COUNTY OF SACRAMENTO

ENVIRONMENTAL MANAGEMENT DEPARTMENT

NORMAN D. COVELL, DIRECTOR

TC

AIR POLLUTION CONTROL DISTRICT
Richard G. Johnson, Chief

August 9, 1988

Pat Frost
SMUD
PO Box 15830 MS30
Sacramento, CA 95852-1830

Don Becker
Senior Purchasing Agent
Campbell Soup Company
6200 Franklin Blvd
Sacramento, CA 95824

Gentlemen:

Please refer to your applications to construct the following equipment located at 6200 Franklin Blvd, Sacramento:

APPLICATION NOS. 8577 - 8586:

1. Four steam boilers, rated at a total of 400 MM Btu/hr heat input, flue gas recirculation, low NOx burner.

2. One gas turbine, rated at 600 MM Btu/hr heat input, steam injection.

AUTHORITY TO CONSTRUCT

Authorization to construct is hereby granted with the following conditions:

1. The boilers and turbine shall be fired on natural gas only.
   a. In the event of an interruption of natural gas supply or for the routine testing of the emergency fuel system, the boilers and turbine may be fired on No.2 diesel fuel or No.5 fuel oil subject to the limitations in Condition 2.
   b. SMUD/Campbell Soup Company shall submit a written report to the District within 10 days of the start of any period of liquid fuel usage (excluding routine testing) detailing the circumstance of the natural gas service interruption.

2. The use of No.2 diesel fuel or No.5 fuel oil in the turbine and boilers shall not cause SO_2 emissions to exceed 250 pounds per day. SMUD/Campbell Soup Company shall submit a plan to the District specifying how this limit will be achieved and obtain approval prior to using liquid fuels

3. The emission of oxides of nitrogen (NOx) from each boiler shall not exceed:
   a. 40 ppmvd at 3% O_2 when firing natural gas.
   b. The lowest concentration established by source testing when firing No.2 diesel fuel or No.5 fuel oil.

4. The emission of oxides of nitrogen (NOx) from the turbine shall not exceed:
   a. 25 ppmvd at 15% O_2 when firing natural gas.
   b. The lowest concentration established by source testing when firing No.2 diesel fuel or No.5 fuel oil.

5. The majority of the usable thermal exhaust from the gas turbine shall not be diverted to the heat recovery steam generator, for generation of process steam, more than 1500 hours per year. A plan for such recordkeeping shall be submitted to the District for approval prior to operating the turbine.

6. The combined emissions from the boilers and turbine when using natural gas fuel shall not exceed:

Pollutant	pounds hour	pounds day	tons year	tons/calendar quarter Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
NOx	77	1734	144	34	33	44	33
SO_2	0.5	11	0.9				
CO	36	840	75				
ROC	5	103	9				
Particulate	10	217	18				

7. A continuous Emissions Tracking System to calculate the hourly, daily, quarterly and yearly emissions from the boilers and turbine shall be installed and operated to insure the limits in Condition 6 are not exceeded. SMUD/Campbell Soup shall submit a description of such an Emissions Tracking System that will accomplish this requirement to the APCO within 180 days of issuance of the Authority to Construct. SMUD/Campbell Soup must receive approval of the Emission Tracking System from the APCO before operation of the boilers and turbine begins.

8. A continuous system to monitor and record the fuel consumption and the ratio of steam or water injected to fuel fired in the turbine shall be installed in accordance with Rule 805 Section 501.

9. Approved monitors for NOx and O_2 shall be properly installed, maintained, operated and calibrated at all times for each boiler and the turbine (see Attachment 2).
   a. Specifications of the NOx and O_2 monitors chosen for installation shall be submitted to the Air Pollution Control Officer for approval.
   b. A Quality Assurance Plan for the maintenance, operation and calibration of the monitors shall be submitted to the Air Pollution Control Officer for approval.

10. An oxides of nitrogen (NOx) and carbon monoxide (CO) source test of each boiler and the turbine shall be performed and the test results submitted to the Air Pollution Control Officer within 60 days of the initial start-up of the process.
    a. Submit a test plan to the Air Pollution Control Officer for approval at least 30 days before the source test is to be performed.
    b. Notify the Air Pollution Control Officer at least a week prior to the actual source test date.

11. An emission test for NOx shall be conducted each year during the period May 1 through May 31.
    a. Submit a test plan to the Air Pollution Control Officer for approval at least 30 days before the source test is to be performed.
    b. Notify the Air Pollution Control Officer at least a week prior to the actual source test date.

12. Sample ports and test platforms, as necessary, shall be constructed per applicable EPA and OSHA requirements (see Attachment 1).

13. Within 180 days following the issuance of the Authority to Construct SMUD/Campbell Soup Company shall contact the District regarding:
    a. Requirements for the source test specified in Condition 10.
    b. Sampling ports specified in Condition 12.
    c. Continuous monitors specified in Condition 8 and 9.

14. Access, facilities, utilities and any necessary safety equipment for source testing and inspections shall be provided upon request of the Air Pollution Control Officer.

15. A written report of excess emissions shall be submitted to the Air Pollution Control Officer for every calendar quarter. Excess emissions are defined as:
    1) any one hour period during which the average emissions of NOx exceeds the limits of Conditions 3 or 4 or,
    2) any one hour period during which the steam-to-fuel ratio falls below the level that demonstrates compliance or,
    3) any daily period during which the sulfur content of the fuel exceeds 0.5% by weight.

    The report shall include the following:
    a. The magnitude of excess emissions in units of ppmvd and pounds per hour and the date and time of commencement and completion of each time period of excess emissions.
    b. Specific identification of each period of excess emissions that occurs during start-ups, shutdowns and malfunctions (if known), the corrective action taken or preventative measures adopted.
    c. The date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of the system repairs or adjustments.
    d. When no excess emissions have occurred or the continuous monitoring system has not been inoperative, repaired or adjusted, such information shall be stated in the report.

16. Records shall be maintained (i.e. fuel usage rates, boiler load levels, hours of operation, etc.) to verify compliance with all permit conditions. Such records shall be maintained for the most recent two year period and shall be made available to the Air Pollution Control Officer on request.

17. The following are excess emission offsets resulting from the removal of the existing boilers and after offsets have been used for the proposed project.

	tons/calendar quarter			
Pollutant	Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
NOx	9	2	37	11

a. The excess emission offsets shall be available for use as offsets either onsite or offsite subject to the following:
   1. The excess emission offsets shall be subject to the rules in effect at the time they are proposed to be used.
   2. The calculation method of Section 413.2 of Rule 202-New Source Review will not be applicable to these emissions in the future. The actual operating conditions averaged over the last three years were used to quantify the emissions from the existing boilers at the time of permit application. In the future, calculating the emissions by using actual operating conditions over the last three years will not apply.
   3. The District does not consider the replacement of the boilers to be a "source shutdown" as used in Section 413.6 of Rule 202 - New Source Review. The Campbell Soup Company will still exist after the boiler replacement and there will still be a requirement for steam. The new controlled emission boilers are considered to be the same as if an air pollution control system was installed on the old uncontrolled emission boilers. Therefore the restriction to onsite use of the emission offsets will not be applicable to the use of these emissions offsets in the future.

18. Permits to Operate for the existing boilers shall be cancelled when the new boilers and turbine are in normal operation.

Commencing work under this authority to construct shall be deemed acceptance of all the conditions specified.

This, however, does not constitute a permit to operate nor does it guarantee that the proposed equipment will comply with air pollution control regulations.

You are requested to notify this office when construction has been completed. A final inspection will then be made to determine whether the equipment has been constructed according to the plans approved by this District. At that time, operation will be observed and permission to operate will be granted upon compliance with the rules and regulations of the Sacramento County Air Pollution Control District.

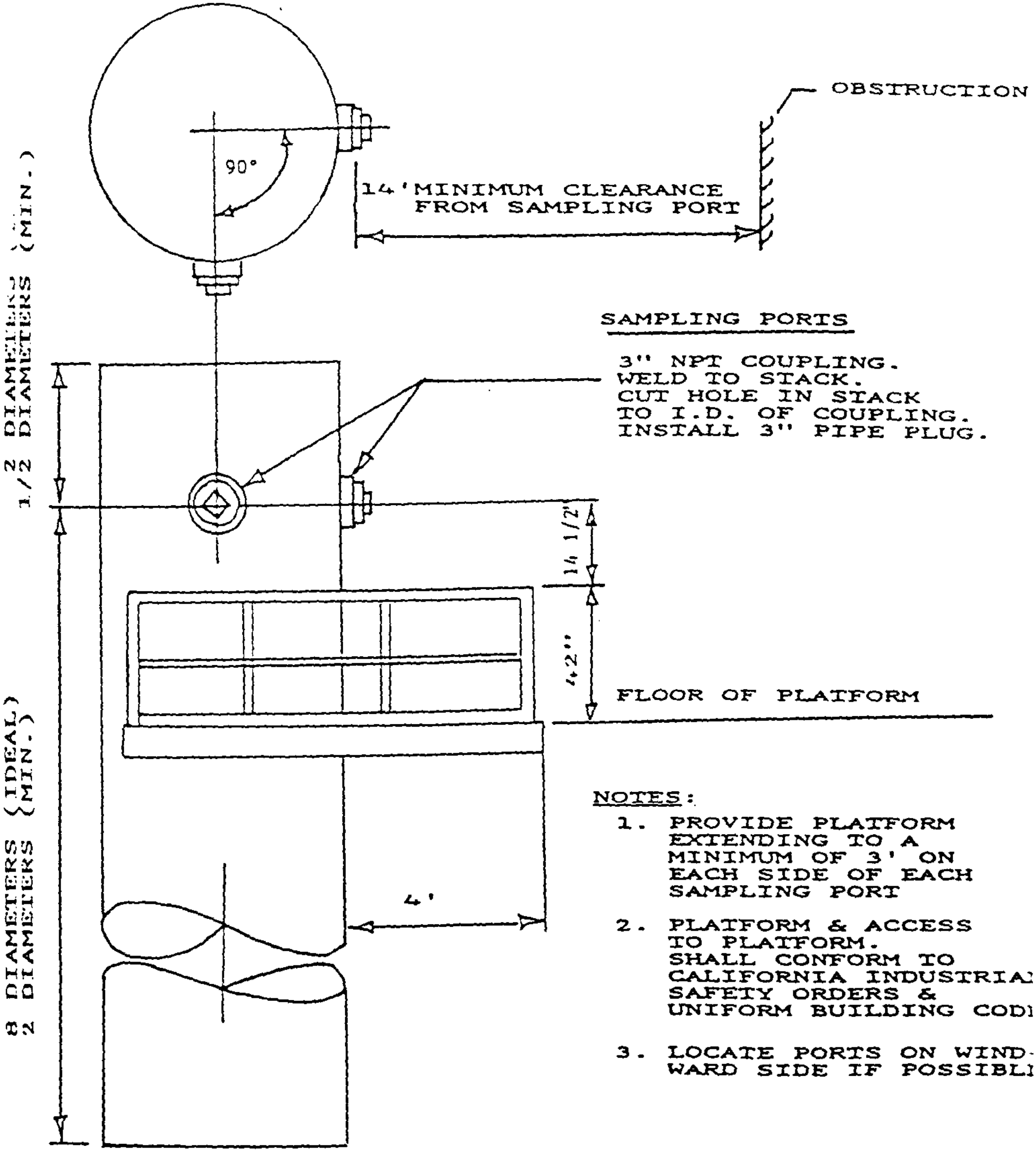
Sincerely,

Bruce Nixon

Bruce Nixon
Air Pollution Control Engineer

AC8577

PLATFORM AND PORT SPECIFICATION SHEET



NOTES:

1. PROVIDE PLATFORM EXTENDING TO A MINIMUM OF 3' ON EACH SIDE OF EACH SAMPLING PORT
2. PLATFORM & ACCESS TO PLATFORM. SHALL CONFORM TO CALIFORNIA INDUSTRIA SAFETY ORDERS & UNIFORM BUILDING COD
3. LOCATE PORTS ON WIND-WARD SIDE IF POSSIBL

IF THE STACK DIAMETER IS TOO LARGE TO TRAVERSE FROM ONE PORT, 4 SAMPLING PORTS AT 90° APART MAY BE USED TO TRAVERSE THE STACK. THIS AVOIDS USING A LONGER PROBE WHICH MAY CAUSE SAGGING ... NONPERPENDICULAR ARRANGEMENT).

ATTACHMENT 2

Continuous Emission Monitors

PERFORMANCE SPECIFICATIONS

NOx and SO_2

:uracy	≤ 20 pct of the mean value of the reference method test data
nt Accuracy	≤ 10 pct
.ion Error	≤ 5 pct of (50 pct, 90 pct) calibration gas mixture value
·ift (2h)	2 pct of span
rift (24h)	2 pct of span
·ation drift (2h)	2 pct of span
ration drift (24h)	2.5 pct of span
)nse time	15 min maximum

O_2 and CO_2

·o drift (2h)	≤ 0.4 pct O_2 or CO_2
ro drift (24h)	≤ 0.5 pct O_2 or CO_2
ılibration drift (2h)	≤ 0.4 pct O_2 or CO_2
ccuracy	≤ 10 pct
Response time	10 min
Calibration	≤ 5 pct of calibration gas value

SACRAMENTO COUNTY AIR POLLUTION CONTROL DISTRICT
8475 Jackson Road
Sacramento, Ca 95826

AUTHORITY TO CONSTRUCT ENGINEERING EVALUATION

SMUD/CAMPBELL SOUP COMPANY

BOILER AND TURBINE PROJECT

PERMIT APPLICATIONS A/C 8577 - 8586

August 9, 1988

Authority to Construct Engineering Evaluation
SMUD/Campbell Soup Company
Boiler and Turbine Project
August 5, 1988

I. INTRODUCTION

A. Background

The Sacramento Municipal Utility District (SMUD) and Campbell Soup Company have submitted a joint application for Authority to Construct for four boilers and a gas turbine on Campbell Soup's property. The project will remove the five existing uncontrolled emissions boilers at Campbell Soup and install four new controlled emissions boilers. The new boilers will have emission controls for nitrogen oxides. The new turbine emissions will be offset by the excess emission reductions from the boilers changing from uncontrolled emissions to controlled emissions.

B. Process Description

1. Process Equipment

The proposed project will consist of four controlled emission steam boilers with a combined output of 300,000 pounds of steam per hour. They will replace five uncontrolled emission boilers that have a combined steam output of 280,000 pounds of steam per hour.

A 49.5 MW cogeneration gas turbine will also be installed to provide electrical peaking power for SMUD and process steam for Campbell Soup Company. The turbine is proposed to run no more than 3499 hours per year, which is approximately 40% of the 8760 hours in a year.

2. Air Pollution Control Equipment

The proposed equipment requires Best Available Control Technology (BACT).

Air pollution control equipment includes:

a. Nitrogen Oxides Controls

BACT for NOx for the boilers is 40 ppmvd at 3% O_2 in the exhaust gas. This will be met by designing the boilers with low NOx burners and flue gas recirculation.

BACT for NOx for the turbine is 25 ppmvd at 15% O_2 in the exhaust gas. This will be met by designing the turbine with steam injection in the combustion zone.

b. Carbon Monoxide Controls

BACT for carbon monoxide from the boilers and the gas turbine is good combustion control to minimize the carbon monoxide emissions.

c. Reactive Organic Compounds Control

BACT for reactive organic compounds from the boilers and gas turbine is good combustion control to minimize the reactive organic compound emissions.

d. Sulfur Dioxide Controls

BACT for sulfur dioxide is the use of natural gas for the primary fuel and the use of low sulfur oil for standby fuel. The standby fuel will be less than 0.5% sulfur by weight.

e. Particulate Controls

BACT for particulate is the use of natural gas for the primary fuel.

C. REGULATORY SUMMARY

The most significant air quality requirements related to the permitting of this project are: 1) Best Available Control Technology and 2) Emission Offsets.

1. Best Available Control Technology

District regulations require the use of Best Available Control Technology to reduce emissions of each pollutant that exceeds a specified emission level. The proposed project will use emission control equipment and techniques considered to be BACT for all applicable pollutants as described above.

2) Emission Offsets

District regulations require that an applicant for a proposed project with emissions in excess of specified levels provide emission reductions to offset the project's emission increases. In this case the applicant will offset the emission increases from the turbine with emission decreases from the boilers.

II PROJECT EMISSIONS

Detailed calculations of emissions are presented in Appendix A, "Emission Estimates for New Boilers and Turbine" and Appendix B, "Emission Estimates for Boilers to be Used as Offsets". The emissions are summarized for the proposed project in the following table.

TABLE 1

WORST CASE EMISSIONS SUMMARY

The worst case hourly, daily and yearly emissions are presented below for the new equipment. These emission rates are based on the maximum emitting capacity of the equipment operating within the limitations imposed as permit conditions. SMUD/Campbell Soup will accept permit conditions limiting the hourly, daily, quarterly and annual emissions from the boilers and turbine.

WORST CASE EMISSIONS

Based on the following operating conditions:	Hourly	Daily	Yearly
Turbine	60 min/hr	22 hrs/day	3499 hrs/yr
Boilers (Half Load)	60 min/hr	22 hrs/day	3362 hrs/yr
Boilers (Full Load)	0 min/hr	2 hrs/day	1040 hrs/yr

		Worst Case pounds/hour	Worst Case pounds/day	Worst Case tons/year
NOx				
	Boilers	10	260	27
	Turbine	67	1474	117
	Total	77	1734	144
SO_2				
	Boilers	0.1	3	0.3
	Turbine	0.4	8	0.6
	Total	0.5	11	0.9
CO				
	Boilers	12	312	33
	Turbine	24	528	42
	Total	36	840	75
ROC				
	Boilers	1	15	2
	Turbine	4	88	7
	Total	5	103	9
Particulate				
	Boilers	1	27	3
	Turbine	9	190	15
	Total	10	217	18

TABLE 2

EMISSION INCREASES, DECREASES AND SUMMARY

The emission increases due to the new controlled emission boilers and the new turbine will be offset by the emission decreases from the removal of the existing uncontrolled emission boilers. The table below indicates that a portion of the excess emission reductions from the controlled emission boilers replacing the uncontrolled emission boilers will be applied to this project.

	Emission Increase Due to New Boilers	Emission Increase Due to Turbine	Emission Offset Due to Old Boilers	Net Emission Increase	
Pollutant	tons/yr	tons/yr	tons/yr	tons/yr	lb/day
NOx	27	117	<117>	27	148
SO_2	0.3	0.6	<0.4>	0.5	3
CO	33	42	<13>	62	340
ROC	2	7	<2>	7	38
Particulate	3	15	<3>	15	82

III. COMPLIANCE WITH APPLICABLE REGULATIONS

In this section the District rules that apply to the proposed project are identified and compliance with the requirements is determined.

A. RULE 202 NEW SOURCE REVIEW

The most significant rule affecting the permitting of the proposed project is the District's Rule 202 New Source Review. The requirements of the rule include: 1) Best Available Control Technology and 2) Emission Offsets.

1. Determination of Best Available Control Technology (BACT)

The requirement for BACT is applicable when the emissions of a given pollutant exceed a specified level as designated in Rule 202.

For the proposed project the worst case emissions given in Table 1 are used to determine if BACT is required for each pollutant. According to Rule 202 BACT is required for NOx when emissions exceed 150 pounds per day and for CO when emissions exceed 550 pounds per day.

a. NOx BACT for Boilers

SMUD/Campbell Soup are proposing to meet an emission limit of 40 ppmvd NOx at 3% O_2 through the use of low-NOx burners and flue gas recirculation. This emission limitation has been determined to be BACT by the APCO for three A/C's issued for similar size boilers within the District.

b. NOx BACT for Gas Turbine
SMUD/Campbell Soup are proposing to meet an emission limit of 25 ppmvd NOx at 15% O_2 through the use of steam or water injection in the turbines combustion zone. BACT in some California APCD's has been determined to be 9 ppmvd NOx for gas turbines that operate enough hours per year to justify the expense of the NOx control system. The APCO has determined that the cost to achieve 9 ppmvd NOx is excessive for the turbine because it will operate in combined cycle mode only a portion of its total operating time. The following table shows the historical steam usage at Campbell Soup:

Average Steam Usage (pounds per hour)	Annual Hours
275,000	786
(210,000 Design output of turbine)	-
190,000	384
150,000	1416
100,000	2784
60,000	1320
21,000	1128
None	960

The turbine will run in simple cycle or partial combined cycle most of its operating time, not fully using the exhaust gas to produce steam to be used for food processing. The temperature reduction needed in the exhaust gas to be compatible with a catalyst type control to achieve 9 ppmvd would not be possible in the simple cycle or partial combined cycle mode.

c. **SO_2 BACT for Boilers and Turbine**
SMUD/Campbell Soup will use natural gas as the primary fuel to the boilers and turbine to minimize the emission of SO_2. Emergency fuel oil will contain less than 0.5% by weight sulfur to also minimize SO_2 emissions.

d. **CO and ROC BACT for Boilers and Turbine**
SMUD/Campbell Soup will use good combustion control to minimize the emission of CO and ROC from the boilers and turbine.

e. **Particulate BACT for Boilers and Turbine**
SMUD/Campbell Soup will use natural gas as the primary fuel to the boilers and turbine to minimize the emission of particulate matter.

2. **Determination of Emission Offsets**

The requirement to offset emissions is applicable if the net emission increase from the proposed project exceeds:

Particulate	150 lb/day
NOx, SO_2, ROC	250 lb/day
CO	550 lb/day

The requirement for offsets is applicable to each individual source of emission that exceeds the above limits because of the way "stationary source" is defined in Rule 202. Internal source emission reductions can not be applied to net out of offsets if a piece of emitting equipment by itself exceeds the limits. In this application the turbine, by itself, exceeds the limits therefore the entire turbine emission must be offset.

For the new boilers and turbine as a total project, SMUD/Campbell Soup proposes to apply internal offsets from the replacement of the existing boilers to keep the net emission increase below the levels specified above. Table 2 indicates the amount of each pollutant from the existing boilers that will be applied to the proposed project. The offset emissions will be provided from the same stationary source so the offset ratio will be 1.0 to 1.0.

B. RULE 401 VISIBLE EMISSIONS

Proper control of combustion parameters on boilers and turbines fired on natural gas and fuel oil results in an exhaust plume that is essentially nonvisible.

C. RULE 406 SPECIFIC CONTAMINANTS

1. The use of emergency fuel oil with a sulfur content less than 0.5% by weight will result in a SO_2 concentration in the exhaust gas less than 0.2% by volume.

2. The concentration of particulate matter in the exhaust gas will be less than 0.1 grains/dscf at 12% CO_2.

D. RULE 420 SULFUR CONTENT OF FUELS

The emergency fuel oil will have a sulfur content less than 0.5% by weight.

E. RULE 805 NEW SOURCE PERFORMANCE STANDARDS - GAS TURBINES

The NSPS requirements for new gas turbines are substantially less stringent than those resulting from BACT requirements of the District's New Source Review Rule. The 75 ppmvd NOx requirement of Section 301.2 will be met by the proposed turbine.
The steam or water injection and fuel monitoring requirements of Section 500 are included as permit conditions.

IV BANKING OF EXCESS OFFSET EMISSIONS

The proposed project will only use a portion of the emission offsets from the replacement of the existing boilers. SMUD/Campbell Soup would like to identify the excess emission reductions so that they can be used for future projects either onsite or offsite. The District regulations do not contain an Emission Banking rule specifying how excess emissions can be quantified and secured for future use. Such a rule has not been adopted because there has not been a need for such a rule in the past and it is expected that there will be minimal need in the future. Instead of diverting limited District resources to the development and adoption of an Emissions Banking rule that may only be applicable to this single project, conditions will be added to the Permit to Operate to accomplish the same purpose. The conditions will specify:

1. The quantity of each pollutant that will be available to be used as emission offsets in the future.

2. The calculation method of Section 413.2 of Rule 202-New Source Review will be applied only once to determine the excess emission offsets. The actual operating conditions averaged over the last three years have been used to quantify the emissions from the existing boilers at the time of permit application. In the future, available offsets will be the amount calculated in this analysis.

3. Excess emission offsets will be governed by the District rules in effect at the time they are proposed to be used.

The excess emission offsets, after removing that portion used to offset the proposed project emissions, are:

NOx 59 tons/yr

The District considers that the excess emission offsets have been obtained from voluntary control of existing emission sources. The replacement of the existing uncontrolled emission boilers with new controlled emission boilers is not considered by the District to be a "shutdown". After the new boilers are installed, the Campbell Soup Company will continue to operate, require steam and produce food products as they have in the past.

V PERMIT CONDITIONS

This section contains a list of permit conditions which the proposed equipment must meet in order to comply with District regulations. The conditions impose control over the operation of the proposed process equipment (such as the type and amount of fuel that can be used) and the air pollution control equipment (such as the minimum allowable steam or water to fuel ratio). The conditions also set emission limitations for applicable pollutants and specify monitoring and source test requirements to assure that these emission limits are not exceeded.

1. The boilers and turbine shall be fired on natural gas only.
   a. In the event of an interruption of natural gas supply or for the routine testing of the emergency fuel system, the boilers and turbine may be fired on No.2 diesel fuel or No.5 fuel oil subject to the limitations in Condition 2.
   b. SMUD/Campbell Soup Company shall submit a written report to the District within 10 days of the start of any period of liquid fuel usage (excluding routine testing) detailing the circumstance of the natural gas service interruption.

2. The use of No.2 diesel fuel or No.5 fuel oil in the turbine and boilers shall not cause SO_2 emissions to exceed 250 pounds per day. SMUD/Campbell Soup Company shall submit a plan to the District specifying how this limit will be achieved and obtain approval prior to using liquid fuels

3. The emission of oxides of nitrogen (NOx) from each boiler shall not exceed:
   a. 40 ppmvd at 3% O_2 when firing natural gas.
   b. The lowest concentration established by source testing when firing No.2 diesel fuel or No.5 fuel oil.

4. The emission of oxides of nitrogen (NOx) from the turbine shall not exceed:
   a. 25 ppmvd at 15% O_2 when firing natural gas.
   b. The lowest concentration established by source testing when firing No.2 diesel fuel or No.5 fuel oil.

5. The majority of the usable thermal exhaust from the gas turbine shall not be diverted to the heat recovery steam generator, for generation of process steam, more than 1500 hours per year. A plan for such recordkeeping shall be submitted to the District for approval prior to operating the turbine.

6. The combined emissions from the boilers and turbine when using natural gas fuel shall not exceed:

	<u>pounds</u>	<u>pounds</u>	<u>tons</u>	tons/calendar quarter			
Pollutant	hour	day	year	Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
NOx	77	1734	144	34	33	44	33
SO_2	0.5	11	0.9				
CO	36	840	75				
ROC	5	103	9				
Particulate	10	217	18				

7. A continuous Emissions Tracking System to calculate the hourly, daily, quarterly and yearly emissions from the boilers and turbine shall be installed and operated to insure the limits in Condition 6 are not exceeded. SMUD/Campbell Soup shall submit a description of such an Emissions Tracking System that will accomplish this requirement to the APCO within 180 days of issuance of the Authority to Construct. SMUD/Campbell Soup must receive approval of the Emission Tracking System from the APCO before operation of the boilers and turbine begins.

8. A continuous system to monitor and record the fuel consumption and the ratio of steam or water injected to fuel fired in the turbine shall be installed in accordance with Rule 805 Section 501.

9. Approved monitors for NOx and O_2 shall be properly installed, maintained, operated and calibrated at all times for each boiler and the turbine (see Attachment 2).
   a. Specifications of the NOx and O_2 monitors chosen for installation shall be submitted to the Air Pollution Control Officer for approval.
   b. A Quality Assurance Plan for the maintenance, operation and calibration of the monitors shall be submitted to the Air Pollution Control Officer for approval.

10. An oxides of nitrogen (NOx) and carbon monoxide (CO) source test of each boiler and the turbine shall be performed and the test results submitted to the Air Pollution Control Officer within 60 days of the initial start-up of the process.
    a. Submit a test plan to the Air Pollution Control Officer for approval at least 30 days before the source test is to be performed.
    b. Notify the Air Pollution Control Officer at least a week prior to the actual source test date.

11. An emission test for NOx shall be conducted each year during the period May 1 through May 31.
    a. Submit a test plan to the Air Pollution Control Officer for approval at least 30 days before the source test is to be performed.
    b. Notify the Air Pollution Control Officer at least a week prior to the actual source test date.

12. Sample ports and test platforms, as necessary, shall be constructed per applicable EPA and OSHA requirements (see Attachment 1).

13. Within 180 days following the issuance of the Authority to Construct SMUD/Campbell Soup Company shall contact the District regarding:
    a. Requirements for the source test specified in Condition 10.
    b. Sampling ports specified in Condition 12.
    c. Continuous monitors specified in Condition 8 and 9.

14. Access, facilities, utilities and any necessary safety equipment for source testing and inspections shall be provided upon request of the Air Pollution Control Officer.

15. A written report of excess emissions shall be submitted to the Air Pollution Control Officer for every calendar quarter. Excess emissions are defined as:
    1) any one hour period during which the average emissions of NOx exceeds the limits of Conditions 3 or 4 or,
    2) any one hour period during which the steam-to-fuel ratio falls below the level that demonstrates compliance or,
    3) any daily period during which the sulfur content of the fuel exceeds 0.5% by weight.

    The report shall include the following:

a. The magnitude of excess emissions in units of ppmvd and pounds per hour and the date and time of commencement and completion of each time period of excess emissions.
b. Specific identification of each period of excess emissions that occurs during start-ups, shutdowns and malfunctions (if known), the corrective action taken or preventative measures adopted.
c. The date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of the system repairs or adjustments.
d. When no excess emissions have occurred or the continuous monitoring system has not been inoperative, repaired or adjusted, such information shall be stated in the report.

16. Records shall be maintained (i.e. fuel usage rates, boiler load levels, hours of operation, etc.) to verify compliance with all permit conditions. Such records shall be maintained for the most recent two year period and shall be made available to the Air Pollution Control Officer on request.

17. The following are excess emission offsets resulting from the removal of the existing boilers and after offsets have been used for the proposed project.

	tons/calendar quarter			
Pollutant	Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
NOx	9	2	37	11

a. The excess emission offsets shall be available for use as offsets either onsite or offsite subject to the following:
   1. The excess emission offsets shall be subject to the rules in effect at the time they are proposed to be used.
   2. The calculation method of Section 413.2 of Rule 202-New Source Review will not be applicable to these emissions in the future. The actual operating conditions averaged over the last three years were used to quantify the emissions from the existing boilers at the time of permit application. In the future, calculating the emissions by using actual operating conditions over the last three years will not apply.
   3. The District does not consider the replacement of the boilers to be a "source shutdown" as used in Section 413.6 of Rule 202 - New Source Review. The Campbell Soup Company will still exist after the boiler replacement and there will still be a requirement for steam. The new controlled emission boilers are considered to be the same as if an air pollution control system was installed on the old uncontrolled emission boilers. Therefore the restriction to onsite use of the emission offsets will not be applicable to the use of these emissions offsets in the future.

18. Permits to Operate for the existing boilers shall be cancelled when the new boilers and turbine are in normal operation.

VI RECOMMENDATION

The conclusion of this review is that all applicable permit requirements have been met by SMUD/Campbell Soup Company and the Air Pollution Control Officer, therefore, has made the decision to issue an Authority to Construct for the following equipment with the conditions discussed:

1. Four steam boilers, rated at a total of 400 MM Btu/hr heat input, flue gas recirculation, low NOx burner.

2. One gas turbine, rated at 600 MM Btu/hr heat input, steam or water injection.

APPENDIX A

EMISSION ESTIMATES FOR NEW BOILERS AND TURBINE

A. EMISSION FACTORS

The following emission factors are used to calculate the emissions from the proposed new boilers and turbine.

Pollutant	Emission Factor	Source of Emission Factor
NOx		
Boilers (Half Load)	10 lb/hour	Manufacturer's Data and 40 ppmvd
Boilers (Full Load)	20 lb/hour	Manufacturer's Data and 40 ppmvd
Turbine	67 lb/hour	Manufacturer's Data and 25 ppmvd
SO_2		
Boilers	0.6 lb/10^6 ft^3 fuel	AP-42, Section 1.4 (10/86)
Turbine	0.6 lb/10^6 ft^3 fuel	AP-42, Section 1.4 (10/86)
CO		
Boilers (Half Load)	12 lb/hour	Manufacturer's Data
Boilers (Full Load)	24 lb/hour	Manufacturer's Data
Turbine	24 lb/hour	Manufacturer's Data
ROC (Reactive organic compounds)		
Boilers	2.8 lb/10^6 ft3 fuel	AP-42, Section 1.4 (10/86)
Turbine	4 lb/hour	Manufacturer's Data
Particulate		
Boilers	5 lb/10^6 ft^3 fuel	AP-42, Section 1.4 (10/86)
Turbine	14 lb/10^6 ft^3 fuel	AP-42, Section 3.1 (12/77)

B. WORST CASE OPERATING CONDITIONS

The following maximum fuel use rates and worst case operating hours are used with the above emission factors to calculate emissions.

Boilers	
Maximum firing rate	400 MM Btu/hr
Maximum fuel use rate	.412 10^6 ft^3 natural gas/hr
Maximum daily hours	22 hours half load and 2 hours full load
Maximum yearly hours	
Half load	3362 hours
Full load	1040 hours
Turbine	
Maximum firing rate	600 MM Btu/hr
Maximum fuel usage rate	.618 10^6 ft^3 natural gas/hr
Maximum daily hours	22 hours
Maximum yearly hours	3499 hours

APPENDIX B

EMISSION ESTIMATES FOR BOILERS TO BE USED AS OFFSETS

A. EMISSION FACTORS

The following tables list:

1. The average monthly natural gas consumption for the each of the five existing boilers at Campbell Soup Company for the period May 1983 through April 1986.

2. The emission factor used for each pollutant for each month of the year.
   a. NOx
      The factors are from a source test performed in April 1985. The factor varies for each boiler. The factor also varies for each month because the boilers are operated at a higher firing rate during the summer canning season.
   b. SO_2
      From AP-42, Section 1.4 (10/86)
   c. CO
      The factors are from a source test performed in April 1985. The factor varies for each boiler.
   d. ROC (Reactive organic compounds)
      From AP-42, Section 1.4 (10/86)
   e. Particulate
      From AP-42, Section 1.4 (10/86)

3. The average monthly pollutant emission for each of the five existing boilers.

B. TOTAL EMISSIONS FROM EXISTING BOILERS

Pollutant	tons/year	tons/calendar quarter			
		Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
NOx	180	39	31	70	40
SO_2	0.4				
CO	13				
ROC	2				
Particulate	3				

NOx EMISSIONS FROM OLD BOILERS

TABLE 1

CAMPBELL SOUP MONTHLY AVERAGE FUEL CONSUMPTION (MM cubic feet/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL
MAY	26.5	15.3	6.1	33.1	0.0	81.0
JUN	20.8	17.4	5.3	13.3	0.8	57.6
JUL	29.6	30.0	18.3	47.2	8.1	133.2
AUG	42.2	38.1	24.7	85.2	29.1	219.3
SEP	37.8	33.5	21.1	71.3	24.5	188.2
OCT	28.2	20.3	11.1	37.3	0.2	97.1
NOV	26.9	22.1	10.3	29.5	0.1	88.9
DEC	33.3	7.7	14.8	34.3	0.0	90.1
JAN	36.9	19.4	10.9	37.5	0.0	104.7
FEB	29.6	6.8	7.2	32.2	0.0	75.8
MAR	28.4	9.2	3.9	36.2	0.0	77.7
APR	26.0	4.5	5.1	31.6	0.1	67.3
TOTAL	366	224	139	489	63	1,281

TABLE 2

CAMPBELL SOUP MONTHLY AVERAGE NOx EMISSION FACTOR (lbs NOx/MM cubic feet)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5
MAY	510	380	110	120	120
JUN	510	380	110	120	120
JUL	558	385	110	123	120
AUG	572	395	110	120	120
SEP	559	387	110	121	120
OCT	510	380	110	120	120
NOV	510	380	110	120	120
DEC	510	380	110	120	120
JAN	510	380	110	120	120
FEB	510	380	110	120	120
MAR	510	380	110	120	120
APR	510	380	110	120	120

TABLE 3

CAMPBELL SOUP MONTHLY AVERAGE NOx EMISSION (lbs/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL
MAY	13515	5814	671	3972	0	23972
JUN	10608	6612	583	1596	96	19495
JUL	16517	11550	2013	5806	972	36857
AUG	24138	15050	2717	10224	3492	55621
SEP	21130	12965	2321	8627	2940	47983
OCT	14382	7714	1221	4476	24	27817
NOV	13719	8398	1133	3540	12	26802
DEC	16983	2926	1628	4116	0	25653
JAN	18819	7372	1199	4500	0	31890
FEB	15096	2584	792	3864	0	22336
MAR	14484	3496	429	4344	0	22753
APR	13260	1710	561	3792	12	19335
TOTAL	192651	86190	15268	58857	7548	360514 lbs per year
	96	43	8	29	4	180 tons per year

smud.wk1

SO2 EMISSIONS FROM OLD BOILERS

TABLE 1

CAMPBELL SOUP MONTHLY AVERAGE FUEL CONSUMPTION (MM cubic feet/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL
MAY	26.5	15.3	6.1	33.1	0.0	81.0
JUN	20.8	17.4	5.3	13.3	0.8	57.6
JUL	29.6	30.0	18.3	47.2	8.1	133.2
AUG	42.2	38.1	24.7	85.2	29.1	219.3
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OCT	28.2	20.3	11.1	37.3	0.2	97.1
NOV	26.9	22.1	10.3	29.5	0.1	88.9
DEC	33.3	7.7	14.8	34.3	0.0	90.1
JAN	36.9	19.4	10.9	37.5	0.0	104.7
FEB	29.6	6.8	7.2	32.2	0.0	75.8
MAR	28.4	9.2	3.9	36.2	0.0	77.7
APR	26.0	4.5	5.1	31.6	0.1	67.3
TOTAL	366	224	139	489	63	1,281

TABLE 2

CAMPBELL SOUP MONTHLY AVERAGE CO EMISSION FACTOR (lbs SO2/MM cubic feet)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5
MAY	0.6	0.6	0.6	0.6	0.6
JUN	0.6	0.6	0.6	0.6	0.6
JUL	0.6	0.6	0.6	0.6	0.6
AUG	0.6	0.6	0.6	0.6	0.6
SEP	0.6	0.6	0.6	0.6	0.6
OCT	0.6	0.6	0.6	0.6	0.6
NOV	0.6	0.6	0.6	0.6	0.6
DEC	0.6	0.6	0.6	0.6	0.6
JAN	0.6	0.6	0.6	0.6	0.6
FEB	0.6	0.6	0.6	0.6	0.6
MAR	0.6	0.6	0.6	0.6	0.6
APR	0.6	0.6	0.6	0.6	0.6

TABLE 3

CAMPBELL SOUP MONTHLY AVERAGE SO2 EMISSION (lbs/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL
MAY	16	9	4	20	0	49
JUN	12	10	3	8	0	35
JUL	18	18	11	28	5	80
AUG	25	23	15	51	17	132
SEP	23	20	13	43	15	113
OCT	17	12	7	22	0	58
NOV	16	13	6	18	0	53
DEC	20	5	9	21	0	54
JAN	22	12	7	23	0	63
FEB	18	4	4	19	0	45
MAR	17	6	2	22	0	47
APR	16	3	3	19	0	40
TOTAL	220	135	83	293	38	769 lbs per year
	0.1	0.1	0.0	0.1	0.0	0.4 tons per year

smud3.wk1

CO EMISSIONS FROM OLD BOILERS

TABLE 1

CAMPBELL SOUP MONTHLY AVERAGE FUEL CONSUMPTION (MM cubic feet/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL
MAY	26.5	15.3	6.1	33.1	0.0	81.0
JUN	20.8	17.4	5.3	13.3	0.8	57.6
JUL	29.6	30.0	18.3	47.2	8.1	133.2
AUG	42.2	38.1	24.7	85.2	29.1	219.3
SEP	37.8	33.5	21.1	71.3	24.5	188.2
OCT	28.2	20.3	11.1	37.3	0.2	97.1
NOV	26.9	22.1	10.3	29.5	0.1	88.9
DEC	33.3	7.7	14.8	34.3	0.0	90.1
JAN	36.9	19.4	10.9	37.5	0.0	104.7
FEB	29.6	6.8	7.2	32.2	0.0	75.8
MAR	28.4	9.2	3.9	36.2	0.0	77.7
APR	26.0	4.5	5.1	31.6	0.1	67.3
TOTAL	366	224	139	489	63	1,281

TABLE 2

CAMPBELL SOUP MONTHLY AVERAGE CO EMISSION FACTOR (lbs CO/MM cubic feet)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5
MAY	12	11	4	37	12
JUN	12	11	4	37	12
JUL	12	11	4	37	12
AUG	12	11	4	37	12
SEP	12	11	4	37	12
OCT	12	11	4	37	12
NOV	12	11	4	37	12
DEC	12	11	4	37	12
JAN	12	11	4	37	12
FEB	12	11	4	37	12
MAR	12	11	4	37	12
APR	12	11	4	37	12

TABLE 3

CAMPBELL SOUP MONTHLY AVERAGE CO EMISSION (lbs/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL
MAY	318	168	24	1225	0	1735
JUN	250	191	21	492	10	964
JUL	355	330	73	1746	97	2602
AUG	506	419	99	3152	349	4526
SEP	454	369	84	2638	294	3839
OCT	338	223	44	1380	2	1989
NOV	323	243	41	1092	1	1700
DEC	400	85	59	1269	0	1813
JAN	443	213	44	1388	0	2087
FEB	355	75	29	1191	0	1650
MAR	341	101	16	1339	0	1797
APR	312	50	20	1169	1	1552
TOTAL	4394	2467	555	18082	755	26254 lbs per year
	2	1	0	9	0	13 tons per year

smud2.wk1

ROC EMISSIONS FROM OLD BOILERS

TABLE 1

CAMPBELL SOUP MONTHLY AVERAGE FUEL CONSUMPTION (MM cubic feet/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL
MAY	26.5	15.3	6.1	33.1	0.0	81.0
JUN	20.8	17.4	5.3	13.3	0.8	57.6
JUL	29.6	30.0	18.3	47.2	8.1	133.2
AUG	42.2	38.1	24.7	85.2	29.1	219.3
SEP	37.8	33.5	21.1	71.3	24.5	188.2
OCT	28.2	20.3	11.1	37.3	0.2	97.1
NOV	26.9	22.1	10.3	29.5	0.1	88.9
DEC	33.3	7.7	14.8	34.3	0.0	90.1
JAN	36.9	19.4	10.9	37.5	0.0	104.7
FEB	29.6	6.8	7.2	32.2	0.0	75.8
MAR	28.4	9.2	3.9	36.2	0.0	77.7
APR	26.0	4.5	5.1	31.6	0.1	67.3
TOTAL	366	224	139	489	63	1,281

TABLE 2

CAMPBELL SOUP MONTHLY AVERAGE POC EMISSION FACTOR (lbs POC/MM cubic feet)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5
MAY	2.8	2.8	2.8	2.8	2.8
JUN	2.8	2.8	2.8	2.8	2.8
JUL	2.8	2.8	2.8	2.8	2.8
AUG	2.8	2.8	2.8	2.8	2.8
SEP	2.8	2.8	2.8	2.8	2.8
OCT	2.8	2.8	2.8	2.8	2.8
NOV	2.8	2.8	2.8	2.8	2.8
DEC	2.8	2.8	2.8	2.8	2.8
JAN	2.8	2.8	2.8	2.8	2.8
FEB	2.8	2.8	2.8	2.8	2.8
MAR	2.8	2.8	2.8	2.8	2.8
APR	2.8	2.8	2.8	2.8	2.8

TABLE 3

CAMPBELL SOUP MONTHLY AVERAGE POC EMISSION (lbs/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL
MAY	74	43	17	93	0	227
JUN	58	49	15	37	2	161
JUL	83	84	51	132	23	373
AUG	118	107	69	239	81	614
SEP	106	94	59	200	69	527
OCT	79	57	31	104	1	272
NOV	75	62	29	83	0	249
DEC	93	22	41	96	0	252
JAN	103	54	31	105	0	293
FEB	83	19	20	90	0	212
MAR	80	26	11	101	0	218
APR	73	13	14	88	0	188
TOTAL	1025	628	389	1368	176	3587 lbs per year
	1	0	0	1	0	2 tons per year

smud4.wk1

PM EMISSIONS FROM OLD BOILERS

TABLE 1

CAMPBELL SOUP MONTHLY AVERAGE FUEL CONSUMPTION (MM cubic feet/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL
MAY	26.5	15.3	6.1	33.1	0.0	81.0
JUN	20.8	17.4	5.3	13.3	0.8	57.6
JUL	29.6	30.0	18.3	47.2	8.1	133.2
AUG	42.2	38.1	24.7	85.2	29.1	219.3
SEP	37.8	33.5	21.1	71.3	24.5	188.2
OCT	28.2	20.3	11.1	37.3	0.2	97.1
NOV	26.9	22.1	10.3	29.5	0.1	88.9
DEC	33.3	7.7	14.8	34.3	0.0	90.1
JAN	36.9	19.4	10.9	37.5	0.0	104.7
FEB	29.6	6.8	7.2	32.2	0.0	75.8
MAR	28.4	9.2	3.9	36.2	0.0	77.7
APR	26.0	4.5	5.1	31.6	0.1	67.3
TOTAL	366	224	139	489	63	1,281

TABLE 2

CAMPBELL SOUP MONTHLY AVERAGE PM EMISSION FACTOR (lbs PM/MM cubic feet)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5
MAY	5	5	5	5	5
JUN	5	5	5	5	5
JUL	5	5	5	5	5
AUG	5	5	5	5	5
SEP	5	5	5	5	5
OCT	5	5	5	5	5
NOV	5	5	5	5	5
DEC	5	5	5	5	5
JAN	5	5	5	5	5
FEB	5	5	5	5	5
MAR	5	5	5	5	5
APR	5	5	5	5	5

TABLE 3

CAMPBELL SOUP MONTHLY AVERAGE PM EMISSION (lbs/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL
MAY	133	77	31	166	0	405
JUN	104	87	27	67	4	288
JUL	148	150	92	236	41	666
AUG	211	191	124	426	146	1097
SEP	189	168	106	357	123	941
OCT	141	102	56	187	1	486
NOV	135	111	52	148	1	445
DEC	167	39	74	172	0	451
JAN	185	97	55	188	0	524
FEB	148	34	36	161	0	379
MAR	142	46	20	181	0	389
APR	130	23	26	158	1	337
TOTAL	1831	1122	694	2444	315	6405 lbs per year
	1	1	0	1	0	3 tons per year

smud5.wk1

APPENDIX C

ALLOWABLE QUARTERLY EMISSIONS FOR BOILERS AND TURBINE

The following is the methodology used to:

1. Calculate the maximum allowable quarterly emissions from the combination of the boilers and the turbine. The purpose of the calculations is to ensure that the new project emissions are offset by emissions that have historically occurred in the same timeframe. It would not be to the benefit of air quality to offset a new source that emits ozone precursors in the summertime with ozone precursor emission reduction credits that historically occurred in the wintertime.

2. Calculate the emission reduction credits remaining after the emissions from the turbine have been fully offset and the net emission increase from the project is less than 250 pounds of NOx per day.

   (The following data is based on NOx only because it is the primary pollutant of concern from the new equipment.)

TABLE C-1

Quarter	(1) Emission Reduction Credits Available (tons)	(2) Emission Reduction Credits Used for Project (tons)	(3) Remaining Emission Reduction Credits (tons)	(4) New Turbine Emissions (tons)	(5) New Boiler Emissions (tons)	(6) Total Project Emissions (tons)	(7) Net Emission Increase (tons)
Jan-Mar	39	30	9	30	4	34	4
Apr-Jun	31	29	2	29	4	33	4
Jul-Sep	70	33	37	29	15	44	11
Oct-Dec	40	29	11	29	4	33	4
Total Annual	180	121	59	117	27	144	23

(1) See Appendix B

(2) Emission reduction credit used for each quarter to fully offset the emissions from the turbine. The third quarter also has 4 tons of additional emission reduction credits to offset the boiler usage so that the net emission increase from the project is less than 250 pounds per day during the quarter.

(3) Column (1) - Column (2)

(4) Emission from the turbine based on 875 hours of operation each quarter.

(5) This is the emission from the boilers based on 829 hours at half load for each of the first, second and fourth quarters. The third quarter is based on 875 hours at half load and 1040 hours at full load.

(6) Column (4) + Column (5)

(7) Column (6) - Column (2)

AES Fax

6-30-88

- SO_2 quality settlement, Max.
- Type of models to be used, Tom.

- Max's comments -

Ask Bill on Policy

- TSP Nonattainment designation
- PM_{10} stds are in effect
- Irregular operations. 81/82

BACT, Barry + CAER (voc)

Call Terry Varkonda

Called Terry on 7-7-88 with DER/EPA comments.

- Scrubbers on Boilers + RB + Smelt tank
- Include non regulated pollutants + toxics
- Dual Co nonattainment for ozone. VOC → CAER.

- Dural Oz increment available?
- Amount of VOC over 100 TPY without net out.

DER / AES 6/30/88

		DER
Buck Oven	488-1344	Siting Coord
Pradeep Raval	"	BAQM
Terry Cole	877 0099	AES
JEFF SWAIN	703-522-1315	AES
KERRY VARKONDA	"	"
Curt Barton	~~Stone Container~~ 404 621 6707	Stone Container/
JOHN MILLICAN	584-5137	Seminole Kraft ENVI SERVICES
Larry Alfred	913-339-2325	Black & Veatch
Barry Andrews	488-1344	BAQM
Max Linn	488-1344	BAQM

June 21, 1988

Mr. Max A. Linn
Meteorologist
Bureau of Air Quality Management
State of Florida
Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32301

Dear Max:

Attached for your review are three (3) copies of the Air Quality Analysis Work Plan (AQAWP) for our AES-Cedar Bay cogeneration plant to be built in Jacksonville. Please provide a copy to Buck Oven and Barry Andrews. I spoke to Buck concerning a time to meet with you to discuss this plan in more detail, and we have tentatively scheduled this meeting for Thursday, June 30th at 1:00 p.m. in Tallahassee.

As far as the agenda goes, I propose we step through the plan page by page, addressing areas needing further discussion as we come to them.

In addition to issues specifically addressed in the AQAWP, there are several other issues we would like to get clarification on during this meeting:

- What are the implications of the ozone non-attainment status of Duval County?
  - What growth allowance exists and what amount will be available for the project ?
- What analysis will be required for trace metals emissions?

AES/Cedar Bay Inc.

1925 North Lynn Street • Arlington, Virginia 22209 • (703) 522-1315 • Telecopier—(703) 528-4510

June 21, 1988

Mr. Max A. Linn
Meteorologist
Bureau of Air Quality Management
State of Florida
Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32301

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- What analysis will be required for trace metals emissions?

AES/Cedar Bay Inc.

1925 North Lynn Street • Arlington, Virginia 22209 • (703) 522-1315 • Telecopier—(703) 528-4510

- Although already addressed in the plan, we want to be sure we are clear on how to deal with the modeled SO_2 exceedence issue. I think our approach effectively addresses DER and BES concerns, but am very interested in hearing feedback from you and others.

I look forward to meeting with you on the 30th.

Sincerely,

Kerry

Kerry Varkonda
Project Development Specialist

cc: James Manning, Division Chief, BESD - Jacksonville

KV/clr
Attachment

bcc: Mr. Jeff Swain, AES
Mr. Tom Tribone, AES
Mr. Terry Cole, Oertel & Hoffman
Mr. John Millican, Envir. Services
Mr. Curt Barton, Stone Container
Mr. Michael Riddle, Seminole Kraft Corp.
Mr. Steve Day, B&V
Mr. Larry Alfred, B&V

DEPARTMENT OF ENVIRONMENTAL REGULATION

ROUTING AND TRANSMITTAL SLIP

ACTION NO	
ACTION DUE DATE	

1. TO: (NAME, OFFICE, LOCATION)	
~~Clair~~	Initial
	Date
2. ~~Larry~~ ys	Initial
	Date
3. Bill	Initial
	Date
4.	Initial
	Date

REMARKS:

FYI - Copies of attachment given to Max, Barry + Dick

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: Patty

DATE 6-24

PHONE

AES CEDAR BAY, INC.
CEDAR BAY COGENERATION PROJECT
B&V PROJECT 14573
B&V FILE 32.0203

AIR QUALITY ANALYSIS WORK PLAN

CONTENTS

LIST OF TABLES

CONTENTS

(Continued)

1.0 INTRODUCTION

AES Cedar Bay, Inc. (AES-CB) proposes to construct the AES Cedar Bay Cogeneration Project to be located in Jacksonville, Florida. The project will incorporate three fluidized bed boilers burning coal and bark (the cogeneration plant) and one chemical recovery boiler burning the black liquor by-product of the adjacent Seminole Kraft paper mill. The cogeneration plant will sell electric power to Florida Power and Light and provide process steam to the kraft paper mill. The chemical recovery boiler will provide steam and electricity for internal consumption at Seminole Kraft. Eight existing boilers fueled by oil, bark, and black liquor will be removed from service as a result of the installation of the proposed sources. The existing smelt dissolving tanks and multiple effect evaporators will also be replaced by new units. Commercial operation of the proposed facility is scheduled to begin in 1992.

The project will replace older, less environmentally efficient equipment with advanced chemical recovery boiler and clean coal technology, resulting in numerous environmental benefits. Major reductions are anticipated in ambient impacts of sulfur dioxide (SO_2), total suspended particular matter (TSP), and particulate matter with aerodynamic diameter less than 10 microns (PM_{10}). In addition, the maximum total reduced sulfur (TRS) emission rate from the new recovery boiler is expected to drop to less than one-third of that from the existing recovery boilers, significantly reducing ambient impacts and thereby odor.

This air quality analysis work plan describes the proposed methodology for obtaining the required air permits for the installation and operation of the proposed emission sources of the AES Cedar Bay Cogeneration Project.

2.0 PROJECT DESCRIPTION

The AES Cedar Bay Cogeneration Project is a cogeneration facility to be located in Jacksonville, Florida. The proposed project site is shown on Figure 2-1. The site is located at the existing industrial site of the Seminole Kraft paper mill on the east bank of the Broward River. The proposed facility will be built between the existing mill and the river.

The AES Cedar Bay Cogeneration Project will generate process steam which will be sold to the adjacent Seminole Kraft Corporation mill and will generate approximately 225 MW of electricity for sale to Florida Power and Light Company (FP&L). The facility will be located at the existing Seminole Kraft pulp and paper mill site where oil, bark, and kraft black liquor are currently burned to produce steam and electric power.

The proposed cogeneration plant will fire bark and coal in three circulating fluidized bed (CFB) boilers which will produce steam at 1,800 psig for a new double automatic extraction condensing turbine generator. This will produce the 225 MW for sale and also 175 psig and 75 psig process steam for the mill. These boilers will be operated by AES-CB and will replace the existing three oil fired boilers and the two bark boilers at the mill.

A new kraft black liquor recovery boiler, which will be operated by Seminole Kraft, will replace the three existing recovery boilers and will produce 1,250 psig steam. A new double automatic extraction condensing turbine generator will produce 42 MW of electric power for internal mill consumption as well as 600 psig and 175 psig process steam for the kraft mill processes. Due to improvements in technology, the new boiler will utilize a noncontact black liquor evaporation system versus the direct contact evaporation system currently in service. As discussed earlier, this will result in a significant reduction in TRS emissions from the recovery boiler. The existing multiple effect evaporators (MEEs) and smelt dissolving tanks (SDTs) will also be replaced as part of this project. A basic process flow diagram for the pulping and chemical recovery equipment is given on Figure 2-2. Noncondensable gases from the new MEE are directed

PROPOSED SITE LOCATION

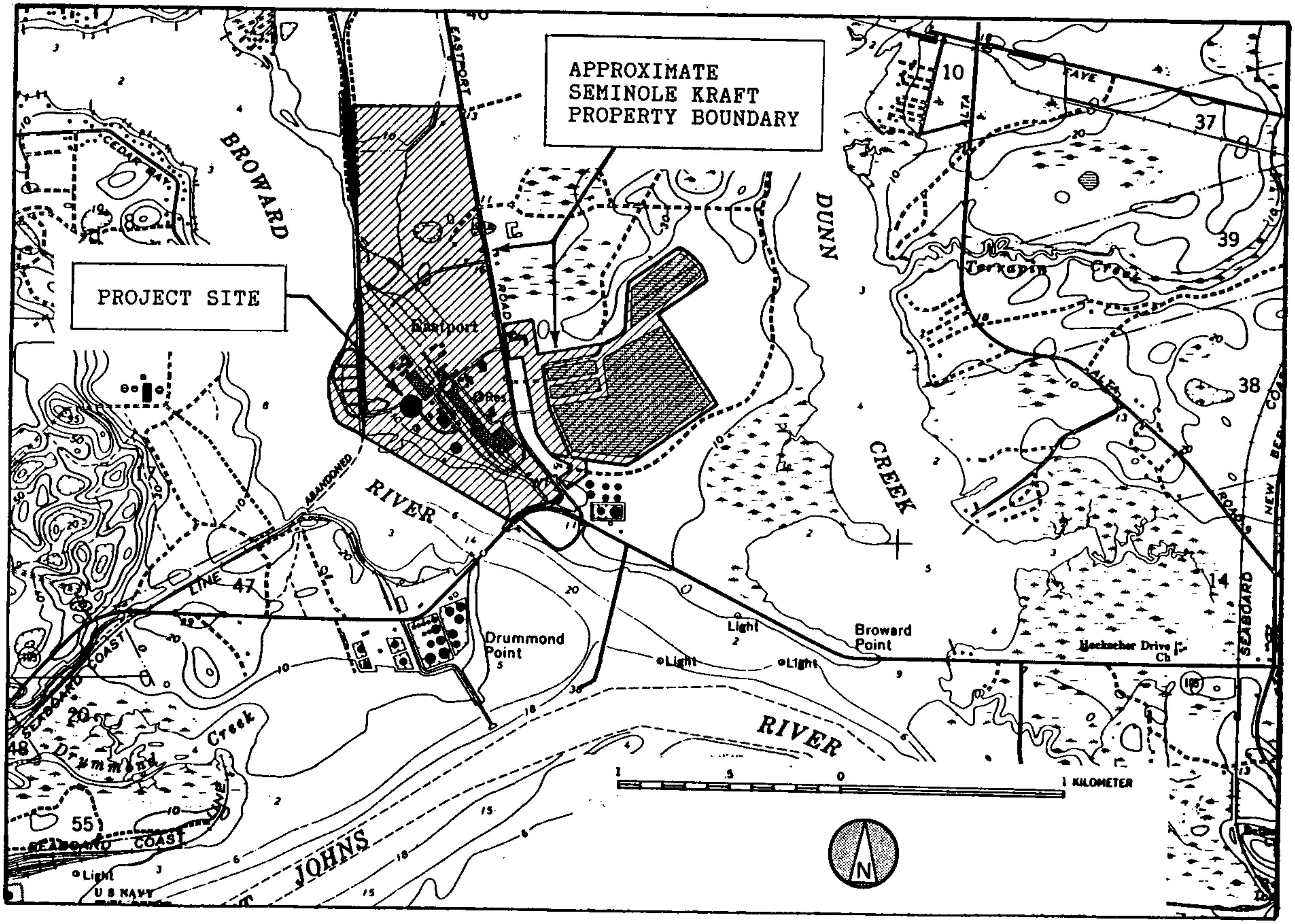

FIGURE 2-1

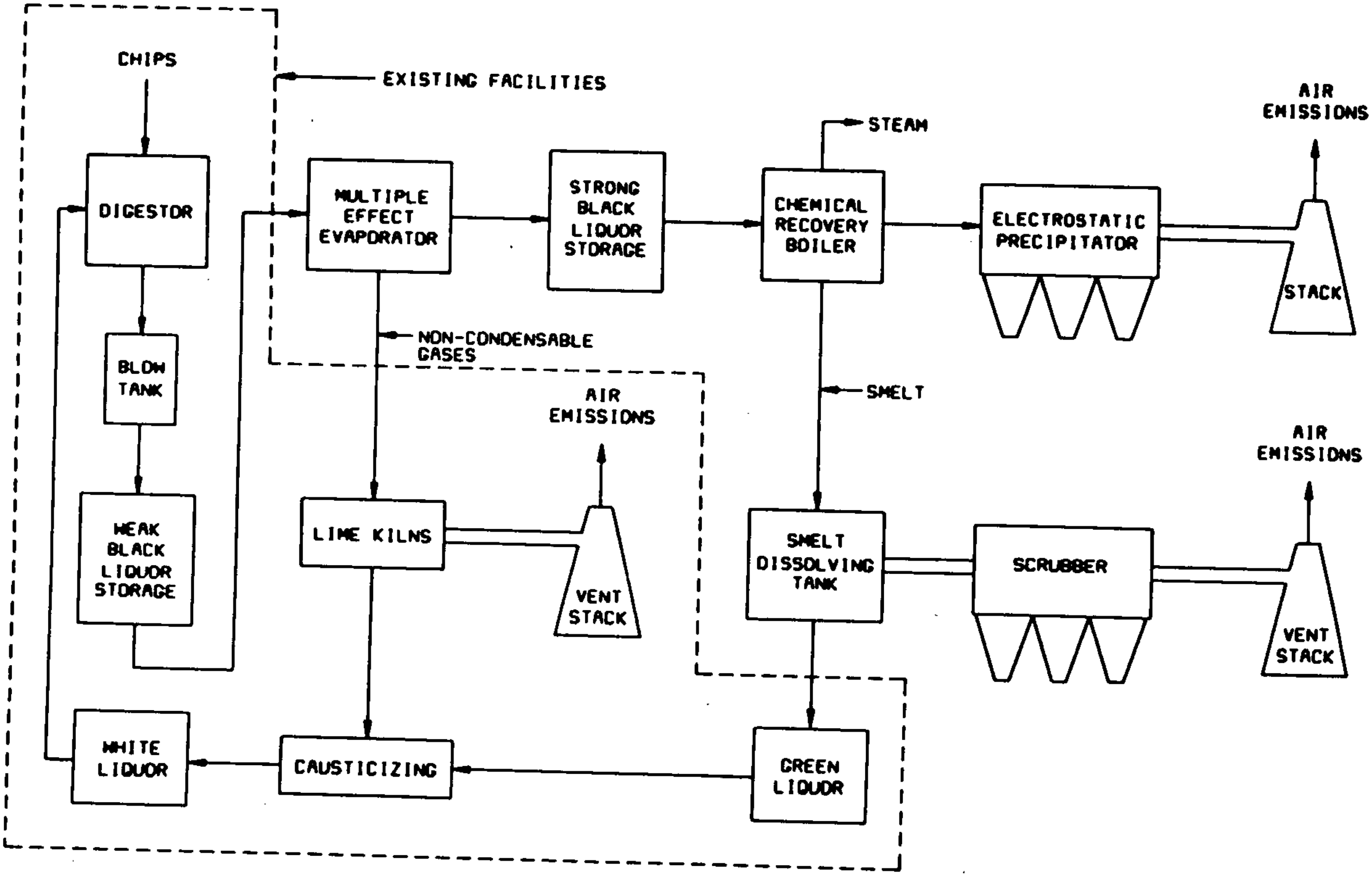

FIGURE 2.2
BASIC PROCESS FLOW
FOR PULPING AND
CHEMICAL RECOVERY

to the existing lime kilns for incineration. The net air emission changes due to the equipment replacement are discussed in Section 3 of this work plan.

The CFB boilers will burn approximately 3,200 MBtu/h. Of this, approximately 96 percent will be coal and the remainder bark. The recovery boiler will burn approximately 1,100 MBtu/h black liquor solids.

Emissions control for the CFB boilers is expected to include:

- o Limestone injection for SO_2 reduction.
- o Baghouses for particulate reduction.
- o Low combustion temperature control for NO_x reduction.

Emissions control features for the recovery boilers are expected to include:

- o Electrostatic precipitators for particulate control.
- o Non-contact black liquor evaporators for total reduced sulfur control.

Emission control for the smelt dissolving tank is expected to include a liquid contact scrubber for particulate and TRS control.

The proposed facility will receive coal by rail or barge according to economic attractiveness.

The coal combustion byproduct (ash) will be stored in silos or on impervious pads for removal from the site. This material may be sent to mines, landfilled, or potentially marketed in the engineering materials industry.

3.0 POLLUTANT APPLICABILITY

The proposed project site area is currently designated attainment for all "criteria" pollutants except ozone. A portion of Jacksonville was formerly designated nonattainment for total suspended particulate matter but was recently designated as unclassifiable with respect to new fine particulate (PM_{10}) standards.

The cogeneration project will be subject to the permitting requirements of the Prevention of Significant Deterioration (PSD) program because the net emissions increase of at least one regulated pollutant is expected to exceed 100 tons per year. Specific regulated pollutants which have net emissions increases at levels that exceed "significant" levels defined by EPA and FDER must be included in the permit application (including a Best Available Control Technology assessment).

Table 3-1 lists the estimated net increases in annual emissions for the cogeneration project. Each net emissions increase is the difference between estimated emissions from the four new boilers and SDT vent and the actual emissions from the eight boilers and SDT vents to be replaced.

Actual emissions are proposed to be based on the average of the last five mill operating years. During this period of time, mill operations were not typical, relative to the mill's capacity or historical operations. Mill ownership changed in 1983 and again in 1985 before being shut down in late 1985. Equipment reliability was poor during these years, as were mill product market conditions. The mill was purchased by Stone Container Corporation in 1986 and restarted in early 1987.

Due to the irregular nature of operations from 1982 through 1987, the proposed method of calculating representative emissions for each source in each year is as follows:

$$\text{Representative Emissions} = \text{Actual Emissions} \times \frac{\text{8400 Hours}}{\text{Actual Hours}}$$

The 8400 hour figure represents 350 operating days per year. The remaining 15 days are assumed as typical downtime needed for equipment maintenance. This is consistent with historical plant operations.

TABLE 3-1. SIGNIFICANT AND NET EMISSION RATES FOR PROPOSED FACILITY

Pollutant	Significant Emission Rates t/yr	Actual Emissions[a] t/yr	Estimated Maximum Emissions[b] t/yr	Net Increase t/yr	Applicable Pollutant Yes/No
Carbon monoxide	100	c	4,765	d	d
Nitrogen oxide	40	c	6,360	d	d
Sulfur dioxide	40	c	10,775	d	d
Particulate matter	25	c	648	d	d
Particulate matter (PM_{10})	15	c	648	d	d
Ozone (volatile organic compounds)	40	c	539	d	d
Lead	0.6	e	e	d	d
Asbestos	0.007	e	e	d	d
Beryllium	0.0004	e	e	d	d
Mercury	0.1	e	e	d	d
Vinyl chloride	1.0	e	e	d	d
Fluorides	3	e	e	d	d
Sulfuric acid mist	7	e	e	d	d
Total reduced sulfur	10	c	44	d	d

[a]Based upon average of sum of 1982, 1983, 1984, 1985, and 1987 actual emissions prorated to represent full years of operation (see Section 3.0).
[b]Based upon proposed design criteria of all proposed sources (detailed in Table 5-4).
[c]Currently in preparation.
[d]Will be included with permit application submittal.
[e]Will be estimated from fuel analysis data or applicable literature information.

The above equation would be used to estimate representative emissions from each source for years 1982 through 1985 and 1987. 1986 would be excluded since the mill did not operate during that year.

Emission figures which were not included as part of the annual mill emission reports will be estimated based on AP-42 factors.

The emission estimates for the proposed new sources assume that all new boilers will be operated at maximum load for the entire year (8,760 hours). These estimates also assume the three CFB boilers to be operated totally on coal, producing higher expected emissions than when burning bark. The "significant" levels for the regulated pollutants are included in the table for comparison.

4.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

A BACT document will be prepared separately for the AES Cedar Bay Cogeneration Project. The BACT analysis will include those pollutants shown to be applicable because of expected significant emissions.

Under the federal Clean Air Act, BACT represents the maximum degree of pollutant reduction determined on a case-by-case basis after consideration of environmental, energy, and economic factors. However, BACT cannot be less stringent than the emission limits imposed through any applicable new source performance standard (NSPS).

The BACT analysis will follow the so-called "top down" approach as presented the December 1, 1987, memorandum from J. Craig Potter to the EPA Regional Administrators. For each pollutant or group of pollutants, the most stringent control available for a similar source or source category will be addressed first. If it can be shown that this level of control is technically or economically infeasible for the source, than the next most stringent level of control will be determined and similarly evaluated until the proposed BACT level is reached.

The proposed BACT control methods will not be finalized until after completion of the BACT analysis, but is expected to include fabric filter control for particulates, a circulating fluidized bed (CFB) boiler with limestone injection and fabric filter control for sulfur dioxide, and a CFB boiler without supplemental control for nitrogen dioxide and carbon monoxide. Because of the nonattainment status of the site and with regard to ozone, the CFB boilers will be analyzed for VOC emissions from the standpoint of Lowest Achievable Emission Rate (LAER). Expected BACT controls for the chemical recovery boiler include an electrostatic precipitator for particulate control and low-odor boiler technology for control of total reduced sulfur (TRS). The BACT control for the MEE system is expected to be incineration in the lime kilns. The BACT control for the smelt dissolving tank is expected to be a liquid contact scrubber for reducing particulate and TRS emissions.

5.0 AIR QUALITY ASSESSMENT METHODOLOGY

An analysis of flue gas emissions will be conducted to facilitate the assessment of the impacts of airborne pollutants on ground level ambient air quality levels, visibility, soils, and vegetation in the project vicinity. This section describes the overall air quality assessment methodology proposed for this study including the various modeling data requirements. The assessment methodology is based on EPA's Guideline on Air Quality Models (Revised) July 1986 (including Supplement A, July 1987) and the UNAMAP 6 dispersion models.

Copies of pertinent air quality modeling runs will be included as a separate appendix to the actual air permit application.

5.1 APPLICABLE AIR QUALITY DISPERSION MODELS

For most air quality modeling assessments it is desirable to use both screening level and refined dispersion modeling techniques. For this project, EPA's screening level model PTPLU-2 and the EPA document entitled Procedures for Evaluating Air Quality Impact of New Stationary Sources (Volume 10--Revised) will be used to determine the highest predicted ground level concentration for various plant operating conditions. The operating conditions of the circulating fluidized bed (CFB) boilers will be evaluated at 50 and 75 percent capacity plus the maximum design for the plant. The worst case operating conditions then will be further evaluated using refined dispersion modeling techniques.

The terrain is level in the vicinity of the proposed Cedar Bay Cogeneration Project. Following the recommended EPA modeling guidance for refined models, the ISCST (Industrial Source Complex Short-term) dispersion model will be used with five years of hourly meteorological data. Concentrations will be predicted for 1-, 3-, 8-, and 24-hour plus annual averaging periods.

The proposed modeling site will be considered rural for modeling purposes based on the land use within a 3-kilometer radius. Standard EPA default modeling options will be used for this analysis.

Building downwash will be used in the modeling assessment as appropriate to consider the effects of nearby buildings. The proposed new sources will utilize good engineering practice (GEP) stack heights. The PSD permit application will include a plot plan and building dimensions to support GEP determinations.

5.2 METEOROLOGICAL DATA

Preprocessed meteorological data obtained from the Florida DER for Jacksonville, Florida, for the five-year period 1981 to 1985 will be used for the dispersion modeling.

5.3 SOURCE DATA

The proposed emissions associated with this project can be classified as fugitive and combustion gas emissions. Combustion gas emissions will be evaluated for operation of the existing sources as well as proposed new sources.

5.3.1 Fugitive Dust Emissions

The generation of particulate emissions from the handling and storage of coal, wood waste, limestone, and combustion waste will be minimized. An estimated fugitive dust emissions inventory will be developed and submitted as part of the permit application. Modeling of ambient air quality impacts will be performed using the recommended ISCST dispersion model. The modeling will include both point and area sources within the plant, as appropriate. Receptors will be positioned at locations on the plant boundary and 100 meters beyond the boundary. The results of the modeling will demonstrate compliance with all particulate air quality standards.

Emission factors and typical dust control efficiencies will be obtained from EPA's Compilation of Air Pollutant Emission Factors (AP-42). The emission inventory will be based on annual material throughput for facility operation.

5.3.2 Combustion Gas Emissions

Combustion gas emissions will be evaluated for operation of the existing sources and for the new sources proposed for this project. The purpose of evaluating both existing and proposed sources is to determine the effects on the ambient air quality of replacing existing equipment with new, efficient, and well controlled boilers equipped with GEP stacks. It is anticipated that the replacement of the existing power and recovery boilers and their respective short stacks with three fluidized bed and one recovery boiler equipped with GEP height stacks will show a net ambient air quality improvement.

5.3.2.1 Existing Source Data. Table 5-1 summarizes the existing Seminole Kraft paper mill source information, including sulfur dioxide emissions in accordance with FDER's emissions inventory. A modeling study was previously performed by the FDER of major sources in the Jacksonville area to assess potential sulfur dioxide levels. For convenience, the FDER study combined similar Seminole Kraft sources into "composite" sources for modeling. The source parameters for the composite sources were developed from the combined worst-case source parameters for the sources included in each composite.

EPA's Guide for Compiling a Comprehensive Emission Inventory (March 1973) is a more refined method of "lumping" similar sources together. The procedure calculates a plume buoyancy term (K) for each individual stack using stack height (H), flow volume (V), exhaust gas temperature (T), and Emission Rates (a) in the following equation.

$$K = (H)(V)(T)/(a)$$

When combining sources, the stack with the lowest K value is selected and its stack parameters are used to represent the composite source. Emissions from all sources are added and used for the composite source. This method simplifies the dispersion modeling effort. Table 5-2 shows the simplified source configuration for the existing Seminole Kraft SO_2 sources. The stack heights for the five combined sources represent less than GEP heights and require modeling of downwash effects induced by buildings in the immediate area of the stacks.

TABLE 5-1. EXISTING SEMINOLE KRAFT SOURCE DATA

Source	SO_2 Emission Rate[a] g/sec	(x.132) lb/L	Stack Height m	Stack Exit Temperature K	Stack Exit Velocity m/sec	Stack Diameter m
P. Boiler #1	54.6	7.2	32.3	433	20.12	1.83
P. Boiler #2	72.7	9.6	32.3	450	21.34	2.13
P. Boiler #3	72.7	9.6	32.3	450	22.86	2.13
B. Boilers	114.0	15.1	41.5	329	13.72	2.44
R. Boiler #1	11.0	1.4	38.4	344	17.68	2.59
R. Boiler #2	14.1	1.9	38.4	344	17.98	2.74
R. Boiler #3	14.1	1.9	38.4	344	16.76	2.74
Lime Kiln #1	0.5	0.07	21.0	344	5.18	1.80
Lime Kiln #2	0.5	0.07	22.9	339	7.62	1.43
Lime Kiln #3	0.5	0.07	22.9	339	10.36	1.13
SDT #1	0.2	0.03	36.6	344	3.96	1.07
SDT #2	0.3	0.04	37.8	344	4.27	1.22
SDT #3	0.3	0.04	37.8	347	4.27	1.22

[a]Based on FDER data; confirmed by AES calculations.

TABLE 5-2. EXISTING COMPOSITE SOURCE DATA

Source	SO2 Emission Rate[a] g/sec	Stack Height m	Stack Exit Temperature K	Stack Exit Velocity m/sec	Stack Diameter m
P. Boilers	200.0	32.3	433	20.12	1.83
B. Boilers	114.0	41.5	329	13.72	2.44
R. Boilers	39.2	38.4	344	16.76	2.74
Lime Kilns	1.5	22.9	339	10.36	1.13
SDTs	0.8	37.8	344	4.27	1.22

[a]Based upon FDER data; confirmed by AES calculations.

5.3.2.2 Proposed Source Data. Table 5-3 summarizes the source data for the three fluidized bed boilers, recovery boiler, and smelt dissolving tank being proposed to replace the existing three oil-fired power boilers, two bark-fueled boilers, three recovery boilers, and three smelt dissolving tanks. The three fluidized bed boilers will exhaust pollutants through a common GEP stack. The recovery boiler will be equipped with a separate GEP stack. The smelt dissolving tank will exhaust through a vent stack. MEE emissions will be routed to the lime kilns for incineration, as they currently are at the Seminole Kraft Mill.

Estimated emission rates for the fluidized bed boilers, recovery boilers, and SDT are given in Table 5-4. The boiler stack heights represent GEP heights based on an enclosed CFB boiler structure of 170 feet in height and a projected width greater than that height. The CRB structure height is estimated at 210 feet; however, the horizontal dimensions are smaller so that the structure does not influence the GEP height of the stacks. A plot plan will be included in the permit application to identify building dimensions and support the GEP determinations.

5.4 RECEPTOR DATA

The ISCST dispersion model can predict ground-level concentrations for receptor locations expressed in either polar coordinates, Cartesian coordinates (x-y), or both. Polar receptor coordinates are proposed for this analysis with the proposed CFB boiler stack located at the center of the receptor array.

Receptor locations will be established at appropriate distances and with adequate density to predict maximum concentrations for the various averaging periods and to identify the significant impact areas for criteria pollutants with significant impacts in offsite locations. With a polar receptor grid, an initial receptor array will be established according to EPA modeling workshop guidance and the PTPLU-2 modeling results. Additional receptor rings (distances) will be selected after reviewing the initial ISCST modeling results. The purpose of the additional receptor rings can be to increase the resolution of receptor spacing in the vicinity of expected maximum predicted concentrations or to extend the grid to the

TABLE 5-3. PRELIMINARY SOURCE DATA FOR NEW SOURCES

Model Parameters	Fluidized Bed Boilers	Recovery Boiler	Smelt Dissolving Tanks
Nearby Building Height	170 feet	210 feet	210 feet
Stack Height	425 feet	425 feet	240 feet
Total Heat Input	3,200 MBtu/h	1,100 MBtu/h[a]	NA
Stack Exit Velocity	3,600 ft/min	3,600 ft/min	3,056 ft/min
Stack Exit Diameter	17 feet	11.5 feet	5 feet
Stack Exit Temperature	265 F	380 F	160 F

[a]Design feedrate of 4.1 million pounds black liquor solids per day.

TABLE 5-4. ESTIMATED POLLUTANT EMISSION RATES

	Circulating Fluidized Bed Boilers		Chemical Recovery Boiler	SDT	
	Emission Rate lb/MBtu	Emissions[a] lb/h	Emissions[b] lb/h	Emission Rate[c] lb/ton BLS	Emissions[d] lb/h
CO	0.19	608	480	--	--
NO_x	0.36	1,152	300	--	--
SO_2	0.60	1,920	540	--	--
PM	0.02	64	73	0.2	11
PM_{10}[e]	0.02	64	73	0.2	11
VOC	0.016	51	72	--	--
TRS	--	--	8	0.03	2

Not based on BACT.

[a]Based upon 3,200 MBtu/h heat input to boilers.

[b]Based upon preliminary estimates from manufacturers' information and a feedrate of 4.1 million pounds black liquor solids (BLS)/day.

[c]One ton of BLS assumed to be 3,000 pounds.

[d]Based on feedrate of 4.1 million pounds BLS/day.

[e]Conservative assumption that all particulate emissions are PM_{10}.

outer bounds of significant impact areas. Higher resolution will be accomplished by bracketing the maximum predicted concentration locations by receptor rings at approximately 100 meter intervals.

6.0 AAQS ANALYSIS

The air quality impact assessment will determine the impact of the proposed facility on the Ambient Air Quality Standards (AAQS). Florida has established some air quality standards that are more restrictive than the National AAQS. The applicable federal and state ambient air quality standards are given in Table 6-1.

Since the air quality assessment will use a five-year meteorological data set, the highest second-highest modeled concentrations will be used to show compliance with all but the annual standards. As part of this assessment, it will be necessary to establish values for pollutant background concentrations.

6.1 POLLUTANT BACKGROUND CONCENTRATIONS

The state of Florida has been conducting air quality monitoring for criteria pollutants at locations throughout the state for many years. The plant site is considered to be in attainment for all criteria pollutants except ozone. Downtown Jacksonville was designated nonattainment for total suspended particulate (TSP), but was recently designated as unclassified for PM_{10}. Monitoring of PM_{10} has been performed in downtown Jacksonville (Adams Street) since early 1986. With the availability of this data and other representative monitoring data, the FDER has indicated that additional ambient air quality monitoring will not be required for this permit application.

The FDER document Ambient Air Quality in Florida 1986 (November 1987) provides the most recent monitoring data for use in establishing background concentrations for the criteria pollutants. FDER and EPA guidance would generally allow use of the highest, second-highest monitored concentrations to establish background concentrations for the project area. For this analysis, 1986 data from all Duval County monitoring sites were reviewed for each pollutant. Generally, data with the highest concentrations were selected; however, location of the samplers and monitoring objectives were also considered.

TABLE 6-1. FEDERAL AND FLORIDA AMBIENT AIR QUALITY STANDARDS

Pollutant	Sampling Period	Federal Standards Primary ug/m^3	Federal Standards Secondary ug/m^3	Florida Standards ug/m^3
Sulfur Dioxide (SO_2)	Annual	80	--	60
	24-hour	365	--	260
	3-hour	--	1,300	1,300
Nitrogen Dioxide (NO_2)	Annual	100	100	100
Particulate Matter (PM_{10})	Annual	50	50	50
	24-hour	150	150	150
Carbon Monoxide[a] (CO)	8-hour	10	--	10
	1-hour	40	--	40
Ozone (O_3)	1-hour	235	235	235
Lead (Pb)	Calendar Quarter	1.5	1.5	1.5

[a]Units are mg/m^3.

Table 6-2 summarizes the existing monitoring data being proposed as conservative values of the background pollutant concentrations for the plant area. These monitoring sites are all located within the vicinity of the proposed plant site or in the Jacksonville metropolitan area. The background concentrations for applicable criteria pollutants except for SO_2 will be combined with the predicted modeled concentrations to demonstrate compliance with the applicable standards.

6.2 APPROACH TO ADDRESS SO_2 MODELED EXCEEDENCE ISSUE

Modeling of the Jacksonville area by the FDER has indicated that if existing permitted sources were to operate at their permitted emission rates, a nonattainment area for SO_2 would exist. In accordance with FDER guidance, AES-CB will approach the permit application process in two segments.

First, AES-CB will demonstrate that net ambient impacts resulting from the project (i.e., ambient impacts from the new circulating fluidized bed and recovery boilers and SDT minus impacts from the existing power, bark and recovery boilers and SDTs, assuming Seminole Kraft permitted emission rates) will be less than significant impact levels at modeled exceedence points. That is, less than 25 ug/m^3 for a 3-hour average, 5 ug/m^3 for a 24-hour average, and 1 ug/m^3 for an annual average.

This expected demonstration is based upon both the use of offsetting emissions and the installation of good engineering practice (GEP) stacks on the new sources at the facility. Present sources are equipped with short stacks which are heavily influenced in the modeling by building downwash effects. GEP stack heights will eliminate the downwash effects of the model.

This analysis is intended to address the FDER concern for the project's impact on the SO_2 modeled exceedence issue in Jacksonville, and is our understanding of the FDER's requirement of an applicant before a permit for new construction can be considered.

Once the above criteria are met, SO_2 ambient impacts will be evaluated in the typical fashion, as described in Section 6.3 for AAQS and Section 7 for PSD increment. There will be no further evaluation relative to the modeled SO_2 exceedence issue beyond that described above.

TABLE 6-2. EXISTING AMBIENT AIR QUALITY MONITORING DATA[a]

	Measured Concentration	Location	Year
Sulfur Dioxide (ug/m^3)			
Annual	10	1960-081-H	1986
24-Hour	63	1960-081-H	1986
3-Hour	321	1960-081-H	1986
Nitrogen Dioxide (ug/m^3)			
Annual	29	1960-032-H	1985[b]
PM_{10} (ug/m^3)			
Annual	31	1960-004-H	c
24-Hour	65	1960-004-H	c
Carbon Monoxide (PPM)			
8-Hour	6	1960-082-H	1986
1-Hour	13	1960-082-H	1986
Lead (ug/m^3)			
Calendar Quarter	0.3	1960-084-H	1986

TSP

Add TSP

[a]From Ambient Air Quality in Florida 1986, Florida Department of Environmental Regulation, November 1987.

[b]1986 not available.

[c]April 1986-March 1987.

6.3 MODELED POLLUTANT CONCENTRATIONS

The net modeled impacts of applicable criteria pollutants will be assessed with regard to compliance with applicable AAQS. First, actual emissions from the existing Seminole Kraft sources, as defined in Section 3.0, will be modeled to establish "base" ambient concentrations. Next, the new sources proposed to replace the existing sources will be modeled with the same receptors. If the net changes of all offsite ambient concentrations are below significant ambient impact levels, then no additional modeling will be performed for that pollutant.

For those criteria pollutants with offsite net impacts greater than significant levels, an emissions inventory of other appropriate existing sources will be established. The inventory will be developed based on the "Screening Threshold" Method for PSD Modeling used by the North Carolina Air Quality Section. This method was previously recommended by the FDER to develop a list of sources to be included in AAQS analyses.

A background concentration for each applicable pollutant and averaging period will then be added to the total modeled impact. The background concentration, as discussed in Section 6.1, very conservatively represents the contributions from all other sources not included in the modeling analysis.

7.0 PSD INCREMENT ANALYSIS

Prevention of Significant Deterioration (PSD) regulations were promulgated as a result of the 1977 Clean Air Act Amendments to ensure that air quality in a defined area does not significantly deteriorate or exceed AAQS while providing a margin for future growth.

PSD regulations apply to areas designated as "attainment" for criteria pollutants. New sources or major modifications to existing sources that emit regulated air pollutants in "significant" amounts must comply with these regulations. As previously discussed, emission rates for the AES-CB analysis will be the net difference between emissions from the new CFBs, recovery boiler, and SDT and emissions from the existing equipment to be replaced. PSD regulations classify all areas of the country. The proposed project site has been classified a Class II PSD area. As a result of this classification, Class II PSD increments will be applicable for this analysis in all areas surrounding the facility.

In addition, any Class I area within 100 kilometers of a proposed source must be assessed to ensure that modeled impacts will not exceed Class I increments. The closest Class I area is the Okefenokee National Wilderness Area in southeastern Georgia. This area is approximately 60 kilometers from the project site. PSD Class I increment consumption will be modeled for this area in addition to the analysis of maximum Class II increment consumption. The modeling of SO_2 for Class I increment consumption will be performed using the ISC model's plume chemical transformation feature. A half-life of 4 hours will be applied for the analysis.

The PSD Class I and II maximum allowable increments are listed in Table 7-1. A source inventory of appropriate PSD increment consumers will be developed in the same manner as for the AAQS analysis. A list of potential PSD consuming sources will be obtained from FDER to use in developing the final source inventory.

TABLE 7-1. PSD CLASS I AND CLASS II AIR QUALITY INCREMENTS

Pollutant	Class I Increment $\mu g/m^3$	Class II Increment $\mu g/m^3$
SO_2		
Annual	2	20
24-Hour	5	91
3-Hour	25	512
Particulates		
Annual	5	19
24-Hour	10	37
NO_x[a]		
Annual	2.5	25.0

[a]Proposed February 8, 1988.

8.0 ADDITIONAL IMPACT ANALYSIS

8.1 VISIBILITY

The nearest PSD Class I area is the Okefenokee National Wilderness Area in southeastern Georgia. This Class I area is approximately 60 kilometers from the site. An analysis of potential visibility degradation will be performed based on EPA guidance materials. A Level-1 assessment is expected to show no significant effect on the visibility in the Class I area. It is anticipated that the removal of the existing boilers and installation of the newer boilers will have a favorable affect on the overall visibility in the project site area as well.

8.2 SOILS AND VEGETATION

The analysis will examine the levels at which the soil and vegetation in the area are adversely impacted by various pollutants and compare these levels with the predicted net impacts due to the proposed facility.

8.3 GROWTH

The potential for secondary effects on air quality will also be assessed. The possible effects of the proposed facility on economic and population growth will be discussed.

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2-4-88

AES JACKSONVILLE PPS.

Owner/Operator of PP facility (Pvt) cogen trend.
Try to have facility get competitive with utilities

140MW @ TX 110 mill. (40%) was controls on PP built before. (Acid control incl.)
120MW @ PA. coal.

- 2 under construction in California (natural gas)
- Most recent project 300MW (Oklahoma) Coal fired (fluid bed)

Seminole Kraft
- Oil/Bark Power Boilers {3 coal/bark, 1 oil, 1 R. Boiler}
- Recovery Boiler odor problem

Generate 250

New 225 MW Cogeneration [1 low odor R. Boiler, 3 coal/bark boilers (fluidized bed)]
Replace the above Boilers.

Steam to S.K.
225 MW thru JEA & FPL

Recovery Boiler needs to comply with TRS rule.

March 10 will have SO_2 meeting in Jacksonville, MAX.

Bruce feels time frame: at least 10 MO after complete application
: or later if litigation.

Check water discharge with EPA for significant change from NPDES.
Steve Day feels the NPDES permit is needed regardless ...

FPL wants need for 1600 MW by mid 90's.

This project may substitute for FPL plan for gas fired combined cycle unit next.

PM10 monitoring data source questions for Bay/Mear
Other requirements past EPA approval of SIP. (1 yr maybe).

AN OVERVIEW OF

AES JACKSONVILLE

COGENERATION FACILITY

FEBRUARY 1988

APPLIED ENERGY SERVICES, INC.

OVERVIEW

- AES has been developing a cogeneration facility on an existing industrial site in Jacksonville, Florida

    - Steam will be sold to the Seminole Kraft paper mill that was refurbished by Stone Container Corporation in the fall of 1986 and restarted in February 1987, and

    - 225 MW of electricity will be wheeled through Jacksonville Electric Authority (JEA) and sold to Florida Power and Light

- The new power facility, valued at approximately $400 million, will consist of the following:

    - one new low-odor recovery boiler and an associated turbine, and

    - three new circulating fluidized bed (CFB) boilers and associated turbine

- The project will replace older, less efficient equipment, improving Seminole Kraft's competitive position and reducing odor emissions.

- Bark and coal will be fired in the CFB boilers to generate steam

- This document provides information about the planned cogeneration facility and AES.

ATTRACTIVE FEATURES OF THE PROJECT

Economic

- Provides attractively priced electricity to Florida ratepayers under a stable rate structure
- Steam at below-market prices improves Seminole Kraft's competitive position, thus improving employment stability.
- $400 million cogeneration project provides up to 660 construction jobs and 95 new permanent jobs at the AES plant;
- Facility increases the tax base in the City of Jacksonville, resulting in expanded tax revenues.
- Supports diversification of industrial mix in Jacksonville

Energy

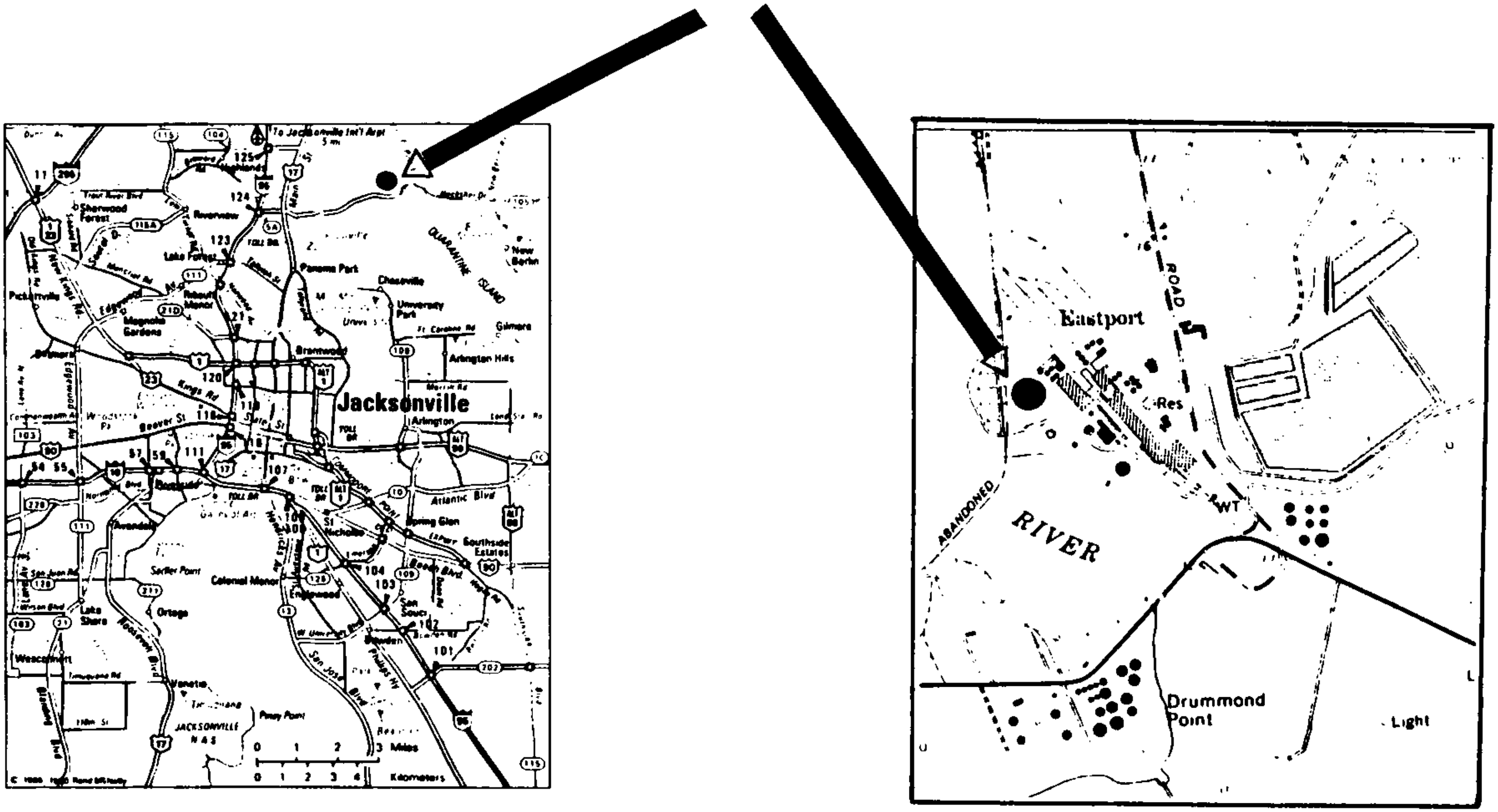
- Facility displaces oil use at the Seminole Kraft mill
- Coal abundantly available and not dependent on foreign suppliers
- Adds needed electric generating capacity in Florida for mid 1990's and beyond
- Consistent with State energy policy that favors coal in new generating facilities

Environmental

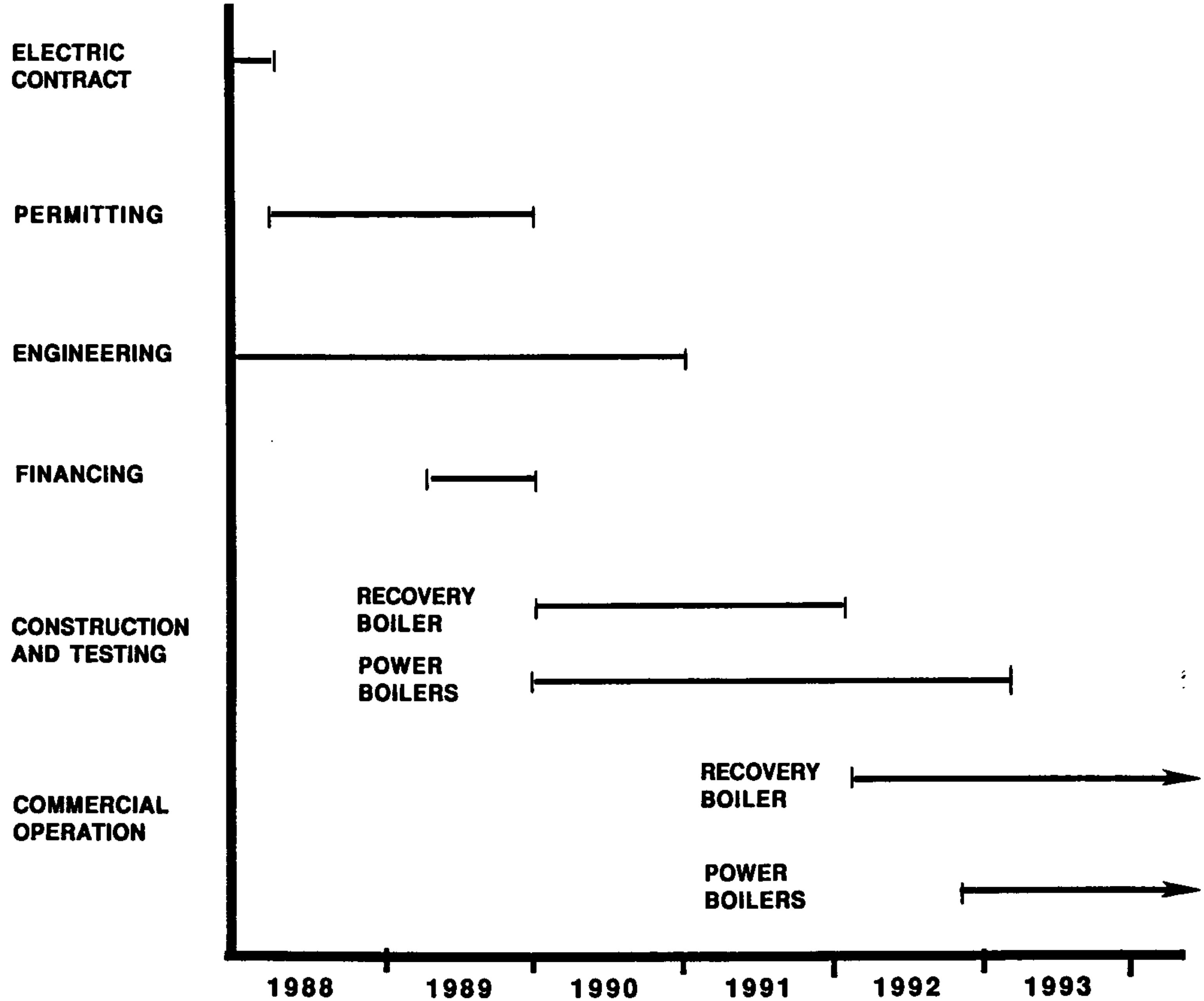
- Located on an existing industrial site adjacent to Seminole Kraft.
- New recovery boiler reduces odor and particulate emissions from the mill
- Offsets emissions from oil-fired boilers at Seminole Kraft mill
- Allows coal to be used with minimal air pollution through application of new technology (i.e., circulating fluidized bed boilers)

AES JACKSONVILLE LOCATION

- The plant will be located on the site of the Seminole Kraft paper mill on Eastport Road



PROJECT SCHEDULE



NEXT STEPS

- Signing of power supply contract with Florida Power and Light (FP&L) expected in the next several weeks
- Initiating site certification and permitting effort; looking forward to working closely with appropriate agencies to facilitate the permitting process
- Engineering, Fuel Procurement, Steam and Wheeling Contract development efforts are underway
- AES looks forward to developing a plant adjacent to Stone Container in Jacksonville as we did in Connecticut (see enclosed press release)
- Questions regarding AES Jacksonville can be directed to Jeffrey V. Swain, Project Director, AES Jacksonville at (703-522-1315)

AES OFFICERS AND DIRECTORS

BOARD OF DIRECTORS	
DENNIS W. BAKKE	COO of AES, Former Deputy Assistant Administrator at the Federal Energy Administration
FRANK JUNGERS	Retired Chairman of the Board and Chief Executive Officer of Arabian American Oil Company (ARAMCO).
HENRY R. LINDEN	Frank Gunsalus Professor of Engineering at Illinois Institute of Technology and Former President of the Gas Research Institute.
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AES EXPERIENCE

AES FACILITY/ LOCATION	CUSTOMERS	COST Million	FUEL	STEAM (#/HR)	POWER (MW)	CONT. START	ON LINE
Deepwater Houston, Texas	Texas Utilities Lyondell Petrochemical	$280	Petcoke	30,000	139	December 1983	June 1986
Beaver Valley Monaca, Pennsylvania	West Penn Power Arco Chemical	116	Coal	145,000	118	September 1985	July 1987
Placerita Newhall, California	Southern California Edison, TOSCO	120	Gas	250,000	99	July 1986	July 1987
Thames Montville, Connecticut	Northeast Utilities Stone Container	250	Coal	65,000	180	December 1986	November 1989
Shady Point Poteau, Oklahoma	Oklahoma G&E AES CO_2 Plant	475	Coal	100,000	320	June 1987	January 1991
Riverside Woonsocket, Rhode Island	New England Electric Boston Edison Eastern Utilities Associates	260	Coal	50,000	180	1989	1991
Barbers Point Oahu, Hawaii	Hawaiian Electric Chevron*	250	Coal	30,000	146	1989	1992
Petrolia Petrolia, Pennsylvania	West Penn Power	280	Coal	30,000	180	1992	1995
Ballinger Creek Frederick, Maryland	Potomac Electric*	270	Coal	30,000	180	1990	1993
Jacksonville	Florida Power & Light Stone Container*	400	Coal	600,000	225	1990	1993
TOTAL		$2701 Million		1,330,000 lb/hr	1767 MW		

* Letter of Intent agreements signed

Applied
Energy
Services,
Inc.

Contact: Mr. Robert F. Hemphill, Jr.
703/522-1315
November 26, 1986

For Immediate Release

AES AWARDS $180 MILLION POWER PLANT CONSTRUCTION CONTRACT TO JAPANESE-AMERICAN JOINT VENTURE. $250 MILLION PROJECT FINANCING COMPLETE.

ARLINGTON, VA, November, 1986: Applied Energy Services, Inc. (AES) announced today that it has awarded a $180 million contract to a joint venture of Marubeni, Toshiba and Pritchard to construct its AES Thames Cogeneration plant in Montville, Connecticut. "We are pleased not only because the Thames plant is our largest project to date but because it incorporates many advanced features to minimize impact on the environment," stated Roger Sant, President and CEO of AES.

The project will cost $250 million and is being financed by a syndicate of banks led by Fuji Bank, Ltd. as Agent. Other participating banks include the Bank of New England, N.A., the Nippon Credit Bank, Ltd., the Bank of Nova Scotia, the Westpac Banking Corporation, the Chuo Trust & Banking Co., Ltd., the Daiwa Bank, Ltd., the Hokkaido Takushoku Bank, Ltd., and the Saitama Bank, Ltd. Salomon Brothers Inc. is serving as Financial Advisor for AES. AES Executive Vice President Dennis W. Bakke praised the leadership of Fuji and the cooperation of the bank group. "Additionally, the subordinated lenders including Marubeni America Corporation, Combustion Engineering Corporation, CSX Transportation and Toshiba International were also critical to a timely and successful financing."

The plant, which is being engineered by Black and Veatch of Kansas City, Missouri, consists of two Combustion Engineering circulating fluidized bed boilers and a Toshiba steam turbine-generator. The plant is scheduled to begin operation in mid-1989. It is expected to produce 180 megawatts of electricity (sufficient to supply 36,000 homes) for sale to Connecticut Light & Power on a 25-year contract, and 60,000 pounds an hour of steam to be sold to a

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subsidiary of Stone Container Corporation. "The plant will be supplied with approximately 600,000 tons of coal each year through an innovative contract with CSX Transportation," explained AES Senior Vice President Robert F. Hemphill, Jr. "This is the first coal plant to be built in New England in many years and our design incorporates the advanced fluidized bed combustion technology."

AES is a privately held company formed in 1981. The company is an independent supplier of steam and electricity and was recently designated the twelfth fastest growing private company in the United States by INC. Magazine. It operates a 140 megawatt petroleum coke fired cogeneration plant in Houston, Texas, is refurbishing a 120 megawatt coal fired cogeneration plant near Pittsburgh, Pennsylvania and is constructing a 100 megawatt natural gas-fired cogeneration plant near Los Angeles, California. In addition, AES is developing several other power plants around the country.

10-28-87

Seminole
[redacted] KRAFT

AES Inc

will build cogen, they will run & own the facility. Jax Kraft's property will be used & also they will buy the steam
250 MW

Problem with SO_2 short term & any ambient.

New Replaces old.

OLD - are oil fired boiles
NEW - coal fired lime injection fluidized.
(better SO_2 control)

Dual C. unclassifiable for SO_2