



NTH Consultants, Ltd.

Infrastructure Engineering
and Environmental Services

608 S. Washington Avenue
Lansing, MI 48933
517.484.6900
517.485.8323 Fax

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MAY 21 2007

May 15, 2007

NTH Project 16-060556

AIR QUALITY DIV.

Mr. John Vial
Senior Environmental Engineer
Michigan Department of Environmental Quality
Air Quality Division
Permit Section, Thermal Process Unit

**RE: Response to Additional Questions and Clarifications Regarding Application 25-07
Holland Board of Public Works**

Dear Mr. Vial:

On May 1, 2007, representatives from the Holland Board of Public Works (HBPW), NTH Consultants, Ltd. (NTH), and Cummins & Barnard, Inc. (C&B) met with you and other staff from the Air Quality Division (AQD) to discuss the status of the application review and yet unresolved questions that you have with our analysis. Specifically, you asked that we provide clarification on four (4) main points:

1. Clarification regarding T-BACT for mercury (Hg).
2. Error in mercury calculation.
3. Current sulfuric acid mist (H₂SO₄) from Unit 3.
4. Updated Human Health Risk Assessment (HHRA).

1) T-BACT for mercury

Emissions of mercury from the proposed CFB are subject to both the federal NSPS Subpart Da and Michigan-specific requirements under Rule 224 for best available control technology for toxics (T-BACT). MDEQ requirements for T-BACT may or may not be more stringent than the proposed level of control or emission limit published by EPA and a thorough control technology analysis is required for toxic air contaminants with respect to energy, environmental, and economic impacts.

MDEQ has guidance for conducting the T-BACT analysis was updated in June 2004. The following analysis comports to the guidance outline.

1. Pollutant Applicability

Mercury does not meet the exception criteria, and is subject to a T-BACT analysis.

2. Identify Process Emissions

This was done in Section 3 of this application. Since the time of the application, this calculation has been fixed as will be discussed below. The facility is proposing a Hg emission limit of 1.05 E-06 lb/MMBtu, or 9.05 E-4 pounds per hour (pph), or 11.60E-06 lb/MWh, which is nearly 50% lower than the currently proposed NSPS limit of 20E-6 lb/MWh.



3. Identify Available Control Options

a. Determine the Base Case

The base case is the emission limit that would apply if the T-BACT analysis were not a regulatory requirement. For this proposed facility, the base case is the NSPS Subpart Da, which is found at 40 CFR 60.45Da, and the specified emission limit for mercury is 20E-6 lb/MWh of output. This limit applies to any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004.

To achieve the base case emission rate, the applicant will rely on existing technologies and systems used for control of particulate matter, sulfur dioxide, and oxides of nitrogen that have been demonstrated to have significant co-benefits for control of mercury emissions. Specifically, use of flue gas desulfurization (FGD), fabric filters, and selective (and non-selective) catalytic reduction. In addition, certain grades of coal have been shown to inherently reduce emissions of mercury due to the constituents within the coal. Recent information available from EPA reports indicate that bituminous coals tend to have significantly lower mercury emissions in the flue gas due to the presence of chlorine in the coal ash content. Studies have shown that the mercury has an affinity to combine with the chlorine in bituminous coal to form mercuric chlorides that are then captured in the downstream particulate collection device.

HBPW will be utilizing subbituminous and bituminous coal ranks with desulfurization occurring inside the furnace through the addition of limestone into the boiler and add-on controls consisting of SNCR and fabric filter. EPA has stated in both the preamble to 40 C.F.R. Part 60 Subparts Da and HHHH, and summary to the reconsideration of the clean air mercury rule (CAMR), that best demonstrated technology for mercury control firing bituminous coal is a fabric filter, flue gas desulfurization, and, to a lesser extent, selective non-catalytic reduction. Several test studies have shown that removal efficiencies for Hg of at least 80% are readily achieved through such a configuration. In this instance, the proposed NSPS limit of 20E-6 lb/MWh represents slightly greater than 80% Hg removal when considering a maximum Hg content in coal of .012 ppmw on a wet basis.

Some of the gaseous (vapor) mercury present in the exhaust gas stream will adsorb to fly ash and other particulate and will be removed by the PM control device. While removal efficiencies range from 0 to 98 percent, data from plants burning only bituminous coals have a much higher removal of mercury. In this project, the PM control device will be a fabric filter.

In addition, divalent mercury (Hg^{2+}) compounds have been shown to be reduced through the use of FGD devices, including both wet and dry systems, especially for plants firing bituminous coals. The reasons stems from the presence of chlorine in the coal and the higher concentration of chlorine in bituminous coals. Bituminous coals tend to have higher levels of chlorine and unburned carbon available for removal of mercury. In this scenario, elemental mercury (Hg^0) is oxidized to form Hg^{2+} due the presence of hydrogen chloride (HCl), which can then be captured by the fabric filter.



Finally, use of SNCR for control of NO_x has been proven to reduce Hg in the flue gas stream as well since a portion of the elemental mercury is catalytically oxidized to divalent mercury as it passes through the SNCR unit. The use of these three technologies in field tests has shown that mercury levels can be reduced by 80% – 90%.

b. Identify Alternative Control Options that are Available at the Time of the Submission of a Complete Application.

Include:

i. ***Transferable and innovative control technologies:***

The only available add-on control technology specifically designated for control of Hg from combustion of coal is activated carbon injection (ACI), but has not yet been commercially proven. In ACI systems, powdered activated carbon (PAC) sorbent is injected into the flue gas upstream of the PM control device. Activated carbon is a specially treated carbon that has been exposed to temperatures of 800 – 900 degrees Celsius. It becomes “activated” such that the carbon is very porous and has a high surface area. The pores allow **vapor-phase mercury** to adsorb to the carbon, which is then collected in the downstream PM control device. The performance of activated carbon is related to physical properties including surface area, pore size, and particle size distribution. Mercury capture is increased with increased pore size and surface area.

ACI has been used in medical waste and other waste combustor applications, but chlorine content of those waste streams tends to be high, and thus the mercury is more amenable to ACI control. Also the mercury content of the waste streams is highly variable, and when the inlet load is very low, 90% control is not achieved (or can not be demonstrated to be achieved because of detection limit issues), but the low emission limits can be demonstrated. ACI is currently undergoing full-scale trials at power plants, including the WE Energy program at Presque Isle Michigan. It is not yet demonstrated technology, and is not available in the sense of performance guarantees for the proposed utility application. It does not represent T-BACT.

ii. ***Processes or alternate modes of operation that inherently produce less pollution:***

In the size of coal-fired power generation boilers that HBPW is proposing, CFB technology with the control systems proposed are the lowest emitting. None inherently produce a lower pollution. Also the blend of western subbituminous and eastern bituminous coals provide the apparent best blend of lower mercury concentration with sufficient chlorine to facilitate removal of the mercury by the control systems.

iii. ***Various configurations of the same technology that achieve different control efficiencies***

There are no other configurations that would improve on the mercury reduction being proposed.



4. Impact Analysis

Since HBPW is proposing the best control system available to meet the proposed emission limit, considerations of energy, economic and environmental considerations to eliminate options are not relevant.

In conclusion, T-BACT is represented by currently demonstrated available technology to an emission level of 20E-06 lb/MWh. This level of emissions is more restrictive than many recently issued permits for coal-fired boilers issued in the past several years. It is also equivalent to the allowed Hg emission from an integrated gasification combined cycle (IGCC) plant.

Beyond T-BACT

HBPW has made the decision to meet the MDEQ proposed requirement of 90% control of mercury in anticipation of technological developments that will provide that level of control. It is yet unclear as to whether installing such an ACI system is necessary to ensure a 90% reduction in mercury emissions. However, since ACI is potentially a part of that future technology, HBPW has committed to install ACI on the proposed new unit #10. Initial testing will show the extent to which it is needed to achieve the proposed emission limit.

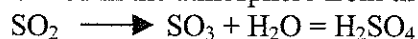
A large drawback to the use of ACI is the "poisoning" of the fly ash and reduced ability to sell the ash to other industries. In other words, use of ACI results in a higher solid waste stream from the process. To minimize the impact on the fly ash, one option is to install a TOXECON® system. In this system, PAC is injected downstream of the primary PM collection device, which is used to collect the fly ash, but upstream of a polishing baghouse that vents to the ambient air. The polishing baghouse or Compact Hybrid Particulate Collector (COHPAC) installed downstream of the sorbent injection is specifically designed to capture the mercury contaminated particulate. HBPW is not proposing to install a polishing baghouse.

2) Mercury Calculation

I have checked the calculation for determining the level of mercury emissions from the proposed boiler provided in the application and have found an error in the Microsoft Excel® spreadsheet. Specifically, one cell was improperly linked that resulted in the dry feed rate of coal being calculated by the mercury content of the coal on a wet basis. In summary, the dry feed rate should be multiplied by the mercury content of the coal on a dry basis, or vice-versa. The mercury emission rate for Unit #10 should be 9.05E-04 lb/hr or 1.05E-06 lb/MMBtu. A new mercury calculation is provided.

3) Sulfuric Acid Mist (H₂SO₄) Emissions from Existing Unit 3

During the meeting on May 1, you questioned whether we had any test data for existing Unit #3 with regard to H₂SO₄ emissions. Neither NTH nor C&B have been able to find test data regarding H₂SO₄ emissions from pulverized coal-fired boilers. In fact, it H₂SO₄ is not routinely emitted as a pollutant from such combustion units due to the temperature of the flue gas. Rather, sulfuric acid mist is formed in the atmosphere from the emissions of SO₃. The reaction is as follows:





It is highly unlikely that H₂SO₄ will be emitted as a primary pollutant from either existing Unit #3 or new Unit #10. Since the emissions of H₂SO₄ have a direct correlation to the emissions of SO₂ (and SO₃), reductions in SO₂ (and SO₃) will naturally lead to reductions in H₂SO₄. The U.S. EPA AP-42 document states as a footnote to Table 1.1-3 that "On average, for bituminous coal, 95% of fuel sulfur is emitted as SO₂, and only about 0.7% of fuel sulfur is emitted as SO₃ and gaseous sulfate."

Since there will be limestone present in the combustion zone of the proposed CFB boiler, if anything the conversion of the sulfur in the coal to SO₂ should be less than for a stoker or pulverized fired boiler. Since the flue gas characteristics of Unit #3 and Unit #10 will be similar (i.e., exit temperature, moisture content), it is likely that the conversion rate of S and SO₂ to SO₃ will be nearly identical. Consequently, the formation of H₂SO₄ be the same or lower for the CFB boiler. Consider the following calculations showing the emissions of H₂SO₄ based on a conversion of sulfur in fuel to SO₃. This shows that it doesn't matter what the conversion rate is, the net effect is an overall reduction of H₂SO₄ from the facility.

Sulfur, S, content of coal in Unit 3 (avg.):	1%
Heat input of Unit 3 (average):	115 MMBtu/hr
Coal Btu Unit 3 (average):	11,500 Btu/lb
Output of Unit 3:	11.5 MWh
Coal usage of Unit 3 (average):	10,000 lb/hr

$$\text{Uncontrolled Unit 3 SO}_2 \text{ Emissions} = 1.0\%S \times \frac{10,000\text{lb}}{\text{hr}} \times \left(\frac{64}{32}\right) = \frac{200 \text{ lb}}{\text{hr}}$$

Sulfur, S, content of coal in Unit 10 (max):	4.3%
Heat input of Unit 10:	865 MMBtu/hr
Coal Btu Unit 10:	11,500 Btu/lb
Output of Unit 10:	78 MWh
Coal usage of Unit 10:	75,218 lb/hr

$$\text{Controlled Unit 10 SO}_2 \text{ Emissions} = \frac{1.4 \text{ lb}}{\text{MWh}} \times \frac{78 \text{ MW}}{\text{hr}} = \frac{109.2 \text{ lb}}{\text{hr}}$$

K₃ = Conversion factor for SO₂ to SO₃ for Unit 3
K₁₀ = Conversion factor for SO₂ to SO₃ for Unit10

$$\begin{aligned} \text{SO}_3 \text{ Net change} &= [\text{SO}_3]_{\text{Unit10}} - [\text{SO}_3]_{\text{Unit 3}} \\ &= K_{10} * [\text{SO}_3]_{\text{Unit10}} - K_3 * [\text{SO}_3]_{\text{Unit 3}} \\ &= K_{10} * 109.2 \text{ lb/hr} - K_3 * 200 \text{ lb/hr} \end{aligned}$$

$$K_{10} = \frac{200}{109.2} K_3 = 1.83K_3$$



Mr. John Vial
May 15, 2007

Note that the net change will always be negative as long as $K_{10} < (200/109.2) * K_3$. Since K_{10} should be equal to or less than K_3 , the net result will always represent a decrease. Therefore, there will be no net increase in emissions of H_2SO_4 or its precursors to trigger PSD.

4) Updated Human Health Risk Assessment

The deposition modeling done in support of the HHRA for mercury used the density of mercury as the particle density in the model. Upon review of the modeling, AQD informed us that the appropriate particle density to use in the model is the density of the fly ash. Mr. Dave Mason of the AQD re-ran the deposition modeling for this project for both the "Before" and "After" scenarios and found that deposition (dry, wet, total) decreases at all receptors. NTH has received a copy of the new AQD output files and have compared them against the output files from the original modeling to determine spatial distribution and net change in deposition at each receptor. The magnitude of the deposition at each receptor either does not change or decreases as a result of the change to the particle density.

With regard to the questions and request by Mr. Robert Sills of the AQD, this information is currently under review. We will provide a response in the coming days under a separate cover letter.

If you have any further questions, please feel free to contact me at (517) 484-6900.

Very truly yours,

NTH Consultants, Ltd.

Jeffrey P. Jaros
Principal Scientist

Attachment

cc: Mr. David Koster, Holland Board of Public Works
Mr. Steve Yambor, Cummins & Barnard, Inc.
Mr. Chuck Hookham, Cummins & Barnard, Inc.
Mr. Delbert Rector, NTH Consultants, Ltd.

JPJ/mjb

Holland Board of Public Works

MERCURY (Hg) EMISSION CALCULATIONS

Actual Mercury Emissions estimated based on a proposed blend of bituminous and subbituminous coal (70:30)

Mercury Emissions - Coal Blend

Fuel Heating Value	11,500 btu/lb
Mercury Content of Fuel, wet	0.12 ppmw
Mercury Content of Fuel, dry	0.128 ppmw
Fuel Burn Rate	865 MMBtu/hr
Fuel Burn Rate, wet	75217 lb/hr
Moisture in fuel	6 %
Fuel Burn Rate, dry	70704 lb/hr
Mercury from boiler	9.03E-03 lb/hr
Mercury from boiler	3.95E-02 tpy
Mercury from boiler	1.04E-02 lb/Tbtu

% Mercury Removal Mercury emissions

	90 %
	3.95E-03 tpy
	7.9 lb/year
	9.05E-04 lb/hr
	1.05E-06 lb/mmBtu
	1.05 lb/Tbtu

LEHIGH ENERGY UPDATE



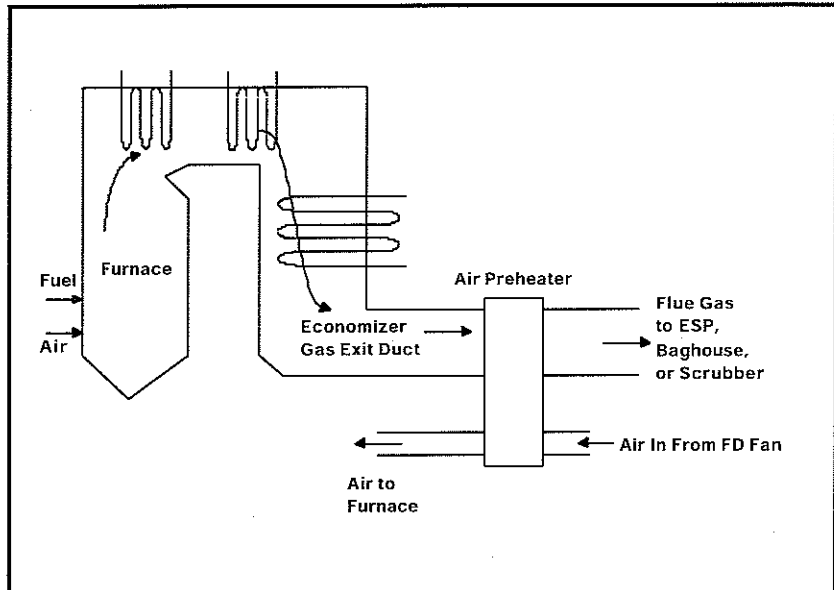
April 1998, Vol. 16 (2)

PREDICTING SULFURIC ACID EMISSIONS FROM POWER PLANTS

Due to concern over the release of potentially harmful toxic metals and chemical compounds to the environment, beginning in 1998, utilities with coal- or oil-fired generating plants will be required to submit an annual Toxics Release Inventory to EPA. The inventory will list amounts of each toxic substance emitted annually from each site; and the database containing this information will be maintained by EPA and made publically available. Sulfuric acid is one of the chemicals on the list of those which must be inventoried. Although, up to now, most utilities have given little thought to the amounts of H_2SO_4 emitted from their stacks, this substance may become a headache for utilities in the future, according to speakers at a recent DOE workshop⁽¹⁾.

Research, performed by the Energy Research Center over the last two decades, shows emissions of H_2SO_4 from the stacks of coal and oil-fired boilers are highly dependent on fuel characteristics and boiler design and operating conditions. To understand how these fit together, it is helpful to examine the processes by which SO_3 and sulfuric acid are formed.

In a typical pulverized coal boiler, combustion gases flow from the furnace to a series of heat exchangers in the convective pass. The gas temperature ranges from 2000 to 2500°F at the furnace exit to 600 to 700°F at the economizer gas exit. The gas temperature then decreases through the air preheater to about 300°F at the air preheater



Sketch of Typical Pulverized Coal Boiler

exit. In the case of units with cold side electrostatic precipitators, flue gas flows from there to the ESP inlet before going up the stack.

Sulfur trioxide (SO_3) is formed at high temperatures in the furnace and convective pass by the reaction of sulfur dioxide (SO_2) with oxygen, and there are numerous design and operating parameters which influence the extent of SO_3 formation. Among these are fuel sulfur content, coal fineness, ash content and composition, convective pass surface area, tube metal surface temperature distributions and excess air level. Thus, the same fuel burned in two different boilers, or in the same boiler at two different operating conditions, can produce substantially different levels of SO_3 . This is illustrated in the table which shows the

concentrations of SO_3 measured in the economizer exit gas ducts at three different pulverized coal boilers. All burn eastern bituminous coals with sulfur contents of 2 to 3 percent. The SO_3 concentrations are markedly different for the three boilers and also vary with load level and economizer O_2 .

The SO_3 formation process is complete once the flue gas reaches the air preheater. The SO_3 then leaves a typical coal-fired boiler as a liquid deposit trapped in the air preheater, as vapor adsorbed onto fly ash, and as H_2SO_4 vapor and mist carried out the stack.

Virtually all utility boilers use air preheaters to transfer energy from the hot gases leaving the economizer to the air flowing into the boiler. Two types of air preheaters, the rotary regenerative type and the

tubular type are in common use, with the regenerative design capturing the largest share of the utility market. Usually, the gas temperature is reduced within the air preheater from an inlet level of 600 to 700°F to an exit level of about 300°F. During this process, the SO₃ undergoes some important changes. Gas phase SO₃ reacts with vapor phase H₂O to form vapor phase H₂SO₄. The extent of this reaction depends on temperature and the reaction is essentially complete by the time the flue gas has reached the cold end of the air preheater.

Condensation of H₂SO₄ and H₂O subsequently occur if the local metal temperatures in the air preheater flow passages drop below the acid dewpoint. Dewpoint is a function of both H₂O and H₂SO₄ concentrations in the flue gas, generally ranging from 250 to 285°F. Some units are operated with the air preheater metal surface temperatures below the dewpoint and others are operated with sufficiently high stack temperatures so no acid condensation occurs.

The ERC has conducted exhaustive studies of acid condensation in air preheaters, using a combination of computer

simulations, laboratory experiments and field investigations. The results show at metal temperatures below the acid dewpoint, the rate of condensation of sulfuric acid on the surface is strongly dependent on the acid concentration of the flue gas and wall temperature. In addition, in a rotary regenerative air preheater, where the flow passages are alternately exposed to combustion air and flue gas, evaporation of condensed acid occurs from the surface of the flow passage to the incoming air stream. The degree to which this evaporation process occurs is primarily a function of the moisture content of the inlet air and the surface temperature of the flow passage.

According to Nenad Sarunac, a Research Engineer with the Center, "Due to the design of the air preheater and its mode of operation, there are strong transverse variations in flue gas temperature and H₂SO₄ vapor concentration leaving the air preheater. Due to condensation within the air preheater, the average SO₃/H₂SO₄ concentration of the gas flowing through the air preheater can easily be decreased by a factor of 2. At the same time, it is not unusual to see extremely large variations in

SO₃/H₂SO₄ vapor concentration from one side of the gas exit duct to the other."

"We believe the tools we've created will be very helpful in developing accurate estimates of annual sulfuric acid emissions from power plants . . . these same techniques can be used to develop . . . strategies for minimizing acid emissions."

In addition to condensing onto cold metal surfaces in the air preheater and at the duct walls, H₂O, SO₃ and H₂SO₄ become adsorbed onto the surfaces of the fly ash particles entrained with the flue gas. The rate of adsorption increases rapidly as the flue gas reaches the cold end of the air preheater, and this process continues as the flue gas flows through the duct connecting the air preheater to the electrostatic precipitator. Recent studies at the ERC show the rate of adsorption to depend strongly on temperature, gas phase SO₃ and H₂O concentrations and ash surface properties. The adsorbed acid and water have a large effect on fly ash resistivity and thus control ESP performance. In some units, additional SO₃ is injected into the flue gas to condition the fly ash and improve ESP collection efficiency.

Sarunac notes, "As a consequence of the factors affecting the formation of SO₃ and condensation, evaporation and adsorption of H₂SO₄, sulfuric acid emissions from a boiler are highly variable. Fuel quality has an obvious influence. But variations also occur with unit load and with boiler and air preheater control settings. In addition, with seasonal changes in inlet air temperature and

Pulverized Coal Fired; 2 - 3% Sulfur Coal			
Unit	SO ₃ (ppm)	Unit Load (MW)	O ₂ (%) at Economizer Gas Exit
A	1 to 2.5	585	2 to 4
A	2.5 to 5	425 & 300	4 to 7
B	20	640	--
C	21 to 24	700	4 to 5
C	27	180	10

Table 1: Measured SO₃ Concentrations in Economizer Gas Exit Ducts of Three Coal-Fired Boilers

ambient humidity, the H_2SO_4 in the stack varies from Winter to Summer in many units."

"In past years, most of the concern with SO_3 dealt with its effect on fouling and corrosion of air preheaters and cold end ductwork and on its role in promoting high ESP collection efficiency. Much of

the work we've done for utilities has focused on optimizing air preheater design and operations and boiler operating conditions to avoid opacity excursions, minimize heat rate and limit expenditures associated with air preheater maintenance. We believe the tools we've created to do this will be very helpful in developing

accurate estimates of annual sulfuric acid emissions from power plants. At the same time, if it becomes desirable to do so, these same techniques can be used to develop boiler operating and component design strategies for minimizing acid emissions." •