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

RECEIVED
APR 13 1992
Bureau of
Air Regulation

APR - 8 1992

4APT-AE

Clair H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental
Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: University of Florida Cogeneration Project (PSD-FL-181)

Dear Mr. Fancy:

This is in response to your letter dated January 16, 1992, which requested assistance in determining the amount of creditable reductions of NO_x emissions which are available from the existing central Heat Plant at the above referenced facility. At issue is the proper use of an AP-42 emission factor for gas/oil fired boilers larger than 100 mmBTU/hr heat input capacity.

The applicant requested that FDER use the discretion allowed under F.A.C., Rule 17-2.100(3)(b) to presume that their actual boiler emissions were equal to the allowable emissions which were based on full load operation. EPA's position on this presumption is stated in the preamble to the August 7, 1980, promulgation of federal Prevention of Significant Deterioration (PSD) regulations at 45 FR 52718:

> "EPA believes that, in calculating actual emissions, emission allowed under federally enforceable source-specific requirements should be presumed to represent actual emissions levels. Source-specific requirements include permits that specify operating conditions for an individual source, such as PSD permits, state NSR permits issued in accordance with Section 51.18(j) and other Section 51.18 programs, including Appendix 5 (the offset Ruling), and SIP emissions limitations established for individual sources. <u>The presumption that federally-enforceable source-specific requirements correctly reflect actual operating conditions should be rejected by EPA or a state, if reliable evidence is available which shows that actual emissions differ from the level established in the SIP or the permit."</u>
> (emphasis added)

From the operating reports submitted by the applicant, it is clear that the units in question did not operate at their allowable limits on a yearly average. Consequently, we concur with your determination that permitted allowable emissions are not equivalent to actual emissions for this source and that an estimation of actual emissions must be made.

In an ideal scenario, the applicant would have test data for each boiler at various load conditions along with the hours each boiler operated at the corresponding load in each year. This data would allow for the most accurate calculation of actual emissions during the years in question.

Absent having available or obtaining test data for the specific boilers, the next most accurate method for estimating actual emissions would be to utilize an established emission factor along with available fuel use data. The NO_x emission factor for gas fired boilers found in Table 1.4-1 of AP-42 requires the use of an emission factor adjustment (Figure 1.4-1) for reduced loads in boilers with a heat input capacity of greater than 100 mmBTU/hr. The applicant has argued that the emissions factor adjustment for load should only be applied on an instantaneous basis and should not be used where long-term averaging is involved.

As stated in your February 14, 1992, letter to EPA, your staff have "[f]ound data showing that, for natural gas-fired boilers, NO_x emissions are generally reduced by percentages equal to or greater than the percent load reduction." This point is confirmed in the position taken by EPA's Office of Air Quality Planning and Standards in a January 8, 1992, letter from Mr. Ron Ryan to Mr. John Reynolds of your staff. The letter stated that "[t]he load reduction coefficient determined from Figure 1.4-1 of AP-42 should be used in conjunction with the utility boiler factors in Table 1.4-1 to estimate emissions accurately." The letter further states that "[i]f estimates were made for several representative periods and summed, the result would be more accurate than using a single average load for the entire period." Note that at no time is it stated that the load reduction coefficient should be disregarded if a single average load is utilized.

As a result, the methods of estimation of actual emissions in order of their relative accuracy are as follows:

1. Stack tests at various loads along with records of hours operated at corresponding loads;

2. AP-42 emissions factors (with load reduction coefficient) along with records of hours operated at corresponding loads;

3 AP-42 emission factors (with load reduction coefficient) along with a single average load;

4. AP-42 emissions factors (without load reduction coefficient) and an assumption that the unit operated at full load.

To date, the applicant has not submitted data corresponding to stack tests or representative periods of load reduction; therefore, options 1 and 2 are not available. Your staff, in a letter to Florida Power dated December 31, 1991, determined that option 3 would provide a more accurate estimation of actual emissions than the option proposed by the applicant (option 4).

Based on the lack of data available from the applicant, the material submitted by your staff, as well as the position taken by OAQPS, we fully support your determination that in this instance, the use of a single average load factor along with corresponding emission factors (and corrections) from AP-42 would constitute representative actual emissions for the purpose of netting.

For reasons of expediency, Florida Power, in their letter to you dated March 5, 1992, has agreed to calculate actual emissions consistent with your determination. We apologize for any inconvenience caused by the delay in our response; however, based on the available information, we are confident that your determination was the correct one for this case.

If you have any questions or comments on this issue, please contact Mr. Gregg Worley of my staff at (404)347-5014.

Sincerely yours,

Sally L. Shaver, for
Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides and Toxics
Management Division

cc: Ron Ryan, OAQPS
J. Reynolds
C. Holladay
A. Kutyna, NE Dist
S. Baruch, NE Dist. Branch
C. Shaver, NPS
LHF/BA/PL
K. Kosky, KBN

Department of Environmental Regulation

Routing and Transmittal Slip

To: (Name, Office, Location)

1. Mrs. Chris Shaver
2. NPS -
3.
4.

Remarks:

FYI
FL Power Corp./U. of FL Cogen.
PSD-FL-181

From	Date
C. H. Fancy	4-8-92
	Phone 904-488-1344

tal memo 7671 | # of pages ▸ 23
From Ken Kosky
Co. KBN
Phone #
Fax # 904-331-9000

ge for the University of
ased on fuel usage obtained
987 fuel AORs; the 1988-90

average. Since the Central
ore appropriate in
the natural gas fuel usage
ral gas fuel use in 1988 was
14.2 percent less than the
igh 1990 average as being
han 1 percent different than
nd an average of the last
sions. The percent

, fuel oil is less important
the application (i.e.,

It should be emphasized that the definition of "actual emissions" found in Rule 17-2.100 (3) F.A.C. specifically allows the use of different time periods than the last two years if it is more representative of normal operation. Indeed, the definition expressly uses the terms "In general" and "representative" in providing guidance in determining actual emission. The subsequent paragraph expressly allows the Department to use different time periods.

State of Florida
Department of Environmental Regulation

District Routing Slip

To: Andy Kutyna Date: 4-8-92

			CC To.
	Pensacola	**Northwest District**	
	Panama City	Northwest District Branch Office	
	Tallahassee	Northwest District Branch Office	
	Apalachicola	Northwest District Satellite Office	
	Tampa	**Southwest District**	
	Punta Gorda	Southwest District Branch Office	
	Bartow	Southwest District Satellite Office	
	Orlando	**Central District**	
	Melbourne	Central District Satellite Office	
X	**Jacksonville**	**Northeast District**	
	Gainesville	Northeast District Branch Office	
	Fort Myers	**South District**	
	Marathon	South District Branch Office	
	West Palm Beach	**Southeast District**	
	Port St. Lucie	Southeast District Branch Office	

Reply Optional ☐ Reply Required ☐ Info Only ☐
Date Due ______ Date Due: ______

Comments:

FPC / U. of FL Cogen
AC 01-204652
PSD-FL-181

From: C. H. Fancy Tel.: SC/278-1344

10 31 90

al memo 7671 | # of pages ▸ 23
From Ken Kosky
Co. KBN
Phone #
Fax # 904-331-9000

e for the University of
sed on fuel usage obtained
'87 fuel AORs; the 1988-90

average. Since the Central
re appropriate in
ie natural gas fuel usage
al gas fuel use in 1988 was
14.2 percent less than the
gh 1990 average as being
ian 1 percent different than
d an average of the last
ions. The percent

fuel oil is less important
the application (i.e.,

1988-90) is less than the five year average.

It should be emphasized that the definition of "actual emissions" found in Rule 17-2.100 (3) F.A.C. specifically allows the use of different time periods than the last two years if it is more representative of normal operation. Indeed, the definition expressly uses the terms "In general" and "representative" in providing guidance in determining actual emission. The subsequent paragraph expressly allows the Department to use different time periods.

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

EPA
Region IV
Atlanta

R ...ntal Regulation

...smittal Slip

To: (Name,

1. Jewell A. Harper

2. U.S. EPA, Region IV

3.

4.

Remarks:

FYI

FL Power Corp/U. of FL Cogen.

PSD-FL-181

attn: Gregg Worley

From	Date
C. H. Fancy	4-8-92
	Phone 904-488-1344

...tal memo 7671 | # of pages ▸ 23

...ds	From Ken Kosky
	Co. KBN
)	Phone #
9	Fax # 904-331-9000

...ge for the University of ...ased on fuel usage obtained ...987 fuel AORs; the 1988-90

... average. Since the Central ...ore appropriate in ...the natural gas fuel usage ...ral gas fuel use in 1988 was ... 14.2 percent less than the ...igh 1990 average as being ...han 1 percent different than ...id an average of the last ...sions. The percent

..., fuel oil is less important ... the application (i.e.,

It should be emphasized that the definition of "actual emissions" found in Rule 17-2.100 (3) F.A.C. specifically allows the use of different time periods than the last two years if it is more representative of normal operation. Indeed, the definition expressly uses the terms "In general" and "representative" in providing guidance in determining actual emission. The subsequent paragraph expressly allows the Department to use different time periods.

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

File Copy

KBN

Post-It™ brand fax transmittal memo 7671	# of pages ▸ 23
To John Reynolds	From Ken Kosky
Co. FDER	Co. KBN
Dept. 91062-0100	Phone #
Fax # 922-6979	Fax # 904-331-9000

April 8, 1992

Mr. C. H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Subject: Alachua County - A.P.
UF Cogeneration Project
AC 01-204652
PSD-FL-181

Attention: John Reynolds

Dear John:

As we discussed yesterday, I have summarized the last five years of fuel usage for the University of Florida's Central Heat Plant. This summary is presented in Table 1 and is based on fuel usage obtained from the Annual Operating Reports (AORs). I have attached the 1991 and 1987 fuel AORs; the 1988-90 AORs have been previously included in the air permit application.

Table 1 presents the total fuel use and the percent difference from the 5-year average. Since the Central Heat Plant is affected by meteorological conditions, a five year average is more appropriate in determining the "representative" fuel use. As can be noticed from Table 1, the natural gas fuel usage (the primary fuel) was quite different for the years 1988 and 1990. The natural gas fuel use in 1988 was 14.4 percent more than the five year average, while the fuel use in 1990 was 14.2 percent less than the five year average. This difference cancelled out in our use of the 1988 through 1990 average as being "representative" of actual emissions. Indeed, the 1988-90 average was less than 1 percent different than the five year average. Clearly, an average of the last two years (1990-91) and an average of the last three years (1989-91) are not "representative" of fuel use and therefore emissions. The percent difference for these two averaging periods is greater than several percent.

For fuel oil firing (the standby fuel), fuel use varied considerably. However, fuel oil is less important due to its total contribution to heat input. The averaging period presented in the application (i.e., 1988-90) is less than the five year average.

It should be emphasized that the definition of "actual emissions" found in Rule 17-2.100 (3) F.A.C. specifically allows the use of different time periods than the last two years if it is more representative of normal operation. Indeed, the definition expressly uses the terms "In general" and "representative" in providing guidance in determining actual emission. The subsequent paragraph expressly allows the Department to use different time periods.

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

KBN

It is my professional opinion that we should use the 1988-90 period as being "representative" of actual emissions. The basis for this is threefold. First, this is the averaging period for which the application was based when submitted and for which the Department did not object during the first round of completeness questions. Second, I have demonstrated that this averaging period is "representative" of normal fuel usage. Finally, the issue related to using the load correction factor, which centered around this data, was conceded to the Department. In fact, considerable effort was expended in submitting additional information that was based on using the Department's recommended corrections. Therefore, the 1988-90 period should be used by the Department to define "actual emissions".

Please call if you have any questions.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President

cc: Scott Osbourn, FPC
W.W. Vierday, FPC
Project File
CHF / BA / PL
John Reynolds
Jewell A. Harper, EPA
Chris Shaver, NPS
Andy Ketyna, MEO

4-8-92 PAm

KFK/mlb

91062A1/8
04/08/92

Table 1. University of Florida Central Heat Plant 5-Year Fuel Use

Period	Natural Gas (10^3 cf)	% Difference from 5 year Average	Fuel Oil (gal.)	% Difference from 5 year Average
1987	1,153,937	-1.88%	20,606	-172.20%
1988	1,357,653	14.36%	604,546	74.65%
1989	1,175,617	-0.02%	163,729	-51.03%
1990	1,020,301	-14.16%	6,446	-190.87%
1991	1,171,521	-0.37%	584,213	71.69%
88-90 Average	1,184,524	0.74%	258,240	-6.62%
90-91 Average	1,095,911	-7.03%	295,330	6.80%
87-91 Average	1,175,806	0.00%	275,908	0.00%
89-91 Average	1,122,480	-4.64%	251,463	-9.27%

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 91 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: NO. 1 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida: Physical Plant Div. Bldg. 473
   Gainesville, FL 32611
4. Description of Source: Black steel stack, south end of plant

II ACTUAL OPERATING HOURS: 2,010.20 hrs/day ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60,000 lbs per hour

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

82.014 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

N/A 10^3 gallons ________ Oil, ________ %S ________ tons Coal

________ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ________________________________

EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________________________________

METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

N/A

II CERTIFICATION:

hereby certify that the information given in this report is correct to the best of my owledge.

________________________________ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

________________________________ TYPED NAME AND TITLE

________________________________ DATE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT

3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904) 396 6959

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 91 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: NO. 2 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida: Physical Plant Div. Bldg. 473
   Gainesville, FL 32611
4. Description of Source: Black steel stack second from south end of plant

II ACTUAL OPERATING HOURS: 4,202.09 hrs/day ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60,000 lbs per hour

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

173.630 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

--N/A-- 10^3 gallons ________ Oil, ________ %S ________ tons Coal

______ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ________________________________

EMISSION RATE(S) (tons/yr)

__________ Particulates __________ Sulfur Dioxide __________ Total Reduced Sulfur

__________ Nitrogen Oxide __________ Carbon Monoxide __________ Fluoride

__________ Hydrocarbon Other (Specify type and units) ____________________

METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

N/A

I CERTIFICATION:

ereby certify that the information given in this report is correct to the best of my wledge.

________________________________ ________________________________
SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE TYPED NAME AND TITLE

____
DATE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT

3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904) 396-6959

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1991 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: NO. 3 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida, Physical Plant Div. Bldg. 473
   Gainesville, FL 32611
4. Description of Source: Black steel stack center of plant

II ACTUAL OPERATING HOURS: 5,371.60 hrs/day ________ days/wk ________ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 120,000 lbs per hour

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

287.180 10^6 cubic feet Natural Gas _______ 10^3 Kerosene

129.151 10^3 gallons ___6___ Oil, ___1.5___ %S _______ tons Coal

_______ 10^3 gallons Propane _______ tons Carbonaceous

_______ 10^6 Black Liquor Solids _______ tons Refuse

Other (Specify type and units) ______________________________

I EMISSION RATE(S) (tons/yr)

_______ Particulates _______ Sulfur Dioxide _______ Total Reduced Sulfur

_______ Nitrogen Oxide _______ Carbon Monoxide _______ Fluoride

_______ Hydrocarbon Other (Specify type and units)______________________________

II METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visiable emission is 8.4 percent opacity. The highest six-minute average was 10.6 percent.

III CERTIFICATION:

hereby certify that the information given in this report is correct to the best of my owledge.

______________________________ ______________________________
SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE TYPED NAME AND TITLE

____
DATE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT

3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904) 396 6959

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1991 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: NO. 4 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida, Physical Plant Div. Bldg. 473
   Gainesville, FL 32611
4. Description of Source: Black steel stack second from north end of plant

II ACTUAL OPERATING HOURS: 4,091.30 hrs/day ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 50,000 lbs per hour

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

134.723 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

71.254 10^3 gallons 6 Oil, 1.5 %S ________ tons Coal

________ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ________

VI EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 10 percent opacity. The highest six-minute was 0 percent.

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

________ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

________ TYPED NAME AND TITLE

________ DATE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT

3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904) 396-6959

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 91 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: NO. 5 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida; Physical Plant Div. Bldg. 473
   Gainesville, FL 32611
4. Description of Source: Black steel stack north end of plant

II ACTUAL OPERATING HOURS: 5,294.30 hrs/day ________ days/wk ________ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

493.974 10^6 cubic feet Natural Gas ______ 10^3 Kerosene

383,808 10^3 gallons ___6__ oil, __1.5__ %S ______ tons Coal

______ 10^3 gallons Propane ______ tons Carbonaceous

______ 10^6 Black Liquor Solids ______ tons Refuse

Other (Specify type and units) ______

EMISSION RATE(S) (Tons/yr)

______ Particulates ______ Sulfur Dioxide ______ Total Reduced Sulfur

______ Nitrogen Oxide ______ Carbon Monoxide ______ Fluoride

______ Hydrocarbon Other (Specify type and units) ______

I METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 wased used a described in 40 cfr 60, appendix A. The visible emission limit is 10 percent opacity. The highest six-minute average was 1.3 percent.

III CERTIFICATION:

hereby certify that the information given in this report is correct to the best of my owledge.

______
SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

______
TYPED NAME AND TITLE

______
DATE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT

3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904) 396-6959

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 87 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 1 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida, Physical Plant Division Building 473, Gainesville, Florida 32611
4. Description of Source: Black Steel stack south end of plant

II ACTUAL OPERATING HOURS: 651 hrs/~~day~~ ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60, 000 lbs per hour

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

26.673 10^6 cubic feet Natural Gas

______ 10^3 Kerosene

0 10^3 gallons #6 Oil, 2 %S

______ tons Coal

______ 10^3 gallons Propane

______ tons Carbonaceous

______ 10^6 Black Liquor Solids

______ tons Refuse

Other (Specify type and units) ______

VI EMISSION RATE(S) (tons/yr)

______ Particulates ______ Sulfur Dioxide ______ Total Reduced Sulfur

______ Nitrogen Oxide ______ Carbon Monoxide ______ Fluoride

______ Hydrocarbon Other (Specify type and units) ______

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

NOT TESTED

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

Ken Kisida

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

Ken Kisida, Utilities Manager

TYPED NAME AND TITLE

February 19, 1988

DATE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT

3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904) 396-6959

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 87 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 2 Steam boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida, Physical Plant Division, Building 473 Gainesville, Flórida 32611
4. Description of Source: Black Steel stack second from south end of plant

II ACTUAL OPERATING HOURS: 2319 hrs/~~day~~ ____ days/wk ____ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60,000 lbs per hour

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

93.48 10^6 cubic feet Natural Gas

0 10^3 gallons #6 Oil, 2 %S

______ 10^3 gallons Propane

______ 10^6 Black Liquor Solids

______ 10^3 Kerosene

______ tons Coal

______ tons Carbonaceous

______ tons Refuse

Other (Specify type and units) ______

VI EMISSION RATE(S) (tons/yr)

______ Particulates ______ Sulfur Dioxide ______ Total Reduced Sulfur

______ Nitrogen Oxide ______ Carbon Monoxide ______ Fluoride

______ Hydrocarbon Other (Specify type and units) ______

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

NOT TESTED

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

Ken Kisida
SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

Ken Kisida, Utilities Manager
TYPED NAME AND TITLE

February 19, 1988
DATE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT

3426 BILLS ROAD
JACKSONVILLE FLORIDA 32207
(904) 396 6959

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 87 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 3 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida, Physical Plant Division, Building 473 Gainesville, Florida 32611
4. Description of Source: Black Steel stack center of the plant

II ACTUAL OPERATING HOURS: 2622 hrs/~~day~~ ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 120,000 lbs per hour

DER Form 17-1.202(6)
Effective November 30, 1982

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

199.013 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

16.823 10^3 gallons #6 Oil, 2 %S ________ tons Coal

________ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ________________________

I EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units)________________

II METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA Method 9 was used as described in 40 CFR 60, Appendix A. The visible emission limit is 20 percent opacity. The highest six-minute average was 13.3 percent.

III CERTIFICATION:

hereby certify that the information given in this report is correct to the best of my owledge.

Ken Kisida

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

Ken Kisida, Utilities Manager

TYPED NAME AND TITLE

February 19, 1988

DATE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT

3420 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904) 396-6959

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 87 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 4 Steam boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida, Physical Plant Division, Building 473 Gainesville, Florida 32611
4. Description of Source: Black steel stack second from north end of plant.

II ACTUAL OPERATING HOURS: 6265 hrs/~~XXX~~ ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 50,000 lbs per hour

DER Form 17-1.202(6)
Effective November 30, 1982

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

274.886 10^6 cubic feet Natural Gas

0.272 10^3 gallons #6 Oil, 2 %S

______ 10^3 gallons Propane

______ 10^6 Black Liquor Solids

______ 10^3 Kerosene

______ tons Coal

______ tons Carbonaceous

______ tons Refuse

Other (Specify type and units) ______________________

I EMISSION RATE(S) (tons/yr)

______ Particulates ______ Sulfur Dioxide ______ Total Reduced Sulfur

______ Nitrogen Oxide ______ Carbon Monoxide ______ Fluoride

______ Hydrocarbon Other (Specify type and units) ______________________

II METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA Method 9 was used as described in 40 CFR 60, Appendix A. The visible emission limit is 20 percent opacity. The highest six-minute average was 5.4 percent.

III CERTIFICATION:

hereby certify that the information given in this report is correct to the best of my nowledge.

Ken Kisida

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

Ken Kisida, Utilities Manager

TYPED NAME AND TITLE

February 19, 1988

DATE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT

3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904) 396-6959

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1987 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 5 Steam boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida, Physical Plant Division, Building 473
   Gainesville, Florida 32611
4. Description of Source: Black Steel stack on north end of plant.

II ACTUAL OPERATING HOURS: 6766 hrs/~~day~~ ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

steam at 120,000 lbs per hour

DER Form 17-1.202(6)
Effective November 30, 1982

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

559,855 10^6 cubic feet Natural Gas ______ 10^3 Kerosene

3.511 10^3 gallons #6 oil, 2 %S ______ tons Coal

______ 10^3 gallons Propane ______ tons Carbonaceous

______ 10^6 Black Liquor Solids ______ tons Refuse

Other (Specify type and units) ______

I EMISSION RATE(S) (tons/yr)

______ Particulates ______ Sulfur Dioxide ______ Total Reduced Sulfur

______ Nitrogen Oxide ______ Carbon Monoxide ______ Fluoride

______ Hydrocarbon Other (Specify type and units) ______

II METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 CFR 60, Appendix A. The visible emission limit is 20 percent opacity. The highest six-minute average was 1.3 percent.

III CERTIFICATION:

hereby certify that the information given in this report is correct to the best of my nowledge.

Ken Kisida

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

Ken Kisida, Utilities Manager

TYPED NAME AND TITLE

February 19, 1988

DATE

Department of Environmental Regulation

Routing and Transmittal Slip

To: (Name, Office, Location)

1. Ms. Jewell A. Harper
2. U.S. EPA, Region IV
3.
4.

Remarks:

PSD - FL- 181

FL Power Corp / U. of FL. Cogen.

attn: Gregg Worley

From	Date
C. H. Fancy	4-7-92
	Phone 904-488-1344

Interior TAKE PRIDE IN AMERICA

ECEIVED

APR 6 1992

Division of Air
sources Management

sent us regarding
ruct a cogeneration
Heat Plant. The
ximately 100 km
0 km south of the
reas administered by

e natural gas-fired
1, 2, and 3, and that
for the new turbine.
are subtracted from
project will result
, a small increase in
volatile organic
ssions.

the proposed emission
both the
odeling analysis
gible impact on the
ondition requiring
d 3 as soon as the
s operated in this
manner, we do not anticipate that the University of Florida project will have a significant impact on sensitive air quality-related resources in the Chassahowitzka or Okefenokee Wilderness Areas.

File Copy
PSD-FL-181

United States Department of the Interior

TAKE PRIDE IN AMERICA

FISH AND WILDLIFE SERVICE
75 Spring Street, S.W.
Atlanta, Georgia
30303

RECEIVED

APR 6 1992

Division of Air
Resources Management

April 2, 1992

Mr. C. H. Fancy
Chief, Bureau of Air Regulation
Florida Department of
Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

We have completed our review of the material that you sent us regarding Florida Power Corporation's (FPC) application to construct a cogeneration facility at the existing University of Florida Central Heat Plant. The University of Florida is located in Gainesville, approximately 100 km northeast of the Chassahowitzka Wilderness Area and 100 km south of the Okefenokee Wilderness Area, both class I air quality areas administered by the Fish and Wildlife Service.

We understand that FPC is proposing to install a single natural gas-fired combustion turbine that will replace existing boilers 1, 2, and 3, and that existing boilers 4 and 5 will only be used as back-up for the new turbine. When the emission reductions from the existing boilers are subtracted from the emission increases from the proposed turbine, the project will result in a significant increase in carbon monoxide emissions, a small increase in emissions of particulate matter, nitrogen oxides, and volatile organic compounds, and a slight decrease in sulfur dioxide emissions.

We were pleased to see that FPC modeled the impact of the proposed emission increases of nitrogen oxides and particulate matter on both the Chassahowitzka and Okefenokee Wilderness Areas. The modeling analysis indicates that the proposed project would have a negligible impact on the class I areas. We recommend that you draft a permit condition requiring FPC to permanently shut down existing boilers 1, 2, and 3 as soon as the new turbine is operational. As long as the facility is operated in this manner, we do not anticipate that the University of Florida project will have a significant impact on sensitive air quality-related resources in the Chassahowitzka or Okefenokee Wilderness Areas.

We appreciate the opportunity to comment on FPC's permit application. If you have any further questions regarding our comments on this project, please contact Tonnie Maniero of our Air Quality office in Denver at 303/969-2071.

Sincerely yours,

James W. Pulliam, Jr.
Regional Director

CHF/BA/PL
John Reynolds
Clem Holladay
Jewell A. Harper, EPA
Andy Kutyna
4-7-93 RAM

Florida Power
CORPORATION

RECEIVED

MAR 6 1992

Bureau of
Air Regulation

March 5, 1992

Mr. C. H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Subject: Alachua County - A.P.
UF Cogeneration Project
AC 01-204652

Dear Clair:

This correspondence provides responses to your letter dated December 31, 1991 as well as revising our application in light the Department's position on the emission factors for load. The responses are presented in the same format as those of your December 31, 1991 letter.

Item 1.

The AP-42 NO_x emission factor for fully loaded natural gas-fired boilers over 100 MMBtu/hr is 550 lbs. NO_x/MM ft^3 of fuel fired. For loads less than 100%, the emission factor is reduced according to AP-42, Figure 1.4-1. The 100% factor was used to calculate offset credits of 195.1 tons/yr of NO_x emissions, thus arriving at a net NO_x increase of 38.8 tons/yr. This level of net emissions (less than 40 tons/yr) would preclude PSD review for NO_x as stated in the application. However, analysis of load factors for UF's boilers Nos. 3 and 5 (capacity over 100 MMBtu/hr) during the three period '88 - '90 indicates otherwise.

FPC Response:

The basis of the application has been revised according to the comments made in the Department's December 31, 1991 letter and subsequent correspondence and discussions. Section 2.0 of the PSD permit application has been revised to reflect lower nitrogen oxides (NO_x) emissions from the combustion turbine and duct burner, and further fuel use reductions in Boilers 4 and 5 in the future. These reductions reduce the net emissions increase of NO_x, as well as particulate matter and PM10, to below the significant emission rates in Table 500-2 of Rule 17-2 F.A.C. The following is a description of the changes made from the original application.

GENERAL OFFICE: 3201 Thirty-fourth Street South • P.O. Box 14042 • St. Petersburg, Florida 33733 • (813) 866-5151
A Florida Progress Company

Item 1

FPC Response (continued)

a. The capacity factors on the combustion turbine (CT) and duct burner (DB) were reduced. The capacity factor for the CT when firing oil was reduced from 5 percent (438 hours per year at full load) to 2.5 percent (219 hours per year at full load). The capacity factor for firing natural gas in the CT when the maximum oil firing occurs, has been reduced from 95 percent to 93 percent. The application has requested the Department to allow 1.9 hours of natural gas firing for each hour in a given year that oil is not fired at its maximum permitted rate. This would allow up to a 97.75 percent capacity factor for natural gas firing in any year where oil is not fired. The capacity factor for the duct burner has been reduced from 90 percent to 30 percent. Section 2.2 and Tables 2-1 and 2-2 provide a detailed description of the change.

   With these revisions, the potential NO_x emissions for the CT/DB are 174.6 tons per year (see Table 2-2). Emissions of other pollutants are also reduced.

b. The NO_x emission factors for Boilers 3 and 5 were revised to be consistent with those calculated by the Department. While we still have technical reservations about using the load correction figure, it is expedient for us to accept the approach based on the needs of the project. It should be recognized by the Department that sufficient information to accurately calculate emissions using this approach does not exist, and previous applications (as well as annual operating reports) did not use this approach.

   Tables 2-3 and 2-4 have been revised to reflect the Department's emission factor.

   Table 2-5 has been revised to reduce the maximum fuel usage in Boilers 4 and 5. The maximum natural gas and distillate fuel oil usage for Boiler 4 has been reduced from 75 MM ft^3/year and 25,000 gallons/year, respectively to 20 MM cf/year and 15,000 gallons/year. Similarly, the fuel use in Boiler 5 has been reduced from 210 MMcf of gas per year and 100,000 gallons of oil per year to 125 MMcf of gas per year and 50,000 gallons of oil per year.

   The net NO_x emission reductions from the existing boilers are: 72.2 tons per year from Boilers 1, 2 and 3, and 62.7 tons per year from Boilers 4 and 5 (actual emissions of 82.43 tons per year minus future emissions of 19.73 tons per year). (See Table 2-6 for all net emission reductions.)

Item 2.

References in the application to the proposed facility being major on the basis of emissions exceeding 250 tons per year should be changed to 100 tons per year since the HRSG is on the "List of 28" major source categories (fossil fuel boiler exceeding 250 MMBtu/hr input including GT exhaust).

FPC Response:

The PSD applicability section of the report (i.e., 3.4) has been revised and is attached. The net emissions increase for NO_x is the potential emissions from the project of 174.6 tons per year minus the emission reductions of 134.9 tons per year, or 39.7 tons per year.

Item 3.

Page 2 of Form 1.202(1), Item C., implies "low NO_x combustors" are being proposed which is not the case. The revised application should explain that Low-NO_x combustors are not currently available for this model turbine but may be within 5 years. The revision should explain what is required in the initial design to provide for future installation of Low-NO_x burners.

FPC Response:

The comment incorrectly assigns meanings to the statements made on page 2 item C of FDER Form 17-1.202(1). The form explicitly uses the language "low NO_x combustors using wet injection". The implication here is that a specially designed combustor using wet injection (i.e., steam) will control NO_x emission. This should not be confused with dry low NO_x combustors which use staged combustion to control NO_x emissions. Dry low NO_x combustors are not available for the aircraft- derivative GE LM 6000 combustion turbine proposed for the project. Inquiries with GE have indicated that a dry low NO_x combustor for this model may be available in mid-1995. Indications are that it may be possible to install this low NO_x combustor on existing machines with a major overhaul. However, the target NO_x emission level is 25 ppmvd corrected to 15 percent oxygen which is the same as that proposed for the project.

Item 4.

Emission calculations are not adequately shown in Appendix A. All calculations affecting emissions should be shown in their entirety. For example, the Appendix "A" calculation for the NSPS NO_x emission limit of 75 ppm corrected to 15 percent oxygen is not carried to completion. The application should clearly show how all emission-related quantities were obtained.

The bases for all calculations are presented in a revised Appendix A. This format has been used and accepted by FDER on previous projects (at least three other projects).

Item 5.

Total steam production should be shown in Table 1-1 along with design capacity of the HRSG.

Total steam production is irrelevant to the air pollutant emissions and NSPS and PSD applicability. Nonetheless, the average steam production when the facility will begin operation in 1994 will be 112,500 lb/hr.

Item 6.

Please evaluate the impact of this project on the following Class I areas: Chassahowitzka National Wilderness Area in Florida and Okefenokee National Wilderness Area in Georgia. This evaluation should include a cumulative PM_{10} and NO_x Class I increment analysis. An expanded air quality related values analysis (AQRV) should be done since there are no significant impact levels for this analysis. The AQRV analysis includes impacts to soils, vegetation and wildlife.

Although the proposed permit revision does not trigger PSD review for PM/PM10 and NO_x, the proposed project's PM and NO_x emissions were evaluated at both the Chassahowitzka Wilderness Area (CWA) and the Okefenokee Wilderness Area (OWA). The results for CWA and OWA are summarized in Tables 1 and 2, respectively, for a generic facility emission rate of 10 g/s. The actual PM and NO_x concentrations are compared with suggested Class I significant impact levels (ref: EPA memorandum from John Calcagni dated 9/10/91) for each area in Table 3.

At the CWA, the maximum annual and 24-hour PM concentrations are 0.001 and 0.031 $\mu g/m^3$, respectively. These concentrations are well below the respective Class I significant impact levels of 0.27 and 1.35 $\mu g/m^3$. The maximum NO_x concentration is 0.002 $\mu g/m^3$ which is well below the Class I significant impact level of 0.1 $\mu g/m^3$.

At the OWA, the maximum annual and 24-hour PM concentrations are 0.001 and 0.034 $\mu g/m^3$, respectively. These concentrations are well below the respective Class I significant impact levels of 0.27 and 1.35 $\mu g/m^3$. The maximum NO_x concentration is 0.0025 $\mu g/m^3$ which is well below the Class I significant impact level of 0.1 $\mu g/m^3$.

Based on these analysis, the proposed project is considered to have a negligible impact upon these Class I areas. Therefore, cumulative modeling and AQRV analyses for these areas are not required.

Item 7.

Please explain the use of terrain elevations at receptor points in the modeling and show how the elevations input into the model were derived.

Terrain elevations were included in the impact analysis for the proposed project because the proposed facility's stack height relative to the variation in terrain elevation in the area is not considered large enough to ignore these effects and assume a flat terrain analysis.

The elevations used for the receptors in the modeling analysis were derived from USGS topographical maps of the site vicinity and represent the maximum elevations within a particular screening receptor sector. A receptor's sector includes the area around the receptor up to half the distance to all adjacent receptors, both radially and azimuthally. For the elevations for the furthest receptor ring, the areas to be included beyond that distance are taken to be equal to half the distance between that ring and the next closest ring.

If you should have any questions or require clarification of the above, please contact Mr. Scott Osbourn of my staff at (813) 866-5158.

Sincerely,

W. Jeffrey Pardue, Manager
Environmental Programs

Enclosure

cc: File (2)

bb:\SHO\University of FL Project

cc: J. Reynolds
C. Holladay
A. Kutyna, NE Dist
S. Baruch, NE Dist. Branch
J. Harper, EPA
C. Shaver, NPS

Table 1. Maximum Predicted Impacts for the Proposed UF Cogeneration Facility At the Chassahowitzka Wilderness Area Using a Generic Emission Rate of 10 g/s

Averaging Time	Year	Concentration ($\mu g/m^3$)	Receptor Location[a] X (m)	Receptor Location[a] Y (m)	Day/ Period
Annual					
	1983	0.007	341100	3183400	- / -
	1984	0.009	341100	3183400	- / -
	1985	0.007	342400	3180600	- / -
	1986	0.007	343700	3178300	- / -
	1987	0.008	341100	3183400	- / -
1-Hour[b]					
	1983	2.366	336500	3183400	159/21
	1984	2.754	341100	3183400	286/ 6
	1985	2.303	334000	3183400	238/23
	1986	2.262	339000	3183400	237/22
	1987	2.961	343700	3178300	199/ 5
3-Hour[b]					
	1983	0.923	342400	3180600	272/ 7
	1984	1.036	339000	3183400	164/ 8
	1985	0.768	334000	3183400	238/ 8
	1986	0.920	336500	3183400	289/ 7
	1987	0.987	343700	3178300	199/ 2
8-Hour[b]					
	1983	0.451	342400	3180600	288/ 1
	1984	0.459	341100	3183400	286/ 1
	1985	0.377	342400	3180600	306/ 3
	1986	0.626	339000	3183400	237/ 3
	1987	0.489	343700	3178300	199/ 1
24-Hour[b]					
	1983	0.170	342400	3180600	288/ 1
	1984	0.176	341100	3183400	286/ 1
	1985	0.154	343700	3178300	292/ 1
	1986	0.244	339000	3183400	237/ 1
	1987	0.178	343700	3178300	199/ 1

[a] UTM Coordinates
[b] All short-term concentrations indicate highest concentrations.

Table 2. Maximum Predicted Impacts for the Proposed UF Cogeneration Facility At the Okefenokee Wilderness Area Using a Generic Emission Rate of 10 g/s

Averaging Time	Year	Concentration ($\mu g/m^3$)	Receptor Location[a] X (m)	Receptor Location[a] Y (m)	Day/ Period
Annual					
	1983	0.007	366000	3384000	- / -
	1984	0.008	383000	3382000	- / -
	1985	0.011	380000	3382000	- / -
	1986	0.009	366000	3384000	- / -
	1987	0.008	378000	3382000	- / -
1-Hour[b]					
	1983	2.328	380000	3382000	136/ 3
	1984	2.954	376000	3382000	100/20
	1985	2.349	380000	3382000	192/ 1
	1986	2.344	380000	3382000	267/24
	1987	2.974	366000	3384000	110/22
3-Hour[b]					
	1983	1.159	374000	3383000	193/ 8
	1984	1.278	390000	3410000	187/ 1
	1985	1.361	380000	3382000	233/ 2
	1986	1.303	366000	3384000	189/ 8
	1987	1.197	378000	3382000	154/ 2
8-Hour[b]					
	1983	0.552	374000	3383000	319/ 1
	1984	0.639	390000	3410000	187/ 1
	1985	0.831	380000	3382000	233/ 1
	1986	0.560	383000	3382000	220/ 1
	1987	0.623	368000	3383000	253/ 1
24-Hour[b]					
	1983	0.181	374000	3383000	193/ 1
	1984	0.216	368000	3383000	188/ 1
	1985	0.259	376000	3382000	56/ 1
	1986	0.206	366000	3384000	189/ 1
	1987	0.267	390000	3384000	354/ 1

[a] UTM Coordinates
[b] All short-term concentrations indicate highest concentrations.

Table 3. Maximum Predicted Pollutant Impacts of the Proposed Facility Compared to Recommended PSD Class I Significant Impact Levels

Pollutant	Averaging Period	Emission Rate (lb/hr)	Generic Impact (μg/m)	Predicted Impact (μg/m)	Class I Significant Impact Level (μg/m)
CHASSAHOWITZKA WILDERNESS AREA					
Particulate Matter	Annual	10.0	0.009	0.001	0.27
	24-Hour		0.244	0.031	1.35
Nitrogen Oxides	Annual	66.3	0.009	0.007	0.1
OKEFENOKEE WILDERNESS AREA					
Particulate Matter	Annual	10.0	0.011	0.001	0.27
	24-Hour		0.267	0.034	1.35
Nitrogen Oxides	Annual	66.3	0.011	0.009	0.1

Note: Short-term maximum impacts are highest predicted concentrations for 1983-87.

CERTIFICATION BY A PROFESSIONAL ENGINEER REGISTERED IN FLORIDA

This is to certify that the revisions contained herein have been prepared by me and found to be consistent with my original certification.

Kennard F. Kosky, P.E.
KBN Engineering and Applied Sciences, Inc.
1034 N.W. 57th Street
Gainesville, FL 32605
Fla. Registration No. 14996
(904) 331-9000

CERTIFICATION BY A PROFESSIONAL ENGINEER REGISTERED IN FLORIDA

This is to certify that the revisions contained herein have been prepared by me and found to be consistent with my original certification.

Kennard F. Kosky
Kennard F. Kosky, P.E.
KBN Engineering and Applied Sciences, Inc.
1034 N.W. 57th Street
Gainesville, FL 32605
Fla. Registration No. 14996
(904) 331-9000

SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable: *Not applicable*

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		

B. Process Rate, if applicable: (See Section V, Item 1) *Not applicable*

1. Total Process Input Rate (lbs/hr): ____________________

2. Product Weight (lbs/hr): ____________________

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary) *See Table 2-1 in PSD Permit application*

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/hr	T/yr	
SO_2	*197.5 (CT Oil)*	*13.8*	*0.8% Sulfur*	*316.1*	*197.5*	*13.8*	*See*
PM	*10 (CT Oil)*	*26.6*	*NA*	*NA*	*10*	*26.6*	*Figure 2-1*
NO_x	*66.3 (CT Oil)*	*174.6*	*126 ppmvd*	*198.9*	*66.3*	*174.6*	*in PSD*
CO	*97.6 (CT DB)*	*326.7*	*NA*	*NA*	*97.6*	*326.7*	*Application*
VOC	*9.63 (CT DB)*	*17.5*	*NA*	*NA*	*9.63*	*17.5*	

[1]See Section V, Item 2.
[2]Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input) *NSPS--0.8% sulfur oil and 75 ppmvd NO_x corrected for heat rate, i.e., 126 ppmvd; FDER Rule 17-2.660.*
[3]Calculated from operating rate and applicable standard.
[4]Emission, if source operated with~~out~~ control (See Section V, Item 3).

D. Control Devices: (See Section V, Item 4) *See Section 4.0 in PSD Application*

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)

E. Fuels *See Table A-1 in PSD Permit Application*

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas-CT	*342,071.2 CF*[a]	*367,818.5 CF*	*348 @ Operating Conditions*
Natural Gas-DB	*59,302.3 CF*[b]	*197,674.4 CF*	*187*
Fuel Oil-CT	*1,039.6 lb*[c]	*20,792.4 lb*	*382.6 @ Operating*
			Conditions

CT = combustion turbine; DB = duct burner
*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, others--lbs/hr.
[a]*8,146.8 hr/yr when also firing oil at 219 hours per year;* [b]*2,628 hr/yr;* [c]*219 hr/yr*

Fuel Analysis:

Percent Sulfur: *NG = 1 grain/100 CF; oil = 0.5% sulfur* Percent Ash: *<0.1*

Density: *~7.2 for oil* lbs/gal Typical Percent Nitrogen: *<0.015*

Heat Capacity: *NG = 946 Btu/CF; Oil = 18,400* BTU/lb *132,480 (Oil)* BTU/gal

Other Fuel Contaminants (which may cause air pollution): *See Appendix A in PSD Permit Application*

F. If applicable, indicate the percent of fuel used for space heating.

Annual Average ______ Maximum ______

G. Indicate liquid or solid wastes generated and method of disposal.

All wastewaters generated from the plant will be discharged to the University of Florida wastewater treatment plant.

2.0 PROJECT DESCRIPTION

2.1 GENERAL DESCRIPTION

The proposed project will consist of installing one CT and one HRSG at the UF Central Heat Plant. The UF Central Heat Plant has five existing boilers which are fired primarily with natural gas; residual oil is used as the backup fuel. The project will replace existing boilers 1, 2, and 3; Boilers 4 and 5 will be operated as backup units for the cogeneration plant. The existing boilers and cogeneration plant will be under the common control of FPC. Therefore, the "facility" for which PSD approval is requested includes the existing Central Heat Plant and the cogeneration plant. This is consistent with the term defined in Florida Department of Environmental Regulation (FDER) Rule 12-2.100(78) Florida Administrative Code (F.A.C.).

The CT will be the new General Electric (GE) LM 6000 machine. The LM 6000 is a newly developed aircraft-derivative machine with a thermal efficiency of approximately 40 percent. This efficiency, developed from advanced aircraft compressor and turbine technology, makes the LM 6000 more efficient than the advanced heavy-frame combustion turbine being offered by certain manufacturers (e.g., the GE Frame combustion turbine). A description of this machine is presented in Appendix A. The CT exhaust will go through the HRSG and exit to the atmosphere through an individual stack. There will be no bypass stack on the CT for simple cycle operation. A flow diagram of the project is presented in Figure 2-1.

The primary fuel for firing the CT will be natural gas; distillate fuel oil will be used as emergency backup when natural gas is curtailed. Operation with distillate oil will not exceed a capacity factor of 2.5 percent or 219 hours per year at full load. There will be supplementary firing of natural gas only in the HRSG.

Air emission sources associated with the proposed project consist of the CT and supplemental firing in the HRSG. Wet injection will be used to control emissions of nitrogen oxides (NO_x) from the CT. The use of natural gas or low-sulfur (0.5-percent-sulfur maximum) distillate fuel oil will minimize the emissions of sulfur dioxide (SO_2) from the unit.

2.2 FACILITY EMISSIONS AND STACK OPERATING PARAMETERS

The emissions and stack parameters for the CT are presented in Table 2-1. These data represent the maximum emissions since air inlet coolers may be installed on the CT to maintain a compressor temperature of 51°F, which will increase generating capability and regulate temperature. Maximum potential annual emissions for the project are presented in Table 2-2. Performance information and maximum emission rates for regulated criteria pollutants, regulated noncriteria pollutants, and nonregulated pollutants from the CT are presented in Tables A-1 through A-5 of Appendix A.

The maximum capacity factors for the combustion turbine will be 93 percent (8,146.8 hours per year) on natural gas and 2.5 percent (219 hours per year) on distillate oil. Because NO_x emissions when firing distillate oil are 1.9 times greater than when firing natural gas, it is requested that the up to 1.9 times more natural gas be allowed for each hour of distillate oil not burned in any given year. The fuel use restriction would be:

Natural Gas Restriction = 348 x 10^6 Btu/hour x 8,146.8 hours/year = 2,835,086 x 10^6 Btu/year and,

Distillate Oil = 382.6 x 10^6 Btu/hour x 219 hours/year = 83,789 x 10^6 Btu/year

or,

Natural Gas = 348 x 10^6 Btu/hr x (8,146.8 + 1.9 x 219 hours/year)

= 2,979,889 x 10^6 Btu/year or 97.75 percent capacity factor

Supplemental firing with natural gas will take place in the duct between the CT and the HRSG. The supplemental firing, at a maximum rate of 187 million British thermal units per hour (x 10^6 Btu/hr), will allow the HRSG to produce additional steam. The firing of natural gas will produce additional air emissions, as shown in Tables 2-1 and 2-2, for the maximum firing rate. These emissions will combine with the CT exhaust gases only during natural gas firing and exhaust through the HRSG stack. Supplemental firing will be limited to a 30 percent capacity factor or an equivalent of 2,628 hours per year at maximum capacity (i.e., 491,436 x 10^6 Btu).

2.3 EXISTING FACILITY EMISSIONS

The proposed facility will include the existing Central Heat Plant which consists of five boilers firing natural gas and residual oil. Boilers 1, 2 and 3 will be taken out of service when the cogeneration plant becomes operational. Boilers 1 and 2 have heat input capacities of 88.5 million Btu per hour. Boiler 3 has a heat input capacity of 160.6 x 10^6 Btu/hr. Boilers 4 and 5 have heat input capacities of 71.7 and 172.2 x 10^6 Btu/hr and will be used only as back-up for the cogeneration plant. The primary fuel for these boilers will be natural gas and will be operated at lower capacity factors than in previous years. The use of residual oil in these boilers will be eliminated and replaced with distillate oil. Copies of the FDER permits are contained in Appendix B.

Because the facility consists of the Central Heat Plant, the net emissions decreases are creditable when evaluating PSD applicability [FDER Rule 17-2.500(2)(e)]. For the Central Heat Plant, the actual emissions representative of operation are presented in Table 2-3 for Boilers 1, 2, and 3, and Table 2-4 for Boilers 4 and 5. These emissions represent an average of the last complete 3-years (1988-90). A 3-year average is considered representative because operation of the Central Heat Plant is affected by meteorological conditions, i.e. heating and cooling requirements. Three years were used since the calendar year 1990 was abnormally warm compared with historical data. A quantitative measure of this is reflected by the number of heating degree days observed by the National Weather Service for Gainesville. In 1990, the heating degree days were 709 compared to a historical average of 1,259. The average heating degree days for 1990 and 1989 was 974 which would normally be considered the two year period identified in the Department's rules [Rule 17-2.100(3)(a)] as applicable for calculating actual emissions. However, this period was not representative of actual emissions. Therefore, a three year average of 1988 through 1990 was used to calculate actual emissions. The heating degree days for this period is 1,104 which is more representative of the operation of the UF heating plant. Copies of the annual operation reports are contained in Appendix B.

Since Boilers 4 and 5 will be operated as backup units for the cogeneration plant, the operation of these sources will be restricted based on fuel use. The fuel use and emissions are presented in Table 2-5. Also, the emission estimates in this table reflect the use of distillate oil rather than residual oil. The elimination of Boilers 1, 2, and 3, and the restriction in fuel use and use of distillate oil in Boilers 4 and 5 will provide net emission decreases for the facility which are presented in Table 2-6.

Table 2-1. Stack, Operating, and Emission Data for the UF Cogeneration Facility (Page 1 of 2)

Parameter	Fuel Type: Fuel Oil[a] Gas Turbine	Fuel Type: Natural Gas Gas Turbine[b]	Fuel Type: Natural Gas Duct Burner[c]
Stack Data (ft)			
Height	93	93	d
Diameter	9.75	9.75	d
Operating Data			
Temperature (°F)	257	257	d
Velocity (ft/sec)	71.5	72.59	d
Building Data (ft)			
Height	57	57	d
Length	54	54	d
Width	14	14	d
Maximum Hourly Emission Data (lb/hr) for Each Emission Unit/Fuel Type			
Sulfur Dioxide	197.5	1.05	0.56
Particulate Matter	10.0	2.5	1.87
Nitrogen Oxides	66.3	35.0	18.7
Carbon Monoxide	70.5	69.5	28.1
Volatile Organic Compounds	4.03	1.59	8.04
Sulfuric Acid Mist	15.1	0.08	0.04
Lead	0.0034	Neg	Neg
Annual Potential Emission Data (TPY) for Each Emission Unit/Fuel Type			
Sulfur Dioxide	21.6	4.6	0.74
Particulate Matter	1.1	10.95	2.46
Nitrogen Oxides	7.26	153.4	24.6

Table 2-1. Stack, Operating, and Emission Data for the UF Cogeneration Facility (Page 2 of 2)

	Fuel Type		
	Fuel Oil[a]	Natural Gas	
Parameter	Gas Turbine	Gas Turbine[b]	Duct Burner[c]
Carbon Monoxide	7.72	304.4	36.9
Volatile Organic Compounds	0.44	7.0	10.6
Sulfuric Acid Mist	1.65	0.3	0.06
Lead	0.00037	Neg	Neg

Note: See Tables A-1 through A-5 in the appendix for more detail.

°F = degrees Fahrenheit.
ft = feet.
ft/second = feet per second.
lb/hr = pounds per hour.
TPY = tons per year.

[a] Performance based on nitrogen oxide emissions of 42 parts per million by volume dry (corrected to 15 percent O_2); sulfur dioxide emissions based on an average sulfur content of 0.5 percent sulfur; annual emission data based on 2.5 percent capacity factor or 219 hours per year at full load.
[b] Performance based on nitrogen oxide emissions of 25 parts per million volume dry (corrected to 15 percent O_2); annual emissions data based on 8,760 hours/year (365 days per year) operation.
[c] Performance based on 187 x 10^6 Btu/hr heat input per heat recovery steam generators and 30 percent capacity factor or 2,628 hours per year operation at full load.
[d] Same as gas turbine natural gas; duct burners will not fire No. 2 oil.

Table 2-2. Maximum Annual Potential Emissions From Proposed Cogeneration Project

Pollutant	Fuel (TPY) Distillate Oil[a]	Fuel (TPY) Natural Gas[b] Gas Turbine	Fuel (TPY) Natural Gas[b] Duct Burner	Total (TPY)
Sulfur Dioxide	21.6	4.3	0.7	26.6
Particulate Matter[c]	1.1	10.2	2.5	13.8
Nitrogen Oxide	7.26	142.7	24.6	174.6
Carbon Monoxide	7.72	282.1	36.9	326.7
Volatile Organic Compounds	0.44	6.5	10.6	17.5
Sulfuric Acid Mist	2.0	0.3	0.05	2.4
Lead	0.00034	Neg	Neg	0.00034

Note: Neg = negative.
PM10 = particulate matter with an aerodynamic diameter less than or equal to 10 micrometers.
TPY = tons per year.

[a]219 hours/year.
[b]93% capacity factor for gas turbine and 30% capacity for duct burner.
[c]PM10.

Table 2-3. Actual Representative Emissions (1988-1990) of Regulated Pollutants, Boilers 1, 2, and 3 (Page 1 of 2)

	Boilers No. 1 & 2[a]		Boiler No. 3[b]		
	Natural Gas	No. 6 Fuel Oil	Natural Gas	No. 6 Fuel Oil	Total
Natural Gas Burned[c]					
(MM ft^3/yr)	208.099		368.275		
No. 6 Fuel Oil[c]					
(gal/yr)		0		12,519	
(% sulfur)		1.85		1.85	
Emission Factor	lb/MM scf	lb/1,000 gal	lb/MM scf	lb/1,000 gal	
Particulate Matter	3	12.64[d]	3	21.5[d]	
Particulate Matter (PM10)	3	8.97[d]	3	15.27[d]	
Sulfur Dioxide	0.6	151.3[e]	0.6	290.5[e]	
Nitrogen Oxides	140	55	310.6[f]	67	
Carbon Monoxide	35	5	40	5	
Volatile Organic Compounds (methane)	3	1	0.3	0.28	
Volatile Organic Compounds (nonmethane)	2.8	0.28	1.4	0.76	
Lead	Neg.	0.0042	Neg.	0.0042	
Fluorides	Neg.	0.052	Neg.	0.052	
Mercury	Neg.	0.00048	Neg.	0.00048	
Beryllium	Neg.	0.00063	Neg.	0.00063	
Arsenic	Neg.	0.0029	Neg.	0.0029	
Sulfuric Acid Mist	Neg.	2.32	Neg.	6.57	
Emission Rate (TPY)					
Particulate Matter	0.31	0.00	0.55	0.13	1.00
Particulate Matter (PM10)	0.31	0.00	0.55	0.10	0.96
Sulfur Dioxide	0.062	0.00	0.110	1.82	1.99
Nitrogen Oxides	14.57	0.00	57.19	0.42	72.18
Carbon Monixide	3.64	0.00	7.37	0.03	11.04
Volatile Organic Compounds (methane)	0.31	0.00	0.06	0.00	0.37

Table 2-3. Actual Representative Emissions (1988-1990) of Regulated Pollutants, Boilers 1, 2, and 3 (Page 2 of 2)

	Boilers No. 1 & 2[a]		Boiler No. 3[b]		
	Natural Gas	No. 6 Fuel Oil	Natural Gas	No. 6 Fuel Oil	Total
Volatile Organic Compounds (nonmethane)	0.29	0.00	0.26	0.00	0.55
Lead	Neg.	0.0000	Neg.	0.0000	0.000
Total Fluorides	Neg.	0.000	Neg.	0.000	0.000
Mercury	Neg.	0.00000	Neg.	0.00000	0.000
Beryllium	Neg.	0.00000	Neg.	0.00000	0.00000
Arsenic	Neg.	0.0000	Neg.	0.0000	0.0000
Sulfuric Acid Mist	Neg.	0.00	Neg.	0.04	0.04

Note: Calculations in this table are performed as follows: Fuel use times emission factor equals emission rate; e.g. 208.099 MM scf/yr x 3 lb/MM scf ÷ 2,000 lb/ton = 0.31 TPY (Note: Roundoff from Lotus may be slightly different than calcualtions using a calculator.).

ft^3/yr = cubic feet per year
gal/yr = gallons per year
% = percent
lb/mm = pounds per millimeter
scf = standard cubic feet
gal = gallons
Btu/hr = British thermal unit per hour
PM = particulate matte
PM10 = particulate matter (PM10)
TPY = tons per year

[a] Boilers 1 and 2 have heat input capacities less than 100 x 10^6 British thermal units per hour; therefore, emission factors for industrial boilers were used.
[b] Boiler 3 has a heat input capacity of greater than 100 x 10^6 British thermal units per hour; therefore, emission factors for utility boilers were used.
[c] Based on annual operating reports (see Appendix B).
[d] Based on equation: 10 S + 3, where S = sulfur content. PM10 is 71% of PM emissions.
[e] Based on equation: 157 S, where S = sulfur content.
[f] Adjusted based on hours of operation and fuel usage; AP-42 load chart used (see FDER letter of 12/31/91).

Table 2-4. Actual Representative Emissions of Regulated Pollutants, Boilers 4 and 5 (Page 1 of 2)

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 6 Fuel Oil	Natural Gas	No. 6 Fuel Oil	Total
Natural Gas Burned (MM ft^3/yr)	155.542		452.609		
No. 6 Fuel Oil					
(gal/yr)		55,207		190,515	
(% sulfur)		1.623		1.97	
Emission Factor	lb/MM scf	lb/1,000 gal	lb/MM scf	lb/1,000 gal	
Particulate Matter	3	19.23[d]	3	22.7[d]	
Particulate Matter (PM10)	3	13.65[d]	3	16.12[d]	
Sulfur Dioxide	0.6	254.8[e]	0.6	309.3[e]	
Nitrogen Oxides	140	55	281.2[f]	67	
Carbon Monoxide	35	5	40	5	
Volatile Organic Compounds (methane)	3	1	0.3	0.28	
Volatile Organic Compounds (nonmethane)	2.8	0.28	1.4	0.76	
Lead	Neg.	0.0042	Neg.	0.0042	
Fluorides	Neg.	0.052	Neg.	0.052	
Mercury	Neg.	0.00048	Neg.	0.00048	
Beryllium	Neg.	0.00063	Neg.	0.00063	
Arsenic	Neg.	0.0029	Neg.	0.0029	
Sulfuric Acid Mist	Neg.	3.98	Neg.	7.0	
Emission Rate (TPY)					
Particulate Matter	0.23	0.53	0.68	2.16	3.61
Particulate Matter (PM10)	0.23	0.38	0.68	1.54	2.82
Sulfur Dioxide	0.05	7.03	0.14	29.46	36.68
Nitrogen Oxides	10.89	1.52	63.64	6.38	82.43
Carbon Monoxide	2.72	0.14	9.05	0.48	12.39
Volatile Organic Compounds (methane)	0.23	0.03	0.07	0.03	0.36

Table 2-4. Actual Representative Emissions of Regulated Pollutants, Boilers 4 and 5 (Page 2 of 2)

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 6 Fuel Oil	Natural Gas	No. 6 Fuel Oil	Total
Volatile Organic Compounds (nonmethane)	0.22	0.01	0.32	0.07	0.61
Lead	Neg.	0.0001	Neg.	0.0004	0.0005
Fluorides	Neg.	0.0014	Neg.	0.0050	0.006
Mercury	Neg.	0.00001	Neg.	0.00005	0.00006
Beryllium	Neg.	0.00002	Neg.	0.00006	0.00008
Arsenic	Neg.	0.0001	Neg.	0.0003	0.0004
Sulfuric Acid Mist	Neg.	0.11	Neg.	0.67	0.78

Note: Calculations in this table are performed as follows: Fuel use times emission factor equals emission rate; e.g. 155.542 MM scf/yr x 3 lb/MM scf ÷ 2,000 lb/ton = 0.23 TPY (Note: Roundoff from Lotus may be slightly different than calculations using a calculator.).

ft^3/yr = cubic feet per year
gal/yr = gallons per year
% = percent
lb/mm = pounds per millimeter
scf = standard cubic feet
gal = gallons
Btu/hr = British thermal unit per hour
PM = particulate matter
PM10 = particulate matter (PM10)
TPY = tons per year

[a] Boiler 4 has heat input capacity of less than 100 x 10^6 Btu/hr; therefore, emissions factors for industrial boilers were used.
[b] Boiler 5 has a heat input capacity of greater than 100 x 10^6 Btu/hr; therefore, emission factors for utility boilers were used.
[c] Based on annual operating reports (see Appendix B).
[d] Based on equation: 10 S + 3, where S = sulfur content. PM10 is 71% of PM emissions.
[e] Based on equation: 157 S, where S = sulfur content.
[f] Based on hours of operation and fuel use. Used AP-42 load correction figure (see FDER letter dated 12/31/91).

Table 2-5. Emissions of Regulated Pollutants for Boilers 4 & 5 After Commercial Operation of Cogeneration Plant (Page 1 of 2)

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 2 Fuel Oil	Natural Gas	No. 2 Fuel Oil	Total
Natural Gas Burned[c]					
(MM ft^3/yr)	20		125		
No. 2 Fuel Oil[c]					
(gal/yr)		15,000		50,000	
(% sulfur)		0.5		0.5	
Emission Factor	lb/MM scf	lb/1,000 gal	lb/MM scf	lb/1,000 gal	
Particulate Matter	3	8[d]	3	8[d]	
Particulate Matter (PM10)	3	5.68[d]	3	5.68[d]	
Sulfur Dioxide	0.6	78.5[e]	0.6	78.5[e]	
Nitrogen Oxides	140	20	281.2	24	
Carbon Monoxide	35	5	40	5	
Volatile Organic Compounds (methane)	3	0.052	0.3	0.052	
Volatile Organic Compounds (nonmethane)	2.8	0.2	1.4	0.2	
Lead	Neg.	0.0013	Neg.	0.0042	
Fluorides	Neg.	0.0049	Neg.	0.052	
Mercury	Neg.	0.00045	Neg.	0.00048	
Beryllium	Neg.	0.00038	Neg.	0.00063	
Arsenic	Neg.	0.00063	Neg.	0.0029	
Sulfuric Acid Mist	Neg.	1.225	Neg.	1.225	
Emission Rate (TPY)					
Particulate Matter	0.03	0.06	0.19	0.20	0.48
Particulate Matter (PM10)	0.03	0.04	0.19	0.14	0.40
Sulfur Dioxide	0.01	0.59	0.04	1.96	2.59
Nitrogen Oxides	1.40	0.15	17.58	0.61[f]	19.73
Carbon Monoxide	0.35	0.04	2.50	0.13	3.01
Volatile Organic Compounds (methane)	0.03	0.00	0.02	0.00	0.05
Volatile Organic Compounds (nonmethane)	0.03	0.00	0.09	0.01	0.12

Table 2-5. Emissions of Regulated Pollutants for Boilers 4 & 5 After Commercial Operation of Cogeneration Plant (Page 2 of 2)

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 2 Fuel Oil	Natural Gas	No. 2 Fuel Oil	Total
Lead	Neg.	0.00001	Neg.	0.00011	0.0001
Fluorides	Neg.	0.00004	Neg.	0.00130	0.001
Mercury	Neg.	0.00000	0.0000	0.00001	0.00000
Beryllium	Neg.	0.00000	Neg.	0.00002	0.00002
Arsenic	Neg.	0.00000	Neg.	0.00007	0.0001
Sulfuric Acid Mist	Neg.	0.01	Neg.	0.03	0.04

Note: Calculations in this table are performed as follows: Fuel use times emission factor equals emission rate; e.g. 20 MM scf/yr x 3 lb/MM scf ÷ 2,000 lb/ton = 0.03 TPY (Note: Roundoff from Lotus may slightly different than calculations using a calculator.).

ft^3/yr = cubic feet per year
gal/yr = gallons per year
% = percent
lb/mm = pounds per millimeter
scf = standard cubic feet
gal = gallons
Btu/hr = British thermal unit per hour
PM = particulate matter
PM10 = particulate matter (PM10)
TPY = tons per year

[a] Boiler 4 has a heat input capacity of less than 100 x 10^6 Btu/hr; therefore, emissions factors for industrial boilers were used.
[b] Boiler 5 has a heat input capacity of greater than 100 x 10^6 Btu/hr; therefore, emission factors for utility boilers were used.
[c] Based on annual operating reports (See Appendix A).
[d] Based on equation: 10 S + 3, where S = sulfur content. PM10 is 71% of PM emissions.
[c] Based on equation: 157 S, where S = sulfur content.
[f] Nitrogen oxides emissions based on ratio of residual and distillate oil emission factors [67 lb/10^3 gallons x 20 lb/10^3 gallons (for distillate) ÷ 55 lb/10^3 gallons (for residual)].

Table 2-6. Net Emission Reductions From Boilers 1 Through 5 at UF Central Heating Plant

	Net Emission Reduction (TPY)		
Pollutant	Boilers[a] 1, 2 and 3	Boilers[b] 4 and 5	Total
Particulate Matter	-1.00	-3.13	-4.13
Particulate Matter (PM10)	-0.96	-2.42	-3.38
Sulfur Dioxide	-1.99	-34.08	-36.07
Nitrogen Oxides	-72.18	-62.69	-134.87
Carbon Monoxide	-11.04	-9.38	-20.41
Volatile Organic Compounds (methane)	-0.37	-0.31	-0.67
Volatile Organic Compounds (nonmethane)	-0.55	-0.49	-1.05
Lead	-0.0000	-0.0004	-0.0004
Fluorides	-0.0003	-0.0051	-0.0054
Mercury	-0.00000	-0.00	-0.00
Beryllium	-0.00000	-0.00006	-0.00006
Arsenic	-0.0000	-0.0003	-0.0003
Sulfuric Acid Mist	-0.0411	-0.7366	-0.7777

Note: TPY = tons per year.

[a]Based on emissions in Table 2-3.
[b]Based on subtracting emissions in Table 2-4 from emissions in Table 2-5.

3.4.2 PSD REVIEW

3.4.2.1 Pollutant Applicability

The proposed project is considered to be a modification to a major facility because the facility is listed as one of the "List of 28" and potential emissions of any regulated pollutant exceed 100 TPY; therefore, PSD review is required for any pollutant for which the net increase in emissions exceeds the PSD significant emission rates presented in Table 3-2 (i.e., major modification). As shown, potential emissions from the proposed project will exceed the PSD significant emission rate for CO. Therefore, the project is subject to PSD review for this pollutant.

Table 3-3. Net Increase in Emissions Due To the UF Cogeneration Facility Compared to the PSD Significant Emission Rates

	Emissions (TPY)				
Pollutant	Potential Emissions From Proposed Project	Net Emission Reduction From Boilers 1-5	Net Emissions Increase	Significant Emission Rate	PSD Review
Sulfur Dioxide	26.6	36.1	-9.5	40	No
Particulate Matter (TSP)	13.8	4.1	9.7	25	No
Particulate Matter (PM10)	13.8	3.4	10.4	15	No
Nitrogen Dioxide	174.6	134.9	39.7	40	No
Carbon Monoxide	326.7	20.4	306.3	100	Yes
Volatile Organic Compounds	17.5	1.05	16.5	40	No
Lead	0.00034	0.0004	0.0002	0.6	No
Sulfuric Acid Mist	2.4	0.78	1.6	7	No
Total Fluorides	0.0014	0.0054	-0.004	3	No
Total Reduced Sulfur[a]	Neg	Neg	Neg	10	No
Reduced Sulfur Compounds[a]	Neg	Neg	Neg	10	No
Hydrogen Sulfide[a]	Neg	Neg	Neg	10	No
Asbestos[a]	Neg	Neg	Neg	0.007	No
Beryllium	0.00011	0.00006	0.00004	0.0004	No
Mercury	0.00013	Neg	0.00013	0.1	No
Vinyl Chloride[a]	Neg	Neg	Neg	1	No
Benzene[a]	Neg	Neg	Neg	0	No
Radionuclides[a]	Neg	Neg	Neg	0	No
Inorganic Arsenic	0.00018	0.0003	-0.00012	0	No

Note: Neg = Negligible.
TPY = tons per year.
All calculations based on 59°F peak load condition.

[a]Emissions of these pollutants considered not to have any emission rate increase.

APPENDIX A

Table A-1. Design Information and Stack Parameters for University of Florida Cogeneration Project

Data A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine Fuel Oil D
General:			
Power (kW)	43,262.0	NA	43,098.0
Heat Rate (Btu/kwh)	8,043.0	NA	8,877.0
Heat Input (mmBtu/hr)	348.0	187.0	382.6
Fuel Oil (lb/hr)	18,313.5	9,842.1	20,792.4
(cf/hr)	367,818.5	197,674.4	
Fuel:			
Heat Content - (LHV)	19,000 Btu/lb	19,000 Btu/lb	18,400 Btu/lb
Sulfur	1 gr/100cf	1 gr/100cf	0.5
CT Exhaust:			
Volume Flow (acfm)	564,678		569,684
Volume Flow (scfm)	239,478		235,916
Mass Flow (lb/hr)	1,036,522		1,030,290
Temperature (oF)	785		815
Moisture (% Vol.)	11.25		8.54
Oxygen (% Vol.)	13.73		13.60
Molecular Weight	27.80		28.05
Steam Injected (lb/hr)	31,402		22,504
HRSG Stack:			
Volume Flow (acfm)	325,200		320,364
Temperature (oF)	257		257
Diameter (ft)	10		9.8
Velocity (ft/sec)	72.59		71.51

Source: General Electric and Stewart and Stevenson, 1991.
Note: All data shown on this table and subsequent tables are for the combustion turbine and duct burner.

Table A-2. Maximum Criteria Pollutant Emissions for Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine Fuel Oil D
Particulate:			
Basis	Manufacturer	0.01 lb/mmBtu	Manufacturer
lb/hr	2.50	1.87	10.0
TPY	10.95	2.46	1.1
Sulfur Dioxide:			
Basis	1 gr/100 cf	1 gr/100 cf	0.5 % Sulfur
lb/hr	1.05	0.56	197.53
TPY	4.60	0.74	21.6
Nitrogen Oxides:			
Basis	25 ppm*	0.1 lb/mmBtu	42 ppm*
lb/hr	35.0	18.7	66.3
TPY	153.4	24.57	7.3
ppm	25.0	NA	42.0
Carbon Monoxide:			
Basis	75 ppm+	0.15 lb/mmBtu	75 ppm+
lb/hr	69.5	28.1	70.5
TPY	304.37	36.86	7.7
ppm	75.0	NA	75.0
VOC's:			
Basis	4 ppm+	0.043 lb/mmBtu	10 ppm+
lb/hr	1.59	8.04	4.03
TPY	7.0	10.57	0.4
ppm	4.0	NA	10.0
Lead:			
Basis			EPA(1988)
lb/hr	NA	NA	3.40E-03
TPY	NA	NA	3.73E-04

* corrected to 15% O2 dry conditions
+ corrected to dry conditions
Note: Annual emission for CT when firning natural gas based on 8,760 hrs/yr and 219 hrs/yr for fuel oil firing. Annual emissions for duct burners on 2,628 hrs/yr (30% capacity factor).

Table A-3. Maximum Other Regulated Pollutant Emissions for UF Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine No.2 Oil D
As (lb/hr)	NEG.	NEG.	0.0016068399732
(TPY)	NEG.	NEG.	1.76E-04
Be (lb/hr)	NEG.	NEG.	0.000956452365
(TPY)	NEG.	NEG.	1.05E-04
Hg (lb/hr)	NEG.	NEG.	1.15E-03
(TPY)	NEG.	NEG.	1.26E-04
F (lb/hr)	NEG.	NEG.	0.012433880745
(TPY)	NEG.	NEG.	1.36E-03
H_2SO_4 (lb/hr)	8.04E-02	4.32E-02	1.51E+01
(TPY)	3.52E-01	0.06	1.65E+00

Sources: EPA, 1988; EPA, 1980

Table A-4. Maximum Non-Regulated Pollutant Emissions for UF Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine No.2 Oil D
Manganese (lb/hr)	NEG.	NEG.	2.46E-03
(TPY)	NEG.	NEG.	2.70E-04
Nickel (lb/hr)	NEG.	NEG.	6.50E-02
(TPY)	NEG.	NEG.	7.12E-03
Cadmium (lb/hr)	NEG.	NEG.	4.02E-03
(TPY)	NEG.	NEG.	4.40E-04
Chromium (lb/hr)	NEG.	NEG.	1.82E-02
(TPY)	NEG.	NEG.	1.99E-03
Copper (lb/hr)	NEG.	NEG.	1.07E-01
(TPY)	NEG.	NEG.	1.17E-02
Vanadium (lb/hr)	NEG.	NEG.	2.67E-02
(TPY)	NEG.	NEG.	2.92E-03
Selenium (lb/hr)	NEG.	NEG.	8.98E-03
(TPY)	NEG.	NEG.	9.83E-04
POM (lb/hr)	3.88E-04	2.09E-04	1.07E-04
(TPY)	1.70E-03	2.74E-04	1.17E-05
Formaldehyde (lb/hr)	3.07E-02	7.57E-02	1.55E-01
(TPY)	1.35E-01	9.95E-02	1.70E-02

Source: EPA, 1988.

Table A-5. Maximum Emissions for Additional Non-Regulated Pollutant for UF Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine No.2 Oil D
Antimony (lb/hr)	NEG.	NEG.	8.36E-03
(TPY)	NEG.	NEG.	9.15E-04
Barium (lb/hr)	NEG.	NEG.	7.47E-03
(TPY)	NEG.	NEG.	8.18E-04
Colbalt (lb/hr)	NEG.	NEG.	3.47E-03
(TPY)	NEG.	NEG.	3.80E-04
Zinc (lb/hr)	NEG.	NEG.	2.61E-01
(TPY)	NEG.	NEG.	2.86E-02
Chlorine[a] (lb/hr)	NEG.	NEG.	1.04E-02
(TPY)	NEG.	NEG.	1.14E-03

Source: EPA, 1979
[a] Assumes 0.5 ppm in fuel oil.

```
A:A1: [W24] 'Table A-1.  Design Information and Stack Parameters for University of Florida (UF)
A:E1: [W6] 1
A:A2: [W24] '          Cogeneration Project
A:E2: [W6] (E1+1)
A:A3: [W24] \_
A:B3: [W18] \_
A:C3: [W18] \_
A:D3: [W18] \_
A:E3: [W6] (E2+1)
A:E4: [W6] (E3+1)
A:A5: [W24] ^Data
A:B5: [W18] "Gas Turbine
A:C5: [W18] "Duct Burner
A:D5: [W18] "Gas Turbine
A:E5: [W6] (E4+1)
A:B6: [W18] "Natural Gas
A:C6: [W18] "Natural Gas
A:D6: [W18] "Fuel Oil
A:E6: [W6] (E5+1)
A:A7: [W24] ^A
A:B7: [W18] "B
A:C7: [W18] "C
A:D7: [W18] "D
A:E7: [W6] (E6+1)
A:A8: [W24] \_
A:B8: [W18] \_
A:C8: [W18] \_
A:D8: [W18] \_
A:E8: [W6] (E7+1)
A:E9: [W6] (E8+1)
A:A10: [W24] ^General:
A:E10: [W6] (E9+1)
A:A11: [W24] 'Power (kW)
A:B11: (,1) [W18] 43262 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:C11: (,1) [W18] "NA
A:D11: (,1) [W18] 43098 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:E11: [W6] (E10+1)
A:A12: [W24] 'Heat Rate (Btu/kwh)
A:B12: (,1) [W18] 8043 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:C12: (,1) [W18] "NA
A:D12: (,1) [W18] 8877 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:E12: [W6] (E11+1)
A:A13: [W24] 'Heat Input (mmBtu/hr)
A:B13: (,1) [W18] (B11*B12/1000000) . . . . . . . . . . . . . . . . . . . . . . . . Power * Heat Rate
A:C13: (,1) [W18] 187 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Maximum Proposed
A:D13: (,1) [W18] (D11*D12/1000000) . . . . . . . . . . . . . . . . . . . . . . . . Power * Heat Rate
A:E13: [W6] (E12+1)
A:A14: [W24] 'Fuel Oil (lb/hr)
A:B14: (,1) [W18] (B13/0.019) . . . . . . . . . . . . . . . . . . . . . . . . Heat Input ÷ Heat Content
A:C14: (,1) [W18] (C13/0.019)
A:D14: (,1) [W18] (D13/0.0184)
A:E14: [W6] (E13+1)
A:A15: [W24] '          (cf/hr)
A:B15: (,1) [W18] (B13/946*10^6) . . . . . . . . . . . . . . . . . . . . . . Heat Input ÷ Heat Content
A:C15: (,1) [W18] (C13/946*10^6)
A:E15: [W6] (E14+1)
A:E16: [W6] (E15+1)
A:A17: [W24] ^Fuel:
A:E17: [W6] (E16+1)
A:A18: [W24] 'Heat Content - (LHV)
A:B18: (,1) [W18] "19,000 Btu/lb . . . . . . . . . . . . . . . . . . . . . . . . . Fuel Specification
```

```
A:C18: (,1) [W18] "19,000 Btu/lb
A:D18: (,1) [W18] "18,400 Btu/lb
A:E18: [W6] (E17+1)
A:A19: [W24] 'Sulfur
A:B19: (,1) [W18] "1 gr/100cf . . . . . . . . . . . . . . . . . . . . . . . . . Maximum Sulfur Content in Natural Gas
A:C19: (,1) [W18] "1 gr/100cf
A:D19: (,1) [W18] 0.5 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Maximum Sulfur Content in Fuel Oil
A:E19: [W6] (E18+1)
A:E20: [W6] (E19+1)
A:A21: [W24] ^CT Exhaust:
A:E21: [W6] (E20+1)
A:A22: [W24] 'Volume Flow (acfm)
A:B22: (,0) [W18] (B24*1545*(460+B25)/(B28*2116.8*60)) . . . . . . . . . . . . . . . . . . . . . . See Note A
A:D22: (,0) [W18] (D24*1545*(460+D25)/(D28*2116.8*60))
A:E22: [W6] (E21+1)
A:A23: [W24] 'Volume Flow (scfm)
A:B23: (,0) [W18] (B24*1545*(460+68)/(B28*2116.8*60)) . . . . . . . . . . . . . . . . . . . . . . . See Note A
A:D23: (,0) [W18] (D24*1545*(460+68)/(D28*2116.8*60))
A:E23: [W6] (E22+1)
A:A24: [W24] 'Mass Flow (lb/hr)
A:B24: (,0) [W18] 1036522 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:D24: (,0) [W18] 1030290
A:E24: [W6] (E23+1)
A:A25: [W24] 'Temperature (oF)
A:B25: (,0) [W18] 785 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:D25: (,0) [W18] 815
A:E25: [W6] (E24+1)
A:A26: [W24] 'Moisture (% Vol.)
A:B26: (F2) [W18] 11.25 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:D26: (F2) [W18] 8.54
A:E26: [W6] (E25+1)
A:A27: [W24] 'Oxygen (% Vol.)
A:B27: (F2) [W18] 13.73 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:D27: (F2) [W18] 13.6
A:E27: [W6] (E26+1)
A:A28: [W24] 'Molecular Weight
A:B28: (F2) [W18] 27.8 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Calculated from GE
A:D28: (F2) [W18] 28.05
A:E28: [W6] (E27+1)
A:A29: [W24] 'Steam Injected (lb/hr)
A:B29: (,0) [W18] 31402 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:D29: (,0) [W18] 22504
A:E29: [W6] (E28+1)
A:E30: [W6] (E29+1)
A:A31: [W24] ^HRSG Stack:
A:E31: [W6] (E30+1)
A:A32: [W24] 'Volume Flow (acfm)
A:B32: (,0) [W18] (B22*(B33+460)/(B25+460)) . . . . . . . . . . . . . . . . . . . . . Adjustment for Temperature
A:D32: (,0) [W18] (D22*(D33+460)/(D25+460))
A:E32: [W6] (E31+1)
A:A33: [W24] 'Temperature (oF)
A:B33: (,0) [W18] 257 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From Design Engineer
A:D33: (,0) [W18] 257
A:E33: [W6] (E32+1)
A:A34: [W24] 'Diameter (ft)
A:B34: (F0) [W18] 9.75
A:D34: (,1) [W18] 9.75
A:E34: [W6] (E33+1)
A:A35: [W24] 'Velocity (ft/sec)
A:B35: (F2) [W18] (B32/60/(B34^2*3.14159/4)) . . . . . . . . . . . . . . . . . . . . . . . . Volume ÷ Flow
A:D35: (F2) [W18] (D32/60/(D34^2*3.14159/4))
A:E35: [W6] (E34+1)
```

```
A:E36: [W6] (E35+1)
A:A37: [W24] \_
A:B37: [W18] \_
A:C37: [W18] \_
A:D37: [W18] \_
A:E37: [W6] (E36+1)
A:E38: [W6] (E37+1)
A:A39: [W24] 'Source: General Electric and Stewart and Stevenson, 1991.
A:E39: [W6] (E38+1)
A:A40: [W24] 'Note: All data shown on this table and subsequent tables are for each
A:E40: [W6] (E39+1)
A:A41: [W24] '      combustion turbine and duct burner.
A:E41: [W6] (E40+1)
```

```
A:A47: [W24] 'Table A-2.  Maximum Criteria Pollutant Emissions for
A:E47: [W6] 47
A:A48: [W24] '          Cogeneration Project
A:E48: [W6] (E47+1)
A:A49: [W24] \_
A:B49: [W18] \_
A:C49: [W18] \_
A:D49: [W18] \_
A:E49: [W6] (E48+1)
A:E50: [W6] (E49+1)
A:A51: [W24] ^Pollutant
A:B51: [W18] "Gas Turbine
A:C51: [W18] "Duct Burner
A:D51: [W18] "Gas Turbine
A:E51: [W6] (E50+1)
A:B52: [W18] "Natural Gas
A:C52: [W18] "Natural Gas
A:D52: [W18] "Fuel Oil
A:E52: [W6] (E51+1)
A:A53: [W24] ^A
A:B53: [W18] "B
A:C53: [W18] "C
A:D53: [W18] "D
A:E53: [W6] (E52+1)
A:A54: [W24] \_
A:B54: [W18] \_
A:C54: [W18] \_
A:D54: [W18] \_
A:E54: [W6] (E53+1)
A:E55: [W6] (E54+1)
A:A56: [W24] 'Particulate:
A:E56: [W6] (E55+1)
A:A57: [W24] '  Basis
A:B57: (,1) [W18] "Manufacturer
A:C57: (,1) [W18] "0.01 lb/mmBtu
A:D57: (,1) [W18] "Manufacturer
A:E57: [W6] (E56+1)
A:A58: [W24] '  lb/hr
A:B58: (F2) [W18] 2.5 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:C58: (F2) [W18] (C13*0.01) . . . . . . . . . . . . . . . . . . . . . . . . Emission Factor Based on GE
A:D58: (F1) [W18] 10 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:E58: [W6] (E57+1)
A:A59: [W24] '  TPY
A:B59: (F2) [W18] (B58*8760/2000) . . . . . . . . . . . . . . . . . . Emissions * 8,760 hours/year ÷ 2,000 lb/ton
A:C59: (F2) [W18] (C58*4.38*0.3) . . . . . . . . . . . . . . . . . . Emissions * 4.38 TPY/lb/hr ÷ 0.3 Capacity Factor
A:D59: (,1) [W18] (D58*219/2000) . . . . . . . . . . . . . . . . . . Emissions * 219 hours/year ÷ 2,000 lb/ton
A:E59: [W6] (E58+1)
A:E60: [W6] (E59+1)
A:A61: [W24] 'Sulfur Dioxide:
A:E61: [W6] (E60+1)
A:A62: [W24] '  Basis
A:B62: (,1) [W18] "1 gr/100 cf
A:C62: (,1) [W18] "1 gr/100 cf
A:D62: (,1) [W18] "0.5 % Sulfur
A:E62: [W6] (E61+1)
A:A63: [W24] '  lb/hr
A:B63: (F2) [W18] (B15*1/7000*2/100)  . . . . . . . . .  Fuel Used (CF/HR) * Sulfur Content * 2 lb SO2/lb S * 1/100 CF
A:C63: (F2) [W18] (C15*1/7000*2/100)
A:D63: (F2) [W18] (D14*0.005*2*0.95)  . . . . . . . .  Fuel Used (lb/hr) * Sulfur Content * 2 lb SO2/lb S * 95% Emitted
A:E63: [W6] (E62+1)
A:A64: [W24] '  TPY
```

```
A:B64: (F2) [W18] (B63*8760/2000)
A:C64: (F2) [W18] (C63*4.38*0.3)
A:D64: (,1) [W18] (D63*219/2000)
A:E64: [W6] (E63+1)
A:E65: [W6] (E64+1)
A:A66: [W24] 'Nitrogen Oxides:
A:E66: [W6] (E65+1)
A:A67: [W24] '  Basis
A:B67: (,1) [W18] "25 ppm*
A:C67: (,1) [W18] "0.1 lb/mmBtu
A:D67: (,1) [W18] "42 ppm*
A:E67: [W6] (E66+1)
A:A68: [W24] '  lb/hr
A:B68: (,1) [W18] (B70/5.9*(20.9*(1-B26/100)-B27)*B22*2116.8*46*60/(1545*(460+B25)*1000000)) . . . . . . . See Note B
A:C68: (,1) [W18] (C13*0.1) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Heat Input * Emission Factor
A:D68: (,1) [W18] (D70/5.9*(20.9*(1-D26/100)-D27)*D22*2116.8*46*60/(1545*(460+D25)*1000000)) . . . . . . . See Note B
A:E68: [W6] (E67+1)
A:A69: [W24] '  TPY
A:B69: (F1) [W18] (B68*8760/2000)
A:C69: (F2) [W18] (C68*4.38*0.3)
A:D69: (,1) [W18] (D68*219/2000)
A:E69: [W6] (E68+1)
A:A70: [W24] '  ppm
A:B70: (,1) [W18] 25 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:C70: (,1) [W18] "NA
A:D70: (,1) [W18] 42 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:E70: [W6] (E69+1)
A:E71: [W6] (E70+1)
A:A72: [W24] 'Carbon Monoxide:
A:E72: [W6] (E71+1)
A:A73: [W24] '  Basis
A:B73: (,1) [W18] "75 ppm+ . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:C73: (,1) [W18] "0.15 lb/mmBtu . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From Engineer
A:D73: (,1) [W18] "75 ppm+ . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:E73: [W6] (E72+1)
A:A74: [W24] '  lb/hr
A:B74: (,1) [W18] (B76*(1-B26/100)*B22*2116.8*28*60/(1545*(460+B25)*1000000)) . . . . . . . . . . . . . . . See Note C
A:C74: (,1) [W18] (C13*0.15) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Heat Input * Emission Factor
A:D74: (,1) [W18] (D76*(1-D26/100)*D22*2116.8*28*60/(1545*(460+D25)*1000000)) . . . . . . . . . . . . . . . See Note C
A:E74: [W6] (E73+1)
A:A75: [W24] '  TPY
A:B75: (F2) [W18] (B74*8760/2000)
A:C75: (F2) [W18] (C74*4.38*0.3)
A:D75: (,1) [W18] (D74*219/2000)
A:E75: [W6] (E74+1)
A:A76: [W24] '  ppm
A:B76: (,1) [W18] 75
A:C76: (,1) [W18] "NA
A:D76: (,1) [W18] 75
A:E76: [W6] (E75+1)
A:E77: [W6] (E76+1)
A:A78: [W24] 'VOC's:
A:E78: [W6] (E77+1)
A:A79: [W24] '  Basis
A:B79: (,1) [W18] "4 ppm+
A:C79: (,1) [W18] "0.043 lb/mmBtu
A:D79: (,1) [W18] "10 ppm+
A:E79: [W6] (E78+1)
A:A80: [W24] '  lb/hr
A:B80: (F2) [W18] (B82*(1-B26/100)*B22*2116.8*12*60/(1545*(460+B25)*1000000)) . . . . . . . . . . . . . . . See Note C
A:C80: (F2) [W18] (C13*0.043)
A:D80: (F2) [W18] (D82*(1-D26/100)*D22*2116.8*12*60/(1545*(460+D25)*1000000)) . . . . . . . . . . . . . . . See Note C
```

```
A:E80: [W6] (E79+1)
A:A81: [W24] '  TPY
A:B81: (,1) [W18] (B80*8760/2000)
A:C81: (F2) [W18] (C80*4.38*0.3)
A:D81: (,1) [W18] (D80*219/2000)
A:E81: [W6] (E80+1)
A:A82: [W24] '  ppm
A:B82: (,1) [W18] 4
A:C82: (,1) [W18] "NA
A:D82: (,1) [W18] 10
A:E82: [W6] (E81+1)
A:E83: [W6] (E82+1)
A:A84: [W24] 'Lead:
A:E84: [W6] (E83+1)
A:A85: [W24] '  Basis
A:D85: [W18] "EPA(1988)
A:E85: [W6] (E84+1)
A:A86: [W24] '  lb/hr
A:B86: (S2) [W18] "NA
A:C86: (S2) [W18] "NA
A:D86: (S2) [W18] (D13*8.9/1000000) . . . . . . . . . . . . . .  From EPA 1988; Page 4-156; Heat Input * Emission Factor
A:E86: [W6] (E85+1)
A:A87: [W24] '  TPY
A:B87: (S2) [W18] "NA
A:C87: (S2) [W18] "NA
A:D87: (S2) [W18] (D86*219/2000)
A:E87: [W6] (E86+1)
A:A88: [W24] \_
A:B88: [W18] \_
A:C88: [W18] \_
A:D88: [W18] \_
A:E88: [W6] (E87+1)
A:E89: [W6] (E88+1)
A:A90: [W24] '* corrected to 15% O2 dry conditions
A:E90: [W6] (E89+1)
A:A91: [W24] '+ corrected to dry conditions
A:E91: [W6] (E90+1)
A:A92: [W24] 'Note: Annual emission for CT when firning natural gas based on 8,760 hrs/yr
A:E92: [W6] (E91+1)
A:A93: [W24] '      and 219 hrs/yr for fuel oil firing.  Annual emissions for duct burners
A:E93: [W6] (E92+1)
A:A94: [W24] '      on 2,628 hrs/yr (30% capacity factor).
A:E94: [W6] (E93+1)
```

```
A:A96: [W24] 'Table A-3.  Maximum Other Regulated Pollutant Emissions for UF
A:E96: [W6] 96
A:A97: [W24] '          Cogeneration Project
A:E97: [W6] (E96+1)
A:A98: [W24] \_
A:B98: [W18] \_
A:C98: [W18] \_
A:D98: [W18] \_
A:E98: [W6] (E97+1)
A:E99: [W6] (E98+1)
A:A100: [W24] ^Pollutant
A:B100: [W18] "Gas Turbine
A:C100: [W18] "Duct Burner
A:D100: [W18] "Gas Turbine
A:E100: [W6] (E99+1)
A:B101: [W18] "Natural Gas
A:C101: [W18] "Natural Gas
A:D101: [W18] "No.2 Oil
A:E101: [W6] (E100+1)
A:A102: [W24] ^A
A:B102: [W18] "B
A:C102: [W18] "C
A:D102: [W18] "D
A:E102: [W6] (E101+1)
A:A103: [W24] \_
A:B103: [W18] \_
A:C103: [W18] \_
A:D103: [W18] \_
A:E103: [W6] (E102+1)
A:E104: [W6] (E103+1)
A:A105: [W24] '  As (lb/hr)
A:B105: [W18] "NEG.
A:C105: [W18] "NEG.
A:D105: [W18] (D13*4.2/1000000) . . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1988, See Table 4-1
A:E105: [W6] (E104+1)
A:A106: [W24] '     (TPY)
A:B106: [W18] "NEG.
A:C106: [W18] "NEG.
A:D106: (S2) [W18] (D105*219/2000)
A:E106: [W6] (E105+1)
A:E107: [W6] (E106+1)
A:A108: [W24] '  Be (lb/hr)
A:B108: [W18] "NEG.
A:C108: [W18] "NEG.
A:D108: [W18] (D13*2.5/1000000) . . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1988, See Table 4-1
A:E108: [W6] (E107+1)
A:A109: [W24] '     (TPY)
A:B109: [W18] "NEG.
A:C109: [W18] "NEG.
A:D109: (S2) [W18] (D108*219/2000)
A:E109: [W6] (E108+1)
A:E110: [W6] (E109+1)
A:A111: [W24] '  Hg (lb/hr)
A:B111: [W18] "NEG.
A:C111: [W18] "NEG.
A:D111: (S2) [W18] (D13*3/1000000) . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1988, See Table 4-1
A:E111: [W6] (E110+1)
A:A112: [W24] '     (TPY)
A:B112: [W18] "NEG.
A:C112: [W18] "NEG.
A:D112: (S2) [W18] (D111*219/2000)
A:E112: [W6] (E111+1)
```

A:E113: [W6] (E112+1)
A:A114: [W24] ' F (lb/hr)
A:B114: [W18] "NEG.
A:C114: [W18] "NEG.
A:D114: [W18] (D13*32.5/1000000) . . . . From EPA 1981; Table 6-1, 2.324 pq/J * 14 pq/J = 32.5 lb/10^6 BTU
A:E114: [W6] (E113+1)
A:A115: [W24] ' (TPY)
A:B115: [W18] "NEG.
A:C115: [W18] "NEG.
A:D115: (S2) [W18] (D114*219/2000)
A:E115: [W6] (E114+1)
A:E116: [W6] (E115+1)
A:A117: [W24] ' H2SO4 (lb/hr)
A:B117: (S2) [W18] (B63*0.05*3.06/2) . . . . SO_2 Emission * 0.005 (%H_2SO_4 Formed) * MW_{H2SO4}/MW_{SO2}
A:C117: (S2) [W18] (C63*0.05*3.06/2) . . . . SO_2 emissions * %H_2SO_4 formed (5%) * MW_{H2SO4}/MW_{SO2} * correction to total SO_2
A:D117: (S2) [W18] (D63*0.05*3.06/2)
A:E117: [W6] (E116+1)
A:A118: [W24] ' (TPY)
A:B118: (S2) [W18] (B117*8760/2000)
A:C118: (F2) [W18] (C117*4.38*0.3)
A:D118: (S2) [W18] (D117*219/2000)
A:E118: [W6] (E117+1)
A:E119: [W6] (E118+1)
A:A120: [W24] _
A:B120: [W18] _
A:C120: [W18] _
A:D120: [W18] _
A:E120: [W6] (E119+1)
A:E121: [W6] (E120+1)
A:A122: [W24] 'Sources: EPA, 1988; EPA, 1980
A:E122: [W6] (E121+1)

```
A:A125: [W24] 'Table A-4.  Maximum Non-Regulated Pollutant Emissions for UF
A:E125: [W6] 125
A:A126: [W24] '          Cogeneration Project
A:E126: [W6] (E125+1)
A:A127: [W24] \_
A:B127: [W18] \_
A:C127: [W18] \_
A:D127: [W18] \_
A:E127: [W6] (E126+1)
A:E128: [W6] (E127+1)
A:A129: [W24] ^Pollutant
A:B129: [W18] "Gas Turbine
A:C129: [W18] "Duct Burner
A:D129: [W18] "Gas Turbine
A:E129: [W6] (E128+1)
A:B130: [W18] "Natural Gas
A:C130: [W18] "Natural Gas
A:D130: [W18] "No.2 Oil
A:E130: [W6] (E129+1)
A:A131: [W24] ^A
A:B131: [W18] "B
A:C131: [W18] "C
A:D131: [W18] "D
A:E131: [W6] (E130+1)
A:A132: [W24] \_
A:B132: [W18] \_
A:C132: [W18] \_
A:D132: [W18] \_
A:E132: [W6] (E131+1)
A:E133: [W6] (E132+1)
A:A134: [W24] '  Manganese (lb/hr)
A:B134: [W18] "NEG.
A:C134: [W18] "NEG.
A:D134: (S2) [W18] (D13*6.44/1000000) . . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1988, See Table 4-1
A:E134: [W6] (E133+1)
A:A135: [W24] '     (TPY)
A:B135: [W18] "NEG.
A:C135: [W18] "NEG.
A:D135: (S2) [W18] (D134*219/2000)
A:E135: [W6] (E134+1)
A:E136: [W6] (E135+1)
A:A137: [W24] '  Nickel (lb/hr)
A:B137: [W18] "NEG.
A:C137: [W18] "NEG.
A:D137: (S2) [W18] (D13*170/1000000)  . . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1988, See Table 4-1
A:E137: [W6] (E136+1)
A:A138: [W24] '     (TPY)
A:B138: [W18] "NEG.
A:C138: [W18] "NEG.
A:D138: (S2) [W18] (D137*219/2000)
A:E138: [W6] (E137+1)
A:E139: [W6] (E138+1)
A:A140: [W24] '  Cadmium (lb/hr)
A:B140: [W18] "NEG.
A:C140: [W18] "NEG.
A:D140: (S2) [W18] (D13*10.5/1000000) . . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1988, See Table 4-1
A:E140: [W6] (E139+1)
A:A141: [W24] '     (TPY)
A:B141: [W18] "NEG.
A:C141: [W18] "NEG.
A:D141: (S2) [W18] (D140*219/2000)
A:E141: [W6] (E140+1)
```

```
A:E142: [W6] (E141+1)
A:A143: [W24] '  Chromium (lb/hr)
A:B143: [W18] "NEG.
A:C143: [W18] "NEG.
A:D143: (S2) [W18] (D13*47.5/1000000) . . . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1988, See Table 4-1
A:E143: [W6] (E142+1)
A:A144: [W24] '     (TPY)
A:B144: [W18] "NEG.
A:C144: [W18] "NEG.
A:D144: (S2) [W18] (D143*219/2000)
A:E144: [W6] (E143+1)
A:E145: [W6] (E144+1)
A:A146: [W24] '  Copper (lb/hr)
A:B146: [W18] "NEG.
A:C146: [W18] "NEG.
A:D146: (S2) [W18] (D13*280/1000000)  . . . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1988, See Table 4-1
A:E146: [W6] (E145+1)
A:A147: [W24] '     (TPY)
A:B147: [W18] "NEG.
A:C147: [W18] "NEG.
A:D147: (S2) [W18] (D146*219/2000)
A:E147: [W6] (E146+1)
A:E148: [W6] (E147+1)
A:A149: [W24] '  Vanadium (lb/hr)
A:B149: [W18] "NEG.
A:C149: [W18] "NEG.
A:D149: (S2) [W18] (D13*30*2.324/1000000) . . . . . . . . . . From EPA 1988, See Page 4-162; 2.324 pq/J = 1 lb/10^6 BTU
A:E149: [W6] (E148+1)
A:A150: [W24] '      (TPY)
A:B150: [W18] "NEG.
A:C150: [W18] "NEG.
A:D150: (S2) [W18] (D149*219/2000)
A:E150: [W6] (E149+1)
A:E151: [W6] (E150+1)
A:A152: [W24] '  Selenium (lb/hr)
A:B152: [W18] "NEG.
A:C152: [W18] "NEG.
A:D152: (S2) [W18] (D13*10.1*2.324/1000000) . . . . . . . . . . . . . . . . . . . . . . . .  From EPA 1988, See Page 4-162
A:E152: [W6] (E151+1)
A:A153: [W24] '     (TPY)
A:B153: [W18] "NEG.
A:C153: [W18] "NEG.
A:D153: (S2) [W18] (D152*219/2000)
A:E153: [W6] (E152+1)
A:E154: [W6] (E153+1)
A:A155: [W24] '  POM (lb/hr)
A:B155: (S2) [W18] ($B$13*0.48*2.324/1000000) . . . . . . . . . . . . . . . . . . . . . .  From EPA 1988, See Page 4-161
A:C155: (S2) [W18] ($C$13*0.48*2.324/1000000)
A:D155: (S2) [W18] ($D$13*0.12*2.324/1000000)
A:E155: [W6] (E154+1)
A:A156: [W24] '     (TPY)
A:B156: (S2) [W18] (B155*8760/2000)
A:C156: (S2) [W18] (C155*4.38*0.3)
A:D156: (S2) [W18] (D155*219/2000)
A:E156: [W6] (E155+1)
A:E157: [W6] (E156+1)
A:A158: [W24] '  Formaldehyde (lb/hr)
A:B158: (S2) [W18] ($B$13*38*2.324/1000000) . . . . . . . . . . . . . . . . . . . . . . .  From EPA 1988, See Page 4-156
A:C158: (S2) [W18] ($C$13*405/1000000)
A:D158: (S2) [W18] ($D$13*405/1000000)
A:E158: [W6] (E157+1)
A:A159: [W24] '     (TPY)
```

```
A:B159: (S2) [W18] (B158*8760/2000)
A:C159: (S2) [W18] (C158*4.38*0.3)
A:D159: (S2) [W18] (D158*219/2000)
A:E159: [W6] (E158+1)
A:A160: [W24] \_
A:B160: [W18] \_
A:C160: [W18] \_
A:D160: [W18] \_
A:E160: [W6] (E159+1)
A:E161: [W6] (E160+1)
A:E162: [W6] (E161+1)
```

```
A:A165: [W24] 'Table A-5.  Maximum Emissions for Additional Non-Regulated Pollutant
A:E165: [W6] 165
A:A166: [W24] '            for  UF Cogeneration Project
A:E166: [W6] (E165+1)
A:A167: [W24] \_
A:B167: [W18] \_
A:C167: [W18] \_
A:D167: [W18] \_
A:E167: [W6] (E166+1)
A:E168: [W6] (E167+1)
A:A169: [W24] ^Pollutant
A:B169: [W18] "Gas Turbine
A:C169: [W18] "Duct Burner
A:D169: [W18] "Gas Turbine
A:E169: [W6] (E168+1)
A:B170: [W18] "Natural Gas
A:C170: [W18] "Natural Gas
A:D170: [W18] "No.2 Oil
A:E170: [W6] (E169+1)
A:A171: [W24] ^A
A:B171: [W18] "B
A:C171: [W18] "C
A:D171: [W18] "D
A:E171: [W6] (E170+1)
A:A172: [W24] \_
A:B172: [W18] \_
A:C172: [W18] \_
A:D172: [W18] \_
A:E172: [W6] (E171+1)
A:E173: [W6] (E172+1)
A:A174: [W24] '  Antimony (lb/hr)
A:B174: [W18] "NEG.
A:C174: [W18] "NEG.
A:D174: (S2) [W18] ($D$13*9.4*2.324/1000000) . . . . . . . . . . . . . . . . . . . . . . . .  From EPA 1979, See Page 137
A:E174: [W6] (E173+1)
A:A175: [W24] '     (TPY)
A:B175: [W18] "NEG.
A:C175: [W18] "NEG.
A:D175: (S2) [W18] (D174*219/2000)
A:E175: [W6] (E174+1)
A:E176: [W6] (E175+1)
A:A177: [W24] '  Barium (lb/hr)
A:B177: [W18] "NEG.
A:C177: [W18] "NEG.
A:D177: (S2) [W18] ($D$13*8.4*2.324/1000000) . . . . . . . . . . . . . . . . . . . . . . . .  From EPA 1979, See Page 137
A:E177: [W6] (E176+1)
A:A178: [W24] '     (TPY)
A:B178: [W18] "NEG.
A:C178: [W18] "NEG.
A:D178: (S2) [W18] (D177*219/2000)
A:E178: [W6] (E177+1)
A:E179: [W6] (E178+1)
A:A180: [W24] '  Colbalt (lb/hr)
A:B180: [W18] "NEG.
A:C180: [W18] "NEG.
A:D180: (S2) [W18] ($D$13*3.9*2.324/1000000) . . . . . . . . . . . . . . . . . . . . . . . .  From EPA 1979, See Page 137
A:E180: [W6] (E179+1)
A:A181: [W24] '     (TPY)
A:B181: [W18] "NEG.
A:C181: [W18] "NEG.
A:D181: (S2) [W18] (D180*219/2000)
A:E181: [W6] (E180+1)
```

```
A:E182: [W6] (E181+1)
A:A183: [W24] '  Zinc (lb/hr)
A:B183: [W18] "NEG.
A:C183: [W18] "NEG.
A:D183: (S2) [W18] ($D$13*294*2.324/1000000) . . . . . . . . . . . . . . . . . . . . . . From EPA 1979, See Page 137
A:E183: [W6] (E182+1)
A:A184: [W24] '    (TPY)
A:B184: [W18] "NEG.
A:C184: [W18] "NEG.
A:D184: (S2) [W18] (D183*219/2000)
A:E184: [W6] (E183+1)
A:E185: [W6] (E184+1)
A:A186: [W24] '  Chlorine^a (lb/hr)
A:B186: [W18] "NEG.
A:C186: [W18] "NEG.
A:D186: (S2) [W18] (D14*0.5/1000000) . . . . . . . . . . . . . . . . . . . . . . . . . . 0.5 ppm in Fuel Oil Assumed
A:E186: [W6] (E185+1)
A:A187: [W24] '    (TPY)
A:B187: [W18] "NEG.
A:C187: [W18] "NEG.
A:D187: (S2) [W18] (D186*219/2000)
A:E187: [W6] (E186+1)
A:A188: [W24] \_
A:B188: [W18] \_
A:C188: [W18] \_
A:D188: [W18] \_
A:E188: [W6] (E187+1)
A:E189: [W6] (E188+1)
A:A190: [W24] 'Source: EPA, 1979
A:E190: [W6] (E189+1)
A:A191: [W24] '  ^a Assumes 0.5 ppm in fuel oil.
A:E191: [W6] (E190+1)
```

EMISSION FACTORS AND CALCULATIONS

Emission factors used in the calculations were obtained from the following sources (references attached):

1. Compilation of air pollutant emiission factors (AP-42) for PM, SO_2, NO_x, CO, and VOC.

2. Estimating air toxics from coal and oil combustion sources (EPA, 1989) for As, Be, Pb, and Hg.

3. Emissions Assessment of Conventional Stationary Combustion Systems: Volume V: Industrial Combustion Sources (EPA, 1981) for F.

The conversions from $lb/10^{-12}$ Btu to $lb/10^3$ gal were calculated as follows:

Residual Oil - EF $lb/10^{12}$ Btu * 18,300 Btu/lb oil * 8.2 lb oil/gal

* $1,000/10^3$ - 1.5×10^{-4} * EF $lb/10^3$ gal

where: EF - emission factor

Distillate Oil - EF $lb/10^{12}$ Btu * 20,996/lb oil * 7.2 lb/gal

* $1,000/10^3$ - 1.512×10^{-4} * EF $lb/10^3$ gal

The conversion from pg/J to $lb/10^{12}$ Btu is as follows:

pg/J * 10^{-12} g/pg * lb/454 grams * 1,055 J/Btu - 2.324 $lb/10^{12}$ Btu

A

Volume is calculated based on ideal gas law:

PV - mRT/M
V - mRT/(MP) for natural gas

where:
P - pressure - 2116.8 lb/ft^2
m - mass flow of gas (lb/hr)
R - universal gas constant - 1545 ft-lb/lb-mole °R
M - molecular weight of gas
T - temperature (K)

B

NO_x is calculated by correcting to 15% O_2 dry conditions using ideal gas law and moisture and O_2 conditions.

Oxygen correction:

$$V_{NOx\ (15\%)} = \frac{V_{NOx\ Dry} * 5.9}{20.9 - \%O_{2\ Dry}}$$

$$V_{NOx\ Dry} = V_{NOx\ (15\%)}\ (20.9 - \%O_{2\ Dry})\ /\ 5.9$$

$$\%O_{2\ Dry} = \%O_{2\ Act}\ /\ (1 - \%H_2O)\ ;\ \%O_{2\ Act} = \%O_{2\ Dry}\ (1 - \%H_2O)$$

$$V_{NOx\ Act} = V_{NOx\ Dry}\ (1 - \%H_2O)$$

Substituting:

$$V_{NOx\ Act} = V_{NOx\ 15\%}\ (20.9 - \%O_{2\ Dry})\ (1 - \%H_2O)\ /\ 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9 - (\%O_{2\ Act}\ /\ (1 - \%H_2O))]\ (1 - \%H_2O)\ /\ 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2)\ /\ 5.9$$

$$m_{NOx} = \frac{PVM_{NOx}}{RT} = V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2) * P * M_{NOx}\ /\ (RT * 5.9)$$

C

CO and VOC are calculated by correcting for moisture using ideal gas law. Same as NO_x calculation except only moisture correction is used:

$$V_{CO\ Act} = V_{CO\ Dry}\ (1 - \%H_2O)$$

$$m_{CO} = PV_{CO\ Act}M_{CO}\ /\ RT$$
$$= PV_{CO\ Dry}\ (1 - \%H_2O)\ M_{CO}\ /\ RT$$

pg/J = picograms per joule

AP-42
SUPPLEMENT C
SEPTEMBER 1990

SUPPLEMENT C

TO

COMPILATION OF AIR POLLUTANT EMISSION FACTORS

VOLUME I: STATIONARY POINT AND AREA SOURCES

TABLE 1.4-1. UNCONTROLLED EMISSION FACTORS FOR NATURAL GAS COMBUSTION[a]

Furnace size & type (10^6 Btu/hr heat input)	Particulate[b]		Sulfur dioxide[c]		Nitrogen oxides[d]		Carbon monoxide[e]		Volatile organics			
									Nonmethane		Methane	
	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$
Utility boilers (> 100)	16 - 80	1 - 5	9.6	0.6	8800[h]	550[h]	640	40	23	1.4	4.8	0.3
Industrial boilers (10 - 100)	16 - 80	1 - 5	9.6	0.6	2240	140	560	35	44	2.8	48	3
Domestic and commercial boilers (< 10)	16 - 80	1 - 5	9.6	0.6	1600	100	320	20	84	5.3	43	2.7

[a]Expressed as weight/volume fuel fired.
[b]References 15-18.
[c]Reference 4. Based on avg. sulfur content of natural gas, 4600 $g/10^6 Nm^3$ (2000 $gr/10^6$ scf).
[d]References 4-5, 7-8, 11, 14, 18-19, 21.
[e]Expressed as NO_2. Tests indicate about 95 weight % NO_x is NO_2.
[f]References 4, 7-8, 16, 18, 22-25.
[g]References 16, 18. May increase 10 - 100 times with improper operation or maintenance.
[h]For tangentially fired units, use 4400 $kg/10^6 m^3$ (275 $lb/10^6 ft^3$). At reduced loads, multiply factor by load reduction coefficient in Figure 1.4-1. For potential NO_x reductions by combustion modification, see text. Note that NO_x reduction from these modifications will also occur at reduced load conditions.

TABLE 1.3-1. UNCONTROLLED EMISSION FACTORS FOR FUEL OIL COMBUSTION

EMISSION FACTOR RATING: A

Boiler Type[a]	Particulate Matter[b]		Sulfur Dioxide[c]		Sulfur Trioxide		Carbon Monoxide[d]		Nitrogen Oxide[e]		Volatile Organics[f] Nonmethane		Volatile Organics[f] Methane	
	kg/10³l	lb/10³gal	kg/10³l	lb/10³gal	kg/10³l	lb/10³gal	kg/10³l	lb/10³gal	kg/10³l	lb/10³gal	kg/10³l	lb/10³gal	kg/10³l	lb/10³gal
Utility Boilers														
Residual Oil	g	g	19S	157S	0.34S[h]	2.9S[h]	0.6	5	8.0 (12.6)(5)[i]	67 (105)(42)[i]	0.09	0.76	0.03	0.28
Industrial Boilers														
Residual Oil	g	g	19S	157S	0.24S	2S	0.6	5	6.6[j]	55[j]	0.034	0.28	0.12	1.0
Distillate Oil	0.24	2	17S	142S	0.24S	2S	0.6	5	2.4	20	0.024	0.2	0.006	0.052
Commercial Boilers														
Residual Oil	g	g	19S	157S	0.24S	2S	0.6	5	6.6	55	0.14	1.13	0.057	0.475
Distillate Oil	0.24	2	17S	142S	0.24S	2S	0.6	5	2.4	20	0.04	0.34	0.026	0.216
Residential Furnaces														
Distillate Oil	0.3	2.5	17S	142S	0.24S	2S	0.6	5	2.2	18	0.085	0.713	0.214	1.78

[a] Boilers can be approximately classified according to their gross (higher) heat rate as shown below:
- Utility (power plant) boilers: >106 x 10^9 J/hr (>100 x 10^6 Btu/hr)
- Industrial boilers: 10.6 x 10^9 to 106 x 10^9 J/hr (10 x 10^6 to 100 x 10^6 Btu/hr)
- Commercial boilers: 0.5 x 10^9 to 10.6 x 10^9 J/hr (0.5 x 10^6 to 10 x 10^6 Btu/hr)
- Residential furnaces: <0.5 x 10^9 J/hr (<0.5 x 10^6 Btu/hr)

[b] References 3-7 and 24-25. Particulate matter is defined in this section as that material collected by EPA Method 5 (front half catch).

[c] References 1-5. S indicates that the weight % of sulfur in the oil should be multiplied by the value given.

[d] References 3-5 and 8-10. Carbon monoxide emissions may increase by factors of 10 to 100 if the unit is improperly operated or not well maintained.

[e] Expressed as NO_2. References 1-5, 8-11, 17 and 26. Test results indicate that at least 95% by weight of NO_x is NO for all boiler types except residential furnaces, where about 75% is NO.

[f] References 18-21. Volatile organic compound emissions are generally negligible unless boiler is improperly operated or not well maintained, in which case emissions may increase by several orders of magnitude.

[g] Particulate emission factors for residual oil combustion are, on average, a function of fuel oil grade and sulfur content:
- Grade 6 oil: 1.25(S) + 0.38 kg/10^3 liter [10(S) + 3 lb/10^3 gal] where S is the weight % of sulfur in the oil. This relationship is based on 81 individual tests and has a correlation coefficient of 0.65.
- Grade 5 oil: 1.25 kg/10^3 liter (10 lb/10^3 gal)
- Grade 4 oil: 0.88 kg/10^3 liter (7 lb/10^3 gal)

[h] Reference 25.

[i] Use 5 kg/10^3 liters (42 lb/10^3 gal) for tangentially fired boilers, 12.6 kg/10^3 liters (105 lb/10^3gal) for vertical fired boilers, and 8.0 kg/10^3 liters (67 lb/10^3 gal) for all others, at full load and normal (>15%) excess air. Several combustion modifications can be employed for NO_x reduction: (1) limited excess air can reduce NO_x emissions 5-20%, (2) staged combustion 20-40%, (3) using low NO_x burners 20-50%, and (4) ammonia injection can reduce NO_x emissions 40-70% but may increase emissions of ammonia. Combinations of these modifications have been employed for further reductions in certain boilers. See Reference 23 for a discussion of these and other NO_x reducing techniques and their operational and environmental impacts.

[j] Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are strongly related to fuel nitrogen content, estimated more accurately by the empirical relationship:

kg NO_2/10^3 liters = 2.75 + $50(N)^2$ [lb NO_2/10^3gal = 22 + $400(N)^2$] where N is the weight % of nitrogen in the oil. For residual oils having high (>0.5 weight %) nitrogen content, use 15 kg NO_2/10^3 liter (120 lb NO_2/10^3gal) as an emission factor.

PB89-194229

United States
Environmental Protection
Agency

Office of Air Quality
Planning And Standards
Research Triangle Park, NC 27711

EPA-450/2-89-001
April 1989

AIR

EPA

ESTIMATING AIR TOXICS EMISSIONS FROM COAL AND OIL COMBUSTION SOURCES

TABLE 4-1. SUMMARY OF TOXIC POLLUTANT EMISSION FACTORS FOR OIL COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^{12}$ Btu) Residual Oil	Distillate Oil
Arsenic	19	4.2
Beryllium	4.2	2.5
Cadmium	15.7	10.5
Chromium	21	48
Copper	280	280
Lead	28[c]	8.9[d]
Mercury	3.2	3.0
Manganese	26	14
Nickel	1260	170
POM	8.4[b]	22.5
Formaldehyde	405[e]	405[e]

[a]All emission factors are uncontrolled, and are applicable to oil-fired boilers and furnaces in all combustion sectors unless otherwise noted.

[b]This value was calculated using all available residual oil data given in Table 4-35. If the upper end of the range of available data is excluded when calculating an average value (which could be used in this table), the average factor for POM from residual oil combustion becomes 4.1 $lb/10^{12}$ BTU.

[c]Applicable to utility boilers only.

[d]Applicable to industrial, commercial, and residential boilers.

[e]The formaldehyde factors are based on very limited and relatively old data. Consult Table 4-37 and accompanying discussion for more detailed information.

PB81-225559

Emissions Assessment of Conventional Stationary Combustion Systems: Volume V: Industrial Combustion Sources

TRW, Inc.
Redondo Beach, CA

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

1981

U.S. Department of Commerce
National Technical Information Service

TABLE 61. COMPARISON OF EXISTING TRACE ELEMENT EMISSION FACTOR DATA WITH RESULTS OF CURRENT STUDY OF OIL-FIRED INDUSTRIAL COMBUSTION SOURCES, pg/J

Element	Distillate oil-fired boilers			Residual oil-fired boilers			
		Existing data			Existing data		
	Current study	Ref. 42	Ref. 43	Current study	Ref. 42	Ref. 21	Ref. 28
Aluminum (Al)	178	15	250	177	156	87	132
Arsenic (As)	3.5	1.3	1.5	1.2	9.1	18	12
Barium (Ba)	1.2	8.4	16	3.3	9.5	29	31
Calcium (Ca)	75	845	450	229	780	[illegible]	[illegible]3
Cadmium (Cd)	1.3	2.5	11	0.66	[illegible]	[illegible]	[illegible].9
Cobalt (Co)	3.8	2.3	1.0	11	[illegible]	[illegible]	[illegible]
Chromium (Cr)	24	36	29	29	[illegible]	[illegible]	[illegible]
Copper (Cu)	37	205	160	10	[illegible]	[illegible]	[illegible]
Fluorine (F)	—	$\boxed{14}$	—	—	[illegible]	[illegible]	[illegible]
Iron (Fe)	363	545	140	83	[illegible]	[illegible]	[illegible]
Mercury (Hg)	—	1.7	1.2	—	[illegible]	[illegible]	5
Potassium (K)	85	60	230	261	2[illegible]	[illegible]	[illegible]
Lithium (Li)	0.5	1.5	1.2	1.1	[illegible]	[illegible].4	1.7
Magnesium (Mg)	42	40	210	24	111	297	2384
Nickel (Ni)	255	112	290	728	804	964	433
Lead (Pb)	24	48	42	2	7	80	34
Antimony (Sb)	—	1.7	5.7	—	21	10	25
Silicon (Si)	735	173	—	8655	1610	400	595
Vanadium (V)	195	30	2.9	366	250	3656	714
Zinc (Zn)	42	40	110	33	46	29	66

[illegible]-FL-18 10/29/[illegible]

Ave. 50.9

UF COGENERATION PROJECT
EXAMPLE CALCULATIONS - NATURAL GAS

ROWS listed below correspond to the ROW listed in Table.

Table A-1: (Note: all other data not calculated but supplied by manufacturer)

ROW 13--Heat Input (10^6BTU/hr):

Power (kw) x Heat Rate (10^6BTU/kwh)

$43{,}262.0 \times 8{,}043/10^6 = 348.0 \times 10^6$ BTU/hr

ROW 14--Natural Gas (lb/hr):

Heat Input (10^6BTU/hr) ÷ Fuel Heat Content (BTU/lb)

$348.0 \times 10^6 \div 19{,}000 = 18{,}313.5$ lb/hr

Note: 19,000 is input as 0.019 since heat input is in 10^6BTU, i.e. 348.0

ROW 15--Natural Gas (CF/hr):

Heat input (10^6BTU/hr) ÷ Heat content (BTU/CF)

$348.0 \times 10^6 \div 946 = 367{,}818.5$ CF/hr

ROW 21--Volume Flow (acfm) - See Note A in emission factors and calculations:

V = mRT/PM

1,036,552 lb/hr x 1,545 x (785 + 460°K) ÷ (27.8 x 2,116.8 lb/ft^2) ÷ 60(min/hr)

= 564,678 acfm

ROW 22--Volume Flow (scfm) - See Note A:

Same as ROW 21 except adjusted for standard temperature of 68°F

1,036,552 lb/hr x 1,545 x (941 + 68°K) ÷ (27.8 x 2,116.8) ÷ 60

= 239,478 scfm

ROW 32--Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

564,678 (acfm) x (257 +460°K) ÷ (785 ÷ 460°K)

= 325,200 acfm

ROW 35--Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

325,200 ft^3/min ÷ 60 ÷ (10^2 ÷ 4 x 3.14159)

= 72.59 ft/sec

<u>Table A-2</u>:

ROWS 59, 64, 69, 75, 81, 118, 156, and 159--(Except Duct Burner) :

Emissions in Tons per year; example for particulate:

2.5 lb/hr x 8,760 hrs/yr ÷ 2,000 lb/ton

= 10.95 ton/yr

For Duct Burner and Oil Firing capacity factors were used. Example for duct burner:
1.87 lb/hour x 0.30 x 8,760 ÷ 2,000 = 2.46 tons per year.

ROW 63--SO_2 Emissions (lb/hr):

367,818.5 cf/hr x 1 gr ÷ 7,000 gr/lb x 2 lb SO_2/lbS ÷100 cf

= 2.82 lb/hr

ROW 68--NO_x Emissions (lb/hr) - See Note B:

25 ppm x [20.9 ÷ 5.9 (1 - 6.1/100) - 14.4] x 2,116.8 lb/ft^2 x 564,678 ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (785 + 460°K) x 10^6 (adjust for ppm)]

= 35.0 lb/hr

ROW 74 and 80--CO, VOC Emissions (lb/hr) - See Note C example for VOC shown:

4 ppm x (1-6.1/100) x 564,678 acfm x 2,116.8 lb/ft^2 x 12 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (785 +460) + 10^6)

= 1.59 lb/hr

Table A-3:

Emission factors for oil presented in Table 4-1 of EPA (1989) multiplied by heat input; example for arsenic: 382.6 x 10^6 Btu/hour x 4.216/10^{12} Btu = 0.0016 lb/hour

ROW 117--H_2SO_4 Mist Emission (lb/hr):

Based on 5 percent SO_2 converted to acid mist

1.05 lb SO_2/hr x 0.05 x 98 ÷ 64 (or a ratio 3.06/2)

= 8.04 x 10^2

Table A-4:

Emission factor multiplied by heat input

U.S. DEPARTMENT OF COMMERCE
National Technical Information Service
PB-296 390

Emission Assessment of Conventional Stationary Combustion Systems; Volume II Internal Combustion Sources

TRW, Inc, Redondo Beach, CA

Prepared for

Industrial Environmental Research Lab, Research Triangle Park, NC

Feb 1979

TABLE 52. COMPARISON OF TRACE ELEMENT EMISSION FACTORS FOR DISTILLATE OIL-FUELED GAS TURBINES AND DISTILLATE OIL ENGINES

Trace Element	Mean Emission Factor, pg/J	
	Distillate Oil Fueled Gas Turbine	Distillate Oil Reciprocating Engine
Aluminum	64	66
Antimony	9.4	12
Arsenic	2.1	2.2
Barium	8.4	14
Beryllium	0.14	0.03
Boron	28	11
Bromine	1.8	4.0
Cadmium	1.8	3.1
Calcium	330	237
Chromium	20	26
Cobalt	3.9	5.7
Copper	578	453
Iron	256	325
Lead	25	26
Magnesium	100	44
Manganese	145	16
Mercury	0.39	0.13
Molybdenum	3.6	12.5
Nickel	526.	564
Phosphorus	127	97
Potassium	185	179
Selenium	2.3	2.1
Silicon	575	301
Sodium	590	1625
Tin	35	9.1
Vanadium	1.9	0.95
Zinc	294	178

EPA-450/2-88-006
October 1988

Toxic Air Pollutant Emission Factors—A Compilation For Selected Air Toxic Compounds And Sources

By
Anne A. Pope
Air Quality Management Division
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

Patricia A. Cruse
Claire C. Most
Radian Corporation
Research Triangle Park, North Carolina 27709

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office Of Air And Radiation
Office Of Air Quality Planning And Standards
Research Triangle Park, North Carolina 27711

October 1988

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		Scotch marine boilers, distillate oil	10300501	POM		17.7 pg/J	Uncontrolled	114
Oil combustion		Cast iron sectional boilers, distillate oil	10300501	POM		<14.9 pg/J	Uncontrolled, home heating application	114
Oil combustion		Hot air furnace, distillate oil	10300501	POM		<0.14 pg/J	Uncontrolled, same reference also lists <15.4 for same boiler/fuel type	114
Oil combustion	49	Boiler flue gas	1	Tetrachlorodibenzo-p-dioxin, 2,3,7,8-	1746016	Not detectable	Low ash, 2% sulfur oil, sampled after heat exch., before ESP, 2378-TCDD detec. limit=<4.2-<7.9 ng/m3	119
Oil combustion	49	Flue gas	1	Tetrachlorodibenzofuran, 2,3,7,8-	51207319	Not detectable	Low ash, 2% sulfur oil, sampled after heat exch., before ESP, 2378-TCDD detec. limit=<0.67-<1.3ng/m3	119
Oil combustion, commercial		Residual oil-fired tangential furnaces	103004	Vanadium	7440622	3660 pg/J	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, commercial		Residual oil-fired wall furnaces	103004	Vanadium	7440622	3660 pg/J	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, commercial		Tangential furnace, residual oil	103004	Selenium	7782492	10.1 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Wall furnace, residual oil	103004	Selenium	7782492	10.1 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Scotch marine boilers, residual oil	10300401	POM		0.95 pg/J heat input	Uncontrolled, represents benzo(a)pyrene only	114
Oil combustion, commercial		Distillate oil-fired tangential furnaces	103005	Vanadium	7440622	30.0 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Distillate oil-fired wall furnaces	103005	Vanadium	7440622	30.0 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Tangential furnace, distillate oil	103005	Selenium	7782492	10.1 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54

Page 4-162

KBN

January 30, 1992

RECEIVED
JAN 31 1992
Division of Air
Resources Management

Mr. C. H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Alachua County--A.P.
UF Cogeneration Project
AC 01-204652

Attention: John Reynolds

Dear Mr. Fancy:

Pursuant to our discussion of January 15, 1992, this correspondence provides additional information concerning nitrogen oxides (NO_x) emission calculations for the University of Florida boilers. As we discussed, it is my opinion that the use of Figure 1.4-1 from AP-42 is not technically appropriate and can produce significant errors. This chart reflects instantaneous load conditions and cannot appropriately account for average operating conditions. Moreover, given the Department's latitude in implementing its regulations, there is no obligation for the Department to use this figure given the uncertainty in its origin and appropriateness to the existing boilers.

Presented in Table 1 is the average fuel usage for Units 3 and 5 for 1988, 1989, and 1990. The average load factor on gas can be calculated directly using fuel usage and hours of operation data presented in the annual operation report. The maximum fuel usage at 100 percent load is specified as cubic feet per hour for each boiler in Specific Condition 1 of each permit. The effective full load operation can be calculated by dividing the total fuel usage by the potential full load fuel usage. The equivalent full load operating hours can be used to calculate average load using the actual operating hours given in the annual operating reports. Adjustments of oil usage are made by subtracting the hours used on oil from the total hours. This calculation is somewhat uncertain since the load factor for oil is also unknown.

The load factors for natural gas presented in Table 1 are different than those calculated and presented in the Department's December 31, 1991 letter. The difference in calculating load factors using two independent methods are as high as about 25 percent. This is one source of error that can be introduced.

Another source of error is using the load coefficients as a means of calculating an average weighted emission factor. Table 2 presents this comparison. This table presents the load reduction coefficient and emission factor as a function of load (taken from Figure 1.4-1). The table also presents some possible operating conditions in terms of the percent of operation at a specific load. For example, if 50 percent

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

KBN

of the time the boiler operated at 100 percent load and 50 percent of the time it operated at 40 percent load then the average weighted load when operating would be 70 percent. The average weighted emission factor can then be calculated by using the specific emission factors for each load. The table also lists the emission factor obtained directly from Figure 1.4-1 using the average weighted load. This example calculation clearly indicates that the appropriate emission factor would be 20 percent higher than an emission factor calculated using an average load. Table 2 presents other examples that clearly indicate an error introduced by using Figure 1.4-1. Since there are no available data to determine the various instantaneous load conditions during the year, the use of Figure 1.4-1 is not technically appropriate. Indeed, all operating reports submitted for natural gas firing from electric utilities over the last 10 years use the emission factor in Table 1.4-1.

The errors introduced when calculating the average load factor and when calculating the average weighted emission factor clearly suggest that using Figure 1.4-1 is inappropriate. There are several other factors that should also be considered.

The Department should also be aware that under Rule 17-2.100(3)(b) Florida Administrative Code, allowable emissions can be specified as actual emissions as long as the limits are federally enforceable. Current interpretation suggests that the existing limits are federally enforceable, since the units in question (Units 3 and 5) have received BACT determinations.

Table 3 presents comparison of potential and requested emissions of NO_x for various scenarios. The permit application requested a 94 percent reduction in potential NO_x emissions from the existing boilers. The request was based on obtaining sufficient emission reductions from the existing units to eliminate the need for PSD review of NO_x. With this strategy the requested potential emissions of NO_x, including the CT/duct burner and limited operation of existing Units 4 and 5, are 298.37 tons per year. This is a decrease in potential emissions of over 800 tons per year or 278 percent. Without this strategy of taking NO_x reductions from Units 4 and 5, there is no need to take any operating limits for Units 4 and 5. Under this scenario, the potential NO_x emissions from Units 4 and 5 are 502 tons per year or 7.8 times higher than originally requested for these units. Clearly the operating limitations proposed in the permit have significant environmental advantages over other scenarios.

Your consideration in this matter is appreciated. Please call if you have any questions.

Sincerely,

Robert C. McCann Jr
for

Kennard F. Kosky, P.E.
President

KFK/tyf

cc: Scott Osbourn
J. Reynolds
C. Holladay
J. Kutyna, NE Dist
J. Harper, EPA
C. Shaver, NPS
BA/PL

91062A1/5

Table 1. UF Heating Plant Fuel Use, Hours of Operation and Average Calculated Load Factor

Unit	Year	Fuel Use		Operation at Full Load		Actual Hours	Load Factor Gas/Oil
		Gas (Mcf)	Oil (gal)	Gas (hrs)	Oil (hrs)		
Unit 3	1988	464,100	26,268	3,033.3	24.6	4,451.6	68.77%
	1989	392,375	11,269	2,564.5	10.6	5,057.2	50.89%
	1990	248,350	19	1,623.2	0.0	2,648.1	61.30%
	Avg.	368,275	12,519	2,407.0	11.7	4,052.3	59.69%
Unit 5	1988	537,506	537,506	3,277.5	503.9	6,411.0	58.83%
	1989	403,205	28,481	2,458.6	26.7	4,549.9	54.57%
	1990	416,485	5,557	2,539.5	5.2	5,115.6	49.73%
	Avg.	452,399	190,515	2,758.5	178.6	5,358.8	54.50%

Table 2. Calculated Emission Factors Under Possible Operating Conditions

Load	Load Reduction Coefficient	Emission Factor (lb/mmcf)	Percent at Load	Percent at Load	Percent at Load	Percent at Load	Percent at Load
100%	1.00	550	50%		65%	75%	
95%	0.90	495					70%
90%	0.81	446		70%			
85%	0.74	407					
80%	0.67	369					
75%	0.60	330					
70%	0.55	303					
65%	0.51	281					
60%	0.48	264					
55%	0.43	237					
50%	0.40	220					
45%	0.37	204					
40%	0.35	193	50%				
35%	??	188					
30%	??	180			35%		
25%	??	172					
20%	??	164					
15%	??	156					
10%	??	148		30%			
5%	??	140				25%	30%
		Average Load =	70%	66%	76%	76%	68%
		Average Emission Factor =	371	356	421	448	389
		Figure 1.4-1 Factor =	303	285	338	338	294
		Difference =	20%	22%	22%	28%	28%

Table 3. Comparison of Existing and Proposed Potential Emissions for the UF Cogeneration Project

Unit	Potential Emissions (tons/year)	Requested Emissions (tons/year)	Emission Reduction (tons/year)	Decrease
1	128.4	0.0	(128.4)	100%
2	128.4	0.0	(128.4)	100%
3	368.6	0.0	(368.6)	100%
4	107.0	5.5	(101.5)	95%
5	395.1	59.0	(336.1)	85%
Total:	1,127.5	64.5	(1,063.0)	94%
Cogen Only	233.9	233.9	NA	NA
w/Cogen and 4&5 Reductions		298.4	(829.1)	278%
w/Cogen and No 4&5 Reductions	736.0		(327.0)	44%
Emissions Increase (without reductions) in Units 4&5		437.6 tons/year 147%		

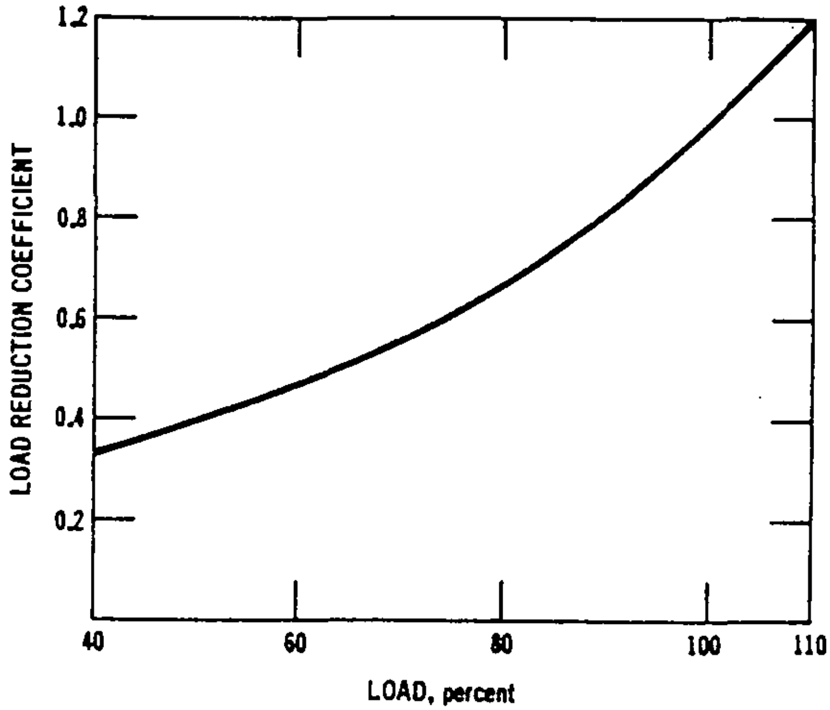

Figure 1.4-1. Load reduction coefficient as function of boiler load. (Used to determine NO_x reductions at reduced loads in large boilers.)

References for Section 1.4

1. D. M. Hugh, et al., Exhaust Gases from Combustion and Industrial Processes, EPA Contract No. EHSD 71-36, Engineering Science, Inc., Washington, DC, October 2, 1971.

2. J. H. Perry (ed.), Chemical Engineer's Handbook, 4th Edition, McGraw-Hill, New York, NY, 1963.

3. H. H. Hovey, et al., The Development of Air Contaminant Emission Tables for Non-process Emissions, New York State Department of Health, Albany, NY, 1965.

4. W. Bartok, et al., Systematic Field Study of NO_x Emission Control Methods for Utility Boilers, APTD-1163, U. S. Environmental Protection Agency, Research Triangle Park, NC, December 1971.

Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

January 16, 1992

Mr. Greg Worley
Air Enforcement Branch
EPA Region IV
345 Courtland Street NE
Atlanta, Georgia 30365

Re: Permit Application AC 01-204652, PSD-FL-181
University of Florida Cogeneration Project

Dear Mr. Worley:

EPA's guidance is needed to resolve an issue with the above PSD permit application. A copy of the application was forwarded to EPA last November. The issue is whether or not to allow emission offset credits for Boilers 3 and 5 as if they had been run at full load. Data from the operation reports show that the boilers did not run at full load during the years in question.

The applicant wants us to disregard the emission factor adjustment called for in AP-42, Figure 1.4-1, for Boilers 3 and 5 so they can escape PSD review for NO_X. They want us to use the discretion provided for in Florida Administrative Code, Rule 17-2.100(3)(b), to presume that their actual boiler emissions were equal to the allowable emissions which were based on full load operation.

We were advised by Ron Ryan, OAQPS, that the AP-42, Table 1.4-1 emission factor should not be applied without adjustment for load according to Figure 1.4-1. The applicant argues that Figure 1.4-1 should apply only to instantaneous determinations and should not be used where long term averaging is involved.

Any input EPA may provide will be appreciated. If more clarification is needed, please contact John Reynolds of our staff at 904-488-1344.

Sincerely,

C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CHF/JR/plm

Florida Department of Environmental Regulation
Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400
Lawton Chiles, Governor
Carol M. Browner, Secretary

January 9, 1992

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. R. W. Neiser
Senior Vice President-Legal and Gov. Affairs
Florida Power Corporation
3201-34th Street South
St. Petersburg, Florida 33733

Dear Mr. Neiser:

Re: Permit Application AC 01-204652, PSD-FL-181

The Department received Florida Power Corporation's letter dated January 2, 1992, and considers it a partial response to one issue in the Department's incompleteness letter of December 31, 1991. The additional information requested below applies only to this one issue concerning NO_X emission factors.

In the absence of NO_X emission test data for the years in question, please provide the following data for Boilers Nos. 3 and 5 at the University of Florida facility:

1. Boiler and burner manufacturer, address and phone number.
2. Date boilers were manufactured and date installed.
3. Boiler and burner type/configuration (provide sketch).
4. Design maximum heat input rate.
5. Full description and dates of all burner modifications, if any.

If clarification is needed on any of the above, please contact the permit engineer, John Reynolds, at (904) 488-1344.

Sincerely,

C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CHF/JR/plm

c: S. Osbourn, FPC
K. Kosky, P.E., KBN
A. Kutyna, NED (w/Jan. 2 ltr)
J. Harper, EPA (" ")
C. Shaver, NPS (" ")

P 832 538 764

Certified Mail Receipt

No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to Mr. R. W. Neiser, FPC	
Street & No. 3201-34th Street South	
P.O., State & ZIP Code St. Petersburg, FL 33733	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Address of Delivery	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 1-13-92 Permit: AC 01-204652 PSD-FL-181	

PS Form 3800, June 1990

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece next to the article number.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. R. W. Neiser
Senior Vice President-Legal and
Gov. Affairs
Florida Power Corporation
3201 - 34th Snreet South
St. Petersburg, FL 33733

4a. Article Number
P 832 538 764

4b. Service Type
☐ Registered ☐ Insured
XX☑ Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery
JAN 16 1992

5. Signature (Addressee)

6. Signature (Agent) [signature]

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

PS Form 3811, October 1990 ☆U.S. GPO: 1990—273-861 **DOMESTIC RETURN RECEIPT**

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

RECEIVED
JAN 16 1992
Division of Air Resources Management

JAN 8 1992

Mr. John Reynolds
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Dear Mr. Reynolds:

To confirm our telephone conversation of January 8, 1992 regarding NO_x emissions estimates for natural gas fired boilers, the load reduction coefficient determined from Figure 1.4-1 of AP-42 should be used in conjunction with the utility boiler factors in Table 1.4-1 to estimate emissions accurately. In addition, the estimates will be more accurate if the load percent used represents a fairly constant level, rather than an average of a widely varying load level. Thus, if estimates were made for several representative periods with different loads and summed the result should be more accurate than using a single average load for the entire period. Removing the hours that the boiler was not operating from the averaging period is the first and probably the largest improvement that could be made to the estimate's accuracy.

I could not find a detailed derivation of Figure 1.4-1 in our background documentation files, although it appears that references 7 and 14 of AP-42 section 1.4 contain a large amount of relevant data. Please call if I can be of further assistance.

Sincerely,

Ronald Ryan

Ronald Ryan
Environmental Engineer
Emission Factors and Methodologies Section

Florida Department of Environmental Regulation
Northeast District • Suite B200, 7825 Baymeadows Way • Jacksonville, Florida 32256-7577
Lawton Chiles, Governor Carol M. Browner, Secretary

January 7, 1992

Mr. Scott Osborn
Florida Power Corporation
Post Office Box 14042
St. Petersburg, Florida 33733

Alachua County - AP
Florida Power Corporation
Cogen Project at U of Fl.

Dear Mr. Osborn:

The applications for transfer of permits enclosed are being returned per the January 06 (Patty Adams and Johnny Cole) teleconference.

The $250.00 for the transfer fees is to be refunded under separate cover.

The cogen certificate is to address the transfer of permits issue.

If there are any questions, please contact Johnny Cole at the letterhead address/telephone number.

Sincerely,

Andrew G. Kutyna, P.E.
District Air Program
Administrator

AGK:JC:bt

cc: Patty Adams, DARM, BAR

Department of Environmental Regulation

Routing and Transmittal Slip

To: (Name, Office, Location)

1. Patty Adams
2. DARM BAR
3.
4.

Remarks:

RECEIVED
JAN 9 1992
Division of Air
Resources Management

From: Air / Jax

Date

Phone

PM 1-2-92 : AirBorne Express # 4055754 846

St. Petersburg, FL

File Copy

AC 01-204652

PSD-FL-181

RECEIVED JAN 3 1992 Division of Air Resources Management

Florida Power
CORPORATION

January 2, 1992

Mr. Barry Andrews
Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

Dear Barry:

Re: University of Florida Cogeneration Project

This letter is in response to questions by your staff regarding the proper application of the NO_x emission factor for natural gas-firing of external combustion sources (AP-42 Section 1.4). Table 1.4-1 presents a NO_x emission factor for utility boilers of 550 lb/10^6 ft^3 of natural gas fired. A footnote to this factor directs the user to "multiply the factor by the load reduction coefficient in Figure 1.4-1 at reduced loads."

As I am the author of the current AP-42 section, I am compelled to submit additional information for your consideration regarding the intent of Figure 1.4-1 within the context of this section. Section 1.4 was originally published in 1973 and included Figure 1.4-1. At that time, no reference was supplied for the figure. When I revised the section in 1982 (the current version is dated October 1986 and reflects some minor editorial changes made to the 1982 version), the figure was retained, although no reference could be identified. The rationale was that the figure may prove helpful for more accurately estimating an instantaneous or short-term emissions rate -- where the load (in percent) required for application of this figure may be readily available. You will note that the figure does not cite application of a "load factor" or a "capacity factor", rather an instantaneous representative load, in percent.

The AP-42 document is a compilation of emission factors, which are average values derived by averaging available data of acceptable quality. These factors are routinely applied in many contexts (e.g., to estimate the collective emissions from a number of sources, as in emission inventories; to predict emissions from new or proposed sources; to obtain annual or short-term emission estimates; etc.) and the document emphasizes that care should be taken to apply each factor in a manner consistent with its intended use.

To help users understand the reliability and accuracy of AP-42 emission factors, each factor is assigned a rating (A through E, with A being the best) which reflects the quality and the amount of data on which the factors are based. In general, factors based on many observations or on more widely accepted test procedures are assigned higher rankings. For instance, an emission factor based on 10 or more source tests on different plants would likely get an A rating, if all tests were conducted using a single valid reference measurement method or equivalent techniques (AP-42, Introduction, p.2). All NO_x emission factors in Section 1.4 have been assigned A ratings.

Given this background, it is my belief that in calculating annual NO_x emissions estimates from a natural gas-fired utility boiler, it is appropriate to apply only the factor provided in Table 1.4-1. Precedent has been set for such an interpretation in numerous applications, some of which have been reviewed by your staff. However, in order to confirm the appropriateness of the use of Figure 1.4-1, I have had discussions with Mr. Ron Ryan of the Emission Factor and Methodologies Section, Emission Inventory Branch, of the Office of Air Quality Planning and Standards. (Mr. Ryan may be contacted at (919) 541-4330.) Mr. Ryan stated that the origin and proper application of Figure 1.4-1 were, at best, unclear. He added that it might be best to apply such a figure to short-term emission estimates only, and contends that such an interpretation is supported by the practical difficulty of obtaining a representative "load" to apply to an annual emission estimate.

If you should have any questions, or wish to meet to discuss this issue in more detail, please do not hesitate to contact me at (813) 866-5158.

Sincerely,

Scott H. Osbourn
Environmental Engineer

cc: Preston Lewis, FDER
Ron Ryan, OAQPS
John Reynolds
Cleve Holladay
Jewell Harper, EPA
Chris Shaver, NPS
Chuck Collins, CO

1/3/92 RAM

File Copy

Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

December 31, 1991

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. R. W. Neiser
Senior Vice President-Legal and Gov. Affairs
Florida Power Corporation
3201-34th Street South
St. Petersburg, Florida 33733

Dear Mr. Neiser:

Re: Permit Application AC 01-204652
UF Cogeneration Project

The subject application and permit fees for the UF cogeneration facility were received by this office on December 2, 1991, after a pre-application meeting on November 13 with FPC staff. About two weeks later FPC staff contacted us to inquire about the status of the application. They emphasized the urgency of the project. We indicated to them that our review had not been completed but that we hoped an incompleteness letter might be avoided. Several days later we discovered that PSD applicability for one of the major pollutants (NO_X) was determined incorrectly in the application. We notified your staff and consultants of this by phone on December 19. In order to complete the application, the following additional information and revisions are required:

1. The AP-42 NO_X emission factor for fully loaded natural gas-fired boilers over 100 MMBtu/hr is 550 lbs. NO_X/MM ft^3 of fuel fired. For loads less than 100%, the emission factor is reduced according to AP-42, Figure 1.4-1. The 100% factor was used to calculate offset credits of 195.1 tons/yr of NO_X emissions, thus arriving at a net NO_X increase of 38.8 tons/yr. This level of net emissions (less than 40 tons/yr) would preclude PSD review for NO_X as stated in the application. However, analysis of load factors for UF's boilers Nos. 3 and 5 (capacity over 100 MMBtu/hr) during the three year period '88 - '90 reveals the following:

Fuel MM ft^3 per yr./Operating hrs per yr.

	'88	'89	'90
No. 3	464.1/4451.6	392.4/5057.2	248.4/2648.1
No. 5	537.8/6411	403.2/4549.9	416.8/5115.6

Dividing the fuel rates by the operating hours gives the following (assume approximately 1,000 Btu required per pound of steam and 946 Btu per ft^3):

Avg. ft^3/hr. (000) / Avg. lbs. Steam per hr. (000)

	'88	'89	'90
No. 3	104.3/98.7	77.6/73.4	93.8/88.7
No. 5	83.9/79.4	88.6/83.8	81.5/77.1

Average load factors are obtained by dividing the steam production by the maximum capacity of 120,000 lbs/hr. The load reduction coefficient is then obtained from AP-42, Figure 1.4-1:

Avg. % Load/Load Reduction Coefficient

	'88	'89	'90
No. 3	82/.65	61/.47	74/.60
No. 5	66/.50	70/.55	64/.49

NO_x emission factors are then obtained by multiplying the load reduction coefficients by the 100% load factor, i.e. 550:

NO_x Emission Factor (lbs/MM ft^3 fuel)

	'88	'89	'90
No. 3	358	259	330
No. 5	275	303	270

A weighted average emission factor for the 3 yr. period can be based on relative operating hours as follows:

Fraction of Total hrs/Emission Factor

	'88	'89	'90	Total
No. 3	.37/132.5	.42/108.8	.21/69.3	310.6
No. 5	.40/110	.28/84.8	.32/86.4	281.2

Thus the NO_x emission credits would be approximately 155 tons/yr instead of the 195.1 tons/yr claimed, resulting in a net increase of about 79 tons/yr instead of 38.8 tons/yr. Due to the above, the application will have to be revised to include PSD review for NOx.

2. References in the application to the proposed facility being major on the basis of emissions exceeding 250 tons per year should be changed to 100 tons per year since the HRSG is on the "List of 28" major source categories (fossil fuel boiler exceeding 250 MMBtu/hr input including GT exhaust).

3. Page 2 of Form 1.202(1), Item C., implies "low NO_x combustors" are being proposed which is not the case. The revised application should explain that Low-NO_x combustors are not currently available for this model turbine but may be within 5 years. The revision should explain what is required in the initial design to provide for future installation of Low-NO_x burners.

4. Emission calculations are not adequately shown in Appendix A. All calculations affecting emissions should be shown in their entirety. For example, the Appendix "A" calculation for the NSPS NO_x emission limit of 75 ppm corrected to 15 percent oxygen is not carried to completion. The set-up is shown, but not the final calculation. The application should clearly show how all emission-related quantities were obtained.

5. Total steam production should be shown in Table 1-1 along with design capacity of the HRSG.

6. Please evaluate the impact of this project on the following Class I areas: Chassahowitzka National Wilderness Area in Florida and Okefenokee National Wilderness Area in Georgia. This evaluation should include a cumulative PM_{10} and NO_x Class I increment analysis. An expanded air quality related values analysis (AQRV) should be done since there are no significant impact levels for this analysis. The AQRV analysis includes impacts to soils, vegetation and wildlife.

7. Please explain the use of terrain elevations at receptor points in the modeling and show how the elevations input into the model were derived.

If further clarification is needed on any of the above, please contact John Reynolds or Cleve Holladay at (904) 488-1344.

Sincerely,

B. Preston Lewis
FOR
C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CHF/JR/plm

c: A. Kutyna, NED
K. Kosky, P.E., KBN
D. Jones, P.E., FPC
J. Harper, EPA
C. Shaver, NPS
Reading File
John Reynolds
Cleve Holladay
12/31/91 RBM

P 832 538 758

Certified Mail Receipt
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to Mr. R. W. Neiser Street & No. Senior VP-Legal & Gov. Affairs FL Power Corp.	
P.O., State & ZIP Code 3201-34th Street South St. Petersburg, FL 33733	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Address of Delivery	
TOTAL Postage & Fees	$
Postmark or Date mailed: 12/31/91 AC 01-204652 PSD-FL-181	

PS Form **3800**, June 1990

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece next to the article number.

I also wish to receive the following services (for an extra fee):
1. ☒ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. R. W. Neiser
Senior V.P.-Legal & Gov. Affairs
Florida Power Corp.
3201-34th Street South
St. Petersburg, Florida 33733

4a. Article Number
P 832 538 758

4b. Service Type
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery JAN 02 1992

5. Signature (Addressee)

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

6. Signature (Agent)
[signature]

PS Form **3811**, October 1990 ☆U.S. GPO: 1990—273-861 **DOMESTIC RETURN RECEIPT**

December 2, 1991

RECEIVED
DEC 3 1991
Division of Air
Resources Management

Mr. C. H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Subject: Alachua County - A.P.
University of Florida Cogeneration Project

Dear Clair:

This correspondence presents information discussed during the November 13, 1991 meeting concerning the above referenced project. As stated at the meeting, a three year period was used to calculate actual emissions for the existing University of Florida Heating Plant. Three years were used since the calendar year 1990 was abnormally warm compared with historical data. A quantitative measure of this is reflected by the number of heating degree days observed by the National Weather Service for Gainesville. In 1990, the heating degree days were 709 compared to a historical average of 1,259. The average heating degree days for 1990 and 1989 was 974 which would normally be considered the two year period identified in the Department's rules [Rule 17-2.100(3)(a)] as applicable for calculating actual emissions. However, this period was not representative of actual emissions. Therefore, a three year average of 1988 through 1990 was used to calculate actual emissions. The heating degree days for this period is 1,104 which is more representative of the operation of the UF heating plant.

As stated at the meeting, the use of a combined cycle configuration for the project will considerably reduce emissions through the use of an efficient combustion turbines and waste heat utilization. Over the twenty year life of the project, an average equivalent of about 374,110 barrels of oil will be saved by the project. The reduction in potential emissions by not using oil will be 107 tons per year (TPY) of PM10, 1,850 TPY of SO_2 and 432 TPY of NOx. In addition, the project will save the University of Florida an average of $5,244,00 per year over 20 years. Indeed, the environmental and economic benefits of the project make it highly advantageous.

91062A1/2

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

Because of the need to proceed expeditiously with this project (i.e., construction start of February 1, 1991), your staff's expeditious review would be greatly appreciated. Please call if you have any questions.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President

cc: Scott Osbourn
W.W. Vierday
Project File
J. Reynolds
C. Holladay
J. Cole, NE Dist
J. Harper, EPA
C. Shaver, NPS
BA/PL

RECEIVED
DER - MAIL ROOM

1991 DEC -2 PM 3:21

Florida
Power
CORPORATION

November 25, 1991

Mr. Clair Fancy
Bureau of Air Regulation
Florida Department of Environmental
Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Dear Mr. Fancy:

Re: University of Florida Cogeneration Project

With regard to our Scott Osbourn and your Patty Adams conversation on November 19, 1991, this is to supplement our filing on November 12, 1991. Enclosed are the original and four copies each of applications for transfer of permit for boilers Nos. 1, 2, 3, 4 & 5 at the Central Heat Plant, University of Florida. Also enclosed is a check in the amount of $2,750.00 which covers the $250.00 application fee for the transfer permits and the additional $2,500.00 to supplement the previous $5,000.00 check for the air construction permit.

On November 12, 1991, Florida Power Corporation submitted an application to construct a 43-megawatt (MW) cogeneration facility at the existing University of Florida (UF) Central Heat Plant. The proposed cogeneration facility will consist of a combustion turbine (CT) with a generating capability of 43 MW. The steam generated by heat recovery steam generators (HRSGs) will be used for injection into the turbine for emission control and exported to the UF thermal distribution system. One hundred percent of UF's steam requirements will be supplied by the cogeneration plant with existing UF boilers #4 & #5 utilized for back-up capacity.

Upon commercial operation of the cogeneration plant, FPC will be responsible for the operation and common control of the University Heat Plant #2 boilers. Boilers #1, #2, & #3 will be retired in place. Boilers #4 & #5 will be operated as back-up capacity as further documented in these applications. Ownership of all these boilers will remain with the University of Florida.

If you have any questions during the review process, please contact me at (813) 866-4511.

Sincerely,

K. L. Small for

W. W. Vierday, Manager
Environmental Programs-Licensing

Enclosures

pag/WWV6.Fancy2.Let

G. Reynolds
C. Holladay
G. Cole, NE Dist (w/ TO requests for AO permits)
BA/PL

Florida Power CORPORATION

ACCOUNTS PAYABLE DEPT. B3F
P. O. BOX 14042
ST. PETERSBURG, FL 33733-4042
(813) 866-5257

REMITTANCE ADVICE

89

CHECK DATE 11/22/91 VENDOR FLORIDA DEPARTMENT OF VENDOR NO. 284216 CHECK NO. 1367547

INVOICE NO.	DATE	OUR ORDER NO.	VOUCHER	GROSS AMOUNT	DISCOUNT	NET AMOUNT
DE1119275 CK66676	11/19/91		9111125914	2,750.00	.00	2,750.00
					TOTAL	2,750.00

001031

THE ATTACHED REMITTANCE IS IN FULL SETTLEMENT OF ACCOUNT AS STATED. IF NOT CORRECT PLEASE RETURN TO ABOVE ADDRESS.

Accounts Payable Department B3F
P.O. Box 14042
St. Petersburg, Fl 33733-4042

Florida Power CORPORATION

63-027
631

DATE 11/22/91 CHECK NO. **1367547**

PAY: $2*THOUSAND*750*DOLLARS AND 00 CENTS $*****2,750.00

NCNB National Bank of Florida
Tampa, Florida

Void after 60 days

TO THE ORDER OF

FLORIDA DEPARTMENT OF
ENVIRONMENTAL REGULATION
2600 BLAIR STONE RD
TALLAHASSEE FL 32399-2400

K E McDonald

[redacted]

November 25, 1991

Mr. Clair Fancy
Bureau of Air Regulation
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Dear Mr. Fancy:

Re: University of Florida Cogeneration Project

With regard to our Scott Osbourn and your Patty Adams conversation on November 19, 1991, this is to supplement our filing on November 12, 1991. Enclosed are the original and four copies each of applications for transfer of permit for boilers Nos. 1, 2, 3, 4 & 5 at the Central Heat Plant, University of Florida. Also enclosed is a check in the amount of $2,750.00 which covers the $250.00 application fee for the transfer permits and the additional $2,500.00 to supplement the previous $5,000.00 check for the air construction permit.

On November 12, 1991, Florida Power Corporation submitted an application to construct a 43-megawatt (MW) cogeneration facility at the existing University of Florida (UF) Central Heat Plant. The proposed cogeneration facility will consist of a combustion turbine (CT) with a generating capability of 43 MW. The steam generated by heat recovery steam generators (HRSGs) will be used for injection into the turbine for emission control and exported to the UF thermal distribution system. One hundred percent of UF's steam requirements will be supplied by the cogeneration plant with existing UF boilers #4 & #5 utilized for back-up capacity.

Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

November 15, 1991

Mrs. Christine Shaver, Chief
Permit Review & Technical Support Branch
National Park Service-Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

Dear Mrs. Shaver:

Re: Florida Power Corporation
University of Fla. Cogeneration Project
PSD-FL-181

Enclosed for your review and comment is the above referenced PSD permit application. If you have any comments or questions, please contact John Reynolds or Cleve Holladay at the above address or at (904)488-1344.

Sincerely,

Patricia G. Adams

Patricia G. Adams
Planner
Bureau of Air Regulation

PA/kt

enclosure

Florida Department of Environmental Regulation

Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

November 15, 1991

Ms. Jewell Harper, Chief
Air Enforcement Branch
U.S. EPA - Region IV
345 Courtland Street, NE
Atlanta, Georgia 30308

Dear Ms. Harper:

Re: Florida Power Corporation
University of Fla. Cogeneration Project
PSD-FL-181

Enclosed for your review and comment is the above referenced PSD permit application. If you have any comments or questions, please contact John Reynolds or Cleve Holladay at the above address or at (904)488-1344.

Sincerely,

Patricia G. Adams

Patricia G. Adams
Planner
Bureau of Air Regulation

PA/kt

enclosure

Recycled Paper