LAKELAND
ELECTRIC & WATER

(813) 499-6603

Excellence Is Our Goal, Service Is Our Job

Farzie Shelton
ENVIRONMENTAL COORDINATOR, Ch E.

June 7, 1995

RECEIVED

JUN 7 1995

Division of Air
Resources Management

VIA HAND DELIVERY

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

RE: City of Lakeland; C.D. McIntosh Unit No. 3
Requests to Revise PSD Permit (PSD-FL-8) and
Modify Site Certification (PA-78-06)

Dear Howard:

The City of Lakeland would like to thank you again for meeting with us at the C.D. McIntosh Power Plant on May 2 and for meeting with us at your offices on April 21 to discuss the City's request to revise its Prevention of Significant Deterioration Permit for Unit No. 3. In response to the Department's request, the City submitted additional information on May 17, 1995, which we hope will provide the Department with sufficient data to complete its review and issue the requested revision. Subsequently, the City received a letter dated May 18, 1995, from Al Linero attaching two memoranda describing a coal-fired unit in Illinois which was permitted by the U.S. Environmental Protection Agency (EPA) at the same time as the McIntosh Unit No. 3 was being permitted by EPA.

We appreciate the Department directing our attention to these memoranda. The November 1978 memorandum from EPA Headquarters clarifies that while "Best Available Control Technology" determinations may require more control than an old New Source Performance Standard (NSPS), each determination is made on a case-by-case basis. EPA may presume that a new source will be able to comply with proposed NSPS standards but that presumption may be rebutted and, again, each determination is case-by-case. The unit described in the memoranda is similar to the McIntosh Unit No. 3, only larger (650 MW compared to 364 MW). It is very interesting to note that the PSD permit issued in August of 1979 for the Illinois unit (eight months *after* the McIntosh permit was issued) provides for a sulfur dioxide limit of 0.96 lb/mmBtu[1] based on a thirty-day rolling average, with *no requirement to install a scrubber.* (A copy of the PSD permit and final determination are enclosed for your information.) Since

[1] It is our understanding that this limit was accepted at least in part because of ambient air quality standard concerns. In fact, annual limits were eventually accepted because of ambient air quality concerns.

no scrubber or sulfur dioxide removal device was required, no corresponding sulfur dioxide removal efficiency was required. EPA's final BACT determination for that unit recognizes that standards under NSPS Subpart Da had been *proposed* but did *not* require compliance with the proposed standards. Instead, EPA issued an independent BACT determination, finding that an emission limit of 0.96 lb/mmBtu based on a 30-day rolling average was sufficient for BACT, without the need for a scrubber or sulfur dioxide removal efficiencies (as *proposed* under NSPS Subpart Da). The *proposed* NSPS Subpart Da standards were more stringent than the *final* standards, requiring scrubbing with a minimum 85 percent sulfur dioxide removal efficiency unless emissions were below 0.20 lb/mmBtu.

As you may recall, the sulfur dioxide limit being proposed by the City of Lakeland for the McIntosh Unit No. 3 is 0.90 lb/mmBtu based on a thirty-day rolling average. In addition, Lakeland is proposing to operate its scrubber at all times, with a minimum overall sulfur dioxide removal efficiency of 85 percent whenever high sulfur coal is burned and 60 percent whenever sulfur dioxide emissions are 0.90 lb/mmBtu or less (also based on a thirty-day rolling average). Because the EPA-issued permit for the Illinois unit was issued subsequent to the McIntosh Unit No. 3 permit and contains a less stringent emission limit than what has been proposed by the City, it seems reasonable for the Department to revise Unit No. 3's permit as requested. Not only is the emission limit proposed by the City lower than the limit in the EPA-issued permit for the Illinois unit (0.90 vs. 0.96 lb/mmBtu), the City has proposed to operate its sulfur dioxide scrubber with 85 and 60 percent overall removal efficiencies.

In other words, if the "Best Available Control Technology" was determined by EPA to be 0.96 lb/mmBtu, thirty-day rolling average, with no scrubbing in August of 1979, it would certainly be reasonable for a BACT determination for a December 1978 permit to be at least as stringent. The City's proposal would, in fact, be *more* stringent than the August 1979 BACT determination for the Illinois unit. We hope that you consider this when deciding whether to revise the City of Lakeland's permit as requested.

If you have any questions or would like any additional information regarding this issue, please let me know. Again, we want to thank you and your staff for your continued cooperation in this matter.

Sincerely,

Farzie Shelton/arm

Farzie Shelton
Environmental Coordinator

cc: Clair Fancy, FDEP
Al Linero, FDEP
Martin Costello, FDEP
Jewell Harper, EPA
Brian Beals, EPA
Ken Kosky, KBN
Angela Morrison, HGSS

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION VII
324 EAST ELEVENTH STREET
KANSAS CITY, MISSOURI - 64106

August 7, 1979

Mr. R.B. Miller
Vice President - Operations
Iowa-Illinois Gas and Electric Company
2016 East Second Street
Davenport, Iowa 52808

Dear Mr. Miller:

Your application for a Prevention of Significant Air Quality Deterioration (PSD) permit has been reviewed in accordance with the PSD regulations found at 43 FR 26403, and codified in the Code of Federal Regulations at 40 CFR 52.21. Based on the information contained in your November 28, 1977, application for a permit to construct, and all the supplemental information which has been submitted since that time, the Environmental Protection Agency (EPA) has determined that your proposal to construct the 650-megawatt coal-fired Louisa Generating Station in Louisa County, Iowa, complies with all applicable federal air pollution control regulations. This letter is your approved PSD permit to construct the plant as proposed, subject to the following conditions:

1. The new generating station will be required to meet the following enforceable best available control technology (BACT) emission limits:

a. sulfur dioxide: 0.96 pounds-per-million-BTUs of heat input, thirty-day rolling average;

b. particulates: 0.03 pounds-per-million BTUs of heat input;

c. oxides of nitrogen: 0.5 pounds-per-million BTUs of heat input, thirty-day rolling average;

2. Within the time limits imposed by 40 CFR 60.8, the Louisa Generating Station shall be performance tested to verify compliance with the BACT emission limits specified in Condition 1. These performance tests to determine compliance with Condition 1 shall be determined in accordance with the testing procedures specified in 40 CFR Part 60, Subpart Da, which are in effect as of the date of initial startup, with the exception that there is no need to install a second set of sulfur dioxide monitors at the outlet to the sulfur removal device since the sulfur dioxide emission limits are to be met by burning low-sulfur coal. Sampling time(s), sampling volume(s), sampling train gas temperature(s), sampling extraction rate(s),

sampling interval(s), and such other matters, will be set forth by the EPA or its delegate(s) at the pretest meeting referenced in Condition 3. Continued compliance with the above-referenced BACT emission limits shall be determined by all continuous monitoring and reporting methods which may be specified in 40 CFR Part 60, Subpart Da as of the date of initial source startup (i.e., operation of the boiler for any purpose), with the exception that the control efficiency of the sulfur dioxide removal device need not be demonstrated, since no flue gas desulfurization is required. Notwithstanding the fact that the Louisa Generating Station is not subject to 40 CFR Part 60, Subpart Da under Section 111 of the Clean Air Act (42 U.S.C. 7411), Subpart Da is being referenced to specify methods for determining compliance with the BACT emission limits specified in Condition 1, which are established under the PSD regulations promulgated pursuant to Section 110 of the Act (42 U.S.C. 7410). Applicable portions of 40 CFR Part 60 which must be met under Section 111 are stated later in this approval;

3. A pretest meeting shall be held at the site of the source at least fifteen days prior to the date of the performance test required by Condition 2. Such meetings shall be attended by the EPA or its delegate(s), the Iowa Department of Environmental Quality (IDEQ), the Iowa-Illinois Gas and Electric Company, and the independent testing firm (if such firm is contracted). It shall be the responsibility of the Iowa-Illinois Gas and Electric Company to schedule this meeting at least fifteen days in advance of the performance tests;

4. The applicant shall submit to the EPA, within six months of the date of this conditional approval, detailed plans, drawings, and operational procedures for the control of dust in the coal handling and storage system. The EPA will review this information to determine if BACT is represented. Failure to meet the BACT requirement will cause this conditional approval to be immediately invalidated;

5. The applicant shall submit to the EPA within six months of the date of this conditional approval, detailed design parameters, specifications, drawings and other information as necessary to demonstrate that the electrostatic precipitator will provide adequate control to meet the above-specified BACT limit for particulate matter. If, upon review, the EPA finds the proposed precipitator is inadequate, the permit will become immediately invalid;

6. Approval to construct the new power plant will become invalid if a continuous program of construction is not commenced within eighteen months after the issuance date of this PSD permit, if construction is discontinued for a period of eighteen months or more, or if construction is not completed within a reasonable period of time;

7. The Iowa-Illinois Gas and Electric Company shall be responsible for the construction and use of a new emission stack at the Grain Processing Corporation, Muscatine, Iowa, to handle the exhaust from the boilers prior to commencement of operation of the Louisa Generating Station. Such stack shall be constructed according to the specifications in the agreement between the Iowa-Illinois Gas and Electric Company and the Grain Processing Corporation, dated July 6, 1979. Detailed plans and specifications, and a construction schedule for this proposed stack shall be submitted to the EPA or its delegate not later than January 1, 1980.

Numerous public comments were received as a result of the two public comment periods which lasted from February 26, 1979, to April 3, 1979, and from July 20, 1979, to August 6, 1979, and the two public hearings held on April 3, 1979, and August 2, 1979. Because of the number of comments received and the length of our response, we have chosen to attach our discussion of the public comments to this letter as a separate document, rather than inserting them in the body of this letter. The reader is referred to the attachment for a complete discussion of the public comments received and the EPA response to such comments.

Your fossil fuel-fired steam generator will be subject to the federally established performance standards for new stationary sources. The applicable regulations are codified in the Code of Federal Regulations at 40 CFR Part 60, Subparts A and D. Subpart A contains certain notification requirements which are outlined as follows:

1. A notification to the EPA of the date construction of an affected facility is commenced, postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are produced in completed form;

2. A notification to the EPA of the anticipated date of initial startup of an affected facility, postmarked not more than 60 days nor less than 30 days prior to such date;

3. A notification of the actual date of initial startup of an affected facility, postmarked within 15 days after such date.

It should be understood that the IDEQ has full responsibility to implement and enforce all requirements of 40 CFR Part 60, Subpart D for fossil fuel-fired steam electric generators. However, certain testing requirements contained in the above conditions are not directly enforceable by the IDEQ, and compliance with such conditions will be determined by the EPA or its delegate(s).

We wish to emphasize that the approval being issued today pertains only to the requirements of 40 CFR 52.21. The approval will not relieve the Iowa-Illinois Gas and Electric Company of its continuing responsibility to comply fully with the requirements of the applicable state implementation plan, the Federal New Source Performance Standards (NSPS) (40 CFR Part 60), or any other requirements of federal, state, or local regulations. Construction activity which is commenced in violation of such other requirements will be at the risk of the company.

The owner and/or operator is reminded that it is his responsibility to demonstrate that his performance testing and monitoring equipment, locations, and procedures will be acceptable according to the applicable regulations. To minimize the many problems created by improper test port locations and unapproved continuous monitoring locations, it is suggested that the EPA Region VII Surveillance and Analysis Division or its delegate(s), and the IDEQ be contacted at the earliest date to avoid delays and expenses caused by replacing and/or modifying locations and equipment.

A recent decision in the U.S. Court of Appeals (copy enclosed) which remanded certain PSD regulations to the EPA for revision, may ultimately affect the conditions of this permit, require imposition of additional conditions, and/or modify the applicability of EPA regulations to your proposal. The effect of the above decision has been stayed pending further court proceedings, and, in the interim, the above-referenced EPA regulations are in full force and effect.

If you wish to withdraw your application for PSD approval or suspend EPA consideration of the application, please provide written notification and return this approval letter within ten calendar days of receipt of this letter. However, you are again reminded that under existing EPA regulations, you are subject to appropriate enforcement action if you construct, modify, or operate your proposed source without a PSD permit. The EPA considers the approval in this letter to be final unless we are otherwise notified by you. Also, any owner or operator who constructs, modifies, or operates an affected source not in accordance with the PSD application as reviewed, approved, and conditioned herein shall be subject to federal enforcement action under Sections 113 and 167 of the Clean Air Act (42 U.S.C. 7413 and 7467).

Future correspondence, notifications, and/or reports relating to the PSD program and the NSPS regulations, except as noted above, should hereafter be submitted to the Director, Enforcement Division, Environmental Protection Agency, Region VII, 324 East 11th Street, Kansas City, Missouri 64106.

A copy of this letter is being made available at the following locations: Environmental Protection Agency, Region VII Office, Kansas City, Missouri; Iowa Department of Environmental Quality, Henry A. Wallace Building, 900 East Grand, Des Moines, Iowa; and at the Muscatine County Auditor's Office, Third and Walnut Streets, Muscatine, Iowa.

Sincerely yours,

David A. Wagoner

David A. Wagoner
Director, Air and Hazardous Materials Division

2 Enclosures

cc: Mr. Charles C. Miller
Director, Air and Land Quality Division
Iowa Department of Environmental Quality

Mr. Richard P. Cool
Community Action Research Group

Mr. Kevin Greene
Citizens for a Better Environment

FILE - PSD-IA - LOUISA

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VII
324 EAST ELEVENTH STREET
KANSAS CITY, MISSOURI 64106

January 19, 1981

Mr. Karl H. Schafer
Vice-President, Energy Supply and Engineering
Iowa-Illinois Gas and Electric Company
206 East Second Street
Davenport, Iowa 52801

Dear Mr. Schafer:

Pursuant to 40 CFR 52.21(r), this letter, and the enclosed final determination and final review document, constitute the final determination of the Environmental Protection Agency (EPA) on reconsideration of the best available control technology (BACT) emission rate for sulfur dioxide in the August 7, 1979 permit issued for the Louisa Generating Station. EPA has determined that the emission rate for sulfur dioxide (0.96 lbs. per million BTU) will be retained as representing BACT for the facility. EPA has also determined to modify the permit to require a limitation on hourly and daily SO_2 emissions, as explained in detail in this document. All other permit conditions remain in effect.

A copy of this letter is being made available at the following locations: Environmental Protection Agency, Region VII Office, Kansas City, Missouri; Iowa Department of Environmental Quality, Des Moines, Iowa; and Muscatine County Auditor's Office, Muscatine, Iowa.

Sincerely yours,

Kathleen Q. Camin
Regional Administrator

Enclosures

cc: Community Action Research Group
Eighth Circuit Court of Appeals, Robert St. Vrain, Clerk of Court

FINAL REVIEW FOR SIGNIFICANT AIR QUALITY DETERIORATION
UNDER 40 C.F.R. 52.21
IOWA-ILLINOIS GAS & ELECTRIC COMPANY
LOUISA GENERATING STATION
LOUISA COUNTY, IOWA
RECONSIDERATION OF BACT FOR SULFUR DIOXIDE

The Environmental Protection Agency (EPA) issued a prevention of significant air quality deterioration (PSD) permit to the Iowa-Illinois Gas and Electric Company (the "Company") on August 7, 1979. As a result of issues raised by the Community Action Research Group of Iowa, Inc. (CARG), EPA determined that it was appropriate to reconsider one aspect of the permit, the emission limitation established as best available control technology (BACT) for sulfur dioxide (SO_2). A detailed account of the permit review and issuance, the allegations in the CARG challenge to the permit, and the rationale for and scope of EPA's reconsideration of the factual basis for the original BACT determination is provided in the preliminary review document for the August 1, 1980 Preliminary Determination. See, August 1 Preliminary Determination at pp. 1-9. Generally, the preliminary determination stated that the August 7, 1979 BACT determination had established the appropriate BACT emission rate for SO_2 removal and should be reaffirmed. The preliminary determination also stated that the rationale for the emission rate was a comparison of the costs associated with more stringent emission limitations (based on various degrees of SO_2 removal -- SO_2 scrubbing) and the amount of PSD increment preserved by such scrubbing systems. EPA determined that the cost of preserving additional increment by requiring SO_2 removal was not reasonable, particularly in view of the relatively small portion of increment consumed without SO_2 scrubbing. The analysis and conclusions are presented in detail in the August 1 Preliminary Determination at pp. 13-21.

EPA has made a final determination that the emission limitation established for LGS in the August 7, 1979 permit for SO_2 should be reaffirmed. Therefore, the permit emission rate of 0.96 lbs. SO_2 per million BTU heat input, 30-day rolling average, is finally adopted by EPA. However, EPA also finally adopts a new permit condition, discussed below, which will affect the operation of LGS. EPA has reached this determination after review of public comment on the August 1 Preliminary Determination. Except as otherwise provided in this final determination, EPA adopts as final the determinations made in the preliminary determination.

EPA has modified in two respects the analysis of impacts of BACT alternatives, which were discussed in the August 1 Preliminary Determination at pp. 13-21, and the conclusions concerning the appropriate BACT for SO_2. First, in response to comments by CARG, EPA has clarified and supplemented the discussion of the air quality impacts of LGS included in the preliminary determination at pp. 14-17. EPA's modification of this analysis is found in Section II of the attached support document.

As a result of the modified analysis of air quality impacts of LGS, EPA is also establishing a new permit condition, which will require that LGS operate at a capacity of 83 percent of full capacity, or limit SO_2 emissions in some other way to 83 percent of the allowable (1.05 lbs. per million BTU) 24-hour emission rate. The rationale for this new permit condition is detailed in Sections II.B.2 and II.B.3 of the attachment to this final determination. The August 7, 1979 permit is amended to add a new condition 8 as follows:

8. Emissions of SO_2 shall not exceed 146,000 pounds per calendar day, nor shall emissions of SO_2 exceed 6,100 pounds per hour for more than 5 hours in any calendar day. Iowa-Illinois Gas and Electric Company shall maintain records of SO_2 emissions for each calendar day and shall submit a summary of such emissions to EPA within 10 days of the end of each calendar month. Any exceedance of the allowable emission rates shall be reported to EPA within 5 working days of its occurrence.

Second, in response to comments, EPA has partially revised its description of the economic impacts of the BACT options, included at pp. 17-18 of the preliminary determination, and the analysis of the relationship between economic and environmental impacts, at pp. 18-21 of the preliminary determination. The latter is described in Section IV. of the attacment. These modifications and all other relevant issues raised in the public comments are explained in detail in the attached response.

The final determination means that EPA has taken final action to retain the emission rate established for SO_2 in the LGS permit, 0.96 lbs. SO_2 per million BTU heat input, 30-day rolling average. The Company has demonstrated that this rate can be met without SO_2 scrubbing. Therefore, no SO_2 scrubber will be required. However, the Company will be required to meet new Condition 8 of the permit, set out above, relating to limitations on operation of LGS.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

May 19, 1995

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Revision to Modification Request
Permit PSD-FL-008, City of Lakeland
C.D. McIntosh, Unit 3

Dear Ms. Harper:

Enclosed for your records is a response to our completeness review of a PSD modification request previously submitted to us by the City of Lakeland. A copy of the original request, dated January 4, 1995, was sent to your office by the City.

We are presently reviewing the City of Lakeland's request and their response to our completeness review. If you have any questions, please call me at (904)488-1344.

Sincerely,

AA Linero 5/19

A. A. Linero, Administrator
New Source Review Section

AL/t

Enclosure

cc: G. Worley, EPA

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
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- 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 below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

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:
Jewell Harper, Chief
Air Branch Program
US EPA - Region IV
345 Courtland St, NE
Atl GA 30308

4a. Article Number
Z 311 902 907

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

7. Date of Delivery

5. Signature (Addressee)
Charles Davis

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

6. Signature (Agent)
MAY 2 3 1995

PS Form 3811, December 1991 ☆U.S. GPO: 1993—352-714 DOMESTIC RETURN RECEIPT

Thank you for using Return Receipt Service.

Z 311 902 907

Receipt for Certified Mail

UNITED STATES POSTAL SERVICE

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

Sent to	Jewell Harper
Street and No.	EPA
P.O., State and ZIP Code	Atlanta, GA
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	

5-19-95
City of Lakeland
PSD-FI-008

PS Form 3800, March 1993

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

May 5, 1995

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Farzie Shelton, Ch.E.
Environmental Coordinator
City of Lakeland
Department of Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5050

Dear Ms. Shelton:

Re: Requests to Modify PA-78-06, PSD-FL-008
City of Lakeland, McIntosh Unit No. 3

We have reviewed your letter of April 6, revising your previous modification requests of Site Certification PA-78-06 and PSD-FL-008 for C.D. McIntosh Unit 3. To finalize our review, the following information is requested.

- Basic drawings of the scrubber serving Unit 3 along with a short process description, the name of the manufacturer, model number and serial number. The basic operating manual would suffice if it has this information.

- Results of the three most recent annual stack tests for particulate matter, nitrogen oxides, and sulfur dioxide.

- Rationale for Best Available Control Technology (BACT) requested by the City (0.90 lb/MMBtu, 55% minimum scrubber efficiency). This should be expressed in a manner similar to the attached "Least-Cost-Envelope." It should also include the NSPS "D" and NSPS "D(a)" cases as well as the 85% removal case. Details of credits and charges as appropriate should be included for reagents, water, energy penalties, fuel cost differentials, SO_2 allowances, etc. You may wish to show three curves and sample backup calculations for roughly 1.1% sulfur fuel, as well as 2.2 and 3.3% sulfur fuel.

- A tabulation (hard copy or diskette) of the past two years worth of coal data, including sulfur content, SO_2 emissions, SO_2 removal efficiency (or sulfur reduction percentage). There is no need for the individual coal analysis sheets.

- o Your proposed method of determining and reporting compliance with the SO_2 emission limit and sulfur reduction (scrubber efficiency) requirement.

Your application will not be considered complete until we receive the foregoing items. However, we will continue to work on your request in order to expedite our action once we receive the requested information.

If you have any questions about this matter, please call me at (904)488-1344.

Sincerely,

A. A. Linero 5/5

A. A. Linero, P.E.
Administrator
New Source Review Section

AAL/kt

Enclosure

cc: Howard L. Rhodes
Clair H. Fancy
Buck Oven

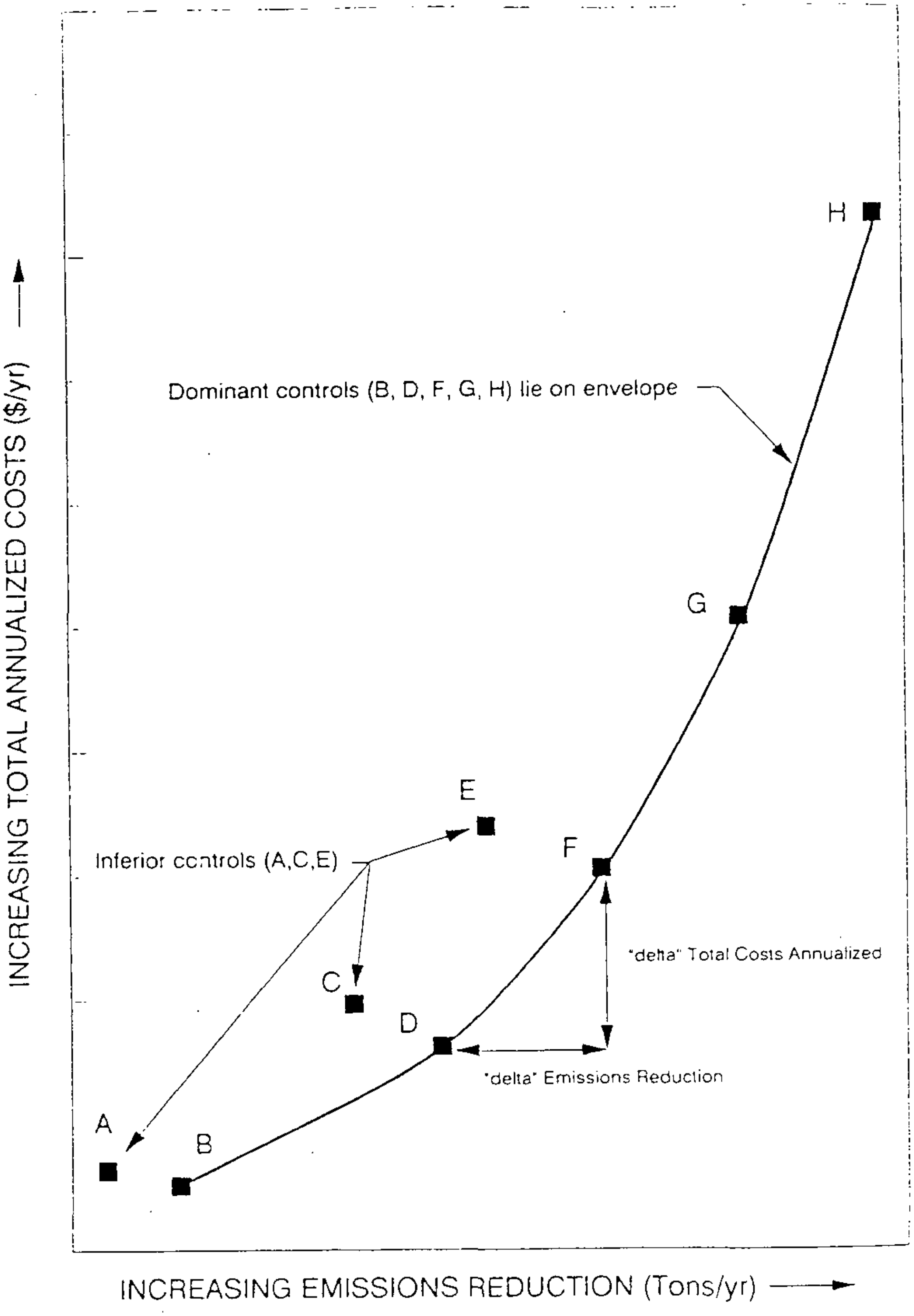

Figure B-1. LEAST-COST ENVELOPE

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- 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 below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

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:
Ms. Farzie Shelton, Ch. E.
Env. Coordinator
City of Lakeland
Dept. of Elec. & Water Utilities
501 East Lemon Street
Lakeland, FL 33801-5050

4a. Article Number
Z 311 902 910

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

7. Date of Delivery
MAY 08 1995 5/08/95

5. Signature (Addressee)

6. Signature (Agent)

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

PS Form 3811, December 1991 ★U.S. GPO: 1992—323-402 DOMESTIC RETURN RECEIPT

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

UNITED STATES POSTAL SERVICE

Sent to: Farzie Shelton	
Street and No.: 501 East Lemon Street	
P.O., State and ZIP Code: Lakeland, FL 33801-5050	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date: Mailed 5/5/95	

PS Form 3800, March 1993

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

May 4, 1995

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Revision to Modification Request
Permit PSD-FL-008, City of Lakeland
C.D. McIntosh, Unit 3

Dear Ms. Harper:

Enclosed for your records is a revision to a PSD modification request previously submitted to us by the City of Lakeland. A copy of the original request, dated January 4, 1995, was sent to your office by the City.

We are presently reviewing the City of Lakeland's request. If you have any questions, please call me at (904)488-1344.

Sincerely,

AA Lin 5/4

A. A. Linero, Administrator
New Source Review Section

AL/t

Enclosure

cc: F. Shelton, City of Lakeland
G. Worley, EPA

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2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Ms. Jewell Harper, Chief
Air Branch Prog.
U.S. EPA - Region IV
345 Courtland St, NE
Atlanta, GA 30365

4a. Article Number
Z 311 902 927

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

7. Date of Delivery

5. Signature (Addressee)
Charles

6. Signature (Agent)

MAY 8 1995

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

Thank you for using Return Receipt Service.

Z 311 902 927

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

UNITED STATES POSTAL SERVICE

PS Form 3800, March 1993

Sent to Jewell Harper	
Street and No. EPA	
P.O., State and ZIP Code Atlanta, GA	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 5-3-95 City of Lakeland	

LAKELAND
ELECTRIC & WATER

(813) 499-6603

Excellence Is Our Goal, Service Is Our Job

Farzie Shelton
ENVIRONMENTAL COORDINATOR, Ch E.

April 6, 1995

VIA HAND DELIVERY

RECEIVED
APR 06 1995
Bureau of
Air Regulation

Hamilton S. Oven, Jr., Administrator
Power Plant Siting Section
Florida Department of Environmental Protection
3900 Commonwealth Boulevard
Tallahassee, FL 32399

RE: City of Lakeland; C.D. McIntosh Unit No. 3; Supplemental Response to Request for Additional Information Regarding Requests to Modify Site Certification (PA-78-06) and to Revise PSD Permit (PSD-FL-8)

Dear Buck:

On January 27, 1995, you requested additional information regarding the above-referenced site certification modification request submitted by the City of Lakeland on December 7, 1994, and Prevention of Significant Deterioration (PSD) permit revision request submitted on January 4, 1995. Your January 27 information request was based on comments received from the Department's Division of Air Resources Management. The City of Lakeland subsequently responded to the request for additional information by letter dated March 9, 1995 (received by the Department on March 10, 1995). Based on a recent meeting with Clair Fancy of the Division of Air Resources Management on March 29, however, the City of Lakeland has decided to supplement that response and to modify its request to revise the PSD permit. Because the response to the Department's request for additional information is being supplemented and because the request to revise the PSD permit is being modified, the Department should have an additional thirty days within which to review the submittal and to request any additional information that is necessary to process the application.

This modified request to revise the City of Lakeland's PSD permit for C.D. McIntosh Unit No. 3 replaces the request previously submitted to the Department on January 4, 1995. A copy of the PSD permit, as proposed to be revised, is enclosed as Exhibit A.

Specifically, the City of Lakeland respectfully requests that specific condition 2.B. be revised to clarify that the 85 percent sulfur dioxide removal efficiency for the flue gas desulfurization system applies only when 3.3 percent sulfur coal is burned. The permit, which was issued by the U.S. Environmental Protection Agency (EPA), states that the flue gas desulfurization system "will operate at a minimum SO_2 removal efficiency of 85 percent." This condition contemplated that high sulfur coal would be used. Both the Site Certification and PSD permit applications stated the sulfur dioxide emissions were based on a 3.3 percent sulfur content of the coal and an 80 percent efficiency rating for the sulfur dioxide scrubber.

The applications also state that 80 percent is the minimum efficiency required when burning 3.3 percent sulfur coal and still complying with EPA's "new" New Source Performance Standards (NSPS). The applications were referring to the *proposed* NSPS sulfur dioxide limit under Subpart Da of Title 40, Code of Federal Regulations (CFR) Part 60, which was subsequently revised to be less stringent. The *proposed* standard for sulfur dioxide emissions under Subpart Da was 1.2 pounds per million British thermal units (lb/mmBtu) and 85 percent reduction when solid fuel is fired. 43 Fed. Reg. 42175 (Sept. 19, 1978). The sulfur dioxide standard was changed in the final version of the rules, which were issued after the McIntosh Unit No. 3 PSD permit was issued, to 1.2 lb/mmBtu and 90 percent reduction *or* 70 percent reduction when emissions are less than 0.60 lb/mmBtu. 40 C.F.R. §60.43a.

As the City has stated in previous correspondence to the Department, EPA has definitively found that NSPS Subpart Da does *not* apply to C.D. McIntosh Unit No. 3 because construction had commenced prior to the date the new NSPS standards were proposed (see letters from the City to the Department dated November 10 and December 1, 1994). Nevertheless, if Unit No. 3's PSD permit is read to imply that the 85 percent removal efficiency applies at all times, even when, for example, emissions are less than 0.60 lb/mmBtu, the sulfur dioxide standard would be significantly more stringent than the NSPS Subpart Da standard. Moreover, Unit No. 3's sulfur dioxide emission limit would be significantly more stringent than sulfur dioxide limits in PSD permits for similar emission units issued during the same time frame.

For example, the PSD permit for Florida Power Corporation's coal-fired Crystal River Units 1 and 2, which was issued on March 30, 1978, has a sulfur dioxide limit of 1.2 lb/mmBtu, with *no* required scrubber or removal efficiency. Like McIntosh Unit No. 3, the Crystal River units were not subject to NSPS Subpart Da. In addition, the PSD permit for Jacksonville Electric Authority's coal-fired St. Johns River Power Park, which was issued on January 14, 1981, has a sulfur dioxide limit of 0.76 lb/mmBtu, which is the equivalent of 4 percent sulfur coal with a 90 percent removal efficiency. The JEA units, which *were* subject to Subpart Da, have a less stringent sulfur dioxide limit than McIntosh Unit No. 3 if 85 percent removal is required when low sulfur fuel is fired. What is more, a relative recent PSD permit issued for the Orlando Utilities Commission's Stanton Unit No. 2 (September, 1991) has a sulfur dioxide limit of 0.85 lb/mmBtu, 3-hour average. Again, this unit is subject to NSPS Subpart Da and has a less stringent limit than if McIntosh Unit No. 3 is required to have 85 percent removal when firing low sulfur coal. For example, with 1 percent sulfur coal, the 85 percent removal requirement in the McIntosh Unit No. 3 permit condition requires an emissions level of 0.24 lb/mmBtu. In contrast, the NSPS limit would be almost twice that--0.47 lb/mmBtu.

Because the original PSD application contemplated that high sulfur (3.3 percent) coal would be fired to achieve an 85 (80) percent removal efficiency, because NSPS Subpart Da does not apply to Unit No. 3, and because the sulfur dioxide standard would be severely stringent if an 85 percent removal efficiency is required when coal with a sulfur content of less than 3.3 percent is used, the City respectfully requests that the Department revise specific condition 2.B. as follows:

> A flue gas desulfurization system will be designed to treat ~~all~~ exhaust gases. ~~and~~ The FGD system will operate at: (1) a minimum SO_2 removal efficiency of 85 percent whenever high sulfur (i.e., 3.3 percent or greater) coal is burned, or (2) a minimum of 55 percent SO_2 removal efficiency when the SO_2 emissions are 0.9 lb/mmBtu or less. The sulfur dioxide emissions from the unit shall not exceed 0.9 lb/mmBtu based on a 30-day rolling average.

The proposed minimum removal efficiency of 55 percent and sulfur dioxide emissions of 0.9 lb/mmBtu will ensure that the scrubber is operated effectively and that the corresponding sulfur dioxide emissions are equivalent to the situation where 3.3 percent sulfur coal is fired with 85 percent removal efficiency. For example, the maximum potential uncontrolled sulfur dioxide emissions for high sulfur coal would be 5.74 lb/mmBtu (3.3% sulfur coal/100 x 2lbSO_2 x 1/11,500 Btu/lb x 10^6 Btu/mmBtu). At a flue gas desulfurization control efficiency of 85 percent, the controlled emission rate would be 0.9 lb/mmBtu [(1-85%/100) x 5.74 lb/mmBtu]. By requiring that sulfur dioxide emissions not exceed 0.9 lb/mmBtu when coal with a sulfur content below 3.3 percent is fired, the City will be ensuring that the sulfur dioxide emissions are no greater than when high sulfur coal is fired with a control efficiency of 85 percent. This emission rate is consistent with what was originally contemplated during the permit review process (85% SO_2 removal with 3.3% sulfur coal at 11,500 Btu/lb). Since the permit currently allows sulfur dioxide emissions up to 1.2 lb/mmBtu with 85 percent sulfur dioxide removal, an emission rate of 0.9 lb/mmBtu is appropriate as the limit for sulfur dioxide removal efficiencies less than 85 percent.

The proposed 55 percent minimum removal efficiency, which will ensure proper operation of the flue gas desulfurization system, is based on a ratio of the maximum potential sulfur dioxide emissions allowed by NSPS Subpart Da and the 85 percent control efficiency established in the original permit. As you know, NSPS Subpart Da requires 90 percent removal, while the PSD permit for McIntosh Unit No. 3 requires 85 percent removal (both with sulfur dioxide limits of 1.2 lb/mmBtu). With 90 percent removal, the resultant emissions are a unit of 0.10, and with 85 percent removal, the resultant emissions are a unit of 0.15--a difference of 50 percent. NSPS Subpart Da also provides that when emissions are 0.6 lb/mmBtu or less, 70 percent removal is required. With 70 percent removal, the resultant emissions are a unit of 0.30.

An equivalent removal efficiency based on the difference between NSPS and the McIntosh Unit No. 3 PSD permit is 50 percent higher than the 0.30 unit, or 0.45, which corresponds to a 55 percent removal efficiency. This is demonstrated through the following calculation:

NSPS Maximum Emissions (not to exceed 1.2 lb/mmBtu) - 0.10 x S(90% removal)
Permit Maximum Emissions (not to exceed 1.2 lb/mmBtu) - 0.15 x S(85% removal)
NSPS Minimum Emissions (not to exceed 0.6 lb/mmBtu) - 0.30 x S(70% removal)
Where: S = uncontrolled SO_2 emissions

Proposed Min. Removal = 0.15/0.10 x 0.30 = 0.45; this is equivalent to 55% removal [(1 - 0.45) x 100%]

With an emission limit of 0.9 lb/mmBtu and a minimum removal efficiency of 55 percent when lower sulfur coal is burned, the City of Lakeland will be ensuring that emissions are no greater than as originally contemplated during the PSD permit review process and that the scrubber is operated effectively. Further, by agreeing to a sulfur dioxide limit of 0.90 lb/mmBtu, based on a 30-day rolling average, which will apply at all times, the overall emissions from the Unit will be less than previously authorized. The City therefore respectfully requests that specific condition 2.B. be revised as set forth above.

The City of Lakeland anticipates that once this issue regarding sulfur dioxide removal efficiency is resolved, at least tentatively, the City may further modify its request for PSD permit revision to address the use of petroleum coke as a fuel. The City expects that any supplemental information regarding petroleum coke would be submitted within the next two weeks or so.

Thank you for your continued cooperation and assistance in this matter. We have scheduled a meeting with Clair Fancy and his staff for Monday, April 10 to discuss this matter in more detail. In the meantime, if you or you staff have any questions about this request please call me at (813)499-6603.

Sincerely,

Farzie Shelton/arm

Farzie Shelton
Environmental Coordinator
Department of Electric and Water Utilities

cc: Clair Fancy, FDEP
Al Linero, FDEP
Bruce Mitchell, FDEP
Angela Morrison, HGSS
Ken Kosky, KBN

FINAL DETERMINATION

Review of a Proposed Air Pollution Source Pursuant to

Environmental Protection Agency Rules for the Prevention of

Significant Deterioration (PSD)

40 CFR 52.21

McIntosh Unit 3

City of Lakeland, Florida

Roger O. Pfaff

U.S. Environmental Protection Agency
345 Courtland Street, N.E.
Atlanta, Georgia 30308

December 27, 1978

Proposed to be Revised 4/6/95

Exhibit A

On November 26, 1978, EPA issued a Preliminary Determination that McIntosh Unit 3 could be approved with conditions under EPA Regulations for Prevention of Significant Deterioration, 40 CFR 52.21. During the 30 day public comment period, ending December 26, 1978, only the City of Lakeland commented on the determination. The City asked that a condition be added to the determination allowing the use of oil as a fuel during periods when the coal feed is lost due to equipment malfunctions.

EPA agreed to allow this request, but only if the flue gases are scrubbed by the SO_2 scrubber. The final conditions are the same as those in the Preliminary Determination except for this extra condition. The full list of conditions of approval follows:

Conditions of Approval

1. <u>For Particulate Emissions from the Boiler:</u>

The source must meet an emission limit, as measured under part (5) as follows:

A. Particulate matter emitted to the atmosphere from the boiler shall not exceed:

Mode of Firing	lb/10^6 Btu Heat Input
Coal	0.044
Coal/Refuse:	0.050
Oil	0.070
Oil/Refuse:	0.075

2. <u>For Sulfur Dioxide from the Boiler:</u>

The source must meet an emission limit, as measured under part (5) as follows:

A. Sulfur dioxide emitted to the atmosphere from the boiler shall not exceed 1.2 pound per million Btu heat input derived from solid fossil fuel.

B. A flue gas desulfurization system will be designed to treat ~~all~~ exhaust gases. ~~and~~ The FGD system will operate at: (1) a minimum SO_2 removal efficiency of 85 percent whenever high sulfur (i.e., 3.3 percent or greater) coal is burned, or (2) a minimum of 55 percent SO_2 removal efficiency when the SO_2 emissions are 0.9 lb/mmBtu or less. The sulfur dioxide emissions from the unit shall not exceed 0.9 lb/mmBtu based on a 30-day rolling average.

C. The burning of oil or a combination of oil and municipal refuse as an emergency fuel without the use of the SO_2 scrubber will be allowed only when the flue gas desulfurization system malfunctions to the extent that the burning of coal would cause emission limitations to be exceeded. Sulfur dioxide emitted to the atmosphere from the boiler shall not exceed 0.8 pound per million Btu under this condition.

D. During malfunctions of equipment which cause an interruption of the coal feed to the boiler, the burning of oil or a combination of oil and municipal refuse will be allowed only if all flue gases are fully scrubbed by the SO_2 scrubber. Sulfur dioxide emitted to the atmosphere from the boiler shall not exceed 0.8 pound per million Btu under this condition.

3. <u>For Particulate Emissions from Materials Handling Operations:</u>

The applicant shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, coal transfer and loading system, limestone handling or storage operation, or fly ash handling or storage operation, gases which exhibit 20 percent opacity or greater.

4. <u>For NO_x Emissions from the Boiler:</u>

The source must meet an emission limit, as measured under part (5) as follows:

A. NO_x emitted to the atmosphere from the boiler shall not exceed 0.7 pound per million Btu heat input when firing coal or coal/refuse.

B. NO_x emitted to the atmosphere from the boiler shall not exceed 0.3 pound per million Btu heat input when firing oil or oil/refuse.

5. Stack Testing

A. Within 60 days after achieving the maximum production rate at which the facility will be operated, but no later than 180 days after initial startup, the owner or operator shall conduct performance tests and furnish EPA a written report of the results of such performance tests. Performance tests shall be conducted for the 4 modes of boiler operation (i.e., coal, coal/refuse, oil, oil/refuse).

B. Performance tests shall be conducted and data reduced in accordance with methods and procedures specified by EPA. Reference methods 1 through 5 as published in Appendix A of 40 CFR 60 will be used for particulate tests. Reference method 6 will be used for SO_2 tests. Reference method 7 will be used for NO_x tests.

C. Performance tests shall be conducted under such conditions as EPA shall specify based on representative performance of the facility. The owner or operator shall make available to EPA such records as may be necessary to determine the conditions of the performance tests.

D. The owner or operator shall provide or cause to be provided, performance testing facilities as follows:

i. Sampling ports adequate for test methods applicable to the facility.

ii. Safe sampling platform(s).

iii. Safe access to sampling platform(s).

iv. Utilities for sampling and testing equipment.

E. Each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified by EPA. For the purpose of determining compliance with an emission limitation, the arithmetic mean of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances beyond the owner or operator's control, compliance may, upon the approval of EPA, be determined by using the arithmetic mean of the other two runs.

6. <u>Continuous Monitoring Requirements</u>

Continuous monitors shall be installed and operated in accordance with 40 CFR 60.45 and 60.13. In addition, a continuous SO_2 monitor shall be installed prior to the flue gas desulfurization system for purposes of calculating SO_2 removal efficiencies.

7. <u>Excess Emission Reporting Requirements</u>

In addition to the requirements of 40 CFR 60.7, each excess emission report shall include the periods of oil consumption due to flue gas desulfurization system malfunction.

49155.02

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(813) 499-6603

Farzie Shelton
ENVIRONMENTAL COORDINATOR, Ch E.

March 9, 1995

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MAR 9 1995
Bureau of Air Regulation

VIA HAND DELIVERY
Hamilton S. Oven, Jr., Administrator
Power Plant Siting Section
Department of Environmental Regulation
3900 Commonwealth Boulevard
Tallahassee, FL 32399-3000

Re: City of Lakeland; C.D. McIntosh Unit No. 3; Responses to Requests for Additional Information and Supplement to Requests to Modify Site Certification (PA-78-06) and to Revise PSD Permit (PSD-FL-8)

Dear Buck:

As you know, the City of Lakeland submitted a request to modify the above-referenced Site Certification on December 7, 1994, and a request to revise the above-referenced air permit on January 4, 1995. The Department of Environmental Protection promptly reviewed these applications and requested additional information by letters dated January 11 and January 27, 1995. We have subsequently prepared responses, and are providing additional information with this letter. The responses to the January 11 and 27 requests are included as Exhibits 1 and 2, respectfully. In addition, supplemental and replacement pages for the air permit application form are included as Exhibit 3.

While the City of Lakeland does not concur with the Department's position that the use of petroleum coke in Unit No. 3 would trigger Prevention of Significant Deterioration (PSD) and Best Available Control Technology (BACT) review, the requested information has been provided in an effort to expedite the Department's review and anticipated authorization to utilize petroleum coke. You may notice that PSD and BACT review information is being provided only for carbon monoxide. The City of Lakeland is proposing limits on the hours of operation when petroleum coke is cofired to prevent any significant net emissions increases of other pollutants, based on the Department's methodology for emission comparisons. The Department's methodology was explained to us at a meeting on February 7 by Clair Fancy and his staff, and based on this methodology and a limit on the hours of operation, PSD and BACT review information is being submitted only for carbon monoxide.

As a result, it is the City's understanding that the Department will issue a BACT determination only for carbon monoxide. The City would like to confirm that this BACT determination and the limitation on the hours of operation will apply only during periods when petroleum coke is cofired. The City of Lakeland will continue to be permitted to operate 8760 hours per year when Unit No. 3 utilizes fuels other than petroleum coke.

Thank you for your prompt attention to this matter. Once you and your staff have had an opportunity to review the attached information, please let us know whether any additional clarification is needed. Your cooperation and assistance with this matter is very much appreciated.

Sincerely,

Farzie Shelton

Farzie Shelton /arm
Environmental Coordinator
Department of Electric and Water Utilities

cc: Clair Fancy, FDEP (Exhibit 2 and 3)
Al Rushanan, FDEP (Exhibit 1)
Jan Mandrup-Poulsen, FDEP (Exhibit 1)
Don Kell, FDEP (Exhibit 1)
Michael Hickey, FDEP (Exhibit 1)
Richard Garrity, FDEP (Exhibit 1)
Angela Morrison, HGSS
Ken Kosky, KBN

MEMO
TCB-0295-14

TO: FARZIE SHELTON

FROM: TIM BATES

SUBJECT: PETROLEUM COKE MODIFICATION REQUEST

DATE: MARCH 2, 1995

This is in response to the Department of Environmental Protection communication dated January 27, 1995, in which the Bureau of Air Regulation is seeking information in relation to the request for modification of site certification for Unit No. 3. I have had the enclosed information assembled. You will find the information organized by lettered paragraph with some brief comments below:

a) **Please specify any operational changes associated with handling and blending the petroleum coke and coal for your application, if you are requesting this option. If there will not be any equipment and/or operational changes, please state this.**

<u>Response:</u> The petroleum coke will be delivered either blended or will be mixed on site using existing operational procedures used to handle coal. Operational procedures will be essentially the same.

b) **Please provide the maintenance records, quality assurance records, listing of monitor downtimes (include cause and corrective actions taken for each downtime), and emissions data recorded from the scrubber inlet SO^2 CEMS for the years 1989 through 1994.**

<u>Response:</u> The analyzers were removed on 3-30-89 and 4-28-89 due to poor performance and inability to keep them functioning properly in the hostile environment. Additionally, the removal efficiency of 85 percent of the sulfur dioxide from the stack gases through installation of a limestone scrubber was based on the expectation of utilizing "high sulfur" coal (sulfur content of greater than 3.0 percent). Therefore, any fuel (or combination of fuels) with a sulfur content of less than 3.1 percent sulfur does not require 85 percent removal efficiency. Since Lakeland has been utilizing fuels containing less than 3.1 percent sulfur, the scrubber efficiency was not a critical issue. However, Unit No. 3 has been in compliance with its allowable emission limit of 1.2 lb/MMBTU.

c) **Please provide the following test data from the trial burn test period in February: Provide all operational data collected from the ESP and wet scrubber, including power levels, scrubber liquid and air flows, and the number of scrubber modules and ESP fields online for each test. Provide boiler operational data for each test including load, excess**

air levels, fuel feed types and rates, and steam rates. If any of this information was provided in the trial burn test report, please indicate where it is located in that document. Please submit fuel analysis data for trace metals (arsenic, beryllium, and mercury) for both the coal and coke burned. Provide scrubber efficiencies for each test run. Provide CEMS data from the scrubber inlet monitor during each test; and, explain the reasons for any monitor downtimes. Submit comparisons of the stack SO^2 CEMS data with the Method 6C data for each test. Compute the relative accuracy based on the limited number of Method 6C tests conducted during February.

Response: Please see data collected and memos under Section "C" of attached information.

d) **Please explain the cause of the sharp decrease in particulate matter emissions and opacity from the low sulfur coal/coke tests compared to both the 2.5% sulfur coal/coke and baseline coal tests. Provide a description of any changes (maintenance, adjustments to operations, liquid and exhaust flow rates, or electrical power inputs) made to the particulate matter and SO^2 control equipment between the test runs conducted in February, 1994.**

Response: See attached memo in Section "D" with supplemental information.

e) **Please submit a monthly summary of the coal sulfur content levels, percent by weight, burned during the previous five years.**

Response: See attached information.

f) **Based on the test results and the approved test protocol, PSD new source review requirements pursuant to Rule 62-212.400(5), F.A.C., shall apply at least to SO^2, NO_x, CO, and H_2SO_4 mist. Part of the new source review requirements includes BACT pursuant to Rule 62-212.410, F.A.C. Therefore, submit a PSD new source review application package for the requested modification.**

Response: You have taken care of per our conversation.

TIMOTHY C. BATES
McIntosh Plant Manager

TCB/lh
Enclosures

cc: Ron Tomlin
Jack Libey

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(813) 499-6603
Farzie Shelton
ENVIRONMENTAL COORDINATOR, Ch E.

February 24, 1995

Mr Scott Sheplak
Department of Environmental Protection
Bureau of Air Regulation
Title V - 1993 FEE
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

**Re: 1994 Annual Operation Licensing Fee for
Lakeland Electric & Water Utilities
McIntosh Power Plant Facility ID# 40TPA530004**

Dear Mr. Sheplak:

Please find enclosed the completed DEP Form 62-213.900(1) and associated source information forms for the above referenced facility. As per our calculations, the annual operation licensing fees for McIntosh Power Plant ID# 40TPA530004 is the sum of $234,721.00. Therefore enclosed you will find a check made payable to the Department of Environmental Protection (Department) covering this amount.

Additionally I would like to bring to your attention that in September 1994 while researching the Departments' files, as part of procedures for modification of Unit No. 3 site Certification permit, we discovered copy of a PSD permit for this unit. It was interesting to note that the maximum allowable particulate matter in the PSD permit were 0.04 and 0.05 lb/MMBTU for burning coal and coal/refuse respectively. However, there are certain letters and communications between City of Lakeland (COL) and EPA that causes COL to believe the PSD limits should be revised to reflect the 0.1 lb/MMBTU.

Presently COL is requesting the Department to modify the PSD permit to reflect 0.1 lb/MMBTU maximum allowable particulate matter. Therefore, until such a time the Department has made a determination, and in order to avoid any penalty and interest on insufficient fee payment, we have utilized 0.1 lb/MMBTU in our calculation. This is on the understanding that the Department would refund all overpayment of fees for the years 1992-1994.

If you should have any questions, please do not hesitate to contact me at(813)499-6603.

Sincerely

Farzie Shelton(Ms)

Enc.

cc: Bill Rodriguez
Ron Tomlin
Jack Libey

info copy.
Tally PSD
- SwD

FLORIDA

Department of Environmental Protection

Lawton Chiles
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

Virginia B. Wetherell
Secretary

January 27, 1995

Ms. Farzie Shelton
Environmental Division
Department of Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5050

Re: McIntosh Power Plant Unit #3, No. PA 74-06-SR
PETCOKE Modification Request

Dear Ms. Shelton:

The Department has reviewed the modification request that you provided on December 7, 1994. Included in this letter are comments received from the Division of Air Resources Management. Please review and respond to these comments as appropriate. Please furnish me with a copy of any response. If you wish my assistance in setting up a meeting with any members of the department's staff, I will be pleased to assist you.

The Bureau of Air Regulation's comments are as follows: The following information is needed to supplement the above referenced request:

a) Please specify any operational changes associated with handling and blending the petroleum coke and coal for your application, if you are requesting this option. If there will not be any equipment and/or operational changes, please state this.

b) Please provide the maintenance records, quality assurance records, listing of monitor downtimes (include cause and corrective actions taken for each downtime), and emissions data recorded from the scrubber inlet SO_2 CEMS for the years 1989 through 1994.

c) Please provide the following test data from the trial burn test period in February: Provide all operational data collected from the ESP and wet scrubber, including power levels, scrubber liquid and air flows, and the number of scrubber modules and ESP fields online for each test. Provide boiler operational data for each test including load, excess air levels, fuel feed types and rates, and steam rates. If any of this information was provided in the trial

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burn test report, please indicate where it is located in that document. Please submit fuel analysis data for trace metals (arsenic, beryllium, and mercury) for both the coal and coke burned. Provide scrubber efficiencies for each test run. Provide CEMS data from the scrubber inlet monitor during each test; and, explain the reasons for any monitor downtimes. Submit comparisons of the stack SO_2 CEMS data with the Method 6C data for each test. Compute the relative accuracy based on the limited number of Method 6C tests conducted during February.

d) Please explain the cause of the sharp decrease in particulate matter emissions and opacity from the low sulfur coal/coke tests compared to both the 2.5% sulfur coal/coke and baseline coal tests. Provide a description of any changes (maintenance, adjustments to operations, liquid and exhaust flow rates, or electrical power inputs) made to the particulate matter and SO_2 control equipment between the test runs conducted in February, 1994.

e) Please submit a monthly summary of the coal sulfur content levels, percent by weight, burned during the previous five years.

f) Based on the test results and the approved test protocol, PSD new source review requirements pursuant to Rule 62-212.400(5), F.A.C., shall apply at least to SO_2, NO_X, CO, and H_2SO_4 mist. Part of the new source review requirements includes BACT pursuant to Rule 62-212.410, F.A.C. Therefore, submit a PSD new source review application package for the requested modification.

Sincerely,

Hamilton S. Oven

Hamilton S. Oven, P.E.
Administrator, Siting
Coordination Office

cc: Richard Donelan
Angela Morrison
Martin Costello

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Farzie Shelton
ENVIRONMENTAL COORDINATOR, Ch E.

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Bureau of
Air Regulation

January 17, 1995

VIA HAND DELIVERY
Clair Fancy, Chief
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

Re: City of Lakeland--C.D. McIntosh Power Plant, Unit No. 3
Request to Amend PSD Permit No. PSD-FL-8

Dear Clair:

Please make the following corrections to the package submitted to the Department On January 4, 1995, in the above-referenced matter:

1. Please remove the "seventh" page 26. (Ref. No. 14262Y1/F3/TVD-S16 (12/30/94) (bottom right corner)) The previous page, which also provides information regarding natural gas and includes a max sulfur content of 1%, is correct.

2. Please replace page 28 (Ref. no. 14262Y1/F3/TVE-PI1 (12/30/94)). Line no. 5 should read "Method of Compliance: Annual Stack Test <u>if > 400 hours of operation.</u>

3. Please replace page 28 (Ref. no. 14262Y2/F3/TVE-PI3a (01/04/95) with the enclosed page (poor copy quality).

Thank you for your assistance in this matter. Please call me if you have any questions.

Sincerely,

Farzie Shelton

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: Rule	
2. Future Effective Date of Allowable Emissions: Not applicable	
3. Requested Allowable Emissions and Units: 0.1 lb/MMBtu	
4. Equivalent Allowable Emissions: 364 lbs/hr	1,594 tons/yr
5. Method of Compliance: Annual Stack Test if >400 hours of operation	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode): The allowable emission limit is based on FDEP Rule 62-296.800; 40 CFR Part 60, Subpart D (see also Attachment 1).	

B. Not Applicable

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):	

Allowable Emissions (Pollutant identified on front page)

C. Natural gas firing

1. Basis for Allowable Emissions Code: Rule		
2. Future Effective Date of Allowable Emissions: Not applicable		
3. Requested Allowable Emissions and Units: 0.2 lb/MMBtu		
4. Equivalent Allowable Emissions:	728 lbs/hr	3,188.6 tons/yr
5. Method of Compliance: Annual stack test if > 400 hours operation		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode): The allowable emission limit is based on FDEP Rule 62-296.800; 40 CFR Part 60, Subpart D, Section 60.44(a)(1) (see also Attachment 1).		

D.

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):		

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(813) 499-6603

Farzie Shelton
ENVIRONMENTAL COORDINATOR, Ch E.

January 4, 1995

Clair H. Fancy, Chief
Bureau of Air Regulation
Division of Air Resources Management
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

RECEIVED
JAN 04 1995
Bureau of Air Regulation

RE: City of Lakeland--C.D. McIntosh Power Plant, Unit No. 3
Request to Amend PSD Permit No. PSD-FL-8

Dear Clair:

The City of Lakeland ("Lakeland") requests minor amendments to the above-referenced prevention of significant deterioration (PSD) permit (and corresponding application) for its McIntosh Power Plant, Unit No. 3. Lakeland originally submitted a PSD permit application to the U.S. Environmental Protection Agency (EPA) in February of 1978, and EPA subsequently issued the permit on December 27, 1978, authorizing construction of the coal-, municipal refuse-, and oil-fired steam electric generation unit. Consistent with its permit, the unit was later constructed and actual start-up occurred on September 1, 1982. As a result of the final unit design, the City has identified several needed changes to the PSD permit and corresponding application:

- Adjust particulate matter limits to 0.1 lb/mmBtu heat input (regardless of the fuel being burned);
- Clarify that the minimum sulfur dioxide (SO_2) removal efficiency of 85 percent applies only when high sulfur coal is burned;
- Delete the requirement to install an SO_2 monitor at the inlet to the scrubber, since the monitor at the stack is sufficient for use in determining SO_2 removal efficiencies; and
- Recognize that natural gas and low sulfur oil may be used as startup fuels or at any other time.

In addition, based on a successful test burn of petroleum coke, the City requests that the PSD permit be amended to specifically allow such fuel to be cofired with permitted fuels. When petroleum coke is blended in the appropriate amounts with coal (or coal and refuse), the particulate matter, sulfur dioxide, nitrogen oxides, and opacity limits will not be exceeded. The total amount of petroleum coke will not exceed 20 percent (by weight).

As we stated in our December 1, 1994, letter to you, neither New Source Performance Standard Subpart Da applicability nor Prevention of Significant Deterioration (PSD) review should be triggered by the requested permit revisions. Based on recent telephone conversations with Bruce Mitchell of the Department's Bureau of Air Regulation, I understand that the Department has concurred with our analysis, except that it may be appropriate to require PSD review for carbon monoxide and sulfur acid mist emissions. As the information from the test burn indicates, however, no increase in sulfuric acid mist emissions should occur as a result of cofiring petroleum coke with other permitted fuels.

The test burn data indicates only a slightly higher emission rate for sulfuric acid mist when cofiring petroleum coke with coal than when coal with a sulfur content of 2.5 percent is burned alone; however, the student "t" test indicates that there is no statistical difference between these emission rates. This approach for determining emission rate changes is consistent with 40 CFR Part 60, Appendix C. Further, while the emission rate for carbon monoxide when petroleum coke was cofired during the test burn is statistically higher than when coal was burned alone during the test, the higher rate is attributable to the differences in grindability between the high and low sulfur coals used and to combustion conditions, as opposed to the characteristics of petroleum coke. (See memorandum from Timothy C. Bates, Acting Plant Manager for McIntosh Power Plant, dated December 29, 1994, included as Attachment C.)

Because no increase in regulated air pollutant emissions will occur as a result of cofiring petroleum coke with other permitted fuels, PSD review should not be triggered for any pollutants. Moreover, even if PSD review is required, control technology review for the boiler should not be required since no physical or operational changes are being made to the boiler to cofire petroleum coke.

The City of Lakeland respectfully requests that the Department accept the requested changes to the PSD application and make the requested changes to the PSD permit. In support of Lakeland's requested permit revisions and to illustrate the requested changes to its application, a permit application has been prepared on the Department's new form and is enclosed as Attachment A. (Some of the information requested on the application form will be submitted within the next few months when the Title V application for the McIntosh Plant is submitted.) In addition, the PSD permit, as proposed to be revised, is enclosed as Attachment B and is also being provided on a computer disk, WordPerfect 5.1 format.

In support of its request, Lakeland provides the following information.

Particulate Matter Limits

The particulate matter limits included in the PSD permit should be changed to 0.1 lb/mmBtu heat input (regardless of the type of fuel burned), consistent with the corresponding Site Certification and New Source Performance Standard (NSPS) Subpart D. The lower limits were included in the permit because it was anticipated that the Unit might be subject to NSPS Subpart Da (40 CFR 60.40a-60.49a), which was proposed on September 19, 1978--just three months prior to issuance of the permit. The Subpart Da requirements would have applied to the Unit *if* it had commenced construction on or after the proposal date of September 19, 1978, even though the rules were not finalized until the following year. After the Unit's permit had been issued, the U.S. Environmental Protection Agency determined in March of 1979 that the Unit had commenced construction on March 21, 1978, *prior* to the effective date of Subpart Da. The Unit was therefore subject only to Subpart D and *not* Subpart Da. The particulate matter limits should therefore be appropriately adjusted to the Subpart D limit of 0.1 lb/mmBtu heat input. 40 CFR § 60.42(a)(1). This limit is also consistent with Rule 62-296.405(1)(b), Florida Administrative Code.

Accordingly, the City requests that Condition No. 1 of the permit be changed as follows:

A. Particulate matter emitted to the atmosphere from the boiler shall not exceed 0.1 lb/mmBtu heat input, regardless of the fuel burned.

~~Mode of Firing~~	~~lb/10^6 Btu Heat Input~~
~~Coal~~	~~0.044~~
~~Coal/Refuse~~	~~0.050~~
~~Oil~~	~~0.070~~
~~Oil/Refuse~~	~~0.075~~

Sulfur Dioxide Removal Efficiency

The City of Lakeland proposed a removal efficiency of 85 percent of the sulfur dioxide from the stack gases through installation of a limestone scrubber based on the expectation of utilizing "high sulfur" coal (sulfur content of 3.3 percent). Because the City's application was based on a proposed revision to the New Source Performance Standards for power plants under Subpart Da and Unit No. 3 is *not* subject to Subpart Da standards, the Unit should *not* be required to comply with an 85 percent removal rate when lower sulfur fuels are burned. *See* letter from the U.S. Environmental Protection Agency to the City of Lakeland dated March 2,

1979. Further, the limit of 1.2 lb/mmBtu heat input applies, regardless of the removal efficiency.

The actual sulfur dioxide emissions will be much less than 1.2 lb/mmBtu even when the 85 percent removal rate is not achieved because the desulfurization unit will continue to operate even when lower sulfur coal (or coal/refuse/petroleum coke combinations) is burned. In other words, the resultant sulfur dioxide emissions when burning a lower sulfur fuel (sulfur content of less than 3.3 percent) and operating the desulfurization unit will be less than the sulfur dioxide emissions would be if high sulfur coal (3.3 percent sulfur) were burned, even with the desulfurization unit operating at an 85 percent removal efficiency. An 85 percent removal efficiency should therefore not be required when lower sulfur fuels are burned.

Accordingly, Condition 2.B. should be changed as follows:

> A flue gas desulfurization system will be installed to treat all exhaust gases. The desulfurization system ~~and~~ will operate at a minimum SO_2 removal efficiency of 85 percent whenever high sulfur (3.3% sulfur) coal is burned.

Monitor for Sulfur Dioxide Removal Efficiency

The PSD permit for McIntosh Unit No. 3 required the installation and operation of sulfur dioxide (SO_2) continuous emissions monitors (CEMs), both before and after the flue gas desulfurization unit, to calculate sulfur removal efficiencies. Consequently, when Unit No. 3 was constructed, SO_2 CEMs were installed both before and after the flue gas desulfurization unit. Subsequent to installation however, the CEM located before the flue gas desulfurization unit has not performed as consistently as desired (and has in fact malfunctioned) due to the high level of sulfuric acid in the flue gas prior to the desulfurization unit. Sulfur removal efficiencies can be determined by calculating the sulfur dioxide emission rate prior to the desulfurization unit based on the sulfur content of the fuel being burned and comparing that rate to the sulfur dioxide emission rate recorded by the CEM installed *after* the desulfurization unit. Because this alternative method of determining the sulfur removal efficiency exists and because it is impracticable to successfully operate a CEM prior to the desulfurization unit, the City respectfully requests that Condition No. 6 be revised as follows:

> Continuous monitors shall be installed and operated in accordance with 40 CFR 60.45 and 60.13. ~~In addition, a continuous SO_2 monitor shall be installed prior to the flue gas desulfurization system for purposes of calculating SO_2 removal efficiencies.~~

Startup Fuels

Because, like all other coal units, Unit No. 3 must be started on natural gas or fuel oil, Lakeland requests that the PSD permit be revised to reflect that natural gas and low sulfur fuel oil may be burned during startup. Further, because these fuels are "clean fuels," Lakeland also requests that the PSD permit be revised to clarify that these fuels may be burned at any time.

Petroleum Coke

As stated above, the City of Lakeland recently conducted a successful test burn of petroleum coke blended with coal. In an effort to use the most cost-effective fuels while not increasing emissions above allowable limits, the City of Lakeland requests that its PSD permit be revised to allow petroleum coke to be burned when blended with coal. Because continuous emissions monitors are installed for sulfur dioxide, nitrogen oxides, and opacity, as required by the PSD permit (Condition No. 6) and NSPS (40 CFR § 60.45), the City can ensure that the emission limits for these pollutants are not exceeded when petroleum coke is blended with coal (or coal and refuse) and burned in Unit No. 3. The City accordingly requests that a Condition No. 8 be added as follows:

<u>8.</u> <u>The following fuels may be burned:</u>

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

In addition to this request to amend the PSD permit and application, Lakeland is seeking a separate modification of the site certification for Unit No. 3, which was issued pursuant to the Florida Power Plant Siting Act (PA-74-06) on December 7, 1978. The request for modification of the site certification, dated December 7, 1994, is attached to the enclosed permit application as Attachment SI-1.

Thank you for your consideration of this request. If you have any questions, please contact me at 813-499-6603.

Sincerely,

Farzie Shelton

arn/ Farzie Shelton
Environmental Affairs
Department of Electric & Water Utilities

(4 copies enclosed)

cc: Hamilton S. Oven, Jr., DEP
Bill Thomas, DEP SW District
Mike Hickey, DEP SW District
Jewell Harper, EPA Region IV
Brian Beals, EPA Region IV
Ken Kosky, KBN
Angela Morrison, HBGS
M. Costello
C. Holladay
J. Novak, Polk Co.
J. Bunyak NPS

45193

MEMO

TCB-1294-13

TO: Farzie Shelton

FROM: Timothy C. Bates, P.E.
Acting Plant Manager

DATE: December 29, 1994

SUBJECT: **Carbon Monoxide (CO) Emission While Utilizing a Mixture of Coal and Petroleum Coke in Unit No. 3 McIntosh Power Plant.**

In reference to the differences in CO emission experienced on stack tests conducted on February 8, 9 and 15 1994 on Unit No. 3 while burning 2.5 % sulfur (S) coal, 90/10 % by weight 2.5 % S coal and coke, 80/20 % by weight low S coal and coke, I would like to explain the causes of increase in emission of CO in relation to the 80/20 % mixture.

The increase in CO emission **is not due to the addition of coke to the coal**. The primary and most important factor causing this increase was due to the hardness (HGI) of the coal that was being used for the mixture. The petroleum coke used in the test burn had a hardness (HGI) of 69 HGI **(the higher the number the softer the fuel)**. The 2.5% S coal used alone and in combination with the coke had a hardness of 61 HGI while the low S coal had the hardness of 43 HGI. The efficiency of fuel combustion is directly related to the fineness of pulverized coal hence the softer (higher HGI) the coal the finer it would pulverize and better it would combust and cause less CO emission.

I have attached a graph (Attachment A) to show the effect of hardness on the performance of the pulverizers on coal fineness. As an example we have graphed both mixtures based on a feed rate of 70,000 lb/hr. You should note at this feed rate the lower hardgrove mixture would be expected to give us a fineness of ≈67% passing 200 mesh and the higher hardgrove mixture would be expected to give us a fineness of ≈85% passing 200 mesh thus resulting in better fuel distribution and combustion and lower CO generation. (Attachment 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 (less fine) it reduces the combustion efficiency and worsens the fuel distribution in the combustion zone, thus forming more CO due to poorer combustion. The change in the CO noted during testing is therefore primarily due to the difference between the high sulfur and low sulfur coal hardness and thus grindability. It should also be noted that the oxygen content of the boiler/stack was lower in the low sulfur test which is another factor in causing the CO concentration to rise.

MEMO

TCB-1294-13

TO: Farzie Shelton

FROM: Timothy C. Bates, P.E.
Acting Plant Manager

DATE: December 29, 1994

I have also attached the section explaining combustion and how it relates to CO generation, from Babcock & Wilcox 40th edition of Steam, (Attachment C).

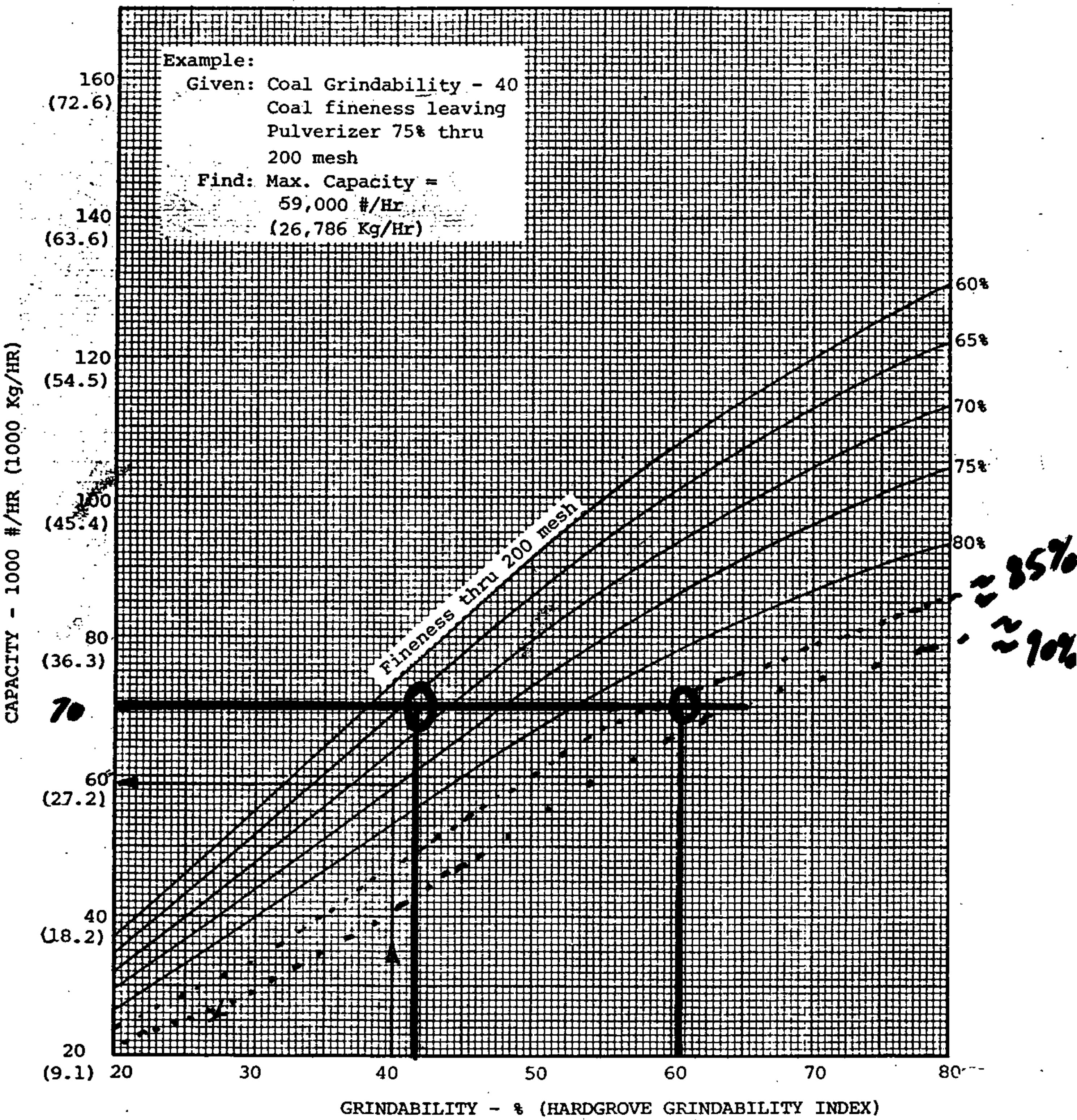
I have also enclosed a page from the 1984 copywright of General Physics Corporation's training material Fundamentals of Power Plant Performance for Utility Engineers, which describes how CO is formed and the items which causes incomplete combustion, thus CO (Attachement D).

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)



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	37.72
% 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

SAMPLE POINT C-3 Auto Sampler

SAMPLE ID # 107-94

ANALYZED BY Steve Parrish

DATE SAMPLED 2/9/94

DATE RECEIVED 2/10/94

SAMPLED BY Unknown

RELEASED BY SEP

PROXIMATE ANALYSIS

	AS RECEIVED	DRY BASIS	A-M FREE
% MOISTURE (TOTAL)	10.64		
% ASH	11.32	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	13751 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	5.69%
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

ATTACHMENT C

Combustion

The manner in which pulverized coal burns depends on its rank and properties as well as the furnace conditions. As a coal particle enters the furnace (see Fig. 2), its surface temperature increases due to radiative and convective heat transfer from furnace gases and other burning particles. As particle temperature increases, the moisture is vaporized and volatile matter is released. This volatile matter, which ignites and burns almost immediately, further raises the temperature of the char particle, which is primarily composed of carbon and mineral matter. The char particle is then consumed at high temperature leaving the ash content and a small amount of unburned carbon. The volatile matter, fixed carbon (char precursor), moisture and ash content of the fuel are identified on a percentage basis as part of the proximate analysis discussed in Chapter 8.

Volatile matter content

Volatile matter is critical for maintaining flame stability and accelerating char burnout. Coals with minimal volatile matter, such as anthracites and low volatile bituminous, are more difficult to ignite and require specially designed combustion systems. The amount of volatile matter evolved from a coal particle depends on coal composition, the temperature to which it is exposed, and the time of this exposure. The American Society for Testing and Materials (ASTM) Method D 3175 stipulates a temperature of 950 ± 20C for seven minutes for volatile matter content determination.[2] Raising the temperature would increase volatile yield with other factors held constant. Coals with higher volatile matter content also benefit from more effective NO_x control by combustion methods. Ignition is influenced by the quality and the quantity of volatile matter. Volatile matter from bituminous and higher rank coals is rich in hydrocarbons and high in heating value. Volatile matter from lower rank coals includes larger quantities of carbon monoxide and moisture (from thermal decomposition) and consequently has a lower heating value. Volatile matter from higher rank coals can provide twice the heating value per unit weight as that from low grade coals.

Char particles

The speed of the char particle combustion depends on several factors including particle size, porosity, thermal environment, and oxygen partial pressure. Char reactions often begin as the coal particle is heated and devolatilizes, but they continue long after devolatilization is complete. Devolatilization is mostly completed after 0.01 seconds but char-based reactions continue for one to two seconds. The char particle retains a fraction of the hydrocarbons. Small particles, with 10 to 20 micron diameters, benefit from high surface to mass ratios and heat up rapidly, while coarse particles heat more slowly. Many coals go through plastic deformation and swell by 10 to 15% when heated. These changes can significantly impact the porosity of the coal particle.

Char oxidation requires oxygen to reach the carbon in the particle and the carbon surface area is primarily within the particle interior structure. Char combustion generally begins at relatively low particle temperatures. Reaction rates are primarily dependent upon local temperature as well as oxygen diffusion and char reactivity. For larger particles, the solid mass is reduced as carbon monoxide (CO) and carbon dioxide (CO_2) form, but particle volume is maintained. Coarse particles, more than 100 micron diameter, burn out slowly as a result of their lower surface to mass ratios. Longer burnout times cause these larger char particles to continue reacting downstream where the flame temperature has moderated.

Rapid heat transfer to and combustion of smaller particles lead to higher particle temperatures. Reaction rates increase exponentially with temperature, and oxygen (O_2) diffusion into the particle becomes the controlling parameter. Particle diameter and density change in the process. At higher particle temperatures, char reactions are so fast that oxygen is consumed before it can penetrate the particle surface. The particle shrinks as the outer portions are consumed, and transport of oxygen from the surroundings to the particle is the factor governing combustion rate.

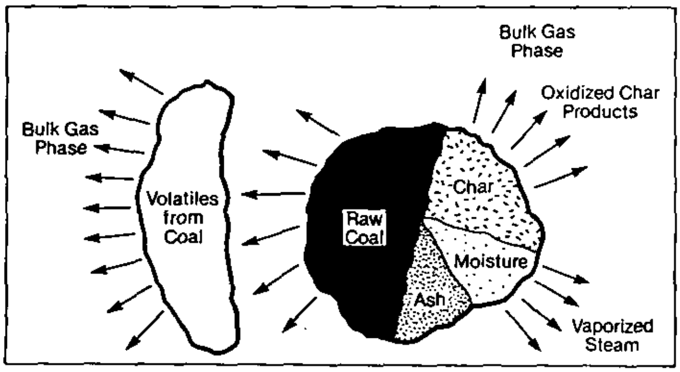


Fig. 2 Coal particle combustion.

Effect of moisture content

The moisture content of the coal also influences combustion behavior. Direct pulverized coal-fired systems convey all of the moisture to the burners. This moisture presents a burden to coal ignition; the water must be vaporized and superheated as the particles devolatilize. Further energy is absorbed at elevated temperatures as the water molecules dissociate.

Moisture content increases as rank decreases as discussed in Chapter 8. 15% moisture is common in high volatile bituminous coals, 30% is seen in subbituminous, and more than 40% is common in some lignites. Moisture contents in excess of 40% exceed the ignition capability of conventional PC-fired systems. Alternate systems are then required to boost drying during fuel preparation and/or divert a portion of the evaporated moisture from the burners. Char burnout is impaired by moisture which depresses the flame temperature. This is compensated for in part by the generally higher inherent reactivities and porosities of the higher moisture coals.

Effect of mineral matter content

The mineral matter, or resulting ash, of the coal is inert and dilutes the coal's heating value. Consequently, more fuel by weight is required as ash content increases in order to reach the furnace net heat input.

The ash absorbs heat and interferes with radiative heat transfer to coal particles, inhibiting the combustion can be controlled by maintaining a set amount of free oxygen in the flue gas. Power plants use oxygen recorders to monitor the amount of excess air used. Portable instruments are also available to check the amount of free oxygen in the flue gas.

Another method of checking the amount of excess air is to measure only the amount of carbon dioxide in the flue gas and use a nomograph. This method is not as accurate as measuring the amount of oxygen.

5.1.3.3.1 Flue Gas Analysis

Flue gas analysis is used for checking combustion effectiveness and overall steam generator efficiency, by determining the gaseous products of combustion. The results of the analysis, CO_2, O_2, CO, and N_2, are reported on a percent-by-volume basis.

Such analysis may be performed by continuous on-line analyzers (in which one or more of the above constituents are indicated), or it may be performed with a portable Orsat analyzer, in which a sample of flue gas is bubbled through water and then passed through chemical reagents that selectively remove the individual gaseous products of combustion.

Since the water vapor portion of the combustion gases is removed by contact with the water in the analyzer, the gas analysis obtained from an Orsat analyzer is always on a dry basis.

5.1.3.3.2 Incomplete Combustion

As the fuel burns, much of it vaporizes. If combustion is not complete, the vaporizing carbon will burn only partially to produce carbon monoxide, instead of burning completely to produce carbon dioxide. Unburned fuel consists mostly of solid carbon particles. These particles become part of the ash.

Incomplete combustion can be caused by (1) insufficient air being supplied with the fuel, (2) the fuel not being mixed properly with the air, (3) the temperature being too low to allow the fuel to burn completely, and (4) the fuel particles being too large to burn thoroughly.