Effective Oct. 6, 1980

Rev

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

BOB GRAHAM
GOVERNOR

JACOB D. VARN
SECRETARY

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

December 3, 1980

Oct 23, 1980
TECW

PP

Ms. Rebecca Hanmer
Regional Administrator
U. S. Environmental Protection
Agency, Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30308

Dear Ms. ~~Hanmer~~: REBECCA

We are pleased to submit the enclosed revision to Florida's State Air Implementation Plan which establishes emission limiting standards for Tampa Electric Company's Francis J. Gannon Station upon the conversion of Units 1 through 4 to solid fuel. The section of Chapter 17-2, Florida Administrative Code (FAC), which is amended by this revision is 17-2.05 (Prohibitive Acts), specifically 17-2.05(6), Table II, E., Emission Limiting Standards - Fossil Fuel Steam Generators.

We hereby certify that the public hearing requirements of 40 CFR 51.4 and 51.6 as well as those of the State of Florida have been satisfied with respect to this revision. The amendments to Chapter 17-2 FAC were adopted by the Florida Environmental Regulation Commission at a duly noticed public hearing on October 23, 1980. Your agency was given thirty days advance notice of the hearing and provided with copies of the materials to be considered.

A detailed response to the 40 CFR 51.4 requirements, a comparative appraisal of regulations, and all relevant administrative and technical exhibits are enclosed for your consideration. On the basis of available evidence, this revision will not jeopardize the attainment or maintenance of Federal or State Ambient Air Quality Standards.

We respectfully request your approval of this revision to the State Air Implementation Plan pursuant to the Clean Air Act as amended, 42 USC 1857 et seq.

Sincerely,

Jake

Jacob D. Varn,
Secretary

Encl.

cc: Steve Smallwood

RESPONSE TO 40 CFR 51.4 REQUIREMENTS

SUBJECT: Emission Limiting Standards - Tampa Electric Company's Gannon Station Upon Conversion of Units 1-4 to Solid Fuel - Revision to 17-2.05(6) Table II, E., Florida Administrative Code.

A. The revision was subject to a public hearing before the Florida Environmental Regulation Commission (ERC) on October 23, 1980, in Tallahassee, Florida.

B. A copy of the public notice which was prominently advertised thirty days prior to the hearing is attached.

C. The U.S. Environmental Protection Agency, Region IV, was notified thirty days in advance of the hearing and provided with copies of the materials to be considered.

D. Transmittal of the materials included herein is intended to satisfy the reporting requirement. The subject revision was adopted by the ERC on October 23, 1980.

E. Certification of compliance with the public hearing requirements of 40 CFR 51.4 and 51.6 is included in the letter of transmittal.

COMPARATIVE APPRAISAL OF REGULATIONS

A petition to amend Chapter 17-2, Florida Administrative Code (FAC), was filed by Tampa Electric Company (TECO) in anticipation of a prohibition order under the Fuel Use Act. Units 1 through 4 at TECO's Francis J. Gannon Generating Station, now operating on low-sulfur No. 6 fuel oil, were originally coal-fired units and, therefore, natural candidates for such an order. Units 5 and 6 at the Gannon Station presently burn coal, and all six units are equipped with electrostatic precipitators to control particulate emissions.

On October 23, 1980, the Florida Environmental Regulation Commission (ERC) amended Section 17-2.05 FAC to establish emission limiting standards for the Gannon Station upon conversion of Units 1-4 to solid fuel. Subsection 17-2.05(6), Table II, E. (1)(b)1.e. had specified emission limiting standards for Units 1-4 on liquid fuel. It was amended to specify that the emission limiting standards would apply to each unit prior to conversion. Subsection 17-2.05(6), Table II, E.(1)(b)2.a. had specified emission limiting standards for Units 5 and 6 on solid fuel. It was amended to include Units 1-4 upon their conversion to solid fuel and add new conditions.

The effect of the amendments is to allow no increase in total particulate or sulfur dioxide emissions to occur at the Gannon Station as a result of the conversion of Units 1-4. This is done by:

1. Maintaining the particulate emission limiting standard at 0.1 lb/MMBTU, two-hour average, for all units.

2. Maintaining the sulfur dioxide emission limiting standard at 2.4 lb/MMBTU, weekly average, for Units 5 and 6.

3. Raising the sulfur dioxide emission limiting standard for Units 1-4 from 1.1 lb/MMBTU on liquid fuel to 2.4 lb/MMBTU, weekly average, on solid fuel while imposing a sulfur dioxide emissions cap of 10.6 tons/hour, weekly average, on Units 1-6 combined.

TECO plans to meet the particulate emission limiting standard through the use of add-on electrostatic precipitators for units 1-4. Stack sampling in accordance with EPA-approved test methods will be used to demonstrate compliance.

The sulfur dioxide emission limiting standard of 2.4 lb/MMBTU will be met through the use of low-sulfur coal (nominally 1.3% S), a firm supply of which is available to TECO from company-owned mines in East Kentucky. Compliance with the sulfur dioxide emission limiting standard will be demonstrated by weekly composite fuel analysis, the technique currently used to assess the compliance status of Units 5 and 6. This technique was found to be an acceptable alternative to the use of continuous emission monitors (Exhibit X).

The sulfur dioxide cap of 10.6 tons per hour is equivalent to the total emission allowed under the current State Implementation Plan (SIP), that is, Units 1-4 (5,989 MMBTU/hour) at 1.1 lb/MMBTU plus Units 5-6 (6,082 MMBTU/hour) at 2.4 lb/MMBTU. Compliance with the cap will be demonstrated by combining the results of the weekly composite fuel analysis with the weekly average operating rate for Units 1-6.

While compliance with the emissions cap will result in no increase in SIP-allowable sulfur dioxide emissions for averaging periods of one week or longer, shorter term emissions could run as high as 14.5 tons per hour (12,071 MMBTU/hour at 2.4 lb/MMBTU). For this reason, a modeling analysis (Exhibit XI) was performed to assess compliance with short-term (3-hour and 24-hour) sulfur dioxide ambient air quality standards with all units emitting at the rate of 2.4 lb/MMBTU.

The modeling analysis indicated that the Florida 24-hour ambient sulfur dioxide standard of 260 ug/m^3 could be exceeded at plant operating rates of 10,500 MMBTU/hour or greater with all units emitting at the rate of 2.4 lb/MMBTU. However, an analysis of sulfur variability in the compliance coal (Exhibit XII) indicated that short-term emissions at or near a rate of 2.4 lb/MMBTU will occur infrequently. To avoid violating ambient standards under such conditions, TECO will implement a regulatory compliance plan (Exhibit XIII) featuring predaily fuel analysis and load shifting when peak loads are projected to exceed 10,500 MMBTU/hour. The compliance plan will be made a part of the operating permit of each unit at the station.

Alternative strategies, including the use of flue gas desulfurization, were examined by TECO and the Department (Exhibit XIV) and found to be less satisfactory than the low-sulfur coal option.

TABLE OF CONTENTS

EXHIBIT I

Letter of Prior Notification to EPA

September 19, 1980

Mr. Winston Smith
Air Programs Branch
Air and Hazardous
Material Division
U. S. Environmental
Protection Agency
Region IV
345 Courtland Street, NE
Atlanta, GA 30365

Dear Mr. Smith:

The attached material includes a proposed amendment to Section 17-2.05(6) Table II E.(1)(b), which will accomodate the conversion from oil to coal fuel of the Tampa Electric Company (TECO) Gannon Plant Units 1-4. Units 5 and 6 are presently using coal. This rule will be considered for adoption by the Florida Environmental Regulation Commission at the October 23, 1980 hearing in Tallahassee.

The proposed rule sets an emission limitation which will not allow the current total allowable emission of sulfur dioxide to increase and will also protect Federal and State Ambient Air Quality Standards. In addition, a regulatory compliance plan is required of TECO for Gannon Units 1-6.

This notification is submitted in compliance with 40 CFR 51.4. Your review and comments prior to the hearing will be most appreciated.

Sincerely,

Steve Smallwood, Chief
Bureau of Air Quality Management

SS/ht

Attachment

EXHIBIT II

Letter Transmitting Public Information Package to District for public Display

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

BOB GRAHAM
GOVERNOR

JACOB D. VARN
SECRETARY

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

MEMORANDUM

TO: Department of Environmental Regulation District Managers
Local Program Directors

FROM: Steve Smallwood

DATE: September 12, 1980

SUBJECT: Rule Amendment

Please note the attached package of proposed amendments to the Rule Chapters 17-2 FAC to be heard by the Environmental Regulation Commission on October 23, 1980, in Tallahassee.

The following are included:

1. A proposed rule Section 17-2.23 and amendments to 17-2.08 and 17-2.02 FAC and copies of the hearing notices. These amendments will establish source sampling methods for the State including both general categories of sources, those which are not regulated by NSPS or NESHAPS and those which are.

2. A proposed amendment to Chapter 17-2.05(6) Table II E.(1)(b) 1.e. and 17-2.05(6) Table II E.(1)(b)2.a, will accomodate the fuel conversion of TECO's Gannon station Units 1-4 from oil to coal fuel. The proposed rule and the required Regulatory Compliance Plan will insure that sulfur dioxide emissions will not exceed the existing allowable emissions. No change is proposed for the particulate limiting standard.

We urge you to forward your comments on these proposals, particularly the proposed source sample rule, to help guide us in our decisions and presentation to the Commission.

This package is to be maintained and made available for public inspection for a 30 day period beginning 30 days prior to October 23, the hearing date as required by 40 CFR 51.

SS:jr

attachments: Proposed rule and hearing notice
for 1 and 2 above

EXHIBIT III

Public Display Package

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

BOB GRAHAM
GOVERNOR

JACOB D. VARN
SECRETARY

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

September 16, 1980

Mrs. Liz Cloud
Department of State
Florida Administrative Weekly
The Capitol
Tallahassee, Florida 32301

Subject: Notice of Public Hearing, October 23, 1980 by the Environmental Regulation Commission Proposed changes to allow the Tampa Electric Company to convert the electric generating plant Gannon 1-4 from oil to coal fuel.

Dear Mrs. Cloud:

Please publish the attached notice of public hearing reference above in the September 19, 1980 issue of the Florida Administrative Weekly.

Should you have any questions, please call me at 8-4807.

Sincerely,

Geneva M. Hartsfield
Administrative Assistant

GMH/es

Attachment

original typed on 100% recycled paper

DEPARTMENT OF ENVIRONMENTAL REGULATION DOCKET NO. 80-25R

RULE NO.: Section 17-2.05, F.A.C.

RULE TITLE: Air Pollution

PURPOSE AND EFFECT: The proposed rule would allow the Tampa Electric Company to convert the electric generating plant Gannon Units 1-4 from oil to coal fuel. The proposed rule will not allow the current total allowable emission of sulfur dioxide (SO_2) to be increased and it will also protect the Florida Ambient Air Quality Standards. No changes are proposed for the particulate emission standard.

SUMMARY: In June 1980, the Department of Energy issued a prohibition on natural gas or petroleum as the primary energy source for Gannon Units 1-4. For this reason, the Tampa Electric Company (TECO) is planning to convert these units to burn coal, the fuel they were originally designed for. The proposed rule will protect the ambient air quality standards and will not allow the total allowable emission of SO_2 to increase. The rule will include specific emission standards for Units 1-6 and require a compliance plan to insure that the applicable emission limits are met on a continuous basis.

SPECIFIC LEGAL AUTHORITY UNDER WHICH THE ADOPTION IS AUTHORIZED AND THE LAW BEING IMPLEMENTED, INTERPRETED, OR MADE SPECIFIC:

Specific Authority 403.061, F.S. Law Implemented 403.021, 403.031, 403.061, 403.087, F.S.

ESTIMATE OF ECONOMIC IMPACT ON ALL AFFECTED PERSONS: The proposed rule will adjust the SO_2 emission standards within specific limits for burning coal in Gannon Units 1-6. The two most realistic scenarios set forth by TECO for this conversion are 1) conversion to burn high

sulfur coal and 2) conversion to burn low sulfur coal. The first scenario (high sulfur) would involve flue gas desulfurization (FGD) units as well as electrostatic precipitators for control of SO_2 and particulate emissions respectively. The second scenario (low sulfur) would not require FGD units. The following costs are for 20 years' operation and represent the difference between the listed alternatives and the cost involved with continuing to burn oil fuel in the units to be converted:

	Capital Costs (Million $)	Production Costs (Million $)
Low Sulfur Coal	82.5	-134 (savings)
High Sulfur Coal	327.5	300 (added costs)

The production costs include operation and maintenance, fuel costs, and other non-capital costs. The low sulfur alternative is the most cost effective. The continuing protection of the ambient air quality standards will result in no additional cost imposed on citizens as a result of pollutants released in the area.

A hearing will be held by the Environmental Regulation Commission:

DATE AND TIME: October 23, 1980, 9:00 A. M.

PLACE: Department of Environmental Regulation, Fourth Floor Conference Room, Twin Towers Building, 2600 Blair Stone Road, Tallahassee, Fla.

A copy of the proposed rule and economic impact statement may be obtained by writing to the Office of Public Information, Department of Environmental Regulation, Twin Towers Building, 2600 Blair Stone Road, Tallahassee, Florida 32301.

Proposed Rule

TABLE II
EMISSION LIMITING STANDARDS

Stationary Sources	Particulates	Sulfur Dioxide per million BTU heat input
17-2.05(6) Table II A-E.(1)(b)1.d. No change		
e. Hillsborough County including Tampa Electric Company Gannon Station Units 1 through 4 prior to conversion to solid fuel, and Hooker's Point Generating Station.	0.1 pounds per million BTU heat input, maximum two hour average	1.1 pounds per million BTU heat input.
f-k. No change		
2. Solid Fuel		
a. Hillsborough County, Tampa Electric Company Francis J. Gannon Generating Station Units 5 and 6 and Units 1-4 upon their conversion to solid fuel.		Units 1-6 in total shall not emit more than 10.6 tons per hour of sulfur dioxide on a weekly average and a maximum unit limit of 2.4 pounds of sulfur dioxide per million BTU heat input on a weekly average. A plan for assuring compliance with Florida Ambient Air Quality Standards will be incorporated into the revised operating permit for the station.

September 18, 1980

EXHIBIT IV

Newspaper Advertisement and Certification of Publication

THE TAMPA TRIBUNE

Published Daily
Tampa, Hillsborough County, Florida

State of Florida
County of Hillsborough } ss.

Before the undersigned authority personally appeared G. T. Gleason, who on oath says that he is Controller of The Tampa Tribune, a daily newspaper published at Tampa in Hillsborough County, Florida; that the attached copy of advertisement being a LEGAL NOTICE

in the matter of Notice that a public hearing will be held by the Florida Dept. of Environmental Regulation, at 9:00 AM, October 23, 1980 for the purpose described herein.

was published in said newspaper in the issues of September 22, 1980

Affiant further says that the said The Tampa Tribune is a newspaper published at Tampa, in said Hillsborough County, Florida, and that the said newspaper has heretofore been continuously published in said Hillsborough County, Florida, each day and has been entered as second class mail matter at the post office in Tampa, in said Hillsborough County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm, or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

G. T. Gleason

Sworn to and subscribed before me, this 25th *day of* September *A.D. 19* 80.

Notary Public State of Florida
My Commission Expires Aug [illegible]

(SEAL)

10-2-80

RECEIVED

PUBLIC HEARING

The Environmental [illegible]ulation Commission [illegible] Department of Environmental Regulation (DER) [illegible] hold a public hearing [illegible]ference Room D, T[illegible]ers Office Building, [illegible] Blair Stone Road, Ta[illegible]see, October 23, 1980 at [illegible] to take final action [illegible]posed amendment to Se[illegible] 17-2.05(6), Table [illegible] (b), FAC, establishing em[illegible]sion limitations for [illegible] Electric Company.

The proposed rule [illegible] allow Tampa Electric C[illegible]pany to convert the [illegible] generating plant [illegible] Units 1-4 from oil to [illegible] fuel. The rule will not [illegible] the current total allow[illegible] emissions of sulfur [illegible] to be increased and [illegible] also protect the Florida Am[illegible]bient Air Quality Standards.

A copy of the propo[illegible] rule will be available [illegible] public inspection [illegible] normal business hours at [illegible] following offices of DER:

2600 Blair Stone Road
Tallahassee
006 South Sixin Street
Ft. Pierce
3201 Golf Course Blvd
Punta Gorda
3426 Bills Road
Jacksonville
3101 W. Highway 98, Suite 73A
Panama City
825 N.W. 23rd Ave., Suite G
Gainesville
3319 Maguire Blvd., Suite 232
Orlando
3301 Gun Club Road
West Palm Beach
11400 Overseas Highway Suites 219-224
Marathon
2180 W. First Street Suite 401
Ft. Myers
160 Governmental Center
Pensacola
7601 Highway 301 N.
Tampa

M3269 Sept. 22, 1980

Tallahassee Democrat

PUBLISHED DAILY

TALLAHASSEE — LEON — FLORIDA

STATE OF FLORIDA
COUNTY OF LEON:

Before the undersigned authority personally appeared A. Parks who on oath says that she is Legal Control Clerk of The Tallahassee Democrat, a daily newspaper published at Tallahassee in Leon County, Florida; that the attached copy of advertising being a Legal Ad in the matter of The Environmental Regulation....

in the ________ Court, was published in said newspaper in the issues of:
Sept. 19.

Affiant further says that the said Tallahassee Democrat is a newspaper published at Tallahassee, in the said Leon County, Florida, and that the said newspaper has heretofore been continuously published in said Leon County, Florida, each day and has been entered as second class mail matter at the post office in Tallahassee, in said Leon County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this publication in the said newspaper.

Audrey Parks

Audrey Parks, Legal Control Clerk

Sworn To And Subscribed Before Me This 22nd day of September A.D. 19 80

Louise S. Forrest

(SEAL) Notary Public

Notary Public, State of Florida at Large
My Commission Expires March 14, 1983
Bonded By American Fire & Casualty Company

The Environmental Regulation Commission of the Department of Environmental Regulation (DER) will hold a public hearing in Conference Room D, Twin Towers Office Building, 2600 Blair Stone Road, Tallahassee, October 23, 1980, at 9 am to take final action on a proposed amendment to Section 17-2.05(6), Table II, E.(1)(b), FAC, establishing emission limitations for Tampa Electric Company.

The proposed rule would allow Tampa Electric Company to convert the electric generating plant Gannon Units 1-4 from oil to coal fuel. The rule will not allow the current total allowable emissions of sulfur dioxide to be increased and it will also protect the Florida Ambient Air Quality Standards.

A copy of the proposed rule will be available for public inspection during normal business hours at the following offices of DER.

2600 Blair Stone Rd. Tallahassee	806 S. Sixth St. Ft. Pierce
3201 Golf Course Blvd. Punta Gorda	3426 Bills Road Jacksonville
3101 W. Hwy 98 Suite 7 & 8 Panama City	825 NW 23rd Ave Suite G Gainesville
3319 Maguire Blvd Suite 232 Orlando	3301 Gun Club Rd West Palm Beach
11400 Overseas Hwy. Suites 219-224 Marathon	2180 W. First St. Suite 401 Ft. Myers
160 Governmental Center Pensacola	7601 Hwy 301 N. Tampa

September 19, 1980
Ad No. 7525642

Ella Bannigan
AP

Date Inv. 10-1-80 By
Date Goods Services Rec'd By
Date Goods Inspected / Appv'd By

REVIEWED BY PURCHASING

EXHIBIT V

Florida Administrative Weekly Notice

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

BOB GRAHAM
GOVERNOR

JACOB D. VARN
SECRETARY

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

September 16, 1980

Mrs. Liz Cloud
Department of State
Florida Administrative Weekly
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Subject: Notice of Public Hearing, October 23, 1980 by the Environmental Regulation Commission Proposed changes to allow the Tampa Electric Company to convert the electric generating plant Gannon 1-4 from oil to coal fuel.

Dear Mrs. Cloud:

Please publish the attached notice of public hearing reference above in the September 19, 1980 issue of the Florida Administrative Weekly.

Should you have any questions, please call me at 8-4807.

Sincerely,

Geneva M. Hartsfield
Administrative Assistant

RECEIVED
SEP 16 3 51 PM '80
DEPARTMENT OF STATE
TALLAHASSEE, FLORIDA

GMH/es

Attachment

original typed on 100% recycled paper

DEPARTMENT OF ENVIRONMENTAL REGULATION DOCKET NO. 80-25R

RULE NO.: Section 17-2.05, F.A.C.

RULE TITLE: Air Pollution

PURPOSE AND EFFECT: The proposed rule would allow the Tampa Electric Company to convert the electric generating plant Gannon Units 1-4 from oil to coal fuel. The proposed rule will not allow the current total allowable emission of sulfur dioxide (SO_2) to be increased and it will a' o protect the Florida Ambient Air Quality Standards. No changes are proposed for the particulate emission standard.

SUMMARY: In June 1980, the Department of Energy issued a prohibition on natural gas or petroleum as the primary energy source for Gannon Units 1-4. For this reason, the Tampa Electric Company (TECO) is planning to convert these units to burn coal, the fuel they were originally designed fc.:. The proposed rule will protect the ambient air quality standards and will not allow the total allowable emission of SO_2 to increase. The rule will include specific emission standards for Units 1-6 and require a compliance plan to insure that the applicable emission limits are met on a continuous basis.

SPECIFIC LEGAL AUTHORITY UNDER WHICH THE ADOPTION IS AUTHORIZED AND THE LAW BEING IMPLEMENTED, INTERPRETED, OR MADE SPECIFIC:

Specific Authority 403.061, F.S. Law Implemented 403.021, 403.031, 403.061, 403.087, F.S.

ESTIMATE OF ECONOMIC IMPACT ON ALL AFFECTED PERSONS: The proposed rule will adjust the SO_2 emission standards within specific limits for burning coal in Gannon Units 1-6. The two most realistic scenarios set forth by TECO for this conversion are 1) conversion to burn high

sulfur coal and 2) conversion to burn low sulfur coal. The first scenario (high sulfur) would involve flue gas desulfurization (FGD) units as well as electrostatic precipitators for control of SO_2 and particulate emissions respectively. The second scenario (low sulfur) would not require FGD units. The following costs are for 20 years operation and represent the difference between the listed alternatives and the cost involved with continuing to burn oil fuel in the units to be converted:

	Capital Costs (Million $)	Production Costs (Million $)
Low Sulfur Coal	82.5	-134 (savings)
High Sulfur Coal	327.5	300 (added costs)

The production costs include operation and maintenance, fuel costs, and other non-capital costs. The low sulfur alternative is the most cost effective. The continuing protection of the ambient air quality standards will result in no additional cost imposed on citizens as a result of pollutants released in the area.

A hearing will be held by the Environmental Regulation Commission:

DATE AND TIME: October 23, 1980, 9:00 A. M.

PLACE: Department of Environmental Regulation, Fourth Floor Conference Room, Twin Towers Building, 2600 Blair Stone Road, Tallahassee, Fla.

A copy of the proposed rule and economic impact statement may be obtained by writing to the Office of Public Information, Department of Environmental Regulation, Twin Towers Building, 2600 Blair Stone Road, Tallahassee, Florida 32301.

EXHIBIT VI

Administrative Procedures Committee Package

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

BOB GRAHAM
GOVERNOR

JACOB D. VARN
SECRETARY

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

September 22, 1980

Mr. Carroll Webb, Executive Director
Joint Committee on Administrative
Procedures
Holland Building, Room 120
Tallahassee, Florida 32304

Re: Proposed Amendments to Section 17-2.05, Florida Administrative Code, Docket Number: 80-25R

Dear Mr. Webb:

Pursuant to Section 120.54(11)(a), Florida Statutes, please find enclosed a copy of the above-referenced rule, a Detailed Written Statement of the Facts and Circumstances Justifying the Proposed Rule, a copy of the Estimate of Economic Impact, a Statement of the Extent to Which the Proposed Rule Establishes Standards More Restrictive than Federal Standards, and a copy of the Notice of the hearing on the proposed rule which was published in the September 19th, 1980, Florida Administrative Weekly.

A hearing on the proposed rule will be held before the Environmental Regulation Commission on October 23rd, 1980.

If you have any questions in this regard, please feel free to call.

Sincerely,

Mary F. Clark

Mary F. Clark
Assistant General Counsel

MFC/pm
Encls.
cc: Burke Jolly
Stephen Smallwood

HAND DELIVERED

original typed on 100% recycled paper

TABLE II
EMISSION LIMITING STANDARDS

Stationary Sources	Particulates	Sulfur Dioxide per million BTU heat input
17-2.05(6) Table II A-E.(1)(b)1.d. No change		
e. Hillsborough County including Tampa Electric Company Gannon Station Units 1 through 4 prior to conversion to solid fuel, and Hooker's Point Generating Station.	0.1 pounds per million BTU heat input, maximum two hour average	1.1 pounds per million BTU heat input.
f-k. No change		
2. Solid Fuel		
a. Hillsborough County, Tampa Electric Company Francis J. Gannon Generating Station Units 5 and 6 and Units 1-4 upon their conversion to solid fuel.		Units 1-6 in total shall not emit more than 10.6 tons per hour of sulfur dioxide on a weekly average and a maximum unit limit of 2.4 pounds of sulfur dioxide per million BTU heat input on a weekly average. A plan for assuring compliance with Florida Ambient Air Quality Standards will be incorporated into the revised operating permit for the station.

September 18, 1980

ECONOMIC IMPACT STATEMENT
Proposed Amendment to Chapter 17-2, F.A.C.
Docket Number 80-25R

Introduction

The proposed rule change, Ch. 17-2.05, will adjust the SO_2 emission standards within specific limits for burning coal in Tampa Electric Company (TECO) Gannon units 1-6. Gannon units 5 and 6 are currently burning coal, and units 1-4 will require conversion to burn coal. The two most realistic scenarios set forth by TECO for this conversion are 1) conversion to burn high sulfur coal (HSC); and 2) conversion to burn low sulfur coal (LSC). Due to high capital costs for pollution control equipment associated with burning HSC, the LSC alternative is the most economical choice.

Cost to the Agency of Implementation

There may be a small amount of additional paperwork required of the DER Bureau of Air Quality Management to implement the proposed rule, but the amount of additional paperwork and personnel time will be easily handled by current staff and existing program funds.

Estimates of the Costs and Benefits

The only two scenarios to be considered here are 1) conversion of Gannon units 1-4 to burn high sulfur coal (HSC); and 2) conversion of Gannon units 1-4 to burn low sulfur coal (LSC). The first scenario (HSC) would involve retrofitting the four units with Flue Gas Desulfurization (FGD) units for control of SO_2 emissions and add-on Electrostatic Precipitators (ESPs). The second scenario (LSC) would not require the FGD units but would require add-on ESPs.

The following estimated costs are for 20 years operation and represent the difference between the listed alternatives and the costs involved with continuing to burn oil fuel in the units to be converted. They include costs for add-on ESPs for units 1-4 to control particulate emissions. Particulate emissions are not addressed by the proposed rule change but are included here for completeness. Their exclusion would lessen the capital costs by between 30 and 40 million dollars and so would also dampen the magnitudes of the other cost estimates but would not affect their basic relationship.

	Capital Costs	Net Production Costs	Total Net Costs, Present Worth
LSC	82.5	(134)	(18)
HSC	327.6	300	140

All costs are in millions of dollars.
( ) indicates a net savings.

The capital costs and net production cost estimates are the differences between the listed alternatives and cost projections for continued oil burning. Production costs include fuel, operation and maintenance, and other non-capital expenses. The Total Net Costs, Present Worth figure is the net cost differences from remaining on oil in 1980 dollars accumulated through time. These cost estimates show the HSC alternative to be very costly. The high capital cost of installing FGD units cannot be offset by low fuel cost and so this alternative has a present worth net cost of \$140 million 1980 dollars when compared to the units 1-4 remaining oil. The LSC alternative could result in a present worth net savings of 18 million 1980 dollars when compared to remaining on oil. Thus conversion to burn LSC fuel is more cost effective than conversion to burn high sulfur coal. It is probable that conversion to LSC will be even less costly than if the units 1-4 were to remain on oil.

If the Gannon units 1-4 are converted to burn LSC, total yearly emissions for Gannon units 1-6 are not expected to exceed current loadings of SO_2. Even though the emission rates for short-term averages may be higher burning LSC than oil, no ambient violations are anticipated. No estimable incremental costs are expected due to emissions resulting from the conversion.

There should be no additional cost to TECO for compliance sampling if the proposed "Fuel Analysis" procedure is used. However, there may be additional costs if stack monitors are required by the DER.

Effects on Employment and Competition

No impacts on competition or employment are anticipated.

Data and Methodology

The information used in this EIS was derived from TECO's "Supplementary Documentation for Gannon Units No. 1-4 Conversion To Coal", employees of the TECO engineering and economic staff, and personnel of the DER Bureau of Air Quality Management.

LG:jb

DETAILED WRITTEN STATEMENT OF THE FACTS AND CIRCUMSTANCES JUSTIFYING THE PROPOSED RULE

The proposed amendments to Section 17-2.05, Florida Administrative Code, would revise the emission limiting standard for sulfur dioxide applicable to Tampa Electric Company's Gannon generating station, Units 1 through 6. The Company presently burns residual fuel oil in Units 1 through 4 and low sulfur content coal in Units 5 and 6. However, the Company has received a proposed prohibition order from the federal Department of Energy under the Energy Supply and Environmental Coordination Act of 1974 which would prohibit the continued use of oil in Units 1 through 4. In addition, conversion of those units to coal would save the Company millions of dollars in operating costs. The present emission limiting standard must be revised to allow the conversion to take place since it reflects the fact that the Company is burning oil. The proposed standard would allow the use of low sulfur coal in all six units and would impose an emissions cap on sulfur dioxide stringent enough to protect ambient air quality standards. No change in the emissions standards for other pollutants is necessary.

STATEMENT OF EXTENT TO WHICH THE PROPOSED RULE IS MORE RESTRICTIVE THAN FEDERAL STANDARDS

The proposed amendments to Section 17-2.05, Florida Administrative Code, are no more restrictive than federal standards.

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

BOB GRAHAM
GOVERNOR

JACOB D. VARN
SECRETARY

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

September 16, 1980

Mrs. Liz Cloud
Department of State
Florida Administrative Weekly
The Capitol
Tallahassee, Florida 32301

Subject: Notice of Public Hearing, October 23, 1980 by the Environmental Regulation Commission Proposed changes to allow the Tampa Electric Company to convert the electric generating plant Gannon 1-4 from oil to coal fuel.

Dear Mrs. Cloud:

Please publish the attached notice of public hearing reference above in the September 19, 1980 issue of the Florida Administrative Weekly.

Should you have any questions, please call me at 8-4807.

Sincerely,

Geneva M. Hartsfield
Administrative Assistant

GMH/es

Attachment

DEPARTMENT OF ENVIRONMENTAL REGULATION DOCKET NO. 80-25R

RULE NO.: Section 17-2.05, F.A.C.

RULE TITLE: Air Pollution

PURPOSE AND EFFECT: The proposed rule would allow the Tampa Electric Company to convert the electric generating plant Gannon Units 1-4 from oil to coal fuel. The proposed rule will not allow the current total allowable emission of sulfur dioxide (SO_2) to be increased and it will also protect the Florida Ambient Air Quality Standards. No changes are proposed for the particulate emission standard.

SUMMARY: In June 1980, the Department of Energy issued a prohibition on natural gas or petroleum as the primary energy source for Gannon Units 1-4. For this reason, the Tampa Electric Company (TECO) is planning to convert these units to burn coal, the fuel they were originally designed for. The proposed rule will protect the ambient air quality standards and will not allow the total allowable emission of SO_2 to increase. The rule will include specific emission standards for Units 1-6 and require a compliance plan to insure that the applicable emission limits are met on a continuous basis.

SPECIFIC LEGAL AUTHORITY UNDER WHICH THE ADOPTION IS AUTHORIZED AND THE LAW BEING IMPLEMENTED, INTERPRETED, OR MADE SPECIFIC:

Specific Authority 403.061, F.S. Law Implemented 403.021, 403.031, 403.061, 403.087, F.S.

ESTIMATE OF ECONOMIC IMPACT ON ALL AFFECTED PERSONS: The proposed rule will adjust the SO_2 emission standards within specific limits for burning coal in Gannon Units 1-6. The two most realistic scenarios set forth by TECO for this conversion are 1) conversion to burn high

sulfur coal and 2) conversion to burn low sulfur coal. The first scenario (high sulfur) would involve flue gas desulfurization (FGD) units as well as electrostatic precipitators for control of SO_2 and particulate emissions respectively. The second scenario (low sulfur) would not require FGD units. The following costs are for 20 years operation and represent the difference between the listed alternatives and the cost involved with continuing to burn oil fuel in the units to be converted:

	Capital Costs (Million $)	Production Costs (Million $)
Low Sulfur Coal	82.5	-134 (savings)
High Sulfur Coal	327.5	300 (added costs)

The production costs include operation and maintenance, fuel costs, and other non-capital costs. The low sulfur alternative is the most cost effective. The continuing protection of the ambient air quality standards will result in no additional cost imposed on citizens as a result of pollutants released in the area.

A hearing will be held by the Environmental Regulation Commission:

DATE AND TIME: October 23, 1980, 9:00 A. M.

PLACE: Department of Environmental Regulation, Fourth Floor Conference Room, Twin Towers Building, 2600 Blair Stone Road, Tallahassee, Fla.

A copy of the proposed rule and economic impact statement may be obtained by writing to the Office of Public Information, Department of Environmental Regulation, Twin Towers Building, 2600 Blair Stone Road, Tallahassee, Florida 32301.

EXHIBIT VII

Certification of Public Hearing

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

BOB GRAHAM
GOVERNOR

JACOB D. VARN
SECRETARY

VICTORIA J. TSCHINKEL
ASSISTANT SECRETARY

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

October 23, 1980

CERTIFICATION OF PUBLIC HEARING: DOCKET NO. 80-25R, Proposed revisions to Section 17-2.05(6), Table II, E.(1)(b), F.A.C., Tampa Electric Company's Gannon Units 1-4.

1. Notice of the proposed revisions was published in the following Florida newspapers on the dates indicated pursuant to federal notice requirements:

   The Tampa Tribune, September 22, 1980
   The Tallahassee Democrat, September 19, 1980

2. Notice of the proposed revisions and public hearing was published on September 19, 1980, in the Florida Administrative Weekly pursuant to the Administrative Procedures Act.

3. Copies of required documents were transmitted by hand delivery on September 22, 1980, to the Executive Director of the Joint Committee on Administrative Procedures.

4. A copy of the notice of public hearing was furnished by U. S. Mail on September 25, 1980, to each person on the Department's official mailing list.

The Department has complied with state and federal regulations relating to public notice, and it is recommended that the notice provided be duly certified.

EXHIBIT VIII

Regulation Subjected to Amendment

TABLE II
EMISSION LIMITING STANDARDS

Stationary Sources	Particulates	Visible emissions	Sulfur dioxide per million BTU heat input	Nitrogen oxides (NO_x) per million BTU heat input, maximum 2 hour average
FOSSIL FUEL STEAM GENERATORS (cont.)				
(1)(b)1.b. Jacksonville Electric Authority's Northside Generating Station	0.1 pounds per million BTU heat input, maximum two hour average	Density of which is equal to or greater than Number 1 of the Ringelmann Chart (20 percent opacity) except that a shade as dark as Number 2 of the Ringelmann Chart (40 percent opacity) shall be permissible for not more than 2 minutes in any one hour	1.98 pounds per million BTU heat input	0.10 pounds (Unit No. 3 only)
c. Jacksonville Electric Authority's Southside and Kennedy Generating Stations			1.10 pounds per million BTU heat input	
d. All other sources in Duval County			1.63 pounds per million BTU heat input	
e. Hillsborough county including Tampa Electric Co. Gannon Station units 1 through 4 and Hooker's Point Generating Station			1.1 pounds per million BTU heat input	
f. Escambia county, Gulf Power Co. Crist Steam Plant units 1, 2 and 3.			1.80 pounds per million BTU heat input	
g. Escambia county, Monsanto Textiles Co. boiler units 1 through 8 in the aggregate			57.5 tons per any 24 hour period	
h. Manatee County, Florida Power and Light Company's Manatee Generating			1.1 pounds per million BTU heat input	0.10 pounds
i. Leon & Wakulla County, City of Tallahassee's A. B. Hopkins and Purdom Generating Stations			1.87 pounds per million BTU heat input	0.30 pounds - Hopkins (Unit No. 2 only)
j. Dade, Broward and Palm Beach Counties, Florida Power and Light Company's Cutler Units No. 4, 5 and 6, Ft. Lauderdale Units No. 4 and 5, and Riviera Units No. 1 and 2.			1-1 pounds per million BTU heat input, except in the event of a fuel or energy crisis declared by the Governor of Florida or the President of the United States	
k. All other areas of the State			2.75 pounds per million BTU Notification concerning the quantity and estimated duration of the increase in emissions shall be given the Department prior to burning the higher sulfur fuel.	
3. Solid fuel				
a. Hillsborough county, Tampa Electric Co. Francis J. Gannon Generating Station Units 5 and 6.			2.75 pounds per million BTU heat input	0.70 pounds (Unit No. 3 only)
b. Hillsborough County, Tampa Electric Company's Big Bend Station, Units 1, 2 and 3			2.4 pounds per million BTU heat input Units 1, 2 and 3 in total shall not emit more than 31.5 tons per hour of sulfur dioxide on a three hour average but in no case to exceed a two hour average emission of 6.5 pounds of sulfur dioxide per million BTU Units 1, 2 and 3 in total shall not emit more than 25 tons per hour of sulfur dioxide on a 24 hour average	
c. Escambia County, Gulf Power Co. Crist Steam Plant units 4, 5, 6 and 7			5.90 pounds per million BTU heat input	
d. All other areas of the State			6.17 pounds per million BTU heat input	

EXHIBIT IX

Amended Regulation

TABLE II
EMISSION LIMITING STANDARDS

Stationary Sources	Particulates	Sulfur Dioxide per million BTU heat input
17-2.05(6) Table II A.-E.(1)(b)1.d. No change		
e. Hillsborough County including Tampa Electric Company Gannon Station Units 1 through 4 prior to conversion to solid fuel, and Hooker's Point Generating Station.	0.1 pounds per million BTU heat input, maximum two hour average	1.1 pounds per million BTU heat input.
17-2.05(6) Table E.(1)(b)1.f. thru k. No change		
2. Solid Fuel		
a. Hillsborough County, Tampa Electric Company Francis J. Gannon Generating Station Units 5 and 6 and Units 1-4 upon their conversion to solid fuel		~~2.4 pounds per million BTU heat input~~ Units 1-6 in total shall not emit more than 10.6 tons per hour of sulfur dioxide on a weekly average and a maximum unit limit of 2.4 pounds of sulfur dioxide per million BTU heat input on a weekly average. A plan for assuring compliance with Florida Ambient Air Quality Standards will be incorporated into the revised operating permit for the station.
17-2.05(6) Table II E.(1)(b) 2.b. thru 17-2.23 No change		

ENTROPY
ENVIRONMENTALISTS, INC.

SPECIALISTS IN AIR POLLUTION MEASUREMENT & MANAGEMENT

THE ACCEPTABILITY OF FUEL ANALYSIS FOR DETERMINING SO_2 EMISSIONS AT THE TAMPA ELECTRIC COMPANY GANNON STEAM GENERATING SYSTEMS

Prepared for

TAMPA ELECTRIC COMPANY

TAMPA, FLORIDA

EXHIBIT X

Entropy Environmentalists, Inc.
Report - Acceptability of Fuel
Analysis for Determining SO_2
Emissions at the Tampa Electric
Company Gannon Steam Generating
Systems

Prepared by

Wallace S. Pitts

Entropy Environmentalists, Inc.

August 1980

P.O. Box 12291, Research Triangle Park, North Carolina 27709
Phone 919-781-3550

THE ACCEPTABILITY OF FUEL ANALYSIS FOR DETERMINING SO_2 EMISSIONS AT THE TAMPA ELECTRIC COMPANY GANNON STEAM GENERATING SYSTEMS

Prepared for
TAMPA ELECTRIC COMPANY
TAMPA, FLORIDA

Prepared by
Wallace S. Pitts
Entropy Environmentalists, Inc.

AUGUST 1980

TABLE OF CONTENTS

INTRODUCTION

Tampa Electric Company (TECO) is considering converting its Gannon Station Units 1 - 4 from oil to coal firing. TECO has been requested to examine alternatives to currently accepted fuel analysis as the mechanism by which compliance with sulfur dioxide emission limitations may be demonstrated.

Entropy Environmentalists, Inc. has been retained by TECO to address the technical merits of the two currently accepted emission monitoring techniques in terms of their use as compliance determination procedures: fuel analysis and continuous emission monitoring. The following discussions, which address the basic requirements of any emission monitoring procedure, demonstrate that fuel sampling is the preferred option.

Before discussing the relative merits of either compliance determination procedure, the goals and requirements of the emission monitoring program should first be delineated. Then the choice of an appropriate emission monitoring procedure can be rationally developed.

EPA PHILOSOPHY ON CONTINUOUS EMISSION MONITORING

The EPA, in the preamble to the promulgation of 40 CFR 51, discusses their rationale for requiring emission monitoring.[1] EPA explains that the emission monitoring and reporting requirements are "designed to partially implement the requirements of Sections 110(a)(2)(F)(ii) and (iii) of the Clean Air Act, which state that implementation plans must provide 'requirements for installation of equipment by owners or operators of stationary sources to monitor emissions from such sources', and 'for periodic reports on the nature and amounts of such emissions'".[2]

In discussing the need for a continuous emission monitoring system, the EPA states that regulatory agencies historically had to rely on infrequent manual source tests and periodic field inspections to provide much of the information necessary to ascertain the compliance status of sources. The discussion also includes the short comings of using infrequent manual source tests as indicators of continuous compliance with emission limitations. Their major concern with the use of manual source tests was the inability to be representative of all operating conditions. Having discussed the problems associated with historical source surveillance/compliance determination techniques, the advantages of continuous emission monitoring systems were outlined. These advantages include:

1) providing a continuous record of emissions under

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1 Requirements for the preparation, adoption, and submittal of Implementation Plans, Federal Register, Vol. 40, No. 194, Monday, October 6, 1975.

2 Ibid.

all operating conditions;

2) a good indicator of whether a source is using good operating and maintenance practices to minimize emission to the atmosphere;
3) providing a valuable record to indicate the performance of a source in complying with applicable emission regulations;
4) signaling of a plant upset or equipment malfunction so that plant operator can take corrective action to reduce emissions; and
5) under certain conditions, data may be sufficient evidence to issue a notice of violation.

EPA summarized their position on continuous emission monitoring by stating, "Use of emission monitors can therefore provide valuable information to minimize emission to the atmosphere and to assure that full-time control efforts, such as good maintenance and operating conditions, are being utilized by source operators".[3]

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3 Op. cit.

EPA POSITION ON FUEL ANALYSIS

The proposed requirements for 40 CFR 51 generally allows the use of fuel analysis as an option to continuous emission monitoring.[4] In addressing the public comments on the proposed requirements, EPA recognized an issue of more importance than the frequency of analysis necessary to determine the sulfur content of the fuel. This issue involves the determination (definition) of what constitutes excess emission when fuel analysis is used as the method to determine source emissions.

The specific problem is that although the sulfur content of a total load of coal (representing, consequently, a relatively long averaging time) may be within acceptable limits, the variability of the sulfur content within that load (which would represent the emissions over a shorter averaging period) might be such as to cause the emission limit to be exceeded. Thus, there exists a strong concern that fuel analysis might not be adequate to protect short-term emission standards.

The initial EPA investigations into this issue indicated "a relative specificity" on the subject.[5] In recognition of this, and in consideration of the fact that the same problem would have to be faced in relation to enforcing New Source Performance Standards, the Agency withheld promulgating fuel analysis provisions. They did, however, state that upon completion of a more thorough investigation of the situation, the Agency would set forth its findings and provide guidance to state and local control agencies on this issue. However, in the interim, continuous emission

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[4] Federal Register, op. cit.

[5] Federal Register, op. cit.

This model provides a mechanism by which short-term emissions can be related to long-term emissions.

Although the major EPA objection to fuel sampling, as presented in the preamble to the promulgated 40 CFR 51, has been resolved through TECO's intensive fuel analysis program, it is proper to also discuss the relative merits of using either fuel sampling or continuous emission monitoring to determine sulfur dioxide emissions. This discussion, which will address the basic requirements of any emission monitoring system, demonstrates that fuel analysis is an equally preferred method for determining sulfur dioxide emissions.

REQUIREMENTS OF EMISSION MONITORING SYSTEMS

The basic requirements of any emission monitoring system are that it: 1) obtain a representative sample; 2) perform an accurate analysis; and 3) not be subject to frequent malfunctions. It is important that these requirements are met simultaneously in order to adequately characterize emissions. For example, it is useless to have an accurate monitoring system which analyzes a portion of an effluent stream that is not representative of the total effluent, or is frequently out of service for extended periods of time.

Representative Sample

In order to adequately characterize emissions over a specified averaging period, the sampling location must first be able to provide an unbiased sample (non-stratified location) and enough samples must be taken during the averaging period to confidently estimate the emissions. Thus, representativeness can be broken into two components - location and number of data points.

It is evident that a monitoring system which provides biased samples is of little value to sources or regulatory agencies. On the other hand, if the sample location is representative, but the number of data points is insufficient, then large uncertainties can exist as to what the emissions actually were during the period.

The adequacy of a sampling location can be ensured for both continuous emission monitoring systems and fuel sampling systems. EPA's Performance Specifications for continuous emission monitoring systems specify clearly the criteria under which monitor locations must be evaluated. These criteria ensure that the monitor location (and, hence, each sample of effluent that the monitor subsequently analyzes) is representative of the total emissions.

The fuel sampling procedure specified in Reference Method 19 (ASTM D-2234, "Collection of a Gross Sample of Coal") also contains requirements for ensuring that sampling procedures are unbiased. These procedures are designed so that the entire cross-section of a conveyor belt is sampled. This prevents any sample bias that may be caused by coal particle segregation (stratification) across a belt face.

The second essential element in characterizing emission levels is the number of data points (samples) collected during an averaging period. Before addressing the principles of this issue, it is important to understand the data capture requirements set forth in relevant Federal Regulations. The distinction between a "continuous" emission monitoring system and the actual data capture requirements must be understood. The performance criteria for continuous monitors do not require that the monitors analyze and report data continuously. In fact, the general monitoring requirements set forth in both 40 CFR 51 and 40 CFR 60 require a continuous monitoring system to sample, analyze and record only one (1) data point per fifteen (15) minutes (96 per 24-hour period).

The amount of data required by NSPS Subpart Da is even less. Subpart Da requires that monitoring systems produce emission data for a minimum of eighteen (18) hours in at least twenty-two (22) out the thirty (30) successive boiler operating days for which cmpliance with the emission limitation is to be determined. Furthermore, only two (2) points per hour are required to calculate the one hour averages. These data requirements imply that thirty-six (36) data points are adequate to represent a 24-hour emission value - (i.e., $\frac{\text{2 Points}}{\text{Hour}} \times \frac{\text{18 Hour}}{\text{Day}} = \frac{\text{36 Points}}{\text{Day}}$).

The actual performance required of instrumental continuous emission monitoring systems at electric utility boilers, therefore, is not to provide a continuous record of emissions, but rather a discrete number of samples from the source effluent. During the development of Subpart Da EPA determined that two (2) data points per hour, as opposed to four (4) data points per hour required by 40 CFR 51 and previously by 40 CFR 60, are sufficient to characterize emission levels.

The fuel sampling procedures set forth in Subpart Da also require this collection and analysis of a discrete number of samples. The minimum sampling requirements of the ASTM procedure depend on the lot size to be sampled, and whether or not the coal has been mechanicallly cleaned.

The required number of samples is given by the following relationship:

$$N_2 = N_1 \sqrt{\frac{\text{Total Tons}}{\text{1000 Tons}}}$$

Where N_2 is the total number of samples;
N_1 is 15 for mechanically cleaned coal and 35 for raw (unwashed) coal

To put the ASTM and continuous emission monitoring system sample requirements in perspective, it is appropriate to compare the minimum number of samples required by ASTM with those required for continuous emission monitoring systems. More specifically, the 24-hour average coal firing rate for Gannon Units 5 and 6 is approximately 3000 and 5000 tons respectively. Therefore, the minimum ASTM sample requirements for Units 5 and 6, based on using raw (unwashed) coal, would be 61 and 78 respectively. The minimum number of samples required by ASTM fuel analysis procedures to determine the emissions over a 24-hour period are less than the 96 required by the continuous monitoring requirements of 40 CFR 51 and 40 CFR 60.13 and are greater than the 36 required by the NSPS, Subpart Da.

The lack of continuous emission data from either continuous emission monitoring systems or ASTM procedure may be disconcerting. It is commonly, and correctly, believed that the more samples that are taken, the better the estimate of the average quantity will be. This can be restated by saying that more samples will yield a more precise estimate of, for example, the 24-hour average emissions. There is, however, an upper limit to the amount of data necessary to adequately determine emission levels over a specified averaging period, above which improved representation is insignificant. For example, if an emission limit is 2.00 lb/MMBtu, it is not necessary to have a precision of $\pm$.001 lb/MMBtu.

A detailed statistical analysis of the ASTM and continuous emission monitoring system minimum data capture requirements was performed in order to determine their relative precisions.[6] The results of this analysis, based on conservative estimates of the relevant statistical properties, are presented in Table 1. Inspection of this Table reveals that, in absolute terms, the 40 CFR 51 and 40 CFR 60.13 requirements result in the most precise estimate of the average SO_2 emissions.

As a practical matter, however, the additional uncertainty introduced by using fuel sampling as opposed to instrumental stack monitoring is not very significant. For example, for Unit 5, suppose the true 24-hour SO_2 emission rate was 2.0 lb/MMBtu. The uncertainty in this value resulting from taking 96 data points over the 24-hour period is (2.0)(0.011) = 0.02 lb/MMBtu and the uncertainty derived through ASTM sampling is (2.0)(.040) = 0.08 lb/MMBtu. The difference between the two values is only .06 lb/MMBtu.

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6 "Variance Calculations for Conveyor Belt Sampling" for Entropy Environmentalists, Inc. by C. H. Proctor, Institute of Statistics, July 1980; and "Further Variance Calculations for Belt Sampling" for Entropy Environmentalists, Inc., C. H. Proctor, North Carolina State University, August 1980.

TABLE 1

COMPARISON OF THE DATA CAPTURE REQUIREMENTS FOR CONTINUOUS EMISSION MONITORING SYSTEMS AND ASTM SAMPLING PROCEDURES ON THE UNCERTAINTY (95% CONFIDENCE INTERVAL), IN A 24-HOUR AVERAGE SULFUR DIOXIDE EMISSION RATE

Data Capture Requirements	95% Confidence Interval as a Percent of the Mean Value	
	Gannon 5	Gannon 6
CEM - 96 *	1.1	1.1
CEM - 36 **	1.9	2.0
ASTM ***	4.0	3.5

* 40 CFR 51 and 40 CFR 60.13

** NSPS 40 CFR 60, Subpart Da

*** ASTM D-2234

Accurate Analysis

The second requirement of an emission monitoring system is that the system must be able to accurately analyze the samples obtained. The accuracy of the analysis depends largely on two (2) factors: 1) the bias of the analytical procedure; and 2) the stability of the analytical method.

The accuracy of instrumental stack monitoring systems is determined through a series of comparative wet-chemical tests (Reference Method). These tests, called the Field Test for Relative Accuracy, are intended to demonstrate the degree to which a continuous emission monitoring system is "capable of measuring emission levels within ±20 percent with a confidence level of 95 percent.[7] The accuracy of the data reported by the continuous emission monitoring system is also affected by the drift (stability) allowed in the Performance Specifications.[8] As an example of this potential impact, consider the effect of the 2.0% span zero drift and the 2.5% of span calibration drift allowed by the Performance Specifications during a 24-hour period on the data reported by an SO_2 analyzer having a full range span of 2000 ppm SO_2. The result of these allowed drifts is that the monitor, when challenged with a zero SO_2 concentration would indicate a concentration of 40 ppm and a concentration of 2090 ppm when challenged with a 2000 ppm SO_2 concentration.[8] The error at full span would be 4.5%. The error when responding

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[7] 40 CFR 60.13 (c)(2)(ii).

[8] 40 CFR 60, Appendix B, Performance Specifications 2 and 3.

to 1000 ppm and 500 ppm SO_2 concentrations would be 6.5% and 10.5% respectively. It is clearly evident that the bias introduced by the drift allowed in the Performance Specifications can compound the 20% bias allowed by the Relative Accuracy Specification. Furthermore, emissions in terms of lb SO_2/MMBtu are generally determined by an SO_2/diluent continuous monitoring system. Since both monitoring systems are allowed to drift within certain ranges, it may be possible that the biases introduced by the independent, diverging drifts could be additive. Thus, the accuracy of the emission data reported by an SO_2/diluent monitoring system may be further influenced by the potentially additive effects of the biases allowed by the Relative Accuracy and Drift Performance Specifications.

Fuel analysis, on the other hand, is fundamentally not subject to either bias or drift. The determination of the sulfur dioxide content of a coal sample (in terms of lb SO_2/MMBtu) is performed using established ASTM procedures which are in themselves unbiased.[9] The use of fuel sampling and the associated ASTM analysis procedures is, therefore, analagous to the use of EPA established Reference Method tests, as opposed to continuous emission monitors for determining sulfur dioxide emissions. Furthermore, the ASTM procedures, which are stable chemical techniques, are not subject to the potential electronic drift problems associated with continuous emission monitoring systems.

Reliable Operation

The third major requirement of any emission monitoring system is the ability of the system to function without excessive loss of data from system malfunctions. It is in regard to

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9 The EPA historically uses ASTM procedures whenever possible. See, for example, 40 CFR 60, Subpart D, Subpart Da, Reference Method 19.

this requirement that the greatest difference may exist between the capabilities of fuel sampling or continuous monitoring systems.

Continuous emission monitoring systems have had a notoriously poor track record in terms of system up-time. This has been well documented in a survey of existing continuous emission monitoring systems.[10] Some of the relevant results of this survey are presented in the following tables (Tables 2 and 3). The data in Table 2 is based on survey respondents which had system availability broken down into frequency and duration. The data indicates that SO_2 monitors experience an average of 3 outages per month with an average duration of 47 hours per outage. Diluent monitors (O_2 or CO_2) experience an average of 1.9 outages per month with an average duration of 33 hours per outage. These outage figures translate into an average monitor availability of 80% for SO_2 monitors, 91% for diluent monitors, and 73% for SO_2 diluent systems.

Table 3 represents the system availability computed using the data from Table 2 (115 respondents for frequency and duration) and the data from respondents who were only able to discuss availability in terms of a percentage value. These data indicate that SO_2 and diluent monitors experience an average percent availability of 67% and 76% respectively, with SO_2/diluent system availabilities of only 51% (assuming that the monitor system failures are random and independent).

EPA has also recognized that continuous emission monitoring systems are subject to poor availability. The continuous

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10 "An Evaluation of the Continuous Monitoring Requirements of the September 19, 1978 Subpart Da NSPS Proposal, January, 1970". Prepared by Entropy Environmentalists, Inc.

monitoring specifications set forth in the September 19, 1978 Subpart Da proposal required a 98.9% data capture rate (availability). After review of public comments on the availability of continuous emission monitoring systems, the EPA significantly relaxed the data capture requirements. The 24-hour data capture requirements were reduced from requiring data during 23 of the 24 hours to only 18 of the 24. This reduction was intended to allow additional time for calibration and to correct minor failures. The EPA is thus acknowledging that these systems may require up to six hours per day for calibration and minor repairs. The EPA also realized that long term outages could also occur. In this regard they further reduced the data capture requirements to allow up to 8 days of data to be lost due to major malfunctions during 30 successive boiler operating days. Thus, the EPA, in response to public comments has recognized the significant limitations which have been seen with attempts to "continuously" operate monitoring systems.

TECO, on the other hand, has experienced excellent reliability in their fuel sampling procedures. During the intensive six-week period during which the 3-hour average SO_2 emissions were determined, only one data point out of a total of 331 (184 for Unit 5 and 147 for Unit 6) was not obtained. In addition, TECO has used fuel sampling and analysis as the compliance demonstration procedure for the weekly SO_2 emission limitation since 1976. Communications with TECO personnel indicate that TECO has not been made aware of any problems regarding the data collected according to these procedures.

TABLE 2

TABULATION OF RESPONSES TO OCTOBER/NOVEMBER 1978 CONTINUOUS MONITORING SURVEY

TABLE 11

AVERAGE NUMBER AND DURATION OF MONITOR OUTAGES/MONTH

	Number of Responses	Average Number of Outages Per Month Per Monitor	Number of Responses	Average Duration of Monitor Outages (Hours Per Outage)
Opacity	46	6.0	52	42
SO_2	30	3.0	30	47
NO_x	11	4.0	12	49
O_2 or CO_2	28	1.9	37	33
TOTAL	115	4.0	131	41

(NOTE: The difference between the number of responses in the first and third columns is due to the fact that some sources which responded were only able to confidently provide data on outage duration.)

TABLE 3

TABULATION OF RESPONSES TO OCTOBER/NOVEMBER 1978 CONTINUOUS MONITORING SURVEY

TABLE 12

AVERAGE NUMBER AND DURATION OF MONITOR OUTAGES/MONTH

	Number of Responses	Average Percentage Availability of Individual Monitors
Opacity	117	74
SO_2	55	67
NO_x	50	67
O_2 or CO_2	85	76
Total	307	72

(NOTE: The values presented in this table represent the total of all combined responses listed in Table 11, in addition to those directly responding in terms of percentage availability.)

CONCLUSION

In conclusion, fuel sampling and analysis is a fully adequate procedure for determining the sulfur dioxide emission at TECO's Gannon Station. Not only does this procedure meet the basic EPA requirements for emission monitoring as stated in the preamble to the promulgation of 40 CFR 51, it also does not suffer from the accuracy and reliability problems that continue to plague continuous emission monitoring systems. Furthermore, the intensive fuel sampling program conducted by TECO has addressed the EPA concern regarding the ability of fuel analysis to adequately characterize short-term sulfur dioxide emission rates.

STATISTICAL APPENDIX

Variance Calculations for Conveyor Belt Sampling

For Entropy Environmentalists, Inc. by C. H. Proctor,

Institute of Statistics, July 1980

We have been requested to furnish sampling variances for estimates of sulfur content based on sampling from the conveyor belt. Our previous work has been with samples from the gas stream and there are a number of questions to answer in order to convert our information on variability and auto-correlations for the gas stream to covariances for the conveyor belt. We propose to use the same specification of the process, namely first order Markov with superposed variation, for both the gas stream and the conveyor belt. Although the mean appears to shift from pile to pile or from time to time and so does the variance, these heterogeneities may be taken into account by using upper and lower limits in the parameter values σ^2, π and λ, while continuing to give greatest credence to the central (estimated) values.

The features of conveyor belt sampling, as it has been described, appear to fit a model of two-stage systematic sampling. In one particular case some 375 tons were moved in 700 seconds; every 20 seconds a sample of 2 lbs. was taken from across the moving stream. I am supposing that drawing the 2 lb. sample requires one second, but some other duration may be more realistic. I also suppose that the 2 lb. sample is picked up in tenths (i.e. 0.2 lb. in each) and again other values of this "rifling factor" can be used if they would seem to be more realistic.

In this example the elementary cluster, EC, is taken to be the 0.2 lb. unit and we suppose that all 375 x 2000 x 5 = 3,750,000 EC are lined in a row. They are separated into 35 "zones" each requiring 20 seconds to pass and containing 107143 EC's. A primary cluster, PC, is defined as the EC's passing in one second which number 5,357. From these 700 PC's 35 are drawn as a a systematic sample and from each PC a sub-systematic sample of 10 EC's is then selected.

The sample design parameters will be defined as follows:

N = No. of EC's in the population.

h = No. of EC in each PC.

n_1 = No. of PC's drawn into first stage systematic sample.

k_1 = Gap, in PC's, for first stage sample, $k_1 = N/(hn_1)$

n_2 = No. of EC's in second stage systematic sample.

k_2 = Gap in EC's, for second stage sample, $k_2 = h/n_2$.

The first stage systematic sample is drawn by selecting at random a starting PC as one from the n_1 in the first zone and then using that same position for selecting the PC in all k_1 zones. The second stage sample is drawn by selecting at random one of the first n_2 EC's in the first selected PC and then taking every k_2th EC afterwards and doing the same (but not rerandomizing the start) in the remaining selected PC's. Sample size is thus $n_1 n_2$ from a population of size $N = n_1 k_1 n_2 k_2$.

The process expected variance of a sample average from such a sample design is:

$$\begin{aligned}
\sigma^{-2}E(V_{2S\text{-}SyS}) = \Big[& (k_1k_2-1)/(n_1n_2k_1k_2) + 2\{[n_1(n_2-1)\rho_2 - n_1n_2\rho_2^{2} \\
& + n_1\rho_2^{n_2+1}] + \rho_3[(n_1-1)\rho_2^{-n_2+1} - (n_1+1)\rho_2^{n_2+1} - 2(n_1n_2-1)\rho_2 \\
& + 2n_1n_2\rho_2^{2}] + \rho_3^{2}[n_1(n_2+1)\rho_2 - n_1n_2\rho_2^{2} - n_1\rho_2^{-n_2+1}] \\
& + \rho_3^{n_1+1}[\rho_2^{n_2+1} + \rho_2^{-n_2+1} - 2\rho_2]\}/[n_1(1-\rho_3)n_2(1-\rho_2)]^{2} \\
& - 2[(n_1hk_1-1)\rho - n_1hk_1\rho^{2} + \rho^{n_1hk_1+1}]/[n_1hk_1(1-\rho)]^{2}\Big]\,\pi \\
& + (1-\pi)/n_1n_2 ,
\end{aligned}$$

where $\rho = e^{-\lambda}$, $\rho_2 = e^{-\lambda k_2}$ and $\rho_3 = e^{-\lambda k_1 k_2 n_2}$.

The situations in which the variance expression may be used seem to be characterized by the values of some ten parameters and so a program was written in PROC MATRIX to convert these specifications into sampling variances. The parameters are as follows:

μ = process mean (= MU)

σ = process standard deviation (= SIG)

$1-\pi$ = proportion superposed variation (= 1 - PI)

λ_1 = correlogram parameter at one-second (=LMS)

A = tons of coal burned in 3 hours (= TPH)

T = time in seconds to create pile (= LDTM)

n_1 = no. of probe samples (= N1)

S = lbs. of coal in each probe sample (= SPS)

n_2 = no. of sub-systematic samples (rifles) in each probe sample (=N2)

d = duration in seconds of taking a probe sample (=DUR)

The calculations are designed first to create a sampling frame as a list of consecutive elementary clusters, EC's, and then apply the variance formula to it. For example, the size of an EC in lbs. of coal is S/n_2 and the number of EC's on the frame is thus $N = 2000\ A\ n_2/S$. The size of an EC in seconds is T/N, while the number of EC's that pass on the conveyor in one second is N/T . Thus the correlogram parameter for the EC process is $\lambda = \lambda_1\ T/N$, while the number of EC's from which each probe sample is drawn is $h = d\ N/T$.

From the data taken every 15 seconds during <u>burning</u> and published by EPA we had found $\hat{\lambda}_1$ as somewhat less than .001 but, as usual, some upper and lower limits may also be used. In the present application we also need to convert $\hat{\lambda}_1$ from burning time units to loading time units. If loading rate is five times as fast as burning rate then $\lambda_1 = .005$.

Although the parameter μ is around 2 parts per million BTU the process variance is not so well known. Such variables have been found to have coefficients of variation around 10% and perhaps this one will be no larger than 20%. Thus we may use $\sigma = .2 \times 2 = .4$.

The basic program output is the quantity from the formula for $\sigma^{-2}E(V_{2S-SYS})$, called EV. The product of the square root of EV and the population coefficient of variation gives the sampling coefficient of variation, called SAMCV in the program. In the present applications there is an assigned total amount of coal and thus one can consider estimating an approximate total weight of sulfur. A rough standard error of this estimate is also given and called SAMSIG. A copy of the program and its output is attached.

The quantities that are herein called "sampling errors" or "sampling standard deviations" are actually process expected quantities and it might be wise to review that definition. When one has collected his sample and found the estimate there exists a deviation quantity which equals the estimate minus the true value. Since we very seldom know the true value we seldom know the deviations, but the quantities are well defined and quite concrete. When squared deviations are averaged over all possible samples from the same lot of coal we have the sampling variance. When sampling variances are averaged over all possible lots of coal we have the process expected sampling variance. It is the square root of this that we have been calling "sampling error."

```
NOTE: THE JOB SYS HAS BEEN RUN UNDER RELEASE 79.3B OF SAS AT TRIANGLE UNIVERSITIES COMPUTATION CENTER.

MACRO _EE
PROC MATRIX;
MU=2;
SIG=.4
PI=1;
LHS=.005;
TPH=375;
LDTM=700;
N1=15;
SPS=2;
N2=1;
DUR=1;
%
MACRO _BE
                              LB_EC=SPS#/N2;
POPLBN=TPH*2000#/LB_EC;
LAM=LHS*LDTM#/POPLBN;
EC_SEC=POPLBN#/LDTM;
H=EC_SEC*DUR;
K1=LDTM#/N1;
K2=H#/N2;
SAMBLK=SPS*N1;
R1=EXP(-LAM);
R2=EXP(-LAM*K2);  R3=EXP(-LAM*K1*K2*N2);
C1=(K1*K2-1)#/(N1*N2*K1*K2);
C2=(N1*(N2-1)*R2-N1*N2*R2*R2+N1*EXP(-LAM*K2*(N2+1)));
C3=R3*((N1-1)*EXP(LAM*K2*(N2-1))-(N1+1)*EXP(-LAM*K2*(N2+1))-(2)*(N1*N2-1))
+(2)*N1*N2*R2*R2);
C4=R3*R3*(N1*(N2+1)*R2-N1*N2*R2*R2-N1*EXP(LAM*K2*(N2-1)));
C5=EXP(-LAM*N2*K2*K1*(N1+1))*(EXP(-LAM*K2*(N2+1))+EXP(LAM*K2*(N2-1))-(2)*R2);
C6=2*((N1*H*K1-1)*R1-N1*H*K1*R1*R1+EXP(-LAM*(N1*H*K1+1)))#/(N1*N1*H*H*K1*K1*(1-
EXP(-LAM))*(1-EXP(-LAM)));
DMN=N1*N2*(1-EXP(-LAM*K1*K2*N2))*(1-EXP(-LAM*K2));
EV=C1+(2)*(C2+C3+C4+C5)#/(DMN*DMN);  EV=EV-C6;EV=PI*EV+(1-PI)#/(N1
NOTE LHS IS LAMBDA FOR ONE SECOND OF LOAD TIME. TPH IS IN TONS
NOTE N2 EQUALS NO. OF RIFFLES PER PROOF SAMPLE & N1 IS NO. OF PROOF SAMPLES;
NOTE LDTM IS LOADING TIME IN SECS. SPS IS LBS IN PROOF SAMPLE
;  NOTE R1 R2 & R3 ARE AUTOCORRELATIONS - EC TO EC, RIFFLE TO
NOTE DUR IS DURATION IN SECONDS OF THE PROOF OPERATION;
PRINT LHS TPH LDTM N1 N2 SPS SAMBLK R1 R2 R3 DUR ;
NOTE NOTE POPLBN IS NO. OF EC IN POPULATION & H IS NO. IN PRIMARY
NOTE ONE MINUS PI IS PROPORTION OF SUPERPOSED VARIATION. MU & SIG ARE PROCESS
NOTE PARAMETERS.  LB_EC IS SIZE OF ELEMENTARY CLUSTER IN LBS;
PRINT POPLBN H  PI MU SIG   LB_EC      ;
NOTE EV IS PROCESS EXPECTED VALUE OF SAMPLING VARIANCE AS FACTOR OF SIGMA-SQ.;
PRINT EV;
POPCV=SIG#/MU;
SAMCV=SQRT(EV)*POPCV;
LBSSF=MU*3.25*TPH;
LBSSE=SAMCV*LBSSF;
NOTE SAMCV IS PROPORTIONAL SAMPLING ERROR & LBSSE IS SAMPLING
PRINT SAMCV LBSSF LBSSE;
SAMSIG=MU*SAMCV;
```

- - - - - - - - - T O P - O F - F O R M - - - - - - - - - -


```
NOTE SAMSIG IS SAMPLING STANDARD DEVIATION;  PRINT SAMSIG;
%
```

```
NOTE: THE PROCEDURE MATRIX USED 0.58 SECONDS AND 140K AND PRINTED PAGES 1 TO [illegible].
56          FE  RE  FE DUR=21   RE
57          TITLE DURATION SET AT 2 SECONDS;
NOTE: THE PROCEDURE MATRIX USED 0.52 SECONDS AND 140K AND PRINTED PAGES [illegible] TO [illegible].

NOTE: SAS USED 140K MEMORY.

NOTE: SAS INSTITUTE INC.
      SAS CIRCLE
      BOX 8000
      CARY, N.C. 27511

- - - - - - - - - T O P - O F - F O R M - - - - - - - - -

- - - - - - - - - T O P - O F - F O R M - - - - - - - - -

                         S T A T I S T I C A L   A N A L Y S I S   S Y S T E M      [illegible]      1

               LMS IS LAMBDA FOR ONE SECOND OF LOAD TIME. [illegible]
                 N2 EQUALS NO. OF RIFFLES PER PROBE SAMPLE & N1 IS NO. OF [illegible]
               LDTM IS LOADING TIME IN SECS. SPS IS LMS IN PROBE SAMPLE [illegible]
                  R1 R2 & R3 ARE AUTOCORRELATIONS - FC TO FC, RIFFLE TO [illegible]
                          DUR IS DURATION IN SECONDS OF THE PROBE OPERATION

                                    LMS          COL1

                                    ROW1         0.005


                                    TPH          COL1

                                    ROW1           375


                                    LDTM         COL1

                                    ROW1           700


                                    N1           COL1

                                    ROW1            35


                                    N2           COL1

                                    ROW1             1


                                    SPS          COL1

                                    ROW1     [illegible]


                                    SAMPLK       COL1

                                    ROW1     [illegible]
```

```
                    R1             COL1
                    ROW1       0.99999[illegible]

---------TOP-OF-FORM----------

         S T A T I S T I C A L   A N A L Y S I S   S Y S T E M   [illegible]

                    R2             COL1
                    ROW1       0.995012

                    R3             COL1
                    ROW1       0.99[illegible]

                    DUR            COL1
                    ROW1              1

     NOTE POPLAN IS NO. OF EC IN POPULATION & N IS NO. [illegible]
   ONE MINUS PI IS PROPORTION OF SUPPOSED VARIATION [illegible]
          PARAMETERS.  LB_EC IS SIZE OF ELEMENTARY CLUSTER IN [illegible]

                    POPLAN         COL1
                    ROW1         375000

                    N              COL1
                    ROW1       [illegible]

                    PI             COL1
                    ROW1              1

                    NU             COL1
                    ROW1              2

                    SIG            COL1
                    ROW1            0.4
```

--------- T O P - O F - F O R M ---------

S T A T I S T I C A L   A N A L Y S I S   S Y S T E M [illegible]

```
LA_EC          COL1
ROW1              2

EV IS PROCESS EXPECTED VALUE OF SAMPLING VARIANCE AS [illegible]

EV             COL1
ROW1    0.00760[illegible]

SAMCV IS PROPORTIONAL SAMPLING ERROR & LASSL IS SAMPLING ERROR [illegible]

SAMCV          COL1
ROW1      0.004[illegible]315

LASSF          COL1
ROW1        2[illegible]17.5

LASSL          COL1
ROW1        12.0205

SAMSTD IS SAMPLING STANDARD DEVIATION

SAMSTD         COL1
ROW1    0.00[illegible]
```

--------- T O P - O F - F O R M ---------

DURATION SET AT [illegible] SECONDS [illegible]

```
LMS IS LAMBDA FOR ONE SECOND OF LOAD TIME. [illegible]
N2 EQUALS NO. OF RIFFLES PER PROOF SAMPLE [illegible]
LDTM IS LOADING TIME IN SECS. SPS IS LMS IN PROOF SAMPLE [illegible]
R1 R2 & R3 ARE AUTOCORRELATIONS [illegible]
DUR IS DURATION IN SECONDS OF THE PROOF OPERATION

LMS            COL1
ROW1          0.[illegible]

T[illegible]            COL1
```

ROW1 375

LDIM COL1
ROW1 700

N1 COL1
ROW1 95

N2 COL1
ROW1 1

SPS COL1
ROW1 2

SAMPLR COL1
ROW1 70

R1 COL1
ROW1 0.99999[illegible]

- - - - - - - - - T O P - O F - F O R M - - - - - - - - - -

DURATION SET AT 2 SECONDS [illegible]

R2 COL1
ROW1 0.99605

R3 COL1
ROW1 0.810731

DUR COL1
ROW1 2

NOTE POPLSN IS NO. OF EC IN POPULATION [illegible]
ONE MINUS R1 IS PROPORTION OF SUPERPOSED VARIATION [illegible]
PARAMETERS. [illegible]

```
                    POPLBN          COL1
                    ROW1          375000

                    H               COL1
                    ROW1         1071.[illegible]

                    PI              COL1
                    ROW1               1

                    MU              COL1
                    ROW1               2

                    SIG             COL1
                    ROW1             0.[illegible]

- - - - - - - - - T O P - O F - F O R M - - - - - - - - - -

                       DURATION SET AT [illegible] SECONDS

                    LB_EC           COL1
                    ROW1               2

EV IS PROCESS EXPECTED VALUE OF SAMPLING VARIANCE AS FACTOR OF [illegible]
                    EV              COL1
                    ROW1      0.00108741

SAMCV IS PROPORTIONAL SAMPLING ERROR & LOSSP IS [illegible]
                    SAMCV           COL1
                    ROW1      0.[illegible]

                    LOSSP           COL1
                    ROW1         [illegible]7.5

                    LOSSE           COL1
                    ROW1         [illegible]
```

```
                              SAMSIG IS SAMPLING STANDARD DEVIATION

                              SAMSIG          COL1

                              ROW1       0.0131993

---------- T O P - O F - F O R M ----------

PROCTOR              SYS             6-PAGES      348-LINES       0-PLOTS # FSTI.ENV.TMP
123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890[illegible]
123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890[illegible]
123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890[illegible]
```

Further Variance Calculations for Belt Sampling

For Entropy Environmentalists, Inc.,

C. H. Proctor, NCSU, August, 1980

In an earlier report, "Variance Calculations for Conveyor Belt Sampling," we furnished a variance formula and a computer program that served to adapt our results for the continuous monitoring data to the conveyor belt case. The formula seems capable of even further extension while the computer program stands in need of some corrections. In the present report we give the extensions, and corrections, and will also discuss more fully how our time series style of approach can be used in the conveyor belt situation.

We must confess that only recently have we studied in detail some reports on American theory and experiences with bulk sampling of coal, ["Symposium on Bulk Sampling," (ASTM 114), "Symposiums on Coal Sampling," (ASTM 162) and a 1958 "Symposium on Bulk Sampling" (ASTM 242)]. We realize that our choice of the time series approach was largely a historical accident since the data from EPA were presented to us as a sequence of observations in time and the first references we consulted (Jowett and Cochran) used the time series approach. The variance component viewpoint is actually more familiar to us statistically and if we had first seen the papers by Bertholf we may have adopted it. The space series or stream model is certainly more realistic and I believe we have shown it is practical as well.

In converting our measure of correlation, λ, from data in time to data in bulk it became necessary to adopt a standard rate of flow which will be taken as one ton per minute. In our preliminary report, "Process Covariance Parameter Estimation," values of 30 $\hat{\lambda}_1$ were found to be around 0.02. Roughly speaking, observations on a time slice when separated by 15 minutes (or by 30 elementary periods, EP's) would be correlated to an extent $e^{-.02} = .98$. Strictly speaking such observations are taken to be free of measurement error and of short term fluctuations. Taking into account short term fluctuations and using the estimates $\hat{\pi} = .9$ with $30\,\hat{\lambda}_2 = 3$ gives a correlation of $.9e^{-.02} + .1e^{-3} = 0.89$.

Standardizing the value $\hat{\lambda}_1 = .02$, which is for a 15 minute interval, to a one minute interval leads to $\lambda_{S1} = .02/15 = .00133$. At present we are not sure at what rate of flow the coal was being burned when EPA's data were collected. We will suppose that it was one ton per minute and thus will leave $\lambda_{S1} = .00133$. The units for λ_{S1} may be called "mixings per ton-minute." That is, when material is mixed so as to make it locally more heterogeneous this decreases correlation or raises the value of λ. Actually mixing may be done by blending, washing, crushing, by natural diffusion of particles, or many other means while "anti-mixing," such as segregation on the belt, may also take place.

The standard estimated value for λ_2, which appeared as $(30)\hat{\lambda}_2 = 3$, becomes $\lambda_{S2} = 0.1$. A difficulty arises in the conversion of the estimate of π. We have noticed in other reports that by changing the size of the elementary period this changes π. Roughly speaking, the longer the elementary period the smaller becomes π, since π reflects the proportion of longer term variation and averaging over a longer elementary period cancells out short term variation.

If one could locate those molecules responsible for a snapshot reading back on the conveyor belt their positions may appear to be normally distributed along a stretch of the belt, although I am only moderately sure about such a "reverse-diffusion" process. Averaging squared interpoint distances gives $2\sigma^2$ where σ^2 is the variance of the normal distribution. If the distribution had been rectangular then its range would be $\sqrt{12}\,\sigma = h$ say and one could use his knowledge of weight of coal per distance unit to find the weight of an increment corresponding to a snapshot. Roughly speaking, we need to know the variance of the effect of a single particle of coal. I suspect there is knowledge of the time required to pass from conveyor belt to stack and what we need to know is the variance of those times or the "rate of diffusion."

If one identifies the variance component for "trend" in the coal sampling literature with longer term fluctuations in our time series model and the component for "increment" with shorter term fluctuations, then the proportion of trend variance can be equated to π. Such values for π were found to range from 5% (Cabin Creek) through 15% (Enos) to 25% (East River). However, these are for percentage of ash whereas our interest is in sulfur, actually parts of sulfur per Btu. Thus we will leave open to further data the setting of the value of π, but suspect it may be somewhere between $\pi = .6$ and $\pi = .1$.

The three sets of data just mentioned (Cabin Creek, Enos and East River) also permitted us to examine the shape of correlogram for bulk sampling of coal and the evidence for the value of λ_1 was reasonably consistent with what had already been estimated. For the Cabin Creek data the shape was close to the exponential and from a value of the first serial correlation of $r_1 = .67$ we find $\hat{\lambda} = .04$. The spacing appeared to be at 3 hours between increments and close to one ton a minute so that $\lambda_5 = .04/180 = .002$. The Enos data also showed the clean exponential shape but the East River data produced a mixed shape. The fact that something over half of data sets yield clean exponential shaped correlograms with a mixed appearance of the others, is similar to our experiences with the continuous monitor data.

After having examined the written accounts of factors affecting level of ash and having begun to glimpse something of the complexities of coal handling and of the physical nature of coal, the earlier decision to use a mixture of exponentials as correlogram shape continues to hold appeal. It was chosen on the basis of appearance of the empirical correlograms backed by Jowett's observations. Appearances continue to favor it but in perhaps a somewhat modified way. That is, no particular stochastic process model of moderate simplicity can possibly fit all the great variety in patterns of interpoint correlation found in coal streams. If just natural process such as affect variation from the mine face were present there may be some chance for a simple model, but the intervention of handling guided by seemingly limitless technical criteria defeat simplicity. About the only common ground seems to be positive autocorrelations at certain scales of separation in the stream.

Having thus reaffirmed our belief in the usefulness as well as in the limitations of our process specification we can now proceed to extend the formula and correct the computer programs. Recall that the formula of page 2 separated into a rather lengthy multiple of π and another simple multiple, namely $(n_1n_2)^{-1}$, of $(1-\pi)$. This result is appropriate for a process specified by correlogram $\pi e^{-\lambda d}$ and where short term variation is error variance. Alternatively, the multiple of $(1-\pi)$ would be $[(n_1n_2)^{-1} - (n_1n_2k_1k_2)^{-1}]$ where the short term variation is superposed variation due to the lump to lump variability in sulfur level.

If the complicated coefficient of π be denoted EV_1 when calculated with $\rho = e^{-\lambda_{S1}}$ and be denoted EV_2 when $\rho = e^{-\lambda_{S2}}$ then the extended formula becomes:

$$\sigma^{-2}\, E(V_{2S-SYS}) = EV_1\pi + EV_2(1-\pi) .$$

Notice that when λ_{S2} is very large (i.e. short term mixing is virtually complete) then

$$\sigma^{-2}\, E(V_{2S-SYS}) = EV_1\pi + [(n_1n_2)^{-1} - (n_1n_2k_1k_2)^{-1}](1-\pi)$$

as just mentioned.

Another difficulty with the program appears to be rounding error. When the snapshot or increment sizes become very small then negative values of EV_1 turned up. We checked the formula by rederiving it and also found its first derivative with respect to λ to prove that as λ moves even a little way from zero the variance will be positive. This derivative is:

$$\frac{dEV}{d\lambda} = [k_1{}^2 n_2{}^2 k_2(k_2 - 1) + k_1{}^2 k_2 - 1]/3N \quad .$$

Since all design parameters are positive integers the derivative is nonnegative. We have used the value of the derivative to approximate the value for EV wheneever it appear. to go negative but this solution is only temporary. The program will need to be rewritten in a more precise language than SAS, PROC MATRIX.

The corrected computer program is included as an Appendix but it will help to reexpress the design parameters in both the language of bulk sampling and of continuous monitoring. In bulk sampling we will usually take one lb. as "elementary cluster" which is actually smaller than is realistic and would have to be formed similar to tissue sections - by freezing and slicing. The so called increments actually obtained by stopping the belt dropping a frame and scraping of the material between plates are not exactly sums of elementary clusters but suffer from boundary effects. Such effects have been rather throughly studied and become insignificant only for relatively large increments such as 50 lbs.

The actual method of sampling being investigated at Tampa is a mechanical collection device that traverses across the bulk stream and picks up a 2 lb "probe sample." Such a device may be represented by the subsampling of an increment. That is, the amount of coal passing as the collector begins until it completes its traverse is the total sample increment while the 2 lbs is a systematic subsample drawn of more or less two elementary clusters. The number of subsamples may be adjusted by changing the definition of elementary cluster amd can be used to reflect uncontrolled boundary effects of the collector. Bias created by the collectors boundary effects must be handled apart.

The design parameter that represents the size of increment is denoted h which is expressed in numbers of EC's . If w be set equal to the weight of one EC then $W = hw$ is the weight of an increment. The value of n_2 equals the number of subsampled EC's and thus $n_2 w$ is the weight of the probe sample. The second stage sampling gap is $h/n_2 = k_2$. Other aspects of the design are n_1 = the number of increments and $k_1 = N/hn_1$ the first stage sampling gap, where N is the total number of EC's in the population being sampled. A minimal set of sampling design parameters are N , n_1 , h and n_2 .

There is in fact an additional design parameter, called p, the number of laboratory pulps analyzed. The full variance formula becomes:

$$V = E(V_{2S-SYS}) + \sigma^2_{ra}/p \quad ,$$

where σ^2_{ra} is the so called variance of reduction and analysis. If one could find a cost function in terms of some cost parameters and having N , n_1 , h n_2 and p as arguments that gives the expense of collecting, analyzing and computing the estimate then it should be relatively straight forward to find optimum sizes for p , h and n_2 .

The appearance of our "time-series" variance expression is certainly more complex than the one arising from the components of variance approach. That one is:

$$\sigma^2_G = \frac{\sigma_t{}^2 + \sigma_i{}^2/w}{N} + \sigma^2_{ra}/p \quad .$$

With the computer program, however, the formula for V becomes quite usable. Its realism is of course, dependent on the aptness of choice of process parameters: σ^2 and μ as well as λ_1 , λ_2 and π . Perhaps its greatest applications are for deciding on sample sizes and levels of accuracy in cases of repeated applications with relatively constant recurring conditions.

In the case of a single, possibly unique, finite population or lot of coal, for which one requires not only an estimate but a self contained estimate of survey error one would be well advised to design the sample in interpenetrating subsamples. That is, instead of drawing, for example, a probe sample every 20 seconds for 700 seconds, one would select at random five start times in the first 100 seconds and successively add 100 to each of the five times until one had designated 35 times for making collections. The coal from each of the 5 start times would be kept separate and five determinations made, one for each series of seven collection times. The average of the five determinations constitutes the overall estimate (barring the appearance of an outlier) and their variability may be used to estimate sampling error.

During repeated use of a sampling plan based on the variance formula it would be useful from time to time to analyze separate increments drawn in a pattern much like that of a two-stage systematic sample and then calculate serial correlation coefficients for the short range and longer range gaps available. These would help to verify or to correct the values of λ_1, λ_2 and also σ^2 being used.

While attempting to provide a single program for variance calculation for both continuous monitoring and bulk sampling one becomes more aware of the possibilities and difficulties in comparing the methods. For example both the collector and the light beam scan some rather vaguely defined portion of the stream. Only when the stream is sectioned can one be relatively sure of reducing boundary bias and then only for quite large sections.

```
MU=1 ... LMS1=.00 ... LMS2=.51 ... PI=;
TPH=3000; LDTM=5600;
LB_EC=1; TFRAME=0;
N1=61; H=1000; N2=2;
*
MACRO _RE
IF TFRAME=0 THEN GOTO PASS;
TN=LDTM#/SEC_EC; LB_EC=TPH*2000#/TN;
GOTO BACK;
PASS: TN=TPH*2000#/LB_EC; SEC_EC=LDTM#/TN;
BACK: IPT=(MU||SIG||PI||LMS1||LMS2||TPH||LDTM);
LAM1=LMS1*SEC_EC#/60; LAM2=LMS2*SEC_EC#/60;
DSN=(TN||N1||H||N2);
NOTE POPULATION & PROCESS PARAMETERS ARE IN IPT MU, SIG, PI, LMS1,LMS2, TPH LDTM
; PRINT IPT; NOTE DESIGN CHARACTERISTICS ARE IN DSN AS TN, N1, H & N2; PRINT
DSN;
K1=TN#/(H*N1); K2=H#/N2; W=H*LB_EC; LW=W#/K2; DUR=H*SEC_EC; SNP=DUR#/K2;
NOTE INCREMENT SIZES & SUBINCREMENT SIZES FIRST IN LBS THEN SECS ARE IN INC;
INC=(W||LW||DUR||SNP); PRINT INC;
SMBLK=W*N1; SSMBLK=LW*N1; BLK=(SMBLK||SSMBLK); NOTE SAMPLE & SUBSAMPLE BULKS I
N LBS ARE IN BLK; PRINT BLK;
NOTE CORRELATIONS BETWEEN EC, BETWEEN SUBSAMPS & BETWEEN PRIMARY SAMPS ARE IN RS
;
LAM=LAM1; TRN=0; EVF=0;
ENT: TRN=TRN+1; IF TRN=2 THEN LAM=LAM2;
R1=EXP(-LAM);
R2=EXP(-LAM*K2); R3=EXP(-LAM*K1*K2*N2);
RS=(R1||R2||R3); PRINT RS;
C1=(K1*K2-1)#/(N1*N2*K1*K2);
C2=(N1*(N2-1)*EXP(-LAM*K2)-N1*N2*EXP(-LAM*K2*2)+N1*EXP(-LAM*K2*(N2+1)));
C3=EXP(-LAM*K1*K2*N2)*((N1-1)*EXP(LAM*K2*(N2-1))-(N1+1)*EXP(-LAM*K2*(N2+1))-(2)*
(N1*N2-(1))*EXP(-LAM*K2)+(2)*N1*N2*EXP(-LAM*2*K2));
C4=EXP(-LAM*2*K1*K2*N2)*(N1*(N2+1)*EXP(-LAM*K2)-N1*N2*EXP(-LAM*K2*2)-N1*EXP(LAM*
K2*(N2-1)));
C5=EXP(-LAM*N2*K2*K1*(N1+1))*(EXP(-LAM*K2*(N2+1))+EXP(LAM*K2*(N2-1))-(2)*EXP(-LA
M*K2));
C6=2*((N1*H*K1-1)*EXP(-LAM)-N1*H*K1*EXP(-LAM*2)+EXP(-LAM*(N1*H*K1+1)))#/
(N1*N1*H*H*K1*K1*(1-EXP(-LAM))*(1-EXP(-LAM)));
DMN=N1*N2*(1-EXP(-LAM*K1*K2*N2))*(1-EXP(-LAM*K2));
EV=C1+(2)*(C2+C3+C4+C5)#/(DMN*DMN); EV=EV-C6;
IF EV>0 THEN GOTO PKUP;
NOTE EV WAS NEGATIVE . ROUNDING?; AL=LAM*TN;
PRINT C1 C2 C3 C4 C5 C6 DMN EV;
EV=LAM*(K1*K1*N2*N2*K2*(K2-1)+K1*K1*K2-(1))#/(3*TN);
PRINT AL EV; PKUP:
IF TRN=1 THEN EVF=EVF+PI*EV; IF TRN=2 THEN EVF=EVF+(1-PI)*EV;
IF TRN=1 THEN GOTO ENT; EV=EVF;
POPCV=SIG#/MU;
SAMCV=SQRT(EV)*POPCV;
LBSSF=MU*3.25*TPH;
LBSSE=SAMCV*LBSSF;
```

- - - - - - - - T O P - O F - F O R M - - - - - - - - -


```
NOTE EV, POPCV, SAMCV, LBSSF & LBSSE ARE IN CSTT
```

55 [illegible]
56 A
57 _II 0821 [illegible] IS ROUNDING ERROR A PROBLEM?

NOTE: THE PROCEDURE MATRIX USED 0.04 SECONDS AND 150K AND PRINTED PAGES 1 TO 2.

NOTE: SAS USED 150K MEMORY.

NOTE: SAS INSTITUTE INC.
SAS CIRCLE
BOX 8000
CARY, N.C. 27511

- - - - - - - - - T O P - O F - F O R M - - - - - - - - - - -

- - - - - - - - - T O P - O F - F O R M - - - - - - - - - - -

POPULATION & PROCESS PARAMETERS ARE IN TPT ON: SIG, PI, (WTH TOL), TPI LOT

TPT	COL1	COL2	COL3	COL4	COL5	COL6	COL7
ROW1	2	0.4	0.6	0.005	5	1000	5000

DESIGN CHARACTERISTICS ARE IN DSN AS TN, N1, N & N2

DSN	COL1	COL2	COL3	COL4
ROW1	6000000	61	2	2

INCREMENT SIZES & SUBINCREMENT SIZES FIRST IN LOS THEN SECS ARE IN T11

T11	COL1	COL2	COL3	COL4
ROW1	2	2	1.0019667	0.0019667

SAMPLE & SUBSAMPLE MASS IN LBS ARE IN NEA

NEA	COL1	COL2
ROW1	122	122

CORRELATIONS BETWEEN ICs BETWEEN SUBSAMPS & BETWEEN PRIMARY SAMPS ARE IN PS

PS	COL1	COL2	COL3
ROW1	1	1	0.992219

CV WAS NEGATIVE - ROUNDING?

C1	COL1
ROW1	0.0001955

C2	COL1
ROW1	1.6520E-11

C3	COL1
ROW1	7.0160E-11

- - - - - - - - - - T O P - O F - F O R M - - - - - - - - - -

C4	COL1
ROW1	-1.0011E-12

C5	COL1
ROW1	1.4925E-14

C6	COL1
ROW1	0.061022

DAN	COL1
ROW1	7.2416E-08

EV	COL1
ROW1	-0.352115

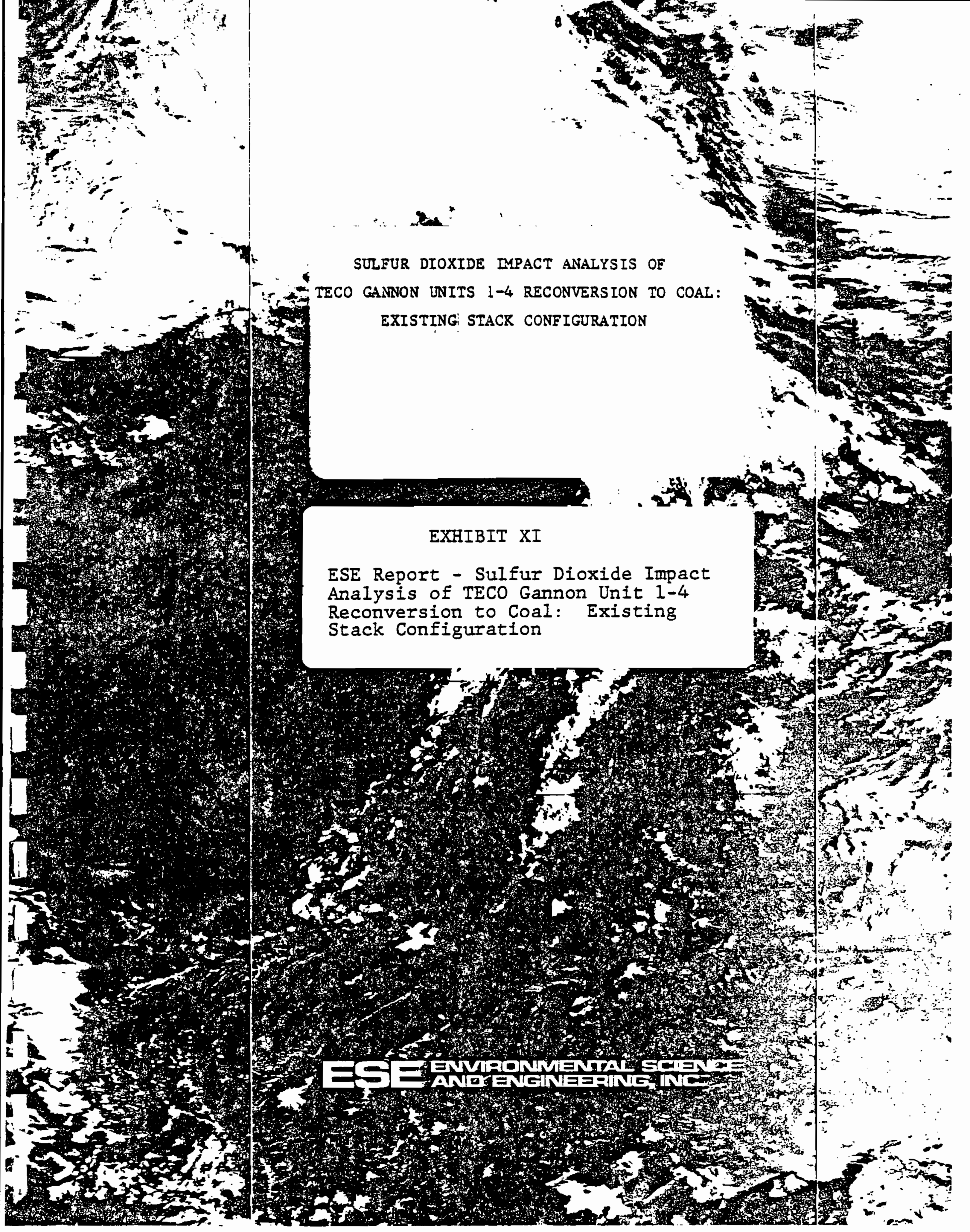
AL	COL1
ROW1	0.666667

LV	COL1
ROW1	.0000104512

RS	COL1	COL2	COL3
ROW1	0.999922	0.999922	0.000475914

EV, POPCV, SAMCV, LOSSE & LOSSL ARE IN EST

EST	COL1	COL2	COL3	COL4	COL5
ROW1	0.00000092	0.2	0.0113412	19500	271.053



SULFUR DIOXIDE IMPACT ANALYSIS OF

TECO GANNON UNITS 1-4 RECONVERSION TO COAL:

EXISTING STACK CONFIGURATION

EXHIBIT XI

ESE Report - Sulfur Dioxide Impact Analysis of TECO Gannon Unit 1-4 Reconversion to Coal: Existing Stack Configuration

ESE ENVIRONMENTAL SCIENCE AND ENGINEERING, INC.

SULFUR DIOXIDE IMPACT ANALYSIS OF TECO GANNON UNITS 1-4 RECONVERSION TO COAL: EXISTING STACK CONFIGURATIONS

INTRODUCTION

Tampa Electric Company (TECO) of Tampa, Florida, has received a draft prohibition order under the Fuel Use Act and is proposing to convert the affected units (Gannon 1 through 4) to low sulfur coal. Currently there exist at Gannon six steam electric generating units with a total generating capacity of 1,270 megawatts. Units 1 through 4 currently burn fuel oil, while Units 5 and 6 burn coal. All units at Gannon are equipped with individual stacks. Unit 4 is serviced by two identical stacks.

Before a reconversion to coal can take place, it must be demonstrated that ambient air quality standards (AAQS) will not be violated as a result of the reconversion. TECO contracted Environmental Science and Engineering, Inc. (ESE) of Gainesville, Florida, to conduct a sulfur dioxide (SO_2) impact analysis of all six units at Gannon burning coal. This study addresses compliance with Florida AAQS based upon the existing stack configuration. For the Gannon station, the State of Florida AAQS are the most stringent applicable standards for SO_2. The AAQS are: 60 ug/m^3, annual arithmetic mean; 260 ug/m^3, 24-hour average; 1,300 ug/m^3, 3-hour average (24-hour and 3-hour levels not to be exceeded more than once per year).

This report presents the data bases, methodology, and results of the dispersion modeling study. All input data are described, and all computer model results are in the appendix.

EMISSIONS INVENTORY

Emissions inventory data for the Gannon station were supplied by TECO. Stack parameters provided included stack height, flow rate, stack exit velocity, stack exit temperature, and stack diameter. Flow rate, stack exit velocity, and temperature were provided by TECO for 100-, 75-, and 50-percent load cases based upon actual (as opposed to design) operating data for the six units using coal. Heat input values for each unit were also provided by TECO. The evaluation was conducted based upon the existing stack configuration at Gannon; stack parameters used in the modeling evaluation are presented in Table 1.

At TECO's direction, the SO_2 emission rate used in the dispersion modeling study for all units at Gannon was 2.4 lb $SO_2/10^6$ Btu heat input. Units 5 and 6 are currently limited to this emission rate.

Sources of SO_2 considered in the analysis in addition to Gannon included all significant sources within about 15 kilometers (km) of Gannon (Figure 1). These included TECO Hookers Point and Gardinier, the two largest emitting sources nearby. In addition, the TECO Big Bend and Florida Power & Light Manatee power plants were included. Stack parameters and SO_2 emission rates for these other sources were obtained from data on-hand at ESE and/or from Air Pollutant Inventory System (APIS) state emission inventory files.

METEOROLOGICAL DATA

Meteorological data used in the dispersion modeling analysis consisted of a 5-year hourly data record from Tampa International Airport (1970 to 1974). Hourly wind direction, wind speed, temperature, and atmospheric stability were developed from these data with the CRSTER meteorological preprocessor program. This program uses EPA's wind direction randomization scheme. Upper air data were also from Tampa for the same period and included the corrections for mixing height data from the National Climatic Center's program.

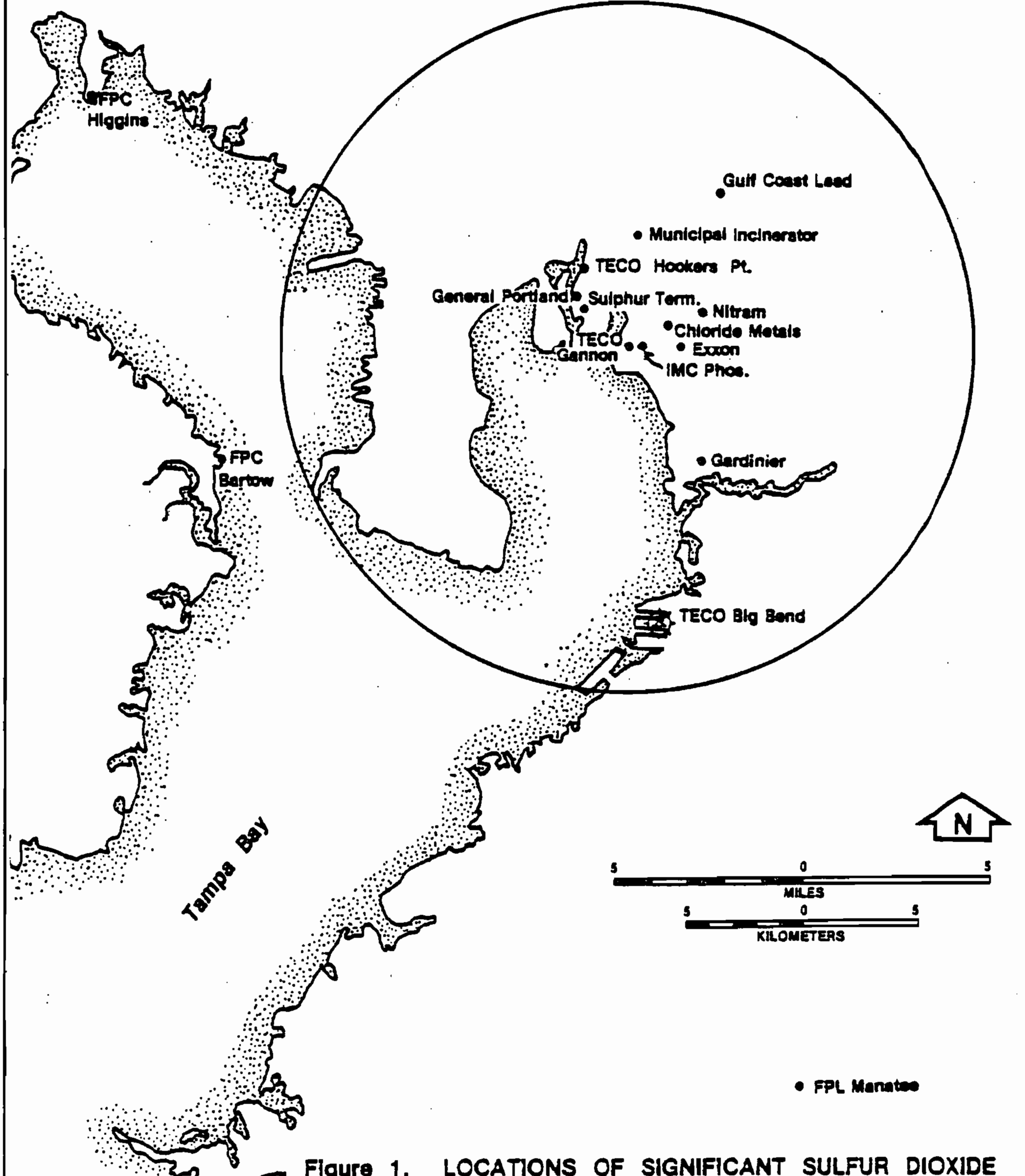


Figure 1. LOCATIONS OF SIGNIFICANT SULFUR DIOXIDE SOURCES IN THE VICINITY OF TECO GANNON.

SOURCE: ENVIRONMENTAL SCIENCE AND ENGINEERING, INC., 1980

DISPERSION MODELING METHODOLOGY

Past dispersion modeling studies conducted by ESE have shown that the short-term averaging times (24 hours or less) are generally critical for determining compliance with AAQS. As a result, annual average impacts were not evaluated in this study.

The EPA-developed Single Source (CRSTER) model was used to identify meteorological conditions associated with Gannon's highest, second-highest predicted impacts for 24-hour and 3-hour averaging times (critical meteorology). Three load scenario cases were evaluated with the CRSTER: all six Gannon units at 100-percent, 75-percent, and 50-percent load.

Multiple CRSTER model executions were performed to evaluate downwind distances ranging from 1.0 to 3.8 km with a 0.2-km receptor spacing. When necessary, additional CRSTER models were executed to evaluate receptor distances of less than 1.0 km (if previous executions indicated a maximum impact value might occur less than 1.0 km downwind). The CRSTER was executed in the rural dispersion mode.

ESE's CRSTER model has been modified to process a 5-year meteorological data base. Highest and second-highest short-term (24-hour and 3-hour) summary tables are output by the model for each year, and a composite summary table is provided at the end of each model execution. The critical meteorology, which resulted in highest, second-highest ground-level impacts for each scenario, can readily be identified by examining these tables.

After the critical meteorology for each load case scenario was identified, the EPA short-term PTMTPW model was used to further refine highest, second-highest concentrations. The PTMTPW model accepts spatially distributed sources, either designated receptors or a receptor grid, and up to 24 hours of meteorology. All SO_2 sources described previously under the EMISSIONS INVENTORY section of this report were entered into the PTMTPW model, along with the critical meteorology and appropriately placed 1.0-km by 1.0-km grids with a 0.1-km receptor spacing. In this manner, the highest, second-highest Gannon concentrations were refined with the inclusion of other SO_2 sources in the vicinity of Gannon.

Based upon the results of the dispersion modeling study, emission limits were identified for the Gannon station in order to meet the applicable AAQS.

RESULTS

Table 2 presents a tabulation of the critical meteorological periods identified for the Gannon station. These critical meteorological periods were used in the PTMTPW refined modeling analysis. For several scenarios, more than one period of critical meteorology was evaluated, since the CRSTER results identified similar highest, second-highest impact concentrations for these periods. In addition, for certain scenarios, critical meteorological periods switched from highest to second-highest impact concentrations. Multiple PTMTPW executions were then necessary to correctly identify the highest, second-highest concentration. In cases where multiple PTMTPW models were executed for a single scenario, the meteorological period resulting in the highest, second-highest concentration was determined. These periods are identified with a dagger (†) in Table 2. These concentrations are also identified in the PTMTPW computer model printouts in the appendix.

Table 3 presents a summary of the highest, second-highest predicted 24-hour and 3-hour SO_2 concentrations for Gannon at 2.4 lb $SO_2/10^6$ Btu after reconversion to coal. The contributions from each Gannon unit to the total are shown, as well as the total contribution from all other SO_2 sources included in the evaluation.

The total summed concentrations can be compared to the Florida AAOS of 260 ug/m^3 (24-hour averaging time) and 1,300 ug/m^3 (3-hour averaging time). As shown, only the highest, second-highest 24-hour impact at 100-percent load, 265 ug/m^3, exceeds any of the AAQS. Of this total, 17 ug/m^3 is due to other nearby sources, based upon continuous 24-hour operation of all sources. As load is decreased uniformly for all Gannon units, maximum impact concentrations also decrease for both the 24-hour and 3-hour averaging times. This result indicates that the decrease in plume rise for the units does not totally account for the decrease in emissions when reducing load, i.e., maximum concentrations are more dependent upon emissions than plume rise.

Comparison of the predicted background SO_2 concentrations shows that the 24-hour background concentrations are higher than the 3-hour background concentrations. This result arises from the relation of the particular wind directions and stabilities causing the maxima to the locations of other SO_2 sources. For 24-hour periods, winds are generally more variable than for 3-hour periods, and stabilities are generally neutral. Such meteorology increases the potential impacts from an array of distributed sources. In comparison, 3-hour critical meteorology generally consists of unstable (A stability) conditions and, at most, three different wind directions. Unstable conditions tend to cause maximum impacts close to the source.

Table 4 presents the calculated maximum SO_2 emissions for the Gannon station to meet the applicable Florida AAQS, based upon the existing stack configuration. The emission rate values are based on all Gannon units emitting at identical emission rates and on the background SO_2 values shown in Table 3. As shown, only the 100-percent load case results in an emission limitation of less than 2.4 lb/10^6 Btu, with the 24-hour averaging time being most stringent for the Gannon station.

Because the CRSTER model is a single source (plant) model, interactions with other nearby sources of SO_2 were not directly evaluated with the 5-year meteorological data base. However, it was assumed that the

Gannon station would dominate local maximum impact concentrations. This assumption has been substantiated by past dispersion modeling studies of Gannon (Prevention of Significant Deteioration Analysis, TECO Gannon Units 1 through 4, Environmental Science and Engineering, Inc., February 1980) and can be supported by examination of the emission inventory, which shows the Gannon station to be the largest SO_2 source in the vicinity. TECO Hookers Point, located about 4 km from Gannon, has similar stack heights to Gannon, but its emissions are on the order of 10 times less than Gannon. TECO Big Bend, including the proposed Big Bend 4 Unit, is the largest source of emissions in Tampa, but is located about 12 km south of Gannon.

Copies of all computer model outputs supporting this impact analysis, including both CRSTER and PTMTPW model results, are included in the appendix.

Table 1. Stack Parameters and SO_2 Emission Rates Utilized in the Gannon Coal Reconversion Impact Analysis

Unit	Load (%)	Heat Input Rate (10^6 Btu/hr)	SO_2 Emission Rate at 2.4 lb/10^6 Btu (g/sec)	Stack Height (m)	Stack Diameter (m)	Exit Temperature (°K)	Flow Rate (1000 acfm)	Velocity (m/s)
1	100	1257.0	380.1			438	500	32.4
	75	942.8	285.1	93.3	3.05	425	383	24.8
	50	628.5	190.1			411	252	16.3
2	100	1257.0	380.1			438	500	32.4
	75	942.8	285.1	93.3	3.05	425	383	24.8
	50	628.5	190.1			411	252	16.3
3	100	1599.0	483.5			427	615	35.4
	75	1199.3	362.7	93.3	3.23	420	469	27.0
	50	799.5	241.8			410	342	19.7
4	100	1876.0	567.3			443*	700	24.6*
	75	1407.0	425.5	93.3*	2.93*	433*	520	18.2*
	50	938.0	263.7			417*	353	12.4*
5	100	2284.0	690.7			416	681	20.7
	75	1713.0	518.0	93.3	4.45	410	552	16.8
	50	1142.0	345.3			407	440	13.4
6	100	3798.0	1148.5			439	1120	23.4
	75	2848.5	861.2	93.3	5.36	423	873	18.2
	50	1899.0	574.3			407	637	13.3

* Two identical stacks service Unit 4. The parameters shown are for each stack.

Source: Tampa Electric Company, 1980.

Table 2. Critical Meteorological Periods Identified for the Gannon Coal Reconversion Impact Analysis

Scenario	Day/Year (Period)*	Radial Direction (degrees)	Downwind Distance (km)
24-Hour Averaging Time			
All units at 100 percent load	194/71†	90	2.2
	284/74	240	2.8
	286/74	240	2.8
All units at 75 percent load	284/74	240	2.6
	286/74†	240	2.6
All units at 50 percent load	284/74†	240	2.2
	286/74	240	2.2
3-Hour Averaging Time			
All units at 100 percent load	178/71(4)†	90	1.8
	194/71(4)	90	1.8
	220/71(5)	90	1.8
All units at 75 percent load	178/71(4)†	90	2.0
All units at 50 percent load	178/71(4)†	90	1.8
	220/71(5)	90	1.8

* Period equals one of the 3-hour periods of the day, beginning at midnight (Period 1) and ending at midnight (Period 8).

† Critical meteorology for indicated scenario.

Source: Environmental Science and Engineering, Inc., 1980.

Table 3. Highest, Second-Highest Predicted SO_2 Concentrations, TECO Gannon Coal Reconversion Study--All Gannon Units at 2.4 lbs/10^6 Btu

Scenario	Highest, Second-Highest Concentration (ug/m^3) 24-Hour	3-Hour
7 Stacks at 100 Percent Load		
Unit 1	29	141
Unit 2	29	142
Unit 3	35	163
Unit 4a	24	128
4b	24	128
Unit 5	49	226
Unit 6	58	188
Subtotal	248	1,117
Background	17	5
TOTAL	265	1,122
7 Stacks at 75 Percent Load		
Unit 1	22	114
Unit 2	28	133
Unit 3	32	153
Unit 4a	24	119
4b	24	119
Unit 5	43	204
Unit 6	49	197
Subtotal	222	1,039
Background	15	6
TOTAL	236	1,045
7 Stacks at 50 Percent Load		
Unit 1	27	114
Unit 2	27	115
Unit 3	29	126
Unit 4a	24	99
4b	25	99
Unit 5	36	153
Unit 6	42	182
Subtotal	209	888
Background	12	8
TOTAL	221	896

NOTE: Sums may not equal total due to round-off error.

Source: Environmental Science and Engineering, Inc., 1980.

Table 4. Maximum SO_2 Emissions to Meet Ambient Air Quality Standards*, TECO Gannon Station Coal Reconversion

Scenario	24-Hour Emission Rate ($lb/10^6$ Btu)	3-Hour Emission Rate ($lb/10^6$ Btu)
7 stacks at 100 percent	2.35	2.78
7 stacks at 75 percent	2.65	2.99
7 stacks at 50 percent	2.85	3.49

* 3-Hour Florida AAOS is 1,300 ug/m^3; 24-hour Florida AAQS is 260 ug/m^3.

Source: Environmental Science and Engineering, Inc., 1980.

APPENDIX A
CRSTER OUTPUT

All Gannon Units At 2.4 lb/10^6 Btu

100 Percent Load

INTRODUCTION

Tampa Electric Company (TECO) is considering the conversion of its Gannon Station Unit 1 - 4 to low sulfur coal of the type presently utilized in Gannon Unit 6. Entropy Environmentalists, Inc. was requested by TECO to perform a statistical analysis of both the long and short term sulfur dioxide emissions.

The emissions data supplied to Entropy consisted of weekly emission data submitted to the Florida Department of Environmental Regulation (DER) and data obtained during a six-week period in which 3-hour sulfur dioxide emission data was taken. The 3-hour data was collected in order to determine the relationships between short-term and long-term SO_2 emission rates. These data are summarized in Tables 1 and 2.

REQUIREMENTS

Tampa Electric Company is proposing a compliance plan to provide assurance that long-term (based on current allowable weekly) and short-term (based on 24-hour and 3-hour dispersion modeling) emission limitations will not be exceeded. The requirements to statistically support this compliance plan are as follows:

I. Long-term

To determine the probability of a weekly emission value exceeding 2.4 lbs. per million BTU.

II. Short-term

A. Twenty-four Hour

To determine, for both the observed weekly mean of 1.86 lbs. per million BTU and the maximum allowable weekly mean of 2.4 lbs. per million BTU, the corresponding upper limit of 24-hour average emission values.

B. Three-Hour

To determine, for the allowable 24-hour emission values (as determined by dispersion modeling, see page iii of this report), the probability of the 3-hour emission value exceeding the corresponding allowable 3-hour emission limit (also determined by dispersion modeling, see page iii of this report).

Table 4. Maximum SO_2 Emissions to Meet Ambient Air Quality Standards*, TECO Gannon Station Coal Reconversion

Scenario	24-Hour Emission Rate ($lb/10^6$ Btu)	3-Hour Emission Rate ($lb/10^6$ Btu)
7 stacks at 100 percent	2.35	2.78
7 stacks at 75 percent	2.65	2.99
7 stacks at 50 percent	2.85	3.49

* 3-Hour Florida AAQS is 1,300 ug/m^3; 24-hour Florida AAQS is 260 ug/m^3.

Source: Environmental Science and Engineering, Inc., 1980.

SUMMARY

The results of the statistical analyses are presented in Table 3 - 5. These Tables were constructed after first determining the statistical properties of the sulfur dioxide emission data. (See Appendix for a detailed discussion of the statistical procedures used.)

Table 3 shows the probability of a 7-day average SO_2 emission value exceeding a given level. This Table shows that the current SO_2 emission limit of 2.40 lb/MMBTU has a probability of being exceeded by 0.001 or 0.1% of the time.

Table 4 shows a reasonable upper limit of 3-hour or 24-hour average SO_2 emissions that corresponds to two specified weekly SO_2 averages. This Table shows that if the weekly mean is 2.40 lb SO_2/MMBTU, then there is only a 5% chance that 3-hour emission rate of 2.61 lb SO_2/MMBTU or a 24-hour SO_2 emission rate of 2.58 lb SO_2/MMBTU will be exceeded.

Table 5 shows the probability of certain critical 3-hour average emission values being exceeded given a specified 24-hour average emission rate. For example, if the 24-hour average emission rate is 2.35 lb SO_2/MMBTU, then a 2.78 lb SO_2/MMBTU 3-hour average has only a 0.0006 probability or .06% chance of being exceeded.

TABLE 1

WEEKLY SO_2 EMISSION RATES FOR GANNON UNIT 6 FOR THE PERIOD JANUARY 1 - JULY 31, 1980

Week	SO_2 Lb/MMBtu	Week	SO_2 Lb/MMBtu
1	1.79	16	1.95
2	1.65	17	2.12
3	1.60	18	2.05
4	1.54	19	1.77
5	1.68	20	1.69
6	-	21	1.73
7	1.55	22	1.92
8	1.94	23	1.79
9	1.75	24	1.98
10	2.09	25	-
11	1.92	26	1.92
12	1.87	27	1.96
13	1.85	28	1.94
14	2.25	29	2.06
15	1.89	30	1.86

TABLE 2

[illegible] SO2 EMISSION RATES
FOR TECO GANNON UNIT 6
BASED ON 625 TONS COAL/HOUR
AVERAGE BURN RATE

OBS	DAY	SEG	SO2
1	630	42	2.085
2	630	43	2.070
3	630	44	2.070
4	630	51	1.765
5	630	52	1.825
6	630	53	1.805
7	630	55	1.690
8	701	56	1.765
9	701	57	1.815
10	701	61	1.925
11	701	62	1.810
12	701	63	1.915
13	701	69	1.640
14	702	70	1.750
15	702	71	1.840
16	702	74	1.775
17	702	73	1.895
18	702	75	1.840
19	702	77	1.785
20	703	81	1.855
21	703	82	1.830
22	703	83	1.780
23	703	84	1.805
24	703	85	1.750
25	703	86	1.845
26	703	87	1.800
27	703	88	1.845
28	703	89	1.760
29	707	92	1.630
30	707	94	1.775
31	707	[illegible]	1.925
32	708	101	1.740
33	708	102	1.815
34	708	105	1.965
35	708	107	2.070
36	708	108	2.200
37	709	112	2.215

TABLE 2

3-HOUR SO2 EMISSION RATES
FOR TECO GANNON UNIT 6
BASED ON 625 TONS COAL/HOUR
AVERAGE BURN RATE

OBS	DAY	SEQ	SO2
38	709	113.0	1.920
39	709	114.0	1.880
40	710	119.0	1.710
41	710	122.0	1.940
42	710	124.0	1.570
43	710	126.0	1.675
44	710	127.0	1.645
45	711	130.0	1.885
46	711	133.0	1.700
47 *	711	134.0	1.720
48	711	135.0	1.750
49	711	136.0	1.740
50	711	140.0	1.680
51 *			
52	714	141.0	1.980
53	714	142.0	1.890
54	714	143.0	2.000
55	714	144.0	1.930
56	714	147.0	2.160
57	714	150.0	2.010
58	714	151.0	2.100
59	714	152.0	2.090
60	715	157.0	2.150
61	715	161.0	1.620
62	715	162.0	1.940
63	715	163.0	1.900
64	715	164.0	2.060
65	715	169.0	1.880
66	715	170.0	1.960
67	715	171.0	2.010
68	715	176.0	1.800
69	715	177.0	2.110
70	715	182.0	1.870
71	716	183.0	2.060
72	717	184.0	1.840
73	717	185.0	1.820
74	717	186.0	1.750

TABLE 2

3-HOUR SO2 EMISSION RATES
FOR TECO GANNON UNIT 6
BASED ON 625 TONS COAL/HOUR
AVERAGE BURN RATE

OBS	DAY	SEQ	SO2
75	717	192	1.75
76	717	193	1.80
77	717	194	1.90
78	717	198	2.03
79	718	199	2.00
80	718	200	2.03
81	718	201	2.05
82	718	202	1.97
83	718	207	1.96
84	718	208	2.10
85	718	209	2.09
86	721	215	1.97
87	721	217	1.97
88	721	218	2.00
89	721	219	1.99
90	721	223	1.99
91	721	224	2.01
92	721	225	2.03
93	721	[illegible]	1.93
94	722	[illegible]	1.79
95	722	233	1.85
96	722	234	1.91
97	722	235	1.91
98	722	239	1.88
99	722	240	2.03
100	722	241	1.89
101	723	245	1.81
102	723	[illegible]	1.94
103	723	250	1.91
104	723	251	1.96
105	723	[illegible]	1.75
106	723	255	1.84
107	723	257	1.75
108	724	259	1.85
109	724	[illegible]	1.85
110	724	263	1.87
111	724	264	1.85

TABLE 2

3-HOUR SO_2 EMISSION RATES
FOR TECO GANNON UNIT 6
BASED ON 525 TONS COAL/HOUR
AVERAGE BURN RATE

OBS	DAY	SEQ	SO_2
112	724	265	1.76
113	725	266	2.02
114	725	267	2.16
115	725	268	2.03
116	725	269	2.09
117	725	273	1.83
118	725	274	1.83
119	725	275	1.75
120	725	278	1.81
121	725	279	2.02
122	728	283	1.70
123	728	284	2.11
124	728	285	1.89
125	728	288	1.92
126	728	289	1.91
127	729	291	1.71
128	729	292	1.78
129	729	294	1.89
[illegible]	729	297	1.81
131	730	298	1.92
132	730	303	1.49
133	730	304	2.07
134	730	307	2.07
135	730	310	2.09
136	730	311	2.05
137	730	312	2.11
138	731	315	1.67
139	731	316	1.87
[illegible]	731	317	1.80
141	731	321	1.78
142	731	322	1.77
143	801	325	1.73
144	801	326	1.74
145	801	329	1.96
146	801	330	2.01
147	801	333	2.02
148	801	335	1.88

TABLE 3

PROBABILITY OF EXCEEDING A GIVEN WEEKLY SO_2 EMISSION RATE

Emission Rate, Lb SO_2/MMBtu	Probability of Weekly SO_2 Average Exceeding Emission Rate
1.40	0.996
1.50	0.980
1.60	0.932
1.70	0.832
1.80	0.633
1.90	0.409
2.0	0.212
2.10	0.085
2.20	0.026
2.30	0.006
2.40	0.001
2.50	0.0001

TABLE 4

95% CONFIDENCE INTERVAL ON 24 AND 3-HOUR AVERAGE SO_2 EMISSION VALUES GIVEN A WEEKLY AVERAGE SO_2 EMISSION RATE OF 2.40 OR 1.86 LB SO_2/MMBTU*

Averaging Period	Value Exceeded Only 5% of the Time	
	Weekly Average 1.86	Weekly Average 2.40
3-Hour	2.08	2.61
24-Hour	2.04	2.58

* 1.86 lb SO_2/MMBtu is the long-term average SO_2 emission rate determined from the analysis of the weekly fuel analysis submitted by TECO to DER.

TABLE 5

PROBABILITY OF EXCEEDING VARIOUS 3-HOUR AVERAGE SO_2 EMISSION VALUES GIVEN A SPECIFIED 24-HOUR AVERAGE

24-Hour Average SO_2 Emission Value	Critical 3-Hour Average SO_2 Emission Value	Probability of Being Exceeded
2.35	2.78	0.0006
2.67	2.99	0.008
2.85	3.49	<0.00002

STATISTICAL APPENDIX

ANALYSIS OF WEEKLY SULFUR DIOXIDE EMISSION RATE AT THE TAMPA ELECTRIC COMPANY GANNON UNIT 6

Dr. A. R. Manson

A plot of Blom's normal scores versus the observed weekly SO_2 levels for 28 weeks of data showed no significant deviation of these weekly SO_2 levels from normality. A comparison with a log-normal distribution showed that weekly SO_2 levels are closer to following a normal distribution than a log-normal one, although no significant deviation exists between the degree of fit using either of the two distributions. The correlation between normal scores and SO_2 levels shows a higher correlation under the assumption of normality than under log-normality.

Report on TECO Time Series Analysis

Prepared for
Entropy Environmentalists, Inc.

by
D. A. Dickey

The data analyzed were 3-hour measurements X_t of sulfur content of coal supplied by Mr. Wallace Pitts of Entropy Environmentalists, Inc. We were interested in developing a scheme to estimate the probability that a randomly selected 3-hour measurement, daily mean, or weekly mean will exceed a specified "critical value" given a value μ for the process mean. We used the data from site 6 only.

The first step was to check the distributional properties of the 3-hour measurements. The normal plots appeared to be consistent with the assumption that the measurements are normally distributed. The mean of the site 6 measurements was $\mu = 1.8968$ with standard deviation $\hat{\sigma}_X = .1327$.

The computation of $P(X_t > C)$ for any given "critical value" C and a mean $\mu = 1.8968$ proceeds as follows:

1) Compute $Z_C = \dfrac{C - 1.8968}{.1327}$

2) Find $P(Z > Z_C)$ in the tables of the standard normal distribution.

To compute the probability that a randomly selected 3-hour measurement X_t will exceed C when the mean μ is some value other than the observed 1.8968, simply replace 1.8968 by the specified μ value in Step 1 and proceed. In this case we have assumed the standard deviation remains at the observed value .1327 regardless of the specified μ.

An alternative procedure is to assume that the coefficient of variation $\sigma_X/\bar{X} = .1327/1.8968 = .06996$ remains fixed. Then we replace 1.8968 by the specified μ and we replace .1327 by $\sigma_X = .06996\mu$.

The estimation of $P(D_t > C)$ and $P(W_t > C)$, where D_t and W_t are daily and weekly means respectively, is now discussed. We need to know the standard deviations σ_D and σ_W of the means of 8 and 56 consecutive 3-hour observations. If the 3-hour measurements X_t are not independent, the formulas $\hat{\sigma}_D = \hat{\sigma}_X/\sqrt{8}$ and $\hat{\sigma}_W = \hat{\sigma}_X/\sqrt{56}$ will *not* be appropriate. Thus our first step is to investigate the correlation structure for the site 6 observations. Autoregressive time series models with up to 4 lags were fitted to the site 6 data. Missing values in site 6 correspond to either weekends or periods in which site 5 was being loaded. Since site 5 was loaded at a different rate than site 6, it was felt that cross products ($X_t\, X_{t-2}$ for example) which were lagged across missing values (X_{t-1} corresponding to site 5) should not be used in estimating the correlation structure of the data. This still left 46 degrees of freedom in a lag 2 model and 88 in a lag 1 model. No lags beyond lag two were significant even at an $\alpha = .60$ significance level. The model chosen for the 3-hour measurements X_t was

$$(X_t-\mu) = \underset{(.1287)}{.5227}\ (X_{t-1}-\mu) + \underset{(.1192)}{.3228}\ (X_{t-2}-\mu) + e_t \ \cdots \tag{1}$$

with $\mu = 1.8968$, $\sigma_X = .1327$. Numbers in ( ) are standard errors.

The standard deviation of D_t is $\sigma_D = (\sigma_X/\sqrt{8})f_D$ where the autocorrelation correlation factor f_D is $\sum_{h=-7}^{7} 8^{-1}(8-|h|)\rho(h)$ and $\rho(h)$ is the autocorrelation function of the process (1) above. This gives $\sigma_D = .10983$. The standard deviation of W_t is $\sigma_W = (\sigma_X/\sqrt{56})f_W$

where f_W is $\sum_{h=-55}^{55} 56^{-1}(56-|h|)\rho(h)$. This gives $\sigma_W = .06376$. To calculate $P(D_t > C)$ or $P(W_t > C)$ follow the steps above replacing $\sigma_X = .1327$ by σ_D or σ_W as appropriate.

FRANCIS J. GANNON STATION

REGULATORY COMPLIANCE

PLAN

EXHIBIT XIII

Francis J. Gannon

Regulatory Compliance Plan

FRANCIS J. GANNON STATION
REGULATORY COMPLIANCE
PLAN

FRANCIS J. GANNON STATION
REGULATORY COMPLIANCE
PLAN

I. Introduction

This compliance plan has been developed to explain how Tampa Electric Company intends to demonstrate that its Gannon Station operations will be maintained in such a manner that current allowable emissions will not be increased and that Florida Ambient Air Quality Standards (AAQS) will be protected.

The current allowable sulfur dioxide emission rate for individual coal burning units at Gannon Station is 2.4 lbs. per million BTU based on a weekly composite fuel analysis. The current allowable sulfur dioxide emission rate for the entire station can be calculated at 10.6 tons per hour, also over a weekly period. Part I of the compliance plan describes how weekly generation data and weekly fuel analyses data will be used to demonstrate compliance with the existing 2.4 lbs/MMBTU and the 10.6 tons per hour limitations.

Allowable emission rates over a 24-hour averaging time are limited by ambient impacts predicted with dispersion modeling. The results of this modeling indicate that maximum emission rates for the protection of AAQS vary inversely with station load. Detailed sulfur variability statistical studies (Entropy, Inc. August 1980) indicate that compliance with a weekly limit 2.4 lbs. per million BTU assures compliance with the 24-hour AAQS up to 10,050 MMBTU per hour (about 83% station load). Part II describes how at load points above 10,050 MMBTU per hour, daily fuel analysis will be performed and examined carefully to ensure operations at appropriate levels.

II. PART I - COMPLIANCE WITH EMISSION LIMITS

The purpose of this portion of the plan is to show compliance with a 2.4 lbs. SO_2/MMBTU emission limit and a 10.6 tons SO_2/hour emission cap over a weekly averaging period and ensure compliance with Florida Ambient Air Quality standards. Inputs to this portion of the plan include weekly station generation data, station heat rate data and weekly composite fuel analysis results.

As shown graphically on Figure 1, the plant operating range to ensure compliance with existing emission limitations is dependant on weekly station load and weekly composite fuel quality (lbs. SO_2/MMBTU). Operating the plant below 8850 MMBTU/HR (73% load) on a weekly average with a 2.4 lb/MMBTU or less fuel automatically ensures compliance with both the emission limit and the emission cap. When the plant is operated above 8850 MMBTU/HR on a weekly average, the fuel quality must be below 2.4 lbs. SO_2/MMBTU. The maximum weekly average heat input for a given fuel quality can be obtained from Figure 1.

Compliance on a weekly basis will be demonstrated in the following manner. A weekly composite fuel analysis will be obtained and the SO_2 emission rate will be calculated using the percent sulfur and the heating value of the fuel in the following equation:

$$\text{lbs } SO_2 = \frac{(\text{percent sulfur}/100)(.95)(2 \text{ lb } SO_2/\text{lb S})(1{,}000{,}000 \text{ BTU/MMBTU})}{(\text{heating value - BTU/lb})}$$

The tons of SO_2/hour will be calculated from the weekly heat input. The weekly heat input is calculated from the weekly generation and the station heat rate as follows:

Heat input, MMBTU = (heat rate, MMBTU/KWH) (generation, KWH)

The tons SO_2 emitted per week will then be calculated as follows:

$$\text{tons } SO_2 = \frac{(\text{heat input, MMBTU})\ (\#SO_2/\text{MMBTU})}{2000\ \#/\text{ton}}$$

III. PART II - COMPLIANCE WITH FLORIDA AMBIENT AIR QUALITY STANDARDS

The purpose of this portion of the compliance plan is to ensure protection of the 24 hour and 3 hour Florida AAQS based on actual conditions modeled and actual load conditions.

The primary input to this part of the compliance plan is the peak load availability and forecast for the following day. If this value is less than 10,050 MMBTU/HR then the sulfur variability statistics and Part I of this plan assure protection of the AAQS and no further action need be taken.

If the projected peak load is above 10,050 MMBTU/HR (see Figure 2), then a fuel analysis of the coal to be burned the following day will be performed. When the result of this fuel analysis is obtained and the lbs SO_2 per MMBTU has been calculated, Figure 2 will be examined to find the maximum allowable operating point. The Plant Superintendent will then be notified of the maximum allowable operating point.

IV. OPERATING FIGURES

FIGURE 1

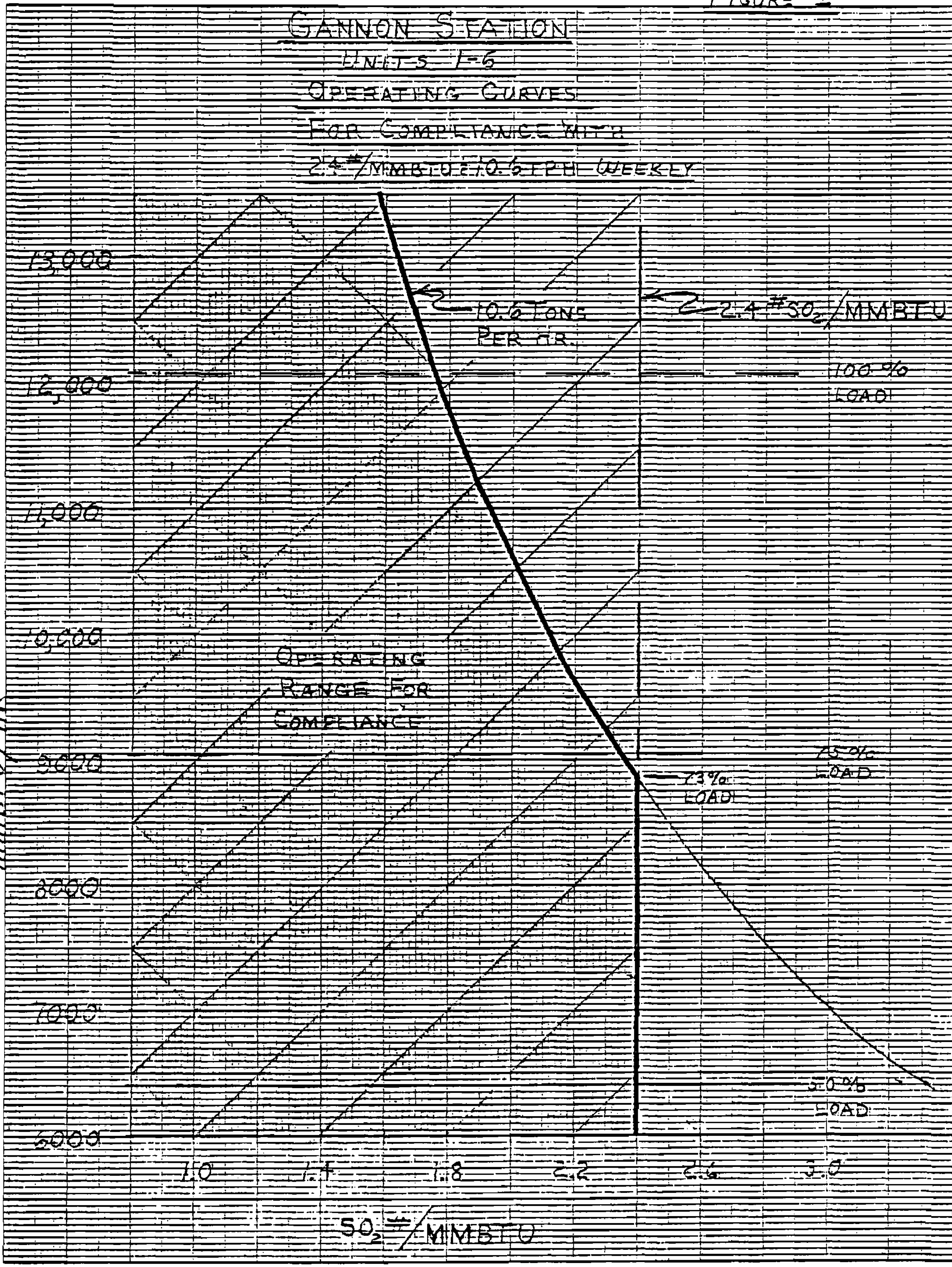
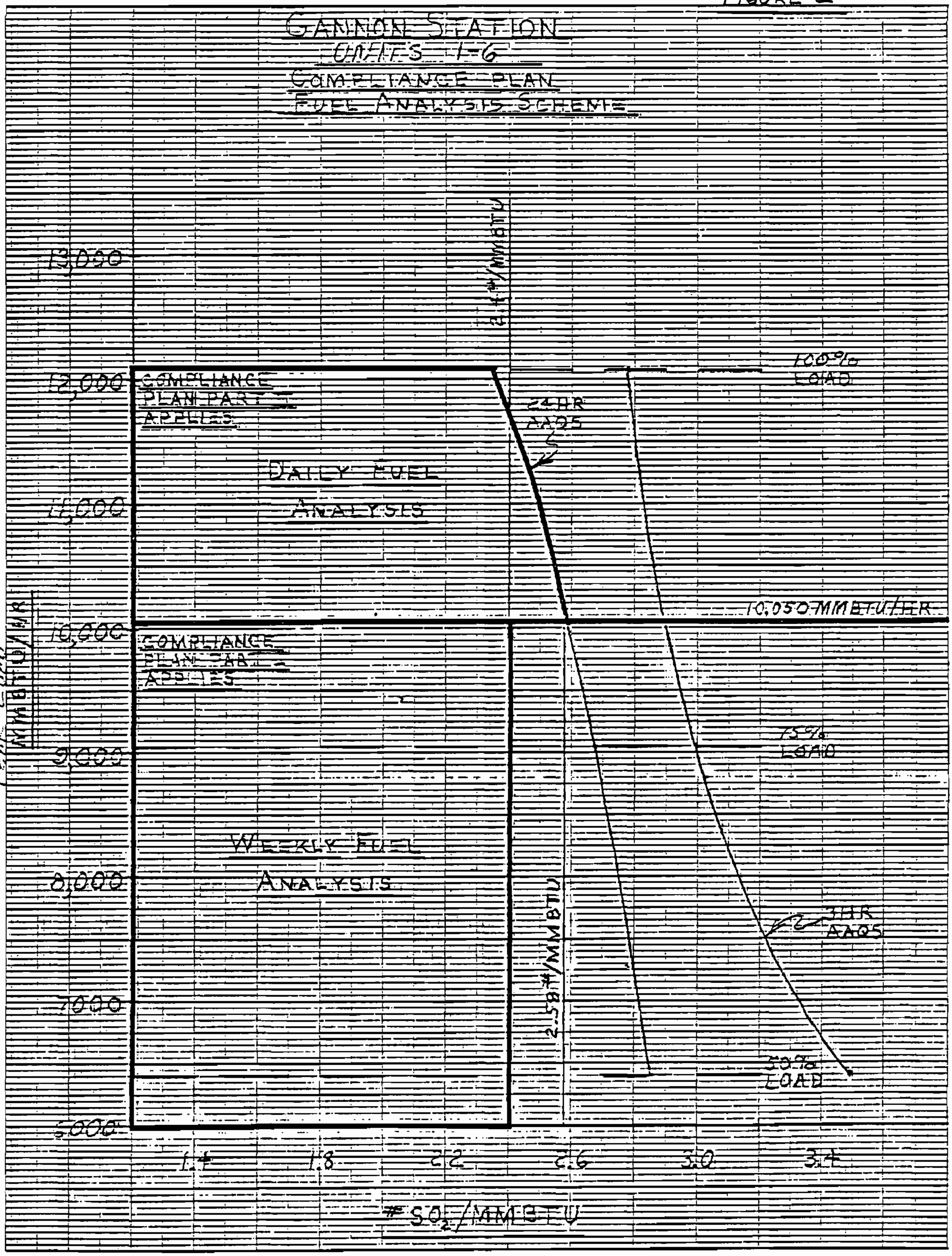

GANNON STATION
UNITS 1-6
OPERATING CURVES
FOR COMPLIANCE WITH
2.4#/MMBTU & 10.6 TPH WEEKLY
10.6 TONS PER HR.
2.4 # SO_2/MMBTU
100 % LOAD
OPERATING RANGE FOR COMPLIANCE
75 % LOAD
73 % LOAD
50 % LOAD
13,000
12,000
11,000
10,000
9000
8000
7000
6000
1.0
1.4
1.8
2.2
2.6
3.0
MMBTU/HR
SO_2 #/MMBTU

FIGURE 2


GANNON STATION
UNITS 1-6
COMPLIANCE PLAN
FUEL ANALYSIS SCHEME
13,000
12,000
11,000
10,000
9,000
8,000
7000
6000
PEAK LOAD
MMBTU/HR
COMPLIANCE PLAN PART ___ APPLIES
DAILY FUEL ANALYSIS
COMPLIANCE PLAN PART ___ APPLIES
WEEKLY FUEL ANALYSIS
2.4#/MMBTU
2.58#/MMBTU
24 HR AAQS
3 HR AAQS
100% LOAD
75% LOAD
50% LOAD
10,050 MMBTU/HR
1.4
1.8
2.2
2.6
3.0
3.4
#SO2/MMBTU

V. COMPLIANCE PLAN VERIFICATION

A. Sulfur Variability

An examination of weekly composite fuel analysis results will allow a straightforward evaluation of overall fuel quality in terms of sulfur dioxide emission rate. To provide an extra level of confidence that sulfur variability after conversion has not changed significantly from that currently observed (Entropy, Inc. August 1980), in one week (7 concurrent days) per year, daily fuel samples will be collected, analyzed, and evaluated statistically.

B. Stack Sampling

At some period in each year when daily fuel samples are being collected, a stack test for sulfur dioxide will be conducted for the purpose of comparing those stack test results to fuel analysis results.

VI. REPORTING

A. Frequency - reporting of compliance status shall be performed on a quarterly calendar basis.

B. Content - quarterly reports will consist of:

1. Weekly average emission rate in lbs/MMBTU and tons/hour of sulfur dioxide.

2. Daily emission rates and generation data for those periods necessary under Part II of the plan.

3. Results of sulfur variability testing (Part V. A) and stack sampling (Part V. B) if performed during the calendar quarter.

EXHIBIT XIV

Pedco Environmental Report -
Evaluation of Alternative Strategies
for the Reconversion of the Gannon
Steam Plan to Burn Coal

PEDCo ENVIRONMENTAL

EVALUATION OF ALTERNATIVE STRATEGIES FOR THE RECONVERSION OF THE GANNON STEAM PLANT TO BURN COAL

Prepared by

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Contract No. 68-02-2535
Task Order No. 19
PN 3280-S

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
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Region IV
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Archie Lee, Project Officer

September 1980

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SUMMARY

The Francis J. Gannon Steam Plant of Tampa Electric Company (TECO) currently has six units with a total generating capacity of 1315 MW. Units 1-4 are oil-fired units with rated capacities of 115, 125, 175, and 210 MW respectively. Units 5 and 6 are coal-fired boilers with rated generating capacities of 265 and 425 MW respectively. The average coal analysis for 1979 was 12,174 Btu/lb, 1.3 percent sulfur, 10.1 percent ash, and 7.6 percent moisture. The average oil analysis was 150,083 Btu/gal with 0.95 percent sulfur.

Electrostatic precipitators (ESPs) control particulate emissions. Units 1 and 2 have ESPs with design efficiencies of 90 percent each. ESPs on Units 3 and 4 have design efficiencies of 93 and 95.5 percent. Based on coal with 3.2 percent sulfur, Units 5 and 6 have design efficiencies of 99.78 percent. Sulfur dioxide (SO_2) emissions are presently not controlled by any flue gas cleansing system.

For 1979, total particulate emissions were 890 tons for all six boilers. This is 0.056 lb/million Btu for the yearly average. The allowable particulate emissions are 0.1 lb/million Btu. Total SO_2 emissions were 38,500 tons for 1979. This is equivalent to 2.42 lb SO_2/ million Btu. Current SO_2 regulations are 1.1 lb/million Btu for Units 1-4. Units 5 and 6 have maximum allowable rates of 2.4 lb/million Btu.

Tampa Electric Company plans to reconvert Boilers 1-4 from oil burning back to coal because of the increasing price of crude oil. TECO's plans include burning low sulfur coal and using an emission bubble cap to meet SO_2 limitations. Add-on ESPs will be installed on Units 1-4 to aid in particulate emissions.

Using low sulfur coal (1.2 percent sulfur), TECO calculates the expected emissions to be 1.73 lb SO_2/million Btu. This is slightly higher than the current limit, so TECO is requesting an overall emission cap of 10.6 ton/hr to limit SO_2 emission levels. However, with the decrease in sulfur content of the coal, the efficiency of the various ESPs also declines as a result of

increased flyash resistivity. Additional collection area is required to maintain the requisite level of collection efficiency. TECO will install additional ESPs on Units 1-4, the first being completed by mid-1983. Their retrofit plan calls for one ESP to be installed every year for four years.

The other option open to TECO is to burn high sulfur coal (3.78 percent sulfur). High sulfur coal raises the efficiency of the ESPs on Units 5 and 6 to approximately 99.9 percent. The ESPs on Units 1-4 will have an operating efficiency of approximately 90 percent. Burning high sulfur coal causes SO_2 to be emitted at higher levels than currently allowed. At present, there is no system at the plant to control the high SO_2 levels. If the switch to high sulfur coal is made, a flue gas desulfurization (FGD) system will have to be installed. This option is extremely costly because of the lack of available space and the difficulty in retrofit. With high sulfur coal, expected emissions are 6.84 lb SO_2/million Btu. An FGD system with a 77.6 percent efficiency will lower the emission rate to 1.53 lb SO_2/ million Btu. The estimated operating efficiency of a lime or limestone FGD is 85 percent or better. This lowers possible SO_2 emission levels to 1.03 lb SO_2/ million Btu or lower.

A lime or a limestone system are the most feasible FGD systems for Gannon. The major drawback, however, is the large required land area required which Gannon does not have. The lime FGD requires less room than the limestone system, but it still requires 1.3 acres for the necessary equipment. Following TECO's installation schedule, PEDCo projects lime FGD capital cost at around \$310 million, using the present ESPs for particulate control. If a Venturi scrubber is installed, the costs are near \$360 million. These costs amount to \$590/kW, \$685/kW with the venturi. Limestone FGD costs are slightly higher, running near \$320 million with ESPs and \$360 million with a venturi. These capital costs amount to \$610/kW, \$686/kW with the venturi. Annual costs for the lime FGD are \$96 million/year (46 mill/kWh) with ESPs or \$114 million/year (55 mill/kWh) with a venturi. Annual costs for a limestone FGD are \$99 million (48 mill/kWh) with existing ESPs or \$114 million (55 mill/kWh) with a venturi.

TECO prefers to use low sulfur coal in conjunction with an emission cap. This enables TECO to help reduce overall costs in switching from high priced crude oil to low cost coal. Annual savings for low sulfur coal in comparison with oil are estimated to be $8.7 million. Annual costs for FGD and high sulfur coal are estimated to be $53.7 million higher than for oil. The following table is a present worth comparison of incremental capital and annual costs relative to burning oil for the two principal TECO options:

- Convert units to low-sulfur coal, using ESPs.
- Convert units to high-sulfur coal, using FGD-ESPs.

For the low-sulfur option, capital costs are incurred to convert the units to coal and to install an ESP. For annual costs, the fuel cost differential is negative, but there are two incremental annual costs. First there is the annual cost associated with the ESP. Secondly, there are annual costs associated with the boiler conversion and with the increased O&M requirements for a coal-fired boiler. These costs have been estimated to be 25 percent of the boiler conversion costs. For the high-sulfur coal option, the cost increments fall into the same categories. In addition, there are capital and annual components for the FGD systems.

Florida has drafted a regulation to limit emissions from the Gannon coal-fired units to 2.4 lb SO_2 per million Btu heat input for each unit on a weekly average. Furthermore, combined emissions from all six boilers are not to exceed 10.6 ton SO_2/h on a weekly basis. TECO is to verify compliance by submitting weekly station generation data and weekly composite fuel quality analysis data. Compliance with 3-hour and 24-hour ambient standards is to be insured by load limiting in conjunction with daily fuel quality; details are to be specified in the station operating permit(s). This new regulation has not been promulgated, pending a public hearing in mid-October, 1980. The intent of the proposed regulation is to allow TECO to demonstrate continuing compliance to the satisfaction of the state agency at reasonable cost. The alternative to the use of routine coal analyses would be to require the installation and operation of a continuous emissions monitoring (CEM) system.

We have visited two utilities that use CEM systems extensively and we have discussed the relative problems associated with demonstration of compliance by coal analysis and by the use of CEM equipment. The following conclusions are based on our visits to these plants and on data supplied to us by the Tennessee Valley Authority (TVA).

OVERALL COST COMPARISONS RELATIVE TO PRESENT OIL-FIRING.

	Low-sulfur coal		High-sulfur Coal		
			Lime FGD	Limestone FGD	
	TECO	PEDCo	PEDCo	TECO	PEDCo
		Capital Costs ($\$ \times 10^6$)			
Boiler conversion costs	36.4	36.4	99.0	99.0	99.0
Capital FGD and ESP costs (1980)	0.0	0.0	205.4	118.4	212.2
Capital ESP costs (1980)	31.0	40.3	0.0	0.0	0.0
TOTAL	67.4	76.7	304.4	217.4	311.2
		Annual Costs ($\$ \times 10^6$)			
Annual fuel costs (1980)	--	(28.5)	(36.96)		(36.96)
Annual FGD and ESP costs (1980)	--	0.0	65.9		68.3
Annual ESP costs (1980)	--	10.7	0.0		0.0
Annual fuel conversion costs	--	9.1	24.8		24.8
TOTAL	--	(8.7)	53.74		56.14

Any system of data collection and reporting that is agreed upon between the utility and the state must report data in a form that is usable to the state and which gives strong evidence that agreed emission limits are being met so that ambient standards will not be violated. The reporting system must be simple enough that the state will not be burdened with a mountain of data to sort through; yet the utility must be able to maintain backup data for a reasonable period of time to defend any challenge that the plant may not be in compliance. By the same token, the utility needs to protect itself from a cumbersome data reduction task. TVA visually integrates 15-minute SO_2 emission averages from strip chart data; this procedure seems too expensive and cumbersome for TECO to have to adopt.

Although an underlying relationship necessarily exists between the sulfur content of coal and the SO_2 emissions from burning the coal, we were unable to correlate TVA's coal analysis data with corresponding CEM data. This may be partly because in our correlation we have not incorporated the variable lag time between loading the bunker and burning the coal. However, some question exists that the two data sets are equivalent for demonstration of compliance with emissions regulations. Whether Florida decides to require coal analysis data or CEM data to demonstrate compliance, the utility must insure that the selected method accurately reflects true SO_2 emissions.

TVA analyzes each coal sample two or three days after the coal is put into the bunker. In most cases the coal is burned about a day before the analysis is completed. Thus the analysis is of little more than historical interest and cannot be used for essentially real-time control. On the other hand CEM data are available only minutes after the coal is burned, and it is conceivable that a system could be developed to divert clean coal into a boiler quickly to bring indicated high SO_2 emissions into line with regulatory limits. However, if no such system is available to TECO, there may be little practical value in eliminating any lag time that coal analysis necessitates.

Because coal has inherent variability in quality, any strategy to comply with emissions regulations must incorporate a statistical analysis to comply with those regulations for a certain minimum percentage of the time. Any regulation that is promulgated should take this statistical variation into account and should permit a given limit to be exceeded only with limited frequency such as one day per month or three weeks per year or ten days per year. Penalties for exceeding the prescribed frequency should be indicated, and the system whereby TECO is to demonstrate continuing compliance should be described in detail.

SECTION 1

INTRODUCTION

This report summarizes the results of a study conducted by PEDCo Environmental, Inc. for the U. S. Environmental Protection Agency (EPA) under Contract No. 68-02-2535, Task No. 19, to provide technical assistance to the State of Florida Department of Environmental Regulation in regard to a petition by Tampa Electric Company (TECO) to revise the Florida State Implementation Plan to permit their Gannon power station to burn low-sulfur coal instead of oil.

TECO is seeking a regulation change from the Florida Department of Environmental Regulation so that the Gannon plant can be converted to low sulfur coal without the need for a flue gas desulfurization (FGD) system.

Our evaluation covers the subjects of low-sulfur coal conversion with electrostatic precipitator (ESP) installation, high-sulfur coal with FGD, and ESP installation, retrofit and coal conversion costs, and continuous emission monitor requirements.

SECTION 2

PLANT DESCRIPTION

The Francis J. Gannon Steam Plant, operated by Tampa Electric Company (TECO), is located four miles southeast of Tampa, Florida, on the East Shore of Hillsborough Bay. The plant has six wet bottom boilers. Boilers 1, 2, 3, and 4, originally coal fired, are Babcock and Wilcox cyclone fired boilers that now use low sulfur No. 6 fuel oil (0.95 percent sulfur average for 1979). Boilers 5 and 6 are Riley pulverized coal turbo-fired boilers with flyash reinjection, that use low sulfur coal (1.3 percent sulfur and 10.1 percent ash averages for 1979) as fuel. All six boilers have electrostatic precipitators (ESPs) to control particulate emissions.

The plant is presently considering plans to reconvert Boilers 1, 2, 3, and 4 from oil back to coal. The addition of add-on ESPs are included in these plans to help control particulate emissions. TECO plans to start the conversion of Boiler 4 by 1983. Following the completion of Boiler 4, Boilers 1, 3, and 2, will be converted in order, with one unit outage per year including six months for ESP tie-in.

The Gannon Plant has performed several studies of the feasibility to convert the oil-fired boilers to coal, including economic evaluations comparing the costs of oil-fired and coal-fired boilers. Comparisons between the costs of low sulfur coal and high sulfur coal have also been projected. These comparisons are being used in the consideration of the various emission control systems required. Low sulfur coal will not produce great amounts of SO_2 (1.73 lb/million Btu) and only add-on ESPs will be needed to control particulate emissions. If high sulfur coal is fired, a new FGD system will be needed to control excessive SO_2 emissions (6.84 lb/million Btu). Either a venturi scrubber or an ESP will be required for particulate control. Boiler design and operating data are listed in Table 2-1. Appendix A is TECO's May 1980 Power Plant Survey Form.

TABLE 2-1. POWER GENERATING UNIT DESIGN AND OPERATING DATA FOR F. J. GANNON PLANT.

Boiler data		Boiler number 1	2	3	4	5	6
Generating capacity		115	125	175	210	265	425
Hours of operation (1979)		5,278	6,416	5,448	5,369	6,630	6,554
Average capacity factor (1979)		48	48	44	42	59	65
Served by stack number		1	2	3	4(a),4(b)	5	6
Boiler manufacturer		B&W	B&W	B&W	B&W	Riley	Riley
Year placed in service		1957	1958	1960	1963	1965	1967
Max. oil consumption (bbl/h)		255	255	344	409	none	none
Max. coal consumption (ton/h)		49.7	49.7	64.9	71.3	93.4	151.4
Max. heat input (million/Btu/h)		1,257	1,257	1,579	1,876	2,284	3,790
Stack height (ft. above grade)		306	306	306	306	306	306
Flue gas rate - max. (acfm)		500,000	500,000	615,000	700,000	681,000	1,120,000
Flue gas temperature (°F)		309	309	266	286	288	292
Emission controls		ESP	ESP	ESP	ESP	ESP	ESP
Emission rates							
Particulates	(lb/million Btu)	0.04	0.04	0.03	0.07	0.004	0.02
	(lb/h) max.	50	50	48	131	10	76
SO_2	(lb/million Btu)	1.03	1.06	0.96	1.10	1.43	1.9
	(lb/h) max.	1,295	1,332	1,535	2,064	3,267	7,330

SECTION 3

FUEL CHARACTERISTICS

The Gannon Plant originally used West Kentucky coal to fire the boilers. As this coal became unavailable, the plant switched to East Kentucky coal. The boilers require an ash content of at least five or six percent to coat the inside of the cyclone burners. Australian and African coal were tried, but difficulties proved them uneconomical.

Presently, the plant has a long-term contract for the import of Polish coal. TECO also owns Cal-Glo mines, which has an estimated 60 million tons in reserve at about 1.9 lb SO_2/million Btu. Low sulfur Polish coal leads to poor ESP performance, so a mixture of Polish and East or West Kentucky coal is used. TECO maintains a stockpile of West Kentucky coal in Louisiana which is readily available by barge.

For 1979, Boilers 5 and 6 used a mixture of coal with a net heating value of 12,174 Btu/lb. On the average, the coal has 10.1 percent ash, 1.3% sulfur, and a 7.6 percent moisture. The average equivalent SO_2 content of this coal was 2.1 lb SO_2 per million Btu. These boilers operate at approximately 88.8 percent efficiency each, with heat inputs of 2691 and 4361 million Btu/h respectively. Fuel sources and analyses for the Gannon boilers are shown in Table 3-1.

TABLE 3-1. FUEL SOURCES OF THE F. J. GANNON PLANT.

COAL (1979)

Quantity (1000 tons)	Source (coal districts)	Supplier
841	8	Cal-Glo Coal Inc.
127	8	Blue Gem Coal and Land Company
26	13	Mineral Land and Mining Company
22	8	Diversified Fuels
14	13	Brilliant Company
111	--	Coal Age (Foreign Supplier, Poland)

AVERAGE COAL ANALYSIS FOR 1979

Btu/lb	% Sulfur	% Ash	% Moisture
12,174	1.3	10.1	7.6

OIL (1979)

3,466,000 bbl 0.95% S 150,083 Btu/gal Western Fuels (Tampa, Florida)

SECTION 4
EMISSIONS AND ALLOWABLE EMISSION RATES

Presently, the Gannon Plant is meeting the emission limitations set by law. Based on 1979 stack test results, particulate emissions for all six boilers did not exceed the 0.1 lb/million Btu limit. SO_2 emissions for Boilers No. 1 through 4 did not exceed the 1.1 lb/million Btu limit, and emissions from Boilers 5 and 6 are within the 2.4 lb SO_2/million Btu limit. Mass emission rates for each stack are found in Appendix A. In the future, TECO requests that a bubble limit for emission control be used. This would limit the overall plant emission rate to 10.6 ton/h. TECO predicts that the plant can limit the load on all six boilers and burn coal with an equivalent SO_2 content of less than 2.4 lb/million Btu to meet the proposed 10.6 ton/h regulation. Present and predicted emission rates for Units 1-6 are shown in Table 4-1. We have estimated that the existing ESPs on Units 1-4 would have a collection efficiency of 50 percent on low sulfur coal.

TABLE 4-1. PARTICULATE AND SULFUR DIOXIDE EMISSIONS FROM THE F. J. GANNON POWER PLANT.

Boiler no.	Actual collection efficiency ESP	Particulate Emissions: Actual rate lb/10^6 Btu	Particulate Emissions: Actual rate lb/h	Particulate Emissions: Allowable rate lb/10^6 Btu	Particulate Emissions: Allowable rate lb/h	Sulfur Dioxide Emissions: Actual rate lb/10^6 Btu	Sulfur Dioxide Emissions: Actual rate lb/h	Sulfur Dioxide Emissions: Allowable rate lb/10^6 Btu	Sulfur Dioxide Emissions: Allowable rate lb/h
1[a]	86.0	0.04	50	0.1	112	1.03	1,295	1.1	1,240
2[a]	91.0	0.04	50	0.1	112	1.06	1,332	1.1	1,240
3[a]	85.0	0.03	48	0.1	147	0.96	1,535	1.1	1,610
4[a]	80.0	0.07	131	0.1	161	1.10	2,064	1.1	1,770
5[b]	99.8	0.004	9	0.1	211	1.43	3,267	2.4	5,171
6[b]	99.8	0.02	76	0.1	342	1.90	7,330	2.4	8,582
1[c]	88.0	0.1	948	0.1	112	1.9	2,388	1.1	1,240
2[c]	88.0	0.1	725	0.1	112	1.9	2,388	1.1	1,240
3[c]	88.0	0.1	1,909	0.1	147	1.9	3,038	1.1	1,610
4[c]	88.0	0.1	2,986	0.1	161	1.9	3,564	1.1	1,770
5[c]	99.8	0.004	9	0.1	211	1.9	4,339	2.4	5,171
6[c]	99.8	0.02	76	0.1	342	1.9	7,202	2.4	8,582
1[d]	88.0	0.1	294	0.1	112	1.1	1,382	1.1	1,240
2[d]	88.0	0.1	121	0.1	112	1.1	1,382	1.1	1,240
3[d]	88.0	0.1	636	0.1	147	1.1	1,729	1.1	1,610
4[d]	88.0	0.1	1,279	0.1	161	1.1	2,063	1.1	1,770
5[d]	99.8	0.004	9	0.1	211	1.9	4,339	2.4	5,171
6[d]	99.8	0.02	76	0.1	342	1.9	7,202	2.4	8,582

[a]Present oil fired boiler.

[b]Present coal fired boiler.

[c]Predicted low sulfur coal fired.

[d]Predicted high sulfur coal fired with FGD.

SECTION 5

FEASIBILITY OF USING ELECTROSTATIC PRECIPITATORS AND LOW-SULFUR COAL

TECO has studied the feasibility of emissions control systems at Gannon using ESPs, FGD systems, venturi scrubbers, or a combination of these to control overall emissions. The current SO_2 emission regulations are 1.1 lb SO_2 per million Btu for Units 1 through 4, and 2.4 lb SO_2/million Btu for Units 5 and 6. TECO plans to use low sulfur coal (1.2 percent sulfur) to fire all six boilers. However, SO_2 emissions are expected to be 1.73 lb SO_2/million Btu. ESP's will be used to control particulate emissions. If high sulfur coal (3.78 percent sulfur) is used, the estimated uncontrolled emission rate is 6.84 lb SO_2/million Btu. Using a 77.6 percent efficient FGD system, emissions will be reduced to 1.53 lb SO_2/million Btu. To comply with current SO_2 regulations via low-sulfur coal, a coal with 0.62 percent sulfur must be used. TECO indicates that a source of such coal has been located in Utah, and that no problems are anticipated in its availability. This coal was not evaluated in this study because of its high cost. However, with low sulfur coal there would be a decrease in the SO_2 content of the resulting flue gas stream and a corresponding decrease in ESP collection efficiency, but even if high sulfur coal were used, the collection efficiency would be inadequate to meet current regulations. Therefore, an FGD system and particulate control system will have to be installed to control emission levels.

ESP SYSTEM

Electrostatic precipitators are used to remove particulates from flue gases. In ESP operation, a system of alternate parallel banks of ionizing wires and collection plates form a high voltage corona. This corona causes the gas molecules to form ions. The ionized gas molecules collide with and charge the dust particles in the flue gas stream. The charged particles migrate towards oppositely charged plates where they adhere and agglomerate.

SECTION 6

FEASIBILITY OF FGD SYSTEMS AT GANNON

The option of using FGD systems at Gannon has been studied by both TECO and PEDCo. Cost estimates have been prepared for the installation of lime and limestone FGD systems in conjunction with new ESPs for the boilers. PEDCo has also estimated costs for the addition of venturi scrubbers to the FGD system in lieu of ESPs. A 77.6 percent efficient FGD system is required to control the SO_2 emissions. Lime and limestone FGD system each have an estimated operating efficiency of 85 percent.

Some of the physical parameters of the lime and limestone FGD systems include scrubber train modules sized in pairs to handle the flue gases from each boiler at its rated capacity with a third module as a spare. For Boiler No. 4, three operating modules and a spare are used. The lime or limestone feed will be 1.3 times stoichiometric requirements. The design SO_2 inlet concentration is 6.84 lb SO_2/million Btu using 3.78 percent sulfur coal. Feeders and conveyors are sized to handle 4.6 times the maximum lime or limestone required. In the absorber, the liquid to gas rate is 40 gallons/1000 standard cubic feet for lime, and 65 gallons/1000 standard cubic feet for limestone. Slurry concentration is 8 percent by weight for either lime or limestone. The flue gas pressure is atmosphere. The total pressure drop through the FGD system will be 15 inches H_2O for Boilers 1 through 4. The flue gas temperatures for the four boilers are: 309°F for Nos. 1 and 2, 266°F for No. 3, and 286°F for No. 4. The flue gas reheater will use low pressure steam for indirect heat exchange. Scrubbed gases at 125°F are reheated to a temperature of 175°F. The clarifiers are sized at 15 square feet of surface area per ton of dry solids removed per day.

PEDCo's estimated FGD costs are shown in Tables 6-1 through 6-4. Lime and limestone costs for FGD-ESP systems are shown in Table 6-1. Present worth capital investment is estimated to be $205 million or $391/kW. Annual costs

TABLE 6-1. COSTS OF FGD WITH ESP FOR GANNON BOILER NO. 1 THROUGH 4.

	Lime FGD				Limestone FGD			
	Capital cost		Annual cost		Capital cost		Annual cost	
Schedule	$\$x10^6$	$/kW	$\$x10^6$	Mills/kWh	$\$x10^6$	$/kW	$\$x10^6$	Mills/kWh
1980	205	391	66	32	212	404	68	33
PEDCo FGD schedule	251	479	79	38	260	495	82	40
TECO FGD schedule	310	590	96	46	320	610	99	48
1990	423	806	135	65	437	833	140	68

TABLE 6-2. COSTS OF FGD WITH VENTURI FOR GANNON BOILERS NO. 1 THROUGH 4.

	Lime FGD				Limestone FGD			
	Capital cost		Annual cost		Capital cost		Annual cost	
Basis	$\$x10^6$	$/kW	$\$x10^6$	Mills/kWh	$\$x10^6$	$/kW	$\$x10^6$	Mills/kWh
1980	238	454	77	37	239	455	78	38
PEDCo FGD schedule	292	556	93	45	292	556	94	45
TECO FGD schedule	360	685	114	55	360	686	114	55
1990	491	935	158	76	491	936	159	77

TABLE 6-3. COMPARISON OF FGD TOTAL CAPITAL INVESTMENT FOR GANNON BOILER NO. 1 THROUGH 4.

	Lime				Limestone				ESP	
	With ESP		With venturi		With ESP		With venturi			
Basis	$\$x10^6$	$/kW	$\$x10^6$	$/kW	$\$x10^6$	$/kW	$\$x10^6$	$/kW	$\$x10^6$	$/kW
1980	205	391	238	454	212	404	239	455		
PEDCo FGD schedule	251	479	292	556	260	495	292	556	49	94
TECO FGD schedule	310	590	360	685	320	610	360	686		
1990	423	806	491	935	437	833	491	936		

TABLE 6-4. COMPARISON OF FGD ANNUAL COSTS FOR GANNON BOILERS NO. 1 THROUGH 4.

	Lime				Limestone				ESP	
	With ESP		With venturi		With ESP		With venturi			
Basis	$\$x10^6$	$/kW	$\$x10^6$	$/kW	$\$x10^6$	$/kW	$\$x10^6$	$/kW	$\$x10^6$	$/kW
1980	66	32	77	37	68	33	78	38		
PEDCo FGD schedule	79	38	93	45	82	40	94	45	13	6
TECO FGD schedule	96	46	114	55	99	48	114	55		
1990	135	65	158	77	140	68	159	77		

are $66 million or 32 mills/kwh. These costs are very high as a result of extremely high flue gas volumes, spare modules, and the difficulty of retrofit. Using TECO's suggested installation schedule, capital investment increases to $310 million and annual costs are $96 million. Table 6-2 shows corresponding costs for FGD-venturi systems. Capital costs are about 15 percent higher than for the FGD-ESP systems. Annual costs are higher by about the same percentage.

Tables 6-3 and 6-4 present the same data in a slightly different format and also show the costs of installing an ESP to be used in conjunction with low sulfur coal by comparison. The capital investment for the ESP is only 15 to 20 percent of that for an FGD system, and the annual cost is about the same percentage.

FGD INSTALLATION REQUIREMENTS

For estimating purposes we have indicated that this FGD installation would be an extremely difficult retrofit. There is essentially no spare land in the vicinity of the Gannon Plant. Our computer program has indicated that area requirements for a limestone system are about 2.1 acres, and for a lime system, the required area would be about 1.3 acres (Table 6-5). In addition, an area of about two acres would be required for an emergency gypsum stock-out pile. There is no single open area at the plant where a two-acre FGD system can be built. One possibility is that the FGD system could be built on part of the area where the existing coal pile is located. Obviously, this is not very satisfactory because the area for stockpiling of coal is already insufficient. The coal displaced by the FGD system would have to be located at another site. One possibility might be to stockpile the coal at the Big Bend plant. The Big Bend plant is located only 15 miles from the Gannon plant, so there would not be a serious time delay if a supply of coal were needed. Another alternative is that a site closer to the plant could be leased by TECO for stockpiling the additional coal. We have not worked out any transportation costs for transfer of the coal from a selected site to the plant, nor have we considered any additional leasing costs if a site near the plant is used for stockpiling coal.

TABLE 6-5. AREA REQUIREMENTS OF FGD EXCLUDING VENTURI FOR GANNON BOILERS NO. 1 THROUGH 4.

	Lime (sq. ft.)	Limestone (sq. ft.)
Feed preparation		
Lime silos	1,600	0
Slakers	400	0
Storage pile	0	33,000
Grinding mills	0	200
Feed tanks	400	900
Total	2,400	34,100
Scrubbing		
Scrubbing trains	43,200	43,200
Fans and misc.	4,320	4,320
Total	47,520	47,520
Sludge handling and disposal		
Effluent tanks	100	100
Clarifiers	6,600	9,800
Vacuum filters and misc.	100	100
Total	6,800	10,000
Grand Total	56,720 (1.3 acres)	91,620 (2.1 acres)

LIME FGD SYSTEM DESCRIPTION

In a lime FGD process, lime slurry is prepared on-site for use in an absorber. Lime is slaked with water to form the slurry, using handling and conveying equipment, lime storage silos, slakers, and slurry storage tanks. The boiler flue gas initially enters an ESP or a venturi scrubber to remove particulates. Booster fans are used to overcome FGD system pressure drops. The flue gas enters the absorber at the base, and is cooled by quenching with water. The flue gas ascends and reacts with the lime slurry to form $CaSO_3$ and $CaSO_4$. The desulfurized gas passes through a demister and is then reheated before it is released to the atmosphere. The slurry passes from the absorber to a circulation tank where it is sparged with air and to precipitate $CaSO_4$ (gypsum). The liquid stream continues to a clarifier where the precipitate, any flyash, and unreacted lime settle out. The clean water from the clarifier is then returned to the circulation tank. The underflow from the clarifier is processed through a vacuum filter to recover gypsum which we have assumed to be salable at a price to offset the cost of removing it from the site. The estimated SO_2 removal efficiency for a lime system is 85 percent or better. A typical lime system is shown in Figure 6-1.

LIME FGD COSTS

PEDCo and TECO have both estimated FGD costs for the Gannon boilers. TECO has calculated that the actual conversion of Boilers No. 1-4 from oil to low-sulfur coal firing will cost approximately $36.4 million; their estimated cost for a new FGD system totals $118.4 million. The total cost of new precipitators will be $31.0 million. This brings the overall cost of the FGD-ESP system to $149.4 million. Adding the cost of the boiler conversions, TECO projects a grand total of $186.0 million to convert and modify Boilers 1-4. All of these costs have been adjusted by PEDCo to mid-1980 dollars. PEDCo's total estimated cost for a lime FGD system with a venturi scrubber is $360 million, not including coal conversion costs. With an ESP instead of a venturi, our cost is $310 million. Adding in TECO's coal conversion cost of $36.4 million, PEDCo estimates a grand total of $346.4 million. Annual costs for the lime FGD and venturi are estimated around $114 million; annual costs for the FGD-ESP system will be approximately $96 million per year. These

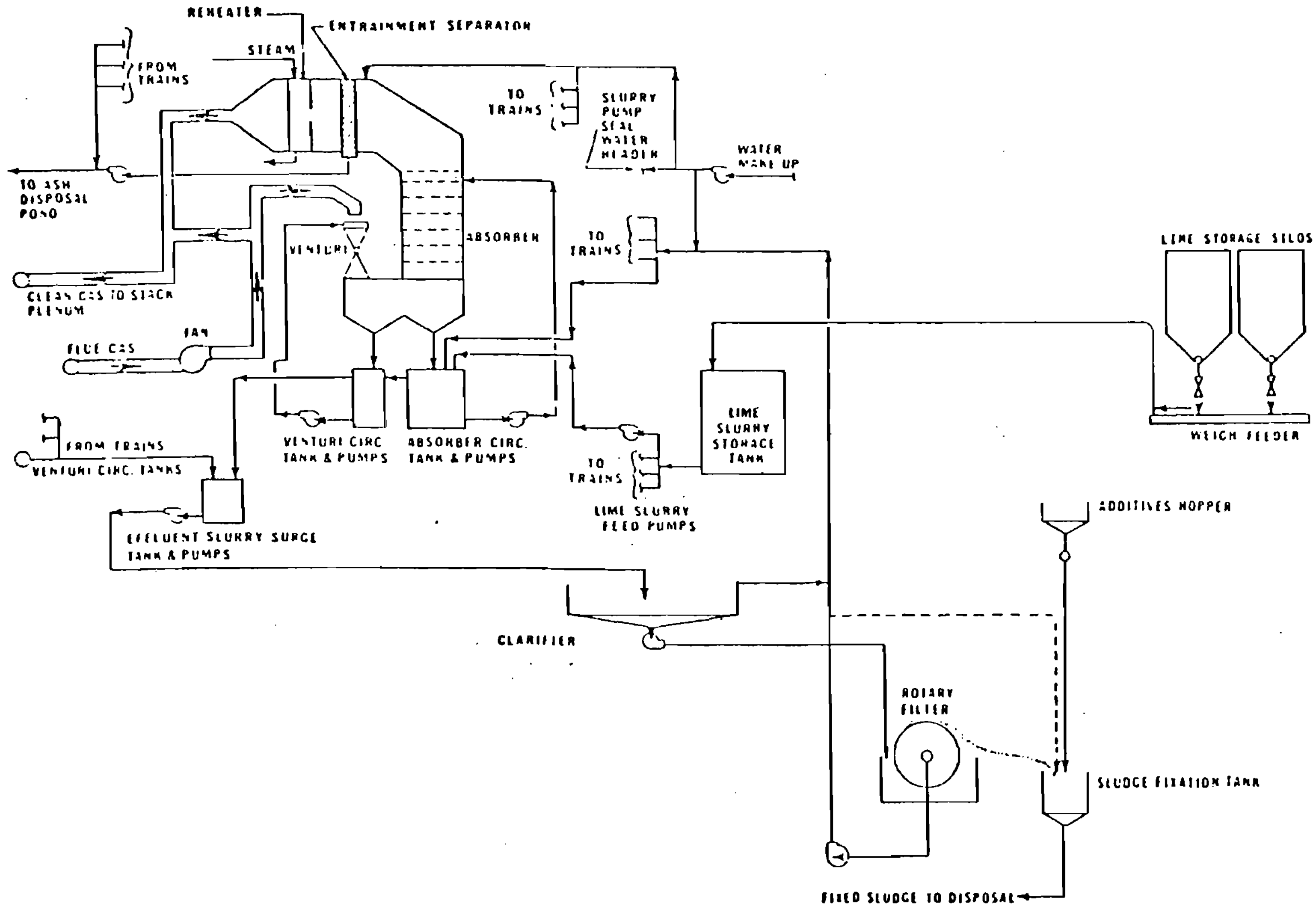


Figure 6-1. Lime slurry system.

PEDCo cost estimates do not include reconversion of the boilers so that they can fire coal.

LIME FGD ADVANTAGES AND DISADVANTAGES

In the lime FGD gypsum process, several storage areas are necessary. Lime storage silos are needed for a 12-day continuous supply of lime. Operating silos are needed which can hold an additional three-day supply of lime. Storage tanks, with 24-hour storage capacity, are needed to hold the prepared slurry, which includes a fresh supply and make-up slurry for the system. An effluent hold tank with a five-minute retention time is required to hold the spent liquor from the absorber, and a permanent site is required for storage of the gypsum.

Lime FGD system is usually at least 85 percent efficient at removing SO_2 from flue gases. Costs are also usually lower and space requirements are less than those for a limestone FGD system. However, a lime system still has large space constraints for the necessary equipment (such as the storage vessels and absorber). The absorber also requires expensive alloys to prevent corrosion of the system.

LIMESTONE FGD

The limestone FGD process is similar to that for lime. Limestone slurry is used as the SO_2 absorbant. Limestone is wet milled to produce a fine slurry in which 95 percent of the particles are smaller than 325 mesh. This process requires an open limestone storage area, handling and conveying equipment, limestone storage silos, wet ball mills, and a slurry storage tank. The SO_2 removal process is identical to the lime process. The flue gas passes through an ESP or a venturi scrubber to remove particulates and continues to the absorber where the SO_2 reacts with the slurry to form $CaSO_3$ and $CaSO_4$. The flue gas is reheated and released to the atmosphere. The slurry passes from the absorber to a circulation tank where it is sparged with air to oxidize $CaSO_3$ to $CaSO_4$ (gypsum) which is precipitated. The liquid stream continues to a clarifier where the precipitate, flyash, and unreacted lime, are settled out. The clean water from the clarifier is then returned to the circulation tank. The underflow from the clarifier is processed through a vacuum filter to recover gypsum which is assumed to be salable at a piece to offset the cost of removing it from the site. The estimated SO_2 removal efficiency for a limestone system is 85 percent or better. A typical limestone system is shown in Figure 6-2.

LIMESTONE FGD COSTS

The capital costs for a limestone FGD system are somewhat higher than for a lime FGD system. PEDCo projects the costs for the entire system (FGD plus venturi) to be $360 million, while the costs for an FGD-ESP system run approximately $320 million, which is three percent higher than for the lime system. Annual costs with a venturi are somewhat less for a limestone system at $114 million. With an ESP, limestone annual costs are estimated to be $99 million, which are three percent higher than for a lime FGD system.

LIMESTONE FGD ADVANTAGES AND DISADVANTAGES

A limestone FGD process requires a larger overall storage area than a lime system. An open storage area with a 30-day supply of limestone is required, as well as storage silos to hold a 12-day supply of limestone and operating silos to hold a three-day supply. Slurry storage tanks with a 24-hour storage capacity are needed for the fresh limestone slurry for the system. An effluent hold tank with a five-minute retention time, is required to hold the spent liquor from the absorber.

A limestone FGD system, like the lime process, is usually 85 percent efficient or better for SO_2 removal. If venturi scrubbers are used, the costs are somewhat lower than those of a lime FGD system. However, the limestone system requires somewhat more space than a lime system mainly because of additional equipment (such as the ball mills and the 30-day open storage area).

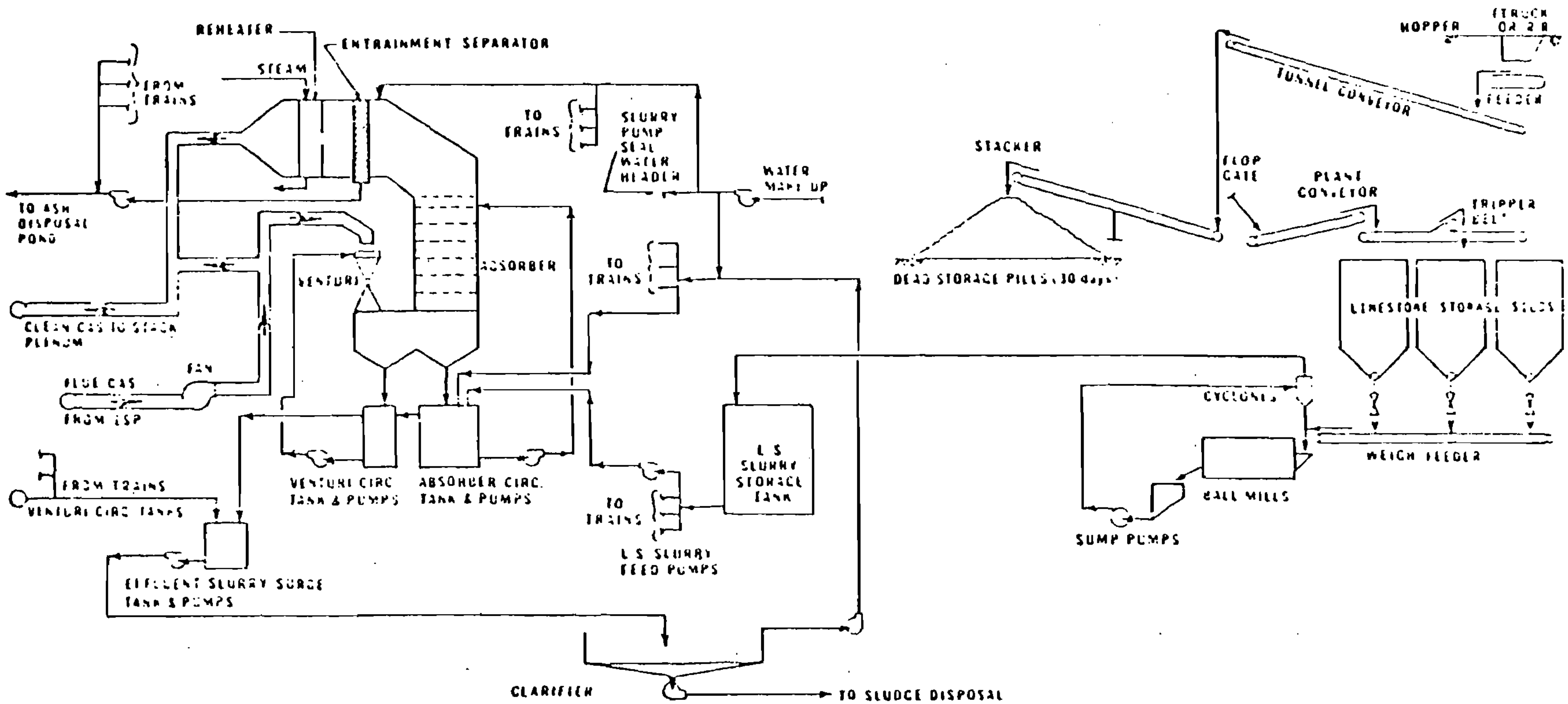


Figure 6-2. Limestone slurry system.

SECTION 7

VENTURI SCRUBBERS WITH ABSORBERS

Another option which we considered is that of using venturi scrubbers in combination with the FGD system. Venturi scrubbers use water spray to trap dust particles for removal from gas streams. The venturi precede the absorbers so that the particulates are removed before the flue gas enters the absorbers. In a venturi scrubber flue gases pass through a venturi at a velocity of 15,000 to 20,000 ft/min, and low-pressure water is added at the throat. The gas pressure drop through the venturi ranges from 10 to about 30 in. H_2O depending on design. The extreme turbulence in the venturi promotes very complete particle-water contact in spite of a relatively short contact time. The dust particle-impregnated water droplets and are collected in a cyclone spray separator. The flue gases then passes to the lime or limestone absorber for SO_2 removal. Generally, we have assumed three absorber modules per boiler, two in operation at full load and one serving as a standby unit. Boiler No. 4 will have four modules, including one standby unit.

PEDCo has determined that using a lime FGD system the capital costs for installing venturis for Boilers 1 through 4 will be around $238 million, with annual operating costs of around $77 million. For a limestone FGD system, capital costs are approximately $239 million, with annual operating costs of $78 million.

PEDCo has also investigated the use of scrubbers on Boilers 3 and 4 alone. If the bubble limit for SO_2 emissions is used, it may be feasible to control Boilers 3 and 4 and to curtail loads on Units 1 and 2 severely to bring the station under the 10.6 ton SO_2/h limit that TECO is requesting. If a lime system with a venturi were used on Boilers 3 and 4, capital costs would be about $126 million and annual operating costs would be $41 million. If the existing ESPs are used instead of venturis, the capital costs fall to $119 million with annual operating costs of $39 million.

SECTION 8

LOW-SULFUR COAL

The success of TECO's proposed strategy to meet a bubble limit of 10.6 tons per hour depends only on three factors: the interpretation of the regulation for enforcement, the quality of the coal, and the station load at the Gannon Plant.

ENFORCEMENT ASPECTS

The bubble limit must be enforced on the basis of some prescribed averaging time. In theory the regulatory agency might require Gannon to show that the emission limit is met during each hour of operation or that the limit is not exceeded for more than a certain number of hours in each week, month, or year. TECO could construct a data handling system to demonstrate compliance on that basis, but a one-hour regulatory time frame would be difficult for TECO to react to. For example, if the station load were such that a one-hour violation occurred and if the SO_2 monitoring system flagged the violation immediately, it might be several hours before TECO could shift the load to another station or purge the bunkers to begin feeding cleaner coal that would bring the unit back within limits. Thus, although one-hour readings might be useful for TECO to maintain emissions within bounds, the reporting of hourly readings might tend to overwhelm the regulatory agency with data that would never be used.

The question that needs to be answered is whether the regulatory agency would tolerate a few excursions above the hourly standard in a given day, enforcing only against emissions that exceed a prescribed limit on a longer time base such as 24 hours. This seems more reasonable than the prospect of creating multiple violations in one episode merely because sophisticated monitoring machinery can be put in place to measure such violations.

A multi-tiered regulation may be in order. For example, it may be appropriate to restrict Gannon to a limit of 254 tons of SO_2 in a calendar day, not to be exceeded more than 4 days per year (1% of the time). Such a regulation might be enforced on the basis of reports submitted by TECO to the state on a weekly or monthly basis in which cumulative daily exceedances would be reported for the calendar year. In addition to the daily limit it might be appropriate to set an hourly limit somewhat greater than 10.6 tons to insure that Gannon would not overload the atmosphere for short periods. For example, the hourly limit might be set at 120 percent of the product of TECO's indicated maximum station heat input and the mean coal equivalent SO_2 content, i.e. 13.7 tons/hr (1.20×1.9 lb $SO_2/10^6$ Btu $\times 12 \times 10^9$ Btu/hr $\div$ 2000 lb/ton). Thus TECO could not operate at full load with inferior coal for short periods in anticipation that the load would not be sustained throughout the day. Any exceedance or multiple exceedance of this limit in a given day would have to be reported and would constitute a daily violation, chargeable against the four allowable daily exceedances per year. The fifth exceedance in a calendar year would constitute a violation, punishable by prescribed fine.

COAL QUALITY

Coal's variability must be accommodated in a pollution control strategy and should be considered carefully in the formulation of an enforceable regulation. If a coal supply has an average equivalent SO_2 emission content of 1.9 lb per million Btu, then at any given instant a portion of that coal, upon combustion will produce more or less than 1.9 lb SO_2 per million Btu. If an emission limit is set at 1.9, the coal will comply about half the time on any averaging-time basis. To insure compliance with the regulation for more than 50 percent of the time it would be necessary to burn coal with a somewhat lower equivalent SO_2 content than 1.9. As the required percentage of time in compliance is increased beyond 50 percent, the equivalent SO_2 content of the coal must be decreased. As the coal variability increases, the margin between the regulatory limit and the mean coal equivalent SO_2 content must also be increased.

The plates are periodically rapped to dislodge the dust particles which then fall into collecting hoppers.

A strong advantage of ESPs is their overall collection efficiency. The design efficiency can be better than 99 percent. However, the sulfur content of coal directly affects the efficiency of flyash removal. A coal with low sulfur content has a poor collection efficiency because of the increased electrical resistivity of the flyash particles. Therefore, with low sulfur coal, larger collection plates are required. Figures 5-1 and 5-2 illustrate the effects of sulfur content on fly ash resistivity and migration velocity. High sulfur coal lowers the resistivity of the flyash and increases the operating efficiency. The existing Gannon ESPs have an estimated 80 to 90 percent flyash collection efficiency. If the conversion is made to low sulfur coal, the efficiencies of the ESPs are expected to drop to less than 75 percent. New ESPs were added to Boilers 5 and 6 to increase design efficiency to 99.7 percent using 3.2 percent sulfur coal, but a switch to low sulfur coal will reduce the efficiency of these ESPs and necessitate the installation of a flue gas conditioning system to meet the particulate regulation of 0.1 lb per million Btu. TECO plans to install add-on precipitators on Gannon Units 1-4.

To compensate for the decline in ESP efficiency with the decline in the sulfur content of the coal, the physical size of an ESP must be increased. We have estimated that an additional ESP specific collection area (SCA) of 580 ft^2 will be required. Capital costs for installing new ESPs on Boilers 1 through 4, will be approximately $40.3 million. Annual operating costs will be approximately $10.7 million per year for all four units.

<u>Low-Sulfur Coal Schedules</u>

TECO has proposed to install ESPs on Boilers 1 through 4, bringing the first unit on line in mid-1983 and an additional unit each year thereafter. This closely corresponds to the PEDCo FGD schedule and is used interchangeably in this report. However, we feel that TECO could expedite the schedule and bring one ESP unit on line every six months after the first one to save additional oil and to avoid some inflation.

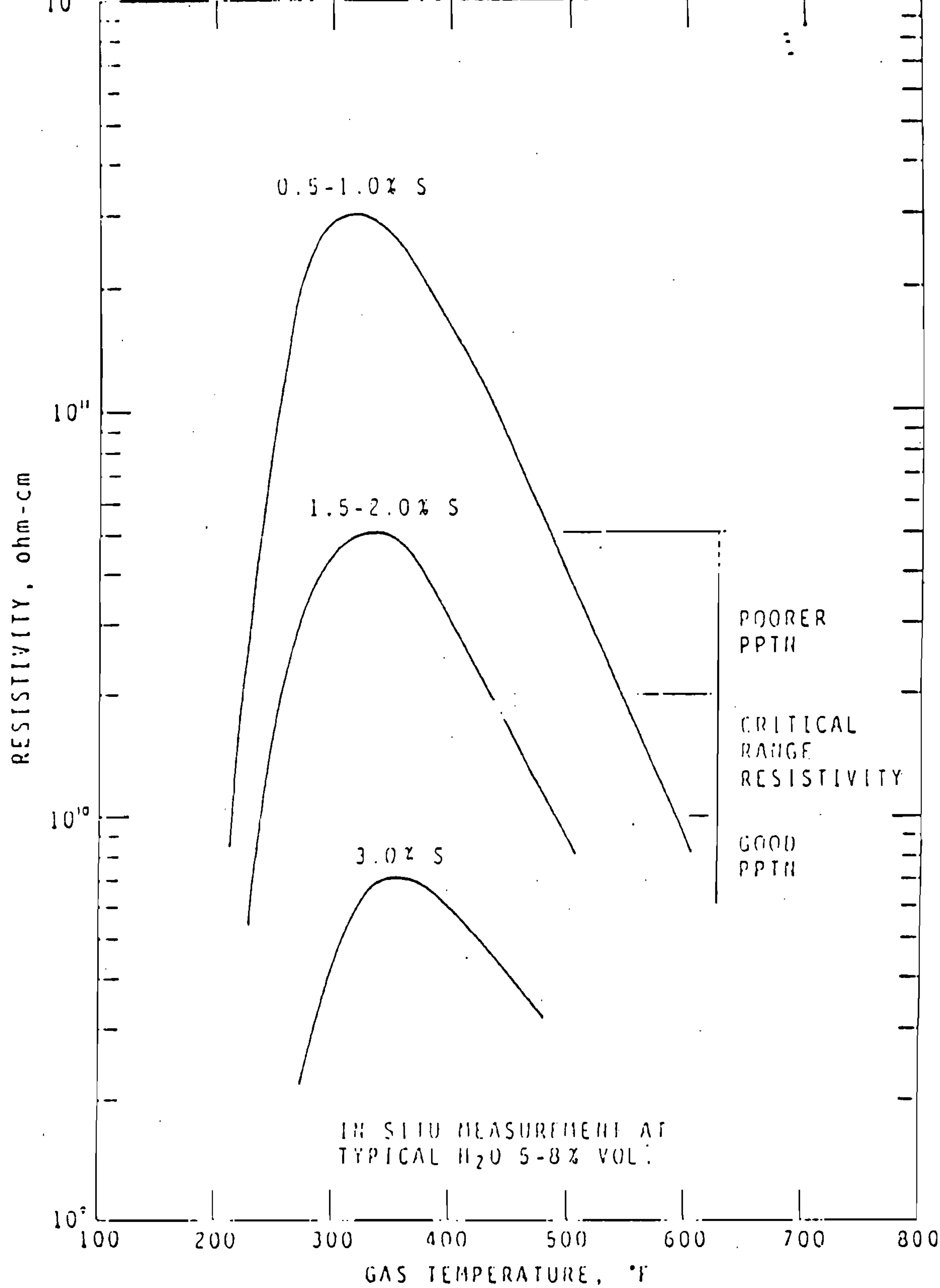


Figure 5-1. Effect of sulfur content and temperature on fly ash resistivity.

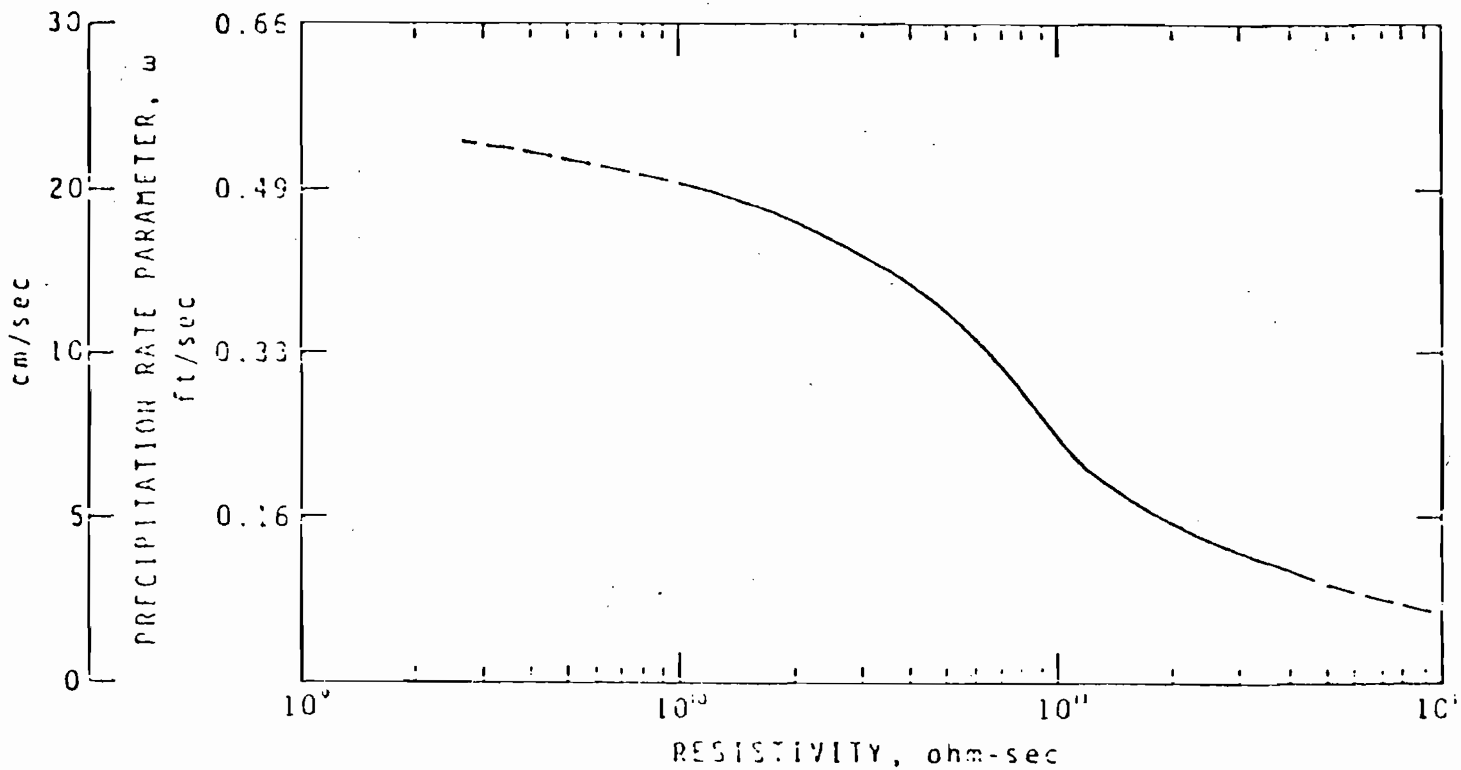


Figure 5-2. Effect of fly ash resistivity on migration velocity.

The introduction of a bubble limit in terms of tons of pollutant per unit of time may permit a facility to comply by means of load reduction in conjunction with the fuel being burned. Table 8-1 shows the percentage of time that a facility is out of compliance as a function of load and of the variability of the equivalent SO_2 content of the coal. The following assumptions are pertinent.

- Emission limit = 254.4 lb SO_2/day
- 24-hour coal equivalent SO_2 content averages are normally distributed
  - Mean = 1.6, 1.9, 2.2 lb SO_2/million Btu
  - Relative standard deviation (RSD) = 3, 6, 12, 18 percent of mean

The table showns that 1.6 lb coal will insure that there is virtually no noncompliance likelihood (<0.1 percent) if the coal SO_2 variability (expressed as RSD) is 3 percent (or less). If the variability of the 1.6 lb coal is 18 percent, the station operating at 100 percent load will be out of compliance 29.5 percent of the time, and only at 70 percent load or less will the station be in compliance essentially all the time. If a 2.2 lb coal with a 12 percent RSD is used at a 70 percent station load, the station will be out of compliance 21.8 percent of the time. This illustrates dramatically that a prediction of compliance or noncompliance relies heavily on an accurate characterization of the coal in terms of its quality and its variability. Using the normality assumption for coal variability we can calculate the likelihood of compliance using any prescribed coal quality (SO_2 mean and RSD), station load, and bubble regulation.

TECO has reported monthly coal quality averages for calendar year 1979 which show a month-to-month RSD of 32 percent. Day-to-day variations for this coal supply would be somewhat larger. The large variation is due in part to the fact that TECO's 1979 coal supply was from six different sources and was reported on an as-received basis. Various techniques such as coal blending and coal cleaning will have to be incorporated to reduce this coal quality variation to a reasonable level.

TABLE 8-1. GANNON NONCOMPLIANCE LIKELIHOOD AS A FUNCTION OF COAL SO_2 QUALITY AND STATION LOAD

	Noncompliance likelihood: percent											
	1.6 lb Coal				1.9 lb Coal				2.2 lb Coal			
Load	RSD %				RSD %				RSD %			
%	3	6	12	18	3	6	12	18	3	6	12	18
100	0.0	5.2	20.6	29.5	99.4	89.6	73.6	66.3	100.0	100.0	95.4	86.9
95		0.5	9.7	19.2	81.3	67.4	58.7	56.0	100.0	99.6	90.8	81.3
90		0.0	3.4	11.1	18.1	32.3	40.9	44.0	100.0	97.0	82.6	73.6
85			0.8	5.3	0.2	7.2	23.3	31.2	97.8	84.4	69.2	63.3
80			0.0	1.9	0.0	0.5	9.7	19.2	52.4	51.2	50.8	50.4
75				0.5		0.0	2.6	9.9	1.5	14.0	29.5	35.9
70				0.0			0.4	3.8	0.0	0.9	12.1	21.8
65							0.0	0.9		0.0	2.9	10.2
60								0.1			0.3	3.3
55								0.0			0.0	0.6
50												0.0

STATION LOAD

TECO maintains that as the Gannon Plant gets older it will be used less so that SO_2 emissions will not exceed current levels. Because the area is nonattainment for SO_2, SO_2 emission increases cannot be permitted in the revised SIP regulation that will be required for the plant. TECO has presented evidence that conversion to low-sulfur coal will not increase emissions beyond the 1979 level for future years through 1989 unless maximum interchange sales are assumed. In that case emissions will still not exceed the 1976 level. As an additional exercise we have calculated the percentage likelihood of exceeding the proposed bubble regulation of 254.4 ton SO_2/day assuming that the station will be loaded as it was in 1979. For this calculation we have used an unofficial TECO tabulation of daily Gannon station loads for 1979. Our results are shown in Table 8-2.

These load frequencies are combined with the estimated likelihoods of being out of compliance with SO_2 regulations, using various qualities of coal at the prescribed assumed loads. Table 8-3 indicates the estimated percentage of days that Gannon would be out of compliance on the basis of TECO's assumed 1979 load distribution. The 1.6 lb coals are not included because they all show essentially zero likelihood of noncompliance using the 1979 load profile.

The data in Table 8-3 indicate that if the 1979 station load profile is typical, the 1.9 lb coals will not result in more than 1 percent noncompliance. However, 2.2 lb coal will result in 1.1 to 4.5 percent noncompliance, depending on the variability of the coal. Our conclusion then is that TECO's low sulfur coal proposal is basically a sound concept, but that sufficient safeguards will have to incorporated into their program to insure that they meet the imposed limits by maintaining proper coal quality and appropriate station loads.

TECO's success in using the proposed low-sulfur coal option depends on the utility's ability to maintain a reliable supply of compliance coal. TECO indicates confidence that by cleaning the coal and using proper additives, the utility will be able to burn the coal in the cyclone-fired boilers. Ash content and ash fusion temperature can be maintained to prevent excessive fouling and slagging of the boilers; coal sulfur content and boiler load can be manipulated to meet the SO_2 emission limit. Adequate ESP capacity can be installed to meet particulate emission requirements. Furthermore, TECO should

TABLE 8-2. DAILY STATION LOADS - GANNON - 1979

Days	Load, %	Relative frequency	Assumed load, %
1	Above 80	0.003	85.0
11	75 - 80	0.030	77.5
20	70 - 75	0.055	72.5
24	65 - 70	0.066	67.5
27	60 - 65	0.074	62.5
30	55 - 60	0.082	57.5
32	50 - 55	0.088	52.5
50	45 - 50	0.317	47.5
61	40 - 45	0.168	42.5
43	35 - 40	0.118	37.5
30	30 - 35	0.082	32.5
17	25 - 30	0.047	27.5
9	20 - 25	0.025	22.5
9	15 - 20	0.025	17.5

TABLE 8-3. PERCENT LIKELIHOOD OF EXCEEDING DAILY SO_2 LIMIT AS A FUNCTION OF COAL QUALITY

		1.9 lb $SO_2/10^6$ Btu coal				2.2 lb $SO_2/10^6$ Btu coal			
Station load, %	Relative frequency	RSD % 3	RSD % 6	RSD % 12	RSD % 18	RSD % 3	RSD % 6	RSD % 12	RSD % 18
85.0	0.003	0.0	0.0	0.1	0.1	0.3	0.3	0.2	0.2
77.5	0.030			0.2	0.4	0.8	0.9	1.2	1.3
72.5	0.059			0.1	0.3	0.0	0.3	1.1	1.6
67.5	0.066			0.0	0.1		0.0	0.5	0.8
62.5	0.074				0.0			0.1	0.5
57.5	0.082							0.0	0.1
52.5	0.088								0.0
≦47.5	0.602								
TOTAL	1.000		0.0	0.0	0.4	0.9	1.1	1.5	3.1

be expected to install and operate continuous opacity and SO_2 emission monitoring equipment to demonstrate compliance with regulations on a continuing basis. A description of various continuous monitors is described in Appendix B.

The conversion of these boilers to coal will result in their more frequent dispatch to meet electrical load, a situation that runs counter to TECO's contention that the boilers will be used less frequently in future years. Some provision must be incorporated in TECO's program to input the environmental restrictions for the station into their economic dispatch system. Regulatory and other implications of overriding TECO's existing economic dispatch program are not addressed in this report.

SECTION 9
SO_2 EMISSIONS REGULATIONS AND CONTINUING COMPLIANCE

BACKGROUND

Although the Tampa area is in compliance with National Ambient Air Quality Standards (NAAQS) for SO_2, compliance is marginal. The three-hour ambient SO_2 standard is in greatest jeopardy; thus the Florida Department of Environmental Regulation (DER) has a responsibility to protect that standard and to insure that TECO does not cause a violation of that standard as a consequence of converting the Gannon boilers to coal. Accordingly, Florida has drafted a regulation to limit emissions from Gannon coal-fired units to 2.4 lb SO_2 per million Btu heat input for each unit on a weekly average. Furthermore, combined emissions from all six boilers are not to exceed 10.6 ton SO_2/h on a weekly basis. TECO is to verify compliance by submitting weekly station generation data and weekly composite fuel quality analysis data. Compliance with 3-hour and 24-hour ambient standards is to be insured by load limiting in conjunction with daily fuel quality; details are to be specified in the station operating permit(s).

This new regulation has not been promulgated, pending a public hearing in mid-October. The intent of the proposed regulation is to allow TECO to demonstrate continuing compliance to the satisfaction of the state agency at reasonable cost. The alternative to the use of routine coal analyses would be to require the installation and operation of a continuous emissions monitoring (CEM) system. In order to investigate the merits of such a requirement we visited Gulf Power Company and the Tennessee Valley Authority (TVA), two utilities that each maintain a number of CEM systems for SO_2.

Gulf Power has seven generating units at its Crist Plant in Penascola, Florida. The company maintains Lear Siegler monitors for opacity, SO_2, O_2, and NO on four coal-fired units at the plant (Units 4-7). A computer system calculates 3-hour averages for lb SO_2 per million Btu for each boiler in 1-hour steps. The regulation at the plant is 4.9 lb SO_2 per million Btu. Gulf Power indicates that the monitors have shown that the standard is never violated. Before the monitors were installed some coal analyses showed violations.

The emissions monitors are serviced by Lear Siegler under a maintenance contract. Plant personnel provide only routine support (1/2 man per year) to the Lear Siegler representative who spends full time maintaining the monitors on 11 units at three Gulf Power plants. Preventive maintenance service by Gulf Power amounts to about 2 man years per year. Thus, the total manpower requirement to service and maintain the monitors on the 11 units is about 3 1/2 people. The maintenance contract to Lear Siegler costs about $70,000 per year. System up-time on the monitors runs about 85 percent. Gulf Power has no legal requirement to maintain the monitors, nor to report CEM data to the state on a routine basis. However, it is possible that reporting requirements may be incorporated into future state operating permit renewals for the plants.

Gulf Power has not prepared any formal comparisons between CEM data and coal analysis data, but Gulf Power personnel indicate that the monitor data seem to run slightly lower than the coal analyses. The amount of the discrepancy was not indicated. Other studies have shown that 90 to 95 percent of the sulfur in coal is emitted as SO_2.

TVA has operated CEM systems for several years as part of a program to curtail emissions during periods of adverse meteorological conditions. More recently TVA has installed a large number of Lear Siegler instruments at various plants in conjunction with a consent agreement with EPA. At the Widows Creek plant TVA maintains seven DuPont SO_2 analyzers and three Lear Siegler systems that each measure SO_2, NO, O_2, and opacity. The Lear Siegler units alternate at 1-minute intervals between the measurement of NO and SO_2. SO_2 data for each monitor are reported for each 15-minute period. At present a full-time statistician transfers strip chart data to report forms that array 96 15-minute average readings for each day. TVA is planning to develop and install a computer system to handle this data load for compliance monitoring. In addition to the statistician, TVA employs four mechanics and one foreman full-time to maintain these instruments. In contrast with Gulf Power, TVA does not subscribe to a maintenance contract with Lear Siegler. Instead, TVA maintains a rather exhaustive instrument diagnosis and repair facility. The instruments seem to require frequent circuit board repairs. TVA will eventually have a total of 111 CEM units in 12 plants, each subject to annual recertification. However, there are no established EPA calibration requirements, according to TVA. Routine calibration (zero and span) is performed automatically once each day on each instrument, and voluntary calibration checks are run quarterly by TVA. Only 20 percent relative accuracy is required at instrument operating conditions. TVA has attained a very high up-time percentage for these instruments by devoting a lot of attention to them. Each time there is an instrument malfunction TVA is required to report the incident to EPA. TVA claims that this involves considerable unnecessary time and expense (including a mailgram).

Each Lear Siegler analyzer system costs about $20,000. TVA recently ordered $250,000 worth of spare parts for all of its plants and is gathering data to define requirements for spare parts and supplies requirements in greater detail.

For each boiler TVA fills the coal bunker each night for the next day's burn and collects a coal sample as the coal is charged into the bunker. This sample is analyzed in the laboratory; results are available about two days after the coal sample is collected. Thus the coal is usually burned a day or so before the coal analysis is completed.

DATA

TVA has provided us with several months of data, including CEM data and coal analysis data. Using these data, three points were investigated.

1. Relationships between short-term and long-term coal or emissions variability.
2. Relationships between coal sulfur content and sulfur dioxide emissions.
3. Relationships between coal analysis data and CEM emissions data.

Beginning on November 19, 1979, TVA has produced daily CEM summaries for Widows Creek Unit 7 that each consist of 96 15-minute average SO_2 emission readings (lb SO_2 per million Btu). These data permit us to estimate the variability in emissions on any time basis that is an integral multiple of

15 minutes. If emissions data points were truly independent it would be possible to calculate the variability for any time frame (i.e., hourly, daily, weekly, etc.) once we know the variability for one time frame. However, emissions data are not really independent; thus short-term and long-term emissions trends make it impossible to infer the variability for one time frame from another one. Variabilities in coal quality and emissions must be estimated by accumulating relatively large quantities of sample data over long periods of time.

TVA has provided 85 days of CEM data formatted in daily arrays each consisting of 96 fifteen-minute SO_2 emission averages for Widows Creek Unit 7. In addition, TVA has sampled and analyzed the coal supply to the Unit 7 bunker each night as the coal is loaded to the bunker for the next day's operation; TVA has also provided these data for 154 days for our analysis. Using these various data, we have calculated the following parameters.

Mean daily emissions based on 24 consecutive daily coal samples:
4.00 lb $SO_2/10^6$ Btu

Mean daily emissions based on the same 24 consecutive days of CEM data:
4.31 lb $SO_2/10^6$ Btu

Daily standard deviation based on 24 consecutive daily coal samples:
0.935 lb $SO_2/10^6$ Btu

Daily standard deviation based on the same 24 consecutive days of CEM data:
0.927 lb $SO_2/10^6$ Btu

Mean daily emissions based on 78 days of CEM data:
4.54 lb $SO_2/10^6$ Btu

Daily standard deviation based on 78 days of CEM data:
0.689 lb $SO_2/10^6$ Btu

Three-hour standard deviation based on 624 three-hour periods (78 days) of CEM data:
0.778 lb $SO_2/10^6$ Btu.

One-hour standard deviation based on 1872 hours (78 days) of CEM data:
0.794 lb $SO_2/10^6$ Btu.

Average daily three-hour standard deviation based on 78 days of CEM data:
0.336 lb $SO_2/10^6$ Btu

Average daily one-hour standard deviation based on 78 days of CEM data:
0.355 lb $SO_2/10^6$ Btu

Mean daily emissions based on 154 daily coal samples:
4.32 lb $SO_2/10^6$ Btu

Daily standard deviation based on 154 daily coal samples:
1.475 lb $SO_2/10^6$ Btu

The above data presentation is somewhat disjointed, but a closer examination reveals several points. For the 24-day period in which there are comparative coal sample and CEM data there is no significant correlation between the daily coal analyses and the average daily CEM analyses. The calculated correlation coefficients for these data were -0.02 and -0.14 based on respective assumed lag times of one day and two days between loading the bunker and burning the coal. Unit 7 is rated at 530 MW, and the bunker is large enough to substain a 24-hour burn at 500 MW. On the average the boiler generates 300 MW so the coal is usually burned within a day or two after it is charged into the bunker. The variable lag time between charging the bunker and burning the coal thus tends to weaken the correlation that we expect between coal data and CEM data, but it does not seem reasonable that the correlation coefficient should be essentially zero. It is disconcerting that the coal data and the CEM data appear to be totally unrelated, and further effort should be exerted to demonstrate the underlying correlation.

The CEM data for the 24-day period indicate that emissions average eight percent higher than the corresponding coal analysis data. Because not all of the sulfur in the coal is converted to SO_2 in the boiler, the CEM data would be expected to be slightly lower than the coal analysis data. This logical inconsistency needs to be investigated in further detail to determine whether or not there is a systematic error in either the coal sampling and analysis procedures, the emissions monitoring system, or the various calculations associated with the analyses. The two data sets should both reflect actual emissions; it is possible that the accuracy in the two data sets for the 24-day term was not sufficient to compare the emissions indicated by the two methods.

The data show that for this plant long-term coal variability tends to the greater than short-term variability. The day-to-day variability for the 24-day period is less than the day-to-day variability over a 154-day period, and a sample 1-hour standard deviation calculated from a single day of data tends to be lower than the 1-hour standard deviation calculated over a longer period. This indicates that overall coal variability should probably not be inferred from short-term data and that conventional statistical procedures are inappropriate if they assume that sample data points are independent.

TVA supplied us with CEM data for the 113-day period from October 19, 1979, through February 8, 1980. In that period the boiler was out of service for all or part of 35 calendar days. Three CEM failures of 4 hours, 8 hours, and 4 hours respectively during that period precluded obtaining complete data on three days when the boiler was operating, so the CEM provided essentially complete data on 96 percent of the days that the boiler operated. This leads us to the conclusion that CEM reliability can be high if good maintenance procedures are adopted, but that maintenance costs are also high, as indicated earlier.

CONCLUSIONS

Our conclusions to this study are necessarily tentative because of its limited scope. Our data base would have to be expanded in order to draw more general conclusions about CEM performance. However, the following conclusions seem appropriate.

Any system of data collection and reporting that is agreed upon between the utility and the state must report data in a form that is usable to the state and which gives strong evidence that agreed emission limits are being met so that ambient standards will not be violated. The reporting system must be simple enough that the state is not burdened with a mountain of data to sort through, but yet the utility must be able to maintain backup data for a reasonable period of time to defend any challenge that the plant may not be in compliance. By the same token, the utility needs to protect itself from a cumbersome data reduction task. TVA's painstaking procedure of visual integration of 15-minute averages from strip chart data appears to be too expensive and cumbersome for TECO to have to adopt.

Although an underlying relationship necessarily exists between the sulfur content of coal and the SO_2 emissions from burning the coal, we have been unable to correlate TVA's coal analysis data with corresponding CEM data. This may be partly because in our correlation we have not incorporated the variable lag time between loading the bunker and burning the coal. However, some question exists that the two data sets are equivalent for demonstration of compliance with emissions regulations. Whether Florida decides to require coal analysis data or CEM data to demonstrate compliance, it is very important to insure that the selected method accurately reflect true SO_2 emissions.

TVA analyzes each coal sample two or three days after the coal is put into the bunker. In most cases the coal is burned about a day before an analysis can be available. Thus the analysis is of little more than historical interest and cannot be used for essentially real-time control. On the other hand CEM data are available only minutes after the coal is burned, and it is conceivable that a system could be developed to divert clean coal into a boiler quickly to bring indicated high SO_2 emissions into line with regulatory limits. However, if no such system is available to TECO, there may be little practical value in eliminating any lag time that coal analysis necessitates.

Because coal has inherent variability in quality, any strategy to comply with emissions regulations must incorporate a statistical analysis to comply with those regulations for a certain minimum percentage of the time. Any regulation that is promulgated should take this statistical variation into account and should permit a given limit to be exceeded only with limited frequency such as one day per month or three weeks per year or ten days per year. Penalties for exceeding the prescribed frequency should be indicated, and the system whereby TECO is to demonstrate continuing compliance should be described in detail.

APPENDIX A

POWER PLANT SURVEY FORM

A. COMPANY INFORMATION:

1. COMPANY NAME: Tampa Electric Company
2. MAIN OFFICE: P.O. Box 111, Tampa, FL 33601
3. RESPONSIBLE OFFICER: G.F. Anderson
4. POSITION: Vice President - Production, Operations, Maintenance
5. PLANT NAME: Gannon Station
6. PLANT LOCATION: Port Sutton Road
7. RESPONSIBLE OFFICER AT PLANT LOCATION: H.D. Broome
8. POSITION: Plant Superintendent
9. POWER POOL N.A.

DATE INFORMATION GATHERED:

Updated May 1980

PARTICIPANTS IN MEETING:

B. ATMOSPHERIC EMISSIONS	Boiler number 1	2	3	4	5
1. PARTICULATE EMISSIONS[a]					
LB/MM BTU (1979 Stack Test Results)	0.04	0.04	0.03	0.07	0.004
GRAINS/ACF N.A.					
LB/HR (FULL LOAD)	50	50	48	131	10
TONS/YEAR (1979)	80	98	93	229	23
2. APPLICABLE PARTICULATE EMISSION REGULATION					
a) CURRENT REQUIREMENT					
AQCR PRIORITY CLASSIFICATION			Florida Administrative Code		
REGULATION & SECTION NO.	17-2.05(6)E.(1)(b)1.e and 17-2.05(6)E.(1)(b)2.a.				
LB/MM BTU	0.1	0.1	0.1	0.1	0.1
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.					
LB/MM BTU					
3. SO_2 EMISSIONS[a]					
LB/MM BTU (1979 Stack Test Results)	1.03	1.06	0.96	1.10	1.43
LB/HR (FULL LOAD)	1295	1332	1535	2064	3267
TONS/YEAR (1979)	2071	2604	2971	3592	7950
4. APPLICABLE SO_2 EMISSION REGULATION					
a) CURRENT REQUIREMENT		Florida Administrative Code			
REGULATION & SECTION NO.	17-2.05(b)E.(1)(b)1.e and 17-2.05(6)E.(1)(b)2.a				
LB/MM BTU	1.1	1.1	1.1	1.1	2.4
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.					
LB/MM BTU					

a) Identify whether results are from stack tests or estimates

C. SITE DATA

1. U.T.M. COORDINATES 360,100 mE and 3,087,500 mN
2. ELEVATION ABOVE MEAN SEA LEVEL (FT) +9.0 MLW
3. SOIL DATA: BEARING VALUE ~2000 #/ft^2

   PILE DATA See attached report
4. DRAWINGS REQUIRED provided to PedCo on May 5, 1980

   PLOT PLAN OF SITE (CONTOUR)

   EQUIPMENT LAYOUT AND ELEVATION

   AERIAL PHOTOGRAPHS OF SITE INCLUDING POWER PLANT, COAL STORAGE AND ASH DISPOSAL AREA
5. HEIGHT OF TALLEST BUILDING AT PLANT SITE OR IN CLOSE PROXIMITY TO STACK (FT. ABOVE GRADE)
6. HEIGHT OF COOLING TOWERS (FT. ABOVE GRADE): N.A.

Month (1972)	Fuel Consumption		Fuel Characteristics				
	Oil Gallons (1000)	Coal Tons (1000)	Oil		Coal		
			Avg S %	Max S %	Min S %	Avg S %	Max S %
January							
February	See attached 1979			See attached 1979 FPC-67 Form - page 2			
March	FPC-67 Form - page 5						
April							
May							
June							
July							
August							
September							
October							
November							
December							

Month (1972)	Average Boiler Load Factors (Weekday)									
	Boiler ___		Boiler ___		Boiler ___		Boiler ___		Boiler ___	
	4 hr Peak Period	Average 24 hr Period	4 hr Peak Period	Average 24 hr Period	4 hr Peak Period	Average 24 hr Period	4 hr Peak Period	Average 24 hr Period	4 hr Peak Period	Average 24 hr Period
January										
February										
March						See attached 1979 FPC-67 Form - page 5				
April										
May										
June										
July										
August										
September										
October										
November										
December										

E. BOILER DATA

	Boiler number 1	2	3	4	5
1. SERVICE: BASE LOAD STANDBY, FLOATING, PEAK		See capacity factor below			
2. TOTAL HOURS OPERATION (~~1978~~) (1979)	5278	6416	5448	5369	6630
3. AVERAGE CAPACITY FACTOR (~~1977~~) (1979)	48%	48%	44%	42%	59%
4. SERVED BY STACK NO.	1	2	3	4a & 4b	5
5. BOILER MANUFACTURER	B&W	B&W	B&W	B&W	Riley
6. YEAR BOILER PLACED IN SERVICE 35 Yr	1957	1958	1960	1963	1965
7. REMAINING LIFE OF UNIT	12	13	15	18	20
8. GENERATING CAPACITY (MW)					
NAMEPLATE	125	125	179.52	187.5	239.36
MAXIMUM CONTINUOUS (Net)	98	108	150	169	214
PEAK (no distinction from maximum continuous)					
9. MAXIMUM HEAT INPUT (MM BTU/HR)	1257	1257	1599	1876	2284
10. FUEL CONSUMPTION: MAX/~~DESIGN~~/AVER					
COAL (TPH)					93.4/77.7
OIL (GPH)	8,044/5080	8,044/5100	10,846/7,573	12,900/8,110	
11. ACTUAL FUEL CONSUMPTION					
COAL (TPY) (1979) x 1000					457.8
OIL (GPY) (1979) x 1000	26,813	32,748	41,262	43,543	
12. WET OR DRY BOTTOM	Wet	Wet	Wet	Wet	Wet
13. FLY ASH REINJECTION (YES OR NO)	N.A.	N.A.	N.A.	N.A.	Yes
14. STACK HGT ABOVE GRADE (FT.)	306	306	306	306	306
15. I.D. OF STACK AT TOP (~~INCHES~~)(Ft)	10.0	10.0	10.6	9.6 each	14.6

Notes:

	Boiler number				
	1	2	3	4	5
16. FLUE GAS CLEANING EQUIPMENT					
a) MECHANICAL COLLECTORS None					
MANUFACTURER					
TYPE					
EFFICIENCY: DESIGN/ACTUAL (%)					
MASS EMISSION RATE:					
(GR/ACF)					
(#/HR)					
(#/MM BTU)					
b) ELECTROSTATIC PRECIPITATOR					
MANUFACTURER	Research Cottrell	Research Cottrell	Research Cottrell	American Standard	Research Cottrell
TYPE					
EFFICIENCY: DESIGN/~~ACTUAL (%)~~ Upgraded	90	90	93	95.5	98.5/99.8
MASS EMISSION RATE See question 2	of this form				
(GR/ACF)					
(#/HR)					
(#/MM BTU)					
NO. OF IND. BUS SECTIONS	6	6	12	8	8
TOTAL PLATE AREA (FT^2)	34,800	34,800	62,400	62,200	106,800 14
FLUE GAS TEMPERATURE @ INLET ESP @ 100% LOAD (°F)	309	309	266	286	288
17. EXCESS AIR: DESIGN/ACTUAL (%)	13	13	16	16	15

Notes:

	Boiler number				
	1	2	3	4	5
18. FLUE GAS RATE (ACFM)					
@ 100% LOAD (Note 1)	500,000	500,000	615,000	700,000	681,000
@ 75% LOAD (Note 2)	383,000	383,000	469,000	520,000	552,000
@ 50% LOAD (Note 2)	252,000	252,000	342,000	353,000	440,000
19. STACK GAS EXIT TEMPERATURE (°F)					
@ 100% LOAD	309	309	266	286	288
@ 75% LOAD	280	280	249	266	278
@ 50% LOAD	265	265	242	252	273
20. EXIT GAS STACK VELOCITY (FPS)					
@ 100% LOAD	79	79	98.8	71.7	64.1
@ 75% LOAD	62	62	74.1	53.8	52.0
@ 50% LOAD	41	41	49.4	35.9	41.4
21. FLY ASH: TOTAL COLLECTED (TONS/YEAR)					
DISPOSAL METHOD		See attached FPC-67 Form - page 7			
DISPOSAL COST ($/TON)					
22. BOTTOM ASH: TOTAL COLLECTED (TONS/YEAR)					
DISPOSAL METHOD		See attached FPC Form - page 7			
DISPOSAL COST ($/TON)					
23. EXHAUST DUCT DIMENSIONS @ STACK	7'0"x24'0"	7'0"x24'0"	7'5"x29'4"	10' I.D.	15' I.D.
24. ELEVATION OF TIE IN POINT TO STACK	116'0"	116'0"	123'9"	106'6"	120'0"
25. SCHEDULED MAINTENANCE SHUTDOWN (ATTACH PROJECTED SCHEDULE)					

Notes:

(1) Based on measurements taken by precipitator manufacturers for performance tests and measurements taken at later dates by TECO.

(2) Estimated based upon Note 1 above and boiler design data.

.2cc sent to P.C
2/2 3/...

RAYMOND

CONCRETE PILE DIVISION

A DIVISION OF RAYMOND INTERNATIONAL INC.

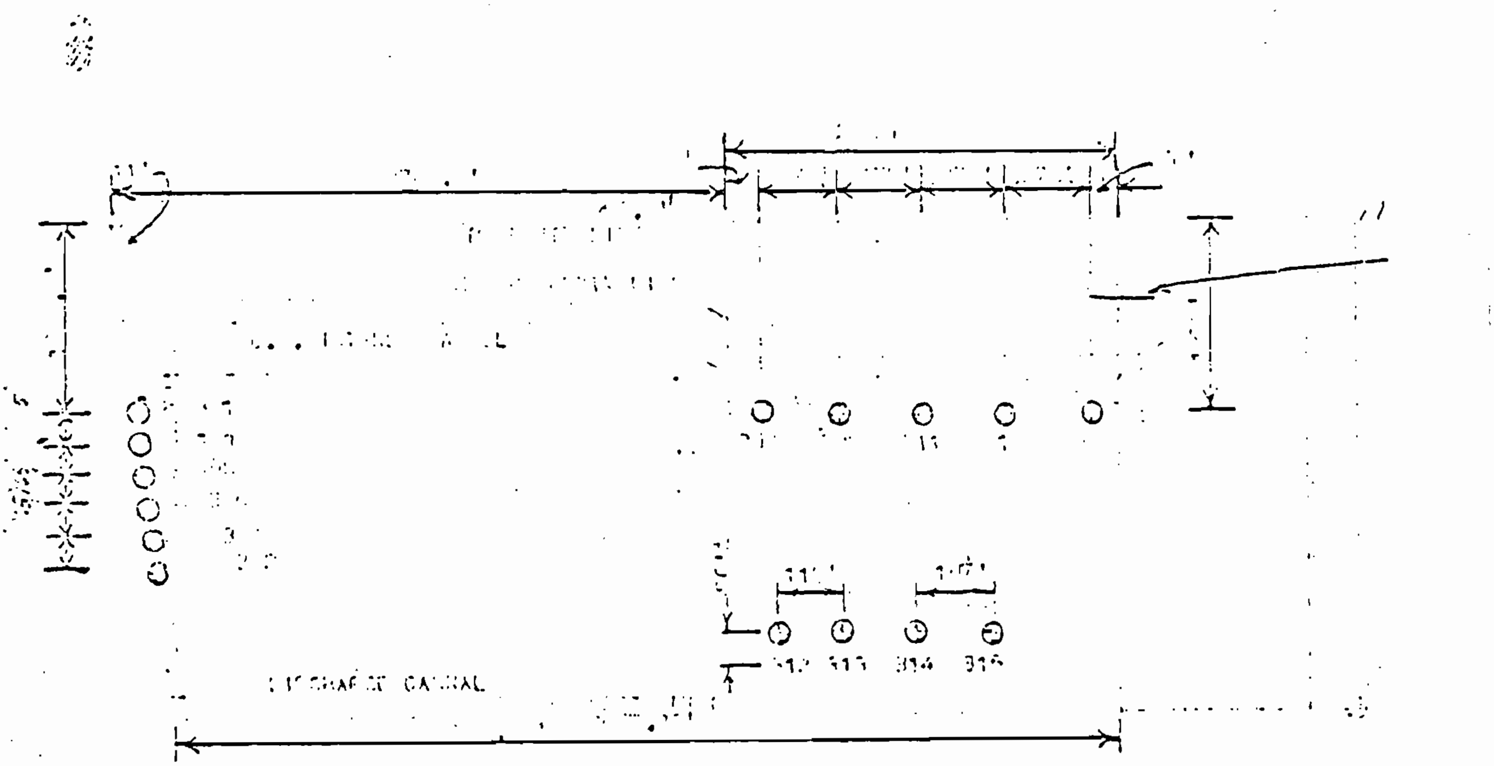
140 CEDAR STREET - NEW YORK 6, N. Y.

To... Date..FEBRUARY 27................19...

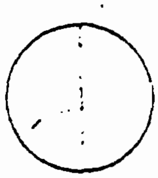
Address..

We have completed the following borings for you at..

with results shown below. In accordance with your instructions, we have sent labelled samples of the strata encountered To...DELIVERED TO CLIENT.................................Address..TAMPA, FLORIDA.................................. Via.......................................under date of.................................Raymond Concrete Pile Co. A Division of Raymond International Inc. LOCATION PLAN SCALE 1" = ...



Compass Points



This boring report prepared in the ....OFFICE of the Raymond Concrete Pile Company A DIVISION OF RAYMOND INTERNATIONAL INC.

By..................

Job No: ....

Sheet 1 of ..3........

TEST BORING REPORT

RAYMOND

CONCRETE PILE DIVISION

A DIVISION OF RAYMOND INTERNATIONAL INC.

To TAMPA ELECTRIC COMPANY

Date [illegible]

Location of Borings BIG BEND STATION, TAMPA ELECTRIC CO., TAMPA, FLORIDA

All borings are plotted to a scale of 1" = 8 ft. using MEAN LOW GULF

Boring No. 310

GROUND SURFACE
ELEV. +8.50'

Depth	Description	Blows
0' – 4'	FINE GRAY SAND W/ LIGHT & DARK-GRAY SILT & SHELLS-FILL	3-3-5
4' – 8'	FINE GRAY SAND SOME GRAY SILT SHELLS TRACES OF ORGANIC [illegible]	4-7-9
8' – 10'6	FINE GRAY SAND GRAY SILT & SHELLS	[illegible]
10'6 – 14'	SHELLS & SILTY FINE GRAY SAND	6-7-10
14' – 18'	FINE GRAY SAND GRAY SILT & SHELLS	4-4-4
18' – 31'6	LOOSE FINE SAND AND GRAY SILT	2-3-2; 2-1-2; 7-7-7
31'6 – 36'6	DENSE FINE GRAY SAND W/GRAY SILT, TRACE OF SHELLS	17-17-21
36'6 – 43'	LIGHT GRAY MARL	24-100
43' – 47'	CEMENTED FINE GRAY SAND & SILT	17-100
47' – 48'6	NOTE A	15-21-43

NOTE A:
DENSE, FINE GRAY SAND GRAY SILT, SOME CLAY AND LIMESTONE FRAGMENTS.

4" CASING USED 21'

WATER LEVEL AT 6'0"

BORING OFFSET 12'0" SOUTH

1-2-8

Boring No. 311

GROUND SURFACE
ELEV. +8.00'

Depth	Description	Blows
0' – 4'	FINE GRAY SAND, SHELLS, SOME GRAY SILT FILL	3-4-3
4' – 7'6	FINE SAND, W/GRAY SILT SHELLS TRACES ROCK FRAG.	8-12-12
7'6 – 27'	FINE GRAY SAND, GRAY SILT, SHELLS, TRACE OF CLAY	1-1-1; 2-3-4; 2-3-2; 3-3-2
27' – 32'	FINE GRAY SAND, GRAY SILT, SOME CLAY, SOME SHELLS	2-2-3
32' – [illegible]	FINE GRAY SAND W/ GRAY SILT & SHELLS [illegible]	[illegible]-12
[illegible] – 36'	NOTE A	[illegible]-24-15
36' – [illegible]	HARD CLAYEY, SANDY GRAY SILT W/ LIMESTONE FRAGMENTS (MARL)	17-100
[illegible]	VERY LOOSE SILTY [illegible], SAND, SOME CLAY	[illegible]

NOTE A:
CLAYEY GRAY SILT, SOME FINE SAND LIMESTONE FRAGMENTS WITH (MARL)

4" CASING USED 21'

BORING OFFSET 15' SOUTH

WATER LEVEL AT 6'0"

1-2-6

RAYMOND

CONCRETE PILE DIVISION

A DIVISION OF RAYMOND INTERNATIONAL INC.

To TAMPA ELECTRIC COMPANY

Date 20 FEBRUARY 19[illegible]

Location of Borings UNIT NO. 1 - [illegible] STATION, TAMPA, FLORIDA

All borings are plotted to a scale of 1" = [illegible] ft. using MEAN LOW WATER as a fixed datum.

Boring No. 313

GROUND SURFACE
ELEV. 7.[illegible]

Depth	Description	Blows
0' – 4'	FINE GRAY SAND, SHELLS, SOME SILT	2-4-5
4' – [illegible]	FINE GRAY SAND AND SHELLS WITH CLAYEY GRAY SILT	6-4-5, 1-2-3, 4-4-4
[illegible] – 22'6"	FINE GRAY SAND WITH CLAYEY GRAY SILT, TRACE [illegible]	3-3-3
22'6" – 27'	CLAYEY [illegible] GRAY SILT WITH [illegible] OF FINE [illegible] SAND	2-2-2
27' – 30'6"	FINE GRAY SAND & CLAYEY GRAY SILT AND SHELLS	1-2-3
30'6" – 33'6"	[illegible]	[illegible]-11-12
33'6" – 47'	CLAYEY SANDY [illegible] GRAY SILT WITH LIMESTONE FRAGMENTS (MARL)	4-[illegible]-11, 37-40-50, 100-70, [illegible]

WL(-) [illegible]

NOTE AT [illegible]: FINE GRAY SAND WITH GRAY SILT AND BANDS OF SILTY GRAY AND GREEN CLAY

USED 21' OF 4" CASING

1-24-[illegible]

Boring No. 314

GROUND SURFACE
ELEV. 7.[illegible]

Depth	Description	Blows
0' – 4'	FINE GRAY SAND, SILT, SOME CLAYEY GRAY SILT	2-2-3
4' – 11'	FINE GRAY SAND, SILT, SOME SILT, TRACE OF CLAY	4-4-4, 2-4-5
11' – 14'	[illegible] FINE SILT & [illegible] SHELLS	11-20
14' – 18'	SHELLS AND SILTY FINE GRAY SAND	4-[illegible]-7
18' – 22'	FINE GRAY SAND & CLAYEY GRAY SILT	5-[illegible]-4
22' – 32'	FINE GRAY SAND, SHELLS AND GRAY SILT	2-2-2, [illegible]
32' – 36'	CLAYEY [illegible] GRAY SILT WITH FINE SAND AND [illegible] OF LIMESTONE (MARL)	3[illegible]-11-[illegible]
36' – 47'	CLAYEY LIGHT GRAY SILT WITH FINE SAND AND [illegible] OF LIMESTONE MARL	[illegible], [illegible]

WL(-) [illegible]

USED 21' OF 4" CASING

1-26-[illegible]

Boring No. 315

GROUND SURFACE
ELEV. 7.[illegible]

Depth	Description	Blows
0' – 4'[illegible]	FINE GRAY SAND SHELLS, SOME SILT	4-4-3
4'[illegible] – [illegible]	CLAYEY SILTY FINE SAND, SOME SHELLS	[illegible]-2, [illegible]-2
[illegible] – [illegible]	SILT & SHELLS, [illegible]	[illegible]
[illegible] – [illegible]	SILTY FINE GRAY SAND, SOME CLAY, TRACE OF SHELL	[illegible]
[illegible] – [illegible]	SILTY DARK GRAY CLAY WITH [illegible] OF FINE SAND	3-[illegible]-5
[illegible] – [illegible]	[illegible] SILTY GRAY AND GREEN CLAY, SOME FINE SAND	[illegible]
[illegible] – [illegible]	CLAYEY SANDY GREEN AND GRAY SILT	[illegible]
[illegible] – [illegible]	LIGHT GRAY MARL WITH LIMESTONE [illegible] TO [illegible] THICK	[illegible]-70, [illegible]

WL(8) [illegible]

USED 21' OF 4" CASING

1-27-[illegible]

TEST BORING REPORT

RAYMOND

CONCRETE PILE DIVISION

A DIVISION OF RAYMOND INTERNATIONAL, INC.

To TAMPA ELECTRIC COMPANY — Date FEBRUARY 20, 1968

Location of Borings UNIT NO. 1 - BIG BEND STATION, TAMPA, FLORIDA

All borings are plotted to a scale of 1" = [illegible] ft. using MEAN LOW WATER as a fixed datum.

Boring No. B-307

GROUND SURFACE ELEV. [illegible]

Depth	Description	Blows
0'–4'	FINE SANDY GRAY SILT, SHELLS, [illegible]	5
4'–9'	LOOSE FINE SAND [illegible] AND DARK GRAY SILT, SOME SHELLS	4
9'–15'6"	LOOSE FINE SAND WITH SOME DARK GRAY SILT, TRACE OF SHELLS	2, 1
15'6"–21'	SHELLS AND SANDY GRAY SILT	10
21'–26'	CLAYEY GRAY SILT WITH LENSES OF FINE SAND, TRACE OF SHELLS	7
26'–30'	SOFT LIMESTONE WITH GRAY SILT AND SHELLS	50
30'–35'6"	CEMENTED FINE GRAY SAND SILT AND CLAY	100/10
35'6"–41'6"	SOFT LIMESTONE WITH LENSES OF CLAYEY GRAY SILT	26/6–60/6, 60–0
41'6"–45'6"	HARD SANDY SILTY BLUE-GRAY CLAY	[illegible]

USED 3" CASING TO 20' AND 2" CASING TO 30'

BORING OFFSET 11'6" SOUTH

FOREMAN NOTES LOSS OF WATER AT 17' AND 30'

12-21-67

Boring No. B-308

GROUND SURFACE ELEV. 7.[illegible]

Depth	Description	Blows
0'–4'6"	FINE SAND WITH GRAY SILT AND SHELLS	2-3-4
4'6"–6'	FINE SAND W/ [illegible] GRAY SILT, SOME SHELLS	1-1-2
6'–13'6"	SHELLS AND SANDY GRAY SILT	11-10-5, [illegible]
13'6"–15'	SILTY FINE GRAY SAND AND SHELLS	5-2-4
15'–39'6"	FINE SAND WITH LIGHT AND DARK GRAY SILT, SOME SHELLS	4-4-5, 2-1-2, 5-11-24, [illegible]-14
39'6"–42'6"	SILTY GRAY AND BLUE CLAY, FINE [illegible] SAND [illegible] SHELLS	7-10-15
42'6"–47'	SOFT LIMESTONE W/ GRAY SILT LENSES	10/[illegible], [illegible]

USED 21' OF 4" CASING

BORING OFFSET [illegible] SOUTH

FOREMAN NOTES LOSS OF WATER AT 13' TO 18'

12-22-67

Boring No. B-309

GROUND SURFACE ELEV. [illegible]

Description	Blows
FINE GRAY SAND, SHELLS, SOME GRAY SILT	1-1-1
FINE GRAY SAND W/ GRAY SILT AND SHELLS	[illegible]
LOOSE FINE GRAY SAND, SILT AND SHELLS	1-1-1
FINE GRAY SAND AND GRAY SILT WITH SHELL LAYERS	3-1-3, 3-1-4
FINE SAND AND GRAY SILT, TRACE OF CLAY	2-1-2
STIFF SILTY SANDY [illegible] GRAY CLAY	7-[illegible]-12
CEMENTED SAND AND GRAY SILT [illegible] LIMESTONE	100/6, 100/4
[illegible] GRAY [illegible] AND CLAYEY [illegible] GRAY [illegible]	13-[illegible]
HARD SANDY SILTY [illegible] GRAY CLAY	[illegible]-37-77
DENSE SANDY CLAYEY [illegible] GRAY SILT	[illegible]

USED 20' OF 4" CASING

FOREMAN NOTES WATER LOSS AT 15'-20'

1-1-68

TEST BORING REPORT

RAYMOND

CONCRETE PILE DIVISION

A DIVISION OF RAYMOND INTERNATIONAL, INC.

To TAMPA ELECTRIC COMPANY

Date FEBRUARY 20, 1968

Location of Borings UNIT NO. 1 - [illegible] STATION, TAMPA, FLORIDA

All borings are plotted to a scale of 1" = 8 ft. using MEAN LOW WATER as a fixed datum.

Boring No. [illegible]-304

GROUND SURFACE ELEV. +[illegible]

0'

TOP OF CASING TO WATER

3'6"

WATER

27'6"

LOOSE GRAY SILT

WT. OF RODS

34'[illegible]"

FINE GRAY SAND, [illegible] SILT, AND SHELLS [illegible]

[illegible]'

CLAYEY BLUISH GRAY SILT AND FINE SAND, SOME SHELLS [illegible]

[illegible]-1[illegible]-30

[illegible]'

CLAYEY BLUISH GRAY SILT, TRACE OF FINE SAND [illegible]

[illegible]

[illegible]2'

NOTE A

1[illegible]-12

[illegible]5'

NOTE A:
[illegible]

USED 45' OF 4" CASING

1-[illegible]-68

Boring No. [illegible]-305

GROUND SURFACE ELEV. +3.[illegible]'

0'

TOP OF CASING TO WATER

3'

WATER

29'

LOOSE GRAY SILT (MUCK)

WT. OF RODS/[illegible]"

34'

FINE GRAY SAND, TRACE OF GRAY SILT AND SHELLS

[illegible]-7-[illegible]

36'6"

2[illegible]-22-12

SILTY, BLUISH GRAY CLAY, FINE SAND AND SOME SHELLS (MARL)

12-2[illegible]-30

17-23-[illegible]

80-[illegible]7-33

[illegible]'

NOTE A 7-1[illegible]-20

[illegible]'[illegible]"

[illegible] [illegible]

53'6"

NOTE A:
FINE T[illegible] [illegible] SAND, SOME CLAYEY GR[illegible] GRAY SILT AND CLAY [illegible]

NOTE B:
SOFT [illegible] [illegible]

USED 45' OF 4" CASING

1-[illegible]-68

Boring No. [illegible]-306

GROUND SURFACE ELEV. +[illegible]

0'

WATER

[illegible]'

WT. OF RODS

VERY LOOSE GRAY SILT

[illegible]'[illegible]"

FINE SAND, GRAY SILT, AND SHELLS [illegible]

[illegible]'

12-[illegible]-16

[illegible]-7-[illegible]

20-[illegible]2-32

MARL - CLAYEY SANDY [illegible] GRAY SILT, SOME SHELLS

[illegible]-6

7-[illegible]-25

[illegible]

[illegible]5'

USED 43' OF 4" CASING

1-[illegible]-68

RAYMOND
CONCRETE PILE DIVISION
A DIVISION OF RAYMOND INTERNATIONAL, INC.

To TAMPA ELECTRIC COMPANY, Date FEBRUARY 20, 1968

Location of Borings UNIT NO. 1 - BIG BEND STATION, TAMPA, FLORIDA

All borings are plotted to a scale of 1" = 8 ft. using MEAN LOW WATER as a fixed datum.

Boring No. B-301

GROUND SURFACE ELEV. [illegible]

- 0' – 3': TOP OF 4" CASING TO WATER = 3'
- 3' – 28'6": WATER
- 28'6" – 35'6": [illegible] GRAY SILT, [illegible] — WT. OF [illegible]
- 35'6" – [illegible]: [illegible] GRAY SILT, LAYERS OF DARK GRAY SILT, SHELLS [illegible]
- [illegible] – [illegible]2': FINE SAND, WITH CLAYEY [illegible] GRAY SILT, SOME SHELLS — 7-[illegible]; [illegible]-17-23
- [illegible]2' – [illegible]6': [illegible] FINE SAND WITH CLAYEY [illegible]ISH GRAY SILT — [illegible]
- [illegible]6' – 65': HARD SILTY BLUISH GRAY CLAY WITH SEAMS OF FINE [illegible] GRAY SAND — [illegible]

USED 45' OF 4" CASING

1-16-68

Boring No. B-302

GROUND SURFACE ELEV. [illegible]

- 0' – 2'6": TOP OF CASING TO WATER SURFACE
- 2'6" – 2[illegible]: WATER
- [illegible] – [illegible]: LOOSE GRAY SILT (MUCK) — WT. OF [illegible]
- [illegible]: FINE SAND, GRAY SILT, SHELLS & [illegible] OF DARK GRAY SILT — [illegible]
- [illegible]: SILTY, STIFF, [illegible] GRAY CLAY, [illegible] FINE SAND, [illegible] SHELLS [illegible] — [illegible]; 7-[illegible]; [illegible]-11
- [illegible]: CLAYEY GRAY SILT, WITH SOME FINE SAND, SHELLS AND SOFT LIMESTONE FRAGMENTS NOTED — [illegible]
- [illegible] – [illegible]6": [illegible] WITH SOFT [illegible] LIMESTONE — [illegible]

USED 45' OF 4" CASING

1-[illegible]-68

Boring No. B-303

GROUND SURFACE ELEV. [illegible]

- 0' – 2'6": TOP OF CASING TO WATER
- 2'6" – 2[illegible]: WATER
- [illegible]: LOOSE GRAY SILT (MUCK)
- [illegible]: FINE GRAY SAND, [illegible] SILT, SHELLS, TRACE OF [illegible] GRAY CLAY — [illegible]
- [illegible]: FINE SAND WITH [illegible] GRAY SILT, TRACE OF SHELLS — 7-1[illegible]
- [illegible]: NOTE A — [illegible]
- [illegible]: SILTY CLAY AND [illegible] CLAY W/ [illegible] FINE SAND AND SHELLS — [illegible]-12-1[illegible]
- [illegible]: CLAYEY [illegible] & [illegible] SILT W/ [illegible] — 1[illegible]
- [illegible] – [illegible]: HARD SILTY BLUISH GRAY CLAY WITH SOME FINE SAND — [illegible]

NOTE A: FINE SAND WITH [illegible] GRAY SILT, [illegible] CLAY, TRACE OF SHELLS

USED 45' OF 4" CASING

1-1[illegible]-68

RAYMOND

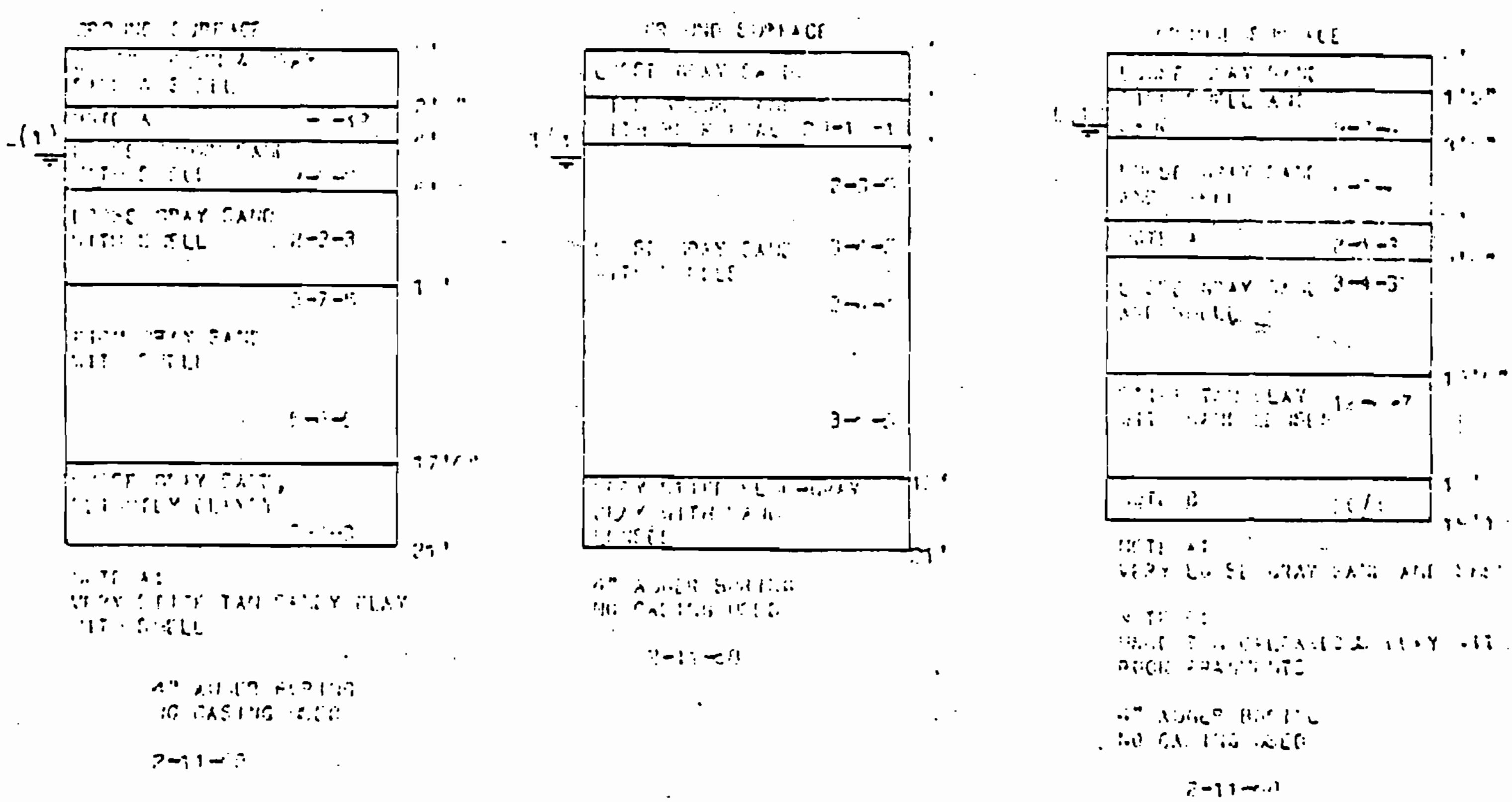
CONCRETE PILE DIVISION

To ______________________ Date ______________________

Location of Borings ______________________

All borings are plotted to scale of 1" = ____ ft. using ______________________ as a fixed datum.

Boring No. ______ Boring No. ______ Boring No. ______



Classifications are made from visual inspection.

Water Levels (WL). Figure indicates time of reading (hours) after completion of boring. Water levels indicated are those observed when borings were made, or as noted. Porosity of the soil stratas, variations of rainfall, site topography, etc., may cause changes in these levels.

Figures in right hand column indicate number of blows required to drive 2" O. D. sampling pipe one foot using a 140 lb. weight falling 30 inches.

Total Footage ______

Foreman ______

Classifications by ______

Job No. ______

Sheet ______ of ______

RAYMOND

CONCRETE PILE DIVISION

To [illegible] COMPANY Date [illegible] FEBRUARY [illegible]

Location of Borings [illegible]

All borings are plotted to scale of 1" = [illegible] ft. using [illegible] SURFACE as a fixed datum.

Boring No. [illegible] Boring No. Boring No.

GROUND SURFACE — 0'

[illegible] & GRAY SAND W/ROOTS		0' – 2'6"
[illegible]	[illegible]	3'6"
LOOSE GRAY SAND WITH SHELL AND ROCK FRAGMENTS	3–3–2	
	4–4–5	[illegible]
[illegible] GRAY SAND, VERY [illegible]	[illegible]–7	12'6"
[illegible] SAND	6–6–6	
	[illegible]	21'

WL ([illegible])

NOTE: AT [illegible] YELLOW SAND WITH SHELL AND ROCK FRAGMENTS

[illegible] AUGER BORING
NO CASING USED

[illegible]

GENERAL NOTE: FIGURES [illegible] IN RIGHT HAND COLUMN OF BORING LOG ARE DEFINED BY THE NOTATION

[illegible] / DENOMINATOR = NUMBER OF BLOWS / PENETRATION IN INCHES

Classifications are made from visual inspection.

Water Levels (WL). Figure indicates time of reading (hours) after completion of boring. Water levels indicated are those observed when borings were made, or as noted. Porosity of the soil stratas, variations of rainfall, site topography, etc., may cause changes in these levels.

Figures in right hand column indicate number of blows required to drive 2" O. D. sampling pipe one foot, using a 140 lb. weight falling 30 inches.

[illegible]

Total Footage [illegible]

Foreman [illegible]

Classifications by [illegible]

Job No. B-[illegible]

Sheet [illegible] of 6

APPENDIX B

CONTINUOUS MONITORS

GENERAL REQUIREMENTS

TECO's Gannon Station will probably be subject to continous monitoring requirements for SO_2 and opacity. System requirements are not highly dependent on the precise SIP regulation that is adopted for the plant, because a computerized data reduction system will be necessary in any case. A recent agreement by West Penn Power for the Mitchell Plant included requirements to transmit ambient data directly to the state on an hourly basis. For Gannon it might be practical to report only the hourly emissions that exceed emission standards and to report daily emissions in a simple report each month. The monthly report format might be as simple as the following:

SO_2 Emissions Report - August 31, 1984

Excursions Above Limits To Date (13.7 ton/h, 254 ton/day) - Gannon

Max. hour	Date	Max ton/h	Ton/day
1100	01-14-84	13.0	270*
1300	04-01-84	13.9*	241
1100	06-17-84	12.8	258*
1400	06-18-84	14.2*	255*
1300	08-27-84	13.8*	259*

*Indicates an exceedance.

Only days with exceedances would be reported. For all reported days, the maximum hourly reading would be reported. Exceedances would be identified by an asterisk. The above report indicates that four days exceeded the daily cap. Short-term (hourly) exceedances accounted for the other infraction. Two days exceeded both the hourly and daily limits.

To implement the SO_2 emission bubble and to insure the successful enforcement of SO_2 emission limits TECO will have to install and operate a sophisticated continuous emissions monitoring system (CMS). The following description of emissions monitoring concepts and requirements for existing boilers is condensed mainly from "Evaluation Of Continuous Monitoring Systems For Stationary Sources", a manual prepared by Engineering-Science, McLean, Virginia, for the U.S. Environmental Protection Agency, Region IV, August 1, 1978.

We have not performed an in-depth cost analysis for continuous emissions monitoring systems that will be required by TECO, but other clients have indicated costs in the neighborhood of $100,000 to monitor a single unit. Some economics can be effected in a system to process and report data for six boilers at once; $500,000 might be a good first guess at the capital cost for the system. At least one operator will probably be required on a full-time basis to maintain the system.

REGULATIONS

On October 6, 1975, EPA adopted requirements for the continuous emission monitoring of certain new and existing sources. The requirements for existing sources were adopted under 40 CFR Part 51, "Requirements for the Preparation, Adoption and Submittal of Implementaion Plans. The requirements for new sources were adopted under 40 CFR Part 60, Standards of Performance for New Stationary Sources. These regulations appeared in the Federal Register at 40 FR 46256, October 6, 1975. The continuous monitoring requirements adopted by EPA are minimum requirements. State and local agencies may, at their discretion, adopt more comprehensive or stringent requirements.

In general, these regulations require that specific categories of industrial sources shall install continuous monitoring systems to monitor emissions of sulfur dioxide, oxides of nitrogen, and opacity. In certain cases, sources are also required to monitor carbon dioxide or oxygen so that the output from the SO_2 and NO_x monitors can be converted to units of the standard. The regulations include requirements for design and performance specifications, procedures for conducting performance evaluations, and requirements for record keeping. These regulations provide the basic framework for EPA's continuous monitoring programs under the Clean Air Act and thus provide a useful reference for federal, state, and local air pollution officials involved in implementing these programs.

The requirements for existing sources to install continuous monitoring systems were designed to partially implement the requirements of Sections 110(a)(2)(F)(ii) and (iii) of the Clean Air Act, which state that implementation plans must provide "requirements for installation of equipment by owners or operators of stationary sources to monitor emissions from such sources", and "for periodic reports on the nature and amounts of such emissions". However, the original implementation plan requirements did not require SIP's to contain legally enforceable procedures mandating continuous emission monitoring and recording. At the time the original requirements were published, EPA had accumulated little data on the availability and reliability of continuous monitoring devices. The Agency felt that the state-of-the-art was such that it was not prudent to require existing sources to install such devices.

Since that time, much work has been done by EPA and others to field test and compare various continuous emission monitors. As a result of this work, the Agency now believes that for certain sources, performance specifications for accuracy, reliability, and durability can be established for continous emission monitors of oxygen, carbon dioxide, sulfur dioxide, and oxides of nitrogen and for the continuous measurement of opacity. Accordingly EPA adopted the requirements now contained at 40 CFR 51.19(e) which requires states to revise their implementation plans to include legally enforceable procedures to require certain stationary sources to install, calibrate, maintain, and operate equipment for continously monitoring and recording emissions. The specific stationary sources and pollutants to be monitored are identified in 40 CFR 51, Appendix P - Minimum Emission Monitoring Require ments. Appendix P outlines the specifics of the applicability of the continous monitoring regulations regarding size (throughput) limitations for the affected facilities, the pollutants that must be monitored, exemptions, performance specifications, and evaluation procedures, data reduction and maintenance requirements, and special considerations regarding alternative procedures.

The States were required to revise their implementation plans to include specific procedures for continuous monitoring systems within one year after EPA adopted its requirements under 40 CFR Part 51; that is, the revised plans were due to be submitted by October 6, 1976. Source owners are required to have the continuous monitoring systems on-line within eighteen months of EPA's approval of promulgation of the revised plans.

Several of the salient features of the CMS requirements for existing sources are discussed in the paragraphs below.

Affected Facilities

Fossil-fuel fired steam generators must, under certain circumstances, be monitored for emissions of opacity, sulfur dioxide, nitrogen oxides, and, if necessary to convert to units of the applicable standard, oxygen or carbon dioxide. No monitoring is required if the annual average capacity factor is less than or equal to 30 percent, as reported to the Federal Power Commission for the calendar year 1974. In addition, monitoring is not required if no SIP emission limitation is in effect.

Opacity monitoring is required for coal-fired units having greater than 250 million Btu/h heat input. Oil and combination oil and gas-fired units are exempt if a particulate collection device is not necessary to meet the SIP emission limit at for particulate collection device is not necessary to meet the SIP emission limit for particulates and the unit has no history of visible emissions violations. Sulfur dioxide monitoring is required for units having a heat input greater than 250 million Btu/h and that utilize SO_2 control equipment.

Reporting Requirements

The SIP's should provide for quarterly reporting by source operators. The reports must contain data regarding excess emissions and periods when the continous monitoring equipment was inoperative (40 CFR 51, Appendix P, Paragraph 4). If neither situation occurred during the quarter, a report documenting the absence of these events must still be filed.

The reports should identify, where applicable, the cause of excess emissions, the dates, times, and magnitude of such emissions and the dates and times when the continuous monitoring system was inoperative and the nature of repairs and adjustments. Excess opacity emissions should be reported as one-minute averages or other time periods prescribed by the state. Excess emissions for SO_2 and NO_x should be reported in units of the standard; the averaging time should be required to be consistent with the averaging period specified in the emission test method used to determine compliance with the applicable SIP emission limitation.

Data reduction procedures are essentially the same as required for new sources under 40 CFR 60. However, the units of the SIP emission limitations may be different from those for sources subject to NSPS, thus requiring some alteration of certain data reduction procedures.

Performance Specifications

The performance specifications for monitors installed on existing facilities are the same as those for new facilities. These specifications are tabulated in Tables II-1 through II-3. It should be noted, however, that for existing sources that purchased an emission monitoring system prior to September 11, 1974, the SIP may provide for an exemption from meeting the performance specifications and associated test procedures for a period not to exceed five years from plan approval or promulgation.

Special Considerations

In Appendix P, Paragraph 6.0, EPA has recognized the difficulty in setting uniform requirements for continuous monitoring systems at existing facilities and has allowed the SIPs to include flexible requirements that will not impede the development of new technology and will provide the minimum installation and operating costs. Alternative monitoring requirements may be adopted on a case-by-case basis. Specific problems that may be encountered (ii) infrequent operation of the facility, (iii) extreme economic burden, and (iv) physical limitations at the facility.

Major Differences in Requirements For New and Existing Sources

EPA allows more flexibility in implementing CMS requirements for existing sources as compared to new sources. For new sources, the continous monitoring system can be integrated into the original design of the facility. Retrofitting CMS equipment on existing facilities may require significant additional expenses relating to altering existing equipment, e.g., representative

TABLE II-1. PERFORMANCE SPECIFICATIONS FOR TRANSMISSOMETERS

	Parameter	Specification
A.	Calibration error*	±3% opacity
B.	Zero drift (24h)*	±2% opacity
C.	Calibration drift (24 h)	±2% opacity
D.	Response time	10 seconds (maximum)
E.	Operation test period	168 hours

*Expressed as a sum of absolute mean value plus 95 percent confidence interval of a series of tests.

PERFORMANCE SPECIFICATIONS
FOR GAS MONITORS

TABLE II-2. SO_2 AND NO_x MONITORS

	Parameter	Specification
A.	Accuracy*	±20% of mean value of reference method test data.
B.	Calibration error*	±5% of each (50%, 90%) calibration gas mixture
C.	Zero drift (2 h)*	2% of Span
D.	Zero drift (24 h)*	2% of Span
E.	Calibration drift (2 h)*	2% of Span
F.	Calibration drift (24 h)*	2.5% of Span
G.	Response time	15 minutes (maximum)
E.	Operational period	168 hours (minimum)

TABLE II-3. CO_2 AND O_x MONITORS

	Parameter	Specification
A.	Zero drift (2 h)*	±0.4% O_2 or CO_2
B.	Zero drift (24 h)*	±0.5% O_2 or CO_2
C.	Calibration drift (2 h)*	±0.4% O_2 or CO_2
D.	Calibration drift (24 h)*	±0.5% O_2 or CO_2
E.	Response time	10 minutes (maximum)
F.	Operational period	168 hours (minimum)

*Expressed as a sum of absolute mean value plus 95 percent confidence interval of a series of tests.

sampling locations may be inaccessible or nonexistent. If retirement of the facility is scheduled in the near future, or if it is operated only on a limited basis, CMS installation and operating costs may not be warranted. Thus, under the requirements of 40 CFR 51, Appendix P, EPA suggests that the States provide for case-by-case determinations of the desirability of continous emission monitoring systems. Similarly, EPA generally requires all new sources within a category to install monitoring systems, whereas smaller existing sources are exempted.

Other major differences between the requirements for new and existing sources are summarized as follows:

- EPA regulates new sources directly NSPS; existing sources are regulated by states according to minimum requirements set by EPA.

- NSPS specify a six-minute averaging time for opacity measurements be used to determine compliance whereas Part 51 specifies a one-minute averaging time (or such time period prescribed by the state) be used to compute excess emissions.

- NSPS specify a three-hour averaging time for gaseous pollutants--Part 51 specifies that the averaging time used by the state for manual compliance testing shall be used.

- Oil-burning and oil/gas-burning boilers are exempted from opacity monitoring requirements if they are existing sources and have no record of visible emissions violations, whereas all such boilers are required to monitor opacity under NSPS.

- Monitors for nitrogen oxides are required only in those AQCR's where the Administrator has called for a control strategy for nitrogen dioxide for Part 51 requirements whereas Part 60 regulations require nitrogen oxides monitors regardless of SIP requirements.

EXTRACTIVE AND IN-SITU MONITORS

All categories of sources required to install continuous gaseous emission monitors are faced with the problem of selecting instruments that will give data representative of the actual source emissions. The extraction of a sample gas from a stack or duct presents a number of problems for extractive continuous analyzers. To obtain accurate results, a representative sample must be extracted and transported to the monitor itself. Beforehand, the sample must be processed by removing particulate matter, water vapor, and, in some cases, specific gases that interfere in the analytical method. In-situ monitors, in contrast with extractive monitors, do not require the removal of particulates or water vapor. The analytical methods used in in-situ monitors have been chosen to avoid these interferences. In-situ monitors do, however, have limitations in their application. If a stack or duct contains entrained water in the form of liquid droplets, light scattering problems and adsorption of the pollutant gases in the liquid may cause the instrument values to differ from those obtained by the EPA reference method. The choice of the type of system (extractive or in-situ) to be used in a given application will often depend upon features of the plant design.

The selection of a monitor is also dependent upon the criteria for performance. An SO_2 emissions monitoring system must meet the following specifications after it is installed on the source:

Accuracy	≦20%
Calibration error	≦5%
Zero drift	
2 hour	≦2% of span
24 hour	≦2% of span
Calibration drift	
2 hour	≦2% of span
24 hour	≦2.5% of span
Response time	15 minutes (maximum)
Operational period	168 hours

Extractive and in-situ SO_2 emission monitors can be characterized by the principles of chemical physics used. The methods used can be grouped into three major categories:

- absorption spectrometers
- luminescene analyzers
- electroanalytical methods

Extractive SO_2 monitors utilize methods from all of these categories, whereas in-situ systems generally use spectroscopic absorption methods. An exception is thermal conductivity used in a few in-situ SO_2 monitors.

EXTRACTIVE ANALYZERS

In the past, either existing ambient air monitors or common laboratory instruments were modified for source-level monitoring applications. Problems tended to arise with the inevitable dilution systems and delicate nature of some of these systems. Many of these earlier problems have since been solved. Extractive analyzers are now designed to specifically monitor at source-level concentrations and are constructed to withstand the rigors of a plant environment.

Absorption Spectrometers

Nondispersive infrared (NDIR) analyzers have been developed to monitor SO_2, NO, CO, CO_2, and other gases that absorb in the infrared, including hydrocarbons. An NDIR analyzer utilizes a broad band of infrared light centered at an absorption peak of the pollutant molecule.

The advantages of the NDIR analyzers are their relatively low cost and the ability to apply the method to many types of gases. Problems associated with the method arise from interfering species, the degradation of optical systems due to corrosive atmospheres, and in some cases, limited sensitivity. Detectors are sensitive to vibration, often requiring electronic and mechanical damping.

MANUFACTURERS OF NDIR MONITORS

Beckman Instruments, Inc. 2500 Harbor Boulevard Fullerton, CA 92634 (714) 871-4848	Bendix Corporation Process Instruments Div. P. O. Drawer 831 Lewisburg, WV 24901 (304) 647-4358
Calibrated Instruments, Inc. 431 Saw Mill River Road Ardsley, NY 10502 (914) 692-9232	Esterline-Angus 19 Rozel Road Princeton, NJ 08540 (609) 452-8600
CEA Instruments (Peerless) 555 Madison Avenue New York, NY 10022 (212) 247-2518	Leeds & Northrop Sumneytown Pike Northwales, PA 19454 (215) 643-2000
Horiba Instruments, Inc. 1021 Buryea Avenue Irvine, CA 92714 (714) 540-7874	MSA Instrument Division Mine Safety Appliances 400 Penn Center Blvd. (412) 241-5900

Infra-red Industries
P. O. Box 989
Santa Barbara, CA 93102

Teledyne
Analytical Instruments
333 West Mission Drive
P. O. Box 70
San Gabriel, CA 91776

Several nondispersive systems are available that use light in the ultraviolet and visible regions of the spectrum rather than in the infrared. To analyze for SO_2, these instruments utilize one of the narrow absorption bands of the ultraviolet absorption spectrum. The instruments work in a similar manner to the NDIR method discussed previously. Essentially, the analyzers measure the degree of absorption at a wavelength in the absorption band of the molecule of interest, (280 mm for SO_2). This method of analysis is often termed "differential absorption" because measurements are performed at two different frequencies. One at the wavelength of maximum absorption and one where SO_2 has minimal absorption.

MANUFACTURERS OF EXTRACTIVE DIFFERENTIAL ABSORPTION ANALYZERS

GEA Instruments
555 Madison Avenue
New York, NY 10022
(212) 247-2518

DuPont Company
Instrument Products
Scientific & Process Div.
Wilmington, DE 19898
(302) 772-5500

Western Research and
Development Ltd.
Marketing Department
#3, 1313 - 44th Avenue, N.E.
Calgary - Alberta T2E GL5
(403) 276-8806

Esterline-Angus
19 Rozel Road
Princeton, NJ 08540
(609) 452-8600

Teledyne
Analytical Instruments
333 West Mission Drive
P. O. Box 70
San Gabriel, CA 91776

Luminescence Methods

Luminescence is the emission of light from a molecule that has been excited in some manner and photoluminescence is the release of light after a molecule has been excited by ultraviolet, visible, or infrared radiation. The emission of light from an excited molecule created in a chemical reaction is known as chemiluminescence. The atoms of a molecule can even be excited to luminescence in a hydrogen flame. These three types of luminescent processes are used in source monitoring applications. Monitors utilizing the effects of luminescene can be very specific for given pollutant species and can have greater sensitivity than some of the absorption or electrochemical methods.

Fluorescence is a photoluminescent in which light energy of a given wavelength is absorbed and light energy of a different wavelength is emitted. In this process, the molecule excited by the light energy will remain excited for about 10^{-8} to 10^{-4} seconds. This period of time will be sufficient for the molecule to dissipate some of this energy in the form of vibrational and rotational motions. When the remaining energy is re-emitted as light, the energy of the light will be lower, meaning light of a longer wavelength (lower frequency) will be observed. Thus, the basis the fluorescence technique is to irradiate the molecule with light at a given wavelength (usually in the near ultraviolet) and to measure the emitted light at a longer wavelength.

The SO_2 fluorescence monitors are customarily calibrated using SO_2 in air mixtures. It has often happened, that a technician will take a convenient cylinder of span gas having SO_2 in nitrogen instead of air. Spanning the instrument with such a mixture will cause the subsequent SO_2 readings to be approximately 30% lower than the true values. Ideally, the best way to span fluorescence analyzers for source application is to use a span gas with a composition similar to that of the stack effluent. Fluorescence monitors, aside from this quenching problem, have no other significant interference problems. Particulates and water must be completely removed from the sampling stream before it enters the sampling chamber or else the instrument will easily be fouled. Permeation tube dryers are generally used in the instrument itself to eliminate any water vapor that is not removed by the extractive system.

MANUFACTURERS OF FLUORESCENCE SOURCE ANALYZERS

Thermo Electron Corporation
Environmental Instruments Div.
108 South Street
Hopkinton, MA 01748
(617) 435-5321

Research Appliance Corp.
Route 8
Gibsonia, PA 15044
(412) 443-5935

Electroanalytical Methods

Another class of instruments based upon electroanalytical methods of measurement has found great utility in source monitoring applications. There are four distinct types of electroanalytical methods used in source monitoring. These are:

- Polarography
- Electrocatalysis
- Amperometric Analysis
- Conductivity

A number of monitors based on polarographic and electrocatalytic methods are available for source monitoring applications. Polarographic analyzers have been developed for a number of gases and can be inexpensive and portable; ideal for inspection work. Complete continuous source-monitoring systems are also available from manufacturers of these instruments. The electrocatalytic or high temperature fuel-cell method, as it is often called, is used to monitor oxygen only. Both extractive and in-stack monitors are available using this technique. The methods of amperometric analysis and conductivity are less widely used and are subject to a number of interferences. They will not be discussed further in the report.

Polarographic analyzers have variously been called voltammetric analyzers or electrochemical transducers. With the proper choice of electrodes and electrolytes, instruments have been developed utilizing the principles of polarography to monitor SO_2, NO_2, CO, O_2, H_2S, and other gases.

The transducer in these instruments is generally a self-contained electrochemical cell in which a chemical reaction takes place involving the pollutant molecule. Two basic techniques are used in the transducer: (a) the utilization of a selective semipermeable membrane that allows the pollutant molecule to diffuse to an electrolytic solution, and (b) the measurement of the current change produced at an electrode by the oxidation or reduction of the dissolved gas at the electrode. For SO_2, the oxidation that takes place is:

$$SO_2 + 2H_2O \rightarrow SO_4^{-2} + 4H^+ + 2e^-$$

The polarographic analyzers in their earlier development were temperature sensitive, but temperature compensation devices are now generally provided to avoid this problem. This electrolyte of the cells will generally be used up in 3 to 6 months of continuous use. The cells can be sent back to the manufacturer and recharged, or new ones can be purchased. It is extremely important that the sample gas be conditioned before entering these analyzers. The stack gas should come to ambient temperature and the particulate matter and water vapor should be removed to avoid fouling the cell membrane.

With proper use, polarographic analyzers can be a valuable tool to an air pollution agency's inspection program or to a source operator wishing to check pollutant levels at various plant locations. Complete systems are also available for continuous monitoring, but should be designed carefully so as to give accurate data.

MANUFACTURERS OF POLAROGRAPHIC ANALYZERS

Dynasciences (Whitaker Corp.)
Township Line Road
Blue Bell, PA 19422
(215) 643-0250

IBC/Berkeley Instruments
2700 DuPont Drive
Irvine, CA 92715
(714) 833-3300

Western Precipitation Division
Joy Manufacturing Company
P. O. Box 2744 Terminal Annex
Los Angeles, CA 90051
(Portable models - not designed for continuous stack application)

Beckman Instruments, Inc.
Process Instruments Division
2500 Harbor Blvd.
Fullerton, CA 92634
(714) 871-4848
(O_2 only)

Interscan Corp.
20620 Superior St.
Chatsworth, CA 91311
(213) 882-2331

Theta Sensors, Inc.
Box 637
Altadena, CA 91001
(213) 798-9101
(will provide systems)

Teledyne Analytical Instruments
333 West Mission Drive
San Gabriel, CA 91776
(213) 282-7181
(O_2 only - micro-fuel cell)

IN-SITU MONITORING SYSTEMS

The problems and expense sometimes associated with extractive monitoring systems have led to the development of instrumentation that can directly measure source-level gas concentrations in the stack. The so-called "in-situ" systems do not modify the flue gas composition and are designed to detect gas concentrations in the presence of particulate matter. Since particulate matter causes a reduction in light transmission, in-situ monitors utilize advanced electro-optical techniques to eliminate this effect when detecting gases. These techniques are:

- Differential absorption
- Gas filter correlation
- Second derivative spectroscopy

Also, as discussed earlier, an electrocatalytic analyzer has been designed to monitor oxygen concentrations in-situ.

Terminology

A number of terms categorize the different types of in-situ monitors.

Cross-stack in-situ monitors measure a pollutant level across the complete diameter or a major portion of the diameter of a stack or duct. There are two types of cross-stack monitors: (a) single pass and (b) double pass. Single-pass and double-pass transmissometers have been discussed earlier, and the distinction holds for in-situ gas monitoring systems. Single-pass systems locate the light transmitter and the detector on opposite ends of the optical sample path. Double-pass systems locate the light transmitter and the detector on one end of the optical sample path. To do this, the light beam must fold back on itself by the use of a retroreflector. Double-pass systems are usually easier to service than single-pass systems since all of the active components are in one location.

In-stack in-situ systems monitor emission levels by using a probe that measures over a limited sample path length. All of the commercial optical in-stack monitors are double-pass systems (the in-stack electrocatalytic oxygen monitor discussed earlier is not an optical system). The path length may vary from 8 cm to a meter. A retroreflector, usually made of quartz, is located at the end of the probe. The in-stack systems are all double-pass and have also been termed short-path monitors. The siting of such systems should follow the same guidelines as those given for extractive systems. A location representative of the pollutant level should be determined before installation.

There are currently only three vendors of in-situ optical gaseous emission monitors. Environmental Data Corporation (EDC) uses the technique of differential absorption to monitor CO_2, SO_2 and NO, and the gas filter correlation technique to monitor CO. Contraves markets an instrument that measures SO_2, NO, CO_2, and CO levels all by the gas filter correlation method. Lear Siegler, Inc. utilizes second derivative spectroscopy to measure SO_2 and NO levels with their in-stack monitor. The following discussion of each of these methods is intended to provide the reader with a background in these new technologies so that informed evaluations may be made of the commercially marketed systems.

Cross-Stack Analyzers

The technique of differential absorption spectroscopy used in the EDC cross-stack gas monitor is similar to that used in the NDUV extractive analyzers discussed earlier. To obtain a narrow band of radiation over which the pollutant molecule will absorb energy, a diffraction grating is used in this analyzer. A grating disperses light from a UV lamp and light of the appropriate wavelength is picked off; one wavelength for monitoring the pollutant level, another to serve as a reference wavelength.

The ratio of intensities in the differential absorption technique is important in the case of in-stack monitors. Particulates in the flue gas will attenuate the amount of light energy passing through the optical path. This is the principle of measurement in the opacity monitors. If the light attenuation is the same for the light energy at the measuring wavelength and that at the reference wavelength, each intensity is reduced by a constant factor.

This satisfies a requirement demanded of all in-situ monitors: that particulates not interfere in the analytical method. Interference due to the broad band absorption by water vapor or other molecular species should similarly cancel out if the measuring and reference wavelengths do not differ too greatly. Further information on this system may be obtained from:

Environmental Data Corporation
608 Fig Avenue
Monrovia, California 91019
(213) 358-4551

The gas-filter correlation (GFC) method is used in an analyzer produced by Contraves-Goerz Corp. to monitor CO_2, CO, SO_2, and NO. This method shows potential in both in-situ and remote pollutant emissions monitoring.

The GFC method has been found to be a very sensitive and specific method in the infrared. The ability to monitor a large number of absorption lines provides greater sensitivity, in some cases, than can be obtained with the differential absorption technique using only filters. The GFC method is an NDIR method; the light is not dispersed.

The Contraves-Goerz system uses only one correlation cell containing CO, CO_2, SO_2, and NO. Full advantage is taken of the spectral characteristics of these molecules to prevent problems of interference in the measurement. More information may be obtained on this system from:

Contraves-Goerz Corporation
610 Epsilon Drive
Pittsburgh, PA 15238
(412) 782-7700

In-Stack Analyzers

At the present time, only one instrument is manufactured that monitors SO_2 and NO in-stack. This is the Lear-Siegler second derivative "stack-gas monitor". Although the second derivation technique is somewhat more complicated than those discussed earlier, an understanding of the method is necessary if a source operator or agency observer has to make an evaluation of different monitoring systems.

This monitor analyzes the gas in-situ; the gas is not extracted, but is monitored as it exists in the flue gas stream. The tip of the probe contains the measuring chamber, which senses across a distance of 10 cm. The instrument therefore does not measure "cross-stack". It is an in-stack "point" monitor or "short-path" monitor. Care should be taken siting such a system since a representative location must be monitored. The guidelines given for siting of the probe of an extractive system could be followed in choosing the location of an in-stack monitor, although EPA has not published any specific siting criteria for this technique outside of the general criteria for representative measuring.

The second derivative in-stack monitor is, of course, limited to monitoring one stack at a time. Vibration can also be a problem since the optical system can suffer in extreme cases. One of the most common problems in this and similar electro-optical systems is the failure of electronic components. The complicated circuitry of such systems in some cases may lead to a higher probability of component failure. A significant feature of the LSI system is that zero and span gases can be used to flood the sample chamber to a pressure greater than the stack static pressure. This provides an alternate method to the use calibration cells if desired. The calibration cells may be used for daily span checks and would save the expense of span gas and associated plumbing systems. The LSI second derivative source monitor may also be modified to measure ammonia concentrations. More information may be obtained on the analyzer from:

Lear Siegler, Inc.
Environmental Technology Division
74 Inverness Drive East
Englewood, CO 90110
(303) 770-3300

DATA HANDLING TECHNIQUES

The continuous emission monitoring regulations do not contain detailed specifications for data handling equipment. Other than specifically requiring that a data recorder be used, in most instances there are few or no additional requirements. Given only rather general "data recorder" requirements, one is tempted to conclude that just about any recorder would be acceptable, but closer scrutiny of the regulations reveals that this is not the case. Performance specifications are stipulated for the entire continuous monitoring system which consists of several subsystems, including the data recorder. Therefore, by being a part of the monitoring system, the data recorder must function properly if the monitoring system is to meet the performance specifications.

The monitoring system data need not be continuously recorded. Continuous monitoring systems must meet only the following operating requirements:

- Opacity monitoring system - minimum of one cycle of sampling and analysis every 10 seconds and one cycle of data recording every 6 minutes.

- Gaseous (SO_2, NO_x, CO_2, O_2) monitoring system - minimum of one cycle of operation (sampling, analyzing, and data recording) every 15 minutes.

The number of different data handling systems greatly exceeds the types of continuous monitors. All data acquisition systems (DAS) can be grouped into three major categories:

- Strip chart recorder

- Data logger and support device

- Mini computer and support device

Strip chart recorders creat a continuous trace of the analog signal corresponding to the parameter being measured. The primary disadvantage to the use of a strip chart recorder is the time requirement involved in manually reducing the data. For opacity monitoring data, six-minute averages have to be calculated from a minimum of 24 equally-spaced points. In the case of gaseous monitoring data, one-hour averages must be calculated from a minimum of four equally-spaced points. Only excess emissions need to be reduced and reported, but the process of reducing a large volume of strip chart data is quite tedious and time-consuming. When measuring SO_2 and/or NO_x at fossil fuel-fired steam generators, the corresponding O_2 (or CO_2) measurement and the appropriate "wet" or "dry" F factor must be used to determine if the pollutant value is an excess emission point.

At most sources the monitoring data are handled with automated data processing (ADP). A single data logger, the most basic type of ADP system, can be an active or passive device. As a passive device, the data logger will collect analog data from the analyzers at pre-selected intervals as required by the standards, transform this analog data to a digital signal using an internal digitizer, and then output this signal to a recording device. As an active device, the data logger incorporates a programmable microprocessor. In this case, after the signal from the analyzer has been digitized, the data is then converted to the proper engineering units and is then output to a recording device. Depending upon the programming capacity of the microprocessor, the data logger can flag or delete periods of analyzer malfunctions and of calibration checks. The data logger may also be used to average the data and to warn of system measurements that exceed the applicable standard. Because the output is in digital form, the data logger can act as a remote device to send data long distances over dedicated telephone lines.

The second kind of available ADP system is that controlled by a mini-computer. Because of the large programming and storage potential of the computer, many data handling functions can be performed automatically. The computer is used frequently to control a remote data logger. Because of the long distance data transmission capabilities of a digital signal, a most significant aspect of the computer is its capability for processing data as it is being collected. Most computer systems available today can perform the following:

- Collect raw data from analyzer/data logger
- Convert data to proper units
- Average data according to standard
- Output data to multiple recording devices
- Automatically control daily calibration of instruments

From an inspector's viewpoint, it is extremely difficult to discern much from a data handling procedure conducted exclusively by automated processing equipment. Even with the examination of chart recorded data, the best that can be expected at this time is the detection of more commonly occurring errors and the identification of trends in the data which may point to possible malfunctions in one of the monitoring subsystems.

DATA REDUCTION PROCEDURES AND EXCESS EMISSION REPORTS

Conversion Factors

Gaseous emission standards for fossil fuel-fired steam generators (FFFSG) covered by NSPS, as well as many state emission limitations for existing facilities in that source category, are expressed in terms of mass per unit of heat input, i.e. lb/10^6 Btu. On the other hand, the output from continuous systems to monitor these emissions is expressed in terms of pollutant concentration, i.e. ppm. In order to determine the compliance status of gaseous emissions from FFFSG, it is, therefore, necessary to apply a conversion factor to the monitor data (ppm) in order to determine the emission rate (lb/10^6 Btu).

This issue of converting monitoring data to units of the standards becomes more complex for the case of steam generators. For these types of fossil fuel-fired facilties, large errors can result in the computation of emission rates if no correction is made for the presence of excess air. These potential inaccuracies can be minimized by simultaneously monitoring a "diluent gas", such as O_2 or CO_2, at the point where the pollutant(s) is measured, and then adjusting or normalizing the pollutant concentration to a common basis.

Therefore, the conversion process for FFFSG in calculating source emission rates in units of the standards from monitoring data in units of concentration involves two additional parameters known as (1) an F factor and (2) a diluent gas concentration. The generalized equations for converting pollutant monitoring data to units of the standard are shown below for the cases where O_2 is the diluent gas monitored and where CO_2 is the diluent gas monitored, respectively.

$$E = K \times Cp \times F \times \frac{20.9}{(20.9 - \%O_2)}$$

and

$$E = K \times Cp \times F \times \frac{100}{\%\ CO_2}$$

where E = pollutant emission rate, lb/10^6 Btu

Cp = pollutant concentration as measured by the continuous monitoring system, ppm

K = constant; factor that converts units of Cp from ppm to lb/dscf

$\%O_2$ = percent volumetric concentration of O_2 determined at same location and same time as Cp

$\%CO_2$ = percent volumetric concentration of CO_2 determined at same location and at same as Cp

F = factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted, dscf/10^6 Btu

F_c = factor representing a ratio of the volume of carbon dioxide generated to the colorific valve of the fuel combusted, dscf/10^6 Btu

Although use of either of the above equations would appear rather uncomplicated and straightforward, conversion of the monitoring data requires that the pollutant and diluent gases be measured on a consistent basis, i.e. either dry or "wet" (including water vapor) and the corresponding F (or F_c) factor also be on that same dry or "wet" basis. It is of utmost importance that conversion calculations do not employ a combination of dry concentration measurements and a "wet" F (or F_c) factor or vice versa. It should be apparent that conversions using the F factor are utilized in conjunction with O_2 measurements. Either method may be used, but consistency in the basis of the calculation is critical.

The F (or F_c) factor for a given fuel can be determined from the stoichiometry of the reactions for complete combustion if the composition of the fuel is known. Therefore, by conducting both an ultimate analysis on the given fuel and a determination of the gross heating value of that fuel, equations for the different basis F factors are derived as follows:

$$F_d = \frac{10^6\ (3.64\%H + 1.53\%C\ 0.57\%S + 0.14\%N - 0.46\%O)}{GCV}$$

$$F_w = \frac{10^6\ (5.57\%H + 1.53\%C + 0.57\%S + 0.14\%N - 0.46\%O + 0.21\%H_2O)}{GCV}$$

$$F_c = \frac{10^6\ (0.321\%C)}{GCV}$$

where: F_d = F factor on a dry basis and O^2 is the diluent gas monitored

F_w = F factor on a wet basis and O_2 is the diluent gas monitored

F_c = F_c factor when CO_2 is the diluent gas monitored (either dry or wet basis)

%H, %C, %S, %N, %O = weight percent of these respective elements in the fuel, as determined by the ultimate analysis

$\%H_2O$ = weight percent of free water in the fuel sample, analyzed on an "as-received" basis

GCV = gross calorific value of the fuel combusted, Btu/lb

It must be emphasized that F_c factors are used in conjunction with CO_2 diluent monitoring; F_d (dry) and F_w (wet) are F factors that correspond to O_2 diluent monitoring.

As shown in Table II-4, average values for F_d, F_w, and F_c have been compiled for the more common types of fossil fuels being burned. The affected facility has been given the option of either using an average F factor value from the table or experimentally determining that value from fuel analysis together with equation 3, 4, or 5 above.

Once the particular F factor has been selected, SO_2 and NO_x continuous monitoring data can be converted from ppm to lb/10^6 Btu using one of the following appropriate equations:

TABLE II-4. F FACTORS FOR VARIOUS FUELS[1]

Fuel Type	F_d dscf/10^6 Btu	F_w wscf/10^6 Btu	F_c scf/10^6 Btu
Coal			
Anthracite	10140 (2.0)	10580 (1.5)	1980 (4.1)
Bituminous	9820 (3.1)	10680 (2.7)	1810 (5.9)
Lignite	9900 (2.2)	12000 (3.8)	1920 (4.6)
Oil	9220 (3.0)	10360 (3.5)	1430 (5.1)
Gas			
Natural	8740 (2.2)	10650 (0.8)	1040 (3.9)
Propane	8740 (2.2)	10240 (0.4)	1200 (1.0)*
Butane	8740 (2.2)	10430 (0.7)	1260 (1.0)
Wood	9280 (1.9)*	-----------	1840 (5.0)

Wood Bark	9640 (4.1)	-----------	1860 (3.6)

[1]Shigehra, R. T., et al "Summary of F Factor Methods for Determing Emissions from Combustion Sources." Source Evaluation Society Newsletter Vol. 1, No. 4, November 12, 1976.

[a]Numbers in parenthesis are maximum deviations (%) from either the midpoint or average F Factors.

Note: To convert to metric system, multiply the above values by 1.123×10^{-4} to obtain scm/10^6 cal.

[b]All numbers below the asterisks (*) in each column are midpoint values. All others are averages.

$$E = C_d F_d \frac{20.9}{20.9 - \%O_{2_d}}$$

$$E = C_w F_d \frac{20.9}{20.9 (1 - B_{ws}) - \%O_{2_w}}$$

$$E = C_w F_w \frac{20.9}{20.9 (1 - B_{wa}) - \%O_{2_w}}$$

$$E = C_d F_c \frac{100}{\%CO_{2_d}} = C_w F_c \frac{100}{\%CO_{2_w}}$$

where

E = Emission rate in lb/10^6 Btu

C_d = Average dry continuous monitor data in lb/dscf obtained by multiplying hourly average concentration in ppm by 2.64×10^{-9} (m) lb/dscf/ppm where

m = molecular wt of pollutant measured
m for SO_2 = 64.07
m for NO_x = 46.01

C_w = Same as C_d but on a wet basis

$\%O_{2_d}$ = Volume percent of O_2 continuously measured over the same time base as pollutant emissions, dry basis

$\%O_{2_w}$ = Volume percent of O_2 continuously measured over the same time base as pollutant emissions, wet basis

$\%CO_{2_d}$ = Volume percent of CO_2 continuously measured over the same time base as pollutant emissions, dry basis

$\%CO_{2_w}$ = Volume percent of CO_2 continuously measured over the same time base as pollutant emissions, wet basis

B_{ws} = Moisture content of stack gas, volume fraction

B_{wa} = Moisture content of air entering combustion chamber, volume fraction

Data Averaging

When continuous monitoring data are being reduced, i.e. converted to units of the standard and then averaged, there are differences in averaging methods depending upon the type of applicable regulation, i.e. either an NSPS or an SIP emission limitation. Only in states which employ NSPS-type emission standards for existing sources will the data averaging scheme be a common procedure.

Opacity--

For opacity data NSPS regulations require that measurements be averaged on a six-minute basis in order to coincide with the Reference Method 9 procedure for evaluating visible emissions. Many state-of-the-art transmissometer systems are now being equipped with an internal, averaging function that automatically stores the opacity measurements over a six-minute interval, integrates that data, and prints out the six-minute averaging value. (Note: This coincides with the NSPS cycle time requirement for measurement of opacity at least once every ten seconds but data recording at least once every six minutes.)

On the other hand, the SIP requirement for opacity data (40 CFR 51, Appendix P) specifies a one-minute averaging of the data or some other time period that is deemed acceptable by the State. In some states the one-minute period is the basis for the opacity standard. Other states have elected to use the option available in Appendix P and have based their opacity standards on a six-minute interval consistent with NSPS. Therefore, the inspector must obviously be familiar with the applicable opacity standard time basis in order to confirm the correct interval for opacity averaging.

Regardless of the time basis for opacity averaging (one-minute or six-minute), that average may be determined either by (1) integration or by (2) arithematic averaging. In the case where arithematic averaging is employed, the regulations require using a minimum of four equally spaced data readings per minute.

Gases--

For averaging data from gaseous monitors on NSPS facilities, the process is rather straightforward. Gaseous monitoring data (either pollutant or diluent) are averaged on an hourly basis. Again the averages may be calculated either by (1) integration over the hourly interval or by (2) arithematic averaging over the hour. In the case of arithematic averages, the regulations require using a minimum of four equally spaced data points for determining an hourly average.

There is no comparable regulation applicable to existing sources subject to a SIP monitoring requirement. Paragraph 4.1 of Appendix P (40 CFR 51) dictates that "The averaging period used for data reporting should be established by the State to correspond to the averaging period specified in the emission test method used to determine compliance with an emission standard for the pollutant/source category in question." That requirement poses few problems for opacity, as previously discussed, over one-minute intervals in lieu of the NSPS six-minute period. However, for gaseous monitoring, each State must specify the averaging periods for required compliance tests.

Excess Emission Reports (EER)

Stationary sources subject to NSPS Regulation 40 CFR 60.7 must submit quarterly written reports of excess emissions. Similarly, 40 CFR 51 requires that all existing stationary sources, directed to implement a continuous monitoring program, must also provide quarterly excess emission reports (EER). This reporting requirement, as originally conceived in the September 11, 1974, proposal of continuous monitoring rules, specified not only quarterly reporting of excess emissions but also quarterly submittal of all monitoring results.

The public comments to that particular proposal were heavily against such procedures citing the voluminous amount of records involved and the associated costs to maintain such a reporting program. Accordingly, the promulgated rules were revised to necessitate only reporting of excess emissions.

An excess emission is one whose average emission over the time period of the subject standard exceeds the emission value. For example, if a new oil-fired steam generator emits SO_2 for three successive hours at rates of 0.6, 0.9, and 0.9 lb/10^6 Btu, it emits at an average of 0.8 lb/10^6 Btu for that three-hour period. Excess emissions are calculated on a three-hour basis for SO_2 from FFFSG, so this 0.8 lb/10^6 Btu (averaged over three hours) does not exceed the applicable 0.8 lb/10^6 Btu standard even though the boiler emitted at a higher rate than the standard for two of the three hours.

In addition to the emission value and the associated time period, some standards have exceptions which permit brief excursions above the nominal value of the standard. This is most prominent with opacity standards which normally allow two to three minutes per hour for emissions greater than the standard. When determining the occurrences of excess emissions, any exceptions such as these must be accounted for and cannot be considered in calculating an excess emission.

The regulations do not specify exact methods to report excess emissions. Basically, the minimum information that must be included in these quarterly reports includes the following:

1. The magnitude of excess emissions, date and time of occurrence (both beginning and ending); conversion factors used in data reduction.

2. Specific periods of excess emissions due to:

   °startup at facility
   °shutdown at facility
   °malfunctions at facility, and nature and cause of malfunction together with the corrective action taken

3. Specific periods when continuous monitoring system was inoperative and the nature of the system repairs

In addition, if during the calendar quarter there were no periods of excess emissions, malfunctions or inoperative monitoring systems, the quarterly report should indicate that information.

Different groups throughout the country are currently addressing the issue of excess emission reports - format, content, means of standardization, etc. Region VIII has developed the form shown on the following pages as a guideline to be used for FFFSG in preparing their emission reports.*

*Floyd, John R., "The Implementation of the NSPS Continuous Monitoring Regulations in EPA, Region VIII, presented at the 71st Annual Meeting of APCA, Houston, Texas, June 28, 1978.