ATTACHMENT E

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30365

MEMORANDUM

DATE:

SUBJECT: Cedar Bay Cogeneration Facility, Jacksonville, Florida

FROM: Wayne J. Aronson, Chief
Program Support Section
Air Programs Branch
Wayne J. Aronson

TO: Robert B. Howard, Chief
NEPA Compliance Branch

Per your request, we have reviewed the site certification application for the proposed construction of the Cedar Bay Cogeneration Facility to be located in Jacksonville, Florida. We offer the following comments:

Application Forms for Each Source

1. Circulating Fluidized Bed (CFB) Boilers

The application states that in addition to burning coal and wood, the CFB boilers will burn No. 2 fuel oil in the estimated amount of 160,000 gallons per year. This fuel will be used as backup/auxiliary fuel. To be more sufficient the application form for the CFB boilers should list No. 2 fuel oil in Section E (Fuels) along with the other fuels. 1.

Section C (Airborne Contaminants Emitted) of the application form requires that all pollutants be listed and contain federally enforceable emission limits for regulated pollutants. Instead of listing the pollutants, the form states that a list of pollutants emitted from this source can be found in the text of the Site Certification Application. Such a reference is impractical. We recommend that all regulated pollutants, along with their federally enforceable limits, be included on the application form. Furthermore, when indicating the pollutants, include any air toxic substances that will be emitted due to the combustion of No. 2 fuel oil. According to the EPA publication titled "Control Technologies for Hazardous Air Pollutants," possible air toxics that might be emitted due to the combustion of oil are (* indicates regulated pollutants): 2.

formaldehyde	*beryllium
polycyclic organic matter	cadmium
*fluoride	chromium
*mercury	cobalt
chlorine	copper
*arsenic	*lead
barium	manganese
zinc	nickel
vanadium	*radionuclides

RESPONSES

1. The FDER application form (Section III Part E - Fuels) for the CFB boiler will be revised to list No. 2 fuel oil as the backup/auxiliary fuel. The estimated quantity will be 160,000 gallons per year.

2. Because of the nature of the supplemental information, it was determined that the data could be summarized more efficiently into a table. The SCA Table 3.4-2 information will be expanded to include regulated and air toxic emission estimates for various proposed sources. The expanded information is included as Attachment A (Tables 1, 2, and 3) to this submittal.

The application form should also specify that the boilers are subject to New Source Performance Standards (NSPS) for electric utility steam generating units (40 CFR Part 60, Subpart Da). In addition to emission limits for sulfur dioxide (SO_2), particulate matter (PM), and nitrogen oxides (NO_x), Subpart Da specifies that permits for electric utility steam generating units must have an opacity limit of 20 percent and contain requirements for the continuous monitoring of SO_2, NO_x, opacity, oxygen (O_2), and carbon monoxide (CO).

2. Kraft Recovery Boiler (KRB)

The application form for the KRB should list all regulated pollutants along with their federally enforceable emission limits, should state that the KRB will be subject to NSPS for kraft pulp mills (40 CFR Part 60, Subpart BB), and the NSPS for industrial-commercial-institutional steam generating units (40 CFR Part 60, Subpart Db), and should indicate that the emission limit of 5 ppm for total reduced sulfur (TRS) emissions will be standardized by correcting the volume, on a dry basis, to 8 percent O_2.

3. Smelt Dissolving Tank (SDT)

Like the application form for the KRB, this application form should state that this unit will be subject to 40 CFR Part 60, Subpart BB, and should list a federally enforceable emission limit for PM.

4. Lime Kiln (LK)

The application form should indicate that this unit will be subject to 40 CFR Part 60, Subpart BB. It should also state that the emission limit of 5 ppm for TRS will be standardized by correcting the dry volume to 10 percent O_2.

In addition to the requirements stated above, all the application forms should specify test methods to be used during compliance testing. The forms should also specify emissions limits that reflect best available control technology (BACT), which will be discussed later in this memorandum. Currently, most of the application forms only specify emission limits that meet the minimum emissions standards of NSPS.

<u>Net Significant Emissions Calculations</u>

Federal PSD regulations require that increases or decreases in pollutant emissions be determined by obtaining the difference in new allowable emissions and either old actual emissions or old allowable emissions, whichever is lower. In this case net emissions increases should be determined by using new allowable emissions and old actual emissions. The

RESPONSES

3. The application form (Section VI Part A) for the CFB boilers will be revised to list the additional NSPS Subpart Da requirements: opacity limit of 20 percent and continuous emission monitoring for SO_2, NO_x, opacity, oxygen (O_2), and carbon monoxide (CO).

4. The application form (Section VI Part A) for the Kraft Recovery Boiler (KRB) will be revised to indicate that the emission limit of 5 ppm for total reduced sulfur will be standardized by correcting the volume, on a dry basis, to 8 percent O_2.

   Approximately 250,000 gallons of oil will be used only for startup. Black liquor solids (BLS) will essentially be the only fuel burned in the KRB. Therefore, our understanding of the only requirements associated with 40 CFR Part 60 (Subpart Db) for the KRB will be to notify the appropriate regulatory agency and maintain a fuel log.

5. The application form (Section VI Part A) for the Smelt Dissolving Tank (SDT) will be revised. It will state that the SDT is subject 40 CFR Part 60, Subpart BB and a particulate emission limit of 0.2 lb particulate per ton of BLS (dry weight).

6. This comment was interpreted to actually be addressing the multiple-effect evaporator (MEE) and not the lime kiln. The lime kiln is an existing source and does not require permit modification. The application form will be revised for the MEE to list the applicable NSPS standards and emission rates.

7. Attachment 8 summarizes the test methods that will be used, as required, during compliance testing.

applicant's net emissions calculation results for PM and TRS are invalid because old actual emissions data were not used for these two pollutants. Actual emissions are defined in the PSD regulations as:

> "...the average rate, in tons per year, at which the unit actually emitted the pollutant during a two-year period which preceeds the particular date and which is representative of normal source operation. The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates and types of materials processed, stored, or combusted during the selected time period.
>
> The Administrator may presume that source specific allowable emissions for the unit are equivalent to the actual emissions of the unit.
>
> For any emissions unit which has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date."

According to the application, the period 1979-1980 was found to be the most representative two-year period of normal operating conditions. However, the total actual emissions for this period were adjusted to "represent the effect of recent control techniques and an imposed particulate emission limit." According to the above definition, such modifications to actual data are not allowed. We request that the net emissions calculations be redone using either test data or other operational data for a two-year period after the control technique changes were made. 8.

Another error in the net emissions calculations is that for PM emissions, maximum expected emissions were used instead of new allowable emissions. New allowable emissions are determined by using emissions limits specified in the application form. Specifically, PM emission limits indicated in the application forms for the proposed CFB boilers and KRB were not used in the net emissions calculations. According to the application form for the CFB boilers, PM emissions will be restricted to 0.03 lb of PM/mmBtu. Converting to a tons per year (TPY) limit indicates a potential to emit in the amount of 419 TPY: 9.

$$\frac{0.03 \text{ lb PM}}{\text{mmBtu}} \times \frac{3189 \text{ mmBtu}}{\text{hr}} \times \frac{8760 \text{ hr}}{\text{year}} \times \frac{1 \text{ ton}}{2000 \text{ lb}} = 419 \text{ TPY}$$

RESPONSES

8. As was stated in the application, emissions for the 1979-1980 peri[illegible] adjusted in order to best represent normal operating condition and current controls and regulatory constraints. The described [illegible] were made in order to arrive at the most representative emission values. The use of these adjustments was discussed with and approved by the DER. Because the adjustments reduced the emissions, they are also more conservative than the unadjusted values. That is, this procedure results in higher predicted net air quality impacts as a result of operation of the proposed project.

9. The emission rates given in Sections VI.A. of the Florida DER application forms are not intended to be maximum allowable emission rates. These values are given (as the form requests) as applicable new source performance standards (NSPS) for the respective sources. Because the net emissions increase in particulate matter is less than the "significant" criteria values for total particulate and PM_{10}, a BACT analysis was not required for particulate matter. Nevertheless, the applicant is proposing a permitted emission rate that is less than NSPS and more typical of current BACT determinations (0.02 lb PM/MBtu).

Similarly, the application form for the proposed KRB indicates a potential to emit PM in the amount of 488 TPY. This potential to emit was calculated by extrapolating the limit (equal to 355 TPY) indicated in Table 3.4-2 of the application to the 0.044 grains/dscf limit specified in the application form:

$$\frac{X}{0.044 \text{ gr/dscf}} = \frac{355 \text{ TPY}}{0.032 \text{ gr/dscf}} \qquad X = 488 \text{ TPY}$$ 10.

where X = maximum possible PM emissions

Table 3.4-2 should be adjusted to reflect each unit's potential to emit PM. According to our calculations, after converting PM emissions limits in the application forms to a TPY basis, the total PM emissions for all proposed sources will equal 965 TPY.

Air Quality Analysis (AQA)

11. The analysis for lead relied on using a 24-hour modeled value to show compliance with the quarterly standard. Instead of a short-term model, we request that a long-term model, such as the Industrial Source Complex Long Term (ISCLT) model, be used for this analysis. The ISCLT model should also be used for the AQA for the PSD permit.

12. Another comment regarding the AQA concerns the placement of the receptors during modeling. If the cogeneration project is under the same ownership as the kraft pulp mill, then a commonly defined plant boundary property line may be used. If the two facilities will have separate owners, then the air contained in the boundary of the kraft pulp mill is considered ambient air. Additionally, public access to the facility must be precluded by a fence or other physical barrier.

RESPONSES

10. The same response as that given for Comment 9 is again appropriate.

11. As discussed with FDER, a conservative estimate for lead impacts would be the 24-hour maximum concentration predicted from the Industrial Source Complex Short-Term (ISCST) dispersion model. This method is widely accepted to represent conservative quarterly estimates.

The quarterly concentration could not exceed the 24-hour concentration since the longer averaging time would "smooth" the data set, resulting in lower concentrations. Thus, the most conservative method was used to demonstrate compliance with the ambient air quality lead standard.

12. The SCA was submitted with Seminole Kraft Corporation and AES Cedar Bay, Inc. being co-applicants. Seminole Kraft Corporation will retain ownership of the proposed kraft recovery boilers (KRB), smelt dissolving tanks (SDT), and multiple-effect evaporators (MEE). The circulating fluidized bed (CFB) boilers will be owned and operated by AES Cedar Bay, Inc., on property leased from Seminole Kraft.

The existing kraft paper mill sources, that are being replaced by this project, have release points that are at heights which are below good engineering practice (GEP) stack heights. Pollutant dispersion from these short stacks can be heavily influenced by building downwash effects. That is, the turbulence can bring the pollutants quickly to the ground before sufficient dilution can occur. This situation can result in high pollutant concentrations near the source.

The proposed sources will utilize GEP stacks and will eliminate building downwash effects on pollutant dispersion. For the SCA, it was demonstrated that the modeled ambient air quality surrounding the facility will improve significantly. This improvement will be based on replacing the existing equipment with new, efficient, and well controlled boilers equipped with GEP stacks. Because of the significant improvement at all the modeled receptors, it is anticipated that there will be significant air quality improvement at any boundary location.

The paper mill is currently fenced to restrict public access. All buildings and coal handling equipment associated with the cogeneration facility will also be enclosed with a fence. The beginning and ending sections of the railroad will not be fenced.

BACT Determinations for the Cogeneration Boiler

1. SO_2 and Other Regulated Pollutant Emissions

The BACT analysis was performed in a "top-down" manner; however, we have concerns about the lack of justifications for not choosing the "top" level of control (wet limestone scrubber) as BACT and the lack of consideration of the amounts of other regulated and unregulated (air toxics) pollutants emissions that could be controlled if the "top" level of control was installed.

The applicant chose a limestone injection system (90% removal efficiency) as BACT. The main reason for not choosing the wet limestone scrubber (capable of reducing SO_2 emission by 94%) was cost. The applicant claimed the levelized annual cost for the wet limestone scrubber will be $43.6 million and the annual cost for the proposed limestone injection system will be $35.8 million. By using information in Table 10.8-3 of the application, the incremental annualized cost calculated is $636 per ton of SO_2 removed; however, this cost appears inflated because it was assumed that the boilers would only operate at 87 percent capacity. Actually, because the application form does not restrict capacity, it must be assumed that the facility will operate at 100 percent capacity; therefore, cost should be determined on that basis. Another error in the cost per ton value for each SO_2 removal alternative was that the applicant did not include, along with SO_2 emissions, the amounts of other pollutants, i.e., unregulated pollutants (including air toxics mentioned earlier) and other regulated pollutants, that could be reduced. According to Table 10.8-9 of the application, BACT analyses were also required for the following pollutants, all of which may be reduced by use of an SO_2 removal system: 13.

lead	mercury	H_2SO_4 mist
fluorides	beryllium	

By using the annual costs tabulated in Table 10.8.8 of the application and the maximum control capability of each alternative (based on 100 percent capacity), we calculate an incremented cost of $553.45 per ton of SO_2 removed if the "top" level of control is chosen (see Table 1). When the estimated removal amounts of pollutants in Table 2 are included, the incremental cost for the wet limestone scrubber is $531.15 per ton of pollutants removed. The cost per ton value will be even lower once it is determined which unregulated pollutants would be controlled by the scrubber.

We feel that a cost of $531.15 per ton of pollutants removed for the "top" control is reasonable. Not only could SO_2 emissions be further reduced by 3353 TPY if the "top" alternative was chosen over the proposed SO_2 reduction control technology, but lead, other regulated non-criteria pollutants, and some unregulated pollutants could further be reduced by at least 1417 TPY (see Tables 2 and 3).

RESPONSES

13. Cost was not the only criterion used in the BACT analysis for rejecting a 94 percent SO_2 removal wet limestone scrubber FGD system as BACT for the Cedar Bay Cogeneration Plant. There is an environmental risk associated with use of a wet limestone scrubber. Wastes from a wet limestone scrubber consist primarily of calcium sulfate dihydrate and calcium sulfite hemihydrate. These compounds are difficult to dewater and fixate into materials of relatively low permeability. Lower permeabilities increase the potential for leachate from these waste. The potential for leachate of trace metals and compounds into groundwater supplies represents a significant enviromental risk for wet limestone FGD process.

Alternatively, wastes from a CFB boiler FGD system consist primarily of calcium sulfate anhydrate (plaster of Paris) and unreacted quantities of lime. The controlled conditioning of this hygroscopic material with water results in a landfillable material with very low permeabilities. The cementatious properties of wastes from a CFB boiler minimizes the risk of leachate.

Wet limestone FGD systems are also energy intensive processes. Limestone must be crushed, slurried, and held in suspension in preparation for use. Contact of the slurry with the flue gas is accomplished by circulating large quantities of slurry in scrubber modules. Wastes from the scrubbing process contain large quantities of water which must be removed during thickener and vacuum filtration process steps. In addition, scrubber modules have large pressure drops requiring increased induced draft fan power. The analysis concluded that the wet limestone scrubber FGD system consumes almost three times the energy that a CFB boiler AQCS requires.

The incremental annualized cost calculated by the EPA of $636 per ton is in error. Annualized costs should be compared to the next level of control to determine the cost effectiveness of the more restrictive control alternative. Incremental costs calculated in this manner are the fundamental measure of cost effectiveness for varying levels of control. Therefore, the incremental cost of $2,700 per additional ton of SO_2 removed listed in the text is correct.

In addition, it is not correct that total levelized annual costs would remain unchanged for an increase in capacity factor from 87 percent to 100 percent. This assumption neglects to consider additional costs for limestone, energy, and waste disposal accrued for removing SO_2 during these additional hours of operation. Accounting for these considerations results in an incremental cost of $2,200 per incremental ton removed to go from 90 percent to 94 percent SO_2 removal at a 100 percent capacity factor.

The analysis conceded that a wet limestone scrubber FGD system designed for 94 percent SO_2 removal would be likely to remove larger quantities of regulated and unregulated non-criteria pollutants. However, the analysis concluded that this benefit did not outweigh aforementioned economic, environmental, and energy disadvantages associated with use of a 94 percent SO_2 removal wet limestone scrubber FGD system. Therefore, BACT regarding the control of SO_2 emissions from the Cedar Bay Cogeneration Plant is the use of circulating fluidized bed boilers with in-bed desulfurization.

Table 1. Sulfur Dioxide Emissions and Incremental Costs

Alternative	Uncontrolled Emissions (TPY)	SO_2 Removal Eff (%)	Annual Emissions (TPY)	Controlled Emissions (TPY)	*Annual Costs ($/year)	Incremental Cost($/ton)
Pulverized (PC)/Wet Limestone Scrubber	83,807	94.0	5028	78,779	43,600,000	553.45
CFB Boiler/ Fabric Filter	83,807	90.0	8380	75,426	35,850,000	475.30
PC Boiler/ Wet Limestone Scrubber	83,807	90.0	8380	75,426	41,290,000	547.42
PC Boiler/ Lime Spray Dryer	83,807	90.0	8380	75,426	46,640,000	618.35

*Obtained from Table 10.8-8 of the application

Table 2. Lead and Non-criteria Pollutant Emissions

Alternative	Compound	Uncontrolled Emissions (TPY)	Removal Eff. (%)	Estimated Emissions (TPY)	Estimated Removal (TPY)	PSD Significance (TPY)
Wet Limestone Scrubber	Lead	109.00	98.1	2.08	106.92	0.6
	Fluorides	2412.24	99.4	14.50	2397.74	3.0
	Mercury	4.06	10.0	3.65	0.41	0.1
	Beryllium	31.70	99.4	0.18	31.52	0.0004
	H_2SO_4 mist	1285.04	60.0	514.00	771.04	7.0
CFB Boiler/ Fabric Filter	Lead	109.00	10.0	98.10	10.90	0.6
	Fluorides	2412.24	50.0	1206.12	1206.12	3.0
	Mercury	4.06	10.0	3.65	0.41	0.1
	Beryllium	31.70	95.0	1.59	30.12	0.0004
	H_2SO_4 mist	1285.04	50.0	642.50	642.50	7.0

Table 3. Difference in Amount of Regulated Pollutants Removed Between Alternatives (1) and (2)

Compound	Difference (TPY)
Lead	96.02
Fluorides	1192.62
Mercury	0.0
Beryllium	1.4
H_2SO_4 mist	128.54
Total	1417.60

2. NO_x Emissions

The applicant chose a NO_x emissions limit of 0.36 lb NO_x/mmBtu as BACT without adequately justifying why Thermal De-NO_x controls were technically or economically infeasible for this project. The applicant gave two main reasons why Thermal De-NO_x controls should not be considered as BACT, both of which are unsubstantiated. They are:

1. Test data is not available from three facilities in California that are using Thermal De-NO_x controls on CFB boilers; and

2. The temperature for optimum SO_2 emissions control from the proposed CFB boilers is 1560°F. This temperature is not in the temperature range (1600°F - 1900°F) for optimum NO_x emissions control by Thermal De-NO_x.

Because the burden of proof is on the applicant to prove that a "top" level of control is clearly technically or economically infeasible, unless better arguments are presented, Thermal De-NO_x may be considered as BACT for this source. We recommend that data be submitted that reflects how SO_2 and NO_x emissions will be effected if the SO_2 removal system and Thermal De-NO_x were allowed to operate at temperatures slightly out of their optimum operational range, i.e., what will be SO_2 and NO_x control trade-offs. We also recommend that the applicant evaluate the possibility of cooling the effluent stream leaving the Thermal De-NO_x system. We feel that by cooling this stream to 1560°F, it would be technically feasible to operate both the Thermal De-NO_x system and the limestone scrubber. The applicant should also evaluate the use of a urea injection process in the BACT analysis for this source. Information on a urea injection process named NO_xOUT, manufactured by Fuel Tech, Inc., is attached for the applicant's review. 14.

The applicant also rejected Thermal De-NO_x as BACT because of cost. The applicant claimed that the incremental costs to control NO_x emissions with Thermal De-NO_x controls on the proposed CFB boilers and on a pulverized coal (PC) boiler are \$1500/ton and \$1300/ton of NO_x removed, respectively. However, by using the annual cost information contained in Table 10.8-12 of the application and assuming a maximum removal efficiency of 60 percent, we calculate that at 100 percent capacity the incremental costs associated with operating Thermal De-NO_x on the CFB boilers and PC boiler are \$1263 and \$1137/ton of NO_x removed, respectively (see Table 4). Additionally, by using Thermal De-NO_x controls, NO_x emissions will further be reduced by approximately 3,000 TPY for each type boiler. Based on the cost information presented in the application, we feel that Thermal De-NO_x is a viable control option for this source.

Table 4. Nitrogen Oxides Emissions and Incremental Costs Associated with Thermal De-NO_x

Alternative	Uncontrolled Emissions (TPY)	NO_x Removal Eff (%)	Annual Emissions (TPY)	Controlled Emissions (TPY)	Total Annual Costs (\$/year)	Incremental Cost(\$/ton)
CFB Boiler/ Thermal De-NO_x	5028.42	60.0	2011.37	3017	3,810,000	1263.00
PC Boiler/ Thermal De-NO_x	5587.13	60.0	2235.00	3352	3,810,000	1137.00

RESPONSES

14. References made to Thermal DeNOx are somewhat generic in nature. The Thermal DeNOx system as licensed by Exxon is the most commercia proven selective non-catalytic NO_x reduction (SNCR) system avai We recognize the commercial viability of the NOxOUT process. The NO_xOUT system is capable of approximately the same NO_x reduction performance as the Thermal DeNOx system. System chemistries for the two systems are similar, except that Thermal DeNOx uses ammonia for additive whereas NOxOUT uses urea. Budget estimates obtained for both of these systems indicate that they are comparably priced. Therefore, costs listed in the BACT analysis with regard to a Thermal DeNOx system can be assumed to be analogous for a NOxOUT system.

Subsequent communications with parties involved with the two oper fluidized boilers with selective non-catalytic NO_x reduction sys have provided additional information regarding these installatio The Corn Products project located in Stockton, California has passed compliance tests. However, ammonia slip emissions have exceeded the targeted value of 20 ppm when maintaining compliance with NO_x emission requirements. The Cogeneration National project also located in Stockton, has not been able to meet NO_x emission requirements while maintaining compliance with CO and SO_2 emission requirements. The plant is continuing with adjustments targeted at achieving coincidental compliance with all air permit requirements.

Operation of the CFB boiler at 1560 F already occurs outside the optimum temperature range for SNCR applications of 1600 to 1900 F. A temperature of 1560 F is optimal for SO_2 removal. Increasing combustion temperatures to better fit within the optimum SNCR temperature window will increase NO_x emissions from the boiler (increased thermal NO_x from combustion air) and decrease the efficiency of the SO_2 removal process (due to sintering of limestone particles). The more typical approach would be if a problem exists with SNCR system efficiency at the 1560 F temperature, then hydrogen would be injected with the ammonia to raise localized gas temperatures into the optimum range. Use of hydrogen onsite would pose a safety risk to the project.

Total levelized annual costs would not remain unchanged for an increase in capacity factor from 87 percent to 100 percent. This assumption neglects to consider additional costs for ammonia and energy accrued during additional hours of operation. Accounting for these considerations results in an incremental cost of \$1,400 and \$1,200 per incremental NO_x ton reduced at a 100 percent capacity factor using a SNCR system on CFB and pulverized coal boilers, respectively.

Lack of SNCR operational data and operational temperature concerns are not the only reasons given for rejecting SNCR systems as BACT. The consideration of environmental factors also supports the selection of combustion controls as BACT. SNCR systems emit various amine compounds formed by unreacted ammonia exiting these systems. This represents a potential adverse human health effect, since many amine compounds are known or suspected carcinogens. Although ammonia emissions are not regulated nationally, at least one district in California recently set a limit of 10 ppm. Unreacted ammonia emissions from an SNCR system could be as high 30 ppm.

Therefore, based on economic, environmental, and energy considerations BACT for NO_x emissions from the Cedar Bay Cogeneration Plant is a CFB boiler with combustion controls for minimizing NO_x emissions.

BACT Determinations for SO_2 Emissions from the KRB

According to the BACT/LAER Clearinghouse, there are two KRBs operating that have SO_2 emission limits lower than the SO_2 emission limit of 180 ppm for the proposed KRB. One KRB located in Kentucky is limited to an SO_2 emissions limit of 100 ppm and a KRB in Wisconsin is limited to an SO_2 emissions limit of 158 ppm. The applicant claims that the boiler in Kentucky is having problems with meeting its SO_2 limit and that no operational data is available on the boiler in Wisconsin. We feel that these are not sound reasons for rejecting the SO_2 emission limits for these facilities as BACT. Without additional information regarding operational or design differences between the boilers in Kentucky and Wisconsin and the proposed boiler, an SO_2 emissions limit in the range of 100-158 ppm may be required as BACT for the proposed source. 15.

Thank you for allowing us to provide our input. If you have any questions or comments regarding our comments, please feel free to contact me or Karrie-Jo Shell of my staff at extension 2864.

Attachment

15. As indicated in Section 10.9 of the BACT analysis, the lowest SO_2 emission requirement found in BACT/LAER Clearinghouse documents is 100 ppmvd for a KRB in Kentucky. The plant is still having trouble meeting this low emission limit. Accordingly, the plant is applying to the state to increase their SO_2 emission limit to 200 ppm.

The second lowest SO_2 emission limit for a KRB is 158 ppmvd for a facility being built in Wisconsin. Performance tests for this facility will be performed in the next six to nine months.

No other KRB facilities listed in the BACT/LAER Clearinghouse documents have SO_2 emission limits less that 180 ppmvd. Based on this information and the objective of maintaining maximum flexibility regarding KRB manufacturer selection, it is still felt that KRB combustion controls designed to meet a 180 ppmvd SO_2 emission limit represents BACT for the Cedar Bay KRB.

ATTACHMENT B

EMISSION COMPLIANCE TEST METHODS

Performance Parameter	Referenced Test Code
Carbon Dioxide (CO)	40 CFR Part 60 Method 10
Nitrogen Oxides (NO_x)	40 CFR Part 60 Method 7
Sulfur Dioxide (SO_2)	40 CFR Part 60 Method 6
Total Suspended Particulate (TSP)	40 CFR Part 60 Method 5 or 17
Lead (Pb)	40 CFR Part 60 Method 12
Beryllium (Be)	40 CFR Part 61 Method 104
Mercury (Hg)	40 CFR Part 61 Method 101
Fluorine	40 CFR Part 60 Method 13A or 13B
Sulfuric Acid Mists (SO_3)	40 CFR Part 60 Method 8
Total Reduced Sulfur (TRS)	40 CFR Part 60 Method 16A
Non-Methane Hydrocarbons	40 CFR Part 60 Method 25A or 25B
Opacity	40 CFR Part 60 Method 9 or Appendix B Specification 1

12105 37.040

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:

	pounds	pounds	tons	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.

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.

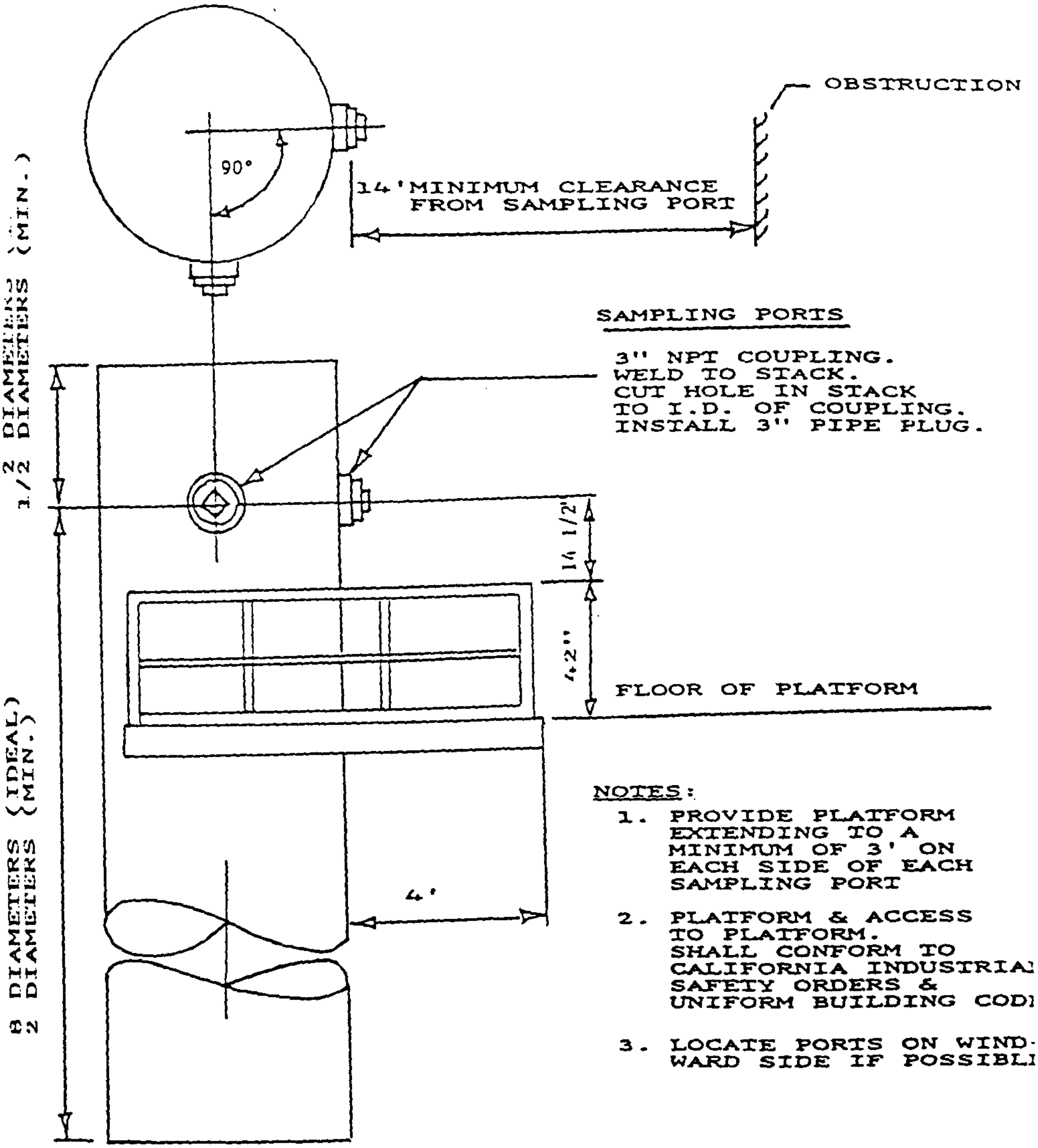
Sincerely,

Bruce Nixon

Bruce Nixon
Air Pollution Control Engineer

AC8577

PLATFORM AND PORT SPECIFICATION SHEET



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

NO_x and SO_2

:uracy	$\leq$ 20 pct of the mean value of the reference method test data
nt Accuracy	$\leq$ 10 pct
.ion Error	$\leq$ 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)	$\leq$ 0.4 pct O_2 or CO_2
ro drift (24h)	$\leq$ 0.5 pct O_2 or CO_2
ılibration drift (2h)	$\leq$ 0.4 pct O_2 or CO_2
ccuracy	$\leq$ 10 pct
Response time	10 min
Calibration	$\leq$ 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:

	pounds	pounds	tons	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
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 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)