Retracted 12/4/87 via phone call with BP + Cynthia Sawyer. BP

NOT VALID

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32301-8241

DEPARTMENT OF ENVIRONMENTAL REGULATION STATE OF FLORIDA

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

October 22, 1984

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Tom V. Brown
Vice President and Resident Manager
Container Corporation of America
North Eighth Street
Fernandina Beach, Florida 32034

Dear Mr. Brown:

Re: Amendment to the Construction Permit: AC 45-35532

The Department is in receipt of Ms. Cynthia L. Sawyer's letter dated August 21, 1984, which contained information to support a revision of the original BACT determined NO_x emission limit contained in the above referenced construction permit. Since an amendment revising the original BACT determined NO_x emission limit was signed October 12, 1984, the Department shall make the following changes and additions:

Specific Conditions:

No: 9

From: Maximum emission limits are:

Pollutant	lb/MMBTU	lb/hr
Particulate	0.1	102
SO_2	1.2	1,225
NO_x	0.6	612
Opacity	20% except 27% for one 6 minute period per hour.	

To: Maximum emission limits are:

Pollutant	lb/MMBTU	lb/hr
Particulate	0.1	102
SO_2	1.2	1,225
NO_x	0.7	700
Opacity	20% except 27% for one 6 minute period per hour.	

A10F VXL10

No. 13: (new Specific Condition)

Permitted fuels shall be in accordance with 40 CFR 60.44(a)(3).

Attachments to be incorporated:

4. Cynthia L. Sawyer's letter dated August 21, 1984.
5. John C. Brown's memo dated August 27, 1984.
6. Cynthia L. Sawyer's letter dated September 13, 1984.
7. John C. Brown's letter dated September 14, 1984.
8. Amended BACT Determination dated October 12, 1984.

This letter must be attached to your construction permit, No. AC 45-35532, and shall become a part of that permit.

Sincerely,

Victoria J. Tschinkel

Victoria J. Tschinkel
Secretary

VJT/ks

cc: James T. Wilburn
Doug Dutton
John C. Brown
Cynthia L. Sawyer
Nancy Wright

enclosures

Container Corporation of America

Paper Mill Division
North Eighth Street
Fernandina Beach, Florida 32034
Phone 904 261-5551

8P4/

August 21, 1984

Mr. John C. Brown Jr., P.E.
Air Section Supervisor
FDER
Northeast District
3426 Bills Road
Jacksonville, Florida 32207

Dear Mr. Brown:

I have reviewed your August 14, 1984 letter in which you stated that we are to submit a written request for a ruling by the Department on whether .49 or .42 lb/MMBTU applies to the NO_X continuous monitoring requirement. This letter will serve as that request. I have also sited specific sections of 40 CFR, Part 60, Subpart D that substantiate our position that .49 lb/MMBTU is the appropriate value for our No. 7 Solid Fossil Fuel Boiler.

In accordance with section 60.45 (b)(3), Subpart D, we elected to delay the installation of a continuous NO_X monitor until after the initial performance tests under section 60.8 were completed. Section 60.45 (b)(3) also states that if the owner or operator demonstrates during the performance test that emissions of nitrogen oxides are less that 70 percent of the applicable standards in section 60.44, a continuous monitoring system for measuring nitrogen oxides emissions is not required. Section 60.44 (a)(3) lists .70 lb per million BTU as the applicable standard for solid fossil fuel boilers. Our performance test showed .43 lb per million BTU or 61 percent of the applicable standard sited above. Therefore, a continuous monitoring system for nitrogen oxides is not required.

Based on the above-referenced sections from New Source Performance Standards we anticipate a favorable ruling by the Department on this matter.

Sincerely,
CONTAINER CORPORATION OF AMERICA

David R. James

David R. James
Environmental Engineer

DRJ/jrb

NOTE: Department review indicated 0.48 lb/MM Btu average
JB

For Routing To District Offices And/Or To Other Than The Addressee			
To:		Loctn.:	
To:		Loctn.:	
To:		Loctn.:	
From:		Date:	
Reply Optional [ ]	Reply Required [ ]	Info. Only [ ]	
Date Due:	Date Due:		

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

NORTHEAST DISTRICT, JACKSONVILLE
9/11

Bruce — RBM 9/12/84
please investigate & draft reply. I am guilty of holding this one.
Clair

TO: Clair Fancy, BAQM

FROM: JB John Brown

DATE: August 27, 1984

SUBJECT: Nassau County - AP
Container Corporation of America
#7 Power Boiler - Permit No. AC45-35532
Ruling on Permit Condition

Please review the attached request from Container to determine whether a continuous monitoring system (CEMS) for nitrogen oxides is required on #7 power boiler.

The construction permit was issued based on 0.60 lb/MMBTU allowable emissions for nitrogen oxices. This would suggest the requirement for a continuous monitoring system if more than 0.36 lb/MMBTU nitrogen oxides were observed during performance tests (60.45 (b)(3), Subpart D, CFR). 0.45 lb/MMBTU were observed during performance testing.

The applicant suggests that the applicable standard in 60.44, Subpart D is 0.70 lb/MMBTU and therefore continuous monitoring is required only if 0.49 lb/MMBTU nitrogen oxides were observed during performance testing.

Please note that the applicant is not contesting the 0.60 lb/MTU NO_x allowable emissions, but feels that the CEMS should be based on paragraph 60.44(a)(3), Subpart D.

JB:vk

File: AC 45-35532

Container Corporation of America

Paper Mill Division
North Eighth Street
Fernandina Beach, Florida 32034
Phone: 904 261-5551

September 13, 1984

Mr. Bruce Mitchell
DER - Bureau of Air Quality Management
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32301-8241

Dear Mr. Mitchell:

As discussed in our phone conversation this morning, this letter is written verification that we do not plan to burn lignite or 25% by weight of coal refuse in No. 7 Coal Fired Power Boiler. No. 7 Power Boiler only burns washed bituminous coal. My understanding from our conversation is this verification will allow the NO_x limit to be changed from .6 lb/mmBTU to .7 lb/mmBTU, because the .6 lb/mmBTU only applies to boilers burning lignite or coal refuse [as stated in 40 CFR 60.44(a)(4)] and will also add a specific condition stating we cannot burn lignite or coal refuse.

If you have any additional questions or comments, please do not hesitate to call.

Sincerely yours,

CONTAINER CORPORATION OF AMERICA

Cynthia L. Sawyer

Cynthia L. Sawyer
Environmental Group Leader

jrb

DER
SEP 21 1984
BAQM

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT

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

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

G. DOUG DUTTON
DISTRICT MANAGER

September 14, 1984

Ms. Cynthia Sawyer
Environmental Group Leader
Container Corporation of America
North Eighth Street
Fernandina Beach, Florida 32034

Dear Ms. Sawyer:

Nassau County - AP
Container Corporation of America
No. 7 Power Boiler
Nitrogen Oxides and SO_2 Monitoring Requirement

The following information is provided to document the conversations with Mr. Bruce Mitchell and me on September 13, 1984.

Mr. Mitchell has indicated that he is willing to modify the construction permit for No. 7 power boiler to require an emissions limiting standard of 0.70 lb/10^6 BTU per CFR 40, Section 60.44(a)(3) subject to the following:

1. Certification that you have not used, are not using, and will not utilize lignite or a solid fossil fuel containing 25 percent by weight, or more of coal refuse.

2. That the permit condition be changed to limit future use of No. 7 power boiler to the fuel input specified by 40 CFR, Section 60.44(a)(3).

Please note that we have not received the additional information required for completion of the operating permit review for No. 7 power boiler. Also, please expedite the request for approval of your alternate method for monitoring sulfur dioxide.

Failure to complete the action required to obtain the operating permit for No. 7 power boiler most expeditiously will necessitate enforcement action by the Department.

Please send me copies of all letters to the Bureau of Air Quality Management and EPA.

Your cooperation is appreciated.

Sincerely,

John C Brown Jr

John Brown, P.E.
Supervisor Air Section

gpv

JB:vk

cc: Bruce Mitchell
Enforcement

Best Available Control Technology (BACT) Determination
Container Corporation of America
Nassau County
Amendment

NOT VALID

This amended BACT determination revises only the NO_x emission limit contained in the BACT determination dated December 30, 1980.

The affected source is a 1000 million Btu per hour heat input coal/wood waste fired steam generator (power boiler No. 7) installed at the applicant's plant site located on the inland side of Amelia Island.

BACT Determination Requested by the Applicant:

Pollutant	Emission Limit
Nitrogen Oxides	0.7 lb/million Btu heat input

Date of Receipt of a Complete BACT Application:

December 12, 1980

Date of Publication in the Florida Administrative Weekly:

December 19, 1980

Review Group Members:

The revised determination was based upon comments received from the New Source Review Section and the Northeast District.

BACT Determination by DER:

Pollutants	Emission Limit
Nitrogen Oxides (NO_x)	0.7 lb/million Btu heat input based on the gross calorific value of the fuel combusted.

Compliance with the nitrogen oxide emission limitation will be in accordance with the applicable test methods and procedures as set forth in Subsection 60.46, New Source Performance Standards (NSPS), Subpart D.

BACT Determination Rationale:

The December 30, 1980 BACT determination was based on the NSPS, 40 CFR 60.40, Subpart D. Rationale for the NO_x standard was based on Subsection 60.44(a)(4) of the NSPS, or 0.60 lb NO_x per million Btu derived from lignite or lignite and wood residue.

The applicant has submitted a letter indicating that no lignite will be fired in power boiler No. 7, only coal and wood residue. The applicant, therefore, requests that the NSPS, Subsection 60.44(a)(3), be the limiting standard for NO_x emissions, that is 0.70 lb NO_x per million Btu heat input derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25%, by weight, or more of coal refuse).

The New Source Performance Standards, Subpart D, Subsection 60.45(b)(3) states: that if the owner or operator demonstrates during the performance test that emissions of nitrogen oxides are less than 70 percent of the applicable standard in Subsection 60.44, continuous NO_x monitoring is not required. The performance test for power boiler No. 7 was 0.43 lb NO_x per million Btu or 61.4 percent based on the 0.7 standard and 71.6 percent based on the 0.6 standard. No continuous NO_x monitoring will be required if the emission limit is changed as requested. The actual NO_x emitted will be unaffected.

The Department agrees with the applicants request and has revised the NO_x emission limit as per specific condition 9 of their construction permit, No. AC 45-35532. All other air pollutant emission limits, based upon the December 30, 1980 BACT determination, are not to be changed.

Air quality modeling predicts no violation of any PSD increment or ambient air quality standard resulting from the revised NO_x emission limit.

Details of the Analysis may be Obtained by Contacting:

Edward Palagyi, BACT Coordinator
Department of Environmental Regulation
Bureau of Air Quality Management
2600 Blair Stone Road
Tallahassee, Florida 32301

Recommended By:

CH Fancy

C. H. Fancy, Deputy Bureau Chief

Date: 10/11/84

Approved By:

Victoria J. Tschinkel

Victoria J. Tschinkel, Secretary

Date: 10/12/84

EFP/agh

P 408 530 306

RECEIPT FOR CERTIFIED MAIL

NO INSURANCE COVERAGE PROVIDED—
NOT FOR INTERNATIONAL MAIL

(See Reverse)

Sent to Mr. Tom V. Brown	
Street and No.	
P.O., State and ZIP Code	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to whom and Date Delivered	
Return Receipt Showing to whom, Date, and Address of Delivery	
TOTAL Postage and Fees	$
Postmark or Date 10/26/84	

PS Form 3800, Feb. 1982

PS Form 3811, Jan. 1979

RETURN RECEIPT, REGISTERED, INSURED AND CERTIFIED MAIL

SENDER: Complete items 1, 2, and 3.
Add your address in the "RETURN TO" space on reverse.

1. The following service is requested (check one.)
   - [x] Show to whom and date delivered. ¢
   - [ ] Show to whom, date and address of delivery. ¢
   - [ ] RESTRICTED DELIVERY Show to whom and date delivered. ¢
   - [ ] RESTRICTED DELIVERY. Show to whom, date, and address of delivery. $

   (CONSULT POSTMASTER FOR FEES)

2. ARTICLE ADDRESSED TO:
   Mr. Tom V. Brown
   CCA, North Eighth Street
   Fernandina Beach, FL 32034

3. ARTICLE DESCRIPTION:

REGISTERED NO.	CERTIFIED NO.	INSURED NO.
	P408530306	

(Always obtain signature of addressee or agent)

I have received the article described above.
SIGNATURE ☐Addressee ☐Authorized agent

J. Sanders

4. DATE OF DELIVERY 10/29/84 C — POSTMARK: FERNANDINA BEACH, FL OCT 29 AM 1984 32034

5. ADDRESS (Complete only if requested)

6. UNABLE TO DELIVER BECAUSE: — CLERK'S INITIALS

☆GPO : 1979-300-459

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32301-8241

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

October 15, 1984

Mr. James T. Wilburn, Chief
Air Management Branch
USEPA, Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30365

Dear Mr. Wilburn:

Re: Request for Alternate Procedure for Compliance Monitoring of SO_2 for Power Boiler No. 7: Container Corporation of America

The Florida Department of Environmental Regulation has received a request from the above referenced source for an alternate procedure for compliance monitoring of SO_2 for an NSPS source. Would you please have someone in your staff review and comment on the enclosed proposal and advise us as soon as possible.

If there are any questions, please call Bruce Mitchell at (904)488-1344 or write to me at the above address.

Sincerely,

C. H. Fancy, P.E.
Deputy Chief
Bureau of Air Quality
Management

CHF/BM/s

cc: John C. Brown, Jr.

enclosure

DEPARTMENT OF ENVIRONMENTAL REGULATION

ROUTING AND TRANSMITTAL SLIP

CENTRAL AIR PERMITTING

ACTION NO

ACTION DUE DATE

1. TO: (NAME, OFFICE, LOCATION)	INITIAL / DATE
ADAMS AMODIO FANCY GEORGE	
2. HANKS HERON HOLLADAY KING	
3. MITCHELL, Becky MITCHELL, Bruce	
4. PALAGYI POWELL ROGERS SVEC THOMAS	

REMARKS:

What do you think of their proposal as it relates to permit conditions?

Since the boiler was originally permitted in accordance with Subpart D, I see no objection on either State or Fed permits if the sampling plan is in full accordance with the amendments and if the amendments are promulgated as proposed.
BT

INFORMATION
- REVIEW & RETURN
- REVIEW & FILE
- INITIAL & FORWARD

DISPOSITION
- REVIEW & RESPOND
- PREPARE RESPONSE
- FOR MY SIGNATURE
- FOR YOUR SIGNATURE
- LET'S DISCUSS
- SET UP MEETING
- INVESTIGATE & REPT
- INITIAL & FORWARD
- DISTRIBUTE
- CONCURRENCE
- FOR PROCESSING
- INITIAL & RETURN

FROM: Clair

DATE 10/10

PHONE

Container Corporation of America

Paper Mill Division
North Eighth Street
Fernandina Beach, Florida 32034
Phone 904 261-5551

October 5, 1984

DER
OCT 1984
BAQM

Mr. Bill Vogel
Air and Waste Management Division
EPA
345 Courtland Street
Atlanta, Georgia

Dear Mr. Vogel:

Enclosed is a copy of CCA's procedures for compliance monitoring of SO_2 by sampling and testing of coal. The Northeast subdistrict suggested we send your office a copy of these procedures for your office to approve as an alternative method for determining compliance with the SO_2 limit. We have reviewed our procedures with the Florida DER subdistrict and they approve of our SO_2 sampling and testing methods. They are awaiting your decision on this matter so an operating permit can be issued. Your prompt reply will be appreciated.

If you have any additional questions, please do not hesitate to be in contact with me.

Sincerely,

CONTAINER CORPORATION OF AMERICA

David R. James

for: Cynthia L. Sawyer
Environmental Group Leader

Enclosure

jrb

cc: C. H. Fancy, BAQM
John C. Brown, Jr, Northeast District

Container Corporation of America

Paper Mill Division

North Eighth Street
Fernandina Beach, Florida 32034

Phone: 904 261-5551

CONTAINER CORPORATION OF AMERICA

COAL SAMPLING AND TESTING PROCEDURES

FOR COMPLIANCE MONITORING OF SO_2

FOR #7 POWER BOILER

INTRODUCTION

INTRODUCTION TO COAL TESTING

Coal Testing at Container Corporation of America's Fernandina Beach Mill demonstrates compliance with the 1.2 lbs SO_2/mmBTU on a 30-day rolling average. Container has contracts with two coal companies that supply approximately 5,000 tons of coal per week to the CCA's Fernandina Beach facility. In CCA's construction permit for this NSPS source, the amount of sulfur allowed in the coal is calculated as follows:

$$\text{ALLOWABLE \% SULFUR} = 6.32 \times 10^{-5} \times (\text{BTU per lb coal})$$

The coal which is purchased is low surfur coal with high BTU values. The coal purchasing contract states that the coal cannot exceed 1.2 lb SO_2/mmBTU. The buyer will reject the coal if it does not meet the requirements in the contract for SO_2. CCA felt as though it would be best to have the coal analyzed prior to receiving the shipment at the mill. Therefore, the coal is analyzed by each coal mine and it is also analyzed by a commercial laboratory. If there is a discrepency in the analyses, both the mine and the lab run their test again. The sample is also sent to an independent lab to verify which analysis is correct.

Since the boiler came on line, CCA has been following this procedure for SO_2 compliance monitoring. During the past year and a half, no sample has gone over the 1.2 lbs SO_2/mmBTU limit. This procedures handbook is to identify our coal sampling and testing procedures which document compliance with the 1.2 lbs SO_2/mmBTU allowable.

SAMPLING POINT SELECTION

SAMPLING POINT LOCATION

We elected to have the coal sampled and analyzed at each respective mine site prior to shipments. These analyses are received at our mill before the coal shipments arrive, affording us the opportunity to reject shipments not meeting contract and/or compliance conditions.

If sampling were performed at the mill and the analysis showed non-compliance with SO_2, it would be very difficult to distinguish and/or remove the non-compliance coal from the storage system.

In conjunction with the analyses conducted at the mine sites, duplicate coal samples are sent to an independent laboratory (Commercial Testing, Charleston, WV) for verification of the mines' results. To date, comparison of analyses has been excellent.

SAMPLING METHODS

SAMPLING METHODS

Not only is the sampling location important but also the method by which the coal is sampled. The sample collection is accomplished at the coal mines by different sampling methods. The Golden Oaks Mine uses a J. A. Redding automatic coal sampling system (schematic attached). This is a two stage continuous sampler. Coal shipments to CCA from Golden Oaks consist of approximately 20 to 25 railcars per lot. This sampler has a primary cutter which randomly cuts the full stream of the coal being loaded. During the entire loading about 7,500 lbs. go to the secondary system where it is crushed to a 8 mesh and split into a 50 lb. sample. This sample is then put through a riffler which splits the sample down to the 5 lb. increment that is sent to Commercial Testing for duplicate analysis.

The Peabody Mines (Stickney and Robin Hood, WV) use a semi-mechanical system. The loading operator stops the conveyor belt and takes a straight cut of approximately 50 lbs. across the belt. This is done four times per railcar. The lot size is approximately 16 to 20 railcars. There are approximately 64 to 80 incremental samples per lot. The sample is then crushed to 8 mesh and further divided by a riffler. The sample is split until a 5 to 10 lb. sample is obtained. This sample is also sent to Commercial Testing and to Peabody's in-house laboratory. Both of these coal mines sampling procedures meet ASTM method 2234 for sample size and number of increments.

PURCHASE CONTRACT

COAL SPECIFICATIONS

TABLE 2

PURCHASE CONTRACT
COAL SPECIFICATIONS

Washed coal crushed to size of 2" x 0"

BTU/lb	12,500 minimum
Moisture, as received	8% maximum
Ash, as received	11% maximum
Volatile	30% minimum
Sulfur	1.2 lbs SO_2/mmBTU maximum

Coal not meeting specifications for SO_2 will be rejected.

TEST METHODS

TEST METHODS

	ASTM METHOD				
	Sample Collection	Sample Preparation	Sulfur	Moisture	GCV
Method 19	D2234	D2013	D3177	D3173	D3176*
Golden Oaks	D2234	D2013	Leco Sulfur Analyzer	D3302	D3286
Peabody	D2234	D2013	D3177	D3302	D3286
Commercial Testing	---	D2013	D3177	D3302 D3173	D3286

* This is the ASTM method for an Ultimate Analysis which does not include GCV. ASTM D 3286 is the method to determine GCV.

The Peabody mine participates in a round robin program where they receive an unknown sample once a month for analysis. Peabody also checks their analysis using standard samples on a more frequent basis.

Commercial Testing and Engineering in Charleston, WV serves as the independent laboratory. A copy of their standard laboratory procedure is enclosed. Following is a comparison of results based on sulfur analyses by the mines and Commercial Testing. These are monthly averages and show very little difference between analysts. All the records on compliance monitoring of SO_2 are maintained by the mill Environmental Group.

CCA NO. 7 POWER BOILER

Emissions lb SO_2 mm BTU as determined by Sulfur Analysis of the coal. Mining Company vs Commercial Testing.

Mining Company

1984	Golden Oaks	Commercial Testing
January	0.96	1.02
February	0.94	1.02
March	0.97	1.05
April	0.96	1.01
May	1.02	1.05
June	0.99	1.05

1984	Peabody	Commercial Testing
January	0.97	1.05
February	0.96	1.08
March	1.10	1.14
April	1.05	1.06
May	1.07	1.07
June	1.05	1.06

COMMERCIAL TESTING & ENGINEERING CO.
GENERAL OFFICES: 228 NORTH LA SALLE STREET, CHICAGO, ILLINOIS 60601 · AREA CODE 312 726-8434

WEST VIRGINIA DIVISION MANAGER
TOM BRAZEAU

PLEASE ADDRESS ALL CORRESPONDENCE TO:
P.O. BOX 808, CHARLESTON, WV 25323
OFFICE TEL. (304) 925-6631

February 23, 1984

Cindy Sawyer
Container Corp. of America
Mill Div., North 8th Street
Fernandina Beach, Florida 32034

Dear Cindy,

Commercial Testing & Engineering Co. in Charleston receives 1000-2000 grams of 8 Mesh coal samples directly from two suppliers that is to be shipped to Container Corp. of America.

The coal sample is identified by railcar no's. and airdried in accordance with ASTM D3302 sec. 3.2.2, 3.2.3 and 3.3 at 10°C above ambient temperature until the moisture loss is less than 0.1% per hour. The sample is then riffled to 1000 grams and pulverized to -60Mesh. This sample is subdivided to between 75 and 100 grams and thoroughly mixed in a sample shaker.

This sample is then sent to the laboratory where the following test are performed. Residual Moisture ASTM D3173-79 Ash ASTM D3174-82, Volatile Matter ASTM D-3175 sec. 6.1, Gross Calorific Value ASTM D3286-77 and Sulfur determination ASTM D3177-1982 sec. 3.3.

C.T.&E. adheres to ASTM procedures and has internal (daily) as well as external (weekly) quality control samples run under identical procedures for quality assurance.

If you have any other questions please feel free to contact me at your convenience.

Very truly yours,

COMMERCIAL TESTING & ENGINEERING CO.

Edwin B Snellings

Edwin B. Snellings, Manager
Charleston Office

EBS/tk

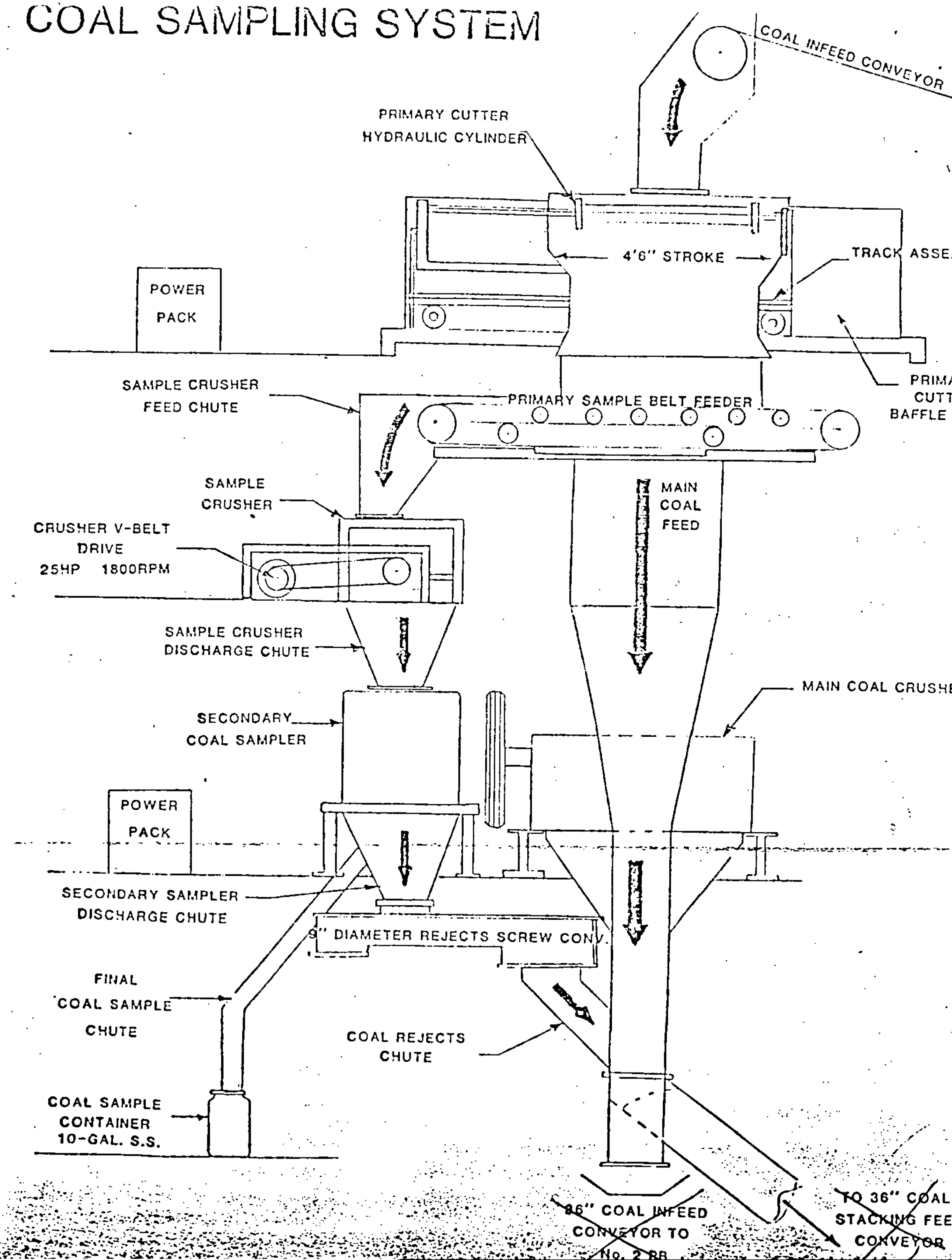
Charter Member

CONCLUSION

CONCLUSION

CCA feels the sampling method and analysis are sufficient to meet the fuel analysis specified by CFR 40 60.45(b)(2). In the Federal register dated Oct. 21,1983, Standards of Performance for New Stationary Sources, proposed revisions stated if the fuel is sampled, it must meet ASTM D-2234. As we stated ealier, these samplers do meet ASTM Method D-2234 and are also analyzed by ASTM methods. We believe this demonstrates compliance with CFR 40 60.45(b)(2).

COAL SAMPLING SYSTEM



ENVIRONMENTAL PROTECTION AGENCY - STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES - FOSSIL-FUEL-FIRED STEAM GENERATORS - DEADLINE FOR COMMENTS IS DECEMBER 20, 1983

According to the Federal Register of October 21, 1983:

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL 2325-3]

Standards of Performance for New Stationary Sources; Fossil-Fuel-Fired Steam Generators

AGENCY: Environmental Protection Agency.

ACTION: Proposed revision of rule.

SUMMARY: On December 23, 1971, the Environmental Protection Agency promulgated standards of performance for large fossil-fuel-fired steam generating units constructed after August 17, 1971 (40 CFR Part 60, Subpart D). The changes to Subpart D being proposed today would establish sulfur dioxide compliance, emission monitoring, and reporting requirements on a 30-day rolling average basis. Electric utility steam generating units constructed after September 18, 1978, would not be affected by the proposal since they are subject to Subpart Da. For steam generators firing low-sulfur compliance fuels, the proposal would allow sulfur dioxide compliance testing by continuous emission monitoring, stack testing, or fuel sampling and analysis. For steam generators equipped with flue gas desulfurization systems, compliance testing could be conducted by either continuous emission monitoring or stack testing. The proposed revisions would become effective 1 year after promulgation. The proposal includes a new sulfur dioxide compliance test method (Reference Method 19A) which incorporates the revised test methods and data reduction procedures.

DATES: Comments on the proposed revisions are requested by December 20, 1983. The revision would become effective 1 year after promulgation.

ADDRESS: Comments should be submitted (in duplicate if possible) to: Central Docket Section (LE-131), U.S. Environmental Protection Agency, 401 M Street, SW., Washington, D.C. 20460. Attention: Docket No. A-81-15.

Docket. Docket No. A-81-15, containing supporting information used in developing the proposed revision, is available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section, West Tower Lobby, Gallery 1, Waterside Mall, 401 M Street, SW., Washington, D.C. 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Fred L. Porter, or Mr. Walter H. Stevenson, Standards Development Branch, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5624.

SUPPLEMENTARY INFORMATION:

Background

On December 23, 1971, EPA promulgated standards of performance for large fossil-fuel-fired steam generating units (36 FR 24876; 40 CFR Part 60, Subpart D). The standards limit emissions of sulfur dioxide (SO_2), particulate matter, and oxides of nitrogen. The SO_2 emission standard for coal is 520 ng/J (1.2 lb SO_2 per million Btu) heat input and for fuel oil is 340 ng/J (0.8 lb SO_2 per million Btu) heat input. The SO_2 standard can be met by the use of low-sulfur fuels, flue gas desulfurization (FGD), or a combination of the two.

When the SO_2 standards were promulgated in 1971, there were little data available on short-term variability of SO_2 emissions; it was expected that short-term stack tests would be satisfactory for assessing compliance with the SO_2 standard at facilities using either low-sulfur compliance fuel or FGD. Compliance demonstration was required through the use of EPA Reference Method 6 (minimum 3-hour test period).

Subpart D also required that continuous SO_2 emission monitors be installed and operated. For facilities using compliance fuel, continuous SO_2 monitors were not required, provided that fuel sampling and analysis were conducted. Continuous SO_2 emission monitoring systems has not been extensively evaluated by EPA in 1971 and, because of this, performance specifications (including data reduction and reporting requirements) were not included in the 1971 regulation. Therefore, the monitoring requirements proposed in August 1971 indicated that a review of continuous emission monitoring systems would be conducted and additional guidance provided at a later date (36 FR 15704).

The guidance on continuous monitoring systems was provided on October 6, 1975, when EPA promulgated a number of changes to Subpart D (proposal at 39 FR 32852 and promulgation at 40 FR 46250). Included were performance specifications for continuous emission monitoring systems and emission reporting requirements for FGD-equipped steam generators. For FGD-equipped units, the revision required that the data collected by the

SO_2 monitor be used to prepare quarterly reports of excess emissions. A 3-hour averaging period, consistent with the Method 6 stack test, was specified for data reduction purposes.

In the proposal to the 1975 changes, EPA had included SO_2 excess emissions reporting requirements for both FGD and non-FGD-equipped steam generators. However, comments received on the proposed monitoring requirements pointed to a number of problems with the proposed fuel analysis option and the impact of coal sulfur variability on reporting excess emissions. Comments and discussions with coal suppliers and electric utility companies led the Agency to conclude that the proposed requirements for fuel analysis were inadequate and inconsistent with the existing fuel supply situation. Recognizing that additional study would be necessary before meaningful provisions could be developed, the fuel analysis provisions of Subpart D were reserved in the regulation.

Since 1975, EPA has conducted a number of studies to assess both the sulfur variability in coal and the variation in FGD performance. Today's proposel is based on these studies and completes the SO_2 emission monitoring requirements for steam generators using compliance fuels and revises the provisions for FGD-equipped units.

Rationale for Proposal

When EPA proposed emission standards for large fossil-fuel-fired steam generating units in 1971, EPA indicated that the 520 ng/J (1.2 lb SO_2 per million Btu) emission limit for coal-fired units could be complied with by using either flue gas desulfurization or low-sulfur coal. In developing the standard, EPA reviewed U.S. coal reserve data to determine the potential impacts of the standard on compliance coal reserves. As indicated in the background document for the 1971 standard, a high grade coal with a sulfur content of 0.7 percent or less was judged capable of complying with the standard (II-A-001 p. 5). In selecting a 0.7 percent sulfur compliance coal as one basis of the standard, EPA estimated that about one-fourth of the U.S. recoverable coal reserves could be expected to comply (II-B-001). In arriving at this estimate, the Agency considered the average sulfur content of the fuel reserves but did not consider sulfur content variability or the effect of averaging time.

Many facilities subject to Subpart D have elected to use compliance fuel. A survey conducted by EPA in 1978 indicated that approximately 200 coal-fired electric utility boilers subject to Subpart D will have begun operation by 1983. Of these, approximately one-half plan to use compliance coal. The other half plan to use FGD systems (II-A-003).

The issue of averaging time for the SO_2 standard relates to both the variability of sulfur content of the coal and FGD performance. In relation to compliance coals, the variability of sulfur has been addressed in various EPA studies since 1975 and studies continue (II-A). From the studies completed to date, it is clear that coal is not homogeneous and the sulfur content of coal used in a steam generator can vary, even when the coal is supplied from the same mine. In addition to geological properties, some of the factors that affect coal sulfur content variability include mining practices, coal preparation procedures, on-site coal handling procedures (including the on-site mixing of coal from various suppliers), and chemical characteristics of the coal. These factors can interact and result in complex sulfur variability patterns which are difficult for boiler operators to predict or manage on a short-term basis.

The record shows that this variability and these effects were largely not recognized by EPA or by commenters when the standard was adopted in 1971. Because the sulfur content of coal supplied to a steam generator varies with time, the averaging time associated with an SO_2 emission limit can affect the supply of coals that can comply with the standard without the use of FGD. As the averaging period associated with an emission standard is shortened, coals with a lower mean sulfur content are required to assure compliance. Table 1 shows the estimated range of mean sulfru levels required to meet a 520 ng/J (1.2 lb per million Btu) heat input standard for different averaging times. Table 2 shows the estimated U.S. low-sulfur coal reserves that would be expected to comply with various mean sulfur levels listed in Table 1.

Combined, Tables 1 and 2 show that interpretation of the SO_2 standard on a short-term basis severely limits supplies of compliance coals. The tables show that about 10 percent, or less, of the U.S. coal reserves would be expected to comply with the SO_2 standard on a 3-hour basis. However, on a 30-day rolling average basis, about 25 percent of the coal reserves could comply with Subpart D and this is consistent with the intended effects when the standard was adopted in 1971.

Proposed Averaging Time and Monitoring Requirements

Based on these analyses (II-B-002), EPA believes that a 30-day period is an appropriate averaging period for evaluating compliance fuels and makes the standard conform to the original intent. The rolling average allows for daily enforcement. Averaging periods longer than 30 days were judged to be unnecessary. Longer averaging periods would have relatively little additional effect on mitigating the effect of coal sulfur variability compared to the 30-day rolling average. Shorter averaging periods would severely limit compliance coal supplies for plants subject to the standard and could lead to the use of costly coal blending facilities.

TABLE 1.—ESTIMATED MEAN SO_2 EMISSION LEVELS REQUIRED TO COMPLY WITH A 520 NG/J (1.2 LB/MILLION BTU) EMISSION LIMIT AT DIFFERENT AVERAGING BASES

Averaging periods (rolling average)	Required mean SO_2 Emissions[1] ng/J	Lb SO_2/10^6 Btu
90-days	450	1.04
30-days	410	0.95
3-hour	265	0.62

Source: Docket A-81-15, II-B-002.

[1] Based upon 24-hour relative standard deviation and autocorrelation values of 0.20 and 0.72, respectively.

TABLE 2.—ESTIMATED NATIONAL LOW-SULFUR COAL RESERVES[1]

Required mean SO_2 emission ng/J	Lb SO_2/10^6 Btu	Estimated recoverable U.S. coal reserves (percent)
260	0.6	5 to 7.
300	0.7	10 to 15.
345	0.8	15 to 22.
385	0.9	20 to 25.
430	1.0	25 to 30.
470	1.1	30 to 40.

Source: Docket A-81-15, II-B-002.

[1] Based upon a ±20 percent accuracy level of estimated coal reserves.

In addition, EPA also proposes to apply the 30-day rolling average to FGD-equipped units. Similar to the short-term fluctuations in SO_2 emissions experienced when combusting compliance fuels, FGD performance and associated SO_2 emissions from FGD equipped units also experience short-term fluctuations. The short-term variation in FGD performance was not well understood when Subpart D was adopted in 1971 and is not appropriately addressed by a short-term 3-hour compliance test. Based on a thorough review of FGD performance data, which was conducted in conjunction with the revised NSPS for utility steam generating units (Subpart Da; 44 FR 33580), EPA has concluded that a 30-day rolling average best typifies the performance of a well-designed and properly operated FGD system. At promulgation of Subpart Da, EPA concluded that a 30-day average allows adequate time for owners or operators to respond to operating problems affecting FGD efficiency, permits greater flexibility in procedures necessary to operate FGD systems in compliance with the standard, and can reduce the effects of coal sulfur variability on maintaining compliance (44 FR 33595). These same considerations are applicable to evaluating the performance of FGD-equipped units subject to Subpart D and a 30-day rolling average is included in this proposal.

The proposed revision would make Subpart D consistent with the intent and the anticipated effect at the time it was adopted and does not make it a more stringent regulation with which to comply. By determining compliance through continuous methods, it will better ensure that sources continuously comply with the standard. Finally, the proposal provides an averaging time that is consistent with the capability of the control technology. If adopted, the revisions would become effective 1 year after promulgation. This lag time provides the necessary time for planning, procurement, installation, and start-up of monitoring systems and data processing equipment which will be required.

A number of factors contribute to the need for allowing a 1-year period to implement the revisions. Sources that now have continuous emission monitors for determining excess SO_2 emissions would have to develop data retrieval and reduction capabilities for determining the 30-day rolling average. Most sources would opt to install electronic data storage and processing systems which are presently available but have delivery periods of several months. Development of data reduction procedures for individual sources would add to the time needed for installation and initiation of the data gathering.

Sources that do not have SO_2 monitoring systems installed would have to order equipment, prepare the measurement sites, install the monitors, conduct the performance specification tests, and develop a quality assurance/quality control program to maintain the quality of the data. The time required to complete these tasks could take 1 year. Most of the above tasks would also have to be done by sources that would use fuel sampling and analysis procedures in lieu of continuous monitors. Not all of the sources which now perform fuel sampling and analysis follow the procedures specified in Method 19A. In some cases, modification of existing sampling or analysis procedures may be necessary.

A new SO_2 stack testing method (Method 6B), was promulgated in the Federal Register on December 1, 1982 (47 FR 56073) and is included in this proposal as an optional SO_2 measurement procedure. Use of Method 6B to determine SO_2 emissions would suggest that less than a 1-year lead time would be necessary for implementing the proposal; however, Method 6B was only recently promulgated and at present, no manufacturers commercially market a Method 6B sampling system.

Based on these factors, EPA has concluded that a 1-year lead time for complying with the revised monitoring requirements would be reasonable. Owners or operators of facilities that wish to implement the revision prior to the 1-year period may apply to the Administrator for approval. Until the revision is implemented, Subpart D would remain in effect in its present form and compliance would continue to be determined through the use of Method 8.

Compliance Methods

The proposed SO_2 compliance provisions would replace Method 6 with Method 19A. Under the proposal, a source employing a continuous emission monitoring system to determine SO_2 emissions would use hourly data averaged for the past 30 boiler operating days to determine a 30-day average emission rate. This procedure is repeated for each day and results in the calculation of a 30-day rolling average emission rate. SO_2 emissions data collected during startup, shutdown, or system malfunction are not included in calculation of the 30-day rolling average emission rate. However, such periods must be identified in the quarterly SO_2 emissions report. If SO_2 emissions are measured through the use of Method 6B or by fuel sampling and analysis, as allowed under proposed Method 19A, SO_2 emissions report. If SO_2 emissions a daily basis and the SO_2 emission rate for the past 30 boiler operating days would be averaged to determine a 30-day average emission rate.

In calculating SO_2 emission rates, all valid SO_2 emissions data are used. It is recognized, however, that data may not be available for 100 percent of the time. Under the proposal, minimum data requirements are included and supplemental sampling would be required, if necessary, to assure that the data requirements are met. For SO_2 continuous emission monitoring systems, the minimum SO_2 data availability requirements would be 22 days of SO_2 emissions data for each 30 days of boiler operation and for fuel sampling and analysis systems and Method 6B stack testing procedures would be 27 days of SO_2 emissions data for each 30 days of boiler operations.

In announcing the use of continuous emission monitors for compliance determinations in Subpart Da in June 11, 1979, EPA indicated that quality assurance procedures were being developed (44 FR 33611). During 1980 and 1981, EPA distributed draft quality assurance procedures for continuous monitoring systems for technical review. When these procedures complete review and are adopted, they will be applicable to SO_2 continuous emission monitors used under today's proposal and Subpart Da. The procedures would require daily instrument drift measurement and quarterly accuracy audits. Additionally, EPA recently promulgated changes in Performance Specification 2 and 3 (Appendix B) which will simplify the continuous emission monitoring system performance evaluation required under § 60.13.

Method 6B may be used to determine daily SO_2 stack emission rates instead of continuous emission monitors. Method 6B uses an SO_2 collection system, based upon Reference Method 6, with an on/off timer to collect an integrated SO_2 sample over a 24-hour period. Analysis of the Method 6B sample provides a 24-hour integrated SO_2 emission rate.

If fuel sampling is selected for determining the daily SO_2 emission rate, sampling systems meeting the minimum requirements of the specific portion of ASTM Method D-2234 (coal) and ASTM Method D-270 (oil) included in Method 19A would be used. These are the same sampling methods included in Method 19 for new electric utility steam generating units subject to Subpart Da. For coal-fired steam generators, sampling on a daily "as-fired" basis in proposed. This would mean that coal would be sampled as the coal silos (bunkers) that supply coal to the coal pulverizers are filled. The coal sample would be analyzed for sulfur content and specific heat, the potential SO_2 emission level (ng/J, lb per million Btu) would be calculated, and used as the 24-hour SO_2 emission rate for the day the coal was bunkered. For fuel oil, a "drip type" sample would be collected at the burner while oil is being fired. Fuel samples would be analyzed using ASTM procedures (included in Method 19A).

For coal-fired steam generators, the proposal assumes that 95 percent of the sulfur in the coal is discharged to the atmosphere as SO_2. This assumption is based upon studies which indicate that about 5 percent of the sulfur in the coal is retained in the pulverizer rejects, bottom ash, and fly ash. The owner or operator of a steam generator may petition the Administrator to permit use of a lower value for the sulfur in the coal discharged to the atmosphere, provided data are made available to substantiate a lower value.

Under the proposal, the fuel sampling and analysis procedures contained in Method 19A are included as an EPA approved "alternative test method." As defined under § 60.2 and discussed under § 60.8(b), the fuel sampling option under Method 19A could be selected by an owner or operator to determine SO_2 emissions; however, since it is an alternative test method, EPA or the implementing State air pollution control agency retains the authority to require periodical SO_2 testing by Method 6B or continuous emission monitors to demonstrate the adequacy of the alternative test method.

Proposal of the fuel sampling and analysis procedures as alternative test methods is based on the Administrator's judgment that these procedures are sufficiently accurate to be used as a basis for determining compliance with the standard. Under section 307(b)(2) of the Act, the owner will be precluded from challenging these procedures in any enforcement proceeding. Of course, use of these procedures is optional; any owner that wishes not to use them to determine compliance is free to choose either of the other two methods. Finally, as with any alternative method, the Administrator retains the authority to withdraw approval for its use at a particular facility if, in his judgement, it would not be sufficiently accuete to determine compliance at that facility.

Under the proposal, ASTM D-2234 Type I, Conditions A, B, or C, and Systematic Spacing would be used for coal sampling. This approach would allow both automated and manual coal sampling methods to be used; however, automated sampling is expected to predominate. For units not using automated coal sampling systems or for supplemental sampling due to failure of the primary system, manual sampling would be done in accordance with ASTM requirements, including proper sampling device geometry, number of sample increments, and increments taken evenly spaced in time or position.

In cases where more than one steam generator subject to Subpart D is installed at a site, a single fuel sampling system may be used to sample the coal as it is bunkered to individual units. A daily "as fired" coal sample would be collected for each unit and would be analyzed to determine the daily SO_2 emission rate for each unit.

Because of the wide variation in design and operation of steam generation facilities, there may be alternative SO_2 monitoring sites, fuel sampling locations, or procedures that may be appropriate for specific steam generators. In such cases, the owner or operator of a facility may petition the Administrator to approve other alternate monitoring procedures.

Miscellaneous

Under Executive Order 12291, EPA is required to judge whether this action would be a "major rule" and, therefore, subject to certain requirements of the Order. The Agency has made a preliminary determination that the revision would result in none of the adverse economic effects set forth in Section 1 of the Order as grounds for finding a "major rule." While this action is primarily a clarification of an earlier rule, there are some additional monitoring and reporting requirements. However, the additional costs are far less than the $100 million specified in the Order as defining a "major rule." Moreover, the revision will not result in a major increase in costs or prices and will not disrupt market competition. The Agency has, therefore, concluded that this revision would not be a "major rule" under Executive Order 12291.

Additionally, under Section 317 of the Clean Air Act, the Administrator is required to prepare an economic impact assessment for revisions determined by the Administrator to be substantial. The Administrator has determined that these revisions are not substantial and has not prepared an economic impact assessment.

The reporting and recordkeeping provisions of the regulation that this rulemaking revises have previously been cleared by OMB (OMB clearances 2000-0207 and 2000-0142). A clearance package reflecting the reporting requirements contained in this proposal has been submitted to OMB for review under Section 3504(h) of the Paperwork Reduction Act of 1980. Comments on these requirements should be submitted to the Office of Information and Regulatory Affairs of OMB, Attention: Desk Officer for EPA. The final rule package will respond to any OMB or public comments on information collection requirements.

Pursuant to 5 U.S.C. 605(b), the Administrator certifies that these revisions do not have a significant impact on a substantial number of small entities. The proposed revision will not affect a substantial number of small entities since the standard only applies to steam generators larger than 73 MW (250 million Btu per hr) heat input and well over 90 percent of these facilities will be large electric utility and industrial manufacturing companies. If the standards does not apply to any small entities, the impacts are insignificant as the emission monitoring costs would be less than 1 percent of the annualized boiler costs.

List of Subjects in 40 CFR Part 60

Air pollution control, Aluminum, Ammonium sulfate plants, Asphalt, Cement industry, Coal copper, Electric power plants, Glass and glass products, Grains, Intergovernmental relations, Iron, Lead, Metals, Metallic minerals, Motor vehicles, Nitric acid plants, Paper and paper products industry, Petroleum, Phosphate, Sewage disposal, Steel sulfuric acid plants, Waste treatment and disposal, Zinc, Tires, Incorporation by reference, Can surface coating, Sulfuric acid plants, Industrial organic chemicals, Organic solvent cleaners.

(Sec. 111, 301(a) of the Clean Air Act, as amended; 42 U.S.C. 7411, 7601(a))

Dated: October 12, 1983.

Alvin L. Alm,

Acting Administrator.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

In 40 CFR Part 60, §§ 60.41, 60.43, 60.45, and 60.46 are amended and §§ 60.48 and 60.49 are added as follows:

1. Section 60.41 is amended by adding paragraphs (g) and (h) as follows:

§ 60.41 Definitions.

* * * * *

(g) "24 hour period" means the period of time between 12:01 a.m. and 12:00 midnight. A starting time other than 12:01 a.m. may be used for the 24-hour period. If a starting time other than 12:01 a.m. is used, the starting time must be defined in the quarterly emissions report and must be constant for the entire calendar quarter.

(h) "Boiler operating day" means a 24-hour period during which any fossil fuel is combusted in the steam generator.

2. Section 60.43 is amended by adding paragraph (d) as follows:

§ 60.43 Standard for sulfur dioxide.

* * * * *

(d) Compliance with the emission limitations under this Section are determined on a 30-day rolling average basis in accordance with Method 19A (Appendix A).

3. Section 60.45 is amended by revising paragraphs (b)(2), (4), and (e); deleting paragraphs (f) and (g)(2), and adding paragraphs (b)(5), (h), (i), (j), (k), and (l) as follows:

§ 60.45 Emission and fuel monitoring.

* * * * *

(b) * * *

(2) The continuous emission monitoring system for measuring sulfur dioxide required under paragraph (a) of this Section is not necessary, if Method 6B or the alternative fuel sampling and analysis procedure under Method 19A (Appendix A) is used. The fuel sampling and analysis procedures included in Method 19A are approved as alternative SO_2 test methods for steam generators subject to this subpart and a written application for approval under § 60.13(j) is not required. The fuel sampling and analysis procedures in Method 19A are alternative test methods and the Administrator retains the authority to periodically require SO_2 testing by Method 6B or continuous emission monitors or to withdraw the approval for specific facilities.

* * * * *

(4) If an owner or operator does not install any continuous monitoring systems for sulfur oxides and nitrogen oxides as provided under paragraphs (b)(1) and (b)(3) or (b)(1) and (b)(5) of this Section, a continuous monitoring system for measuring either oxygen or carbon dioxide is not required.

(5) For affected facilities that combust more than 75 percent wood or wood residue on a quarterly (calendar) heat input basis, a continuous monitoring system for measuring sulfur dioxide emissions in not required. Such facilities are required to maintain quarterly records of percent of wood or wood residue fired on a heat input basis.

* * * * *

(e) For any continuous monitoring system installed under paragraph (a) of this Section, the following conversion procedure shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million Btu):

(1) For sulfur dioxide data, procedures under Section 3 of Method 19A (Appendix A) are used.

(2) For nitrogen oxides data, procedures under Section 5 of Method 19 (Appendix A) are used.

(f) [Reserved]

(g) * * *

(2) [Reserved]

* * * * *

(h) The continuous monitoring systems under paragraph (a) of this section are operated and data are recorded during all periods of operation of the affected facility including periods of startup, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(i) When sulfur dioxide emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data are obtained by using an alternate monitoring procedure under Method 19A or by using other monitoring systems as provided by the Administrator as necessary to provide emission data as required under paragraph (k) of this section.

(j) For continuous emission monitoring systems, the 1-hour average SO_2 emissions required under paragraph § 60.13(h) are expressed in ng/J (lbs/million Btu) heat input and used to calculate the average emission rates under § 60.48. The 1-hour averages are calculated using the data points required under § 60.13(b). At least two points must be used to calculate the 1-hour averages.

(k) The minimum data requirements for sulfur dioxide emissions data collected using Method 19A are as follows:

(1) For continuous emission monitoring systems, data from at least 75 percent of the boiler operating hours per day in at least 22 out of 30 successive boiler operating days are required.

(2) For stack testing (Method 6B), data from at least one test run per day in at least 27 out of 30 successive boiler operating days are required.

(3) For coal sampling and analysis, data from coal samples representative of the coal supplied to the steam generator or to the coal silos (bunkers) each boiler operating day in at least 27 out of 30 successive boiler operating days are required.

(4) For oil sampling and analysis, data from oil samples representative of the oil supplied to the steam generator each boiler operating day in at least 27 out of 30 successive boiler-operating days are required.

(l) In meeting the data requirements under paragraph (k) of this section, a combination of the test procedures included under Reference Method 19A (Appendix A) may be used. If SO_2 emissions data from continuous emission monitoring systems under paragraph (k)(1) of this section are supplemented with SO_2 emissions data from stack testing (Method 6B) or by fuel sampling and analysis procedures contained in Method 19A, the minimum data requirements of paragraph (k)(1) of this section apply.

4. Section 60.46 is amended by revising paragraph (a)(4), (c) and (f) and removing paragraph (d) as follows:

§ 60.46 Test methods and procedures.

* * * * *

(a) * * *

(4) Method 19A for sulfur dioxide emission rate and

* * * * *

(c) For Method 7, the sample site shal be the same as that selected for Method 5. The sampling point in the duct shall be at the centroid of the cross Section o at a point no closer to the wall than 1 m (3.28 ft.). Removed

(d) [Reserved]

* * * * *

(f) For each run using the methods specified by paragraphs (a)(3) and (a)(5 of this section, the emissions expressed in ng/J (lb/million Btu) are determined following the procedures in Section 5 of Method 19 (Appendix A) (see § 60.47 fo sulfur dioxide emissions calculations).

* * * * *

5. Sections 60.48 and 60.49 is added a follows:

§ 60.48 Sulfur dioxide compliance provisions.

(a) After the initial performance test required under § 60.8, compliance with the sulfur dioxide emission limitations under § 60.43 is based on the average emission rate for 30 successive boiler operating days [as determined followin the procedures under Method 19A (Appendix A)]. Following the initial performance test, a separate performance test is completed at the en of each boiler operating day and a new 30 day average emission rate for sulfur dioxide is calculated to determine compliance with the standards.

(b) For the initial performance test required under § 60.8, compliance with the sulfur dioxide emission limitations i based on the average emission rates fo sulfur dioxide for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rat at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(c) In determining compliance with t standard following Method 19A, all sulfur dioxide emissions data (except sulfur dioxide emissions data obtained during startup, shutdown, or malfunction) are included in determining compliance.

(d) If an owner or operator has not obtained the minimum quantity of emission data as required under § 60.45(k), compliance with the emission requirements under § 60.43 of this Subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in Section 6 of Reference Method 19A (Appendix A).

§ 60.49 Sulfur dioxide reporting requirements.

(a) The owner or operator of any affected facility shall submit the written reports required under paragraph (b) of this section and Subpart A to the Administrator for every calendar quarter. All quarterly reports shall be submitted by the 30th day following the end of each calendar quarter.

(b) For sulfur dioxide, the following emission data are submitted to the Administrator for each 24-hour period:

(1) Calendar Date.

(2) The average sulfur dioxide emission rate (ng/J or lb/million Btu) for each 30 successive boiler operating days ending with the last 30-day period in the quarter; reasons for noncompliance with the emission standards, and description of corrective action taken.

(3) Identification of the boiler operating days for which pollutant or diluent data have not been obtained following methods under Method 19A (Appendix A); justification for not obtaining sufficient data; and description of corrective actions taken.

(4) Identification of the times when emission data from FGD equipped steam generators have been excluded from the calculation of average emission rates because of start-up, shut-down, malfunction, or other reasons; and justification for excluding data for reasons other than start-up, shut-down, or malfunction.

(5) For facilities combusting mixtures of fossil fuel and wood or fossil fuel and wood residue, the percentage of heat input to the steam generator provided by wood or wood residue during the calendar quarter.

6. Part 60, Appendix A is amended by adding Method 19A to read as follows:

Method 19A—Determination of Sulfur Dioxide Emission Rates From Fossil-Fuel-Fired Steam Generators

1. Principle and Applicability

1.1 Principle.

1.1.1 Fuel samples are collected and analyzed for sulfur and heat content and the sulfur dioxide emission rate is determined from the analysis data. Procedures are described for coal and oil; or

1.1.2 Sulfur dioxide and oxygen or carbon dioxide concentration data are obtained using emission testing procedures and are used to determine sulfur dioxide emission rates. Procedures are described for continuous emission monitoring systems using instrumental or manual techniques.

1.2 Applicability. This method is applicable for determining sulfur dioxide (SO_2) emission rates from fossil fuel-fired steam generators.

2. As-Fired Fuel Analysis

Collect the fuel samples from a location in the fuel handling or processing system that provides a sample representative of the fuel bunkered or consumed during a boiler operating day. For the purpose of this method, a fuel lot size is defined as the weight of fuel bunkered or consumed during each boiler operating day. For reporting and calculation purposes, the gross sample shall be identified with the calendar day on which sampling began. Alternate definitions of fuel lot sizes may be specified subject to prior approval of the Administrator.

2.1 Fuel Sampling.

2.1.1 Solid Fossil Fuel. Use coal sampling procedures meeting the requirements of ASTM D 2234[1] Type I, Conditions A, B, or C and systematic spacing. As a minimum, determine the number and weight of increments required per gross sample according to paragraph 7.1 of ASTM D 2234[1]. As used in this method, systematic spacing is intended to include evenly spaced increments in time or increments based on equal weights of coal passing the collection area.

2.1.2 Liquid Fossil Fuel. Use the procedure for continuous sampling described in Method 19, Section 2, paragraph 2.2.1.

2.2 Fuel Analysis.

2.2.1 Solid Fossil Fuel. Determine the percent sulfur content (%S) and gross calorific value (GCV) of the solid fossil fuel on a dry basis fro each gross sample. Use ASTM D 2013[1] for sample preparation, ASTM D 3177[1] for sulfur analysis, ASTM D 3173[1] for moisture analysis and ASTM D 2015[1] for GCV determination.

2.2.2 Liquid Fossil Fuel. Determine the percent sulfur content (%S) and gross calorific value (GCV) of the liquid fossil fuel. Use ASTM D 240[1] for GCV determination and ASTM D 129[1] for sulfur analysis. These values can be assumed to be on a dry basis.

2.3 Calculation of Sulfur Dioxide Emission Rate Using Fuel Analysis Data.

2.3.1 Daily Emission Rate. Calculate the daily SO_2 emission rate as follows:

For Solid Fossil Fuel:

$$E_{SO_2} = 0.95K \times \frac{(\%S)}{GCV} \quad \text{(Equation 19A-1)}$$

[1] Use the most recent revision or designation of the ASTM procedure specified.

For Liquid Fossil Fuel:

$$E_{SO_2} = \frac{K(\%S)}{GCV} \quad \text{(Equation 19A-2)}$$

Where:

E_{SO_2} = SO_2 emission rate; ng/J (lb/10^6 Btu).

%S = Sulfur content of the fuel on a dry basis; weight percent.

0.95 = Allowance for 5.0 percent sulfur removal in coal pulverizer rejects and ash.

GCV = Gross calorific value of the fuel on a dry basis; kJ/kg (Btu/lb).

K = Conversion Factor: 2×10^7 for SI units; 2.0×10^4 for english units.

If more than one fuel type is bunkered or consumed during the day, use the following equation to calculate the daily sulfur content per unit of heat content as follow:

$$\frac{\%S}{GCV} = \sum_{k=1}^{n} Y_k \left(\frac{\%S_k}{GCV_k}\right) \quad \text{(Equation 19A-3)}$$

Where:

Y_k = The fraction of total heat input derived from each fuel type, k.

$\%S_k$ = Sulfur content of each fuel type, k, on a dry basis; weight percent.

GCV_k = Gross calorific value for each fuel type, k, on a dry basis; kJ/kg (Btu/lb).

n = Number of different fuel types.

For the purpose of this method, fuel type is meant to differentiate between classes of fossil fuel (e.g., solid or liquid), classifications of solid fossil fuel (e.g., bituminous or subbituminous coal), or grades of liquid fossil fuels (e.g., crude or residual). Sampling of fuel types contributing less than one percent of the total heat input in a boiler operating day (e.g., light fuel oils used during boiler startup or for combusiton stabilization in solid fossil fuel fired boilers) is not necessary.

2.3.2 Determination of 300-Day Rolling Average. Calculate the mean 30-day SO_2 emission rate for 30 successive boiler operating days (rolling average) as follows:

$$E_{30} = \frac{1}{n} \sum_{1}^{n} E_{SO_2} \quad \text{(Equation 19A-4)}$$

E_{30} = SO_2 emission rate as a 300-day rolling average; ng/J (lb/10^6 Btu).

n = Number of daily SO_2 emission rates obtained in the 30 boiler operating day period.

3. Continuous Emission Monitoring System (CEMS)

Measurement of SO_2 concentration and oxygen (O_2) or carbon dioxide (CO_2) at the same exhaust location representative of the total emissions are required. Install and operate the CEMS in accordance with 40 CFR 60, Appendix B, Performance specifications 2 and 3 and as required in the applicable subpart.

3.1 Sampling. Use the CEMS data for SO_2 and O_2 or CO_2 concentrations obtained following the procedures in Section 3.

3.2 Determination of an F Factor. Select an applicable f factor as described in Method 19, Section 5.2.

3.3 Calculation of Emission Rate. Determine the hourly SO_2 emission rate as described in Method 19, Section 5.3.

3.4 Calculation of the 30-Day Rolling Average. Calculate the mean 30-day emission rate using all the available hourly averages in ng/J (lb/10^6 Btu) for 30 successive boiler operating days (rolling average) as follows:

$$E_{ao} = \frac{1}{n} \sum_{1}^{n} E_{hoi} \qquad \text{[Equation 19A-5]}$$

where:

E_{ao} = SO_2 emission rate as a 30-day rolling average; ng/J (lb/10^6 Btu).

n = Total number of hourly values available for calculation of the 30-boiler operating day average.

E_{hoi} = Hourly SO_2 emission rate, average of at least two 15-minute measurement values and determined as in Section 3.3; ng/J (lb/10^6 Btu).

4. Manual Sampling Using Method 6B

Method 6B may be used as either an intermittent sample on a schedule of at least one increment per 2-hour interval or a continuous sample for a 24-hour composite for analysis. Measurement of SO_2 and CO_2 concentration at the same exhaust location representative of the total emissions are required. An initial stratification test is required to verify the adequacy of the sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train installed and operated at the candidate location and a second similar train operated using a three (or more) point traverse. Method 6B, Method 6A, or a combination of Methods 6 and 3 are suitable measurement techniques.

The minimum requirements for selecting the traverse location are as follows: Establish a "measurement line" that passes through the centroidal area and in the direction of any expected stratification. (The centroidal area is a concentric area that is geometrically similar to the stack or duct cross section and is greater that 1 percent of the stack or duct cross-sectional area.) If this line interferes with the measurement at the candidate location, displace the line up to 30 cm (or 5 percent of the equivalent diameter of the cross section, whichever, is less) from the centroidal area. Locate three traverse points at 16.7, 50.0 and 83.3 percent of the measurement line. If the measurement line is longer than 2.4 meters and pollutant stratification is not expected, the tester may choose to locate the three traverse points on the line at 0.4, 1.2, and 2.0 meters from the stack or duct wall. This option must not be used after wet scrubbers or a points where two streams with different pollutant concentrations are combined. The tester may select other traverse points provided that they can be shown to the satisfaction of the Administrator to provide a representative sample over the stack or duct cross section. If method 6B is used, sampling time and timer operation may be adjusted for the stratification test to collect an adequate sample volume; however, both sampling trains are to be operated similarly.

If the mean of the absolute difference between the three paired runs agree to within 10 percent, the location is adequate for the Method 6B 24-hour tests. If the agreement is not within 10 percent, choose a new location and repeat the stratification tests.

4.1 Sampling. All sample collection shall be within 3 cm of the sample location meeting the stratification test in section 4.0.

4.2 Determination of a F_c Factor. Select an applicable F_c factor as described in Method 19, Section 5.2.

4.3 Calculation of a Boiler Operating Day Emission Rate. Determine a daily SO_2 emission rate, E_{SO_2}, as described in Method 6A, Section 7.6.2 (Equation 6A-8); in ng/J (lb/10^6 Btu).

4.4 Calculation of the 30-Day Rolling Average. Calculate the mean 30-day emission rate using the daily measured values in ng/J (lb/10^6 Btu) for successive boiler operating days (rolling averages) as follow:

$$\bar{E}_{ao} = \frac{1}{n} \sum_{1}^{n} E_{aoi} \qquad \text{(Equation 19A-6)}$$

where:

E_{ao} = SO_2 emission rate 30-day rolling average, ng/J (lb/10^6 Btu).

E_{aoi} = Daily SO_2 emission rates, ng/J (lb/10^6 Btu).

n = Number of daily SO_2 emission rates obtained in the 30 boiler operating day period.

5. Calculation of Emission Rate from Combined Cycle-Gas Turbine Systems

Determine the SO_2 emission rate from the steam generator as described in Method 19, Section 5.4

6. Calculation when Available Emission Measurement Data Are Less Than the Minimum

Perform the following calculations when the number of data values is less than the minimum required in the applicable subpart for calculation of the 30-day rolling average.

6.1 Mean Emission Rate. Calculate the mean emission rate for the reporting period using all emission measurement values (hourly averages for CEMS and daily averages for fuel sampling and Method 6B) and the following equation:

$$\bar{E} = \frac{1}{n} \sum_{1}^{n} E_{SO_2} \quad \text{[Equation 19A-7]}$$

where:

$\bar{E}$ = Mean SO_2 emission rate for the reporting period, ng/J (lb/10^6 Btu).

n = Number of available emission rate values for the reporting period hourly averages for CEMS, daily averages for other methods.

E_{SO_2} = Measured emission rate values, ng/J (lb/10^6 Btu).

6.2 Standard Deviation of Mean. Calculate the standard deviation of the mean of the available emission rate values using the following equation:

$$S_{\bar{E}} = \left[\sqrt{\frac{1}{n} - \frac{1}{max}}\right]\left[\sqrt{\frac{\sum_{1}^{n}(\bar{E} - E_{SO_2})^2}{n-1}}\right] \quad \text{(Equation 19A-8)}$$

where:

$S_{\bar{E}}$ = Standard deviation of the mean of the emission values for the reporting period, ng/J (lb/10^6 Btu).

max = The maximum number of data values that should have been recorded during the reporting period.

n = The number of available emission rate values for the reporting period-hourly averages for CEMS, daily averages for other methods.

6.3 Confidence Limit. Calculate the upper and lower confidence limit for the mean emission rate using the following equation:

$$E_L = \bar{E} - t_{0.95} S_{\bar{E}}$$

(Equation 19A-9)

$$E_U = \bar{E} + t_{0.95} S_{\bar{E}}$$

(Equation 19A-10)

where:

E_L = The lower confidence limit for the mean emission rate; ng/J (lb/10^6 Btu).

E_U = The upper confidence limit for the mean emission rate; ng/J (lb/10^6 Btu).

$t_{0.95}$ = Values shown below for the indicated number of data points (n).

Values for $t_{0.95}$

n	$t_{0.95}$	n	$t_{0.95}$	n	$t_{0.95}$
2	6.31	8	1.89	22-26	1.71
3	2.42	9	1.86	27-31	1.70
4	2.35	10	1.83	32-51	1.68
5	2.13	11	1.81	52-91	1.67
6	2.02	12-16	1.77	92-151	1.66
7	1.94	17-21	1.73	152 or more	1.65

The values of this table are corrected for n-1 degrees of freedom. Use n equal to the number of emission rate values.

[FR Doc. 83-28360 Filed 10-20-83; 8:45 am]
BILLING CODE 6560-50-M