

A&WMA'S 100th Annual Conference & Exhibition

June 26-29, 2007

Pittsburgh, Pennsylvania

GHOST IN THE MACHINE: MERCURY EMISSIONS FROM NON RECOVERY COKING OPERATIONS

Paper # 387

Lance S. Traves, CHMM Managing Principal & Charles Sisia Project Consultant Labyrinth Management Group 239 South Court Street Medina, Ohio 44256
(330) 764-4825

"Where does the answer lie." Police, 1981.

ABSTRACT

During the past decade increasing attention has been focused on the regulation and control of electrical generation and selected industrial sources of mercury emissions. Based at least in part on this increased attention, the Ohio EPA issued a Major Source Permit to Install (PTI) that contained a first-ever mercury emission limit for a coking operation in the United States in June 2004. This nonrecovery coking mercury emission limit was equivalent to 95% control based on USEPA research on mercury removal by spray dryer absorbers (SDA) and high-efficiency fabric filter baghouses operated at coal-fired utility boilers.

This paper discusses the technical and air emission differences between non-recovery coking operations and coal-fired boilers that indicate mercury emission control from SDA and fabric filter systems at these operations would be expected to vary significantly. Following this discussion, an analysis will be presented of the results of mercury emission testing conducted at two operating non-recovery coking operations in 2006. This analysis indicates that waste gas mercury removal efficiencies associated with SDA and fabric filter baghouse emission controls at non-recovery coke operations may range from 16% to 30%. These emission test results also indicate that traditional mercury-specific controls such as activated carbon injection may not be as effective in mercury removal at non-recovery coking operations as previously expected. Finally, a brief discussion will be presented of the important policy implications these new findings have on the future environmental regulation of mercury emissions from a wide range of industrial sources including non-recovery coking operations and primary steel furnaces.

INTRODUCTION

Mercury emissions from energy production and industrial operations in the United States is an increasing public concern.¹ The adverse human health and environmental impacts from mercury emissions have resulted in extensive public and private research on the nature and control of mercury emissions. According to the United States Environmental Protection Agency (USEPA), the largest source of airborne mercury emissions in the United States is the stationary electric utility coal combustion boilers.² As a result, USEPA and at least a dozen states have undertaken regulatory actions in the past few years to reduce mercury emissions from these coal combustion sources. These regulatory actions are expected to reduce mercury emissions from stationary electric utility coal-combustion boilers by at least 70% by the year 2010.³

In contrast with coal combustion, estimates of mercury emissions from coking operations (both by-product and non-recovery) have not been generally available.⁴ Historical testing conducted at by-product coking plants has indicated that mercury emissions from combustion stacks were not generally present. Based on limited European data, USEPA estimated that total annual mercury emissions from coke plants in the United States were only approximately 0.7 tons in 1997.⁵ As a result, coking operations have not been subject to much public concern or regulation regarding mercury emissions. However, this environment changed dramatically beginning in 2004.

In April 2004, FDS Coke Plant, LLC proposed the construction of a non-recovery coking plant near Lake Erie in Toledo, Ohio. The plant was designed to charge 2.052 million tons of coal on an annual basis using state-of-the-art technology that incorporated a number of new innovations that act to reduce air pollutant emissions. However, the FDS Coke Plant was a Major Source being located in an area with a troublesome past associated with existing air emission sources. As a result, public interest and concern regarding the potential environmental and health impacts from air pollutant emissions from the proposed FDS Coke Plant were significant. These impacts included aerial deposition of the mercury emissions associated with the proposed plant.

Based on the limited available information, a technically justified estimate of actual mercury emissions from the FDS Coke Plant could not be generated for the air permit application. Technical experts expected some co-removal of mercury in waste gas emissions from the plant as a result SO₂ and particulate air pollution control (APC) equipment. However, a reasonable “controlled” mercury emission estimate could not be developed in the short time period associated with responding to significant public comments. These comments included requests by Sierra Club, the State of Michigan, and the Canadian Province of Ontario to restrict mercury emissions from the plant. As a result of the extensive public comments, Ohio EPA issued a Major Source Permit to Install (PTI) for the FDS Coke Plant in June, 2004 that contained the first-ever mercury emission limit for a coking operation in the United States.⁶

The Ohio EPA’s mercury emission limit for the FDS Coke Plant was equivalent to an estimated 95% control efficiency.⁷ The basis for the plant’s mercury emission limit was USEPA findings associated with the Coal Fired Electric Utility Mercury MACT.⁸ These findings indicated that total mercury emissions from bituminous coal-fired utility boilers were reduced by up to 98% with APC systems consisting of a spray dryer absorber (SDA) and fabric filter baghouse.⁹

The FDS Coke Plant's design incorporated a semi-dry SDA and fabric filter baghouse to control SO₂ and particulate emissions. Therefore, Ohio EPA believed it was reasonable to establish a mercury emission limit for the FDS Coke Plant that was consistent with USEPA's proposal for new electric utility coal-fired boilers.

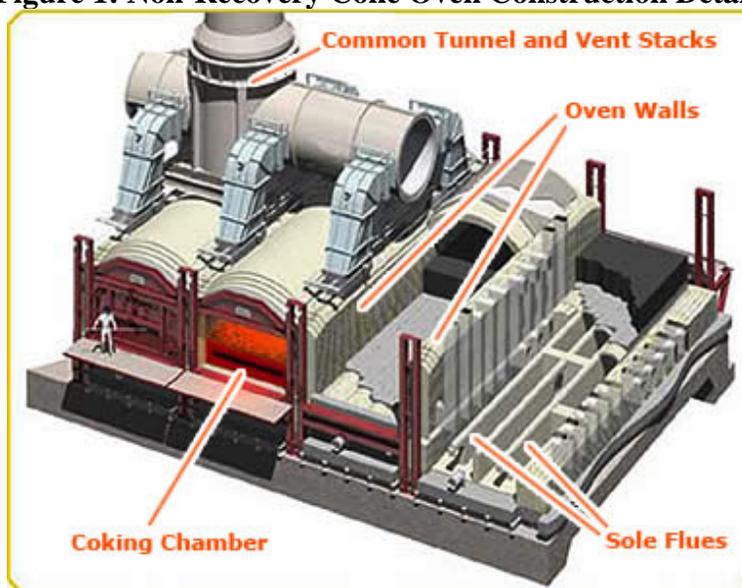
FDS Coke Plant, LLC subsequently appealed the Ohio EPA PTI and obtained the ability to revise the mercury emission limit after performance of required emission testing. This concession was based in large part on information provided to Ohio EPA on the number of important differences between coal-fired boilers and non-recovery coking operations that would adversely impact mercury control by SDA and baghouse fabric filter APC systems at non-recovery coke plants.

COAL COMBUSTION VERSUS NON-RECOVERY COKING

The combustion of coal in utility boilers consists of the direct chemical oxidation (i.e., burning) of the volatile matter and organic carbon contained in the coal in the presence of excess oxygen to create heat. This combustion process results in primarily ash (composed of inorganic silicas and metals), combustion by-products such as sulfur dioxides, nitrogen oxides, carbon dioxides, and incomplete combustion products such as trace unburned carbon, volatile organic compounds (VOCs), and trace metals.¹⁰

In contrast, the non-recovery coking process uses both direct and indirect high-temperature heating in an oxygen deficient atmosphere to concentrate the carbon in the coal and transform the coal into coke.¹¹ The "carbonization process" is accomplished using heat to make the volatile matter and carbonization by-products evolve from the coal. In non-recovery coke ovens, evolved gases are first partially combusted (i.e., burned) above the coal in the oxygen deficient atmosphere maintained in the coke oven (see Figure 1).

Figure 1: Non-Recovery Coke Oven Construction Details



Source: Sun Coke Company Website

This combustion of the evolved gases above the coal charge creates direct heat for the coking process to continue. The partially combusted gases exit the top of the oven chamber, then circulate through the oven walls into the sole flue where additional combustion of the gases occurs in the presence of additional oxygen. This additional sole flue combustion provides indirect gasification heat to the coal charge. The combusted gases then exit the sole flues and enter the common waste gas tunnel for complete secondary combustion prior to APC and eventual exhaust.

The overall efficiency of the combustion process in a coal-fired utility boiler depends greatly on the technique and design of the equipment.¹² A key criterion for all coal-fired utility boiler configurations is the relative efficiency in the complete combustion of the organic carbon and volatile matter in the coal with the resulting generation of inorganic ash (fly or bottom). For example, when coal is burned by pulverizing the coal and entraining the coal particles in the primary air being fed into the boiler, USEPA estimates that 60% to 80% of the total ash generated from the combustion process is fly ash.¹³ This fly ash would be classified as particulate matter (PM) that is subsequently reduced prior to emission using APC systems such as fabric filter baghouses.

In contrast, the carbonization process associated with coking is conducted in an oxygen deficient environment to minimize the creation of ash and the resulting waste gas PM. The creation of ash during the coking process reduces the overall coke yield.

Overall, the fundamentally distinct processes of coal combustion and non-recovery coking result in important differences in key characteristics of the waste gas emissions and potential mercury removal at coal-fired utility boilers and non-recovery coke batteries. These differences have been further demonstrated by mercury emission testing recently conducted at non-recovery coking operations in late 2005 and 2006.

2005/2006 NON-RECOVERY COKE PLANT EMISSION TESTING

Two different non-recovery coking plants were required by USEPA and Ohio EPA to undertake mercury emission testing programs beginning in late 2005 and ending in mid-2006.¹⁴ The plants included the Indiana Harbor Coke Company (IHCC) operation located in East Chicago, Indiana and the Haverhill North Coke Company (HNCC) operation located in Haverhill, Ohio. Both of these non-recovery coking operations use a SDA and fabric filter baghouse for the control of waste gas emissions of SO₂ and PM. The co-removal of mercury by this APC equipment configuration at non-recovery coking operations is important new information.

The mercury emission testing program at IHCC included two sets of mercury emission tests (three runs each) conducted approximately 6 months apart. These mercury emission tests included using Method 101A and the Ontario Hydro Method to obtain pre and post-control total and speciated mercury concentrations in the waste gas. As part of the mercury test program, IHCC also determined the mercury content of the coal blends charged to the ovens during the performance of the testing.

The mercury emission testing program at HNCC used Method 101A to obtain pre and post-control total mercury concentrations. Mercury speciation was not conducted as part of the HNCC mercury testing program. In addition, the mercury content of the coal was not specifically tracked during the testing activities. However, HNCC has an existing air permit requirement to monitor and record the average monthly mercury content of coal charged to the ovens. Therefore, this coal mercury content information was available for the time period associated with the testing.

In addition to the recent mercury emission testing, both IHCC and HNCC have also conducted other emission testing activities that provide additional insights into important differences between coal-fired combustion and non-recovery coking waste gas characteristics. These differences have the potential to adversely impact the potential removal of mercury by SDA and fabric filter baghouse APC systems at non-recovery coking operations.

Coal Combustion and Non-Recovery Coking Waste Gas Characteristics

Based on research conducted in support of the proposed mercury NESHAP rule (40 CFR Part 63 Subpart UUUU), there has been an extensive amount of information generated on the waste gas characteristics of coal-fired utility boilers. In contrast, existing information on the waste gas characteristics for non-recovery coking operations is relatively limited. However, even with this limited information, a number of important differences in the waste gas characteristics between coal-fired utility boilers and non-recovery coke ovens can be identified. These differences result from both the distinct equipment and chemical processes involved in the emission sources.

A summary comparison of selected uncontrolled waste gas characteristics for coal-fired utility boilers and non-recovery coke ovens obtained from various technical reports is provided in Tables 1 and 2.¹⁵ Differences in the waste gases include both the physical characteristics and specific pollutant loading rates and exhaust gas concentrations.

Physical Characteristics

As shown in Table 1, waste gas from coal-fired utility boilers is typically slightly lower in temperature and percentage moisture than expected for non-recovery coke plants. Waste gas flow in coal-fired utility boilers is also generally larger than non-recovery coke plants. These lower temperatures and moisture contents have an impact on mercury removal efficiency by SDA and fabric filter baghouse (see discussion below).

Pollutant Loading

Based on the combustion process, overall waste gas pollutant loading is significantly greater in coal-fired utility boilers than in non-recovery coke oven waste gases. As shown in Table 1, one key difference is the amount of PM present in the waste gas. Coal-fired utility boilers will have an estimated 15 to 30 times more filterable PM in the uncontrolled waste gas than non-recovery coking plants. The PM content of a waste gas is a key consideration in removal of mercury within a waste gas stream using SDA and fabric filters.¹⁶ This results from the impact that mercury speciation has on the removal efficiency of this type of APC equipment.

Table 1. Comparison of Coal-Fired Utility Boiler and Non-Recovery Coking Oven Waste Gas Characteristics

Characteristic/ Pollutant	Uncontrolled Bituminous Coal Combustion Boiler Waste Gas			Uncontrolled Non-Recovery Coke Oven Waste Gas		
	Value		Conc. Comments/References	Value		Conc. Comments/References
Temp (C°)	121 - 177		USEPA (April 2002) , Table 7-1	180 - 200		Average range post-HRSG (IHCC, HNCC, FDS)
Flow Rate (dscfm)	11,000 - 4,000,000		USEPA (April 2002), Table 7-1	240,000 590,000		Average range (IHCC, HNCC, FDS)
% Moisture	9 - 12		Range of values reported in literature.	12.6 - 21		Jewel Table 7-4, IHCC (12/99), HNCC (3/06)
	lb/ton¹	Conc.		lb/ton²	Conc.	
Filterable PM	33-66	2.4 gr/dscfm	Filterable PM is classified as >0.3 microns in size. Conc. from ICR Reference 4 and 6	0.05 - 1.8	0.0023 - 0.0455 gr/dscfm	Jewel Table 7-1, IHCC (12/99), HNCC (3/06)
Condensable PM	NA	NA	Condensable PM is primarily organic compounds.	0.15	0.0068 gr/dscfm	Jewel Table 7-1, Condensable PM is primarily organic compounds.
SO ₂	32	1,600 - 20,000 ppm	Lb/ton SO ₂ calculated using 0.85% Sulfur consistent w/ Jewel testing. Concentration based on range of values reported in literature.	9.3 - 12	400 - 600 ppm	Range of average values documented at Jewel and IHCC (12/99).
NO _x	10-31	100 - 300 ppm	NO _x concentration will vary depending on boiler design.	0.66 - 1	48.8 - 60 ppm	Jewel (9/92) and IHCC (12/99)
CO	0.5	7 - 119 ppm	CO concentration will vary greatly depending on boiler design.	0.05- 0.13	11 - 22 ppm	Jewel (9/92), IHCC (12/99), HNCC (3/06)

¹ Based on AP-42 Coal Combustion, Uncontrolled Coal Table 1.1-17, Values represent a range of factors in literature. SO₂ loading will depend on coal sulfur content.

² Based on AP-42 Non-Recovery Coke Ovens, Table 12.2-20. Based on single set of tests conducted at 1 operation. SO₂ loading will depend on coal sulfur content.

Significant differences between coal-fired utility boilers and non-recovery coking waste gas characteristics can also be observed in the SO₂ and NO_x loading rates. As shown in Table 1, these loading rates and waste gas concentrations are from 10 to more than 30 times higher in waste gas from coal-fired utility boilers.

The difference in SO₂ and NO_x loading results from the goal of complete combustion of carbon in coal-fired boilers versus conversion of coal to carbon at coking operations. The higher concentrations of SO₂ and NO_x also appear to impact the speciation of mercury in waste gas.

Finally, as shown in Table 2, the loading rates for a number of metals in waste gas from coal-fired utility boilers are also higher than non-recovery coking operations. This is not unexpected based on utility boilers' objective of burning all the organic carbon contained in the coal and the resulting release in some form of all the metals present in the coal. In contrast, non-recovery coking operations do not burn coal so specific forms of metals including mercury may remain in the carbonized coke and not enter the waste gas.

Table 2. Comparison of Coal-Fired Utility Boiler and Non-Recovery Coking Oven Waste Gas Metal Characteristics

Characteristic/ Pollutant	Uncontrolled Bituminous Coal Combustion Boiler Waste Gas	Uncontrolled Non- Recovery Coke Oven Waste Gas
	lb/ton ¹	lb/ton ²
Arsenic	0.017	0.0013
Beryllium	0.0021	0.00002
Cadmium	0.0011	0.00018
Chromium	0.032 - 0.040	0.00063
Lead	0.013	0.0031
Manganese	0.0058 - 0.076	0.00030
Nickel	0.026-0.033	0.00058

¹ Based on AP-42 Coal Combustion, Uncontrolled Coal Table 1.1-17. Values represent a range of factors discussed in literature. Metal loading rates will vary depending on coal metal concentrations.

² Based on AP-42 Non-Recovery Coke Ovens, Table 12.2-20. Based on single set of tests conducted at Jewel Plant. Metal loading rates will vary depending on coal metal concentrations.

Mercury Speciation Differences

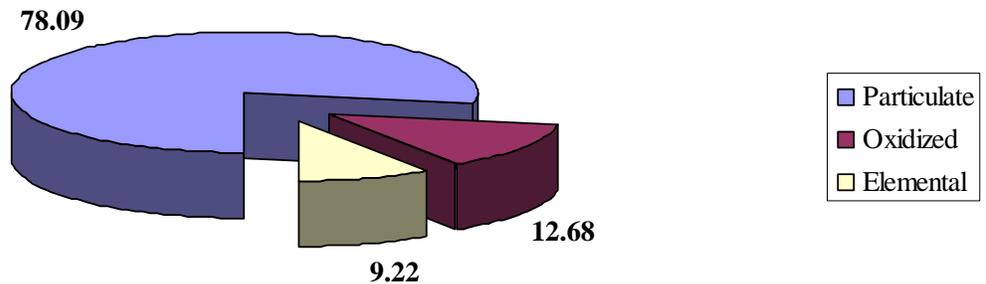
According to USEPA, the term *speciation* is used to denote the relative amounts of three forms of mercury in waste gas from a coal-fired utility boiler or non-recovery coking operation. These forms include particle-bound, oxidized, and elemental.¹⁷ Mercury in coal primarily exists as sulfur-bound compounds (i.e., oxidized) and compounds associated with the organic carbon fraction (i.e., particle-bound). Only small amounts of elemental mercury are typically in coal.¹⁸

A large number of parameters have been identified by researchers to impact mercury speciation and/or the mercury removal efficiency of SDA and fabric filter baghouses at coal-fired utility boilers. These parameters would also be expected to impact mercury speciation and the mercury removal efficiency of SDA and fabric filter baghouses at non-recovery coking operations.

When coal is burned in an utility boiler, combustion of all the organic carbon and the high temperatures (2700 °F) will release and vaporize all the mercury in the coal to form gaseous elemental mercury (i.e., Hg^0). The subsequent cooling of the waste gas and interaction of the gaseous elemental mercury with other combustion products such as fly ash (PM) and chlorine then results in a larger portion of the elemental mercury being converted to oxidized or particle-bound mercury. Oxidized mercury compounds in the waste gas may include mercuric chloride ($HgCl_2$), mercury oxide (HgO), and mercury sulfate ($HgSO_4$).

Extensive mercury testing conducted at 31 coal-fired utility boilers under the Phase III Information Collection Request (ICR) supporting the Mercury NESHAP demonstrated that the overall average pre-control proportion of total mercury that was particle bound for these boilers was approximately 78% (see Figure 2). In contrast, the average pre-control proportion of total mercury that was oxidized or in elemental form was approximately 13% and 9%, respectively.

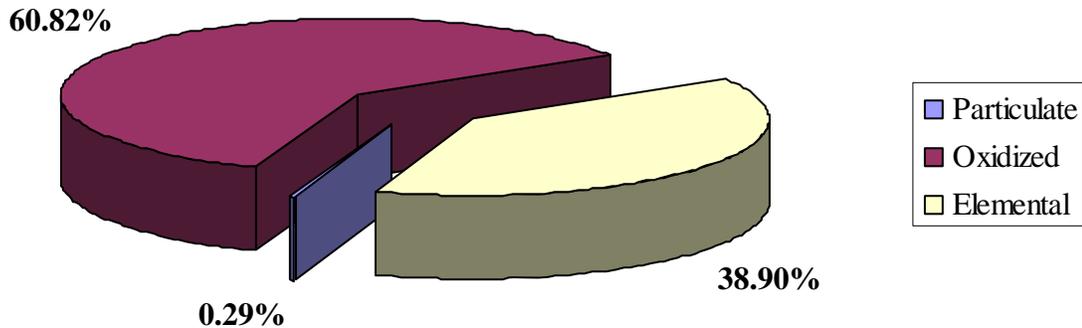
Figure 2: Mercury Speciation for uncontrolled (Inlet) Waste Gas from Bituminous Coal-Fired Utility Boilers



Source: USEPA ICR Electric Utility NESHAP Phase II Test Data

Based on mercury testing results from IHCC, pre-control mercury speciation at non-recovery coking operations is dramatically different than at coal-fired boilers.¹⁹ As shown in Figure 3, the proportion of particle-bound mercury to total mercury in the pre-control waste gas at a non-recovery coking operation averaged approximately 0.15%.

Figure 3: IHCC Speciated Mercury Analysis at FGD Inlet



Note: Results are based on the average of six emission test runs conducted at IHCC.

Furthermore, the average pre-control proportion of total mercury that was oxidized or in elemental form increased to approximately 62% and 37%, respectively. The dramatic increase in the amount of elemental and oxidized mercury in non-recovery coke oven waste gas is not unexpected. As discussed above, the non-recovery coking process characteristics and lower PM content of the waste gas point toward the proportion of particle-bound forms of mercury being significantly lower than present in coal-fired utility boiler waste gas.

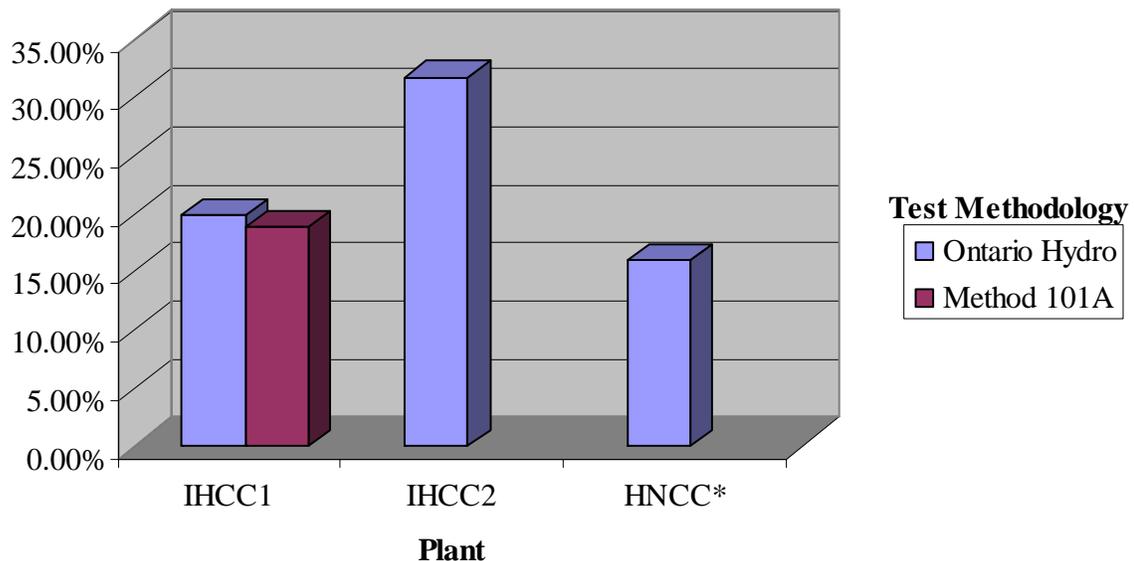
USEPA's existing AP-42 emission factor estimates that the mercury emissions per ton of coal coked at a non-recovery coking operation are only about 25% less than from a ton of coal combusted in a utility boiler. As expected, based on the recent IHCC test data, a much greater proportion of total inlet mercury concentrations to a SDA and fabric filter baghouse at a non-recovery coking plant are elemental and oxidized forms.

These speciated forms of mercury would be expected to be poorly controlled by a SDA and fabric filter baghouse configuration. This conclusion is dramatically shown by the results of the mercury emission testing conducted at the IHCC and HNCC non-recovery coke plants. Therefore, these recent testing results have important regulatory policy implications for non-recovery coking operations.

MERCURY REMOVAL AT NON-RECOVERY COKE PLANTS

As shown in Figure 4, the average total mercury removal effectiveness for SDA and fabric filter baghouse configurations at non-recovery coking operations are estimated to range from a low of approximately 16% to a high of approximately 30%. These rates are significantly lower than the 98% or greater mercury removal experienced at coal-fired utility boilers.

Figure 4: Total Mercury Removal by SDA / Fabric Filter at Non-Recovery Coke Plants

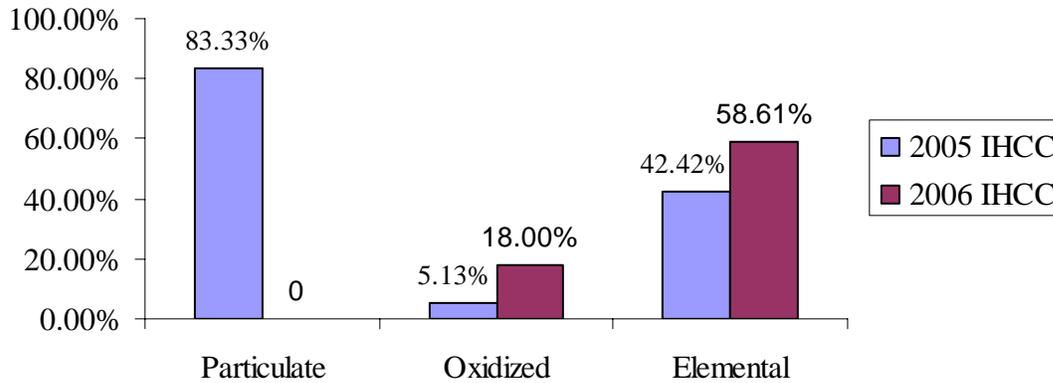


Note: HNCC mercury removal rate was estimated based on monthly mercury coal composition information, emission test coal charging information, and measured outlet mercury concentrations.

The low mercury removal rates by a SDA and fabric filter baghouse equipment configuration at non-recovery coke plants is not unexpected based on the important differences in the mercury speciation between coal-fired utility boiler and non-recovery coke plant waste gas. As discussed above, more than 99% of the total mercury present in non-recovery coke oven waste gas entering the SDA is in the oxidized or elemental form.

Based on the IHCC emission test results, particulate mercury in non-recovery coke oven waste gas is still well controlled by the SDA and fabric filter baghouse equipment configuration. As shown in Figure 5, more than 83% of the inlet particulate mercury was controlled by the SDA and fabric filter. This is an especially high removal rate given the extremely low particulate loading present in non-recovery coke plant waste gas.

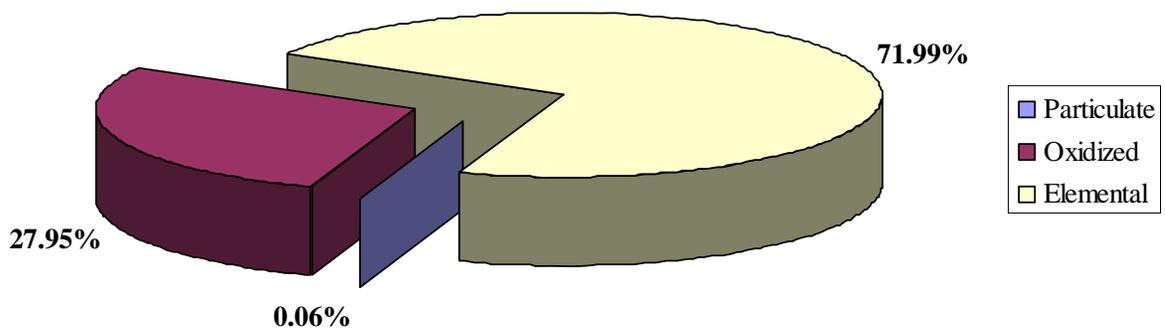
Figure 5: Control of Speciated Mercury by SDA / Fabric Filter



Note: Results based on average of three emission test runs conducted for each year

In contrast to particulate mercury, the removal of oxidized and elemental mercury is at a much lower rate and with important variability. Elemental mercury control by the SDA and fabric filter APC equipment configuration ranges from approximately 42% to 58%. However, the apparent higher elemental mercury removal rate may result from the conversion of elemental mercury to oxidized mercury by the SDA (see Figure 6). Oxidized mercury removal by a SDA and fabric filter equipment configuration appears to range from approximately 5% to 18%.

Figure 6: IHCC FGD Outlet Speciated Mercury Emissions



Note: Results based on calculated average across a total of six emission test runs.

As shown in Figure 6, the lower relative rate of removal for oxidized mercury may result from the conversion of elemental mercury to oxidized mercury by the SDA. The mercury speciation of the IHCC waste gas exiting the SDA and fabric filter was on average 71.99% oxidized, 27.95% elemental and 0.06% particulate.

By comparison, the oxidized content of the inlet waste gas to the SDA was only approximately 39%. These results would indicate the conversion of elemental mercury to oxidized mercury by the SDA. The conversion of elemental mercury to oxidized mercury by the SDA at a non-recovery coke plant would be consistent with research on coal-fired utility boilers. This research has shown that at least four general parameters have an impact on mercury speciation and mercury removal by a SDA and fabric filter baghouse.^{20 21} These parameters include:

- 1) Coal Composition
- 2) Plant Process Conditions
- 3) Waste Gas PM Composition
- 4) Waste Gas Chemical Characteristics

Each of these parameters contains a number of different factors that would likely impact mercury speciation and removal by SDA and fabric filter baghouse configurations at non-recovery coke plants. Therefore, the 16% to approximately 30% total mercury removal rates recently identified may vary further across non-recovery coke plants. However, these uniformly low total mercury removal rates have important environmental regulatory policy implications for both non-recovery coke and potentially integrated steel plants.

REGULATORY POLICY IMPLICATIONS

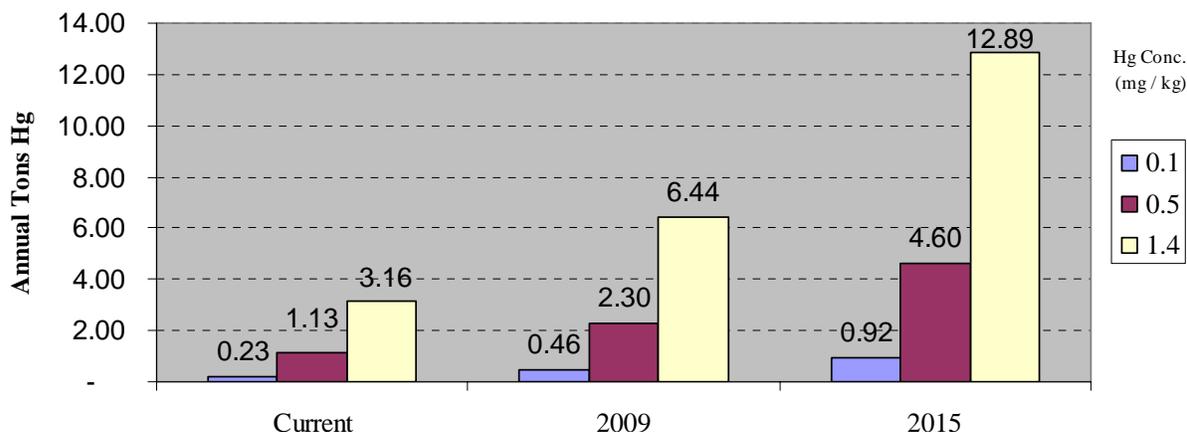
Based on historical information, mercury emissions from coke plants have not been identified as significant sources of aerial deposition by USEPA. Therefore, regulatory actions by USEPA and most states have not focused on limiting mercury emissions from non-recovery coking operations. However, the recently documented low co-removal of mercury by SDA and fabric filter baghouse equipment at non-recovery coke plants combined with the increased production of coke by non-recovery plants in the United States could change this in the near future.

The US Department of Energy Information Agency estimates that approximately 24.2 million tons of coal was used by US coke plants in 2003. Operating non-recovery coke plants currently used approximately 2.8 million tons of coal (11.5%).

As shown in Figure 7, based on an average removal rate of 25% by the SDA and fabric filter baghouse, annual mercury emissions from coal usage at currently operating non-recovery coke plants (three plants) would range from approximately 0.2 to 3.2 tons, depending on the mercury content of the charged coal. The mid-range of this annual non-recovery coke plant mercury emission rate would exceed USEPA's prior 1997 total mercury emission estimate for all 24 captive and merchant coke plants in the United States.

Furthermore, completion of the proposed FDS Coke Plant and a Phase II component at HNCC will increase the annual coal usage at non-recovery coke plants to approximately 6 million tons by 2009. The resulting estimated annual mercury emissions from non-recovery coke plants would range from 0.5 to 6.4 tons, depending on the mercury content of the coal used if mercury-specific controls (i.e., activated carbon injection) were not required at the operations.

Figure 7: Total Projected Non-Recovery Hg Emissions 2006 - 2015



Note: Hg Concentrations in coal based on actual range of coal mercury content information from IHCC and HNCC testing data.

More importantly, as the majority of existing by-product batteries get more than 40 or 50 years old increasing numbers of these by-product plants could very likely be replaced with non-recovery coke plants. According to USEPA, non-recovery coking is estimated to be 30% less costly than by-product coking because of the lower required labor inputs and absence of recovery plant operations.²² In addition, non-recovery coke plants are estimated to produce less than ½ of CO₂ equivalent emissions than by-product plants, an increasing important concern.²³

Based on these industry factors, one might reasonably predict that non-recovery coke plants could make up 50% of the production capacity by 2015. As shown in Figure 6, if this increase occurs and only SDA and fabric filter baghouses are specified as APC equipment then annual mercury emissions from non-recovery coke plants would range from 0.9 to 13 tons, depending on the mercury content of the coal used. At the high-end of this annual mercury emission rate, non-recovery coke plants would be the largest single industrial manufacturing source of mercury in the US by 2015.

In response to the increased public concerns regarding mercury emissions, state environmental regulatory agencies in Ohio, Pennsylvania, and Illinois have already taken steps to reduce the mercury emissions at proposed new non-recovery coke plants by requiring add-on mercury control using the injection of activated carbon (AC). The Ohio EPA's permit-to-install (PTI) issued to both the FDS Coke Plant and HNCC Phase II require the use of AC injection as a mercury-specific add-on control. The actual reduction in mercury to be obtained from AC injection is still unknown because these new plants have not begun operation. However, based on utility coal-fired boiler research, we do know that wide range of factors can influence mercury reduction using AC injection. Further research into this issue will likely be required.

Finally, USEPA has completed rulemaking to reduce mercury emissions from utility coal-fired boilers to an annual cap of 15 tons by 2018. This rulemaking was a tremendous undertaking in terms of both agency research and staff time. Completion of this effort means USEPA's attention can be turned to other potential regulatory efforts.

The recent mercury emission testing results for non-recovery coke plants points toward the underestimation of mercury emissions from both coke and iron/steel manufacturing. According to USEPA information, captive by-product coke plants were located at 13 integrated iron and steel plants in 2000. These integrated iron and steel plant typically use conditioned coke oven gas as fuel for the basic oxygen furnaces. As a result, one could expect elemental or oxidized mercury to be present in the conditioned coke oven gas and, subsequently emitted by the steel furnaces. As a result, iron and steel manufacturing plants may also be a more significant source of mercury emission than previously identified. Additional research will clearly be required to answer this question.

In closing, state regulation of mercury emissions from non-recovery coke plants was started by Ohio EPA in June 2004. If or when these early state regulatory efforts will result in uniform USEPA regulatory actions is anyone's guess at this point. However, the new information being obtained from the non-recovery coke plant mercury emission testing activities is pointing to where the answers lie.

¹ Federal Register Vol. 69, No. 20 pp 4652-4752 dated January 20, 2004

² *Mercury Study: Report to Congress: Volume 1 Executive Summary*, Table 3-1, USEPA December 1997; EPA 452/R-97-003,

³ ³ Federal Register Vol. 70, No. 95 pp 28606-28700 dated May 18, 2005

⁴ See Table 3-1, Mercury Study Report to Congress. Volume II: *An Inventory of Anthropogenic Mercury Emissions in the United States*, EPA December 1997 452-R-92-004. Office of Air Quality Planning and Standards,

⁵ See Chapter 4, Section 4.4. Mercury Study Report to Congress. Volume II: *An Inventory of Anthropogenic Mercury Emissions in the United States*, December 1997 EPA 452-R-92-004. Office of Air Quality Planning and Standards,.

Ohio Environmental Protection Agency, Final Permit to Install for FDS Coke Plant, LLC dated June 14, 2004 (Application No. 04-01360).

⁷ Labyrinth Management Group correspondence to Mr. Mike Hopkins with Ohio EPA on *Technical Feasibility Issues Associated with Mercury Emission Limits for Emission Unit B901 in the FDS Coke Plant PTI 04-1360*, dated December 17, 2004.

⁸ Various correspondences from Mike Hopkins and Bob Kossow with Ohio EPA to Matt Stanfield with Toledo Department of Environmental Services during June 2004. The Coal-Fired Electric Utility MACT is National Emission Standard for Hazardous Air Pollutants (NESHAP) regulation (40 CFR Part 63 Subpart UUUU) and alternative Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units

⁹ Federal Register Vol. 69, No. 20 pp 4652-4752 dated January 20, 2004

¹⁰ Office of Air Quality, *Study of Hazardous Air pollutant Emissions from Electric Utility Steam Generating units – Final Report To Congress*, Vol. 2 Appendices, USEPA February 1998.

¹¹ *NESHAP for Coke Ovens: Pushing Quenching, and Battery Stacks – Background Information for Proposed Standards, Final Report*, USEPA February 2001.

¹² *Emission Factor Documentation for AP-42 Section 1.1 Bituminous and Subbituminous Coal Combustion* USEPA April 1993.

¹³ *Ibid*, pg 2-21.

¹⁴ IHCC mercury emission testing was conducted as a Supplemental Environmental Project under a Consent and Final Order between USEPA and IHCC issued on September 29, 2005. HNCC mercury emission testing was conducted as part of required testing for PTI 07-00511.

¹⁵ Tables 1 and 2 references include the following documents:

Clean Air Engineering, *Mecklenburg Cogeneration LP Unit 1 APC System Clarksville, Virginia*, January 27, 2000.

Energy & Environmental Research Center, *Final Report Mercury Speciation Sampling for the ICR at Public Service Company of Colorado Valmont Station*, January 2000.

IT-Air Quality Services Group, *Non-Recovery Coke Oven Waste Heat and Air Pollution Characterization* Jewel Coal & Coke Company Vansant, Virginia, January 11, 1990.

Metro Environmental, *Source Emissions Survey of First Energy Corporation Ohio Edison Company W.H. Sammis Power Plant Unit Number 1 Baghouse Inlet Duct and South Outlet Duct Stratton, Ohio* for EPRI, September 1999.

Mostardi-Platt Associates, Inc., *Particulate Emission Study performed for Primary Energy at the Indiana Harbor Coke Company Cokenergy Facility*, May 11 and 12, 1998.

Mostardi-Platt Associates, Inc., *Gaseous and Lead Emissions Compliance Test Program Indiana Harbor Coke Company Cokenergy Facility*, December 2 and 3, 1999.

Roy F. Weston, Inc., *Information Collection Request Assessment of Speciated Mercury Emissions from a Coal-Fired Boiler*, November 1999.

Office of Air Quality, *Testing Non-Recovery Coke Ovens for Standards Development Jewell Coal & Coke Company Vansant, Virginia*, USEPA September 1992.

Office of Air Quality, *Emission Factor Documentation for AP-42 Section 1.1 Bituminous and Subbituminous Coal Combustion*, USEPA April 1993.

¹⁶ *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report to Congress, Volume 2. Appendix I* USEPA dated February 1998

¹⁷ *Control of Mercury Emissions from Coal Fired Electric Utility Boilers: Interim Report* USEPA dated April 2002. p. 5-1

¹⁸ *Ibid*, p. 5-1

¹⁹ IHCC reports *Speciated Mercury and Total Mercury Emission Study*, prepared by Platt Environmental Services dated February 8, 2006 and *Speciated Mercury Emissions Study* prepared by Platt Environmental Services dated July 20, 2006.

²⁰ *Control of Mercury Emissions from Coal Fired Electric Utility Boilers*, USEPA April 2002, p 5-7

²¹ ENSR Corporation *Multivariable Method to Estimate The Mercury Emissions of the Best-Performing Coal-Fired Utility Units Under the Most Adverse Circumstances Which Can be Expected to Recur*, March 4, 2003

²² *Appendix B, Development of Coke Battery Cost Functions* used in support of USEPA's 1993 MACT final rule on coke ovens. USEPA

²³ Based on confidential LMG non-recovery waste gas composition calculations and evaluation of public reporting of CO₂ equivalent emissions from by-product coke plants in signatory countries to the Kyoto Protocol.