Barry

Resource Recovery Office
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February 9, 1987

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BAQM

Mr. Bruce Miller
Air Program Branch
Environmental Protection Agency, Region IV
345 Courtland Street
Atlanta, Georgia 30365

RE: South Broward Resource Recovery Project (PSD-FL-105) -- Comments on stating emission rates in pounds per hour.

Dear Mr. Miller,

I am writing today to provide comments on the apparent intent of your office to modify the draft PSD permit for the South Broward Resource Recovery Project to provide emission limits in pounds per hour instead of pounds per million British thermal units (lb/MMBtu). We believe this is a significant change which is contrary to recent regulatory action of the Agency and industry practice.

I would refer you to a discussion of the appropriate units for specifying emission rates contained in the Federal Register, Vol. 49, No. 119, Page 25107, June 19, 1984 (Copy Enclosed). It is the conclusion of the Agency that "A mass per unit of heat input format was selected for the purposed standards since this format directly relates to the net quantity of pollutants emitted to the amount of fuel fired in the steam generating unit." I do not think it is necessary for me to recite all of the reasons given by the Agency for this conclusion. We agree with the conclusion and received concurrence from the Florida Department of Environmental Regulation. Both the state permit conditions and the draft final determination and PSD permit provide emission rates, except for particulate, in lb/MMBtu. I have and will continue to argue that even particulate emissions should be stated in lbs/MMBtu as the current New Stationary Sources Standard (11/86) for particulate at waste burning facilities is stated in these units (0.10 lb/MMBtu).

Several weeks ago we were told your compliance branch was concerned with how heat input could be established if lb/MMBtu rates were used. This can be done accurately without any additional Agency effort using monitoring procedures that have been developed which utilize Standard ASME Test Codes and plant instrumentation. With my letter to you of January 14, I enclosed several technical papers on this subject. This approach is being used almost universally in the resource recovery industry today.

We would urge you to reconsider restating emission rates in pounds per hour. All emission rates should be stated in lb/MMBtu. I have, however, enclosed with this letter a table which expresses the emission rates proposed in my letter of January 14, 1987, in pounds per hour for your reference.

In my discussion with Wayne Aronson last week, he indicated your office was also considering adding to the permit emission rates expressed in parts per million for Sulfur Dioxide, Nitrogen Oxides and Carbon Monoxide . These values would apparently be used in conjunction with Continuous Emission Monitoring (CEM) devices. Mr. Aronson stated no firm decision had yet been made on requiring a CEM for Sulfur Dioxide but CEMs would probably be required for Nitrogen Oxides and Carbon Monoxide.

We have already agreed to installation of Oxygen and Opacity CEM's. We believe that along with annual stack tests required by the state permit these CEM's will provide more than enough information for the plant operator to comply with permitted emission rates and for your Agency to monitor the plant.

Before closing, I would once again ask that we be included in any discussions during the permit decision making process. If I had not contacted Mr. Aronson last week, we would be unaware of any of the important matters addressed in this letter. The only written communication concerning our application received by this office from EPA Region IV to date is a letter dated **September 17, 1985**, from Mr. Winston Smith related to State Implementation Plan problems because of provisions of the Florida Power Plant Siting Act. We have not received a single word related specifically to our application. We have not received any feed back on what we feel were reasonable proposals and technical matters requireing consideration contained in my letters to you dated December 1, 1986, and January 14, 1987. Along with the North Broward Resource Recovery Project, the subject of our application has been proposed to meet a critical need for an environmentally sensitive means of disposing of solid waste in the unique South Florida environment. I am sure that better communications between our two public agencies would result in a better permit and Project. I urge you to get us more involved and keep us better informed as to the status of our permit.

Sincerely yours

Thomas M. Henderson

Thomas M. Henderson
Project Director

TMH/bd

Enclosure: Federal Register, Vol. 49, No. 119, Pages 25107 and 25108, June 19, 1984; and
Maximum Emission Rates in Pounds per Hour and Parts per Million

cc: F. T. Johnson, County Administrator
Cliff Schulman, Greenberg Traurig Askew
Tim Smith, Greenberg Traurig Askew
Ken Kosky, KBN Engineering
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Winston Smith, EPA Air, Pesticides & Toxics Division
Wayne Aronson, EPA Air Program Branch
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MAXIMUM EMISSION RATES
SOUTH BROWARD RESOURCE RECOVERY PROJECT

	Proposed Emission Rates		
	In Application	January 14, 1987 Letter	
Pollutant	lb/hr[1]	lb/hr	ppm[2]
Particulate Matter	71.8	36.7 [0.015gr/dscf-12%]	
Sulfur Dioxide	533.8	301.9	124 ppm[3]
Nitrogen Dioxides	543.5	539.2	309 ppm[4]
Carbon Monoxide	87.4	86.3	81 ppm[5]
Lead	2.9	1.51	
Fluorides	17.5	3.88	
Beryllium	0.0009	0.00091	
Mercury	0.89	0.895	
Sulfuric Acid Mist	45.6	Operating Practice < 150.95 lb/hour Total Sulfur	

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1 Emission Rates presented in pounds per hour on Page 2-17 of the Technical Support Document.

2 All Emission Rates in ppm corrected to 12% CO_2.

3 Maximum 3-hour average.

4 Maximum 30-day rolling average. Maximum 3-hour average - 350 ppm.

5 Maximum 30-day rolling average. Maximum 1-hour average - 400 ppm.

under the proposed standards of performance. Similarly, nitrogen oxides have been selected for regulation under the proposed standards of performance.

Sulfur dioxide emissions from industrial-commercial-institutional steam generating units have been selected for regulation under a separate proposal. As part of the deliberations on reauthorization of the Clean Air Act, amendments were introduced in the 97th Congress that would have changed the definition of standard of performance. Development of sulfur dioxide standards for industrial-commercial-institutional steam generating units was suspended shortly after the start of the 97th Congress in 1981, pending the outcome of the Clean Air Act amendments. However, amendments to the Act have not been adopted by Congress to date and, rather than continue to defer development of new source performance standards for sulfur dioxide, analysis of standards for sulfur dioxide emissions has been resumed. Sulfur dioxide emission standards for industrial-commercial-institutional steam generating units will be proposed as a separate rulemaking.

The potential impacts associated with this "phased" approach to proposing particulate matter and nitrogen oxides standards now and proposing sulfur dioxide standards in the future have been considered. There appears to be no reason for delaying the proposal of emission standards for particulate matter and nitrogen oxides while waiting for the sulfur dioxide standards to be developed. State sulfur dioxide standards now in effect would not interfere with compliance with today's proposed standards for particulate matter or nitrogen oxides. Similarly, when standards are proposed for sulfur dioxide, they would not be retroactive and would affect only new steam generating units built after that date. Since the standards will not affect steam generating units which have commenced construction prior to that time, this will assure that no unreasonable impacts occur. Any unforeseen impacts a sulfur dioxide standard may have on particulate matter and nitrogen oxides emissions control will be addressed at the time sulfur dioxide standards are proposed. In the interim, the present standards of performance limiting sulfur dioxide emissions from large fossil fuel-fired steam generating units (40 CFR Part 60, Subpart D) will remain in effect. No potential problems have been identified which might result from proposal of standards for particulate matter and nitrogen oxides today and proposal of standards for sulfur dioxide in the future.

Carbon monoxide and hydrocarbons were not selected for regulation due to their relatively low emission rates and the lack of any control technology for these pollutants which is reasonable in cost. Trace metals have not been selected for regulation under the proposed standards because of the lack of information on the performance of alternative control technologies to reduce these emissions. It is anticipated that the proposed particulate matter standard would result in significant reductions in trace metal emissions.

Trace amounts of radionuclides present in coal are also emitted by industrial-commercial-institutional steam generating units but are not a direct subject of these proposed regulations. Control of particulate matter emissions from coal-fired steam generating units to low levels is expected to bring about a corresponding reduction in emissions of radionuclides. Further discussion of the control of radionuclides from coal-fired steam generating units can be found in the Federal Register (48 FR 15085, April 6, 1983) as part of recently proposed standards for radionuclides under section 112 of the Act.

The proposed standards would limit emissions from steam generating units firing natural gas, residual and distillate oil, coal, wood, solid waste and fuel mixtures containing any of these fuels. Steam generating units or incinerators with heat recovery firing only municipal-type solid waste or steam generating units firing only wood (5 percent fossil fuel or less on an annual basis) would be covered by the proposed particulate matter standards, but not by the proposed nitrogen oxides standards. Similarly, steam generating units firing only oil or natural gas would be subject to the proposed standard for nitrogen oxides, but not to the proposed standards for particulate matter emissions. Emissions of particulate matter from the combustion of natural gas are low and therefore the costs of further emission control would be unreasonably high. Control of particulate matter from oil-fired steam generating units will be considered in the development of the sulfur dioxide standards.

The proposed standards would cover only industrial-commercial-institutional steam generating units with heat input capacities of greater than 29 MW (100 million Btu/hour). Analyses of the projected new steam generating unit population indicate that nearly all new steam generating units larger than 29 MW (100 million Btu/hour) heat input capacity will be industrial-type steam generating units with only a few commercial and institutional steam generating units in this size range. The steam generating unit size limit of 29 MW (100 million Btu/hour) heat input capacity would, thus, include only the largest commercial and institutional steam generating units and would concentrate the scope of the proposed standards on industrial-type steam generating units.

In addition to differences in application, the type of steam generating unit fuels which are combusted in steam generating units above 29 MW (100 million Btu/hour) heat input capacity is markedly different from the type combusted in steam generating units below this size. Depending on future energy pricing scenarios, from 25 to 75 percent of all new steam generating units larger than 29 MW (100 million Btu/hour) heat input capacity are expected to combust coal as the primary steam generating unit fuel. For units less than 29 MW (100 million Btu/hour) up to 90 percent of the fuel is expected to be natural gas or fuel oil. Additionally, the use of firetube-type steam generating units becomes more common for units of 29 MW (100 million Btu/hour) heat input capacity or less. Watertube-type steam generating units predominate among steam generating units larger than 29 MW (100 million Btu/hour) heat input capacity.

Development of new source performance standards limiting emissions of sulfur oxides, nitrogen oxides, and particulate matter from steam generating units smaller than 29 MW (100 million Btu/hour) heat input capacity is planned. In this small steam generator size range, the type of unit used, the physical design characteristics of these units, the cost impacts of emission control systems on steam production costs, and the steam generation applications are often different than for larger steam generating units. Because these factors have been found to be materially different, a separate study for these smaller steam generating units is appropriate. This will assure that an adequate evaluation is conducted on the technical and economic factors associated with applying emission controls to smaller steam generating units.

C. Selection of Formats for Emission Limits

Three possible formats were considered for the emission limits in the proposed standards: (1) Concentration,

(2) emissions per unit of steam generating unit energy output, and (3) emissions per unit of steam generating unit heat input. The criteria used for selecting the format were: (1) The ability of the format chosen to reflect the application of the best system of emission reduction, and (2) the ease of monitoring and compliance testing.

A concentration format measures the ability of the control system to reduce the level of pollutants relative to the volume of flue gas and provides a direct measure of the performance of the control equipment. There is, however, the potential that the effectiveness of a concentration standard can be reduced by dilution of the exhaust gases discharged to the atmosphere with excess combustion air, thus lowering the concentration of pollutants emitted but not the total mass emitted. This problem can be corrected by using a concentration standard at a reference carbon dioxide or oxygen level. Use of such a correction, however, renders this format functionally equivalent to a mass per unit of heat input format with respect to measurements needed to determine compliance. Thus, a concentration format was not selcted for the proposed standards.

A format of emissions per unit of steam generating unit energy output would make the process of determining compliance with the proposed standards very complicated. A format of this type would require measurement of pollutant emissions followed by calculation of the steam generating unit energy output which would require measurements of the steam production rate, steam quality, and condensate return conditions. The cumulative effect of requiring all these measurements would be to complicate compliance testing and monitoring, increase the likelihood for error, and increase costs for compliance testing and monitoring without significant benefits.

It is suggested that this format would create an incentive to purchase more efficient steam generating units and to increase operational efficiency. However, an incentive to purchase more efficient steam generating units would exist in any case because less efficient steam generating units would have to combust more fuel and use a larger emission control device compared to more efficient steam generating units which would produce the same amount of steam while firing less fuel.

Using a mass per unit of energy output format, standards which are based on best systems of emissions reduction applied to less efficient steam generating units may not reflect the best system of emissions reduction when compared to more efficient steam generating units. This outcome may not be consistent with the basic requirements of section 111 of the Clean Air Act that standards of performance reflect the application to all affected facilities of the best systems of continuous emission reduction considering costs and other impacts. Adjusting standards in some manner to reflect application of the best systems of emission reduction on all steam generating units would render this format functionally equivalent to a mass per unit of heat input format. Therefore, a format of emissions per unit of energy output was not selected for the proposed standards; however, this would not in any way discourage the use of higher efficiency steam generating units.

A mass per unit of heat input format was selected for the proposed standards since this format directly relates the net quantity of pollutants emitted to the amount of fuel fired in the steam generating unit. Monitoring and emission testing used to determine compliance with standards written in this format would be based on established methods. Additionally, this format is consistent with other standards established for steam generators (Subparts D and Da of 40 CFR Part 60). The major feature of this format, however, is that the required degree of emission control would be the same for all similar steam generating units burning the same amounts of fuel.

Emission credits for cogeneration systems and for combined cycle units were also considered and are discussed under the *Cogeneration Steam Generators—Emission Credits* and the *Combined Cycle Steam Generators—Emission Credits* sections of this preamble (See **REQUEST FOR COMMENTS** section).

D. Selection of Demonstrated Emission Control Technology and Emission Limits Nitrogen Oxides

1. Introduction

Nitrogen oxides (NO_x) formed during fuel combustion are composed of thermal NO_x and fuel-nitrogen NO_x. Thermal NO_x is formed through a reaction between the nitrogen and oxygen present in the combustion air. In contrast, fuel-nitrogen NO_x is the result of a reaction between nitrogen present in the fuel and oxygen present in the combustion air.

Nitrogen and oxygen in the combustion air can combine to form thermal NO_x at the elevated temperatures found in steam generating unit flames. Increased formulation is due to two factors: high combustion temperatures and high concentrations of oxygen in the presence of nitrogen. Boiler operating and design conditions which elevate combustion temperatures include increasing design heat release rates, full load operation, and preheating combustion air. Fuel moisture, on the other hand, will lower combustion temperatures. This lower temperature is a result of the cooling effect created by the evaporation of the moisture as the fuel burns. High concentrations of oxygen in the presence of nitrogen exposed to the high combustion temperatures are generally associated with the use of large amounts of excess air introduced early in the combustion zone.

The fuel nitrogen component of NO_x emissions is generated by the reaction of nitrogen in the fuel with oxygen in the combustion air. The two steam generating unit operating conditions which contribute most to fuel-nitrogen NO_x formation are increased fuel nitrogen content and the presence of large amounts of excess air in the combustion region where the fuel nitrogen evolves from the fuel.

Because of the influence of fuel nitrogen content, various fuels fired in steam generating units have widely differing NO_x characteristics. For example, natural gas and distillate oils contain little, if any, fuel nitrogen. As a result, nearly all of the NO_x emissions produced by the combustion of these fuels is thermal NO_x. Accordingly, the uncontrolled emissions from firing these low nitrogen fuels are generally much lower than from firing residual oils and coal.

Residual oils and nonfossil fuels are characterized by varying, but generally greater, amounts of fuel nitrogen than natural gas or distillate oil. As a result of these higher fuel nitrogen levels, total NO_x emissions from firing residual oils are comprised of both thermal NO_x and fuel-nitrogen NO_x. Uncontrolled emissions from residual oil combustion are generally higher than for natural gas and distillate oil, but less than for coal. Nonfossil NO_x emissions are generally in the same range as those from gas and distillate oil fuels.

Coal contains a substantial amount of fuel nitrogen relative to natural gas and oil. Consequently, NO_x emissions resulting from coal combustion typically include both thermal NO_x and significant quantities of fuel-nitrogen NO_x. The level of NO_x emissions generated by coal combustion is also dependent on steam generating unit type. In order of increasing NO_x emissions, the three basic steam generating unit types used to fire coal