentially unsatisfactory situation the precipitator on each 600 MW unit will have to be enlarged by a minimum of 10 percent to insure that it develops the required efficiency.

SO_2 and NO_x emissions both tend to decrease when RDSF is burned and thus should not present any problems. It should be pointed out that the unpredictable nature of RDSF may make it difficult, if not impossible, to obtain monetary penalties for non-performance of the Air Quality Control System while firing RDSF. However, this is subject to confirmation during the actual AQCS acquisition process.

3.4 Corrosion and Erosion

Due to the bad experiences with corrosion and erosion that many water wall incinerators have experienced, there is cause for concern about corrosion and erosion in the boiler, precipitator, and scrubber. The corrosion mechanisms in incinerators have been traced to the formation of metal chloride deposits on tube surfaces and refuse is typically higher than coal in chloride content. The erosion problems are attributable to the higher refuse ash content. However, contrary to incinerator experience, there have been no reports of serious corrosion or erosion in co-fired high pressure utility boilers.

3.5 RDSF Handling and Firing Equipment

It is assumed that all processing of the RDSF will be done at another facility operated by the Jacksonville Department of Sanitation and not on the power plant site. Therefore some means must be provided to transport the RDSF to the power plant. If the processing plant is within about a mile of the power plant, one large overhead conveyer could be used. If much further than a mile, then some means of road transport, such as 75 cu. yd. transfer trailers will be required. In either case, storage systems should be provided on the power plant to provide storage of approximately one day's processing of RDSF (1500 tons). An order-of-magnitude conceptual estimate of the total installed cost of the RDSF equipment and the boiler and precipitator modifications in 1985 dollars is $49,129,000.

3.6 Economic Analysis

Electric power generation costs should not be subsidized by the sanitation department, nor should the JEA subsidize refuse disposal. For this reason, the value of the RDSF has been calculated based on the assumption that JEA will "break even." The maximum "gross fuel fee" which would be paid by the JEA for the energy provided (less additional operating costs) would be \$36.60/ton (\$3.03/10^6 Btu), if the costs of installing and operating the RDSF facilities at the power plant site are directly assumed by the City of Jacksonville. For comparison the cost of coal in 1985 is projected to be approximately \$77.72/ton (\$3.11/10^6 Btu).

If the cost of installing and operating the RDSF facility at the power plant are assumed directly by JEA, a maximum "net fuel fee" of \$25.51/ton (\$2.07/10^6 Btu) results. This represents the net revenue available to the City of Jacksonville from operations at the power plant. On an annual basis, a net revenue of almost $13,593,000 results in the first year, 1985. Projected revenues increase every year, and result in a levelized net revenue of $66,890,000.

4.0 RECOMMENDATIONS

Based on the experiences of other RDSF facilities and considering the anticipated operating conditions of the new power plant, there do not appear to be any insurmountable barriers to the co-firing of RDSF. However, as pointed out above, there are significant costs as well as potential risks that must be assumed. Since boiler and precipitator modifications are required to accomodate the environmentally acceptable co-combustion of RDSF, a decision on the RDSF question should be made as soon as possible.

The success of such a venture is largely dependent on the quality of the RDSF supplied by the processing plant. Consequently, before a decision is made on whether to proceed with incorporating this equipment into the power plant design, an in-depth conceptual study must be made of the impact of resource recovery on the overall economics of refuse collection, transportation, and disposal in the City of Jacksonville, including the economics associated with the proposed RDSF processing plant. This study should be completed expeditiously to support boiler and precipitator procurement.

A decision to proceed with the RDSF system should only be made:

a - If the overall system economics are favorable, after consideration of all factors including fuel savings, power plant costs, processing plant costs, landfill savings, transport economics, etc.,

b - If the JEA and the Jacksonville Department of Sanitation can agree on a design of the processing facility, on fuel specifications and quality controls and on responsibilities for costs,

c - If the JEA is willing to accept the risk of potential operating problems associated with co-firing RDSF,

d - If an assessment of the various environmental impacts (both favorable and unfavorable) has acceptable results, and

e - If all affected parties agree that the undertaking is in the best interest of the City of Jacksonville.

Once an agreement is reached, it should be embodied in a simple contract which would clearly delineate the responsibilities of the JEA and the City of Jacksonville.

II INTRODUCTION

The subject of resource recovery and, in particular, energy recovery from the burning of municipal solid waste (MSW) has received increasing attention over the past decade. A practice in Europe for many years, energy recovery from MSW in the United States had been hampered by a number of factors in the past including:

a - Ready access to landfill sites,

b - Availability of relatively cheap primary fuels,

c - Lack of facilities for utilization of waste heat from municipal incinerators (for example, equipment for district heating has been installed in only a handful of cities),

d - Lack of willingness by utility companies to accept the risks of equipment damage and reduced availability from burning fuels derived from MSW,

e - Lack of willingness on the part of municipalities and private corporations to erect processing facilities without substantial commitments from utilities to accept the processed refuse

f - Concern over environmental regulations that place severe restriction on both air-borne and water-borne emissions from waste handling and burning systems.

Today, the situation is rapidly changing. Approved landfill sites are no longer readily available. Primary fuels are increasing in price day by day. The technology for processing, handling, and burning RDSF is developing rapidly. Finally, evidence is mounting that the environmental problems associated with energy recovery from refuse are not as severe as once thought.

The purpose of this study was to assess the technical and environmental feasibility of co-firing refuse-derived solid fuel (RDSF) with coal in the new Jacksonville Electric Authority (JEA) 600 MW Coal-Fired Power Plant(s). The study is organized into four main sections. The first section discusses the basic assumptions of the study including boiler operating parameters, coal properties, anticipated RDSF production rates and RDSF properties. The second section addresses the state-of-the-art in co-firing RDSF with coal in utility boilers. In this section relevant experience from previous RDSF experiments is introduced. The third section describes in detail the equipment required to enable RDSF to be co-fired in the proposed power plant and summarizes the capital costs. The fourth section presents the incremental capital and operating costs for the RDSF facility plus a calculation of the maximum "break-even" price that could be paid for the RDSF as a fuel.

III DISCUSSION

1.0 DESIGN CRITERIA FOR THE RDSF SYSTEM

The purpose of this section is to establish the basic assumptions for the conceptual design of the RDSF handling system and for the assessment of the impact of co-firing RDSF on power plant operations.

1.1 General Description of RDSF and Its Processing

Technology for energy recovery from MSW covers a broad range of final fuel products. At one end of the spectrum is the burning of raw garbage on a series of traveling grates in a waterwall incinerator. This is the predominant technology employed in Europe. The other end of the spectrum is occupied by pyrolysis gases and even chemical conversion to ethanol or methanol. The technology under consideration in this study is referred to as supplemental-firing or co-firing of refuse-derived solid fuel (RDSF) with coal.

Table 1.1.1 presents an analysis of typical raw MSW.

Table 1.1.1 Typical Analysis of Raw Municipal Solid Waste (MSW)

	Percent by Weight
Paper, Cardboard	51
Plastics	4
Food Waste (Natural Organics)	5
Yard Waste (Wood)	6
Other Combustibles (Cloth, Tar, Etc.)	2.5
Ferrous Metals	3
Other Non-Ferrous Metals	0.2
Glass	8
Ceramics and Other Materials	20

RDSF technology involves sufficient processing to carry the raw garbage through the following operations:

A. Removal of oversized objects (refrigerators, engine blocks, etc.),

B. Breaking up of all containers (bags, boxes, bottles, etc.),

C. Extraction of the metals,

D. Extraction of as much non-metallic inert material as possible (especially glass), and

E. Shredding of the combustible material to a size that can be semi-suspension fired in a boiler.

The result is a fluffy (but not powdered or pulverized) material with relatively little odor. The conversion rate from raw garbage to RDSF is normally about 70 to 80 percent by weight.

Because of its nature, MSW and the RDSF derived from it through the processes described above have highly variable properties. Table 1.1-2 presents typical ranges for the properties of RDSF as experienced at several recent demonstration plants (Ref. 1 and 2).

Table 1.1-2 Range of Properties of RDSF from Actual Demonstration Plants

Higher Heating Valve	4500-6500 BTU/lb
Bulk Density (Uncompacted)	2.5 - 8 lb/ft^3
Maximum Particle Size	1 1/2" - 4"
Ultimate Analysis	
Carbon	24-40 Percent
Hydrogen	4-6 Percent
Oxygen	20-45 Percent
Nitrogen	0.2-0.8 Percent
Sulfur	0.1-0.4 Percent
Chlorine	0.2-0.6 Percent
Moisture	15-30 Percent
Ash	6-30 Percent

A commercial brand of RDSF known as ECO-FUEL II, which is much more homogeneous as well as lower in moisture and higher in carbon, is now on the market. This RDSF goes through further chemical and mechanical processing to produce a dustlike material which is somewhat easier to burn from the fluff material. However, because of the additional processing, the cost of ECO-FUEL II is very near that of oil (Ref. 3). ECO-FUEL II is mentioned here only to distinguish it from fluff RDSF which is described in the previous paragraphs and which is the only type of RDSF under consideration in this report.

1.2 Predicted RDSF Characteristics for JEA

One of the longest running, perhaps most successful, and certainly the most thoroughly documented, demonstrations of co-firing RDSF and coal has been conducted by the City of Ames, Iowa under several grants from the EPA. Through continual refinements in their processing facility Ames has succeeded in making the highest quality RDSF yet produced using purely mechanical processing techniques. (Ref. 1 and 4).

For design purposes in this report the composition of the Ames RDSF is used as the average composition of the RDSF which is expected from the processing facility at Jacksonville. Unfortunately, RDSF composition can vary somewhat from city to city and from season to season. Before any detailed design work is done it is recommended that some attempt be made to analyze the MSW at Jacksonville to determine if there are any unusual characteristics that might impact on the design of the system.

For purposes of the present study it is assumed that all processing of the RDSF will be accomplished at a facility separate from the power plant. This processing facility will not be owned or operated by JEA. For this reason it is very important that JEA set definite specifications for what is and what is not an acceptable RDSF product.

The three components of RDSF that can have the greatest influence on the design of a co-firing system are chlorides, ash, and moisture content. A maximum percentage has been assumed for each of these three components. For ash the maximum has been estimated at 15 percent based on experience at Ames (the limit set for ash is explained in subsequent paragraphs). The maximum for moisture is estimated to be 25 percent again based on Ames' experience. The maximum amount of chlorides is estimated to be 0.5 percent based on a survey of data from a number of incineration and co-firing systems.

Using these maximums and adjusting the percentages of the other elements (C, H, O, S, N) for the high moisture and ash content, the "worst case" composition, whch is shown in Table 1.2-1 was generated. Also shown in the Table is the average expected composition of the RDSF as well as the composition of the performance coal for the new JEA power plant. It can be seen that the "worst case" RDSF is lower in carbon and sulfur content but higher in oxygen, chlorine, ash and moisture content than the performance coal.

A power plant normally retains the option of refusing coal that does not meet contract specifications. Likewise, a power plant should have the option of rejecting RDSF that does not meet certain specifications. Probably the only component of the RDSF that the processing plant has any direct control over is the ash content. Moreover, as discussed in Section III paragraph 2.3.1, the amount of ash and its composition can have a major impact on boiler performance. Ash content should be controlled as much as is possible.

Through proper processing, it has been demonstrated that the ash content of RDSF can be maintained in the range of 10 percent (Ref. 4). Therefore, it is not unreasonable for JEA to reserve the right to reject RDSF if the ash content exceeds 15 percent. It is recommended that grab samples be taken and analyses run of the RDSF processed each day in accordance with ASTM Interim Procedure E38. If a significant number of samples reveal ash contents in excess of 15 percent, then that day's RDSF production should be set to landfill rather than to the power plant. The ash analysis is similar to the ASTM procedure for coal, and it is assumed that the same laboratory equipment would be used.

Table 1.2-1 Expected Compositions of RDSF Versus the JEA Coal

	RDSF		Coal	
	Worst Case	Average	Performance	Maximums
Higher Heating Value (Estimated) Btu/lb (As Fired)	5100	6100	12,400	-
Ultimate Analysis (%)				
Carbon	30.4	36.7	68.9	78.0
Hydrogen	4.5	5.4	4.4	5.8
Oxygen	24.2	29.2	7.8	9.8
Nitrogen	0.2	0.3	1.2	1.9
Sulfur	0.2	0.2	0.6	4.0
Chlorine	0.5	0.2	0.1	0.3
Ash	15.0	9.6	9.0	18.0
Moisture	25.0	18.4	8.0	15.0
	100.0	100.0	100.0	
Ash Fusion Temp. (Soft) ^{o}F	-	2150	2300	
Ash Fusion Temp. (Fluid) ^{o}F	-	2200	2350	

In addition to the limits on ash, specifications should also be set on the particle top-size of the RDSF. The processing facility should be designed to shred the RDSF to a nominal 1 1/2" x 0" (or minus 1 1/2") size. This leads to a size distribution similar to that shown in Table 1.2-2. To achieve this size distribution, which has been found to allow adequate burnout of combustibles in a semi-suspension firing system, the processing facility should include at least two stages of shredding or a flail mill and a shredder. If it becomes obvious that the top-size of the RDSF exceeds 1 1/2 inch, then the material must be rejected by the JEA and returned for reshredding. RDSF top-size is controlled by adjustment of the shredder grates.

Heat content of the RDSF stream should also be tested on a regular basis. While heat content will not be used as a basis for accepting or rejecting RDSF, it will provide data to use in periodically checking the fuel fee calculation to insure that a fair price is being paid for the RDSF.

Table 1.2-2 Typical Size Distribution for 1 1/2" x 0" RDSF (Ref. 1)

	Percent by Weight
Larger than 63mm (2 1/2")	3.4
38.1 mm (1 1/2") to 63 mm (2 1/2")	9.2
19 mm (3/4") to 38.1 mm (1 1/2")	43.3
9.5 mm (3/8") to 19 mm (3/4")	14.2
4.8 mm (3/16") to 9.5 mm (3/8")	11.5
2.4 mm (3/32") to 4.8 mm (3/16")	7.2
Smaller than 2.4 mm (3/32")	11.2
Total	100.0

1.3 RDSF System Design Criteria

The amount of raw refuse that will be available for conversion to RDSF for co-firing of the new power plant is 1950 tpd. This raw garbage will in turn yield an amount of RDSF equal to roughly 1460 tpd. Using the average RDSF heating value of 6100 Btu/lbm, the average amount of energy available from the RDSF is determined below:

$$\text{Energy From RDSF/Day} = \underline{1460 \text{ tons/day} \times 2000 \text{ \#/ton} \times 6100 \text{ Btu/\#}}$$

$$= 17{,}812 \times 10^{6} \text{ Btu/Day}$$

Due to the variability of the heating value of RDSF and the instability of a coal flame at reduced loads, it is recommended by the boiler manufacturers that RDSF not be fired unless boiler load exceeds 70 percent of design load.

Based on historical availability and load data the load profile shown in Table 1.3-1 has been established for each JEA boiler:

Table 1.3-1 JEA Load Regimen

Hours Per Year	Load Percent of Maximum Continuous Rating (MCR)
500	100 Percent
3700	92 Percent
1300	75 Percent
950	50 Percent

Assuming that RDSF is not fired unless boiler load is 75 percent of design load or greater, then RDSF can only be burned for 5500 hours per year, roughly 63 percent of the time, or about 15 hours per day. This leads to an average energy contribution by RDSF of:

$$\text{Energy From RDSF/Hour} = 17{,}812 \times 10^6/15 = 1{,}187 \times 10^6 \text{Btu/Hr}$$

The design energy input to each boiler is approximately $6{,}096 \times 10^6$ Btu /hr. Therefore, the RDSF would initially provide the following minimum fraction of energy input to the two boilers:

$$1{,}187 \times 10^6 \;/\; 2 \times 6{,}096 \times 10^6 = \sim 10 \text{ Percent}$$

The boiler manufacturers have recommended that the maximum heat input from RDSF be kept below 30 percent of the total heat input of the boiler. Since the majority of the demonstration plants that have co-fired RDSF have held the RDSF firing rate to below 20 percent, this value has also been conservatively selected as the maximum percentage of RDSF for the present system. At 20 percent of the heat input to one boiler, the required rate of RDSF firing is calculated as follows;

$$\begin{aligned}\text{Maximum RDSF Firing Rate} &= 0.20 \times (6{,}096 \times 10^6 \text{ Btu/Hr}) \\ &= 1{,}219 \times 10^6 \text{ Btu/Hr}\end{aligned}$$

or in tons per hour,

$$\begin{aligned}\text{Maximum RDSF Firing Rate} &= \frac{1{,}219 \times 10^6 \text{ Btu/Hr}}{6100 \text{ Btu/lb} \times 2000 \text{ lb/tons}} \\ &= 99.9 \text{ tph}\end{aligned}$$

There will be occasions when only one boiler is operating, and it will be necessary to fire the boiler at its maximum RDSF rate of 20 percent total heat input in order to keep up with RDSF production. This leads to the conclusion that all the equipment feeding RDSF to the boiler and all predictions concerning the impact of co-firing RDSF on the boiler, its auxiliaries, and its AQCS system must be based on providing 20 percent of the boiler heat input with RDSF. This, in turn, leads to a design firing rate of approximately 100 tph of RDSF at the design load of each boiler. Table 1.3-2 summarizes the basic RDSF system design parameters.

Table 1.3-2 Summary of RDSF System Design Data

RDSF Heating Valve	6,100 Btu/lbm
Coal Heating Valve	12,400 Btu/lbm
MSW collection rate for Jacksonville,	1,950 tpd
Processed RDSF Production Rate	1,460 tpd
Minimum Percent Heat Input from RDSF	10 Percent of 2 Boilers
Design Percent Heat Input from RDSF	20 Percent of 2 Boilers
Calculated Maximum RDSF Firing Rate (per boiler)	99.9 tph
Nominal Design RDSF Firing Rate (per boiler)	100 tph

2.0 IMPACT OF CO-FIRING RDSF ON POWER PLANT OPERATION

When RDSF is co-fired with coal in a power plant, there are several areas of the boiler and air quality control system (AQCS) operation that may be affected. The purpose of this section is to explore these areas and assess the magnitude of these impacts. The discussion will cover each of the following major subjects:

a - Boiler Physical Modifications

b - Boiler Thermal Efficiency

c - Boiler Operations and Auxiliary Equipment

d - Air and Water Quality Control Systems (AQCS)

e - Corrosion of Boiler and AQCS

2.1 Boiler Physical Modifications

In the last few years a large amount of experience has been gained with co-firing RDSF in pulverized-coal boilers. The sizes of these boilers range from 35 MW to 358 MW with steam conditions up to 2400 psia and 1050°F.

RDSF is typically pneumatically conveyed or hauled in transfer trailers to the power plant. There it is unloaded into a storage or surge bin. From the surge bin it can either be fed through a rotary lock feeder and pneumatically conveyed into the boiler or fed to a live-bottom hopper with metering screw conveyors that control the feed rate to the boiler.

In early demonstration tests, the RDSF nozzles were either located between or above the coal nozzles. It was thought that this location would reduce dropout and improve combustion of the RDSF by introducing it directly into the fireball. This location for the RDSF nozzles was also initially chosen for the Ames installation. However, subsequent testing at Ames revealed that injection of the RDSF below the coal nozzles reduced particulate emissions and did not increase dropout of material to the bottom ash hopper (Ref. 1). This effect will be discussed further in connection with performance of the AQCS equipment.

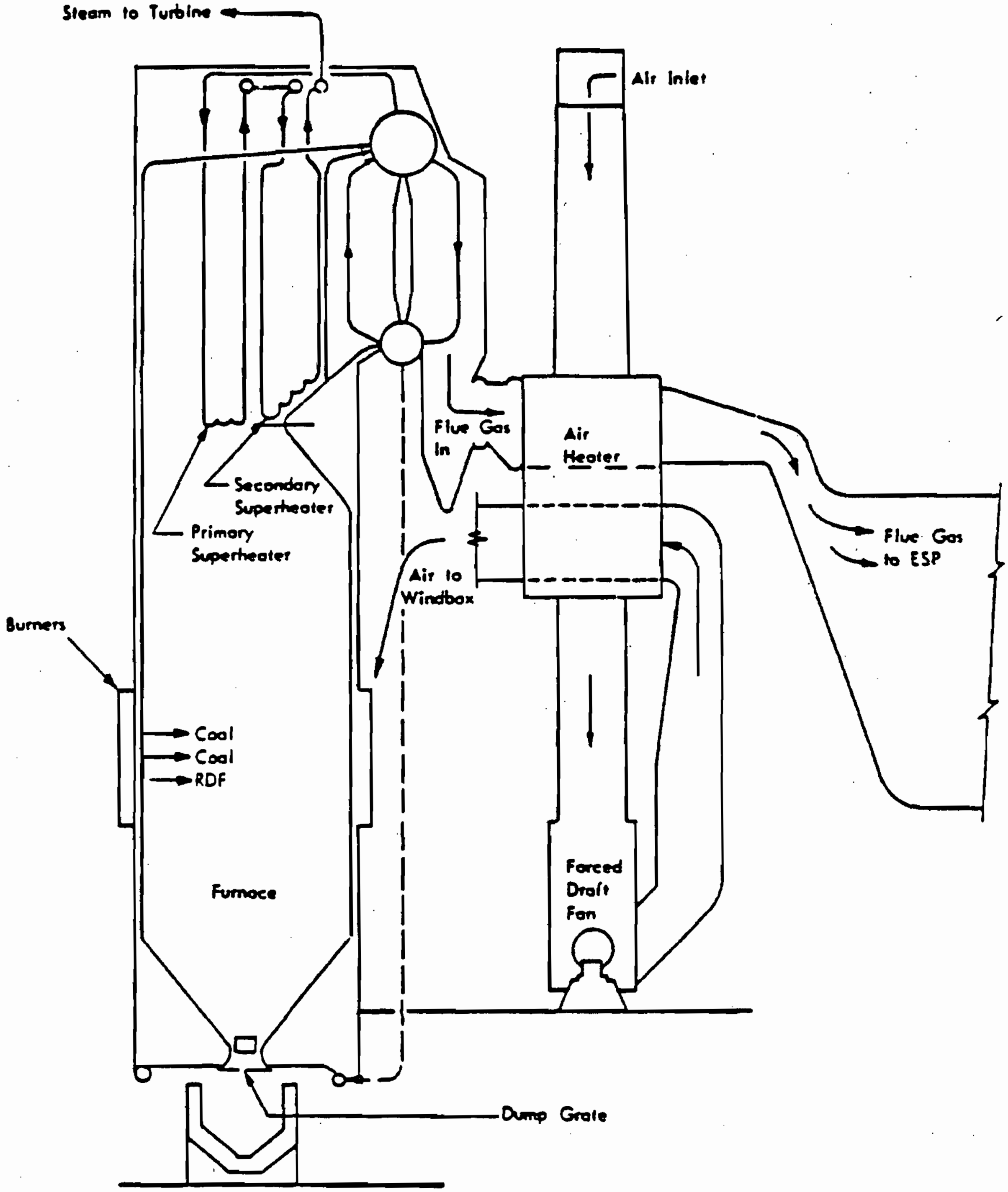
Early attempts to burn RDSF in a pulverized coal boiler also met with major problems from dropout of unburned material into the bottom ash hopper. Because of the large particle size of RDSF compared to pulverized coal, it is just not possible to burn RDSF in a full suspension firing mode. This experience has led to the installation of dump-grates similar to those used in bark boilers at the throat of the bottom ash pit. The elevation view in Figure 2.1-1 shows a typical pulverized coal boiler modified to burn RDSF. Note the location of the RDSF nozzles and the dump grate.

The dump grate is supplied with unheated combustion air from an auxiliary air fan. The air is introduced both above and below the dump grate as shown in Figure 2.1-2. The dump grate is typically made in four sections (2 pairs). Each pair of sections can be manually dumped by the operator (See Figures 2.1-3 and 4). Typical dumping frequency is about every 1-1/2 hours. The RDSF flow is interrupted briefly each time before the dump grates are opened.

The controls for firing RDSF are relatively simple. Typically, the feedrate of RDSF to the boiler is set by the operator and is held constant. Boiler load must be in the range of 70 percent of design load in order to introduce RDSF. If boiler load drops below this threshold, the RDSF feed is tripped off in order to insure that flame stability at low load is not impaired by the variable quality of the RDSF.

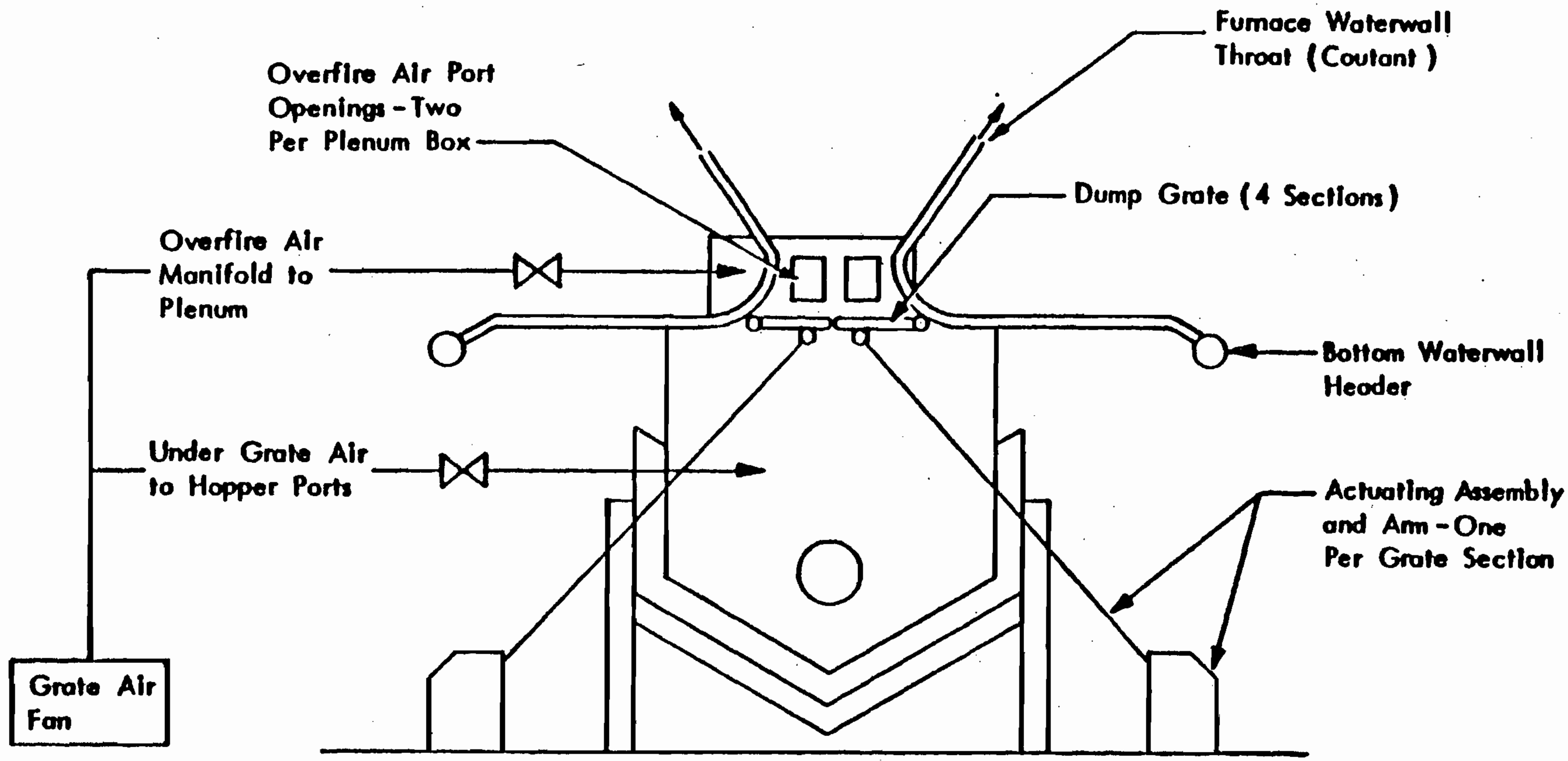
2.2 Boiler Thermal Efficiency

There is no question that boiler thermal efficiency is reduced when RDSF is co-fired. The magnitude of the efficiency reduction depends primarily on the amount of moisture contained in the RDSF and on what fraction of the total heat input is supplied by RDSF. In general, it can be stated that as the moisture content of the RDSF increases, boiler efficiency will decrease. Likewise, as the percentage of RDSF input to the boiler increases, efficiency will decrease. These effects are expected and can be predicted by a heat-loss balance on the boiler.



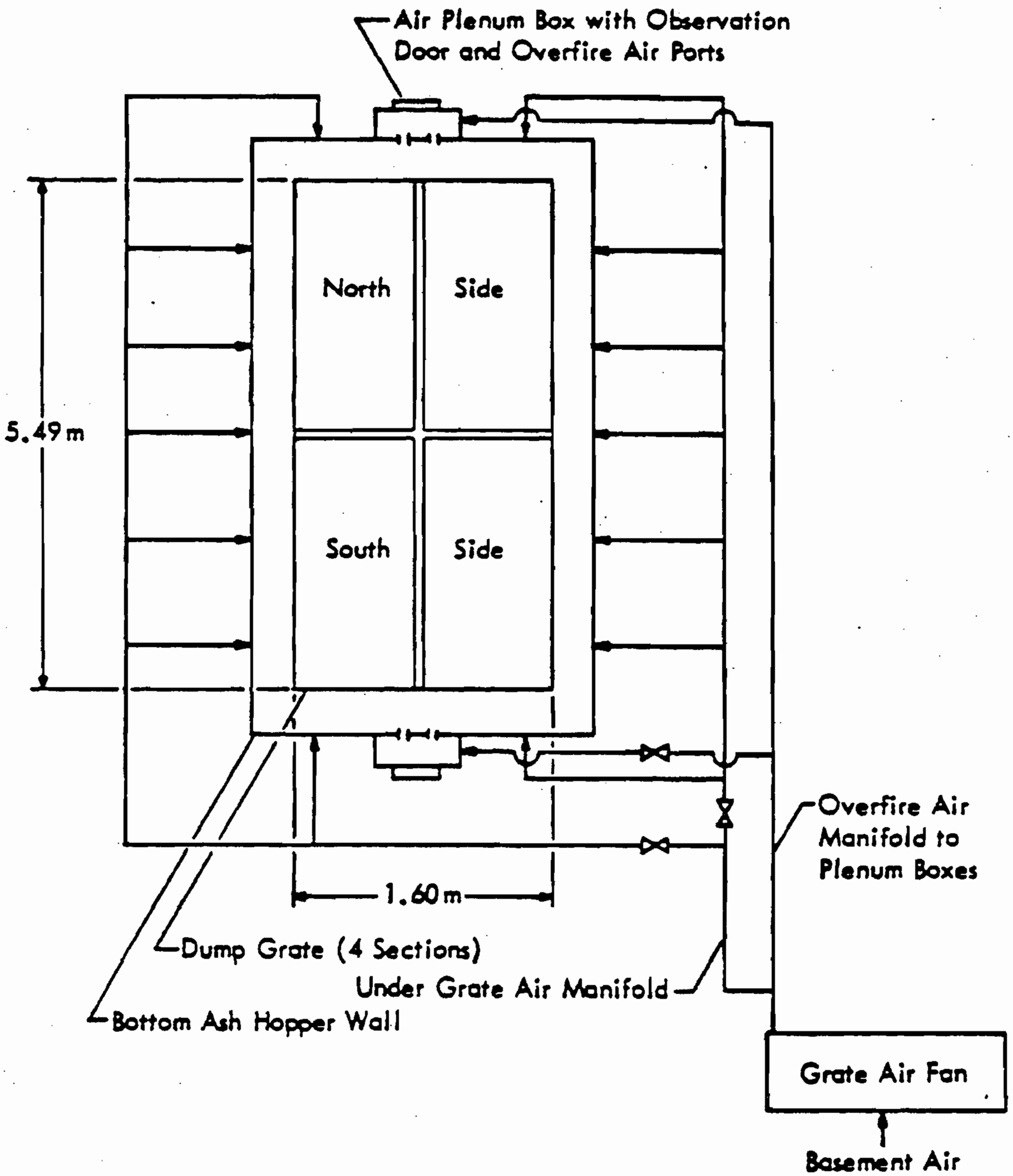
ELEVATION VIEW OF TYPICAL RDSF CO-FIRED PULVERIZED COAL BOILER

FIGURE 2.1-1



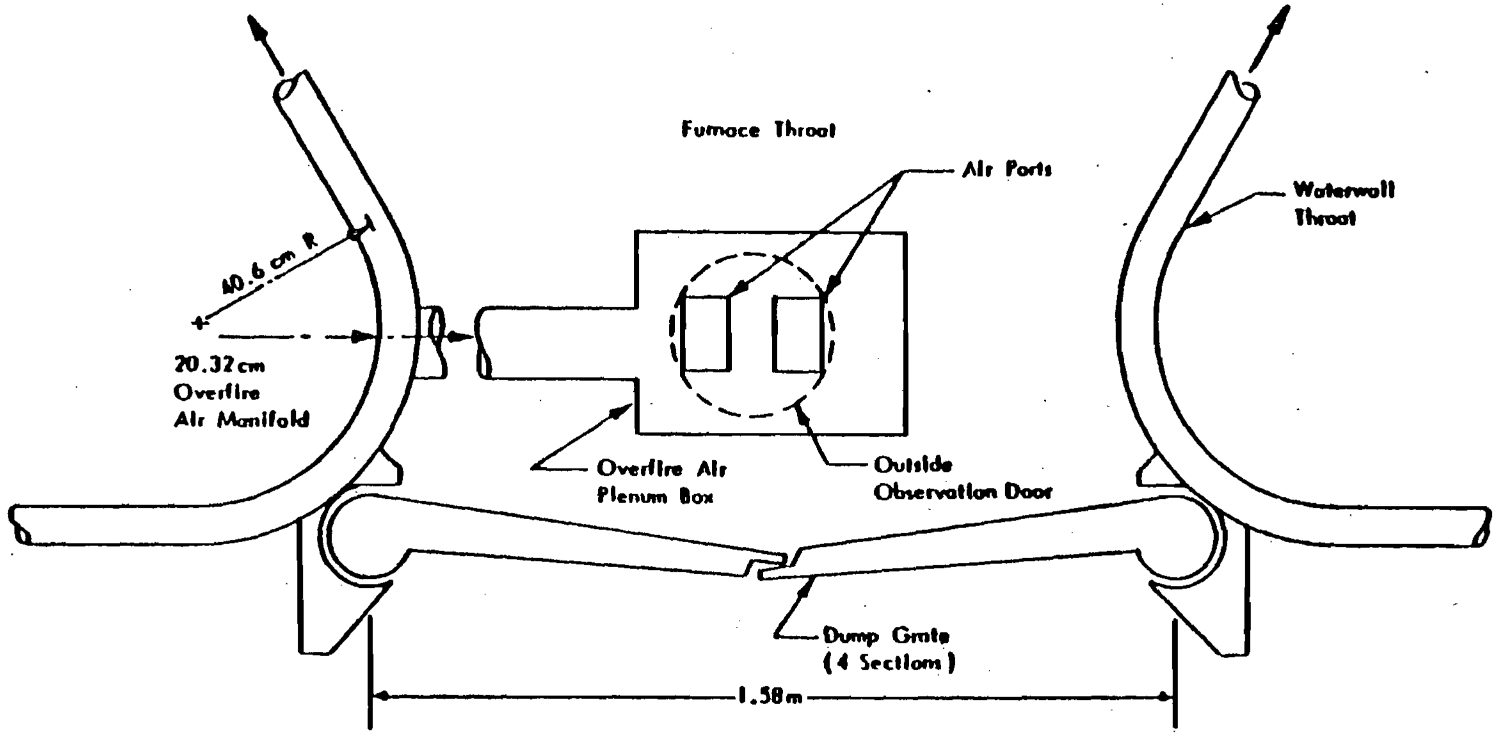
ELEVATION VIEW OF TYPICAL DUMP GRATE INSTALLATION

FIGURE 2.1-2



PLAN VIEW OF TYPICAL DUMP GRATE INSTALLATION

FIGURE 2.1-3



CROSS SECTIONAL VIEW OF TYPICAL DUMP GRATE AND OVERFIRE AIR PORT

FIGURE 2.1-4

Heat-loss due to the sensible heat contained in the flue gases exiting the regenerative air heater is always one of the most singificant losses from a boiler. The greater the percentage of moisture in the flue gas becomes, the larger will be the boiler heat loss due to moisture, assuming that stack temperature does not vary significantly.

Table 2.2-1 presents an estimate of flue gas composition based on two different fuel compositions. The first fuel is 100 percent performance coal and the second fuel is a mixture of 62 percent performance coal and 38 percent "worst case" RDSF. The 62%/38% mixture is in the proportions required to obtain 20 percent of the total heat input from the RDSF. The data in Table 2.2-1 is for complete combustion with 20 percent excess air. It can be seen that the percent by volume of H_2O in the flue gas increases from 8.9 percent to 11.1 percent. This means that the heat loss due to all sources of moisture could increase approximately 25 percent over its value with coal only.

Table 2.2-1 Estimated Flue Gas Compositions for Coal Vs. Coal/RDSF Mixture

	Flue Gas Composition (% by Vol.)	
	Performance Coal	62% Coal/ 38% RDSF
CO_2	14.2	13.9
H_2O	8.9	11.1
SO_2	.05	.04
N_2	73.6	71.8
O_2	3.3	3.2

NOTE: Assumes complete combustion and 20 percent excess air.

Another area where some efficiency is lost when co-firing RDSF is the regenerative air heater. Total flue gas volumetric flow is increased when RDSF is introduced. This occurs for two reasons. First, even though less air is required to burn a pound of RDSF than a pound of coal, the total flow of fuel (by weight) increases when RDSF is introduced. This in itself increases flue gas flow. Secondly, the greater percentage of moisture in the flue gas reduces the density of the flue gases (water vapor is less dense than nitrogen, carbon dioxide, or oxygen). This increase in volumetric flow reduces the effectiveness of the air heater. Moreover, with an increased percentage of moisture, the flue gas has a slightly higher specific heat capacity (i.e., less temperature drop is required to give up the same amount of heat). The net result of all this on the air heater is a rise in flue gas outlet temperature (as much as 12-15°F) with a corresponding loss in boiler efficiency. If an attempt were made to oversize the preheater to lower the flue gas temperature when RDSF is burned then flue gas tempertures may dip below the sulfuric acid dew point when 100 percent coal is burned. For this reason, consideration should be given to the incorporation of an air heater or economizer bypass control to hold air heater flue gas outlet temperature within acceptable limits.

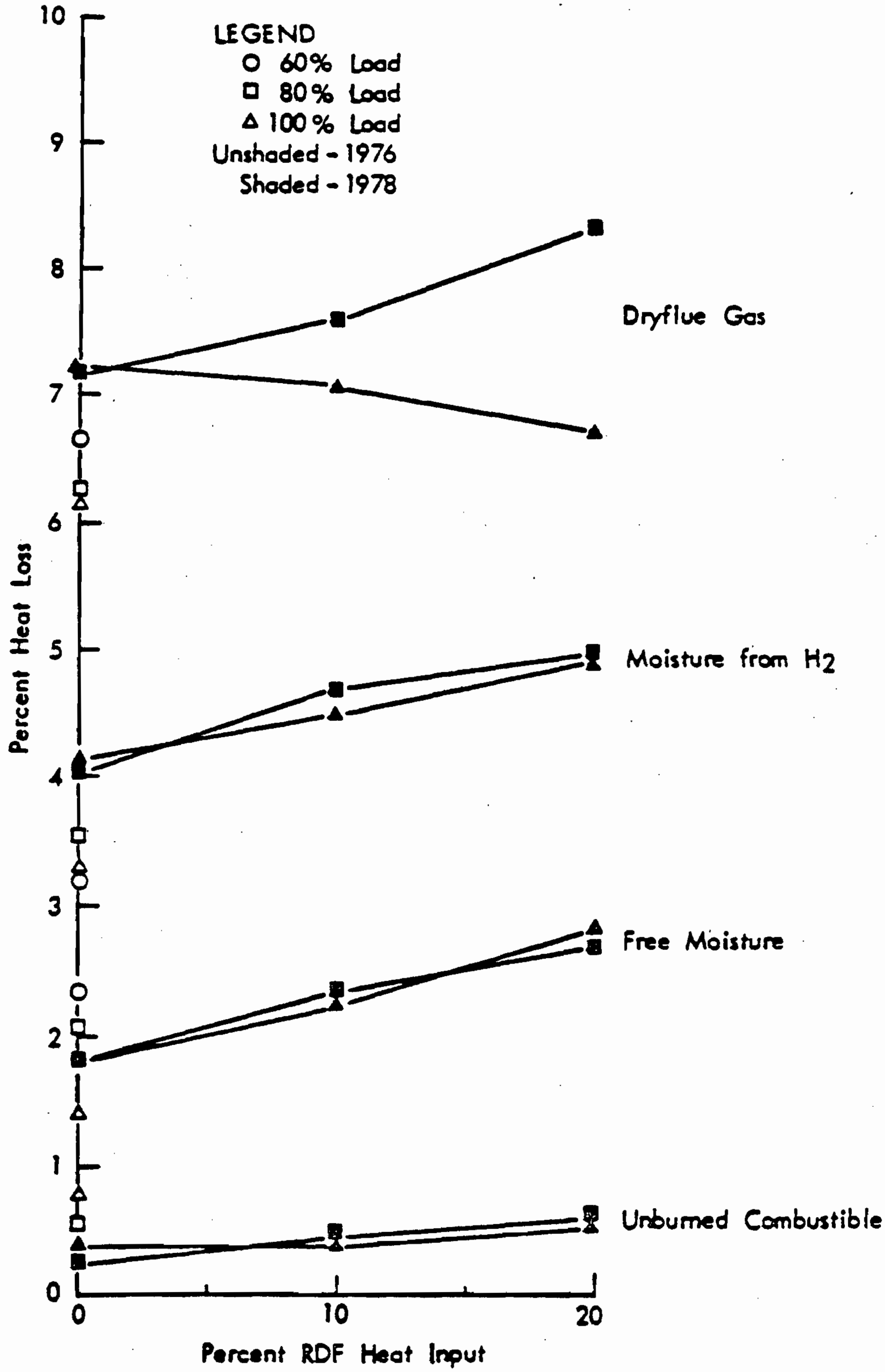
The last area where efficiency losses can occur is in combustible losses in the fly ash and bottom ash. Experience has shown that the percentage of combustibles in the ash can be maintained at about the same level with coal/ RDSF mixtures as with coal only. However, the total amount of ash almost always goes up when coal/RDSF mixtures are burned. This tends to increase the loss of unburned material in the fly ash by a small amount.

It is commonly believed that a greater amount of excess air is required to burn a coal/RDSF mixture. The most recent demonstrations show that this is not the case. With proper location of the RDSF nozzles and with a dump grate installed in the boiler, combustion of coal/RDSF mixture can be completed with 20 percent excess air, which is the normal design excess air for a pulverized coal boiler. Therefore, efficiency losses due to increased excess air are avoidable.

Figure 2.2-1 is an example from the Ames project of the increases in each component of efficiency loss as the percentage of RDSF increases. The drop in dry flue gas loss for the 100 percent load case is a result of a drop in excess air. This drop in excess air occurred because the tendency toward increased flue gas flow when RDSF was introduced could not be handled by the induced draft fan. As a result forced draft air could not be increased to maintain the excess level. By totaling the efficiency losses for the 80 percent load case (See Table 2.2-2) it is evident that total efficiency loss is about 3 percent greater for 20 percent RDSF/80 percent coal versus 100 percent coal.

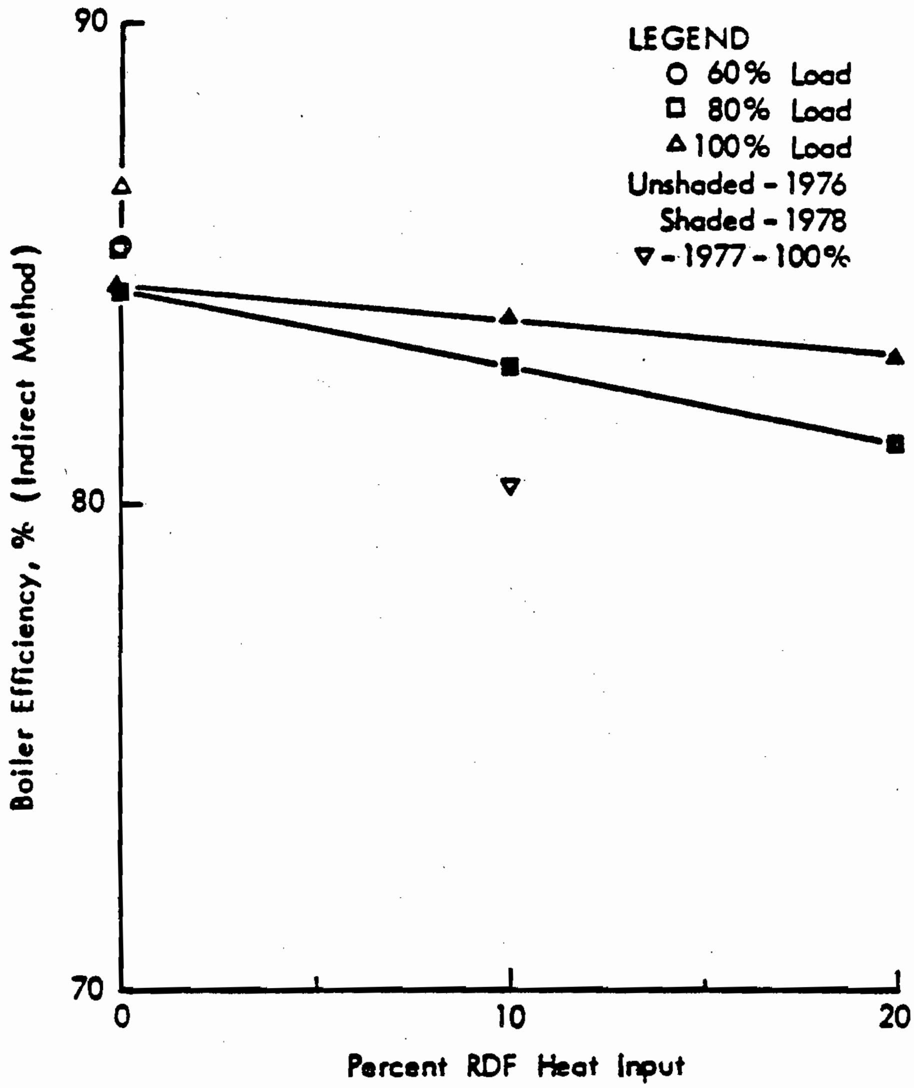
Table 2.2-2 Efficiency Losses Due to RDSF Co-Firing (Ref. 1)

Efficiency Loss Component	100% Coal	20% RDSF/100% Coal	Increase
Dry Flue Gas	7.2	8.3	1.1
Moisture from Combustion of H_2	4.0	4.9	0.9
Free Moisture from Fuel	1.8	2.6	0.8
Unburned Combustibles in Ash	0.3	0.6	0.3
Total Efficiency Loss	13.3%	16.4%	3.1%



BOILER EFFICIENCY LOSSES VS. PERCENT RDSF INPUT (REF. 1)

FIGURE 2.2-1



NET BOILER EFFICIENCY VS. PERCENT RDSF INPUT (REF. 1)

FIGURE 2.2-2

Thus, overall boiler thermal efficiency may be expected to be about 3 percent less when RDSF is co-fired at 20 percent of the total heat input. This drop in efficiency is apparent in Figure 2.2-2 which depicts boiler efficiency as a function of percent RDSF heat input for the Ames project. Again, the fact that the efficiency is better at 100 percent load is because excess air actually decreased as RDSF was increased due to lack of induced draft fan capacity.

2.3 Boiler Operations and Auxiliary Equipment

2.3.1 Bottom Ash System

One of the components of boiler auxiliary equipment that is likely to be affected by co-firing RDSF is the bottom ash handling system. If the performance coal is fired in the boiler at 100 percent load, approximately 24 tph of bottom and fly ash will be generated. However, when a 20 percent RDSF/80 percent coal mixture is fired at 100 percent of design boiler load and the RDSF approaches the "worst case" composition, approximately 39 tph of bottom ash and fly ash will be formed. Thus, there may be as much as a 63 percent increase in total ash.

Moreover, there is a tendency when co-firing RDSF for a greater percentage of the total ash to be converted to bottom ash. For instance, during coal firing at Ames, the bottom ash was typically about 10 percent of the total ash. However, when 20 percent RDSF/80 percent coal was burned, the bottom ash increased to 38 percent of the total ash. The actual quantity of bottom ash increased about six times with 20 percent RDSF/80 percent coal vs. 100 percent coal at 100 percent of boiler design load. This effect is borne out by tests at another demonstration plant, which showed no significant increases in dust loading to the precipitator with a 20 percent RDSF mixture even though the coal averaged about 7 percent ash and the RDSF averaged 22 percent ash. (Ref. 2). This means that most of the additional ash input from the RDSF was actually converted to bottom ash. The net result as far as the bottom ash system is concerned is that bottom ash may have to be pulled out of the hopper as much as 3 to 4 times more frequently than normal. This, in turn, may increase maintenance costs and hasten wear out of this equipment.

2.3.2 Wall Slagging

There has been a definite tendency toward increased slagging when RDSF has been co-fired with coal in older (i.e. pre-1970), higher heat release boilers which have been retrofitted with RDSF co-firing capability. This is normally attributed to the glass in the RDSF. Careful processing can substantially reduce the amount of glass in the RDSF. However, 1 to 2 percent glass can still be expected. A major component of glass is sand (SiO_2). Tests run at Ames comparing the composition of coal ash and

RDSF ash indicates that SiO_2 in the coal ash averages 36.43 percent and in the RDSF ash it averages 51.95 percent. On the other hand Fe_2O_3 averages 22.83 percent in the coal ash and 5.13 percent in the RDSF ash.

These trends are evident in Table 2.3.2-1 which is an analysis of the bottom ash and fly ash for 100 percent coal and for 20 percent RDSF/80 percent coal. Note that by far the biggest changes in ash composition occur in the bottom ash as opposed to the fly ash, and the components most affected by the RDSF are SiO_2 (increases), Fe_2O_3 (decreases), and MgO (decreases). Also note that SO_3 decreases substantially when RDSF is burned. Possible explanations for this will be covered under the discussion on AQCS performance.

Other possible contributors to the formation of slag are metal salts that are formed from metals introduced with the RDSF. Analyses of MSW indicate that it contains significantly higher amounts of metals such as sodium, lead, and zinc than coal. These metals form chloride and sulfate salts, which tend to be stable compounds, that will either melt at furnace temperatures or form very fine particulate matter. The effects of salts will be discussed further in the section of this report covering corrosion and the section on SO_2 control.

With such a dramatic change in composition, the bottom ash is almost certain to have vastly different properties when RDSF is fired. Table 2.3.2-2 is a comparision of ash fusion temperatures for coal and RDSF. Note that the ash fusion temperatures for RDSF are generally 200 + degrees lower than for coal in an oxidizing atmosphere. The lower ash fusion temperatures can contribute to softer, more molten material on the furnace walls. Slagging has generally been observed in the upper part of co-fired furnaces particularly in the area just above the upper burner level. In several cases soot blowers were not effective in shedding the slag. The only means to shed the slag was to rapidly drop load and use thermal shock to free the slag from the walls.

Table 2.3.2-2 Ash Fusion Temperatures for JEA Performance Coal and RDSF (RDSF Data From Ref. 1)

Reducing Atmosphere	Coal	RDSF
Initial Deformation	1950	2100
Softening	2050	2130
Hemispherical	2050	2150
Fluid	2150	2190
Oxidizing Atmosphere		
Initial Deformation	2300	2120
Softening	2400	2150
Hemispherical	2400	2190
Fluid	2500	2220

All temperatures in ^{o}F.

TABLE 2.3.2-1

TYPICAL COMPOSITIONS OF BOTTOM ASH AND FLY ASH (REF. 1)

	Bottom Ash			Fly Ash		
	100 % Coal	20% RDSF 80% Coal	Difference	100% Coal	20% RDSF 80% Coal	Difference
SO_3	15%	1.3	-14.5	3.23	2.43	-0.8
Al_2O_3	6.46	10.9	+4.44	17.0	19.3	+2.3
SiO_2	13.8	55.3	+41.5	41.5	44.1	+2.6
TiO_2	.08	1.06	+ .98	1.24	1.32	+ .08
K_2O	.41	.82	+ .41	1.63	1.65	+ .02
CaO	19.2	11.03	- 8.17	6.99	6.65	-0.34
Fe_2O_3	28.2	11.27	-16.93	24.8	19.5	-5.3
Na_2O_3	1.01	4.46	+ 3.45	1.56	1.67	-0.11
MgO	13.6	2.26	-11.34	0.80	1.10	+ .30
P_2O_5	.34	.52	+ .18	0.73	0.88	+ .15

This problem must be discussed with the boiler manufacturers and an appropriate mitigating measure developed. A possible fix would be the incorporation of additional soot blowers or water lances in the areas of the boiler where this may be a problem. If temperature cycling is found to be the only practical means of shedding slag, then backup power costs during deslagging could be substantial. However, in the opinion of at least one boiler manufacturer, the limitations placed on heat release in modern, coal fired boilers should minimize, if not entirely eliminate, the slagging problem if the boiler is designed with RDSF co-firing in mind. (Ref. 11).

As discussed in Section III.1.2, above, the best way to mitigate the ash problem is to control the ash in the RDSF by proper design and operation of the processing plant, enforced by a sampling program, and by rejection of unsatisfactory RDSF.

2.3.3 Fan Power Requirements

As mentioned in the discussion on boiler efficiency, there is a definite increase in the volume flow of flue gases when RDSF is co-fired with coal. Calculations show that the actual volumetric flow rate of flue gas will increase approximately 5.7 percent when 20 percent RDSF/80 percent coal is fired versus 100 percent coal at the same boiler load. This increase in volume flow rate with its corresponding increase in velocity will result in approximately an 11.7 percent increase in flue gas pressure drop. Moreover, there will be about a 4.9 percent increase in flue gas mass flow. Since induced draft fan horsepower is proportional to mass flow rate and system pressure drop, the total induced draft fan power requirements will increase roughly 17.2 percent. This could lead to as much as a 2280 hp increase in induced draft fan power requirements per boiler.

The increase in induced draft fan horsepower will also be accompanied by an increase in forced draft fan power requirements. Forced draft fan air flow will be increased by about 5.4 percent and total forced draft fan horsepower will be increased by about 17.1 percent for a 20 percent RDSF/80 percent coal mixture versus 100 percent coal. This will raise forced draft fan power requirements by about 370 hp per boiler at design load.

Even though the amount of oxygen is higher in the refuse then in the coal, which tends to reduce combustion air requirements, the total mass flow of fuel (coal and RDSF combined) increases substantially (about 34 percent). The net result is an increase in the forced draft air requirements.

Therefore, between both the induced draft and forced draft fans there is a net increase of 2650 horsepower per boiler when RDSF is fired at 20 percent of the heat input at full boiler load. With regard to induced draft fan capacity, the fan will be sized for 117 percent of boiler design flue gas flow (on coal) and 137 percent of system design flue gas pressure drop . Thus, the capacity of the fan should be adequate for any foreseeable combination of RDSF/coal co-firing.

2.3.4 Superheat Temperature

Experience has shown that there is a tendency for the steam superheat temperature to increase when RDSF is co-fired. This is believed to be a result of the lower radiant characteristics of an RDSF flame versus a coal flame. The reduction in heat transfer by radiation causes the flue gases to be hotter as they approach the upper part of the furnace and the superheater tubes. This is the same effect that has been known for sometime for gas and wood as compared to oil and coal as the trends in Figure 2.3.4-1 indicate. The net result is that tempering water flow may have to be increased between primary and secondary superheater banks to prevent overheating of the secondary superheater tubes. The same effect is likely to be observed on reheater tubes.

2.4 Air And Water Quality Control Systems

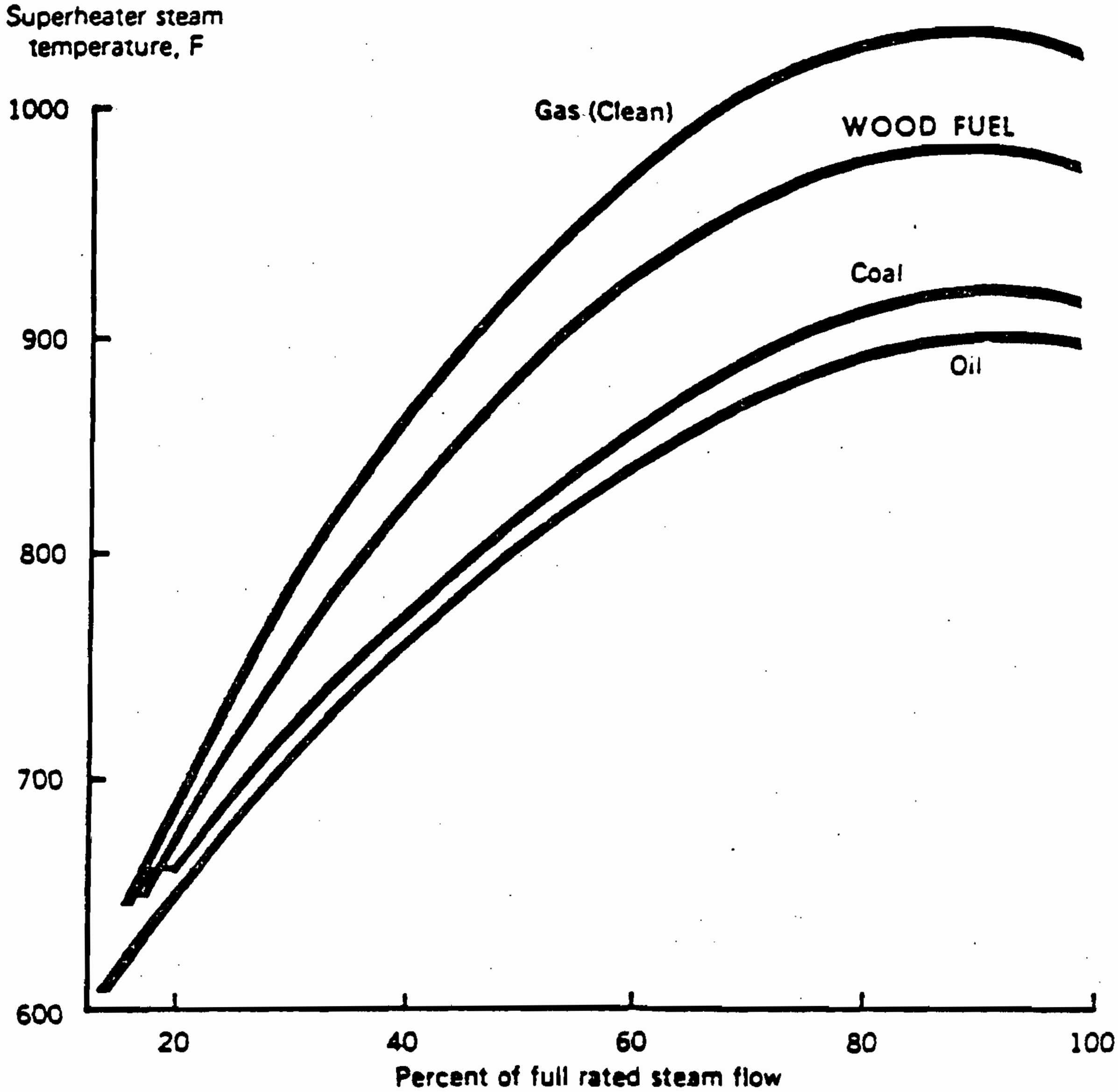
2.4.1 Air Quality Control System

2.4.1.1 Particulate Control

There is substantial evidence that precipitator efficiency is impaired when RDSF is co-fired with coal. Tests conducted at the Ames facility during 1978, show approximately a 1-2 percent drop in precipitator efficiency as the RDSF is increased to 20 percent of the total heat input (See Figure 2.4.1.1-1). Similar results were obtained at another demonstration plant at St. Louis (Ref. 2).

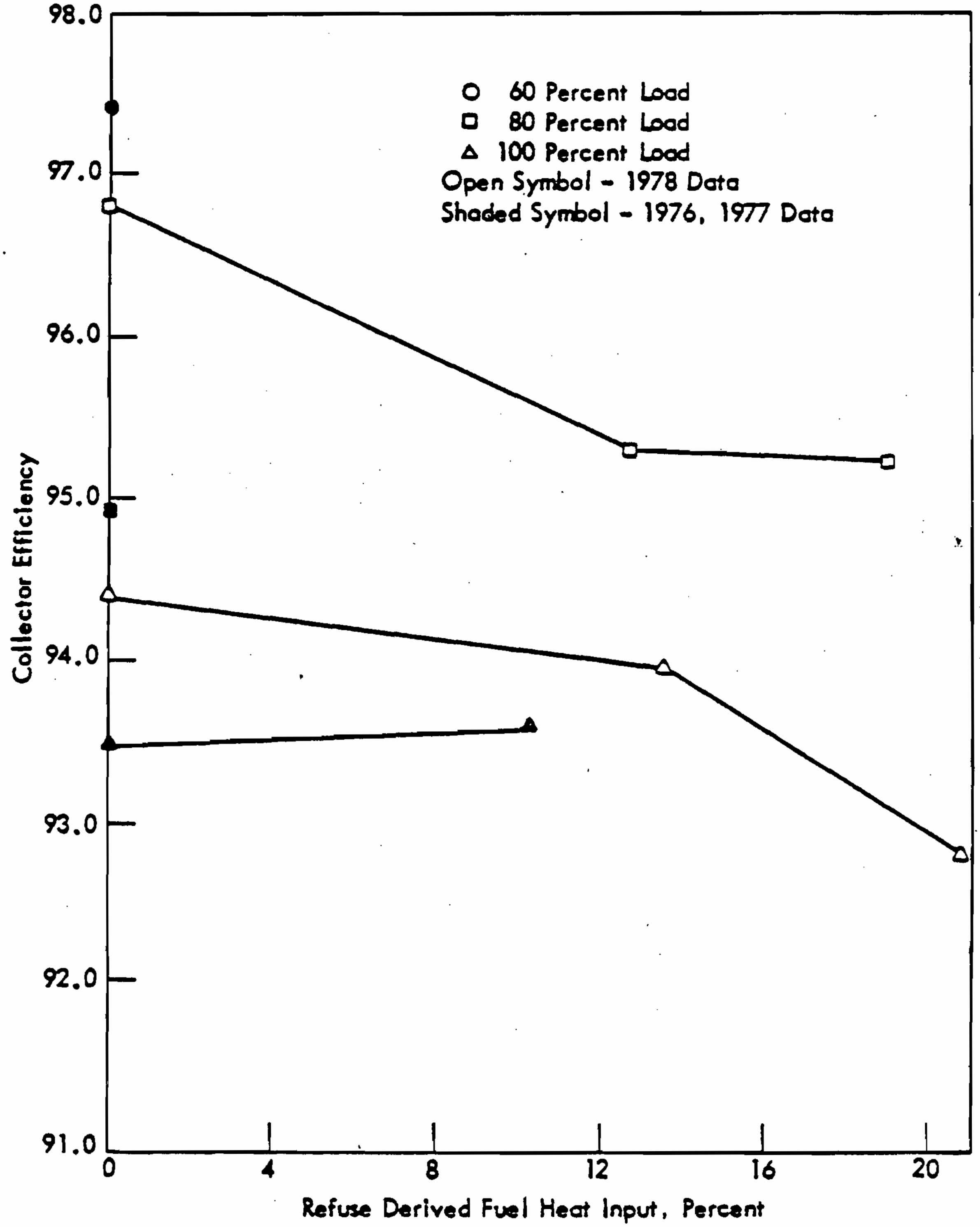
There are basically three reasons why the efficiency of the precipitator decreases. First, the flue gas flowrate increases with RDSF, which in turn increases the velocities in the precipitator. Residence time in the precipitator is critical to collection of the fly ash. Secondly, the resistivity of the fly ash increases when RDSF is introduced. This increase in resistivity is shown dramatically in Figure 2.4.1.1-2, which shows an increase from about 3×10^{11} ohm-cm at 100 percent load and 100 percent coal to about 5.5×10^{11} ohm-cm at 100 percent load and 20 percent RDSF. Finally, there is greater difficulty in collecting the carbon particles from the combustion of paper, cloth, etc.

Indications are that the increased resistivity may be a greater problem than the increase in flue gas velocities. As resistivity increases there is a greater tendency for the precipitator to spark. In fact, sparking rates at the St. Louis facility actually increased by a factor as high as 20 when RDSF was introduced. Since a high sparking rate can damage the precipitator by burning out wires, the rectifier control sets are designed to reduce the power input to the fields as the sparking rate increases. At St. Louis power levels were reduced from 4-18 percent when RDSF was fired. Naturally, as input power is reduced, collection efficiency decreases.



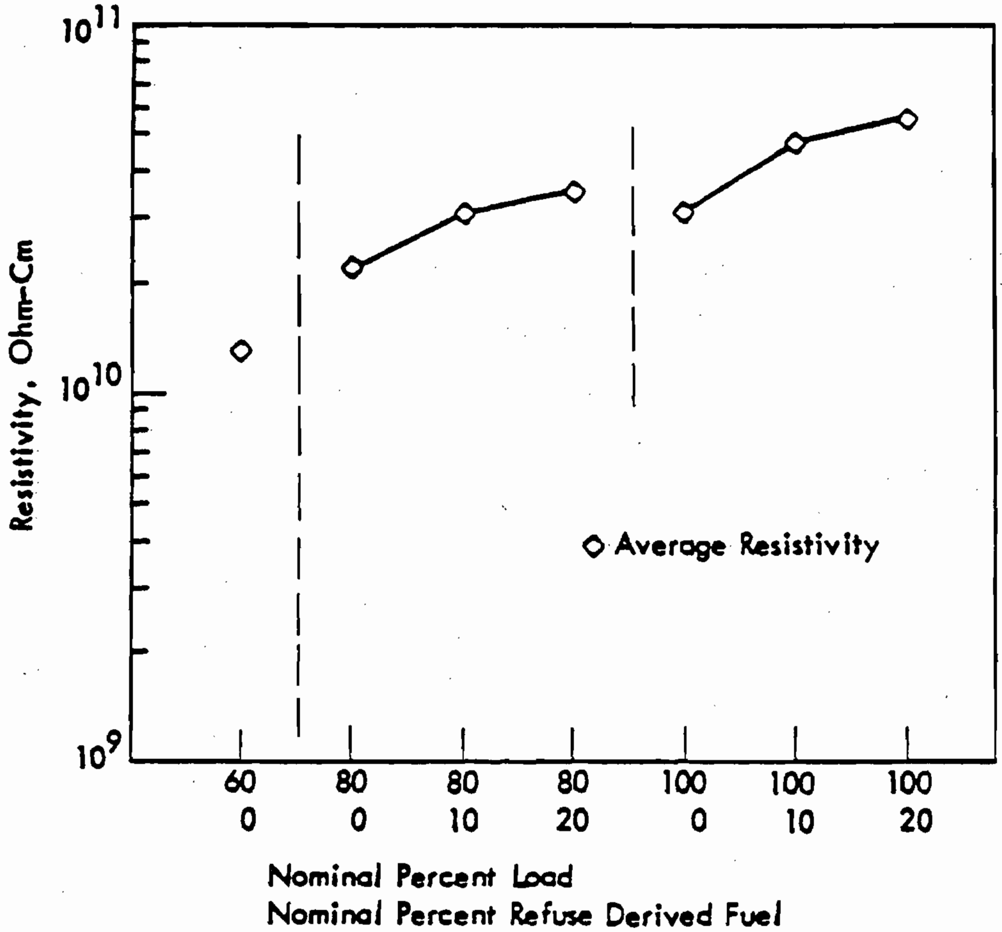
EFFECT OF FUEL ON UNCONTROLLED SUPERHEATER STEAM TEMPERATURE

FIGURE 2.3.4-1



PRECIPITATOR EFFICIENCY VS. PERCENT RDSF INPUT (REF. 1)

FIGURE 2.4.1.1-1



FLY ASH RESISTIVITY VS. PERCENT RDSF INPUT (REF. 1)

FIGURE 2.4.1.1-2

The resistivity of the ash increases when RDSF is introduced probably as a result of the lower sulfur content of the RDSF (compared to coal), which in turn reduces the sulfur content of the flue gas. Tests at Ames showed that the SO_2 and SO_3 in the flue gas is cut almost in half when RDSF approaches 20 percent of the heat input (See discussion on SO_2 emissions in Section 2.4.1.3).

Contrary to expectations, tests showed that there was no significant increase in inlet dust loading to the precipitator when RDSF is fired (this result was with the RDSF nozzles located above or between the coal nozzles). This is consistent with the finding that the additional ash input into the boiler as RDSF is increased tends to increase the bottom ash rather than the fly ash.

In addition to the decrease in precipitator efficiency at Ames when RDSF was fired, it was noted that the particulate matter often contained pieces of a black sooty substance believed to be unburned carbon, which could not be collected by the precipitator. Complaints were even received from persons living near the plant. As a result, the decision was made to relocate the RDSF nozzles to a position below the coal nozzles. This apparently improved the soot problem, actually lowered the inlet dust loading to the precipitator, and reduced the total particulate emissions. However, the precipitator efficiency still went down when RDSF was fired because of the other effects described above.

At JEA, the EPA mandated particulate emission limit is 0.03 lbm/10^6Btu, which in turn requires a precipitator collection efficiency of 99.78 percent. It is uncertain whether this emission limit can be met if RDSF is burned at up to 20 percent of the total heat input, unless the precipitators are substantially increased in size. The precipitators for the Ames and St. Louis projects were designed for 98 percent and 97.5 percent respectively, which, in precipitator design terms, is an order of magnitude less critical than the present JEA design.

It is known that co-firing of refuse tends to result in an increase in carbon material (primarily soot) being discharged from the boiler (see discussion above). This material accepts an electric charge easily, but it also gives up its charge very easily with the result that re-entrainment into the gas stream can readily occur.

To allow for this contingency a precipitator designed for refuse co-firing should be sized along the lines of a precipitator designed for residual oil service. Soot deposits are a characteristic of even the best residual oil flames. This in turn means that gas velocities should approach 3.0 feet per second instead of the 4.5 feet per second normally used in coal service.

If the present precipitator design is retained and a 33 percent decrease in flue gas flow is required to reduce flow velocity from 4.5 fps to 3.0 fps, the boiler load must be reduced at least 33 percent. This in turn would bring the boiler load below the 70 percent load threshold that the boiler manufacturer's recommend for firing RDSF. At that operating point, no RDSF could be fired because the boiler control logic would prevent it. Thus, there is a possibility that if no modification is made to the precipitator, it will not be possible to fire RDSF and meet the allowable particulate emission limit.

A more acceptable alternative is to size the precipitator very conservatively in order to remain within the 0.03 $lbm/10^6 Btu$ limit. The width of the precipitator will have to increase by about 33 percent to reduce the gas velocity the required amount. The increase in width will be accompanied by a reduction in length, while the total plate area will be increased by about 10 percent. This in turn results in approximately a 10 percent increase in cost for both precipitators.

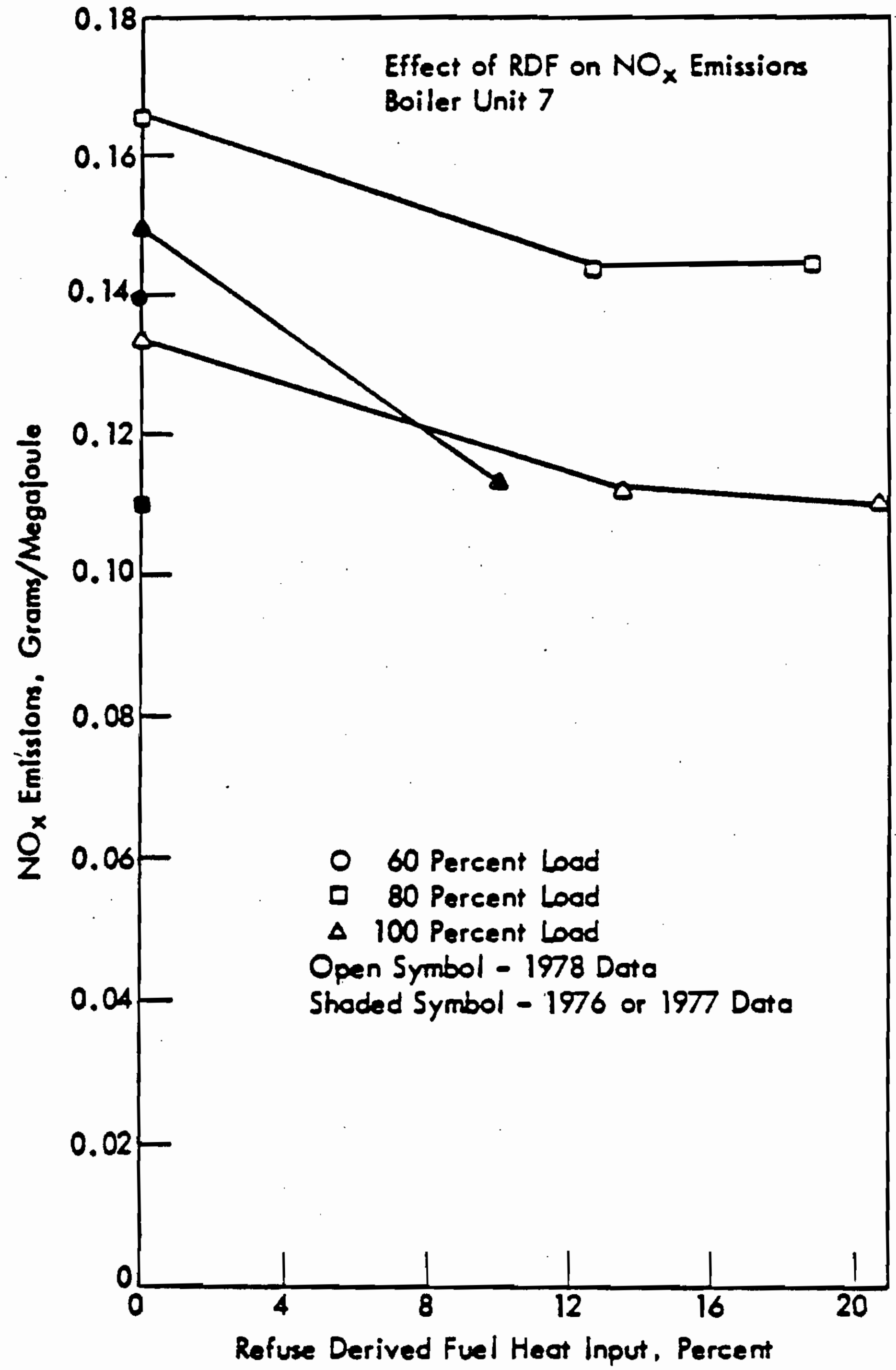
In spite of an increase in precipitator size, it may still be difficult if not impossible to obtain guarantees on the precipitators involving significant monetary penalties for non-performance. The absence of experience with co-firing RDSF in modern boilers fitted with high (99.8 percent) precipitators and the uncertain properties of the ash formed from co-firing with coal make it difficult to predict precipitator performance. The same statement applies although not as rigidly, to guarantees of NO_x by the boiler supplier and guarantees of SO_2 by the scrubber vendor. This is, of course, subject to confirmation during the actual AQCS procurement cycle.

2.4.1.2 NO_x Control

The control of NO_x is not a problem when RDSF is co-fired as illustrated in Figure 2.4.1.2-1. There are two possible reasons for this finding. First, RDSF tends to be lower in fuel-bound nitrogen than coal. Fuel bound nitrogen has been found to be a major contributor to the formation of NO_x. Secondly, the slower combustion characteristics and higher moisture content of RDSF tend to keep flame temperatures slightly lower than with a pure coal flame. A high flame temperature, which contributes to the dissociation of the N_2 and O_2 molecules, have been linked to NO_x formation. In general, NO_x emissions appear to decrease by 10 to 20 percent when RDSF is co-fired at 20 percent of the total heat input.

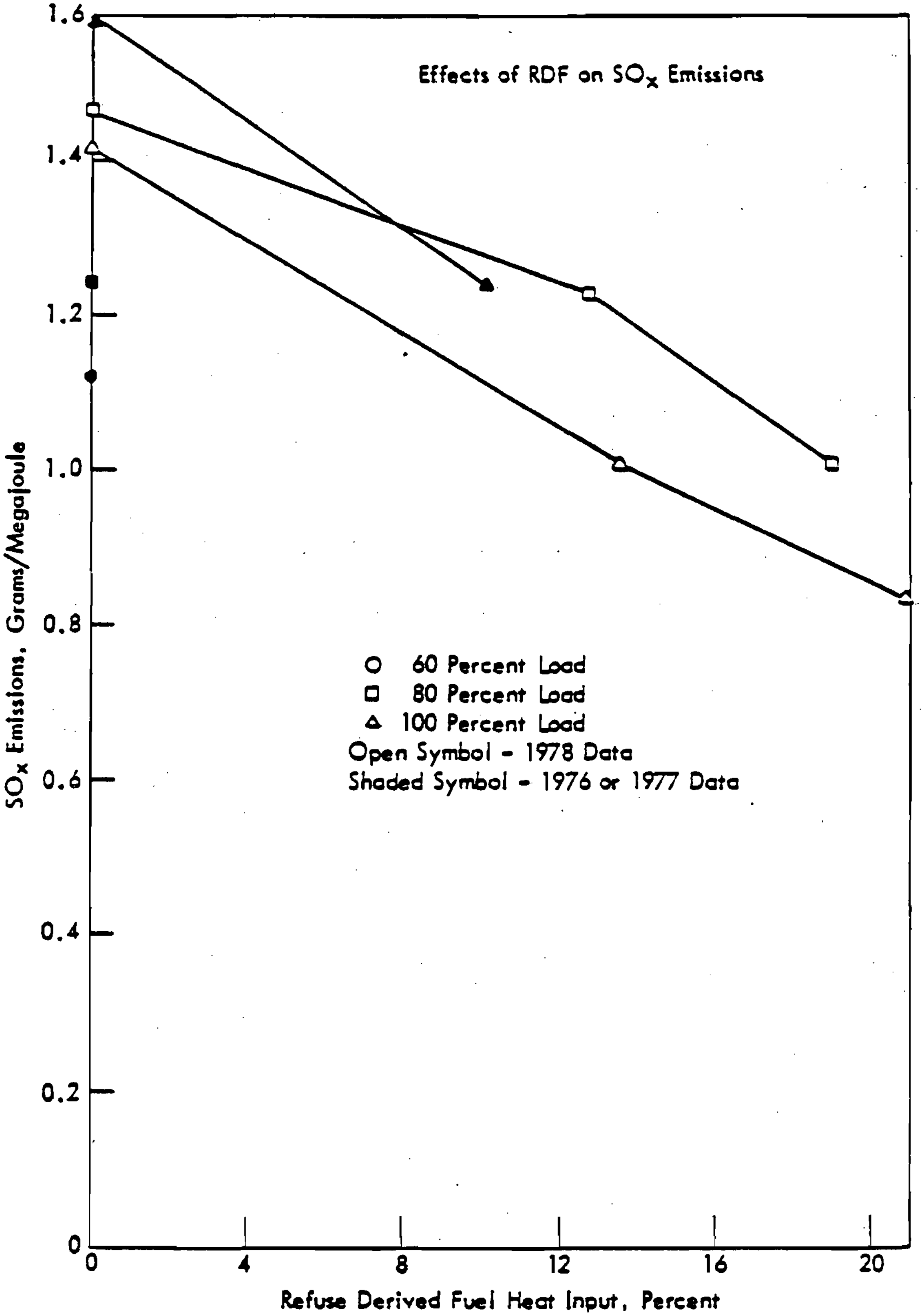
2.4.1.3 SO_2 Control

It has been widely verified that RDSF contains substantially less sulfur than even most low sulfur coals. The sulfur content of RDSF is typically 0.1 to 0.4 percent, while the sulfur content of coal may run from 0.5 to as high as 6 to 7 percent. The result in virtually all cases, when RDSF is co-fired with coal, is a substantial reduction in the emissions of SO_2 and SO_3. A good example of this effect from the Ames system is shown in Figure 2.4.1.3-1. SO_2 and SO_3 emissions were reduced by almost 42 percent as RDSF was increased to 20 percent of the heat input.



NO_x EMISSIONS VS. PERCENT RDSF INPUT (REF.1)

FIGURE 2.4.1.2-1



SO_x EMISSIONS VS. PERCENT RDSF INPUT (REF. 1)

FIGURE 2.4.1.3-1

Often the reduction in SO_2 emissions is more than can be explained by the dilution effect mentioned above. Intensive research into the corrosion mechanisms of MSW, when fired alone or when converted to RDSF and co-fired with coal, has led to the hypothesis that the following type of reaction may be taking place.

$$\text{Metal Chloride} + SO_2 + O_2 + H_2O \longrightarrow \text{Metal Sulfate} + HCl$$

The significant reduction in SO_2 emissions is good evidence of this reaction. As noted in the section on boiler slagging, it is known that RDSF contributes significant quantities of metals, which tend to form chlorides and sulfates. Further evidence for this reaction is the the increasing tendency for chlorine in the RDSF/coal fuel mixture to be converted to HCl as the amount of sulfur in the coal increases (this effect will be discussed further in the section on chloride emissions).

HCl is an extremely soluble gas and it will be absorbed readily in the SO_2 scrubber. However, the increase in chlorine concentration in the scrubber liquor will tend to tie up the calcium as $CaCl_2$ and reduce the free calcium ions available for the reactions leading to the formation of $CaSO_4$. Thus, limestone or lime reagent addition may have to be increased slightly to accommodate the increased chlorine in the scrubber liquor.

Unfortunately, since all of the RDSF demonstration plants operated to date have been modifications of existing units, none have been equipped with SO_2 scrubbers, so there is no actual experience of the effect of RDSF on scrubber performance. How much the reduction in SO_2 may be when firing RDSF depends a great deal on the sulfur content of the coal selected and on the sulfur and trace metals content of the RDSF.

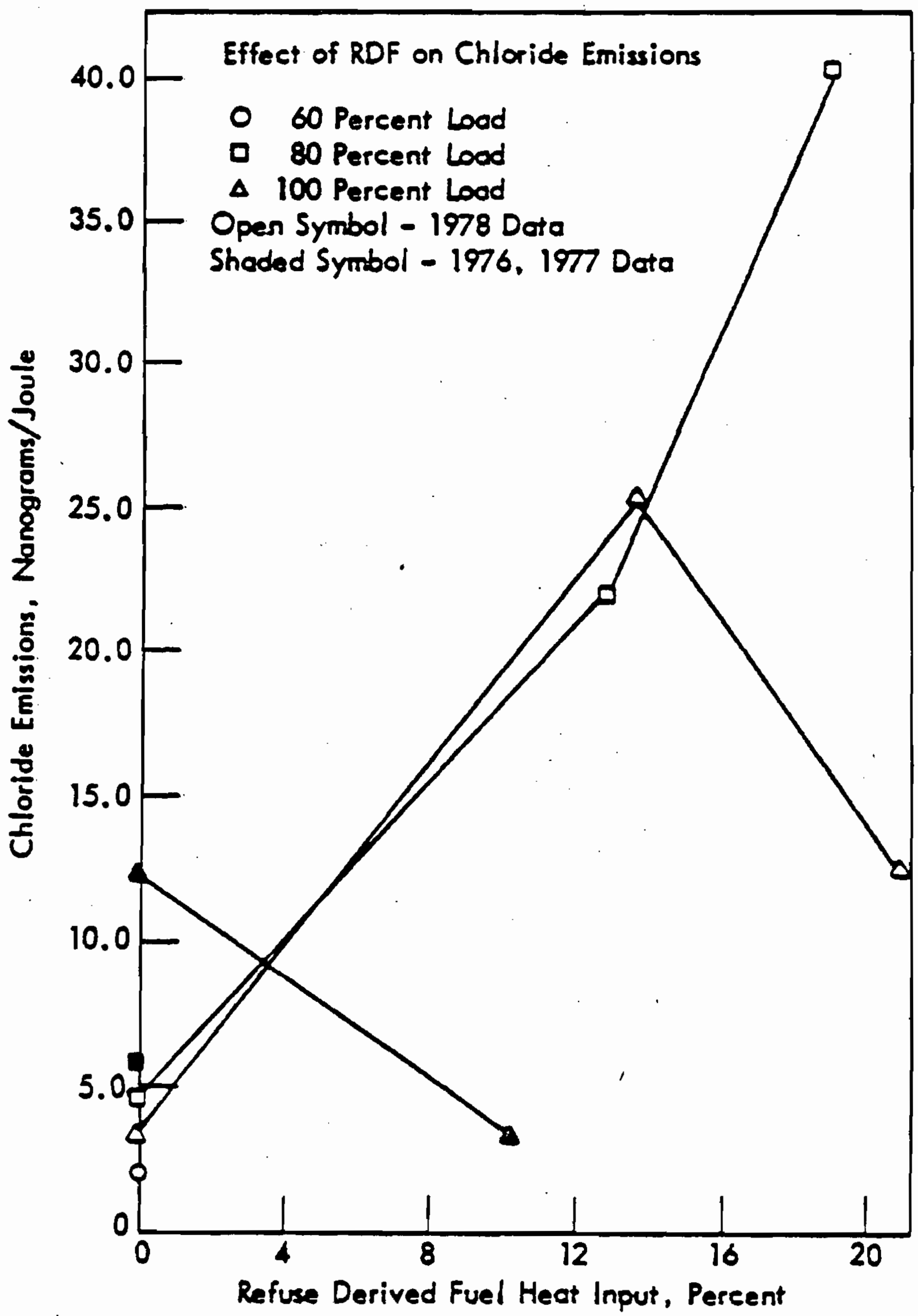
2.4.1.4 Chloride Emissions

Chloride emissions tend to increase noticeably when RDSF is co-fired with coal. The reasons for this seem to be twofold. First, RDSF has a higher chloride content than coal. This is believed to be due to the presence of chlorinated plastics (e.g. polyvinylchlorides) in RDSF. Secondly, the reaction discussed previously for conversion of metal chlorides to metal sulfates tends to favor the formation of HCl which is carried out with the flue gas.

In the tests at Ames, chlorine concentrations in the flue gas increased 2 to 8 times when RDSF was co-fired at up to 20 percent of the heat input as shown in Figure 2.4.1.4-1. In the present system, however, chlorides will probably be trapped in the SO_2 scrubber and should not present an air quality problem.

2.4.1.5 Trace Element Emissions

Table 2.4.1.5-1 is a comparison of the composition of several trace elements in the coal and RDSF at Ames. Only those elements where there is a substantial difference in concentration are shown. Note the tremendous increases in lead, zinc, and copper. Zinc is believed to enter



CHLORIDES EMISSIONS VS. PERCENT RDSF INPUT (REF. 1)

FIGURE 2.4.1.4-1

the RDSF through the filler material in paper. Lead and Copper are probably from inks used in newsprint and colored pictures. The lead, zinc, and copper also were found to increase in the bottom ash when RDSF was fired. Only zinc and lead increased in the fly ash.

Table 2.4.1.5-1 Concentrations of Trace Elements in Coal and RDSF (Ref. 1)

Element	Coal	RDSF
Zinc	66	763
Lead	36	613
Copper	15	572
Manganese	76	194
Gallium	2.5	16
Vanadium	83	154
Chromium	19	34

Concentrations in ppm.

Table 2.4.1.5-2 shows the concentrations of various trace elements in the flue gases at Ames. The scrubber should tend to trap these trace elements and significantly reduce their concentrations in the flue gases at JEA.

Table 2.4.1.5-2 Trace Elements in Flue Gases (Ref. 1)

Element	Flue Gas Concentration (Pg/J)
Cobalt	234
Arsenic	385
Zinc	70.6
Copper	25.6
Manganese	9.5

All others below detection limits.

Pg/J - picograms/joule

NOTE: Trace Elements Sampled While Firing 20 Percent RDSF

Increased emissions of lead, zinc, beryllium, chromium, copper, fluorine, mercury-vapor, mercury-solid, gallium, potassium, and titanium when co-firing RDSF were reported in a survey of emissions tests at several facilities (Ref. 12). Of this list only beryllium and mercury have been addressed in the standards prepared to date by EPA under NESHAPS (National Emission Standards for Hazardous Air Pollutants). These limits are not applicable to a coal-fired power plant or refuse co-fired power plant.

2.4.2 Water Quality

2.4.2.1 Bottom Ash Sluice Water

Since the bottom ash may be in contact with water if a wet system is employed, concentrations of contaminants in the sluice water may be important. Early experience at St. Louis before implementation of the air classifier in the processing plant showed that bottom ash water did not meet state limits for biological oxygen demand (BOD), dissolved oxygen, and suspended solids (Ref. 5). However, that boiler was not equipped with a dump grate. There were no indications of sluice water contamination at Ames, which did employ a dump grate.

Due to the possible increase in bottom ash generation and sluice water flow, the sizing of the ash settling pond will have to be reviewed if it is decided that RDSF will be burned. There is presently only a 20 percent margin in the design capacity of the pond and additional land for a larger pond is not readily available. Alternatives that would have to be considered wold be deepening the pond by raising the berms or provision for a remote landfill site.

2.5 Corrosion

Corrosion in boilers co-firing RDSF has been a concern due to very bad experience in waterwall incinerators firing 100 percent raw garbage, both in Europe and the U.S. in the last two decades (Ref. 6). Material losses of 0.1 to 0.2 mils per hour have been reported for steels in incinerator service burning raw, unprocessed refuse. As more and more data on co-firing becomes available, however, it is rapidly becoming apparent that bulk incineration of pure, raw refuse and co-firing have relatively little in common when it comes to the severity of corrosion.

The best example of this was a series of experiments run in a stoker-fired boiler at the Municipal Electric Plant in Columbus, Ohio (Ref. 7). Table 2.5-1, which is taken from this report, shows corrosion rates of steels and stainless steels for situations where RDSF was co-fired at up to 74 percent by weight versus a case where 100 percent refuse was fired. Corrosion rates for co-firing are substantially lower than for 100 percent refuse, and comparable to those experienced when burning 100 percent coal (0.01 to 0.02 mils per hour).

These results are verified by the initial corrosion tests at Ames, where two stoker-fired units operated for 1000 hours with up to 50 percent by weight RDSF (Ref. 8). Corrosion of waterwall tubes was nonexistent and corrosion of superheater tubes, if any, was less than 0.025 mm. Corrosion data on the pulverized-coal unit at Ames is not available yet.

TABLE 2.5-1

CORROSION RATES FOR VARIOUS ALLOYS AS A FUNCTION OF METAL TEMPERATURE (REF. 7)

(All data in mils/hour)

Alloy	Metal Temp. F	Probe 30 1% Coal	Probe 28 3% S Coal	Probe 34 5% S Coal	Probe 31 3% S Coal 28 W % Refuse	Probe 33 5% S Coal 27 Wt % Refuse	Probe 35 3% S Coal 36 Wt % Refuse	Probe 36 3% S Coal 42 Wt % Refuse	Probe 37 3% S Coal 75 Wt % Refuse	100% Refuse
A106	500	0.004	0.005	0.002	0.002	0.002	0.003	0.001	0.006	0.16
	700	0.008	0.007	0.020	0.010	0.021	0.008	0.012	0.013	0.18
	900	0.022	0.027	0.063	0.030	0.068	0.031	0.035	0.020	0.20
T11	500	0.005	0.005	0.002	0.004	0.003	0.002	0.002	-	0.10
	700	0.006	0.007	0.013	0.005	0.018	0.006	0.005	-	0.12
	900	0.013	0.022	0.034	0.022	0.037	0.020	0.020	-	0.18
316	500	0.003	Nil	Nil	Nil	Nil	Nil	Nil	0.004	-
	700	0.005	Nil	0.001	0.001	0.001	Nil	Nil	0.004	0.056
	900	0.006	0.001	0.002	0.001	0.002	0.004	0.002	0.004	0.056
446	500	0.003	Nil	Nil	0.001	0.001	-	-	-	-
	700	0.007	Nil	0.005	0.001	0.001	-	-	-	0.050
	900	0.001	0.001	0.001	0.001	-	-	-	-	0.050
310	500	Nil	Nil	Nil	Nil	Nil	Nil	Nil	0.0005	-
	700	Nil	Nil	Nil	0.0005	0.0005	Nil	Nil	0.0007	0.032
	900	0.0001	0.0005	0.0005	0.0005	0.001	0.0005	0.001	0.001	0.032
JS700	500	Nil	Nil	-	Nil	-	-	-	-	-
	700	Nil	Nil	-	0.0005	-	-	-	-	-
	900	0.0006	Nil	-	0.0005	-	-	-	-	-
405	500	-	-	0.001	-	0.001	Nil	Nil	-	-
	700	-	-	0.003	-	0.009	0.002	0.006	-	-
	900	-	-	0.008	-	0.010	0.010	0.012	-	-
P5	500	-	-	-	-	-	0.003	-	-	-
	700	-	-	-	-	-	0.008	0.012	-	-
	900	-	-	-	-	-	0.020	0.013	-	-
P9	500	-	-	-	-	-	-	-	0.009	-
	700	-	-	-	-	-	-	-	0.010	-
	900	-	-	-	-	-	-	-	0.012	-
347	500	-	-	-	-	-	-	-	0.002	-
	700	-	-	-	-	-	-	-	0.002	-
	900	-	-	-	-	-	-	-	0.002	-

Another series of corrosion tests were run at Milwaukee, Wisconsin, where RDSF has been co-fired since 1977, in two 2400 psi, 1050°F pulverized coal units rated at 310 MW each (Ref. 10). This test program used corrosion probes mounted in several areas of the backend of the boiler from the superheater tubes down to the air heater. A metal temperature range of 220°F to 1210°F was included, and RDSF heat input rates ranged from 10 to 15 percent. Coals ranged from 1.0 to 3.9 percent sulfur (average sulfur content was 2.4 percent). The study concluded that wastage of boiler materials did not appear to be noticeably affected by the co-firing of RDSF.

Why corrosion rates are substantially lower in co-fired boilers as opposed to incinerators is not well understood. Chloride concentrations increase when RDSF is fired and sulfates and chlorides are found in deposits of co-fired units just as they are found on badly-corroded incinerator tubes. It is believed that the reaction

$$\text{Metal Chloride} + SO_2 + O_2 + H_2O \longrightarrow \text{Metal Sulfate} + HCl$$

occurs in incinerators and the same reaction appears to exist in co-fired units as described in previous sections of this report.

The major difference between the deposits in co-fired units and incinerators is a reduction of the chloride concentration within the deposit. Moreover, co-firing is usually accompanied by larger increases in HCl emissions than just the increased weight of chlorine input would indicate. This evidence seems to verify that the above reaction is indeed occuring. Due to the larger amounts of sulfur available from the coal in a co-fired unit, the sulfate and HCl formation is favored much more heavily.

The Ames tests verified that significant amounts of sulfates were in the deposits of the stoker boiler waterwalls and superheater tubes, yet corrosion rates were undetectable. Hence, it would appear that the metal chlorides are the major contributors to incinerator corrosion. In co-fired units the chlorides tend to be converted to HCl. HCl vapor is not very corrosive as long as it is not allowed to condense to a liquid. It should be noted, however, that the coal for the Ames tests contained 3.5 to 6.7 percent sulfur which would tend to favor sulfate formation. Also, the Columbus, Ohio tests used coal with 3 to 5 percent sulfur.

In summary, to date there has been no evidence of significant corrosion on any components of a boiler or precipitator in co-firing service as long as the sulfur content of the coal averages 2.5 percent or greater. If the sulfur content of the coal were to drop below 2.5 percent, there may be a greater tendency for chloride corrosion.

With regard to corrosion of the scrubber and its auxiliary equipment, co-firing of RDSF will probably have relatively little additional effect. The scrubber environment is already an extremely corrosive one and material selections based on normal scrubber service should be adequate to handle the additional corrosion potential which would be expected from condensing HCl vapors.

3.0 RDSF HANDLING AND FIRING EQUIPMENT

This section describes all the equipment required to receive, store, and burn the processed RDSF. It is assumed that all processing of the RDSF is done at a separate facility built and operated by the Jacksonville Department of Sanitation.

3.1 Alternatives for RDSF Transport, Storage, and Handling

There are two possible options with regard to the transporting of the RDSF from the processing facility to the power plant. If the processing site is more than a mile away from the power plant site, then RDSF could be loaded into 75 cu. yd. transfer trailers for transport to the power plant. If the processing plant is closer than a mile, it may be possible to use belt conveyors to transfer material to the power plant site. The costs for both options will be presented, since each has some advantages over the other.

Another question that must be considered is the location of storage in the RDSF flow scheme. In order to minimize the unit cost of processing RDSF, the processing plant should always operate close to design rate and should be planned to operate on an 8-hour day initially, if possible, which will permit expansion to two shift operations as the waste stream increases. The present rate of garbage pick-up at Jacksonville is about 1950 tpd. At a 75 percent conversion rate, this will produce approximately 1460 tpd of RDSF. Therefore, the production rate of RDSF will be roughly 1460 tpd per 8 hour day operation or 183 tph. Since the maximum continuous burn rate of the RDSF is 200 tph (100 tph per boiler), there will be many days when it will not be possible for the power plant to burn a whole day's production of RDSF in 8 hours. Hence, there is is a need to provide storage for the RDSF, in addition to that provided in the raw refuse pit going into the processing plant. This additional storage should be provided between the processing plant and the power plant for the reasons discussed below.

If storage were to be provided only in the raw refuse pit before the processing plant, then the processing plant must be designed for 200 tph (two lines at 100 tph each) in order to match the burning capability of the two boilers. The problem with this design approach is that there may be days when only one boiler is burning RDSF at a reduced rate of perhaps only 50 tph. Then the processing plant can only operate at 50 tph or less. The garbage that cannot be processed during the day, which amounts to 1064 tons [(183-50) tph x 8 hours], must be processed the next day or the plant must operate extra shifts (all at one half of design capacity for one line) in order to catch up. If extra shifts are not worked and the garbage is processed the next day, then the raw refuse storage pit may fill before the next day is over, and the excess garbage will have to be landfilled with a resulting loss of revenue as well as an additional landfilling cost. Of course, additional storage can be provided in the raw refuse storage pit, but with this design, the processing plant can only process what the boilers can burn at any given time, and it may be difficult for the processing plant to keep up with raw garbage collection.

On the other hand, if the storage capacity is provided between the processing plant and the boiler, then even if the boilers can only burn 50 tph there will be no need to landfill waste. The processing plant will process 1460 tons each day. If this flow is discharged starting in the morning into a empty plant storage system, it will accumulate at the rate of 133 tph for a total of 1064 tons at the end of an 8 hour day of processing (see calculations below).

Storage System Filling Rate - Burn Rate = Net Rate of Filling

$$\frac{1460 \text{ tpd}}{8 \text{ hrs/day}} - 50 \text{ tph} = 133 \text{ tph}$$

The boiler will burn RDSF continuously at the rate of 50 tph and the storage system will only have remaining 660 tons [1460 tons - (50 tph x the remaining 16 hrs.] by the beginning of the next processing day. At that rate, the same operating mode could be maintained for more than 2 days before running out of storage capacity. During the 2 days, the processing plant can continue to run at full capacity.

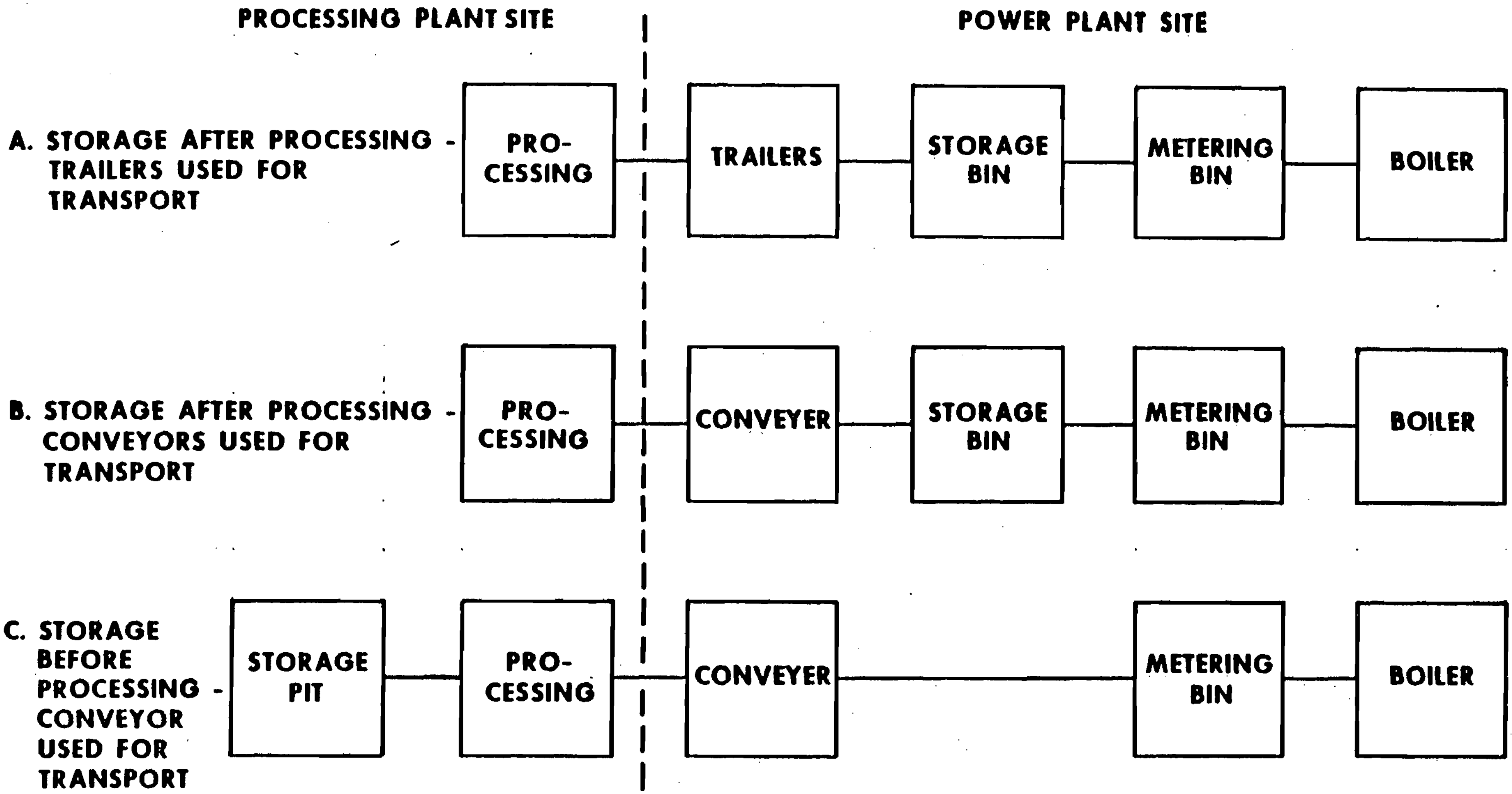
The point of this discussion is the following: To limit storage capacity to the raw refuse pit before the processing plant will result in coupling the processing plant operations very closely to the power plant operations, which is undesirable from a scheduling and cost standpoint. Consequently, it is recommended that RDSF storage capacity be provided between the processing plant and the power plant. The options which have been discussed are diagrammed in Figure 3.1-1. However, as a result of the reasons discussed above, only options A and B appear to be viable alternatives. Consequently, the remaining discussion concentrates on flow schemes A and B.

3.2 Equipment Requirements for Transporting RDSF in Transfer Trailers.

Each of the major pieces of equipment for receiving RDSF in transfer trailers; unloading, storing, and metering the RDSF to the boilers; and all boiler and AQCS modifications necessary to burn RDSF are described below. A layout of the proposed equipment and equipment schematic are presented in Figures 3.2-1 and 3.2.2 at the end of this section.

3.2 Unloading Bin (Item A, Figure 3.2-2)

The size of the unloading bin is determined by the number of trucks that must be unloaded simultaneously. Assuming a bulk density for the RDSF of 15 lb. per cu. ft., this number is determined as follows:



OPTIONS FOR STORAGE AND TRANSPORT OF RDSF

FIGURE 3.1-1

$$\text{Normally RDSF Transfer Rate} = \frac{1460 \text{ tpd}}{8 \text{ hr/day}} = 183 \text{ tph}$$

$$\text{Converting to cu. yds. per hr.} = \frac{183 \text{ tph} \times 2000 \text{ lb./ton}}{15 \text{ lb./ft}^3 \times 27 \text{ ft}^3\text{/yd}^3} = 904 \text{ yd}^3\text{/hr}$$

$$\text{Number of trucks required per hour} = \frac{904 \text{ yd}^3\text{/hr}}{75 \text{ yd}^3\text{/truck}} = 12 \text{ trucks/hr.}$$

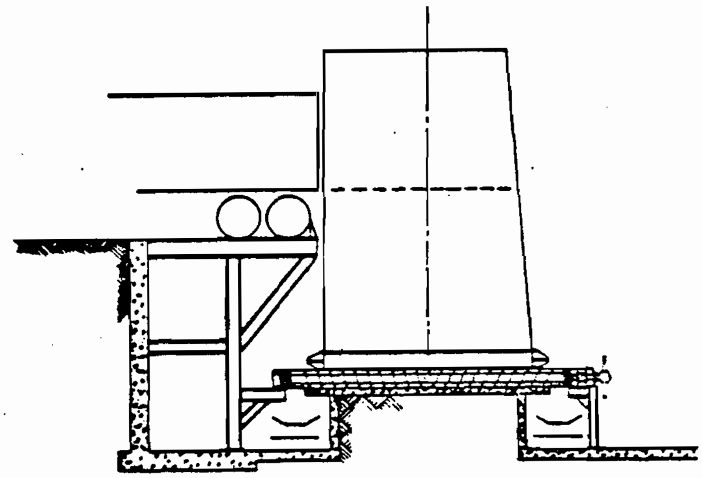
Assuming that it takes 10 minutes to unload one truck, then each truck station can handle 6 trucks per hour. Thus, as a minimum, 2 truck unloading stations must be provided. However, to allow for non-uniform dispatching of trucks and to allow for future expansion of the facility, an unloading station capable of handling 3 trucks simultaneously is necessary. The cost of the trucks are not included in the analysis. A tractor and trailer combination can be expected to cost in the neighborhood of $100,000. The trailers are equipped with a ram device that travels from the front to the back of the trailer in several minutes, pushing the material out the backend into the unloading bin.

A cross sectional view of the unloading bin is shown in Figure 3.2.1-1. The bin is approximately 18 ft. wide at the bottom, 36 ft. high, and about 36 ft. long. The bin is equipped with 27 screw conveyors that cover the bottom of the bin and discharge material to both sides of the bin where it falls on belt conveyors on either side. The screws are capable of emptying the bin at the rate of 300 tph. In order to keep the equipment above ground, an elevated apron with a turnaround must be provided to raise the trailer beds up to the elevation of the unloading bin. The apron just in front of the unloading bin should be covered to prevent rain from entering the bin.

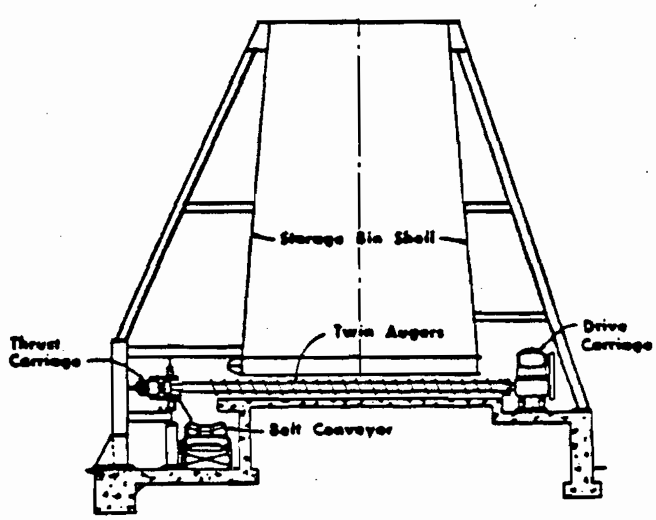
In order to prevent the escape of dust from the unloading bin, a dust control system consisting of a blower and baghouse will be provided. The exhaust system will pull a vacuum on the bin, the baghouse will trap the dust, and a rotary air lock will return the dust to a downstream conveyor.

3.2.2 Conveyors from Unloading Bin to Storage System

Horizontal conveyors receive the RDSF from the unloading bin screw conveyors, run the length of the unloading bin, and deposit the RDSF on elevating belt conveyors that lead up to the storage bin. Each horizontal conveyor has a capacity of 150 tph and is about 40 feet long. All conveyors in the system are designed to run at no more than 200 feet per minute to avoid loss of RDSF due to windage. Bulk density on all conveyors is assumed to be 8 pounds per cu. ft.



UNLOADING BIN



STORAGE BIN

CROSS SECTIONAL VIEW OF UNLOADING BIN AND STORAGE BIN

FIGURE 3.2.1-1

Elevating conveyors carry the RDSF to the top of the storage bins. These conveyors have a 14° incline. Each elevating conveyor has a capacity of 150 tph and is about 140 feet long. All conveyors in the RDSF system have enclosed galleries. Each transfer point is protected from loss of fugitive dust by a dust control system consisting of a blower and baghouse. Dust is collected from the exhaust and returned to the conveyors.

3.3 Equipment Requirements for Transporting RDSF by Conveyor

As mentioned previously, if the processing plant is located within a mile of the power plant, it may be economical to use one long belt conveyor to carry the material to the storage bins. The required conveyor would be 84 inches wide and would be approximately 3600 feet long if the processing plant were located across Island Drive. The installed cost of such a conveyor in 1980 dollars would be approximately $5,500,000.

The conveyor would eliminate the unloading bin and its associated conveyors as well as trailer packers at the processing facility and the transfer trailers themselves. This equipment would be worth approximately $1,800,000. It is estimated that the difference in initial capital cost ($3,700,000) would be offset in approximately 7 years by savings in operating costs of the trucks and in driver salaries.

3.4 Storage Systems (Items B and C on Figure 3.2-2)

The total amount of storage is based on one day's production of RDSF (1460 tons). Two storage systems have been selected with each system having a capacity of 750 tons for a total nominal storage capacity of 1500 tons. The volume of the bin in each system is about 100,000 cu. ft. and the bulk density of the RDSF in storage is about 15 lb. per cu. ft. The storage system bins (See Figure 3.2.1-1 for cross sectional view) are approximately 275 feet long, 40 feet high, and 35 feet wide at the bottom.

Each bin is equipped with a distributing conveyor that runs the length of the bin at the top. As the RDSF moves along this conveyor, a travelling plow moves back and forth along the belt distributing the RDSF evenly into the bin. The top of the bin is enclosed. Two pairs of travelling screw conveyors are used to empty each bin. Each pair of screws has a capacity of 50 tph and travels back and forth covering one-half the bin length. The screw conveyors discharge onto a horizontal belt conveyor that runs the length of the storage bin.

3.5 Conveyors from Storage Bin to Packer Building

Horizontal belt conveyors approximately 275 feet long carry the RDSF at the rate of 100 tph from each storage system to a pair of elevating belt conveyors leading up to the packer building. The pair of elevating conveyors also have a capacity of 100 tph each.

3.6 Packer Building (Items D and E on Figure 3.2-2)

The purpose of the packer building is to provide a means for unloading the storage systems if the boilers are down or if for some reason they cannot burn RDSF. RDSF has a tendency to set up if allowed to sit in storage for more than 2 to 3 days. The packer building houses 2 horizontal belt conveyors, each with a capacity of 100 tph and each equipped with a retractable plow. With the plow in the retracted position the RDSF will pass through the packer building to the boiler. With the plow down, the plow will push the RDSF off the belt into the hopper of a transfer trailer packer. The trailer packers with a capacity of 506 cu. yd. per hour each have a ram device which pushes the material into the trailers and then automatically shuts down when the material is packed with a preset maximum force. Each packer is capable of unloading its corresponding bin in about 16 hours.

3.7 Conveyors from Packer Building to Metering Bin

These conveyors carry the RDSF from the packer building to the metering bin which is located near the firing level of the boilers.

3.8 Fluffing Rolls (Item F on Figure 3.2-2)

The fluffing rolls are mounted at the end of the conveyors that dump into the metering bin. Their purpose is to fluff and aerate the RDSF to facilitate its ready combustion in the boilers.

3.9 Metering Bins and Pneumatic Feeders (Items G, H, I on Figure 3.2-2)

The purpose of the metering bin is to provide some surge capacity and to provide a place to measure the level of RDSF for control of the belt conveyors feeding from the storage bin. If the metering bin level gets too high, then flow from the storage bin is halted. After the level of the metering bin is reduced, then flow is resumed again.

The pneumatic feeders consist of a rotary air lock feeder and pneumatic blower. The speed of the air lock feeder determines the feed rate of RDSF to the boiler. The air lock feature prevents blow back of air into the metering bin. The blower provides the air to convey the RDSF to the boiler. The costs of both the metering bins and pneumatic feeders are included in the cost of the boiler modifications in Table 3.11-1.

3.10 Boiler Modifications (Item J on Figure 3.2-2)

The boiler modifications consist of the RDSF nozzles and the dump grate which were discussed in Section III-2.1 of this report.

3.11 Precipitator Modifications

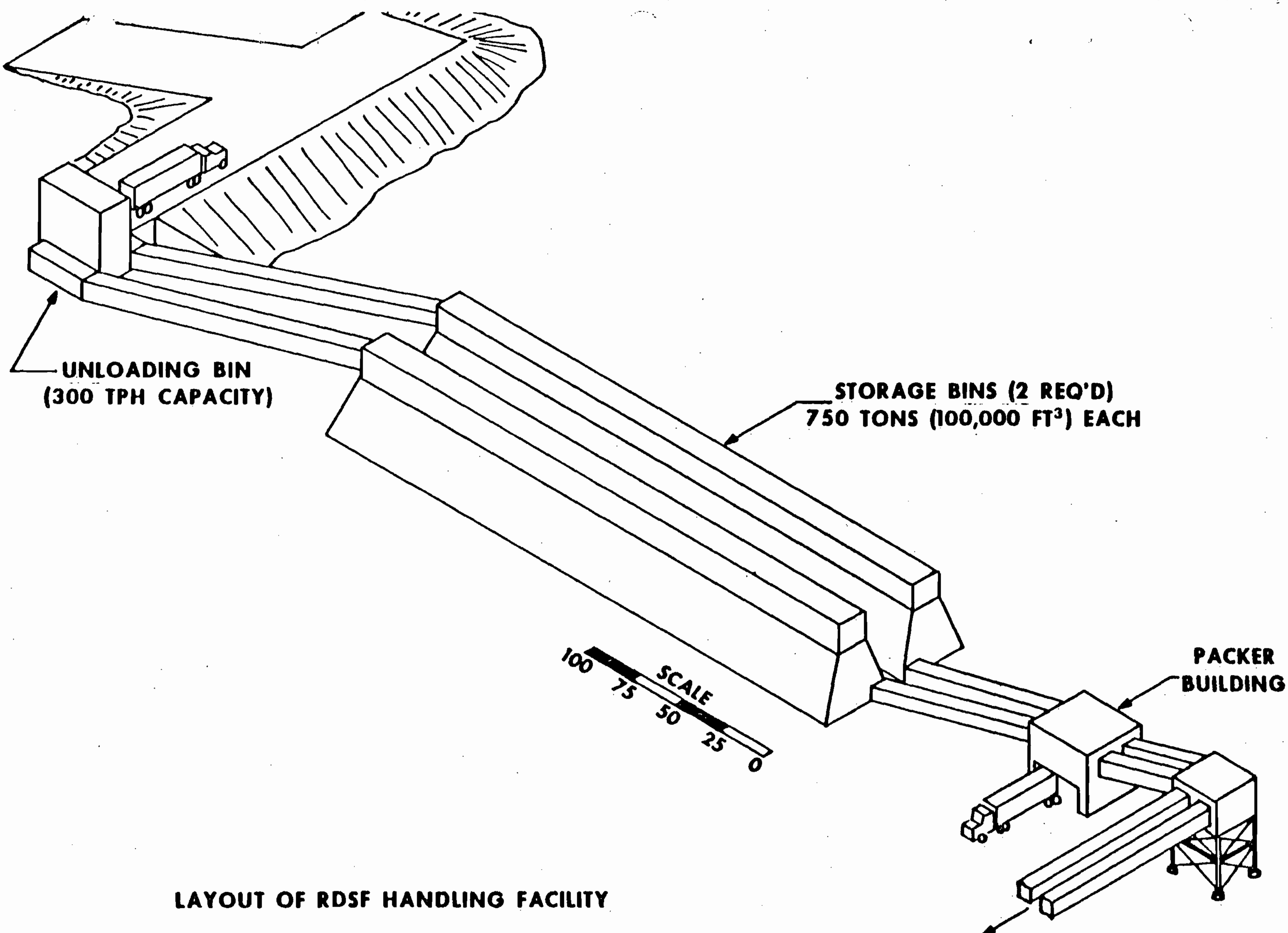
To date, there is no experience with very high (99.8+) efficiency precipitators on boilers co-firing RDSF with coal. It is estimated that in order to insure that particulate emissions are kept below 0.03 lb. per million Btu, it will be necessary to enlarge the precipitators by at least 10 percent. An order-of-magnitude estimate of the costs resulting from this modification and associated changes in the ductwork is included in the cost analysis.

3.12 Capital Cost Analysis

Conceptual estimates of the capital costs for all capital equipment are summarized in Table 3.11-1. The costs for each individual item were based on order-of-magnitude estimates of today's cost, expressed in 1980 dollars. The costs are totaled and then indirect construction costs, cost of services, escalation and a 20 percent contingency are added to give a total cost in 1985 dollars. The following factors were used for escalatio.. (10.5 percent - 1980, 9 percent - 1981, 8 percent - 1982, 8 percent-1983). Interest during construction is based on 3 years at 7.5 percent p-- year. Finally, the capacity charge based on 1736 Kw (maximum operating electrical load) at $890/Kw is added to give the total initial project cost in 1985 dollars.

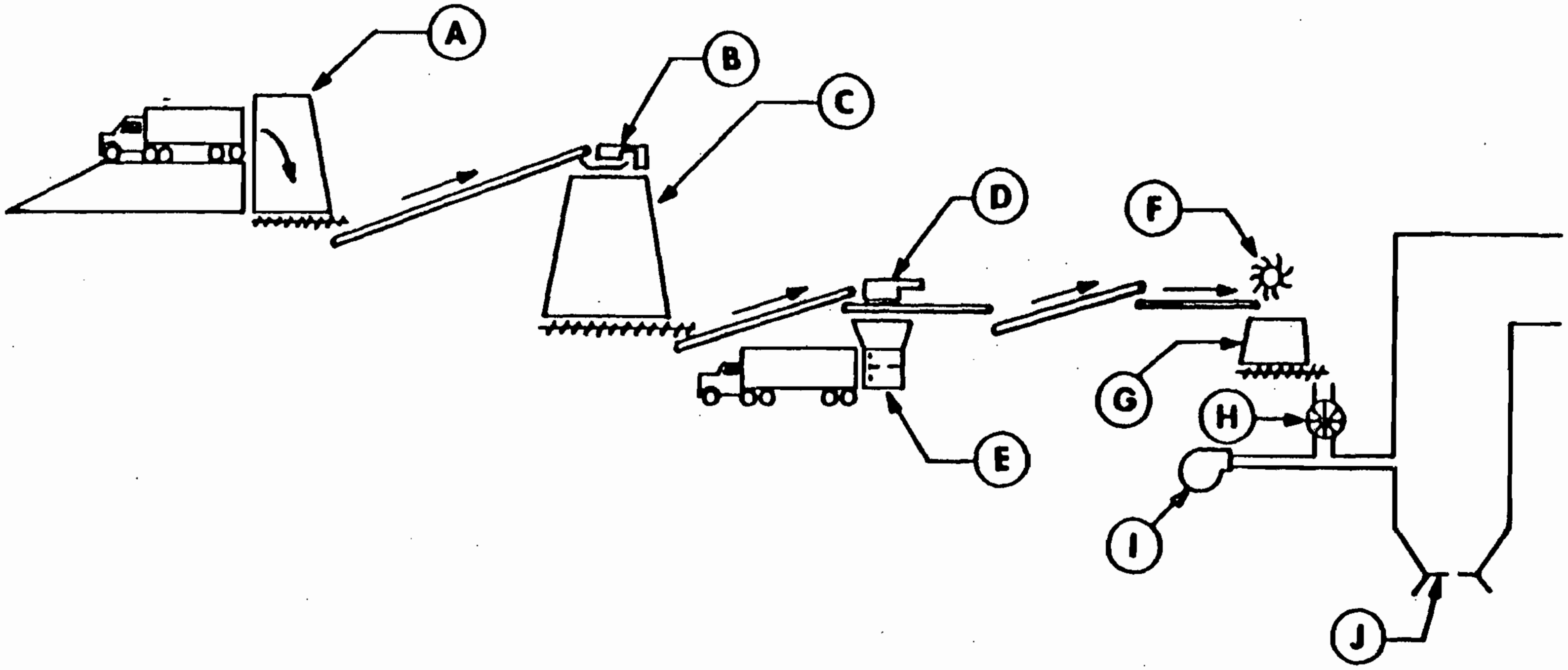
TABLE 3.11-1
ORDER-OF-MAGNITUDE CONCEPTUAL ESTIMATES
CAPITAL COSTS OF PLANT MODIFICATIONS FOR
CO-FIRING REFUSE DERIVED SOLID FUEL

Item	Description	Costs ($1000)
(1)	RDSF Equipment	7,885
(2)	Boiler Modifications	4,650
(3)	Precipitator Modifications	7,715
(4)	Total Direct Construction Cost (1980)	20,250
(5)	Indirect Costs and Cost of Services	2,430
(6)	Contingency	4,536
(7)	Escalation	11,159
(8)	Interest During Construction	9,210
(9)	Total Project Cost (1985)	47,584
(10)	Maximum Electrical Load	1,736 kW
(11)	Capacity Charge	1,545
(12)	Total Capital Cost (1985)	45,129
(13)	Fixed Charges (11.11%)	5,458



LAYOUT OF RDSF HANDLING FACILITY

FIGURE 3.2-1



A — UNLOADING BIN - 300 TPH CAPACITY - HANDLES UP TO 3 TRAILERS SIMULTANEOUSLY

B — TRAVELLING PLOW - DISTRIBUTES RDSF INTO STORAGE BIN

C — STORAGE BIN - 2 REQUIRED - EACH WITH 750 TON CAPACITY

D — RETRACTABLE PLOW - USED TO DIVERT RDSF INTO PACKERS - 2 REQUIRED

E — TRANSFER TRAILER PACKER - 2 REQUIRED - EACH WITH 506 YD^3/HR CAPACITY

F — FLUFFING ROLL - 2 REQUIRED

G — METERING BIN - 2 REQUIRED

H — ROTARY AIR LOCK FEEDER - 2 REQUIRED

I — PNEUMATIC BLOWER - 2 REQUIRED

J — BOILER DUMP GRATE - 2 REQUIRED

SCHEMATIC OF RDSF HANDLING FACILITY

FIGURE 3.2-2

4.0 ECONOMIC ANALYSIS OF RDSF FACILITY

This section presents an economic analysis of the proposed refuse burning facility. The objective of this section is to present the assumptions and calculations leading to the estimation of a fuel fee, which will be paid by the power plant to the Department of Sanitation. The fuel fee, along with the reduction in landfill costs, provides the cash flows which in turn must offset the capital and operating costs of the processing plant.

4.1 Assumptions of Economic Analysis

For purposes of the economic analysis it is assumed that all direct capital costs and operating costs for the RDSF installation will be accounted for separately from other plant capital and operating costs, wherever practicable. It is assumed that the power plant does not benefit from the burning of the refuse. For the purposes of this study the structuring of the "fuel fee" allows the power plant to "break even". This is based on the principle that the power plant should assume little or no risk in the venture. All electrical equipment directly associated with RDSF handling and burning should be separately metered where possible. Likewise, the operating labor and maintenance on the RDSF equipment should be separately accounted for. This data will be used to perform a periodic review of the fuel fee to insure that a fair price is being paid for the RDSF. In the long run this will insure that the utility and its customers do not subsidize garbage disposal and, likewise, that the sanitation department does not subsidize power generation.

Table 4.1-1 presents the basic assumptions used for the economic analysis.

4.2 Operating Costs

4.2.1 Electric Power

The trailer unloading system and boiler feed system will have maximum power consumptions of 570.7 kW and 330.8 kW respectively. The power consumption per ton of RDSF handled is more useful for calculation of the true operating costs. This number, which is 3.6 kWH per ton of RDSF, is used to develop the following costs for direct electric power.

Total RDSF Burned per year = 1460 tpd x 365 days/yr
= 532,900 tpy

Direct Electric Power Cost = 532,900 tpy x 3.6 kWH/Ton x 0.0204$/kWH x 1.57 (Esc. to 1985)
= $61,444/yr

TABLE 4.1-1
ASSUMPTIONS OF ECONOMIC ANALYSIS

Annual Fixed Charge Rate		11.11 Percent	
Escalation: Labor:	1980	10.5 Percent	Total 63 Percent to 1985
	1981	9 Percent	
	1982	8 Percent	
	Balance	8 Percent	
Energy:		9.6 Percent	Total 57 Percent to 1985
Labor Cost (1980 $)		$30,000/yr	
Energy Charge (1980 $)		$ .0204/kW	
Coal Cost - As-Fired (1980 $)		$ 1.98/10^6Btu	
Coal Handling and Pulverizing (1980 $)		$ .034/10^6Btu	
Levelization Factors:	Material	3.9529	
	Labor	3.8948	
	Energy	3.8635	

There are also indirect electric power costs resulting from increased load on the induced draft and forced draft fans. The increased fan power under worst conditions is 2650 hp at 20 percent heat input from RDSF. Since the average RDSF burn rate is 10 percent of two boilers, the average increase in fan power is found as follows.

$$\text{Average Increase in Fan Power} = \frac{10\%}{20\%} \times 2(2650)\text{hp} = 2650 \text{ hp or } 1977 \text{ kW}$$

As discussed in Section 1.1 and Table 1.1-4, RDSF firing would occur, on the average, 5300 hours per year.

The cost of this power on a continuous basis is calculated below:

Indirect Electric Power Cost = 1977 kW x 5300 hr/yr x $.0204/kWH x 1.57 = $335,592.

4.2.2 Labor Costs

Labor costs are based on a requirement for two operators two shifts per day to supervise trucks, to operate the RDSF handling equipment, and to sample the RDSF for determining the Btu and ash content. Additionally, one boiler plant operator will be required one-half time two shifts per day on the boiler to monitor RDSF feed equipment operation and to operate the dump grate on an hourly basis. The labor costs attributable to the RDSF equipment operators are broken out in the calculations, as they may be directly charageable to the Department of Sanitation. The labor charges associated with the Boiler Plant Operator and not broken out, as it would be difficult to separate them from the cost of normal operations.

4.2.3 Maintenance Costs

Based on actual experience, maintenance costs on RDSF equipment run approximately 2.5 percent of the initial capital cost of the equipment itself. In the fuel fee calculations, maintenance is broken into two components - that associated with the RDSF equipment external to the powerhouse and that associated with the RDSF equipment within the powerhouse. The cost of maintenance on the handling and storage equipment is separated because it may be decided to bill these charges directly to the Department of Sanitation. The other maintenance costs, which are attributable to the boiler feed equipment and dump grate are not readily separable. It is assumed that the firing of RDSF will have no impact on the balance of the plant's facilities.

4.3 Coal Savings

The savings of coal is calculated on the basis of the Btu's supplied by the RDSF, adjusted for the fact that boiler efficiency is reduced by as much as 3 percent when 20 percent RDSF is burned. In a manner similar to the fan power calculation, the average efficiency drop when RDSF is burned is calculated as follows:

$$\frac{10\%\ \text{Average Heat Input}\ X\ 3\%}{20\%\ \text{Max Heat Input}} = 1.5\%$$

Assuming that boiler efficiency on coal alone is 89 percent, then efficiency at the average RDSF firing rate is 87.5 percent. Thus, the amount of coal saved is found as follows:

$$532{,}900\ \text{tpy RDSF} \times 2000\ \text{lb/ton} \times 6100\ \text{Btu/lb RDSF}\ X\ \frac{.875}{.89}$$

$$= 6.392\ X\ 10^{12}\ \text{Btu}$$

At the 1985 cost of coal ($\$3.11/10^6$ Btu), this is worth $19,879,000 per year. In a similar manner the savings in coal handling and pulverizing costs are worth $319,600 per year in 1985 dollars.

4.4 Assumptions for Fuel Fee Calculation

The fuel fee must be calculated on a year by year basis. This section will present a calculation of the fuel fee for the year 1985 and will give a projection of levelized fuel fees over 40 years to the year 2025.

The fuel fee is estimated in two different ways. The first approach assumes that all direct labor, direct electricity, direct maintenance, and fixed charges on all capital are charged directly to the Department of Sanitation. This results in a higher value for the fuel fee, since the power plant is bearing the least amount of the cost of getting the RDSF to the boiler. This is called the "gross" fuel fee.

The other approach subtracts off the estimated costs of the direct labor, direct electricity, direct maintenance, and fixed charges on capital. This results in a "net" fuel fee. The net fee represents the estimated net revenue received by the Department of Sanitation from the operations at the power plant.

4.5 Fuel Fee Calculations for 1985

Table 4.5-1 shows the calculations for the gross fuel fee. Costs are shown in parentheses to indicate that they are subtracted in the calculation. Table 4.5-2 shows the calculations for the net fuel fee. The gross fuel fee is $36.60 per ton ($\$3.03/10^6$ Btu) and the net fuel fee is $25.51 per ton ($\$2.07/10^6$ Btu). For comparison the cost of coal in 1985 is projected to be approximately $77.72 per ton ($\$3.11/10^6$ Btu).

4.6 Projected Fuel Fee (Levelized)

Tables 4.6-1 and 4.6-2 present levelized estimates of the gross and net fuel fees over the life of the plant through the year 2025. Although the rate of RDSF production is likely to increase by approximately 1.5 percent per year (from 1460 tpd in 1980 to 2648 tpd in the year 2025) in accordance with projected population growth in Duval County (Ref. 9), the levelized figures in Tables 4.6-1 and 4.6-2 conservatively assume no increase in refuse processing or RDSF firing rate. The levelized gross annual fee is $74,114,000 and the annual levelized net fuel fee is $66,890,000.

TABLE 4.5-1
GROSS RDSF FUEL FEE

Item	Description	Amount ($1000)
(1)	Energy Savings (Displaced Coal)	$19,879
(2)	Coal Processing Savings	320
(3)	Electric Power: RDSF Equipment FD and ID fans (Net)	(0) (336)
(4)	Labor Costs (Boiler Operator Only)	(49)
(5)	Maintenance Costs (Boiler Equip. 2.5% of $12,365*)	(309)
(6)	Capital Costs (All Borne by Sanitation Dept.)	(0)
(7)	Gross Annual RDSF Fuel Fee	$19,505
(8)	Annual Tons RDSF	532,900 tons/yr.
(9)	Gross RDSF Fuel Fee Per Ton	$36.60/ton

* $4,650 + $7,715 = $12,365 is the cost of the boiler and precipitator modifications from Table 3.11-1.

TABLE 4.5-2
NET RDSF FUEL FEE

Item	Description	Amount ($1000)
(1)	Gross Annual RDSF Fuel Fee	$19,505
(2)	Labor Cost (Sanitation Dept.)	(196)
(3)	Maintenance Cost (RDSF Equip. 2.5% of $7,885*)	(197)
(4)	Electric Power (RDSF Equip.)	(61)
(5)	Capital Costs (AFCR = 11.11%)	(5,458)
(6)	Net Annual RDSF Fuel Fee	$13,593
(7)	Annual Tons RDSF	532,900 tons/yr.
(8)	Net RDSF Fuel Fee Per Ton	$25.57/ton

* $7,885 is cost of the RDSF equipment from Table 3.11-1.

TABLE 4.6-1
LEVELIZED GROSS RDSF FUEL FEE

Item	Description	Amount ($1000)
(1)	Energy Savings	$76,803
(2)	Electric Power - RDSF Equipment	(0)
(3)	FD and ID Fans (Net)	(1296)
(4)	Labor Costs (Boiler Operator Only)	(190)
(5)	Maintenance Costs (Boiler Equipment)	(1,203)
(6)	Levelized Capital Costs (All Borne by Sanitation Dept.)	(0)
(7)	Levelized Annual RDSF Gross Fuel Fee	$74,114
(8)	Annual Tons RDSF (Assumed Constant)	532,900tons/yr
(9)	Levelized Gross RDSF Fuel Fee Per Ton	$139.08/ton

TABLE 4.6-2
LEVELIZED NET RDSF FUEL FEE

Item	Description	Amount ($1000)
(1)	Levelized Gross RDSF Fuel Fee	$74,114
(2)	Labor Cost (Sanitation Dept.)	(763)
(3)	Maintenance Cost (RDSF Equip.)	(767)
(4)	Electric Power (RDSF Equip.)	(236)
(5)	Levelized Capital Cost (same as annual fixed charges)	($5,458)
(6)	Levelized Annual Net Fuel Fee	$66,890
(7)	Annual Tons RDSF (Assumed Constant)	532,900tons/yr.
(8)	Levelized Net Fuel Fee Per Ton	$125.52/ton

5.0 CONCLUSIONS

The purpose of this study was to assess the technical and environmental feasibility of co-firing RDSF in the new Jacksonville power plant. Based on the experience of others and considering this experience in the light of anticipated conditions at the new power plant, there appear to be no insurmountable barriers to the co-firing of RDSF. However, several of the obstacles can only be overcome at considerable cost, which must, in turn be offset by the anticipated revenues if the proposed project is to be economically viable.

5.1 Effects on Boiler and AQCS Operations

With regard to the effects of co-firing RDSF on boiler and AQCS operations the following conclusions can be stated.

a. The magnitude of the impact on boiler operations resulting from co-firing RDSF will be largely dependent on the quality of the RDSF provided by the processing plant. Hence, there is a need for early and continual involvement of the JEA in the development of RDSF fuel specifications and in the actual design of the processing plant.

b. The nature of the effects of co-firing RDSF can be summarized as follows:

- Substantial increases in bottom ash generation may be anticipated, even with the installation of the dump grate. This can probably be handled by increasing the frequency of pulling bottom ash from the boiler hoppers. Sizing of the ash settling pond will have to be reviewed.

- Increases in flue gas volume, mass, velocity, and pressure drop will be observed, resulting from increased moisture in the flue gas. Induced draft fan power may increase as much as 17 percent at maximum RDSF firing rates.

- A reduction of as much as 3 percent in boiler thermal efficiency at a 20 percent RDSF flow may take place, again due primarily to increased flue gas moisture content.

- An increased potential for furnace wall slagging with a potential for increased costs due to additional soot blowers or other slag control measures is anticipated. Sudden load shedding may sometimes be required to shed slag (if other measures are not 100 percent effective). An increase in superheat temperature may occur requiring a desuperheater control system capable of providing more spray down water.

- A loss of up to 2 percentage points in precipitator efficiency over a 100 percent coal design. Precipitator size must be increased at least 10 percent to regain the required efficiency.

- A probable reduction in SO_2 emissions with the amount of reduction depending on relative sulfur concentration in the coal and the RDSF.

- A reduction in NO_x emissions.

- A potential for increased organics and solids in the ash sluice water.

- A potential for increased corrosion in the boiler, precipitator, and scrubbers due to increased in chlorides in the flue gases.

5.2 Economic Analysis

The initial cost in 1985 dollars of the RDSF facilities is $49,129,000. This figure includes all unloading, storage, and conveying equipment as well as all boiler and precipitator modifications.

Based on the available data and the results of this investigation, the maximum "gross fuel fee" which would be paid by the JEA for the RDSF is estimated to be $36.60 per ton in 1985 dollars. This number assumes that the costs of owning and operating the RDSF facilities at the power plant site are all directly assumed by the City of Jacksonville.

If the costs of owning and operating the RDSF facility at the power plant are assumed by the JEA, an estimated maximum "net fuel fee" of $25.51 per ton results. This number also represents the net revenue available to the Department of Sanitation from operations at the power plant. On an annual basis, an estimated net revenue of about $13,593,000 results in the year 1985. Levelized annual net revenue over the life of the plant is estimated to be $66,890,000/yr.

6.0 RECOMMENDATIONS

6.1 Criteria for a Decision on Refuse Co-firing

A decision to proceed with the RDSF system must include the following essential ingredients:

a. Favorable economics of the total RDSF system including the processing plant. Naturally, a major consideration in the economics is the future availability of landfill sites.

b. A satisfactory agreement between JEA and the Department of Sanitation on the quality of the RDSF and on the method for calculating the fuel fee.

c. A willingness on the part of JEA to accept the risk of potential operating problems associated with co-firing the RDSF.

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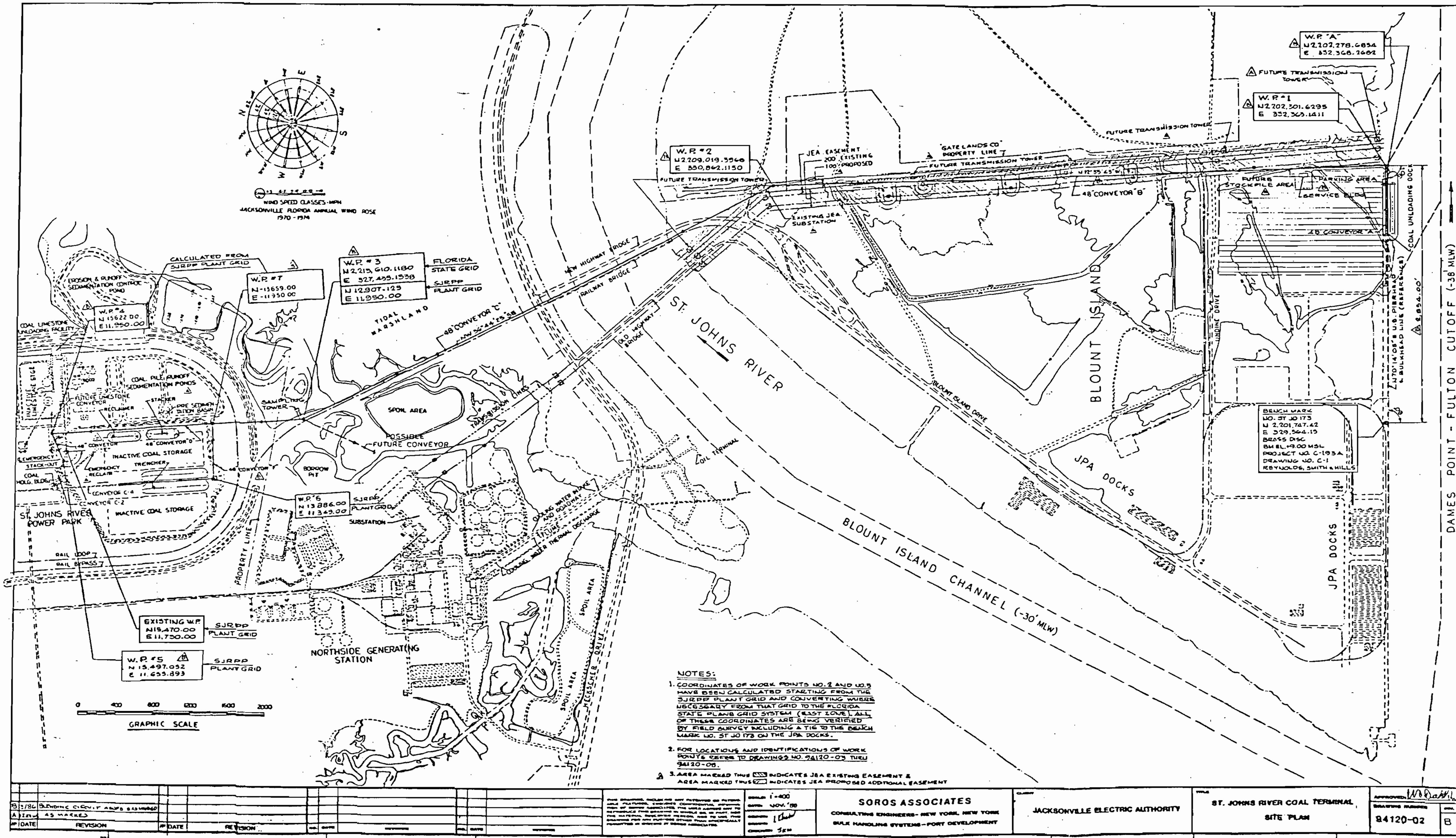
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JACKSONVILLE FLORIDA ANNUAL WIND ROSE
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E 352,368.2662
FUTURE TRANSMISSION TOWER
W.P. #1
N 2,202,301.6295
E 352,365.1411
FUTURE TRANSMISSION TOWER
W.P. #2
N 2,209,019.3568
E 330,862.1150
FUTURE TRANSMISSION TOWER
JEA EASEMENT
200' EXISTING
100' PROPOSED
"GATE LANDS CO" PROPERTY LINE
FUTURE TRANSMISSION TOWER
48" CONVEYOR "B"
FUTURE STOCKPILE AREA
PARKING AREA
SERVICE BLDG.
48" CONVEYOR "A"
COAL UNLOADING DOCK
EXISTING JEA SUBSTATION
CALCULATED FROM SJRPP PLANT GRID
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N-13659.00
E-11950.00
W.P. #3
N 2,215,610.1180
E 327,455.1558
FLORIDA STATE GRID
N 12907.129
E 11,950.00
SJRPP PLANT GRID
EROSION & RUNOFF SEDIMENTATION CONTROL POND
W.P. #4
N 15622.00
E 11,950.00
COAL LIMESTONE UNLOADING FACILITY
TIDAL MARSHLAND
48" CONVEYOR "C"
NEW HIGHWAY BRIDGE
RAILWAY BRIDGE
OLD HIGHWAY BRIDGE
ST. JOHNS RIVER
BLOUNT ISLAND
BLOUNT ISLAND DRIVE
COAL PILE RUNOFF SEDIMENTATION PONDS
FUTURE LIMESTONE CONVEYOR
RECLAIMER
STACKER
PRE SEDIMENTATION BASIN
SAMPLING TOWER
SPOIL AREA
TRANSMISSION LINES
POSSIBLE FUTURE CONVEYOR
48" CONVEYOR
48" CONVEYOR "D"
INACTIVE COAL STORAGE
TRENCHER
EMERGENCY STACK-OUT
EMERGENCY RECLAIM
COAL HDLG. BLDG.
CONVEYOR C-4
CONVEYOR C-2
48" CONVEYOR
BORROW PIT
OIL TERMINAL
BENCH MARK
NO. ST JO 173
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E 329,564.15
BRASS DISC
BM EL. +9.00 MSL
PROJECT NO. C-193A
DRAWING NO. C-1
REYNOLDS, SMITH & HILLS
JPA DOCKS
JPA DOCKS
ST. JOHNS RIVER POWER PARK
INACTIVE COAL STORAGE
W.P. #6
N 13,886.00
E 11,349.00
SJRPP PLANT GRID
SUBSTATION
COOLING WATER INTAKE AND ROADWAY
COOLING WATER THERMAL DISCHARGE
PROPERTY LINE
RAIL LOOP
RAIL BYPASS
BLOUNT ISLAND CHANNEL (-30' MLW)
SPOIL AREA
SPOIL AREA
HECKSCHER DRIVE
EXISTING W.P.
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E 11,750.00
SJRPP PLANT GRID
W.P. #5
N 15,497.032
E 11,655.893
SJRPP PLANT GRID
NORTHSIDE GENERATING STATION
0 400 800 1200 1600 2000
GRAPHIC SCALE
DAMES POINT - FULTON CUTOFF (-38' MLW)
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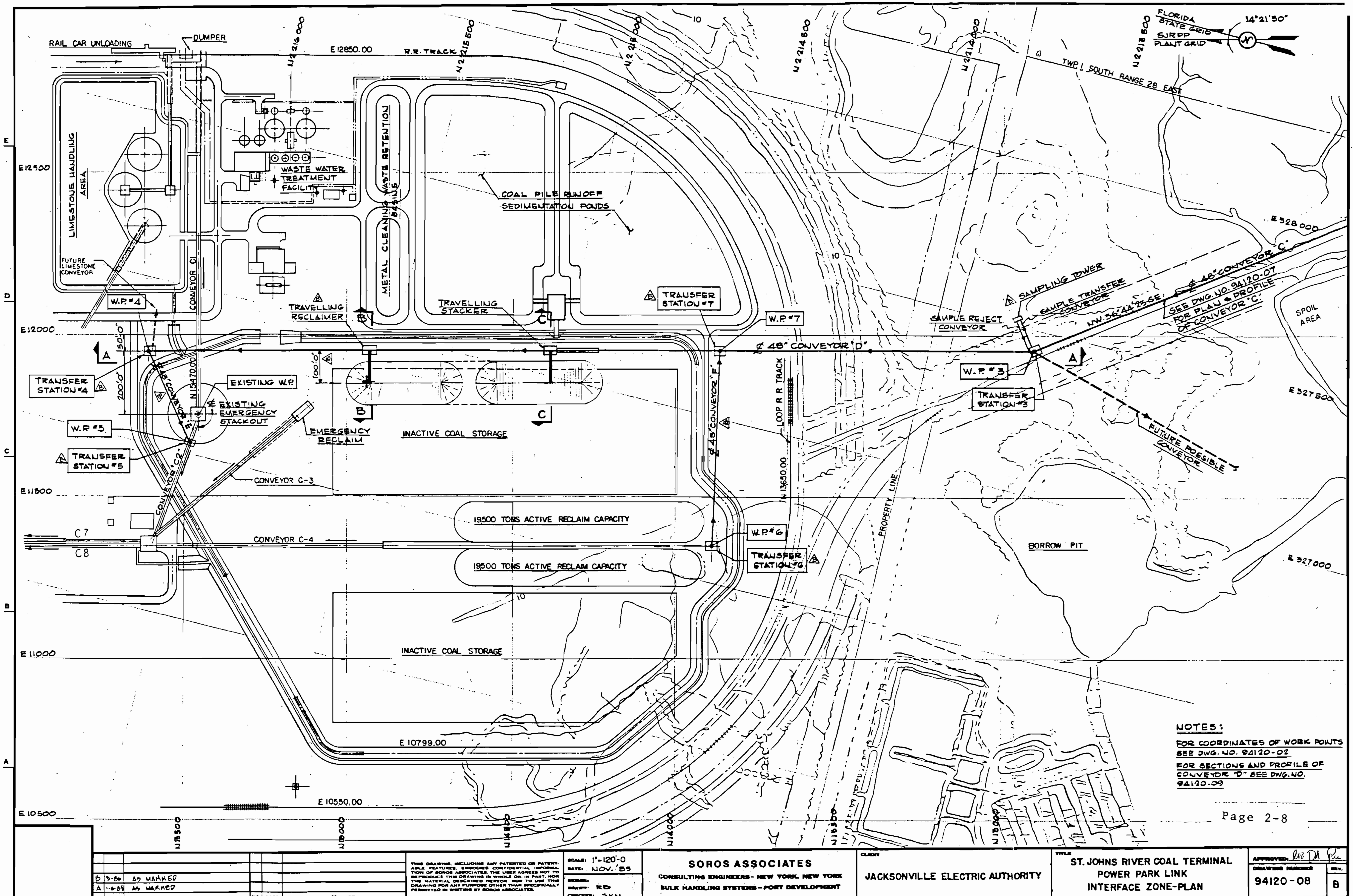
2. FOR LOCATIONS AND IDENTIFICATIONS OF WORK POINTS REFER TO DRAWINGS NO. 94120-03 THRU 94120-06.
3. AREA MARKED THUS INDICATES JEA EXISTING EASEMENT & AREA MARKED THUS INDICATES JEA PROPOSED ADDITIONAL EASEMENT
SOROS ASSOCIATES
CONSULTING ENGINEERS - NEW YORK, NEW YORK
BULK HANDLING SYSTEMS - PORT DEVELOPMENT
SCALE 1"=400
DATE NOV. '80
JACKSONVILLE ELECTRIC AUTHORITY
ST. JOHNS RIVER COAL TERMINAL
SITE PLAN
94120-02
B
DATE
REVISION



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DUMPER
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R.R. TRACK
N 2 216 000
N 2 215 500
N 2 215 000
N 2 214 500
N 2 214 000
N 2 213 500
FLORIDA STATE GRID
SJRPP PLANT GRID
14°21'50"
TWP. 1 SOUTH RANGE 28 EAST
LIMESTONE HANDLING AREA
FUTURE LIMESTONE CONVEYOR
WASTE WATER TREATMENT FACILITY
METAL CLEANING WASTE RETENTION BASINS
COAL PILE RUNOFF SEDIMENTATION PONDS
E 12500
E 12000
E 11500
E 11000
E 10500
W.P. #4
CONVEYOR C1
TRAVELLING RECLAIMER
TRAVELLING STACKER
TRANSFER STATION #7
W.P. #7
SAMPLING TOWER
SAMPLE TRANSFER CONVEYOR
SAMPLE REJECT CONVEYOR
N.W. 36°44'23" S.E.
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SEE DWG. NO. 94120-07 FOR PLAN & PROFILE OF CONVEYOR "C"
SPOIL AREA
E 328 000
E 327 500
E 327 000
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W.P. #3
TRANSFER STATION #3
FUTURE POSSIBLE CONVEYOR
TRANSFER STATION #4
EXISTING W.P.
N 15470.00
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EMERGENCY RECLAIM
INACTIVE COAL STORAGE
LOOP R R TRACK
℄ 48" CONVEYOR "F"
W.P. #5
TRANSFER STATION #5
CONVEYOR C2
CONVEYOR C-3
N 13650.00
PROPERTY LINE
19500 TONS ACTIVE RECLAIM CAPACITY
C7
C8
CONVEYOR C-4
W.P. #6
TRANSFER STATION #6
BORROW PIT
INACTIVE COAL STORAGE
E 10799.00
E 10550.00
N 18500
N 18000
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N 13500
N 13000
50'-0"
100'-0"
200'-0"
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FOR COORDINATES OF WORK POINTS SEE DWG. NO. 94120-02
FOR SECTIONS AND PROFILE OF CONVEYOR "D" SEE DWG. NO. 94120-09
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A 1-6-85 AS MARKED
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DATE: NOV. '85
DRAWN: KB
CHECKED: SKM
SOROS ASSOCIATES
CONSULTING ENGINEERS - NEW YORK, NEW YORK
BULK HANDLING SYSTEMS - PORT DEVELOPMENT
CLIENT
JACKSONVILLE ELECTRIC AUTHORITY
TITLE
ST. JOHNS RIVER COAL TERMINAL
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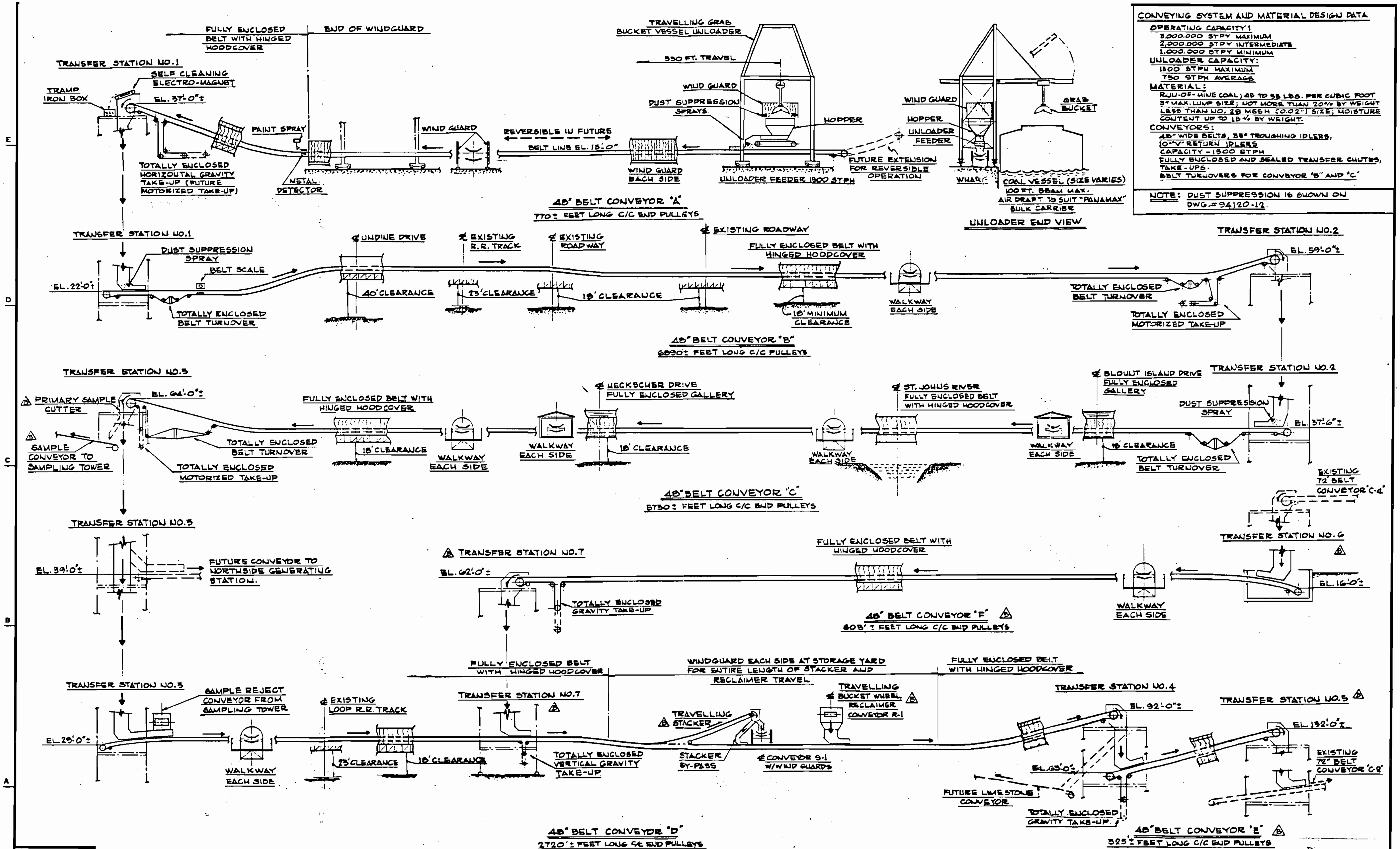

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DESIGN: W.A.C.
DRAWN: RB
CHECKED: S.K.M.

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CONSULTING ENGINEERS - NEW YORK, NEW YORK
BULK HANDLING SYSTEMS - PORT DEVELOPMENT

CLIENT: JACKSONVILLE ELECTRIC AUTHORITY

TITLE: ST. JOHNS RIVER COAL TERMINAL
SYSTEM FLOW DIAGRAM
MATERIAL HANDLING

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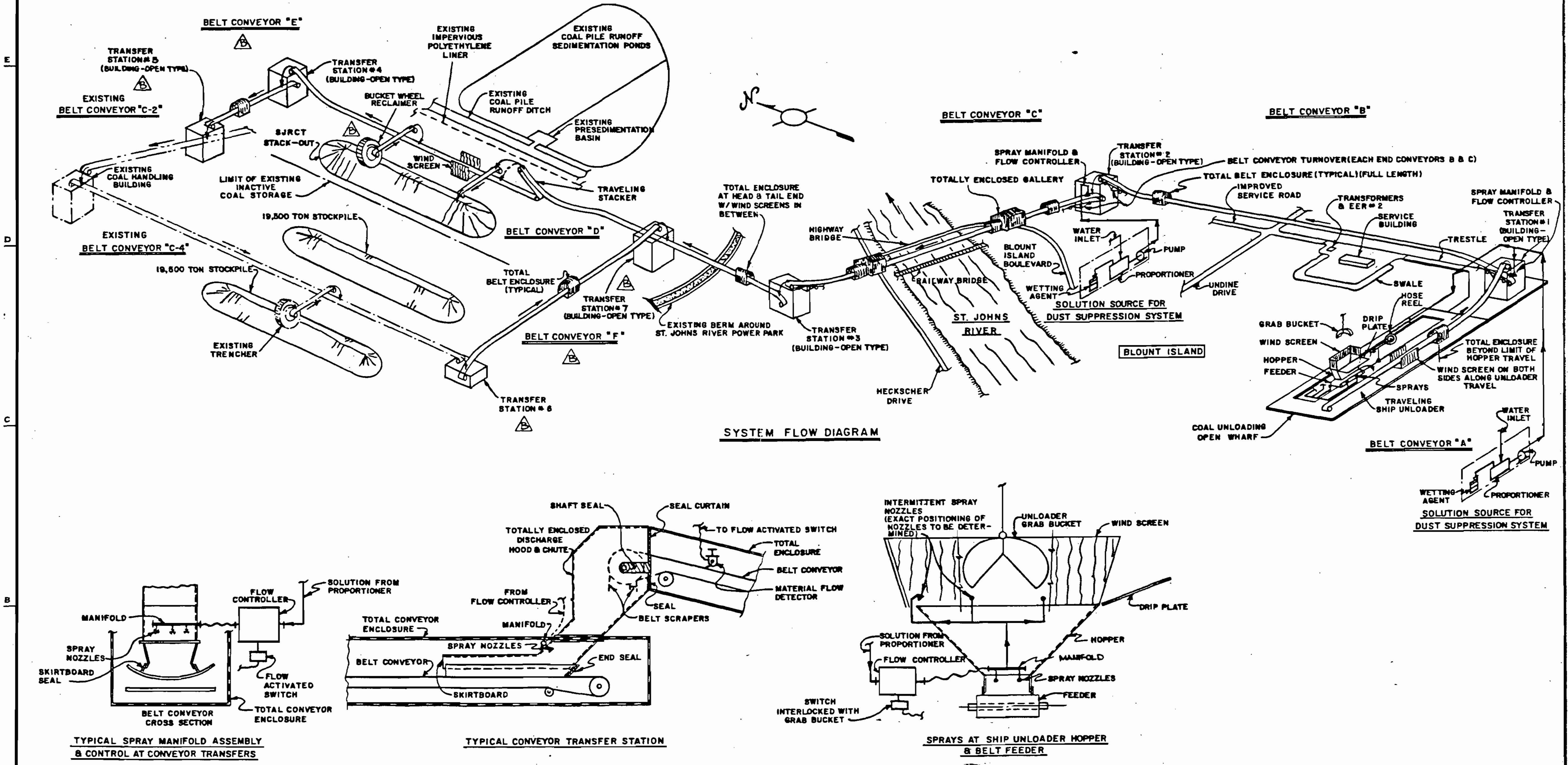

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CHECKED: SKM

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CONSULTING ENGINEERS - NEW YORK, NEW YORK
BULK HANDLING SYSTEMS - PORT DEVELOPMENT

CLIENT: JACKSONVILLE ELECTRIC AUTHORITY

TITLE: ST. JOHNS RIVER COAL TERMINAL SYSTEM FLOW DIAGRAM DUST CONTROL - WET

APPROVED:
DRAWING NUMBER: 94120-12
REV.: B

REV.	DATE	REVISION
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A	1-28-86	AS MARKED

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SCALE: 1"=2000'-0"
DATE: NOV. '85
DESIGN:
DRAWN: RB
CHECKED: SKM

SOROS ASSOCIATES
CONSULTING ENGINEERS - NEW YORK, NEW YORK
BULK HANDLING SYSTEMS - PORT DEVELOPMENT

CLIENT: JACKSONVILLE ELECTRIC AUTHORITY

TITLE: ST. JOHNS RIVER COAL TERMINAL
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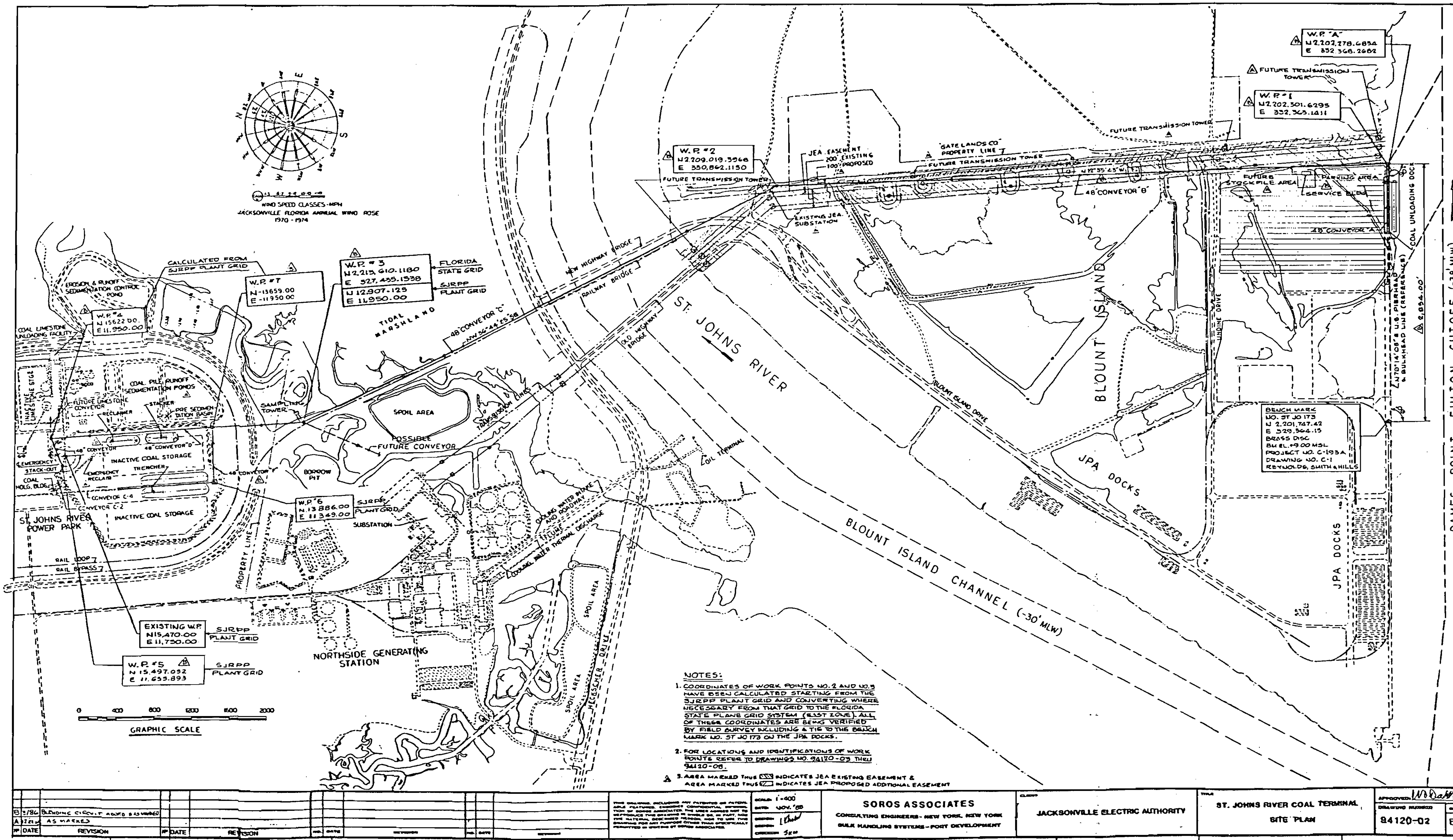

WIND SPEED CLASSES-MPH
JACKSONVILLE FLORIDA ANNUAL WIND ROSE
1970 - 1974
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E 352,368.2682
FUTURE TRANSMISSION TOWER
W.P. "1"
N 2,202,301.6295
E 352,365.1411
FUTURE TRANSMISSION TOWER
GATE LANDS CO PROPERTY LINE
W.P. "2"
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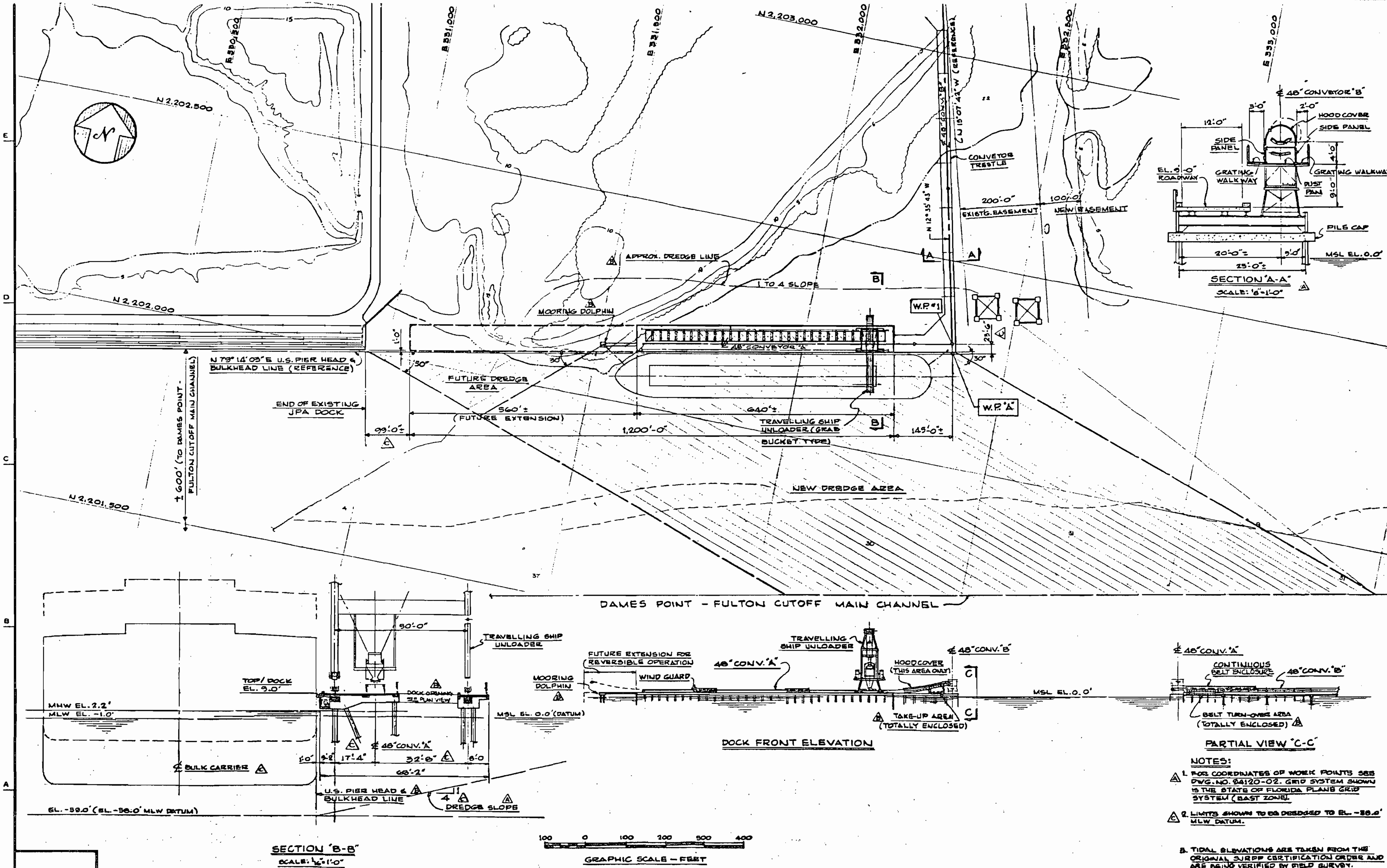
E 350,842.1150
JEA EASEMENT
200' EXISTING
100' PROPOSED
FUTURE TRANSMISSION TOWER
EXISTING JEA SUBSTATION
48" CONVEYOR "B"
FUTURE STOCKPILE AREA
PARKING AREA
SERVICE BLDG
48" CONVEYOR "A"
COAL UNLOADING DOCK
U.S. PIERHEAD & BULKHEAD LINE (REFERENCE)
DAMES POINT - FULTON CUTOFF (-38' MLW)
CALCULATED FROM SJRPP PLANT GRID
W.P. "3"
N 2,215,610.1180
E 327,435.1538
FLORIDA STATE GRID
N 12,907.125
E 11,950.00
SJRPP PLANT GRID
W.P. "7"
N-13659.00
E-11950.00
W.P. "4"
N 15622.00
E 11,950.00
EROSION & RUNOFF SEDIMENTATION CONTROL POND
COAL LIMESTONE UNLOADING FACILITY
TIDAL MARSHLAND
48" CONVEYOR "C"
NEW HIGHWAY BRIDGE
RAILWAY BRIDGE
OLD HIGHWAY BRIDGE
ST. JOHNS RIVER
BLOUNT ISLAND
BLOUNT ISLAND DRIVE
BLOUNT ISLAND CHANNEL (-30' MLW)
JPA DOCKS
COAL PILE RUNOFF SEDIMENTATION PONDS
INACTIVE LIMESTONE STORAGE
FUTURE LIMESTONE CONVEYOR
RECLAIMER
STACKER
PRE SEDIMENTATION BASIN
SAMPLING TOWER
SPOIL AREA
POSSIBLE FUTURE CONVEYOR
TRANSMISSION LINES
48" CONVEYOR
48" CONVEYOR "D"
INACTIVE COAL STORAGE
TRENCHER
EMERGENCY STACK-OUT
EMERGENCY RECLAIM
COAL HDLG. BLDG.
CONVEYOR C-4
CONVEYOR C-2
BORROW PIT
OIL TERMINAL
W.P. "6"
N 13,886.00
E 11,349.00
SJRPP PLANT GRID
SUBSTATION
COOLING WATER INTAKE AND ROADWAY
COOLING WATER THERMAL DISCHARGE
ST. JOHNS RIVER POWER PARK
INACTIVE COAL STORAGE
RAIL LOOP
RAIL BYPASS
PROPERTY LINE
BENCH MARK
NO. ST JO 173
N 2,201,747.42
E 329,364.15
BRASS DISC
BM EL.+9.00 MSL
PROJECT NO. C-193A
DRAWING NO. C-1
REYNOLDS, SMITH & HILLS
EXISTING W.P.
N15,470.00
E 11,750.00
SJRPP PLANT GRID
W.P. "5"
N 15,497.052
E 11,655.893
SJRPP PLANT GRID
NORTHSIDE GENERATING STATION
SPOIL AREA
HECKSCHER DRIVE
0 400 800 1200 1600 2000
GRAPHIC SCALE
NOTES:
1. COORDINATES OF WORK POINTS NO. 2 AND NO. 3 HAVE BEEN CALCULATED STARTING FROM THE SJRPP PLANT GRID AND CONVERTING WHERE NECESSARY FROM THAT GRID TO THE FLORIDA STATE PLANE GRID SYSTEM (EAST ZONE). ALL OF THESE COORDINATES ARE BEING VERIFIED BY FIELD SURVEY INCLUDING A TIE TO THE BENCH MARK NO. ST JO 173 ON THE JPA DOCKS.
2. FOR LOCATIONS AND IDENTIFICATIONS OF WORK POINTS REFER TO DRAWINGS NO. 94120-03 THRU 94120-08.
3. AREA MARKED THUS INDICATES JEA EXISTING EASEMENT & AREA MARKED THUS INDICATES JEA PROPOSED ADDITIONAL EASEMENT
B 3/86 BLENDING CIRCUIT ADDED & AS MARKED
A AS MARKED
DATE REVISION
DATE REVISION
SCALE 1"=400'
DATE NOV. '80
SOROS ASSOCIATES
CONSULTING ENGINEERS - NEW YORK, NEW YORK
BULK HANDLING SYSTEMS - PORT DEVELOPMENT
JACKSONVILLE ELECTRIC AUTHORITY
ST. JOHNS RIVER COAL TERMINAL
SITE PLAN
94120-02
B



NO.	DATE	REVISION
C	3-86	AS MARKED
B	2/3/86	AS MARKED
A	11/7/85	DREDGE SLOPE & TO 1 ADDED, MORE INFORMATION ADDED TO SECT. A-A & NOTE 1

THIS DRAWING, INCLUDING ANY PATENTED OR PATENTABLE FEATURES, EMBODIES CONFIDENTIAL INFORMATION OF SOROS ASSOCIATES. THE USER AGREES NOT TO REPRODUCE THIS DRAWING IN WHOLE OR IN PART, NOR THE MATERIAL DESCRIBED HEREON, NOR TO USE THIS DRAWING FOR ANY PURPOSE OTHER THAN SPECIFICALLY PERMITTED IN WRITING BY SOROS ASSOCIATES.

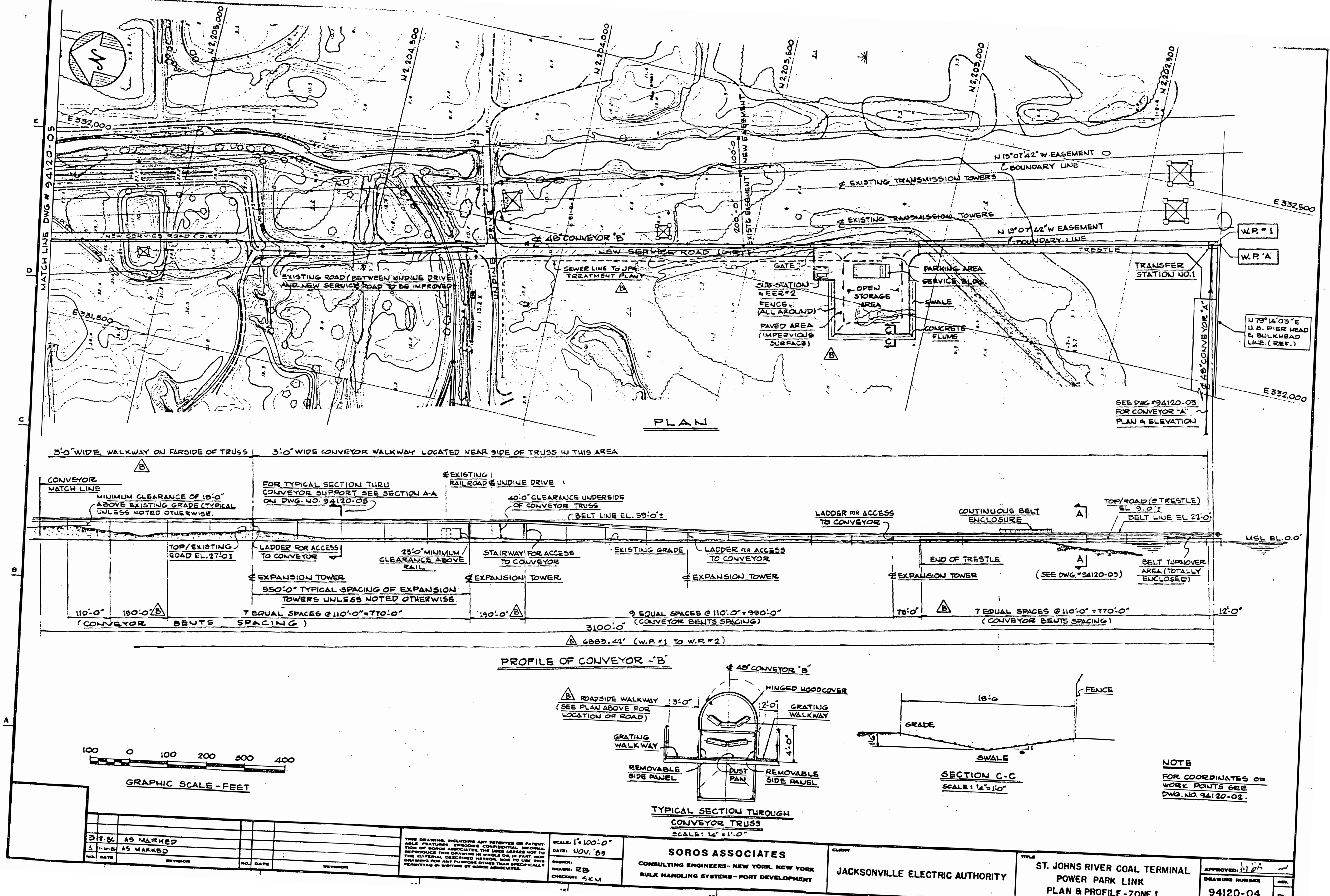
SCALE: 1" = 100'-0" & AS SHOWN
DATE: NOV. '85
DESIGN:
DRAWN: RB
CHECKED: SEM

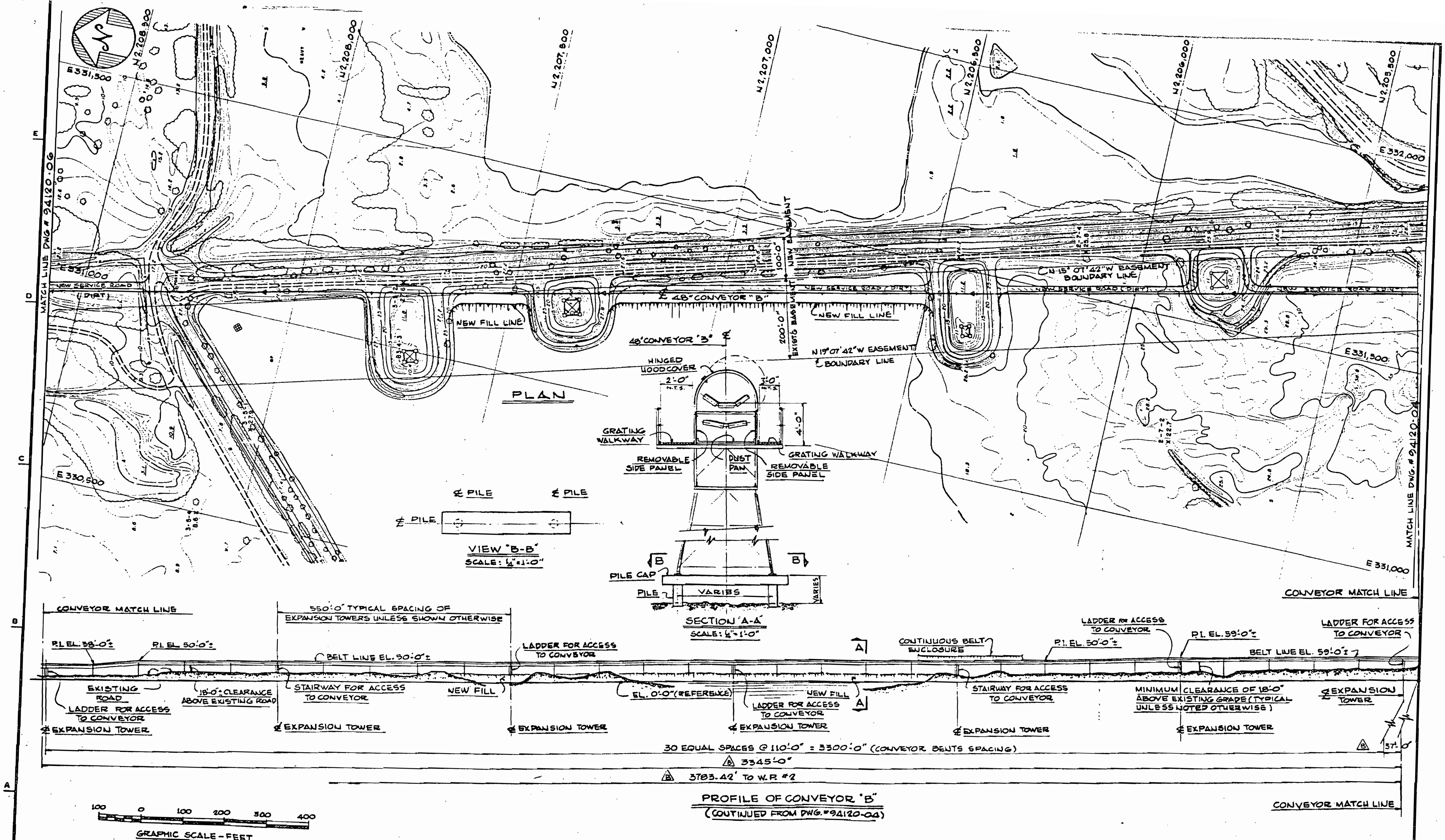
SOROS ASSOCIATES
CONSULTING ENGINEERS - NEW YORK, NEW YORK
BULK HANDLING SYSTEMS - PORT DEVELOPMENT

CLIENT: JACKSONVILLE ELECTRIC AUTHORITY

TITLE: ST. JOHNS RIVER COAL TERMINAL
DOCKSIDE ZONE
DREDGING & WHARF

APPROVED:
DRAWING NUMBER: 94120-03
REV. C


MATCH LINE DWG # 94120-05
E 332,000
E 331,500
E 332,500
N 2,203,000
N 2,204,500
N 2,204,000
N 2,205,500
N 2,203,000
N 2,202,900
N 13°07'42" W EASEMENT
BOUNDARY LINE
℄ EXISTING TRANSMISSION TOWERS
N 13°07'42" W EASEMENT
BOUNDARY LINE
NEW SERVICE ROAD (DIRT)
℄ 48" CONVEYOR "B"
NEW SERVICE ROAD (DIRT)
TRESTLE
W.P. # 1
W.P. 'A'
TRANSFER STATION NO. 1
EXISTING ROAD (BETWEEN UNDINE DRIVE AND NEW SERVICE ROAD TO BE IMPROVED)
SEWER LINE TO JPA TREATMENT PLANT
GATE
SUB-STATION & EER #2
FENCE (ALL AROUND)
PAVED AREA (IMPERVIOUS SURFACE)
OPEN STORAGE AREA
PARKING AREA
SERVICE BLDG.
SWALE
CONCRETE FLUME
N 79°14'03" E U.S. PIER HEAD & BULKHEAD LINE (REF.)
℄ 48" CONVEYOR "A"
SEE DWG #94120-03 FOR CONVEYOR "A" PLAN & ELEVATION
PLAN
3'-0" WIDE WALKWAY ON FARSIDE OF TRUSS
3'-0" WIDE CONVEYOR WALKWAY LOCATED NEAR SIDE OF TRUSS IN THIS AREA
CONVEYOR MATCH LINE
MINIMUM CLEARANCE OF 18'-0" ABOVE EXISTING GRADE (TYPICAL UNLESS NOTED OTHERWISE.
FOR TYPICAL SECTION THRU CONVEYOR SUPPORT SEE SECTION A-A ON DWG. NO. 94120-05
℄ EXISTING RAILROAD ℄ UNDINE DRIVE
40'-0" CLEARANCE UNDERSIDE OF CONVEYOR TRUSS
BELT LINE EL. 59'-0" ±
LADDER FOR ACCESS TO CONVEYOR
CONTINUOUS BELT ENCLOSURE
TOP/ROAD (℄ TRESTLE) EL. 9.0' ±
BELT LINE EL 22'-0"
MSL EL. 0.0'
TOP/EXISTING ROAD EL. 27'-0"±
LADDER FOR ACCESS TO CONVEYOR
23'-0" MINIMUM CLEARANCE ABOVE RAIL
STAIRWAY FOR ACCESS TO CONVEYOR
EXISTING GRADE
LADDER FOR ACCESS TO CONVEYOR
END OF TRESTLE
BELT TURNOVER AREA (TOTALLY ENCLOSED)
(SEE DWG. #94120-03)
℄ EXPANSION TOWER
℄ EXPANSION TOWER
℄ EXPANSION TOWER
℄ EXPANSION TOWER
550'-0" TYPICAL SPACING OF EXPANSION TOWERS UNLESS NOTED OTHERWISE.
110'-0"
130'-0"
7 EQUAL SPACES @ 110'-0" = 770'-0"
130'-0"
9 EQUAL SPACES @ 110'-0" = 990'-0"
78'-0"
7 EQUAL SPACES @ 110'-0" = 770'-0"
12'-0"
(CONVEYOR BENTS SPACING)
(CONVEYOR BENTS SPACING)
(CONVEYOR BENTS SPACING)
3100'-0"
6883.42' (W.P. #1 TO W.P. #2)
PROFILE OF CONVEYOR -'B'
℄ 48" CONVEYOR 'B'
HINGED HOODCOVER
ROADSIDE WALKWAY (SEE PLAN ABOVE FOR LOCATION OF ROAD)
3'-0"
2'-0"
GRATING WALKWAY
GRATING WALKWAY
4'-0"
REMOVABLE SIDE PANEL
DUST PAN
REMOVABLE SIDE PANEL
TYPICAL SECTION THROUGH CONVEYOR TRUSS
SCALE: 1/4" = 1'-0"
18'-6
FENCE
GRADE
SWALE
SECTION C-C
SCALE: 1/4" = 1'-0"
NOTE
FOR COORDINATES OF WORK POINTS SEE DWG. NO. 94120-02.
100 0 100 200 300 400
GRAPHIC SCALE - FEET
3 8-86 AS MARKED
1 1-6-86 AS MARKED
NO. DATE REVISION
NO. DATE REVISION
SCALE: 1" = 100'-0"
DATE: NOV. '85
DRAWN: RB
CHECKED: SKM
SOROS ASSOCIATES
CONSULTING ENGINEERS - NEW YORK, NEW YORK
BULK HANDLING SYSTEMS - PORT DEVELOPMENT
CLIENT
JACKSONVILLE ELECTRIC AUTHORITY
TITLE
ST. JOHNS RIVER COAL TERMINAL
POWER PARK LINK
PLAN & PROFILE - ZONE 1
DRAWING NUMBER
94120-04



NOTE:
FOR COORDINATES OF WORK POINTS SEE DWG. NO. 94120-02.

NO.	DATE	REVISION	NO.	DATE	REVISION
B	2-86	AS MARKED			
A	1-86	AS MARKED			

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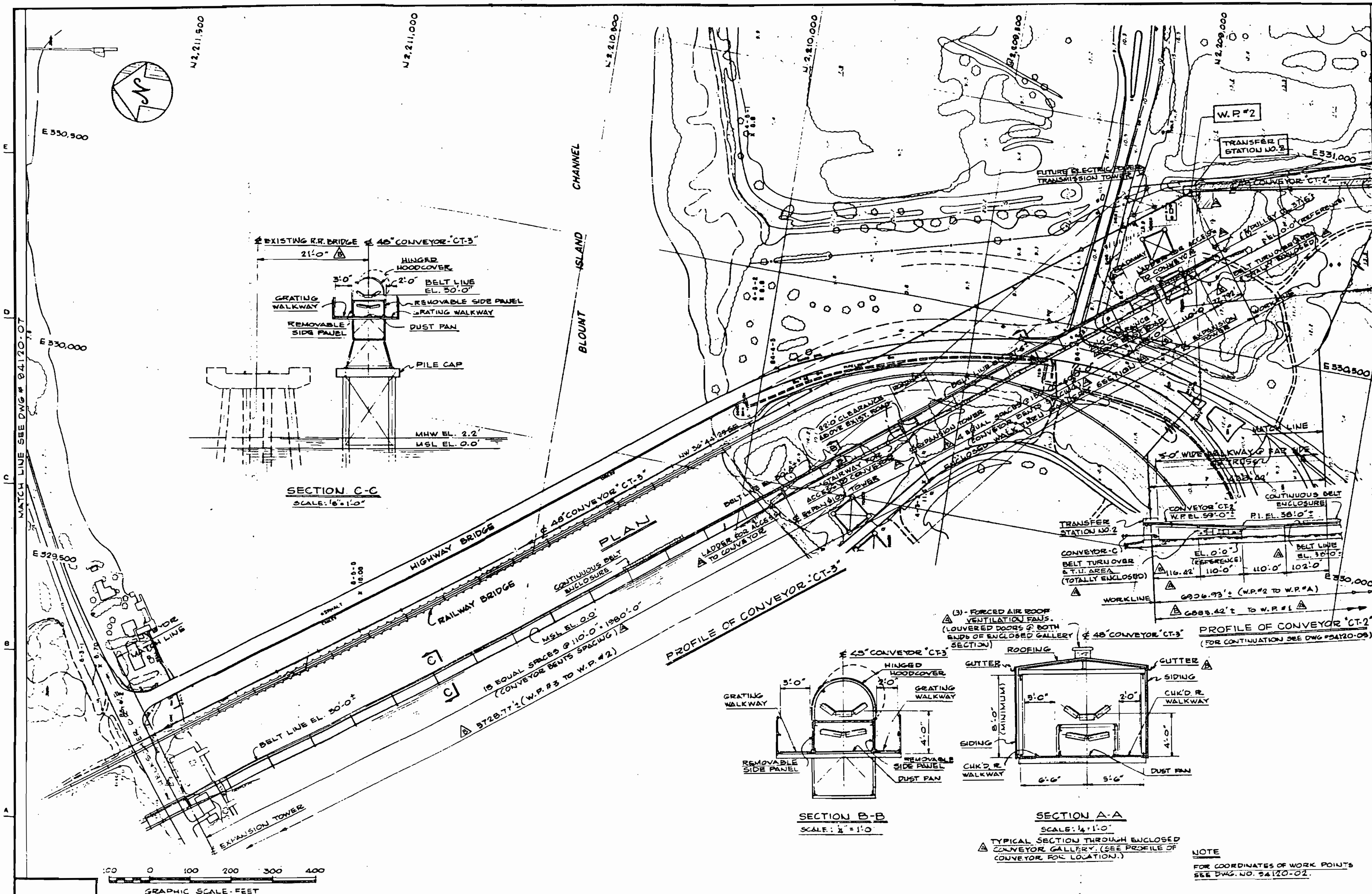
SCALE: 1"=100'-0"
DATE: NOV. '85
DESIGN:
DRAWN: RB
CHECKED: SKM

SOROS ASSOCIATES
CONSULTING ENGINEERS - NEW YORK, NEW YORK
BULK HANDLING SYSTEMS - PORT DEVELOPMENT

CLIENT: JACKSONVILLE ELECTRIC AUTHORITY

TITLE: ST. JOHNS RIVER COAL TERMINAL
POWER PARK LINK
PLAN & PROFILE - ZONE 2

APPROVED:
DRAWING NUMBER: 94120-05
REV.: B



NO.	DATE	REVISION
3		AS MARKED
2		AS MARKED

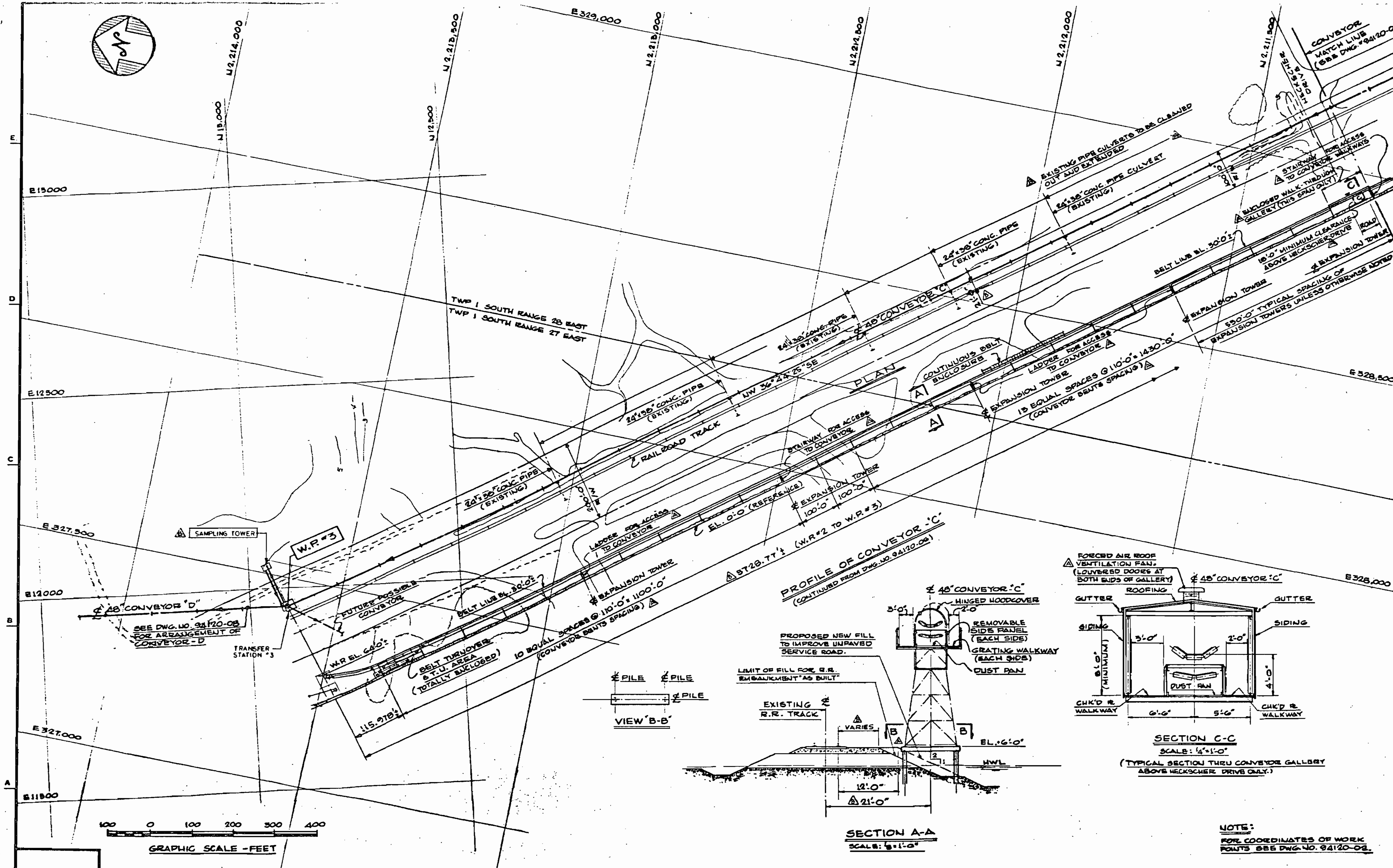
SCALE: 1" = 100'-0"
DATE: NOV. '85
DRAWN: RB

SOROS ASSOCIATES
CONSULTING ENGINEERS - NEW YORK, NEW YORK
BULK HANDLING SYSTEMS - PORT DEVELOPMENT

CLIENT: JACKSONVILLE ELECTRIC AUTHORITY
FLORIDA POWER & LIGHT COMPANY

TITLE: ST. JOHNS RIVER COAL TERMINAL
POWER PARK LINK
PLAN & PROFILE - ZONE 3

DRAWING NUMBER: 94120-06
REV.: B



NO.	DATE	REVISION	NO.	DATE	REVISION
B	4/86	AS MARKED			
A	12/85	AS MARKED			

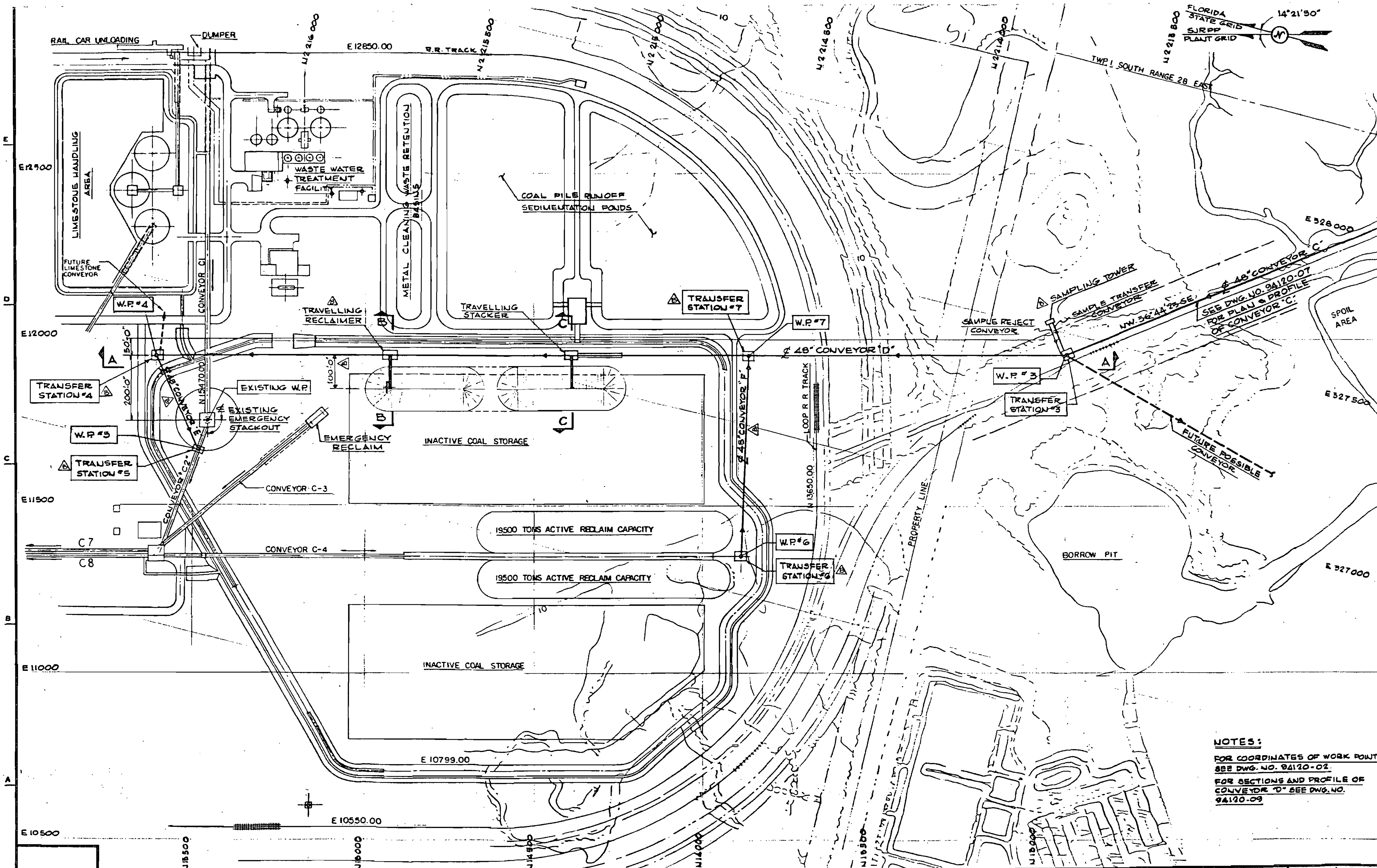
SCALE: 1"=100'-0"
DATE: NOV. '85
DESIGN:
DRAWN: RB
CHECKED: SKM

SOROS ASSOCIATES
CONSULTING ENGINEERS - NEW YORK, NEW YORK
BULK HANDLING SYSTEMS - PORT DEVELOPMENT

CLIENT: JACKSONVILLE ELECTRIC AUTHORITY

TITLE: ST. JOHNS RIVER COAL TERMINAL POWER PARK LINK PLAN & PROFILE - ZONE 4

APPROVED:
DRAWING NUMBER: 94120-07
REV. B



NOTES:

FOR COORDINATES OF WORK POINTS SEE DWG. NO. 94120-02.

FOR SECTIONS AND PROFILE OF CONVEYOR 'D' SEE DWG. NO. 94120-09

NO.	DATE	REVISION
B	3-86	AS MARKED
A	1-6-86	AS MARKED

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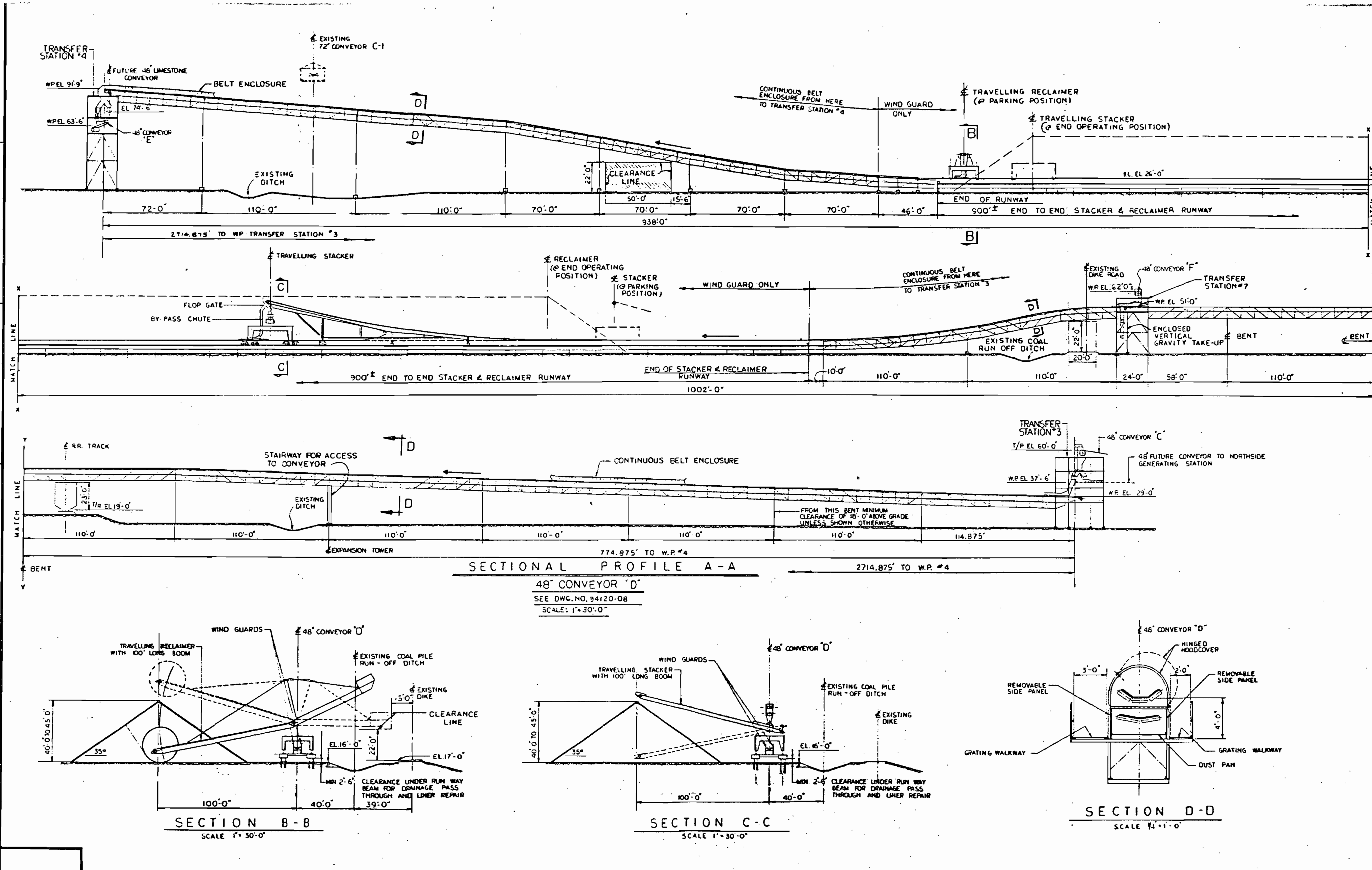
SCALE: 1" = 120'-0
DATE: NOV. '85
DESIGN:
DRAWN: RB
CHECKED: SKM

SOROS ASSOCIATES
CONSULTING ENGINEERS - NEW YORK, NEW YORK
BULK HANDLING SYSTEMS - PORT DEVELOPMENT

CLIENT: JACKSONVILLE ELECTRIC AUTHORITY

TITLE: ST. JOHNS RIVER COAL TERMINAL POWER PARK LINK INTERFACE ZONE-PLAN

APPROVED:
DRAWING NUMBER: 94120-08
REV. B



NO.	DATE	REVISION
6	10/7/86	REDRAWN - BLENDING CIRCUIT ADDED

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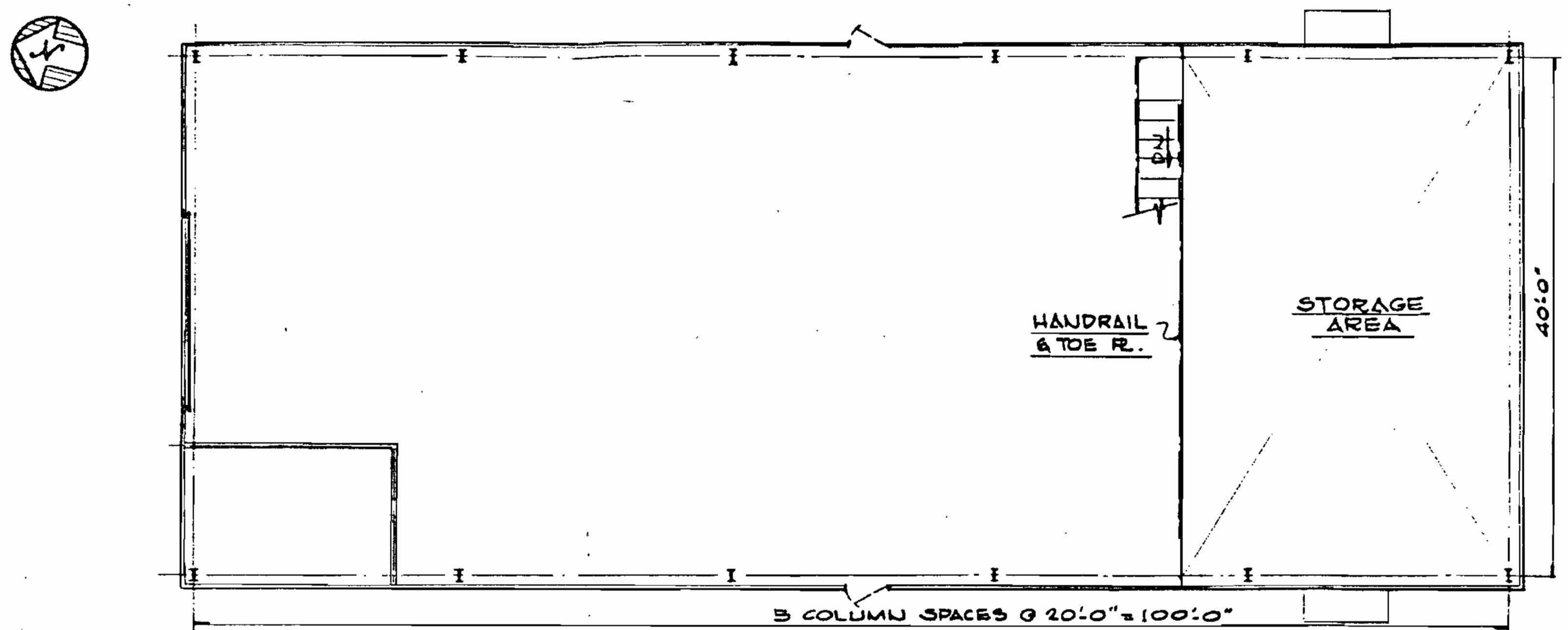
SCALE: AS SHOWN
DATE: MARCH 1986
CHECKED: SKM

SOROS ASSOCIATES
CONSULTING ENGINEERS - NEW YORK, NEW YORK
BULK HANDLING SYSTEMS - PORT DEVELOPMENT

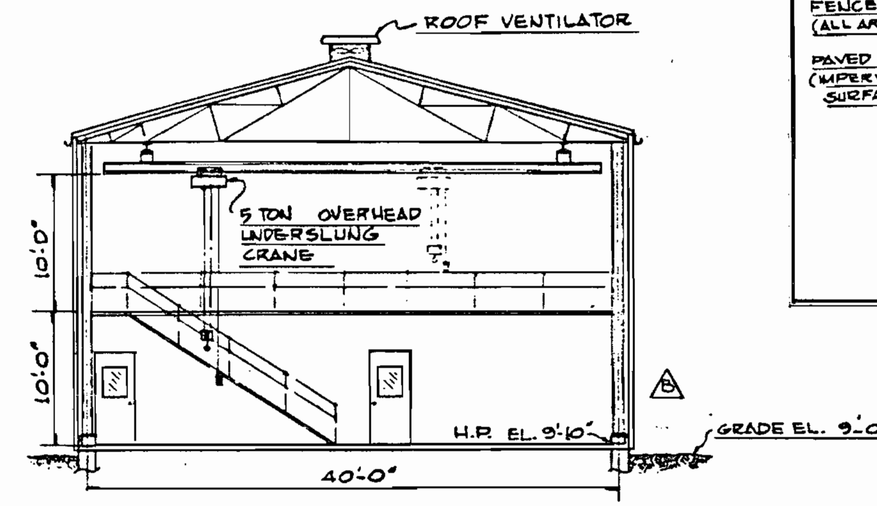
CLIENT: JACKSONVILLE ELECTRIC AUTHORITY

TITLE: ST. JOHNS RIVER COAL TERMINAL POWER PARK LINK INTERFACE ZONE - SECTIONS & PROFILE

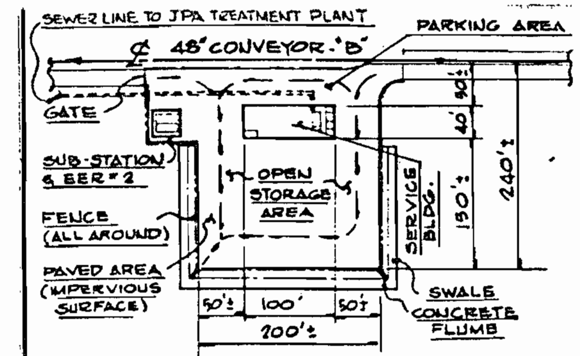
DRAWING NUMBER: 94120-09
REV. B



MEZZANINE FLOOR PLAN

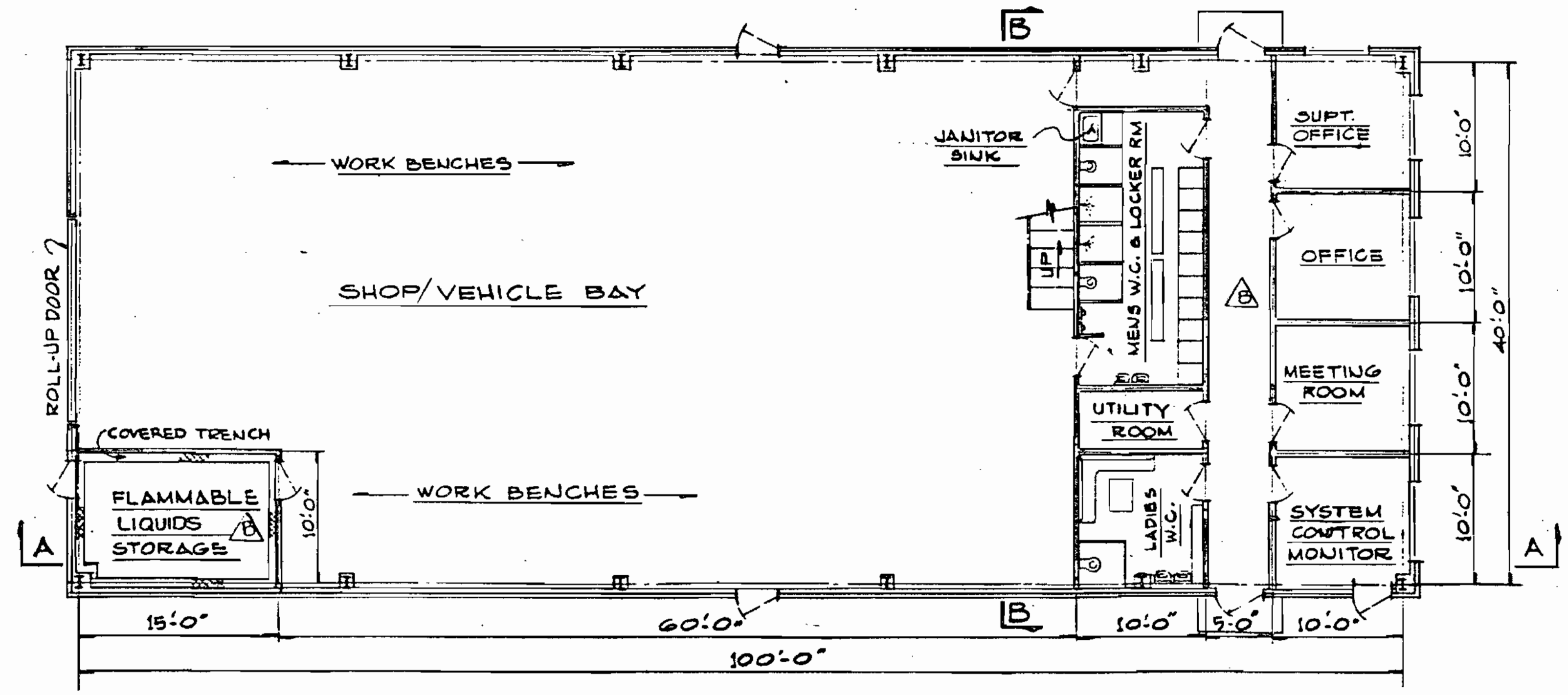


ELEVATION B-B

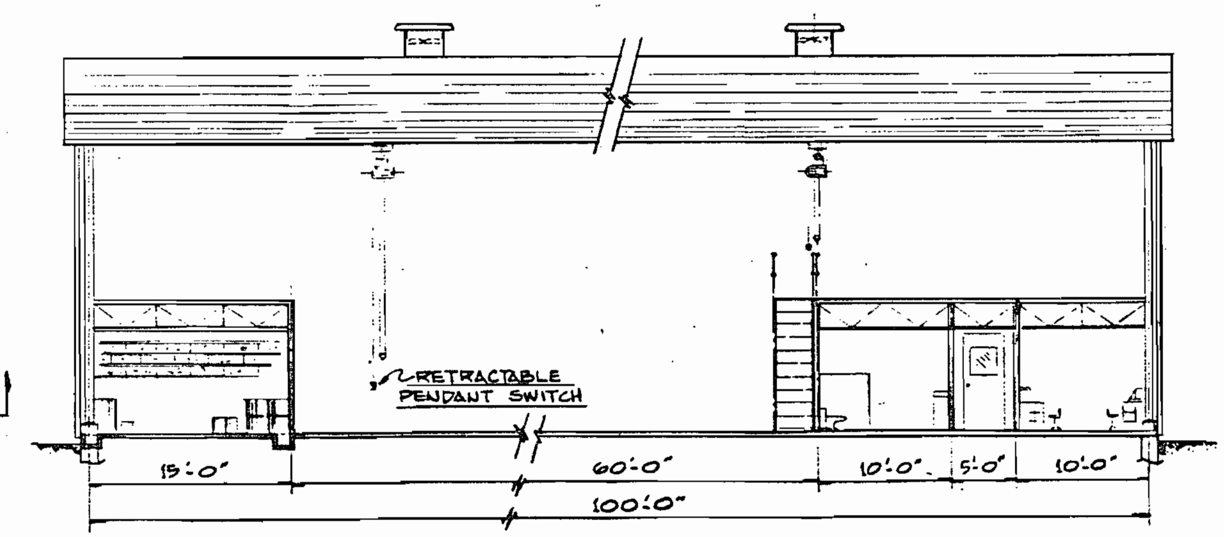


KEY PLAN

SCALE: 1" = 100'



FLOOR PLAN



ELEVATION A-A

GRAPHIC SCALE-FEET

NOTE:
FOR LOCATION OF SERVICE BUILDING
SEE DWG. NO. 94120-04.

NO.	DATE	REVISION
B	2-'86	AS MARKED
A	12-16-86	REDRAWN

THIS DRAWING, INCLUDING ANY PATENTED OR PATENTABLE FEATURES, EMBODIES CONFIDENTIAL INFORMATION OF SOROS ASSOCIATES. THE USER AGREES NOT TO REPRODUCE THIS DRAWING IN WHOLE OR, IN PART, NOR THE MATERIAL DESCRIBED HEREON, NOR TO USE THIS DRAWING FOR ANY PURPOSE OTHER THAN SPECIFICALLY PERMITTED IN WRITING BY SOROS ASSOCIATES.

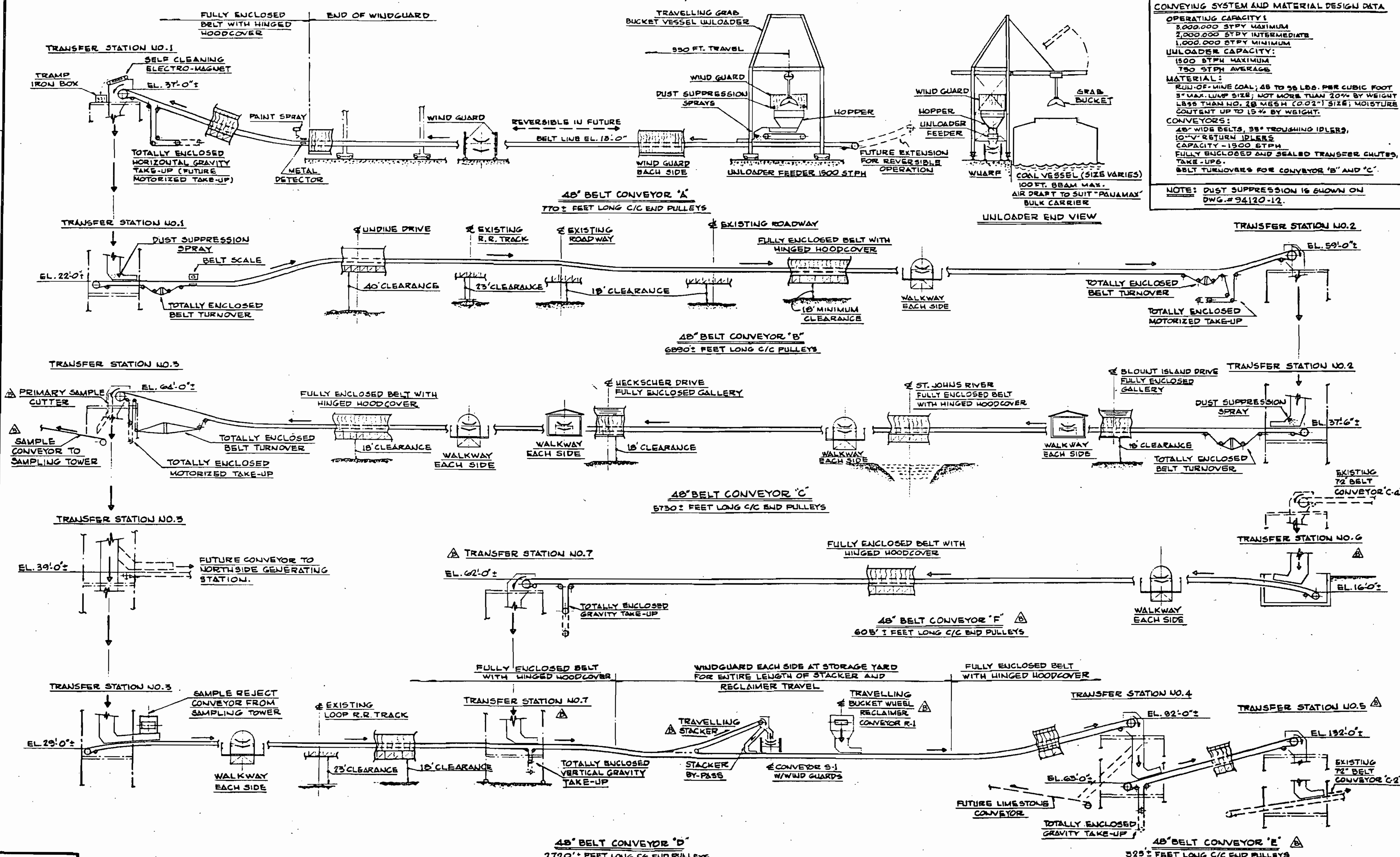
SCALE: 1½" = 10'-0"
DATE: DEC. 85
DESIGN:
DRAWN: RB
CHECKED: SKM

SOROS ASSOCIATES
CONSULTING ENGINEERS - NEW YORK, NEW YORK
BULK HANDLING SYSTEMS - PORT DEVELOPMENT

CLIENT
JACKSONVILLE ELECTRIC AUTHORITY

TITLE
ST. JOHNS RIVER COAL TERMINAL
SERVICE BUILDING LAYOUT

APPROVED
DRAWING NUMBER 94120-10
REV. B



CONVEYING SYSTEM AND MATERIAL DESIGN DATA

OPERATING CAPACITY:
- 3,000,000 STPY MAXIMUM
- 2,000,000 STPY INTERMEDIATE
- 1,000,000 STPY MINIMUM

UNLOADER CAPACITY:
- 1500 STPH MAXIMUM
- 750 STPH AVERAGE

MATERIAL:
- RUN-OF-MINE COAL; 48 TO 58 LBS. PER CUBIC FOOT
- 3" MAX. LUMP SIZE; NOT MORE THAN 20% BY WEIGHT LESS THAN NO. 28 MESH (0.02") SIZE; MOISTURE CONTENT UP TO 15% BY WEIGHT.

CONVEYORS:
- 48" WIDE BELTS, 35° TROUGHING IDLERS, 10° "V" RETURN IDLERS
- CAPACITY - 1500 STPH
- FULLY ENCLOSED AND SEALED TRANSFER CHUTES, TAKE-UPS.
- BELT TURNOVERS FOR CONVEYOR "B" AND "C".

NOTE: DUST SUPPRESSION IS SHOWN ON DWG.# 94120-12.

REV.	DATE	REVISION
B	2/86	BLENDING CIRCUIT CONV. 'B' 'F' ADDED
A	1/86	AS MARKED

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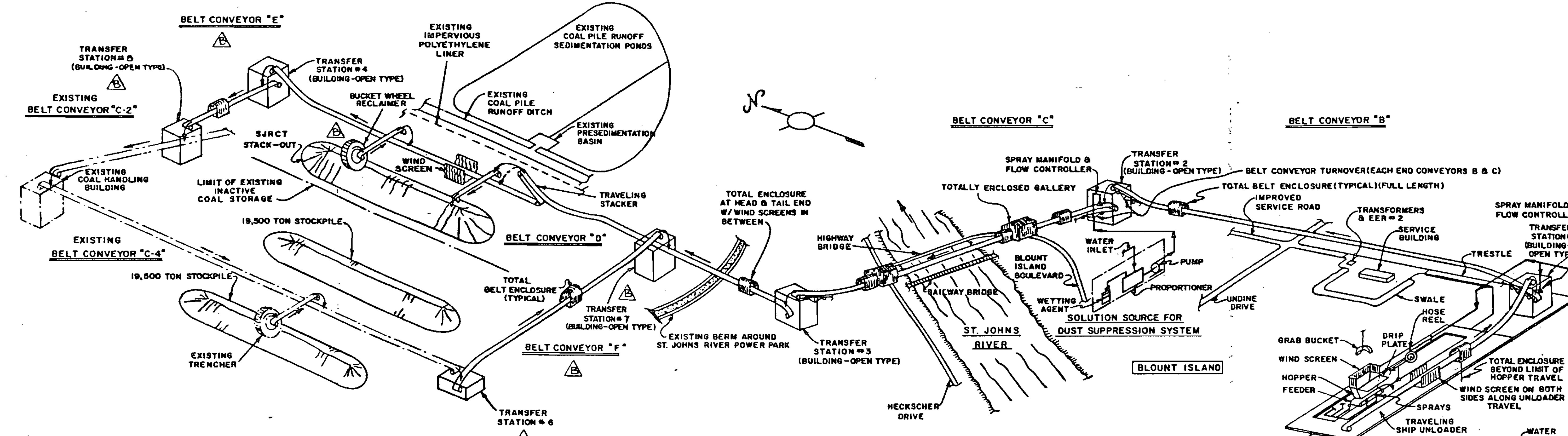
SCALE: NONE
DATE: NOV. '85
DESIGN: WAC
DRAWN: RB
CHECKED: S.K.U.

SOROS ASSOCIATES
CONSULTING ENGINEERS - NEW YORK, NEW YORK
BULK HANDLING SYSTEMS - PORT DEVELOPMENT

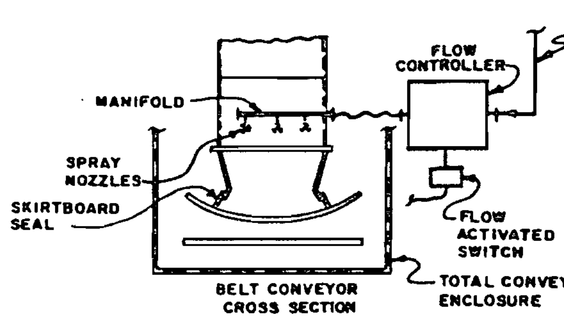
CLIENT: JACKSONVILLE ELECTRIC AUTHORITY

TITLE: ST. JOHNS RIVER COAL TERMINAL SYSTEM FLOW DIAGRAM MATERIAL HANDLING

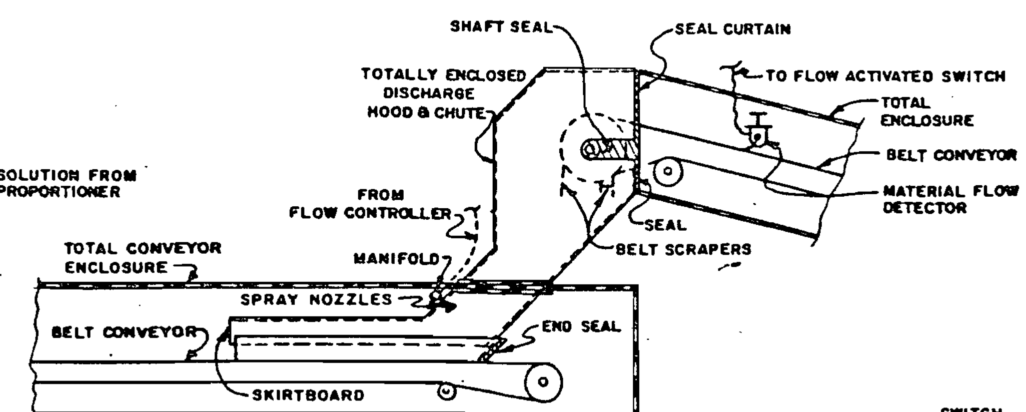
APPROVED: WTA/ 7?
DRAWING NUMBER: 94120-11
REV. B



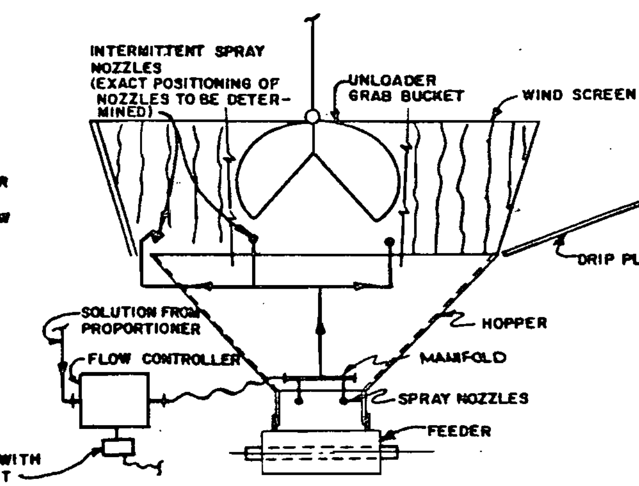
SYSTEM FLOW DIAGRAM



TYPICAL SPRAY MANIFOLD ASSEMBLY & CONTROL AT CONVEYOR TRANSFERS



TYPICAL CONVEYOR TRANSFER STATION



SPRAYS AT SHIP UNLOADER HOPPER & BELT FEEDER

NO.	DATE	REVISION
B	2/86	REDRAWN - BLENDING CIRCUIT ADDED
A	4/21/86	AS MARKED

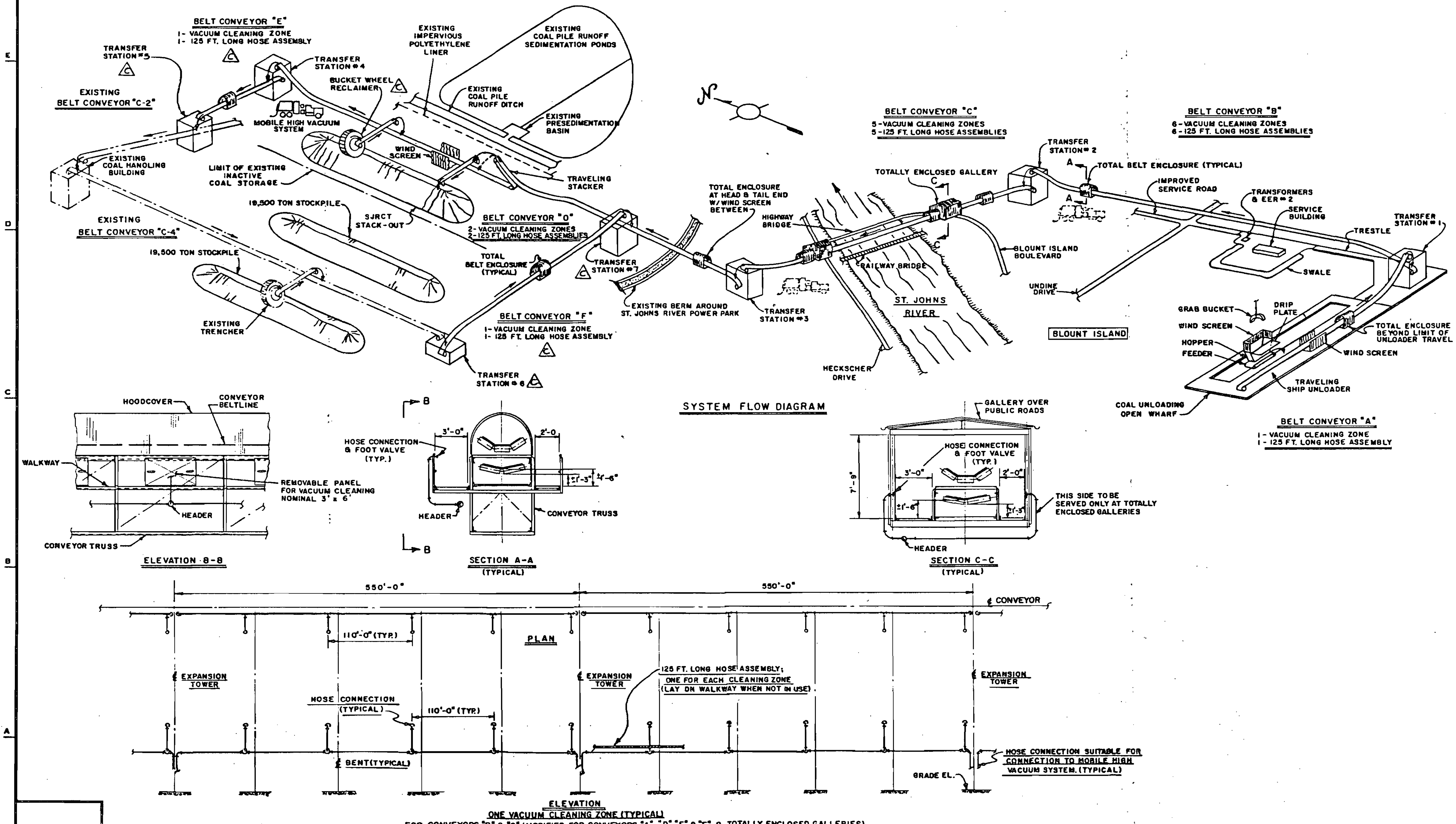
SCALE: NONE
DATE: 11/85
DESIGN: WAC
DRAWN: JMR
CHECKED: SKM

SOROS ASSOCIATES
CONSULTING ENGINEERS - NEW YORK, NEW YORK
BULK HANDLING SYSTEMS - PORT DEVELOPMENT

CLIENT: JACKSONVILLE ELECTRIC AUTHORITY

TITLE: ST. JOHNS RIVER COAL TERMINAL
SYSTEM FLOW DIAGRAM
DUST CONTROL - WET

APPROVED:
DRAWING NUMBER: 94120-12
REV.: B



NO.	DATE	REVISION
C	2/86	REDRAWN - BLENDING CIRCUIT ADDED
B	1/6/86	AS MARKED
A	12/23/85	AS MARKED

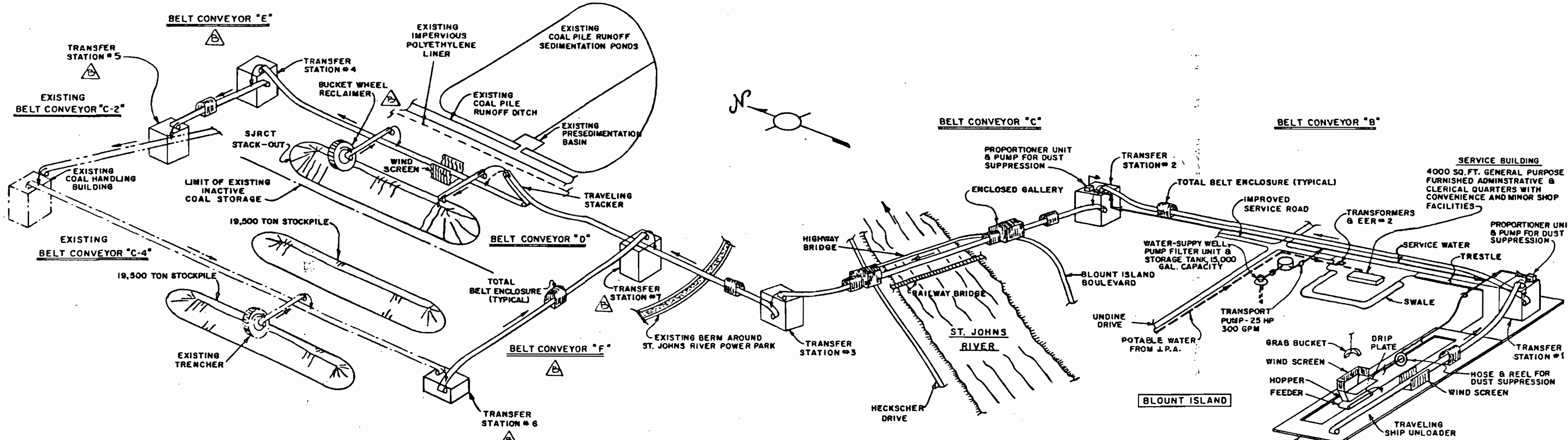
SCALE: NONE
DATE: 11/85
DESIGN: WAC
DRAWN: JMR
CHECKED: SKM

SOROS ASSOCIATES
CONSULTING ENGINEERS - NEW YORK, NEW YORK
BULK HANDLING SYSTEMS - PORT DEVELOPMENT

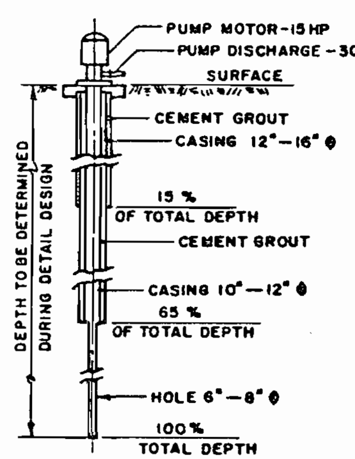
CLIENT: JACKSONVILLE ELECTRIC AUTHORITY

TITLE: ST. JOHNS RIVER COAL TERMINAL
SYSTEM FLOW DIAGRAM
DUST CONTROL - DRY

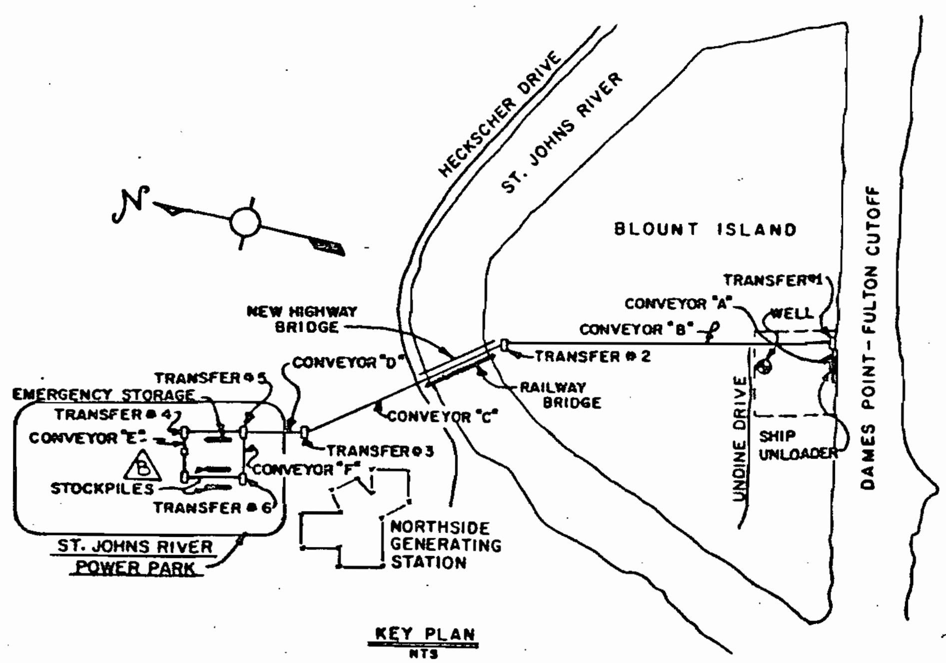
APPROVED: M. D. Jr.
DRAWING NUMBER: 94120-13
REV: C



SYSTEM FLOW DIAGRAM



DRILLED WELL



KEY PLAN
NTS

DUST CONTROL WATER CONSUMPTION
9,000,000 GAL/YEAR MAXIMUM

POTABLE WATER CONSUMPTION
25 GAL/MIN. INTERMITTENT DEMAND

NO.	DATE	REVISION
B	2/86	REDRAWN-BLENDING CIRCUIT ADDED
A	1/6/86	AS MARKED

SCALE: NONE
DATE: 11/85
DESIGN: WAC
DRAWN: JBR
CHECKED: SKM

SOROS ASSOCIATES
CONSULTING ENGINEERS- NEW YORK, NEW YORK
BULK HANDLING SYSTEMS-PORT DEVELOPMENT

CLIENT
JACKSONVILLE ELECTRIC AUTHORITY

TITLE
ST. JOHNS RIVER COAL TERMINAL
SYSTEM FLOW DIAGRAM
POTABLE & SERVICE WATER DISTRIBUTION

APPROVED:
DRAWING NUMBER 94120-16
REV. B