LAKELAND
ELECTRIC & WATER

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Farzie Shelton
ENVIRONMENTAL COORDINATOR, Ch E.

October 19, 1995

VIA HAND DELIVERY

Howard L. Rhodes, Director
Division of Air Resources Management
Department of Environmental Protection
Magnolia Park Courtyard
Tallahassee, FL 32301

RE: City of Lakeland C.D. McIntosh Unit No. 3--Requested Amendment of PSD Permit No. PSD-FL-008 and Modification of Site Certification No. PA-78-06

Dear Howard:

As you may recall, the City of Lakeland originally submitted a request to modify the Site Certification for its C.D. McIntosh Unit No. 3 on December 7, 1994, and submitted a request to revise the Prevention of Significant Deterioration (PSD) permit on January 4, 1995. The City subsequently revised its request regarding the PSD permit on April 6, 1995, while the City's request to modify the Site Certification was held in abeyance pending the outcome of the PSD permit revision request.

The City's April 6 submittal focused on the sulfur dioxide emission limit and removal efficiencies. A PSD permit amendment was subsequently issued by the Department, which has been accepted by the City, and those issues have therefore been resolved. As stated in the City's April 6 submittal to the Department and during our August 11 meeting, because those issues have been resolved, the City intends to again request that the PSD permit and Site Certification be modified to address the use of petroleum coke as a fuel. This letter and the attached documents constitute a revised request for PSD permit amendment (as described below). A separate notification to reinitiate the Department's review of the City's request for Site Certification modification is being submitted to the Department's Power Plant Siting Section.

After you and your staff have had an opportunity to review the information being provided, we would like to set up a meeting to discuss this submittal. If additional information is needed, please let us know within 30 days and we will provide you with the information immediately.

1. ***Petroleum Coke***--As you know, the City of Lakeland conducted a successful test burn of petroleum coke blended with coal and coal/refuse in 1994. In an effort to use the most cost-effective fuels while not increasing emissions above allowable limits, the City of Lakeland respectfully requests that its PSD permit be revised to allow petroleum coke to be burned when

blended with coal and other fuels. Because continuous emissions monitors have been installed for sulfur dioxide, nitrogen oxides, and opacity, as required by the PSD permit (Specific Condition No. 6), New Source Performance Standard Subpart D (40 CFR § 60.45), and the federal acid rain program (40 CFR Part 75), the City can ensure that the emission limits for these pollutants are not exceeded when petroleum coke is blended with coal or other fuels and burned in Unit No. 3.

Based on what the City of Lakeland believes to be an appropriate analysis, PSD review should not be triggered for any pollutant. While the City does not concur with the Department's prior determination that the use of petroleum coke would constitute a "physical or operational change" to the Unit No. 3 boiler, in an effort to expedite review of its request for authorization to burn petroleum coke as a fuel, the City has assumed for purposes of determining PSD applicability that the use of petroleum coke constitutes an operational change. The issue then becomes whether a significant net emissions increase will result from the use of petroleum coke.

As you know, the Department's rules require a comparison of "past actual" emissions and "representative future actual" emissions to determine whether a significant net emissions increase will occur as a result of a physical or operational change. Rule 62-212.400(2)(e)1., F.A.C. Under the Department's rules, "past actual emissions" are determined based on the average rate, in tons per year, at which the unit actually emitted the pollutant during a consecutive two-year representative period during the last five years. The Department's September 11, 1995, letter to the City states that in determining "past actual" emissions for McIntosh Unit No. 3, past actual sulfur dioxide emissions should be determined based on the new sulfur dioxide emission limits along with "actual hours of operation, actual fuel combusted, capacity factors, etc." The Department's letter goes on to state that for other pollutants, past actual emissions should be based on past (or new) compliance tests, continuous emissions monitoring data, applicable inferences from the petroleum coke test burn, engineering estimates, etc. Consistent with the Department's recommendations, past actual emissions have been calculated using this type of information, as set forth in Exhibit A.

"Representative future emissions" are based on the average rate at which the emissions unit is *projected* to emit a pollutant for the two-year period after a physical or operational change. Future actual emissions are projected by multiplying (1) the hourly emissions rate, based on the unit's capabilities following the change and federally enforceable operational restrictions affecting the hourly emissions rate, and (2) the projected capacity utilization following the change, based on historical annual utilization and other available information regarding the unit's likely post-change capacity utilization (excluding utilization rate increases based on utility system growth). (40 CFR § 52.21(b)(33), incorporated by reference in Rule 62-212.200(2)(d), F.A.C.) Unit No. 3 is a base-loaded unit, and the average annual

hours of operation for Unit No. 3 over the past two years (which are representative) are 8042. Because the City does not anticipate increasing the Unit's utilization rate as a result of using petroleum coke, the most accurate comparison between past actual and future projected actual emissions would be based on short-term emission rates. Otherwise, statistically insignificant differences in short-term rates could potentially be extrapolated into statistically significant differences in annual rates. A comparison of short-term rates is more appropriate to determine whether emission increases can be expected in the future as well as whether a change in emissions will result from the use of petroleum coke.

A comparison of past actual emissions to future projected emissions of *sulfur dioxide* indicates that a net emissions increase would occur. The City, however, proposes to accept a federally enforceable emissions limit of 0.718 lb/mmBtu when burning petroleum coke to ensure that no significant net emissions increase would result. As shown in Exhibit A, the past actual emissions (calculated based on the revised PSD permit) are 7948 tons per year, at an emissions rate of 0.718 lb/mmBtu. By accepting emission limits of 0.718 lb/mmBtu and 7948 tons per year when burning petroleum coke, the future projected emissions would not increase. Because no increase in emissions occurs, PSD does not apply to sulfur dioxide emissions and BACT review is not triggered. As also shown in Exhibit A, the actual *particulate matter, nitrogen oxides, carbon monoxide, and sulfuric acid mist* emissions will also not increase as a result of petroleum coke use. Because a significant net emissions increase does not result, PSD does not apply to those emissions and BACT review is not required. PSD is therefore not triggered nor is BACT required for any pollutant.

The City therefore respectfully requests that Condition No. 2B be changed as follows:

> A flue gas desulfurization system will be installed to treat exhaust gases and will operate such that whenever coal is burned, sulfur dioxide in gases discharged to the atmosphere from the boiler shall not exceed 1.2 pounds per million Btu heat input and 10 percent of the potential combustion concentration (90 percent reduction), or 35 percent of the potential combustion concentration (65 percent reduction), when emissions are less than 0.75 pounds per million Btu heat input. Compliance with <u>this</u> ~~the~~ sulfur dioxide emission limitation and percent reduction requirement shall be determined on a 30-day rolling average (<u>based on days when no petroleum coke is burned</u>). <u>Whenever petroleum coke is burned, sulfur dioxide emissions shall not exceed 0.718 lb/mmBtu (based on a 30-day rolling average) or 7948 tons per year.</u>

The City also requests that a Condition No. 8 be added as follows:

8. The following fuels may be burned:

Coal only
Oil only
Coal and up to 10% refuse (based on heat input)
Oil and up to 10% refuse (based on heat input)
Coal and up to 20% petroleum coke (based on weight)
Coal and up to 20% petroleum coke (based on weight) and 10% refuse (based on heat input)

2. ***Startup Fuels***--Because, like all other coal units, Unit No. 3 must be started on natural gas or fuel oil, the City requests that the PSD permit be revised to reflect that natural gas and low sulfur fuel oil (e.g., diesel) may be burned during startup. Further, because these fuels are "clean fuels," the City also requests that the PSD permit be revised to clarify that these fuels may be burned at any time. The current permit allows the use of fuel oil in at least emergency situations, and such the permit should be revised to clarify that use is allowed at any time. The City therefore requests that the following language be included in the permit:

8. The following fuels may be burned:

. . .

Natural Gas
Low Sulfur Fuel Oil (e.g., diesel)

3. ***Permit Application***--The City has revised portions of the permit application previously submitted on January 4, 1995. An original and three copies are enclosed with this submittal (as part of Exhibit A).

Again, the City would like to thank you and your staff for your responsiveness to our requests. Please let us know if additional information is needed and we will provide the same to you immediately.

Sincerely,

Farzie Shelton/arm

Farzie Shelton
Environmental Coordinator

cc: Clair Fancy, DEP
Al Linero, DEP
Martin Costello, DEP
Hamilton S. Oven, Jr., DEP
Jewell Harper, EPA Region IV
Brian Beals, EPA Region IV
Ken Kosky, KBN
Angela Morrison, HGSS

65993

CITY OF LAKELAND C.D. MCINTOSH UNIT 3
REVISED APPLICATION FOR CO-FIRING PETROLEUM COKE

This correspondence provides information on the City's application to co-fire petroleum coke and coal at McIntosh Unit 3. The information presented herein addresses the issues raised in the Department's September 11, 1995, correspondence. The information is organized according to each pollutant addressed in the Department's letter. For completeness, portions of the previous application have been revised and are enclosed herein.

Sulfur Dioxide Emissions

As noted in the September 11, 1995, correspondence, the Department proposes that the determination of actual sulfur dioxide (SO_2) emissions for comparison the future representative actual annual emissions should be based on the recently revised SO_2 emission limits.

The City proposes to co-fire petroleum coke and coal at a calculated allowable 1994 and 1995 emission rate based on the information presented in the application on heat input, coal heat content, 1994 and 1995 coal sulfur contents and annual usage rates, and allowable emission rate. The calculated allowable emission rate is as follows:

Design Data:

Coal usage for Unit 3 = 159.6 tons coal/hour

Heat input for Unit 3 = 3,640 MMBtu/hour

Note: Coal usage and heat input are the design basis provided in the application and the recently revised BACT determination.

Uncontrolled SO_2 Emissions:

1994 sulfur content = 1.12 percent (see attachment)

1995 sulfur content = 1.22 percent (see attachment)

1994/1995 average sulfur content = 1.17 percent

Note: Coal quality data are attached.

159.6 tons coal/hr x 0.0117 ton sulfur/ton coal x 2 tons SO_2 /ton sulfur

= 3.7346 tons SO_2

Calculated allowable SO_2 emission rate (based on revised BACT):

3.7346 tons SO_2 x (1 - 0.65) = 1.3071 tons/hr

1.3071 tons/hr x 2,000 lb/ton x 1 hr/3,640 MMBtu = 0.7182 lb/MMBtu

Calculated annual allowable SO_2 emissions:

1994 usage = 991,351 tons/year

1995 usage = 949,553 tons/year (prorated from January through September)

(Usage through September = 710,213.75 tons; days in October, November, and December = 92; prorated usage = 710,213.75 tons x 365 x 1/273)

Actual emissions = 970,452 tons/year x 0.0117 ton sulfur/ton coal x 2 tons SO_2/ton sulfur x (1 - 0.65) = 7,948.0 tons/year

The City proposes an emission limit of 0.7182 lb/MMBtu (30-day rolling average) when burning 10 to 20 percent petroleum coke. Because of the complexity of determining the exact proportions of coal at percentages less than 10 percent (this would usually occur at the beginning and end of blending), the emission limit in the revised BACT would govern.

The proposed emission limit is also supported by the coal quality of the 1994 and 1995 compliance tests. The allowable SO_2 emission rate is calculated as follows:

1994 Coal Quality

1.26% S/100 x 2 lb SO_2/lb S x 1/12,847 Btu/lb x 10^6 x 0.35 = 0.687 lb/MMBtu

1995 Coal Quality

1.29% S/100 x 2 lb SO_2/lb S x 1/12,806 Btu/lb x 10^6 x 0.35 = 0.705 lb/MMBtu

1994/95 Average

(0.687 + 0.705)/2 = 0.696 lb/MMBtu

The coal quality data are attached.

The City also proposes to co-fire petroleum coke and coal so that emissions when co-firing do not exceed 7,948.0 tons/year which represents the calculated actual allowable emissions for 1994/1995. Taking together the proposed SO_2 emissions limit when co-firing and the actual hours of operation, the calculated actual annual SO_2 emissions and the "representative future SO_2 emissions" would be equal

for PSD purposes. Therefore, PSD review would not be necessary according to Rule 62-212.200(2)(d), F.A.C. and 40 CFR 52.21(b)(33).

Sulfuric Acid Mist Emissions

The co-firing test data do not support the Department's contention that the presence of vanadium in petroleum coke increases sulfuric acid mist emissions over the range of petroleum coke to be fired (i.e., up to 20 percent). As discussed in Attachment 1, statistical analysis clearly demonstrated that there was no statistically significant difference between any of the test conditions. As shown in Table 1 of Attachment 1, all tests were determined to be not statistically different based on the procedures in 40 CFR Part 60 Appendix C for determining increases in emission rates (see attached Appendix C). Moreover, the test condition using 10 percent petroleum coke with 90 percent coal was 11.25 percent *lower* than the coal-only test. The 20 percent petroleum coke with 80 percent coal was only 6.25 percent higher than the coal-only test. If there was an effect of vanadium in petroleum coke, then the effect should be consistent between test runs which is clearly not the case.

The conclusion that vanadium concentrations did not affect sulfuric acid mist concentrations in the range requested (up to 20 percent) is also supported by analyses of vanadium in the 10 percent and 20 percent petroleum coke and coal mixtures. The average vanadium concentrations were:

10 percent petroleum coke and high sulfur coal 311 ppm

20 percent petroleum coke and low sulfur coal 177 ppm

Again, if sulfuric acid mist emissions are directly proportional to vanadium, then the tests demonstrated the opposite effect.

Carbon Monoxide Emissions

The information previously presented supports the City's position that CO was a result of factors other than the use of petroleum coke. The data presented in Attachment 1 clearly suggest that the grindability and oxygen concentration are the major factors for the difference between coal-only and coal with 20 percent petroleum coke. Indeed, the effect of petroleum coke would appear to lower CO concentrations since the 10 percent petroleum coke with 90 percent high-sulfur coal was 7.4 percent *lower* than the high-sulfur coal-only test. If petroleum coke had an effect, it would have been apparent in this test comparison. The major difference using a slightly higher percentage of petroleum coke was the kind of coal, i.e., high sulfur versus low sulfur.

would have been apparent in this test comparison. The major difference using a slightly higher percentage of petroleum coke was the kind of coal, i.e., high sulfur versus low sulfur.

As noted in Attachment 1, oxygen concentration was quite different and lower during the low sulfur coal/20 percent petroleum coke test burn. This difference was about 0.8 percent O_2 or about 10 percent lower than the high sulfur coal test condition. Changes in oxygen concentration of this magnitude can have a significant influence on CO concentrations. Difference of several 100 ppm CO has been observed with oxygen concentrations of as little as 0.1 percent change.

Taking together the test data and engineering principals of CO formation, it is concluded that using up to 20 percent petroleum coke will not increase emissions of CO.

Nitrogen Oxides Emissions

The City does not believe additional tests of NO_x emissions are necessary and co-firing petroleum coke will not cause an increase in NO_x emissions. As discussed in Attachment 1, statistical analysis clearly demonstrated that there was no statistically significant difference or increase in NO_x emissions between any of the test conditions. While the test condition using 10 percent petroleum coke with 90 percent coal was 1.4 percent *higher* than the coal-only test, the 20 percent petroleum coke with 80 percent coal was 23.5 percent *lower* than the coal-only test. If there was an effect on NO_x emissions using petroleum coke, then the effect should be consistent between test runs, which was not the case. Indeed, there is more variability within the test method itself than the 1.4 percent difference detected.

Moreover, the 1995 CEM data support the variability in NO_x emissions that occur. The monthly NO_x emissions for 1995 are as follows: January - 0.50 lb/MMBtu; February - 0.47 lb/MMBtu; March - 0.45 lb/MMBtu; April - 0.51 lb/MMBtu; May - 0.49 lb/MMBtu; June - 0.54 lb/MMBtu; July - 0.56 lb/MMBtu. The NO_x emissions during the 1995 compliance test averaged 0.63 lb/MMBtu while low-sulfur coal was being used. During the test burn, the NO_x emission rates were 0.55 and 0.41 lb/MMBtu, respectively, for the 10 percent and 20 percent petroleum coke test burns. Clearly, the NO_x emission rate when firing coal or a blend of coal and petroleum coke within the proposed range is a function of combustion conditions and not the fuel.

Particulate Matter Emissions

Emissions of particulate when firing petroleum coke were all less than when firing coal. Therefore, no effect of co-firing petroleum coke on the emission rate was observed, and PSD is not applicable since there is no increase in emissions.

Summary

The City proposes that the Department approve the co-firing of up to 20 percent petroleum coke with coal at an emission rate not to exceed 0.718 lb/MMBtu and no more than 7,948 tons per year when co-firing petroleum coke and coal. This would effectively produce no net increase in actual emissions. For the other pollutants, no increase in emissions is attributable to firing petroleum coke. The test results for NO_x and sulfuric acid mist were determined to be not different based on 40 CFR Part 60 Appendix C. Emissions of CO are attributable to combustion conditions and not petroleum coke firing.

Professional Engineer's Statement

This revision to the original application is submitted under the same certification provided with the original application.

Signature

10/16/95
Date

SEAL

Professional Engineer Registration No. 14996

REVISED APPLICATION PAGES

(Note: The previous pollutant information pages are not relevant to the requested change. Only SO_2 will be affected by co-firing.)

Category II: All Air Operation Permit Applications Subject to Processing Under Rule 62-210.300(2)(b), F.A.C.

This Application for Air Permit is submitted to obtain:

[ ] Initial air operation permit under Rule 62-210.300(2)(b), F.A.C., for an existing facility seeking classification as a synthetic non-Title V source.

Current operation/construction permit number(s): _____

_____

[ ] Renewal air operation permit under Rule 62-210.300(2)(b), F.A.C., for a synthetic non-Title V source.

Operation permit to be renewed: _____

[ ] Air operation permit revision for a synthetic non-Title V source. Give reason for revision; e.g., to address one or more newly constructed or modified emissions units.

Operation permit to be revised: _____

Reason for revision: _____

_____

Category III: All Air Construction Permit Applications for All Facilities and Emissions Units

This Application for Air Permit is submitted to obtain:

[X] Air construction permit to construct or modify one or more emissions units within a facility (including any facility classified as a Title V source).

Current operation permit number(s), if any: PA 74-06-SR (PPSA); PSD-FL-008

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

Current operation permit number(s): _____

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Professional Engineer Certification

1. Professional Engineer Name: **Kennard F. Kosky**
   Registration Number: **14996**

2. Professional Engineer Mailing Address:
   Organization/Firm: **KBN Engineering and Applied Sciences, Inc.**
   Street Address: **6241 NW 23rd Street, Suite 500**
   City: **Gainesville** State: **FL** Zip Code: **32653-1500**

3. Professional Engineer Telephone Numbers:
   Telephone: **(904) 336-5600** Fax: **(904) 336-6603**

4. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance (a) that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; or (b) for any application for a Title V source air operation permit, that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application;

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application; and

(3) For any application for an air construction permit for one or more proposed new or modified emissions units, the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

Kennard F. Kosky — October 16, 1995
Signature — Date

(seal)

* Attach any exception to certification statement.

Application Contact

1. Name and Title of Application Contact:
   Ms. Farzie Shelton, Environmental Coordinator

2. Application Contact Mailing Address:

   Organization/Firm: **Lakeland Department of Electric and Water Utilities**
   Street Address: **501 East Lemon Street**
   City: **Lakeland** State: **FL** Zip Code: **33801-5099**

3. Application Contact Telephone Numbers:

   Telephone: **(941) 499-6603** Fax: **(941) 499-6688**

Application Comment

This application is being submitted to obtain FDEP recognition that petroleum coke can be burned in McIntosh Unit 3. There will be no new construction of facilities or changes in the current procedures when petroleum coke is being fired in Unit 3. The application also addresses minor amendments to the PSD approval and previous application.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Name, Location, and Type

1. Facility Owner or Operator: **City of Lakeland, Department of Electric and Water Utilities**			
2. Facility Name: **C.D. McIntosh Power Plant**			
3. Facility Identification Number: **40TPA530004** [ ] Unknown			
4. Facility Location Information: Facility Street Address: **3030 East Lake Parker Drive** City: **Lakeland** County: **Polk** Zip Code: **33805**			
5. Facility UTM Coordinates: Zone: **17** East (km): **408.5** North (km): **3,105.8**			
6. Facility Latitude/Longitude: Latitude (DD/MM/SS): Longitude (DD/MM/SS):			
7. Governmental Facility Code: **4**	8. Facility Status Code: **A**	9. Relocatable Facility? [ ] Yes [X] No	10. Facility Major Group SIC Code: **49**
11. Facility Comment:			

Facility Contact

1. Name and Title of Facility Contact: **Ms. Farzie Shelton, Environmental Coordinator**
2. Facility Contact Mailing Address: Organization/Firm: **City of Lakeland, Department of Electric and Water Utilities** Street Address: **501 East Lemon Street** City: **Lakeland** State: **FL** Zip Code: **33801-5099**
3. Facility Contact Telephone Numbers: Telephone: **(941) 499 - 6303** Fax: **(941) 499 - 6688**

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate:
   3,640 mmBtu/hr

2. Maximum Incineration Rate:
   Not applicable lbs/hr tons/day

3. Maximum Process or Throughput Rate: Not Applicable

4. Maximum Production Rate: Not Applicable

5. Operating Capacity Comment:
   Emissions unit burns coal and refuse-derived fuel (RDF); The emissions unit is authorized to burn residual oil.

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule:
Co-firing of coal (and coal/refuse) with petroleum coke.

hours/day		days/week	
weeks/yr	8,760	hours/yr	

Emissions Unit Information Section 1 of 1

Segment Description and Rate Information: Segment 5 of 7

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): **Coal and petroleum coke (80/20 weight basis)**	
2. Source Classification Code: **10100101**	
3. SCC Units: **Tons**	
4. Maximum Hourly Rate: **152.6**	5. Maximum Annual Rate: **970,452**
6. Estimated Annual Activity Factor: **Not applicable**	
7. Maximum Percent Sulfur: **3.3**	8. Maximum Percent Ash: **< 15**
9. Million Btu per SCC Unit: **23.85**	

10. Segment Comment:

Maximum hourly rates and percent sulfur will vary depending upon mixture. Coal and petroleum coke will be blended to a maximum sulfur content of 3.3 percent. Typical sulfur content of petroleum is 5 percent. Maximum hourly rate based on 122.1 TPH coal and 30.5 TPH petroleum coke. Heat content of mixture based on maximum hourly rate (TPH) and maximum heat input rating for unit of 3,640 MMBtu/hr. Maximum annual rate based on calculated actual allowable emissions for 1994 and 1995.

Heat contents of coal and petroleum coke are 22.81 and 28.0 MMBtu/ton (see also FA-1).

Emissions Unit Information Section 1 of 1

Segment Description and Rate Information: Segment 6 of 7

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode):
   Coal, petroleum coke, and RDF; coal/coke.

   (80/20 weight basis at 90% of heat input; RDF at 10% heat input)

2. Source Classification Code: **10100101**

3. SCC Units: **Tons**

4. Maximum Hourly Rate:	5. Maximum Annual Rate:
168.8	**1,020,452**

6. Estimated Annual Activity Factor: **Not applicable**

7. Maximum Percent Sulfur:	8. Maximum Percent Ash:
3.3	**< 15**

9. Million Btu per SCC Unit: **21.56**

10. Segment Comment:
    Maximum hourly rates and percent sulfur will vary depending upon mixture. Coal, RDF, and petroleum coke will be blended to a maximum sulfur content of 3.3 percent for coal/ petroleum mixture. Maximum hourly rate based on 100.9 TPH coal, 40.4 TPH RDF, and 27.5 TPH petroleum coke. Heat content of mixture based on maximum hourly rate (TPH) and maximum heat input rating for unit of 3,640 MMBtu/hr. Maximum annual rate based on calculated actual annual allowable emissions for 1994 and 1995, and 50,000 tons/year of RDF usage.

Emissions Unit Information Section 1 of 1

Segment Description and Rate Information: Segment 7 of 7

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): Natural gas	
2. Source Classification Code: 10100601	
3. SCC Units: Million cubic feet	
4. Maximum Hourly Rate: 3.529	5. Maximum Annual Rate: 30,914
6. Estimated Annual Activity Factor: Not applicable	
7. Maximum Percent Sulfur: 0.003	8. Maximum Percent Ash: Negligible
9. Million Btu per SCC Unit: 1,031.4	
10. Segment Comment: Natural gas is proposed as a supplementary fuel. Heat content of mixture based on maximum hourly rate (TPH) and maximum heat input rating for unit of 3,640 MMBtu/hr.	

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 1 of 1

1. Pollutant Emitted: SO_2
2. Total Percent Efficiency of Control: 87.0 %
3. Primary Control Device Code: 067
4. Secondary Control Device Code: Not applicable
5. Potential Emissions: 2,613.5 lbs/hr 7,948 tons/yr
6. Synthetically Limited? [ ] Yes [X] No
7. Range of Estimated Fugitive/Other Emissions: Not applicable [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/yr
8. Emission Factor: 0.718 lb/MMBtu Reference: Proposed emission limit
9. Emissions Method Code: [ ] 1 [X] 2 [ ] 3 [ ] 4 [ ] 5
10. Calculation of Emissions: 3,640 MMBtu/hr x 0.718 lb/MMBtu = 2,613.5 lb/hour 0.033 lb sulfur/lb coal x 2 lb SO_2/lb sulfur x 2,000 lb/ton x ton/23.85 MMBtu x (1 - 0.87) = 0.718 lb/MMBtu
11. Pollutant Potential/Estimated Emissions Comment: The overall efficiency of sulfur dioxide removal (i.e, 87.0 percent) applies to using a maximum 3.3 percent for the co-firing mixture.

Allowable Emissions (Pollutant identified on front page)

A. Co-Firing

1. Basis for Allowable Emissions Code: **ESCPSD**
2. Future Effective Date of Allowable Emissions: **Not applicable**
3. Requested Allowable Emissions and Units: **0.718 lb/MMBtu (30-day rolling average)**
4. Equivalent Allowable Emissions: **2,613.5** lbs/hr **7,948** tons/yr
5. Method of Compliance: **Annual stack test**
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode): **The allowable emission limit is based on FDEP Rule 62-212.200(2)(d) F.A.C. and 40 CFR Part 52.21(b)(33) and calculated actual allowable emissions to limit the emission rate and actual emissions below PSD significant emission rate.**

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lbs/hr tons/yr
5. Method of Compliance:
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

2. Increment Consuming for Nitrogen Dioxide?

If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

[ ] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[X] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code:			
PM	[X] C	[ ] E	[ ] Unknown
SO2	[X] C	[ ] E	[ ] Unknown
NO2	[ ] C	[ ] E	[ ] Unknown

4. Baseline Emissions:			
PM	lbs/hr		tons/yr
SO2	lbs/hr		tons/yr
NO2		11,160	tons/yr

5. PSD Comment: **Potential emissions assumed for NO_x baseline.**

I. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

This subsection of the Application for Air Permit form provides supplemental information related to the emissions unit addressed in this Emissions Unit Information Section. Supplemental information must be submitted as an attachment to each copy of the form, in hard-copy or computer-readable form.

Supplemental Requirements for All Applications

1. Process Flow Diagram	
[X] Attached, Document ID: PFD-1	
[ ] Not Applicable	[ ] Waiver Requested
2. Fuel Analysis	
[X] Attached, Document ID: FA-1	
[ ] Not Applicable	[ ] Waiver Requested
3. Detailed Description of Control Equipment	
[ ] Attached, Document ID: _____	
[X] Not Applicable	[ ] Waiver Requested
4. Description of Stack Sampling Facilities	
[ ] Attached, Document ID: _____	
[X] Not Applicable	[ ] Waiver Requested
5. Compliance Test Report	
[ ] Attached, Document ID: _____	[X] Not Applicable
[ ] Previously Submitted, Date: _____	
6. Procedures for Startup and Shutdown	
[ ] Attached, Document ID: _____	[X] Not Applicable
7. Operation and Maintenance Plan	
[ ] Attached, Document ID: _____	[X] Not Applicable
8. Supplemental Information for Construction Permit Application	
[X] Attached, Document ID: SI-1	[ ] Not Applicable
9. Other Information Required by Rule or Statute	
[ ] Attached, Document ID: _____	[X] Not Applicable

ATTACHMENT 1

DISCUSSION OF TEST BURN

ATTACHMENT 1 - DISCUSSION OF TEST BURN

The City of Lakeland requested in August 1993 authorization from the Florida Department of Environmental Protection (FDEP) to conduct a trial test burn of co-firing petroleum coke and coal (see August 16, 1993 letter from Ms. Farzie Shelton, Environmental Coordinator for Lakeland Department Electric and Water Utilities to Mr. Buck Oven of FDEP). FDEP authorized the trial burn in January 1994 (see letter from Mr. Oven to Ms. Shelton dated January 31, 1994). The trial test burn was conducted in February 1994 with a report of the results furnished to FDEP (see Emission Test Report by Environmental Science & Engineering, Inc. dated February 1994). Three operating conditions were evaluated during the trial test burn:

Condition 1. High-sulfur coal only,

Condition 2. A 90/10 percent blend of high-sulfur coal and petroleum coke, and

Condition 3. A 80/20 percent blend of low-sulfur coal and petroleum coke.

Note: High-sulfur in this context refers to coal with a sulfur content of 2.5 percent. Low-sulfur refers to 1 percent sulfur coal.

Measurements were conducted using U.S. Environmental Protection Agency (EPA) and FDEP sampling procedures for particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide, and sulfuric acid mist.

The potential applicability of the Prevention of Significant Deterioration (PSD) rules [Rules 62-212.400(2)(d)4, Florida Administrative Code (F.A.C.)] as they may apply to modifications are related to whether a source has a significant increase in actual emissions. The results of the trial test can be used to determine if an emissions increase has occurred. In order to determine any differences in emissions rate for the pollutants that were sampled during the trial test burn, confidence intervals using the student "t" test were performed and are presented in Table 1. Calculations are attached. The results of the evaluation indicated that, except for CO, there was either no statistical difference between emissions from the three test conditions or that emissions when co-firing petroleum were lower than when firing high-sulfur coal. Unit 3 is currently authorized to burn coal with 3.3 percent sulfur content. While the emission rate for sulfuric acid mist under Condition 3 was higher than the emission rate for high-sulfur coal only test condition (Condition 1), the differences were not statistically significant. This was confirmed

using the approach outlined in Appendix C of 40 Code of Federal Regulations (CFR) Part 60 for determination of emission rate change (see calculations).

The emission rate of carbon monoxide for Condition 3 was statistically higher than Condition 1. The increase in CO emission was not due to petroleum coke in the coal/petroleum coke mixture. The primary and most important factor causing this increase was due to the hardness measured by the Hardgrove Grindability Index (HGI) of the coal that was being used for the trial test mixture in test condition 3. The petroleum coke used in the test burn had a high HGI. The higher the number, the softer the fuel. The 2.5 percent S coal used in test conditions 1 and 2 (alone and in combination with the coke) had a hardness of 43 HGI. The efficiency of fuel combustion is directly related to the particle size of pulverized coal; the softer (higher HGI) the coal, the greater amount of small particles which will produce overall better combustion and less CO concentrations.

Attached is a graph (Insert A) to show the effect of hardness on the performance of the pulverizers on coal particle size referred to as "fineness." As an example, both mixtures have been plotted based on a feed rate of 70,000 lb/hr. At this feed rate, the lower hardgrove mixture would be expected to give a fineness of $\approx$67 percent passing 200 mesh while the higher hardgrove mixture would be expected to give a fineness of $\approx$85 percent passing 200 mesh. This results in better fuel distribution and combustion and concomitantly lower CO generation. Insert B shows the hardness for the two mixtures used during the tests and an analysis of the petroleum coke used in the mixtures. If the fineness is reduced (i.e., a lower amount of small particles) it reduces the combustion efficiency and degrades the fuel distribution in the combustion zone, thus forming more CO. Therefore, the change in the CO noted during testing is primarily due to the difference between the high sulfur and low sulfur coal hardness and thus grindability.

The higher CO can also be affected by the oxygen (O_2) concentrations observed during the each test condition. The O_2 concentrations during Condition 3 (80/20 coal petroleum coke blend) averaged 6.9 percent. In contrast, the O_2 concentrations during Condition 1 (high-sulfur coal only) averaged 7.7 percent. CO and O_2 concentrations are inversely proportional, suggesting that the higher CO concentrations were a result of combustion conditions and not the fuel. This observation is confirmed by the results for Condition 2 in which O_2 concentrations were the

highest (7.8 percent) and CO emission rate was the lowest [0.05 pound per million British thermal units (lb/MMBtu)].

Table 1. Statistical Evaluation of Trial Test Burn for Co-Firing Petroleum Coke at City of Lakeland McIntosh Plant - Unit 3

Pollutant	Test Condition (a)	Average	"t" - distribution Lower 90% C.I.	"t" - distribution Upper 90% C.I.	Conclusions (b)
Particulate	1. HSC Only	0.0481	0.0381	0.0582	1=2>3
	2. HSC w/10% PC	0.0459	0.0329	0.0589	2=1>3
	3. LSC w/20% PC	0.0141	0.0096	0.0187	3<1&2
Sulfur Dioxide	1. HSC Only	1.0866	1.0639	1.1094	1=2>3
	2. HSC w/10% PC	1.1087	1.0618	1.0618	2=1>3
	3. LSC w/20% PC	0.8935	0.8585	0.9284	3<1&2
Nitrogen Oxides	1. HSC Only	0.5391	0.5353	0.5428	1=2>3
	2. HSC w/10% PC	0.5466	0.5329	0.5602	2=1>3
	3. LSC w/20% PC	0.4126	0.4052	0.4199	3<1&2
Carbon Monoxide	1. HSC Only	0.0054	0.0044	0.0064	1=2<3
	2. HSC w/10% PC	0.0050	0.0047	0.0053	2=1<3
	3. LSC w/20% PC	0.0890	0.0231	0.1549	3>1&2
Sulfuric Acid Mist	1. HSC Only	0.0240	0.0166	0.0315	1=2=3
	2. HSC w/10% PC	0.0213	0.0167	0.0258	2=1=3
	3. LSC w/20% PC	0.0255	0.0174	0.0336	3=1=2

(a) HSC = High Sulfur Coal; LSC = Low Sulfur Coal; PC = Petroleum Coke

(b) "1, 2, and 3" refer to test conditions; "=" means no significant difference between test conditions; "< and >" refers to a significant difference betwen test conditions.

Calculations for Table 1

Calculations:

PM HSC Only	
Run 2	0.054
Run 3	0.0483
Run 4	0.0421
Mean	0.04813333
STD. DEV.	0.00485958
V	2
ta/2	2.92
C.I.	0.01003383

PM-HSCw/10%PC	
Run 5	0.0399
Run 6	0.0432
Run 7	0.0546
Mean	0.0459
STD. DEV.	0.00629762
V	2
ta/2	2.92
C.I.	0.01300302

PM-LSCw/20%PC	
Run 8	0.0151
Run 9	0.0162
Run 10	0.0111
Mean	0.01413333
STD. DEV.	0.0021914
V	2
ta/2	2.92
C.I.	0.00452469

SO2 HSC Only	
Run 1	1.0744
Run 2	1.1011
Run 3	1.0844
Mean	1.08663333
STD. DEV.	0.01101403
V	2
ta/2	2.92
C.I.	0.02274124

SO2-HSCw/10%PC	
Run 4	1.1399
Run 5	1.0865
Run 6	1.0997
Mean	1.1087
STD. DEV.	0.02271035
V	2
ta/2	2.92
C.I.	0.04689124

SO2-LSCw/20%PC	
Run 7	0.9113
Run 8	0.8707
Run 9	0.8984
Mean	0.89346667
STD. DEV.	0.01693799
V	2
ta/2	2.92
C.I.	0.03497275

NOx HSC Only	
Run 1	0.5385
Run 2	0.5372
Run 3	0.5415
Mean	0.53906667
STD. DEV.	0.00180062
V	2
ta/2	2.92
C.I.	0.00371783

NOx-HSCw/10%PC	
Run 4	0.5544
Run 5	0.5382
Run 6	0.5471
Mean	0.54656667
STD. DEV.	0.00662437
V	2
ta/2	2.92
C.I.	0.01367767

NOx-LSCw/20%PC	
Run 7	0.4104
Run 8	0.4097
Run 9	0.4176
Mean	0.41256667
STD. DEV.	0.00357056
V	2
ta/2	2.92
C.I.	0.00737232

CO HSC Only	
Run 1	0.0061
Run 2	0.005
Run 3	0.0051
Mean	0.0054
STD. DEV.	0.00049666
V	2
ta/2	2.92
C.I.	0.00102547

CO-HSCw/10%PC	
Run 4	0.0051
Run 5	0.0048
Run 6	0.0051
Mean	0.005
STD. DEV.	0.00014142
V	2
ta/2	2.92
C.I.	0.000292

NOx-LSCw/20%PC	
Run 7	0.0845
Run 8	0.1301
Run 9	0.0523
Mean	0.08896667
STD. DEV.	0.03191837
V	2
ta/2	2.92
C.I.	0.06590351

Calculations for Table 1

H2SO4 HSC Only	
Run 1	0.0248
Run 2	0.028
Run 3	0.0193
Mean	0.02403333
STD. DEV.	0.00359289
V	2
ta/2	2.92
C.I.	0.00741843

H2SO4-HSCw/10%PC	
Run 4	0.0204
Run 5	0.0243
Run 6	0.0191
Mean	0.02126667
STD. DEV.	0.00220958
V	2
ta/2	2.92
C.I.	0.00456222

H2SO4-LSCw/20%PC	
Run 7	0.0208
Run 8	0.0304
Run 9	0.0254
Mean	0.02553333
STD. DEV.	0.00392032
V	2
ta/2	2.92
C.I.	0.00809448

40 CFR Part 60, Appendix C Calculation

H2SO4 HSC Only	
Run 1	0.0248
Run 2	0.028
Run 3	0.0193
Mean	0.02403333
Sa^2	0.00001936
Sp^2	0.00460525
t	0.39891799
t'	2.132

no significant difference

H2SO4-LSCw/20%PC	
Run 7	0.0208
Run 8	0.0304
Run 9	0.0254
Mean	0.02553333
Sa^2	0.00002305

40 CFR Part 60, Appendix C Calculation - Test

Run A	
Run 1	100
Run 2	95
Run 3	110
Mean	101.666667
Sa^2	58.3333333
Sp^2	6.45497224
t	3.47850543
t'	2.132

significant difference-same as CFR Example
Note: CFR example has round-off which produces slightly different values.

Run B	
Run 7	115
Run 8	120
Run 9	125
Mean	120
Sb^2	25

INSERT A

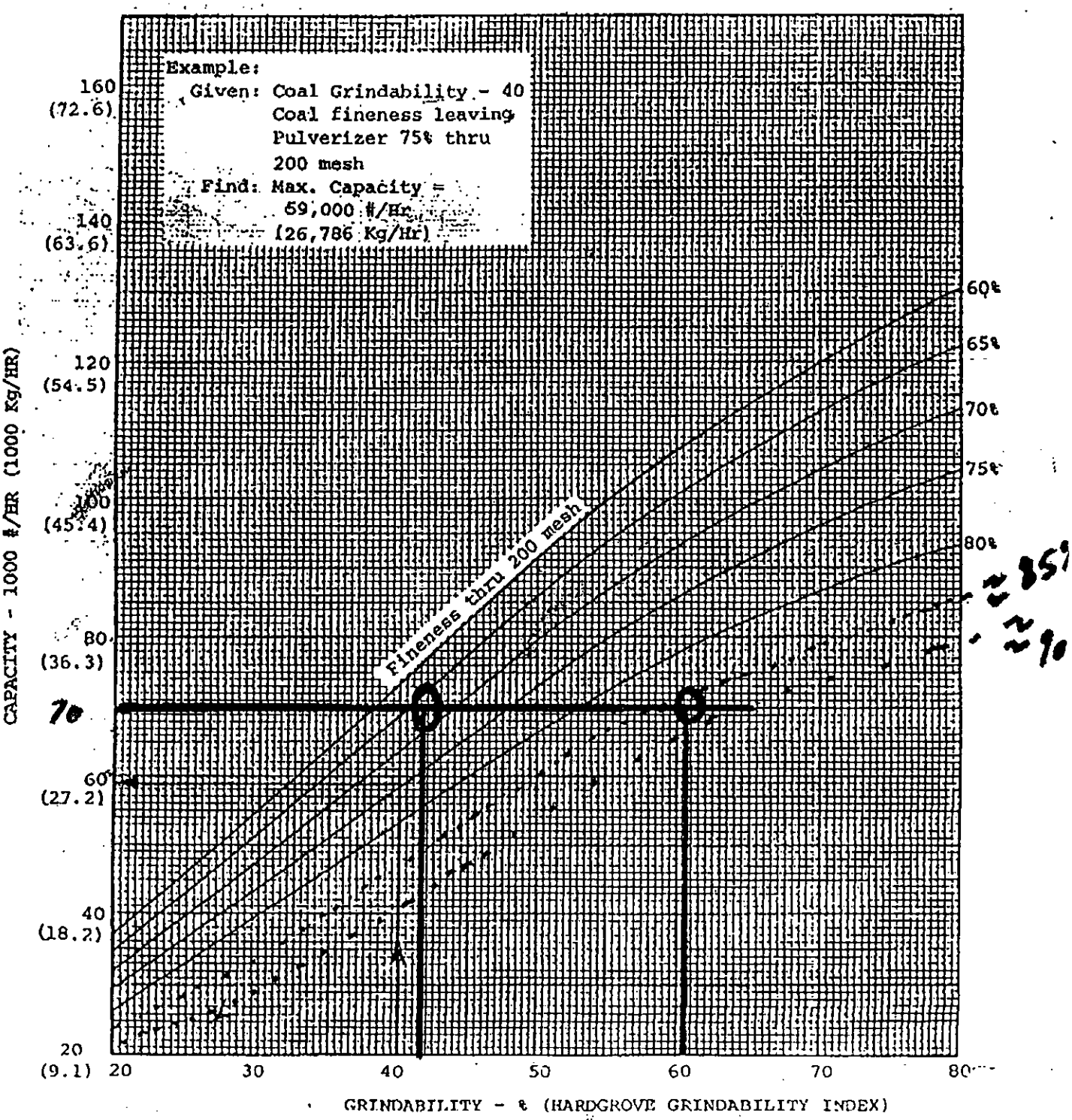
9P1 (FPG)
6R211 -(75)
7A3
57/10-5-77

THE BABCOCK & WILCOX COMPANY
FOSSIL POWER GENERATION DIVISION

ATTACHMENT A

PULVERIZED FUEL SYSTEMS
TYPE MPS 75 PULVERIZER
OPERATING INSTRUCTIONS

FIG. 8 MPS-75 PULVERIZER EXPECTED PERFORMANCE
(NOT CORRECTED FOR MOISTURE)



INSERT B

COAL ANALYSIS

McINTOSH POWER PLANT

DATE ANALYZED 2/17/94 DATE SAMPLED 2/15/94

SAMPLE POINT C-3 Auto Sampler DATE RECEIVED 2/16/94

SAMPLE ID # 112-94 SAMPLED BY Gandy

ANALYZED BY Gandy / Parish RELEASED BY SEP

PROXIMATE ANALYSIS

	AS RECEIVED	DRY BASIS	A-M FREE
% MOISTURE (TOTAL)	7.18		
% ASH	7.34	7.90	
% VOLATILE MATTER	32.25	34.74	37.77
% FIXED CARBON	53.24	57.36	62.28
BTU/LB	12,962	13,965	15,163
% SULFUR	1.54	1.66	1.81

HARDGROVE GRINDABILITY INDEX 43

COAL ANALYSIS

McINTOSH POWER PLANT

DATE ANALYZED	2/14/94	DATE SAMPLED	2/9/94
SAMPLE POINT	C-3 Auto Sampler	DATE RECEIVED	2/10/94
SAMPLE ID #	107-94	SAMPLED BY	Unknown
ANALYZED BY	Steve Parrish	RELEASED BY	SEP

PROXIMATE ANALYSIS

	AS RECEIVED	DRY BASIS	A-M FREE
% MOISTURE (TOTAL)	10.64		
% ASH	11.37	12.66	
% VOLATILE MATTER	23.38	26.17	29.96
% FIXED CARBON	54.66	61.17	70.04
BTU/LB	11,698	13,091	14,989
% SULFUR	2.83	3.17	3.63

HARDGROVE GRINDABILITY INDEX 61

SGS Commercial Testing & Engineering Co.

1212 N. 39th Street
Suite 323
Tampa, Florida 33605
Tel: (813) 248-6566
Fax: (813) 247-2562

January 18, 1994

KOCH CARBON, INC.
P. O. Box 2219
Wichita, KS 67201

CERTIFICATE OF ANALYSIS

KIND OF SAMPLE: PETROLEUM COKE
SAMPLE TAKEN AT: TECO, BIG BEND TERMINAL, TAMPA, FLORIDA
SAMPLE TAKEN BY: CT&E, TAMPA FROM BARGE "WANDA WHEELOCK"
DATED SAMPLED: JANUARY 16, 1994
DATE RECEIVED: JANUARY 17, 1994.

ANALYSIS REPORT NO. 08-1680

	AS RECEIVED	DRY BASIS
Moisture	10.35 %	xxxx
Ash	0.28 %	0.31 %
Volatile Matter	9.11 %	10.16 %
Fixed Carbon (by difference)	80.26 %	89.53 %
Sulfur	4.46 %	4.97 %
Gross Calorific Value	13761 Btu/lb	15339 Btu/lb
Moisture Ash Free Btu		15387

Hardgrove Grindability Index = 69

TRACE ELEMENTS P.P.M.

Silicon, Si	330
Calcium, Ca	155
Iron, Fe	130
Nickle, Ni	218
Vanadium, V	1090

SIZE ANALYSIS (Square Hole)

Over 3	Inch	3.79%
3 x 2	Inch	5.68%
2 x 1	Inch	16.63%
1 x 1/2"	Inch	15.53%
Under 1/2"	Inch	58.36%

COMMERCIAL TESTING & ENGINEERING CO.

Edward B. Linde
Branch Manager

EBL/vl

COAL ANALYSIS DATA

UNIT TRAIN ANALYSIS SHEET 1994

City of Lakeland C.D. McIntosh Unit Number 3

DATE	U.T.#	SULFUR	TONS	TONS/DATE
JAN				
4	1	0.96	9184.90	9,184.90
8	2	0.99	9552.97	18,737.87
11	3	0.94	9442.30	28,180.17
14	4	0.98	9487.57	37,667.74
26	5	0.94	9460.90	47,128.64
				47,128.64
JAN	5	0.96		
YTD	5	0.96		
FEB				
2	6	1.00	9472.62	56,601.26
3	7	2.60	9504.00	66,105.26
7	8	0.97	9306.60	75,411.86
7	9	1.73	9000.00	84,411.86
9	10	1.07	9177.00	93,588.86
10	11	0.98	9484.75	103,073.61
14	12	0.99	9661.97	112,735.58
16	13	1.00	9446.10	122,181.68
16	14	1.06	9336.00	131,517.68
23	15	1.38	9533.80	141,051.48
23	16	1.36	8966.60	150,018.08
				150,018.08
FEB	11	1.28		
YTD	16	1.18		
MAR				
1	17	0.96	9239.70	159,257.78
15	18	1.03	9566.10	168,823.88
15	19	1.02	9279.70	178,103.58
20	20	1.01	9564.00	187,667.58
22	21	1.02	9526.60	197,194.18
25	22	1.05	9559.47	206,753.65
28	23	0.86	9444.90	216,198.55
				216,198.55
MAR	7	0.99		
YTD	23	1.12		
APRIL				
1	24	1.09	9458.60	225,657.15
4	25	0.99	9431.40	235,088.55
8	26	0.90	9513.97	244,602.52
10	27	1.01	9305.20	253,907.72
13	28	1.04	9575.07	263,482.79
15	29	0.98	9134.80	272,617.59
21	30	1.05	9567.32	282,184.91
24	31	0.88	9510.07	291,694.98
27	32	1.00	9128.85	300,823.83
				300,823.83
APRIL	9	0.99		
YTD	32	1.09		

UNIT TRAIN ANALYSIS SHEET 1994

City of Lakeland C.D. McIntosh Unit Number 3

DATE	U.T.#	SULFUR	TONS	TONS/DATE
MAY				
1	33	1.00	9570.00	310,393.83
4	34	0.97	9332.10	319,725.93
8	35	1.04	9529.10	329,255.03
10	36	0.98	9358.30	338,613.33
14	37	1.03	9573.55	348,186.88
15	38	0.87	9553.32	357,740.20
21	39	0.89	9513.87	367,254.07
22	40	0.86	9513.45	376,767.52
28	41	0.70	9501.65	386,269.17
				386,269.17
MAY	9	0.93		
YTD	41	1.05		
JUNE				
3	42	1.22	9530.50	395,799.67
3	43	0.99	9249.40	405,049.07
8	44	1.03	9535.00	414,584.07
9	45	0.96	9269.70	423,853.77
13	46	1.06	9566.95	433,420.72
14	47	1.34	9544.50	442,965.22
18	48	1.10	9428.30	452,393.52
21	49	1.34	9410.00	461,803.52
24	50	1.38	9322.46	471,125.98
				471,125.98
JUNE	9	1.16		
YTD	50	1.07		
JULY				
2	51	1.30	9614.90	480,740.88
2	52	1.09	9506.10	490,246.98
9	53	1.07	9050.17	499,297.15
9	54	1.26	9512.40	508,809.55
16	55	1.26	9946.50	518,756.05
17	56	0.93	8566.30	527,322.35
21	57	1.26	9639.50	536,961.85
22	58	1.08	9573.00	546,534.85
27	59	0.99	9264.80	555,799.65
				555,799.65
JULY	9	1.14		
YTD	59	1.08		
AUG				
1	60	1.30	9469.10	565,268.75
1	61	1.08	9569.27	574,838.02
6	62	1.28	9515.50	584,353.52
8	63	1.00	9127.10	593,480.62
10	64	1.30	9604.50	603,085.12
13	65	1.05	9545.37	612,630.49
16	66	1.06	9574.25	622,204.74
18	67	1.34	9116.90	631,321.64
22	68	0.99	9255.80	640,577.44

UNIT TRAIN ANALYSIS SHEET 1994

City of Lakeland C.D. McIntosh Unit Number 3

DATE	U.T.#	SULFUR	TONS	TONS/DATE
24	69	0.99	9251.40	649,828.84
				649,828.84
AUG	10	1.14		
YTD	69	1.09		
SEPT				
6	70	1.01	9145.40	658,974.24
6	71	1.06	9580.17	668,554.41
11	72	1.07	9571.80	678,126.21
12	73	1.05	9238.50	687,364.71
16	74	1.10	9590.02	696,954.73
18	75	1.01	9123.40	706,078.13
26	76	0.99	9308.90	715,387.03
				715,387.03
SEPT	7	1.04		
YTD	76	1.09		
OCT				
1	77	0.99	9204.70	724,591.73
2	78	1.26	9845.80	734,437.53
6	79	1.30	9587.80	744,025.33
7	80	1.08	9375.55	753,400.88
12	81	1.24	9357.40	762,758.28
14	82	1.09	9575.57	772,333.85
17	83	1.06	9594.72	781,928.57
20	84	1.26	9418.70	791,347.27
22	85	0.99	9324.60	800,671.87
				800,671.87
OCT	9	1.14		
YTD	85	1.09		
NOV				
1	86	0.99	9850.50	810,522.37
1	87	1.34	9511.30	820,033.67
7	88	1.40	9472.90	829,506.57
7	89	1.04	9462.60	838,969.17
13	90	1.07	9565.10	848,534.27
13	91	1.04	9969.20	858,503.47
19	92	1.07	9588.55	868,092.02
20	93	1.36	9428.60	877,520.62
25	94	1.40	9609.90	887,130.52
28	95	1.68	9404.95	896,535.47
				896,535.47
NOV	10	1.24		
YTD	95	1.11		
DEC				
3	96	1.85	9565.20	906,100.67
4	97	1.06	9561.22	915,661.89
9	98	1.40	9524.20	925,186.09
10	99	1.05	9498.27	934,684.36
15	100	1.28	9599.00	944,283.36
15	101	1.10	9583.40	953,866.76

UNIT TRAIN ANALYSIS SHEET 1994

City of Lakeland C.D. McIntosh Unit Number 3

DATE	U.T.#	SULFUR	TONS	TONS/DATE
20	102	1.02	9460.70	963,327.46
21	103	1.42	9424.20	972,751.66
29	104	1.28	9180.00	981,931.66
30	105	1.34	9419.40	991,351.06
				991,351.06
DEC	10	1.28		
YTD	105	1.12		

UNIT TRAIN ANALYSIS SHEET 1995
City of Lakeland
C.D. McIntosh Unit Number 3

DATE	U.T.#	SULFUR	TONS	TONS/DATE
JAN				
4	1	0.98	9500.70	9,500.70
5	2	1.38	9642.20	19,142.90
9	3	0.96	9489.80	28,632.70
10	4	1.32	9432.90	38,065.60
14	5	1.49	9425.40	47,491.00
14	6	1.14	9350.00	56,841.00
19	7	1.48	9510.20	66,351.20
24	8	1.00	9436.10	75,787.30
25	9	0.98	9411.60	85,198.90
30	10	1.42	9496.80	94,695.70
31	11	0.99	9276.50	103,972.20
				103,972.20
JAN	11	1.20		
YTD	11	1.20		
FEB				
5	12	1.01	9362.50	113,334.70
6	13	1.38	9359.50	122,694.20
10	14	0.99	9499.90	132,194.10
13	15	1.40	9418.70	141,612.80
16	16	1.05	9223.75	150,836.55
18	17	1.36	9650.10	160,486.65
21	18	1.34	9340.40	169,827.05
24	19	1.01	9536.60	179,363.65
28	20	1.34	9617.20	188,980.85
				188,980.85
FEB	9	1.21		
YTD	20	1.20		
MAR				
1	21	0.99	9222.95	198,203.80
5	22	1.00	9259.00	207,462.80
8	23	1.34	9430.70	216,893.50
13	24	1.02	9422.30	226,315.80
14	25	1.18	9255.40	235,571.20
19	26	0.99	9320.90	244,892.10
20	27	1.34	9743.50	254,635.60
25	28	1.34	9700.40	264,336.00

UNIT TRAIN ANALYSIS SHEET 1995
City of Lakeland
C.D. McIntosh Unit Number 3

DATE	U.T.#	SULFUR	TONS	TONS/DATE
26	29	1.34	9659.30	273,995.30
				273,995.30
MAR	9	1.17		
YTD	29	1.19		
APRIL				
				273,995.30
APRIL	0	0.00		
YTD	29	1.19		
MAY				
1	30	1.30	9611.10	283,606.40
1	31	0.90	9166.50	292,772.90
6	32	1.32	9451.20	302,224.10
9	33	1.39	9247.25	311,471.35
11	34	1.28	9506.00	320,977.35
16	35	0.94	9445.00	330,422.35
18	36	1.30	9497.40	339,919.75
22	37	0.97	9388.80	349,308.55
23	38	0.92	9279.00	358,587.55
30	39	0.91	9214.20	367,801.75
31	40	0.97	9296.70	377,098.45
				377,098.45
MAY	11	1.11		
YTD	40	1.17		
JUNE				
1	41	1.34	9608.30	386,706.75
7	42	0.95	9444.40	396,151.15
10	43	1.40	9748.60	405,899.75
12	44	1.42	9586.30	415,486.05
16	45	1.50	9605.00	425,091.05
17	46	1.48	9721.40	434,812.45
21	47	1.50	9626.00	444,438.45
23	48	1.48	9602.50	454,040.95
26	49	1.42	9552.60	463,593.55
30	50	1.42	9627.00	473,220.55
				473,220.55
JUNE	10	1.39		
YTD	50	1.22		

UNIT TRAIN ANALYSIS SHEET 1995
City of Lakeland
C.D. McIntosh Unit Number 3

DATE	U.T.#	SULFUR	TONS	TONS/DATE
JULY				
2	51	1.40	9690.00	482,910.55
6	52	1.44	9353.00	492,263.55
9	53	1.42	9525.30	501,788.85
11	54	1.01	9321.90	511,110.75
16	55	1.40	9301.70	520,412.45
17	56	0.99	9366.20	529,778.65
21	57	0.98	9362.40	539,141.05
22	58	1.34	9383.10	548,524.15
				548,524.15
JULY	8	1.25		
YTD	58	1.22		
AUG				
2	59	1.44	9513.80	558,037.95
4	60	1.44	9459.10	567,497.05
7	61	0.98	9585.60	577,082.65
11	62	1.42	9543.60	586,626.25
12	63	1.40	9478.80	596,105.05
16	64	0.99	9510.50	605,615.55
18	65	1.40	9573.60	615,189.15
22	66	1.30	9399.70	624,588.85
23	67	1.34	9465.10	634,053.95
28	68	0.97	9526.70	643,580.65
				643,580.65
AUG	10	1.27		
YTD	68	1.23		
SEPT				
2	69	1.32	9529.10	653,109.75
8	70	0.93	9536.30	662,646.05
13	71	1.28	9449.10	672,095.15
16	72	0.92	9501.70	681,596.85
19	73	1.34	9639.80	691,236.65
22	74	0.92	9494.00	700,730.65
27	75	1.29	9483.10	710,213.75
				710,213.75
SEPT	7	1.14		
YTD	75	1.22		

UNIT TRAIN ANALYSIS SHEET 1995
City of Lakeland
C.D. McIntosh Unit Number 3

DATE	U.T.#	SULFUR	TONS	TONS/DATE
OCT				
5	76	0.00	9396.80	719,610.55
9	77		9349.60	728,960.15
				728,960.15
OCT	2	0.00		
YTD	77	1.19		
NOV				
1	0	0.00	0.00	728,960.15
				728,960.15
NOV	1	0.00		
YTD	78	1.19		
DEC				
0	0	0.00	0.00	728,960.15
				728,960.15
DEC	1	0.00		
YTD	79	1.19		

FROM : T PHONE NO. : 9414996688 Sep. 22 1995 02:57PM P2

LAKELAND ELECTRIC & WATER

Excellence Is Our Goal, Service Is Our Job

MCINTOSH POWER PLANT
3030 E. BAKE PARKER DR.
LAKELAND, FLORIDA 33805

Ph. (813) 499-6600
FAX (813) 499-6686

July 14, 1994

McIntosh Power Plant C-3 Stack Test

Date of Composite Coal Sample: June 08, 1994
Lab I.D. 461-94
Sulfur %WT.: 1.26 Method: Parr 1760

BTU per lb.: 12,847 Method: D-2015

DOUGLAS DOERR
E&W ENGINEER

$\frac{1.26}{100} \times 2 \times \frac{1}{12,847} \times 10^6 = 1.961518 \text{ lb/MMBTU}$

0.6865

FROM : T PHONE NO. : 9414996688 Sep. 22 1995 02:58PM P3

Excellence Is Our Goal, Service Is Our Job

FAX (813) 499-6686

July 31, 1995

McIntosh Power Plant C-3 Stack Test

Date of Composite Coal Sample: June 15, 1995

Lab I.D. 549-95

Sulfur %WT.: 1.29 Method: Parr 1760

BTU per Lb.: 12,806 Method: D-2015

John O'Mahony
Power Production Foreman

$\frac{1.29}{100} \times 2 \times \frac{1}{12,806} \times 10^6 = 20147$ lb/mBTU uncontrolled

0.705 lb/mmBTU

0.705
0.687
$\bar{x} = 0.696$ lb/mmBTU

40 CFR PART 60

APPENDIX C

lation of RM and CERMS Data, Number of RM Tests, Correlation of RM and CERMS Data, Number of RM Tests, and Calculations. This is the same as PS 2, Sections 7.1, 7.2, 7.3, and 7.5, respectively. Note: For Method 16, a sample is made up of at least three separate injects equally spaced over time. For Method 16A, a sample is collected for at least 1 hour.

3.2 Reference Methods. Unless otherwise specified in an applicable subpart of the regulations, Method 16, Method 16A, or other approved alternative, shall be the RM for TRS.

4. Bibliography

1. Department of Commerce. Experimental Statistics. National Bureau of Standards. Handbook 91. 1963. Paragraphs 3-3.1.4, p. 3-31.

2. A Guide to the Design, Maintenance and Operation of TRS Monitoring Systems. National Council for Air and Stream Improvement Technical Bulletin No. 89. September 1977.

3. Observation of Field Performance of TRS Monitors on a Kraft Recovery Furnace. National Council for Air and Stream Improvement Technical Bulletin No. 91. January 1978.

PERFORMANCE SPECIFICATION 6—SPECIFICATIONS AND TEST PROCEDURES FOR CONTINUOUS EMISSION RATE MONITORING SYSTEMS IN STATIONARY SOURCES

1. Applicability and Principle

1.1 Applicability. The applicability for this specification is the same as Section 1.1 of Performance Specification 2 (PS 2), except this specification is to be used for evaluating the acceptability of continuous emission rate monitoring systems (CERMS's). The installation and measurement location specifications, performance specification test procedure, data reduction procedures, and reporting requirements of PS 2, Section 3, 5, 8, and 9, apply to this specification.

1.2 Principle. Reference method (RM), calibration drift (CD), and relative accuracy (RA) tests are conducted to determine that the CERMS conforms to the specification.

2. Definitions

The definitions are the same as in Section 2 of PS 2, except that this specification refers to the continuous emission rate monitoring system rather than the continuous emission monitoring system. The following definitions are added:

2.1 Continuous Emission Rate Monitoring System (CERMS). The total equipment required for the determination and recording of the pollutant mass emission rate (in terms of mass per unit of time).

2.2 Flow Rate Sensor. That portion of the CERMS that senses the volumetric flow rate and generates an output proportional to flow rate. The flow rate sensor shall have provision[illegible] check[illegible] CD for each flow rate parameter that it measures individually (e.g., velocity pressure).

3. Performance and Equipment Specifications

3.1 Data Recorder Scale. Same as Section 4.1 of PS 2.

3.2 CD. Since the CERMS includes analyzers for several measurements, the CD shall be determined separately for each analyzer in terms of its specific measurement. The calibration for each analyzer used for the measurement of flow rate except a temperature analyzer shall not drift or deviate from either of its reference values by more than 4 percent of 1.25 times the average potential absolute value for that measurement. For a temperature analyzer, the specification is 1.5 percent of 1.25 times the average potential absolute temperature. The CD specification for each analyzer for which other PS's have been established (e.g., PS 2 for SO_2 and NO_x) shall be the same as in the applicable PS.

3.3 CERMS RA. The RA of the CERMS shall be no greater than 20 percent of the mean value of the RM's test data in terms of the units of the emission standard, or 10 percent of the applicable standard, whichever is greater.

4. CD Test Procedure

The CD measurements are to verify the ability of the CERMS to conform to the established CERMS calibrations used for determining the emission rate. Therefore, if periodic automatic or manual adjustments are made to the CERMS zero and calibration settings, conduct the CD tests immediately before these adjustments, or conduct them in such a way what CD can be determined.

Conduct the CD tests for pollutant concentration at the two values specified in Section 4.1 of PS 2. For each of the other parameters that are selectively measured by the CERMS (e.g., velocity pressure), use two analogous values: one that represents zero to 20 percent of the high-level value (a value that is between 1.25 and 2 times the average potential value) for that parameter, and one that represents 50 to 100 percent of the high-level value. Introduce, or activate internally, the reference signals to the CERMS (these need not be certified). Record the CERMS response to each, and subtract this value from the respective reference value (see example data sheet in Figure 6-1).

5. RA Test Procedure

5.1 Sampling Strategy for RM's Tests, Correlation of RM and CERMS Data, Number of RM's Tests, and Calculations. These are the same as PS 2, Sections 7.1, 7.2, 7.3, and 7.5, respectively. Summarize the results on a data sheet. An example is shown in Figure 6-2. The RA test may be conducted during the CD test period.

Reference Methods (RM's). Unless otherwise specified in the applicable subpart of the regulations, the RM for the pollutant gas is the appendix A method that is cited for compliance test purposes, or its approved alternatives. Methods 2, 2A, 2B, 2C, or 2D, as applicable are the RM's for the determination of volumetric flow rate.

6. Bibliography

1. Brooks, E.F., E.C. Beder, C.A. Flegal, D.J. Luciani, and R. Williams. Continuous Measurement of Total Gas Flow Rate from Stationary Sources. U.S. Envionmental Protection Agency. Research Triangle Park, NC. Publication No. EPA-650/2-75-020. February 1975. 248 p.

PERFORMANCE SPECIFICATION 7—SPECIFICATIONS AND TEST PROCEDURES FOR HYDROGEN SULFIDE CONTINUOUS EMISSION MONITORING SYSTEMS IN STATIONARY SOURCES

1. Applicability and Principle

1.1 *Applicability.* 1.1.1 This specification is to be used for evaluating the acceptability of hydrogen sulfide (H_2S) continuous emission monitoring systems (CEMS's) at the time of or soon after installation and whenever specified in an applicable subpart of the regulations.

1.1.2 This specification is not designed to evaluate the installed CEMS performance over an extended period of time nor does it identify specific calibration techniques and other auxiliary procedures to assess CEMS performance. The source owner or operator, however, is responsible to calibrate, maintain, and operate the CEMS. To evaluate CEMS performance, the Administrator may require, under Section 114 of the Act, the source owner or operator to conduct CEMS performance evaluations at other times besides the initial test. *See* §60.13(c).

1.1.3 The definitions, installation specifications; test procedures, data reduction procedures for determining calibration drifts (CD) and relative accuracy (RA), and reporting of Performance Specification 2 (PS 2), Sections 2, 3, 5, 6, 8, and 9 apply to this specification.

1.2 Principle. Reference method (RM), CD, and RA tests are conducted to determine that the CEMS conforms to the specification.

2. Performance and Equipment Specifications

2.1 *Instrument zero and span.* This specification is the same as Section 4.1 of PS 2.

2.2 *Calibration drift.* The CEMS calibration must not drift or deviate from the reference value of the calibration gas or reference source by more than 5 percent of the established span value for 6 out of 7 test days (e.g., the established span value is 300 ppm for subpart J fuel gas combustion devices).

2.3 *Relative accuracy.* The RA of the CEMS shall be no greater than 20 percent of the mean value of the RM test data in terms of the units of the emission standard or 10 percent of the applicable standard, whichever is greater.

3. Relative Accuracy Test Procedure

3.1 Sampling Strategy for RM Tests, Correlation of RM and CEMS Data Number of RM Tests, and Calculations. These are the same as that in PS 2, §7.1, 7.2, 7.3, and 7.5, respectively.

3.2 Reference Methods. Unless otherwise specified in an applicable subpart of the regulation, Method 11 is the RM for this PS.

4. Bibliography

1. U.S. Environmental Protection Agency. Standards of Performance for New Stationary Sources; Appendix B; Performance Specifications 2 and 3 for SO_2, NO_x, CO_2, and O_2 Continuous Emission Monitoring Systems; Final Rule. 48 CFR 23608. Washington, DC, U.S. Government Printing Office. May 25, 1983.

2. U.S. Government Printing Office. Gaseous Continuous Emission Monitoring Systems—Performance Specification Guidelines for SO_2, NO_x, CO_2, O_2, and TRS. U.S. Environmental Protection Agency. Washington, DC, EPA-450/3-82-026. October 1982. 26p.

3. Maines, G.D., W.C. Kelly (Scott Environmental Technology, Inc.), and J.B. Homolya. Evaluation of Monitors for Measuring H_2S in Refinery Gas. Prepared for the U.S. Environmental Protection Agency. Research Triangle Park, NC, Contract No. 68-02-2707. 1978. 60 p.

4. Ferguson, B.B., R.E. Lester (Harmon Engineering and Testing), and W.J. Mitchell. Field Evaluation of Carbon Monoxide and Hydrogen Sulfide Continuous Emission Monitors at an Oil Refinery. Prepared for the U.S. Environmental Protection Agency. Research Triangle Park, NC. Publication No. EPA-600/4-82-054. August 1982. 100 p.

[48 FR 13327, Mar. 30, 1983 and 48 FR 23611, May 25, 1983, as amended at 48 FR 32986, July 20, 1983; 51 FR 31701, Aug. 5, 1985; 52 FR 17556, May 11, 1987; 52 FR 30675, Aug. 18, 1987; 52 FR 34650, Sept. 14, 1987; 53 FR 7515, Mar. 9, 1988; 53 FR 41335, Oct. 21, 1988; 55 FR 18876, May 7, 1990; 55 FR 40178, Oct. 2, 1990; 55 FR 47474, Nov. 14, 1990; 56 FR 5526, Feb. 11, 1991]

APPENDIX C TO PART 60—DETERMINATION OF EMISSION RATE CHANGE

1. *Introduction.*

1.1 The following method shall be used to determine whether a physical or operational change to an existing facility resulted in an increase in the emission rate to the atmosphere. The method used is the Student's *t*

test, commonly used to make inferences from small samples.

2. *Data.*

2.1 Each emission test shall consist of n runs (usually three) which produce n emission rates. Thus two sets of emission rates are generated, one before and one after the change, the two sets being of equal size.

2.2 When using manual emission tests, except as provided in §60.8(b) of this part, the reference methods of appendix A to this part shall be used in accordance with the procedures specified in the applicable subpart both before and after the change to obtain the data.

2.3 When using continuous monitors, the facility shall be operated as if a manual emission test were being performed. Valid data using the averaging time which would be required if a manual emission test were being conducted shall be used.

3. *Procedure.*

3.1 Subscripts a and b denote prechange and postchange respectively.

3.2 Calculate the arithmetic mean emission rate, E, for each set of data using Equation 1.

$$E = \sum_{i=1}^{n} \frac{E_i}{n} = \frac{E_1 + E_2 \ldots + E_n}{n} \quad (1)$$

Where:

E_i=Emission rate for the i th run.

n=number of runs.

3.3 Calculate the sample variance, S^2, for each set of data using Equation 2.

$$S^2 = \frac{\sum_{i=1}^{n} (E_i - E)^2}{n-1} = \frac{\sum_{i=1}^{n} E_i^2 - \left(\sum_{i=1}^{n} E_i\right)^2 / n}{n-1} \quad (2)$$

3.4 Calculate the pooled estimate, S_p, using Equation 3.

$$S_p = \left[\frac{(n_a - 1)\, S_a^2 + (n_b - 1)\, S_b^2}{n_a + n_b - 2}\right]^{1/2} \quad (3)$$

3.5 Calculate the test statistic, t, using Equation 4.

$$t = \frac{E_b - E_a}{S_p \left[\frac{1}{n_a} + \frac{1}{n_b}\right]^{1/2}} \quad (4)$$

4. *Results.*

4.1 If $E_b > E_a$ and $t > t'$, where t' is the critical value of t obtained from Table 1, then with 95% confidence the difference between E_a and E_a is significant, and an increase in emission rate to the atmosphere has occurred.

TABLE 1

Degrees of freedom ($n_a + n_b - 2$)	t' (95 percent confidence level)
2	2.920
3	2.353
4	2.132
5	2.015
6	1.943
7	1.895
8	1.860

For greater than 8 degrees of freedom, see any standard statistical handbook or text.

5. Assume the two performance tests produced the following set of data:

Test a	Test b
Run 1. 100	115
Run 2. 95	120
Run 3. 110	125

5.2 Using Equation 1—

$E_a = 100+95+110/3 = 102$

$E_b = 115+120+125/3 = 120$

5.3 Using Equation 2—

$S_a^2 = (100-102)^2+(95-102)^2+(110-102)^2/3-1 = 58.5$

$S_b^2 = (115-120)^2+(120-120)^2+(125-120)^2/3-1 = 25$

5.4 Using Equation 3—

$S_p = [(3-1)(58.5)+(3+1)(25)/3+3-2]^{1/2} = 6.46$

5.5 Using Equation 4—

$$t = \frac{120-102}{6.46\left[\frac{1}{3}+\frac{1}{3}\right]^{1/2}} = 3.412$$

5.6 Since $(n^1+n^2-2)=4$, $t'=2.132$ (from Table 1). Thus since $t > t'$ the difference in the values of E_a and E_b is significant, and there has been an increase in emission rate to the atmosphere.

6. *Continuous Monitoring Data.*

6.1 Hourly averages from continuous monitoring devices, where available, should be used as data points and the above procedure followed.

[40 FR 58420, Dec. 16, 1975]

APPENDIX D TO PART 60—REQUIRED EMISSION INVENTORY INFORMATION

(a) Completed NEDS point source form(s) for the entire plant containing the designated facility, including information on the applicable criteria pollutants. If data concerning the plant are already in NEDS, only that information must be submitted which is necessary to update the existing

NEDS record for that plant. Plant and point identification codes for NEDS records shall correspond to those previously assigned in NEDS; for plants not in NEDS, these codes shall be obtained from the appropriate Regional Office.

(b) Accompanying the basic NEDS information shall be the following information on each designated facility:

(1) The state and county identification codes, as well as the complete plant and point identification codes of the designated facility in NEDS. (The codes are needed to match these data with the NEDS data.)

(2) A description of the designated facility including, where appropriate:

(i) Process name.

(ii) Description and quantity of each product (maximum per hour and average per year).

(iii) Description and quantity of raw materials handled for each product (maximum per hour and average per year).

(iv) Types of fuels burned, quantities and characteristics (maximum and average quantities per hour, average per year).

(v) Description and quantity of solid wastes generated (per year) and method of disposal.

(3) A description of the air pollution control equipment in use or proposed to control the designated pollutant, including:

(i) Verbal description of equipment.

(ii) Optimum control efficiency, in percent. This shall be a combined efficiency when more than one device operates in series. The method of control efficiency determination shall be indicated (e.g., design efficiency, measured efficiency, estimated efficiency).

(iii) Annual average control efficiency, in percent, taking into account control equipment down time. This shall be a combined efficiency when more than one device operates in series.

(4) An estimate of the designated pollutant emissions from the designated facility (maximum per hour and average per year). The method of emission determination shall also be specified (e.g., stack test, material balance, emission factor).

[40 FR 53349, Nov. 17, 1975]

APPENDIX E TO PART 60—[RESERVED]

APPENDIX F TO PART 60—QUALITY ASSURANCE PROCEDURES

PROCEDURE 1. QUALITY ASSURANCE REQUIREMENTS FOR GAS CONTINUOUS EMISSION MONITORING SYSTEMS USED FOR COMPLIANCE DETERMINATION

1. Applicability and Principle

1.1 Applicability. Procedure 1 is used to evaluate the effectiveness of quality control (QC) and quality assurance (QA) procedures and the quality of data produced by any con-

tinuous emission monitoring system (CEMS) that is used for determining compliance with the emission standards on a continuous basis as specified in the applicable regulation. The CEMS may include pollutant (e.g., SO_2 and NO_x) and diluent (e.g., O_2 or CO_2) monitors.

This procedure specifies the minimum QA requirements necessary for the control and assessment of the quality of CEMS data submitted to the Environmental Protection Agency (EPA). Source owners and operators responsible for one or more CEMS's used for compliance monitoring must meet these minimum requirements and are encouraged to develop and implement a more extensive QA program or to continue such programs where they already exist.

Data collected as a result of QA and QC measures required in this procedure are to be submitted to the Agency. These data are to be used by both the Agency and the CEMS operator in assessing the effectiveness of the CEMS QC and QA procedures in the maintenance of acceptable CEMS operation and valid emission data.

Appendix F, Procedure 1 is applicable December 4, 1987. The first CEMS accuracy assessment shall be a relative accuracy test audit (RATA) (see section 5) and shall be completed by March 4, 1988 or the date of the initial performance test required by the applicable regulation, whichever is later.

1.2 Principle. The QA procedures consist of two distinct and equally important functions. One function is the assessment of the quality of the CEMS data by estimating accuracy. The other function is the control and improvement of the quality of the CEMS data by implementing QC policies and corrective actions. These two functions form a control loop: When the assessment function indicates that the data quality is inadequate, the control effort must be increased until the data quality is acceptable. In order to provide uniformity in the assessment and reporting of data quality, this procedure explicitly specifies the assessment methods for response drift and accuracy. The methods are based on procedures included in the applicable performance specifications (PS's) in appendix B of 40 CFR part 60. Procedure 1 also requires the analysis of the EPA audit samples concurrent with certain reference method (RM) analyses as specified in the applicable RM's.

Because the control and corrective action function encompasses a variety of policies, specifications, standards, and corrective measures, this procedure treats QC requirements in general terms to allow each source owner or operator to develop a QC system that is most effective and efficient for the circumstances.

2. Definitions

2.1 Continuous Emission Monitoring Sys-