



**American
Forest & Paper
Association**



**AMERICAN
WOOD
COUNCIL**

Background Materials on Boiler MACT and NHSM

Tuesday, November 13, 2012

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United States Senate

WASHINGTON, DC 20510

July 19, 2012

The Honorable Barack Obama
President of the United States
The White House
1600 Pennsylvania Avenue, NW
Washington, DC 20500


Dear President Obama:

Given that the U.S. Environmental Protection Agency (EPA) has transmitted to OMB the reconsidered rules with regard to industrial boilers, known as the Boiler MACT rules, we are writing to reiterate our interest in this issue of great concern to manufacturers across the country. It has been our shared goal to ensure that the final Boiler MACT rules are achievable, affordable, and protective of public health and the environment, while preventing the loss of thousands of jobs that we can ill-afford to lose. Since the rules were first proposed, we acknowledge that significant revisions have been made. However, we continue to believe that the final rule must be strengthened to include additional compliance time to enable facilities that will be investing billions of dollars to rationally plan for the capital expenses, to clarify the fuel status of key biomass materials, and to establish achievable carbon monoxide (CO) limits for all fuels to ensure the intended benefits.

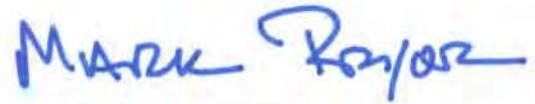
Considering the number of facilities involved and the complexity of the rules, it is necessary to provide compliance time beyond the traditionally provided three years, and we believe this is possible within the authorities provided to EPA and the President under the Clean Air Act. We request that the rules require that EPA or the states provide an extra year to comply if a facility meets reasonable criteria. We also believe that an additional year is warranted through presidential action. Additionally, the rules should clarify the status of key biomass residuals as fuels so that these materials can be used productively rather than placed into landfills with negative environmental consequences. The Boiler MACT rules should list wastewater treatment residuals as non-waste fuels, create a safe harbor or presumption for other biomass residuals, and eliminate the presumption that materials are wastes until proven otherwise. Finally, the current CO limits under the Boiler MACT rules, which are currently unachievable, should be adjusted for all fuels – biomass, coal, and oil – for both new and existing sources. These standards should be based on the capabilities of real-world boilers.

Final Boiler MACT rules that include flexibility to make the rules achievable and that are consistent with the intent of the Clean Air Act and your Executive Order 13563 to “identify and use the best, most innovative, and least burdensome tools for achieving regulatory ends,” are critical to preserving jobs in many manufacturing industries. The rules as they stand today could cost billions of dollars and thousands of jobs. We urge you to carefully consider this need for flexibility and these points as you evaluate the EPA’s proposal.

Sincerely,



Susan Collins
United States Senator



Mark Pryor
United States Senator



Lamar Alexander
United States Senator



Mary Landrieu
United States Senator



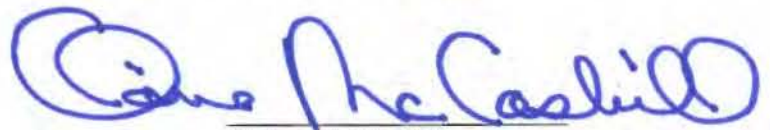
Lisa Murkowski
United States Senator



Herb Kohl
United States Senator



Roy Blunt
United States Senator



Claire McCaskill
United States Senator

Copy To:

The Honorable Jack Lew, Chief of Staff, Executive Office of the President
The Honorable Cass Sunstein, Administrator, Office of Information and Regulatory
The Honorable Lisa Jackson, Administrator, Environmental Protection Agency
The Honorable Jeffrey Zients, Acting Director, Office of Management and Budget

Notes from IEC Call with Tim Hunt of AF&PA and Amy Schaffer of the Recycled Paperboard Technical Association (RPTA)

Friday, October 19, 2012

IEC Call Participants: Jason Price and Eric Reker

During IEC's prior call with Mr. Hunt and Ms. Schaffer on October 8, they agreed to conduct an informal survey of their member companies for information on the generation and use of paper-processing residuals (PPRs). During today's call, they outlined the information that they obtained.

- **Generation of paper processing residuals:** Paper recycling facilities generate between 450,000 and 600,000 tons of PPRs (including OCC rejects) per year (although these data are not recent and the amounts are likely have changed with the increase in recycling). These values reflect the residuals generated by the initial screening process (i.e., to remove metals), materials that do not break down during processing (e.g., paper treated to repel water), and fibers too small to be re-used. There are no definitive data on what portion of this material is old corrugated cardboard, but a broad array of types of recovered fiber, such as old magazines, old newsprint and office paper, are increasingly used at paper recycling mills as recovery rates approach 70 percent of all paper produced.
- **End uses:** Roughly 30 percent of paper processing residuals (approximately 135,000 to 180,000 tons) are burned for their fuel value. At mills that burn paper processing residuals as a fuel onsite, the percentage of this material burned ranges from 55 to 100 percent. PPR are not burned during solid fuel boiler downtime or when combustion conditions and fuel availability dictate a different mix of solid fuels to meet performance characteristics of the boiler. The majority of the burning takes place on-site at the facility where the PPRs are generated. The remaining 70 percent of PPRs that are not burned for energy are mostly landfilled, with minimal amounts used for land applications. Mr. Hunt and Ms. Schaffer noted, however, that some technologies are currently under development for the conversion of paper processing residuals to pellets.
- **On-site versus off-site usage:** Of the roughly 30 percent of PPRs burned as a fuel, a large majority is burned on site. Only 15-20 of the 100+ paper mills across the U.S. burn PPRs as fuel. Many facilities (particularly recycle mills) use natural gas in their boilers and are unable to use solid material as a fuel source. Unless an arrangement can be made with another boiler in the area to use the material, the PPRs generated at facilities that use natural gas boilers are landfilled. Mr. Hunt estimates that no more than 5 percent of PPRs are burned offsite. He noted, however, that this number could increase if EPA were to issue a conditional exclusion for paper processing residuals.

Other notable points made by Mr. Hunt and Ms. Schaffer:

- Between 6 and 10 companies currently burn paper processing residuals in 15 to 20 different mills.
- At some mills, paper processing residuals provide up to 20 to 25 percent of the total solid fuel energy consumed onsite. Thus, paper processing residuals represent a significant source of energy for these facilities.
- In addition to metals removal, PPRs are commonly dewatered to varying degrees as part of the fuel processing preparations.

A Comparison of PAH Levels in Coal Tar Oil and Crossties

				Crude Coke Oven Tar					Coal Tar Distillation Products												Crossties (Note 6)		Coal Tar Oil (Note 7)				
Product Name:				Koppers Crude Coke Oven Tar	Follansbee Rec'd CCOT	Sloss Coal Tar	Arcelor Mittal Coal Tar	Avg. Tar	Coal Tar Distillate		Coal Tar Solvent		Refined Chemical Oil		Carbon Black Feedstock Oil		Carbon Pitch Type A		Coal Tar Creosote (Pressure Appl.)		P2 Creosote	RED P2 Creosote	Avg Creosote	PPM	%	% range	
Source:				Koppers Inc. MSDS	Note 3	Note 4	Note 5		Koppers Inc. MSDS		Koppers Inc. MSDS		Koppers Inc. MSDS		Koppers Inc. MSDS		Koppers Inc. MSDS		Koppers Inc. MSDS		Note 1	Note 2					
Source Date:				9/13/2007	From July 2010 Comments				6/14/2007	1/27/2009	12/13/2007		6/14/2007				6/14/2007				From July 2010 Comments						
Product Use:				Process chemical					Process chemical, solvent, fuel		Fuel, feedstock	Process chemical		Chemical feedstock		Process chemical		Wood preservative									
Physical Form:				Viscous liquid					Liquid		Liquid		Liquid		Liquid		Temp dependent		Liquid								
				Mass (%)	Mass (%)	Mass (%)	Mass (%)	Mass (%)	Mass (%)		Mass (%)		Mass (%)		Mass (%)		Mass (%)		Mass (%)								
Component Name	CAS No.	Molecular Wt.	Rings				Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max							
Coal tar	8007-45-2			100.00%																							
Coal tar distillate									100.00%				100.00%				100.00%										
Solvent naphtha (coal)	65996-79-4																										
Benzene	71-43-2	78.1	1	0.29%					0.00%	0.02%	1.90%	7.40%	0.01%	0.27%		0.01%				0.01%							
Pyridine	110-86-1	79.1	1										0.02%	0.05%													
Toluene	108-88-3	92.1	1	0.07%					0.01%	0.03%	2.60%	3.50%	0.07%	0.27%	0.01%	0.03%				0.01%	0.02%						
Phenol	108-95-2	94.1	1										2.83%	5.44%													
styrene monomer	100-42-5	104.1	1										1.60%	2.50%	0.16%	0.18%											
Ethyl Benzene	100-41-4	106.2	1						0.01%	0.04%	0.50%	0.80%	0.05%	0.11%	0.01%	0.03%											
m-xylene	108-38-3	106.2	1										1.20%	2.30%													
p-xylene	106-42-3	106.2	1						0.00%	0.04%	1.20%	2.30%			0.00%	0.03%				0.01%	0.02%						
o-xylene	95-47-6	106.2	1										0.80%	1.80%													
m-cresol	108-39-4	108.1	1										2.30%	4.10%						0.04%	0.13%						
p-cresol	106-44-5	108.1	1										2.30%	4.10%						0.04%	0.13%						
o-cresol	95-48-7	108.1	1										1.80%	3.40%													
Cresol (mixture)	1319-77-3	108.1	1										0.94%	1.10%													
Indene	95-13-6	116.2	1	0.33%		0.35%	0.90%				12.10%	27.40%	3.07%	4.06%							0.70%	0.50%					
Benzo(furan)	271-89-6	118.1	1										2.41%	7.70%	0.56%	0.83%				0.02%	0.08%						
Indan	496-11-7	118.2	1	0.90%																	0.30%						
2,3-Dihydro-1H-indene	496-11-7	118.2	1										2.70%	4.40%													
Trimethyl benzene	25551-13-7	120.2	1										2.40%	7.70%													
1,2,3-Trimethylbenzene	525-73-8	120.2	1										3.30%	7.00%													
1,3,5-Trimethylbenzene	108-67-8	120.2	1										0.80%	1.70%													
3-Ethyltoluene	620-14-4	120.2	1										0.50%	1.10%													
2,4-Xylenol	105-67-9	122.2	1										0.90%	1.70%													
Naphthalene	91-20-3	128.2	2	9.85%	9.84%	7.60%	3.00%	11.00%	1.20%	14.00%	16.01%	30.66%	43.82%	56.03%	1.40%	11.00%			3.07%	8.33%	8.00%	17.30%		490	4.90%	1.2% - 40%	
Isoquinoline	119-65-3	129.2	2																		0.20%						
Quinoline	91-22-5	129.2	2	0.07%					0.05%	0.39%	0.03%	0.13%	0.79%	1.14%	0.06%	0.34%				0.48%	0.81%	0.80%	0.50%				
Benzo(b)thiophene	95-15-8	134.2	2										0.97%	1.30%													
Benzo(c)thiophene	270-82-6	134.2	2																		0.20%	0.40%					
2-Methyl Naphthalene	91-57-6	142.2	2				0.61%	1.50%													4.60%	2.80%		580	0.0580%	2.8% - 4.6%	
1-Methyl Naphthalene	90-12-0	142.2	2				0.31%	0.65%					1.71%	2.23%							2.10%	1.30%					
Acenaphthylene	208-96-8	152.2	2				1.80%	2.00%													0.13%	0.17%	0.20%		96	0.0096%	0.13% - 0.2%
Diphenyl (Biphenyl)	92-52-4	154.2	2	0.03%					0.08%	0.47%			0.89%	1.23%	0.10%	0.43%				0.61%	1.03%	1.20%	0.71%				
1-Ethynaphthalene	1127-76-0	156.2	2																		0.50%						
Acenaphthene	83-32-9	154.2	3				0.05%	1.05%	2.80%	5.80%					3.40%	5.50%				4.53%	6.00%	6.60%	4.40%	2,200	0.2200%	2.8% - 6.6%	
Fluorene	86-73-7	166.2	3			1.31%	1.20%	1.70%	2.40%	4.20%											4.90%	4.03%		1,200	0.1200%	2.4% - 4.9%	
Carbazole	86-74-8	167.2	3	0.55%		0.49%	0.40%	0.60%					0.26%	0.76%	2.00%	2.60%	0.02%	0.10%		1.50%	1.68%	1.20%	1.40%	220	0.0220%	0.02% - 2.6%	
Phenanthrene	85-01-8	178.2	3	4.60%		3.94%	4.20%	5.10%	15.00%	22.00%			3.71%	7.24%	16.00%	19.00%				11.16%	14.13%	12.60%	9.60%	6,200	0.6200%	3.71% - 19%	
Anthracene	120-12-7	178.2	3			1.33%	0.90%	1.90%	3.70%	4.90%			0.79%	1.83%	4.10%	4.40%				2.80%	3.76%	2.10%	2.90%	1,100	0.1100%	0.79% - 4.9%	
Dibenzofuran	271-89-6	184.3	3	0.03%		1.23%	1.10%	1.70%	1.10%	2.70%			2.45%	3.21%	1.60%	2.40%				2.22%	3.76%	3.70%	2.30%	900	0.0900%	1.1% - 3.76%	
Dibenzothiophene	132-65-0	184.3	3			0.26%															1.20%	0.94%					
Fluoranthene	206-44-0	202.3	4	3.37%		2.30%	1.40%	3.50%	7.10%	14.00%			0.35%	2.18%	7.80%	12.00%	0.77%	1.27%		6.75%	7.41%	6.50%	4.60%	4,200	0.4200%	0.35% - 14%	
Pyrene	129-00-0	202.3	4	2.29%		1.88%	1.30%	2.50%	4.30%	8.60%			0.18%	1.55%	5.00%	8.20%	0.67%	1.19%		4.70%	5.14%	7.90%	4.00%	2,200	0.2200%	0.18% - 8.6%	
1,2-Benzphenanthrene	218-01-9	228.3	4	0.84%					0.48%	2.40%			0.04%	0.27%	0.80%	2.20%	0.72%	1.03%									
1,2-Benzanthracene	56-55-3	228.3	4	0.82%		0.92%	0.80%	0.52%	0.59%	2.30%			0.04%	0.30%	0.88%	2.10%	0.71%	1.04%			0.50%	0.20%		580	0.0580%	0.04% - 2.3%	
Benzo(b)fluorene	243-17-4	216.3	4			0.43%															1.90%						
Benzo(a)fluorene	238-84-6	216.3	4			0.40%															0.90%	0.73%					
Chrysene	218-01-9	228.3	5	0.87%		0.90%	0.50%	1.30%													1.08%	1.18%	1.50%	0.10%	480	0.0480%	0.1% - 1.5%
Benzo(b)fluoranthene	205-99-2	252.3	5	1.38%		0.54%	0.50%	0.40%	0.00%	1.60%			0.13%	0.50%	1.50%	0.72%	0.92%			0.23%	0.37%	0.30%	0.51%	320	0.0320%	0.0% - 1.6%	
Benzo(j)fluoranthene	205-82-3	252.3	5						0.00%	1.60%			0.51%	0.66%	0.51%	1.00%											
Benzo(k)fluoranthene	207-08-9	252.3	5			0.39%	0.30%	0.76%	0.00%	1.60%			0.48%	0.62%	0.51%	1.00%	0.20%							140	0.0140%	0.0% - 1.6%	
Benzo(a)pyrene	50-32-8	252.3	5	0.96%		0.84%	0.48%	1.90%	0.10%	0.63%			0.04%	0.2													

Draft – October 18, 2012

Suzanne Rudzinski
Director
Office of Resource Conservation and Recovery
Office of Solid Waste and Emergency Response
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Mail Code: 5301P
Washington, DC 20460

Re: Construction and Demolition Wood Non-Waste Determination

Dear Ms. Rudzinski:

I am writing on behalf of the Construction Materials Recycling Association Issues and Education Fund (CMRA)¹ and the Biomass Power Association (BPA)² to request a determination that construction and demolition (C&D) wood, when processed and managed as described below, is not a waste when combusted. EPA already has recognized that the practices used by suppliers of C&D wood generate materials appropriate for use as fuel. Specifically, EPA has determined that the practices used by the industry to remove contaminants from C&D wood likely meets the processing requirements of 40 C.F.R. 241.3(b)(4) and that such processing likely results in a legitimate fuel. 76 Fed. Reg. 15456, 15485 (Mar. 21, 2011) (NHSM Rule); 76 Fed. Reg. 80452, 80470 (Dec. 23, 2011) (NHSM Proposal). In this letter, CMRA and BPA are asking EPA to confirm that the practices described below, resulting in the contaminant levels described below, meet the processing and legitimacy criteria of 40 C.F.R. Part 241, and that C&D wood that is managed as described below is a non-waste fuel.

The combustion of C&D wood occurs in every EPA Region. Accordingly, CMRA and BPA are requesting a national determination from you that C&D wood, processed and managed as described below, is a non-waste fuel.

1. C&D wood is processed into a non-waste fuel through removal of contaminants and the improvement of fuel characteristics through sizing.

¹ CMRA promotes the safe and economically feasible recycling of the more than 325 million tons of recoverable construction and demolition materials that are generated in the United States annually. CMRA members are a diverse group of companies and agencies from the many construction and demolition materials recycling disciplines.

² BPA is comprised of 23 member companies who either own or operate biomass power plants, and 16 associate and affiliate members who are suppliers to or customers of the industry. BPA's member companies represent approximately 80 percent of the U.S. biomass to electricity sector.

C&D wood can originate from a variety of construction and demolition sources.³ Construction materials originate from construction, repair or remodeling activities. Demolition materials are generated from the dismantling of buildings (either intentionally or as a result of a natural disaster) or from the removal phase of remodeling. As noted in EPA's Materials Characterization Paper for Construction and Demolition Materials, before processing this material can contain a variety of building products.⁴

C&D wood can be obtained directly from a construction or demolition site or from a contractor that has collected C&D material. It is also obtained from landfill operators that divert, collect and segregate C&D wood at their operations (diversion is required by law in some states, including California). While many C&D wood processors have facilities that are dedicated to that purpose, landfill operators, transfer stations, material recovery facilities, wood yards, and combustion facilities, both municipal and commercial, also can be C&D wood processors. Processing even can occur at the construction or demolition site. While a C&D wood processor may be paid a tipping fee to receive C&D wood, in each of these collection and processing scenarios, C&D wood is a valuable commodity, is never considered a "waste" by the processors or the energy recovery facility, and is not discarded at any point.⁵

Processing consists of sorting the material to remove contaminants, including non-wood materials, wood treated with pentachlorophenol or chromated copper arsenic and other preservatives, and lead.⁶ This processing can be achieved through a variety of mechanical and manual practices and is regulated under state law. As discussed below, the result is a wood fuel

³ C&D wood that does not contain contaminants at concentrations not normally associated with virgin wood, (e.g., trimmings from framing at a construction site or clean dimensional lumber recovered from carefully deconstructed buildings), is clean cellulosic biomass and could be combusted as traditional fuel. 40 C.F.R. 241.2.

⁴ Materials Characterization Paper In Support of the Final Rulemaking: Identification of Nonhazardous Secondary Materials That Are Solid Waste - Construction and Demolition Materials – Building-Related C&D Materials, Feb 3, 2011 EPA-HQ-RCRA-2008-0329-1811

⁵ EPA has recognized that receipt of a tipping fee is not dispositive of whether the material received is a waste and that the management of the material is more relevant. *See* 73 Fed. Reg. 64668, 64703 (Oct. 30, 2008).

⁶ It is important to recognize that states have different requirements that govern the removal of lead from C&D wood. For example, California regulates the levels of lead and other contaminants through permit conditions in air permits issued by the local Air Pollution Control Districts, as well as by the Regional Water Quality Control Boards and the Department of Toxic Substances Control which have regulatory and permit requirements on contaminant levels in ash. For example, California air permits may limit the amount of painted wood used as fuel to less than one percent or may prohibit the use of painted wood all together. In contrast, Maine limits the amount of lead in C&D wood by limiting the amount of fines in the processed wood. *See* Maine Solid Waste Management Rules, Chapter 418, 6.B. The Maine standards are based on studies from the University of, Maine that show that the amount of fines in C&D wood has a stronger correlation to amount of lead in C&D wood fuel than the presence of painted wood. C&D wood that meets Maine standards has levels of lead that are comparable to virgin wood and biomass. *See* Report on the Substitution of Wood from Construction & Demolition Debris for Conventional Fuels in Biomass Boilers Maine Department of Environmental Protection, April 2007, at 17-18, available at <http://www.maine.gov/dep/waste/legislative/documents/legisreportcddfial.pdf>

that meets EPA's contaminant legitimacy criterion.⁷ Rejected wood and non-wood materials are managed in accordance with applicable environmental laws and permits and are not included in the C&D wood that is made into a fuel.

Once contaminants are removed, the remaining C&D wood is sized by grinding it into wood chips conforming to purchaser specifications. This processing can produce a large grind, such as an 8-inch minus product that may be further ground at the energy recovery facility, or a smaller size such as 2-inch minus ready to be fed into the combustion boiler. The C&D wood may be combined with other clean biomass prior to size reduction.⁸

While we do not believe that C&D wood that is managed as discussed above is discarded, if any C&D wood is considered discarded, it is processed into a non-waste fuel. Please confirm that the processing described above meets the definition of processing at 40 C.F.R. 241.2.

2. C&D wood is managed as a valuable commodity.

C&D wood is a valuable commodity and is managed as such at both wood processing and energy recovery facilities. After processing, it is transported to the energy recovery facility in covered chip vans or semi-trailers. At the energy recovery facility, the C&D wood is stored in the plant's wood fuel storage yard. These storage and management practices are the same as are used for virgin wood, a traditional fuel.

C&D wood is typically used as fuel within 30 to 90 days of delivery. Please note that virgin wood, a traditional fuel, often is stored for a longer period of time, depending on numerous factors, including fuel supply market conditions. Slash, tree thinnings and tree residue are obtained during the months of the year that forestry operations can occur, and not when the forest floor is inaccessible (*e.g.*, covered in snow or is too muddy for forestry operations). However, energy recovery facilities operate year round so they typically stock-pile fuel when it is available. Accordingly, it is not unusual for wood that is traditional fuel to be stored longer than C&D wood. In fact, virgin wood may be stored at an energy recovery facility for up to a year.

The fuel that is analogous to C&D wood is clean biomass. C&D fuels are managed in the same way by energy recovery facilities as is traditional clean biomass fuel.

Please confirm that the management practices described above meet the legitimacy criterion for management found at 40 C.F.R. 241.3(d)(1)(i).

⁷As EPA noted in the March 2011 NHSM Rule: "C&D-derived wood can contain *de minimis* amounts of contaminants and other materials provided it meets the legitimacy criterion for contaminant levels." 76 Fed. Reg. at 15486.

⁸ In fact, in Maine regulations require C&D wood to be mixed with conventional fuel at a 50% ratio prior to combustion. *See* Maine Solid Waste Management Rules, Chapter 418, 6.

3. C&D wood has a meaningful heating value and is used as fuel in a combustion unit that recovers energy.

C&D wood has a heating value of averaging about 6800 Btu/lb. as-fired (8400 Btu/lb. dry).⁹ This heating value is higher than the heating value of virgin wood because from wood from the construction or demolition of buildings is primarily kiln-dried wood. Kiln-dried wood has a higher heating value than virgin wood because it has less moisture. The moisture of kiln-dried wood generally ranges from 5 to 15 percent, whereas traditional biomass can contain in the range of 15 to 50 percent moisture. As discussed above, C&D wood is purchased by energy recovery facilities for use as fuel to generate electricity.

Please confirm that C&D wood meets the criterion for heating value at 40 C.F.R. 241.3(d)(1)(ii).

4. C&D wood contains contaminants at levels that are comparable to or lower than traditional fuels that the combustion unit is designed to burn.

C&D wood is biomass. It contains contaminants at levels that are comparable to clean biomass, a traditional fuel. As noted above, EPA already has determined that C&D wood likely meets the legitimacy criteria for contaminants. To make a "complete determination," EPA stated that it needed to see "the comparison of As and Cr concentrations." 76 Fed. Reg. at 15484. As demonstrated in Appendix A, both arsenic levels and chromium levels in C&D wood are comparable to or lower than levels found in virgin wood, providing the basis for EPA to complete its determination that C&D wood is a non-waste fuel. In fact, as demonstrated in Appendix A, the only contaminant present in C&D wood at levels that may be somewhat higher than the levels shown in available data sets for virgin wood is formaldehyde. However, the formaldehyde levels shown in Appendix A are not evidence that C&D wood has contaminant levels that are higher than contaminant levels in wood and biomass. First, the formaldehyde in the samples may have resulted from the test method rather than C&D wood. Second, formaldehyde is a VOC and there are both data and literature indicating that virgin wood can have significant amounts of VOCs. Third, if formaldehyde is present in C&D wood it is likely from resinated wood, which EPA has determined is not a waste when combusted. Appendix A provides a full explanation of these issues.

Please confirm that C&D wood meets the criterion for contaminants at 40 C.F.R. 241.3(d)(1)(iii).

⁹ These Btu values are based on 10 years of data from a New York facility. EPA's Materials Characterization Paper for Construction and Demolition Wood references Btu values for C&D wood between 7750 Btu and 8200 Btu. Both sets of numbers easily demonstrate that C&D wood has significant heating value.

5. Demonstration by combustors that the legitimacy criteria and processing requirements are met.

Both the CISWI MACT and the Boiler MACT rules require a combustor that combusts non-hazardous secondary materials to keep records showing that the fuel meets the legitimacy criteria of Part 241 and, if a non-waste due to processing, records showing how the operations that produced the fuel satisfy the definition of processing. *See* 40 C.F.R. 60.2740 (u) (CISIWI) and 40 C.F.R. 60.7555(d)(2) (Boiler MACT). However, EPA also has clarified that combustors need not test the non-hazardous secondary material that they combust, and instead may rely on existing laboratory results from a generator or combustor or industry-recognized values provided by a national trade organization. 76 Fed. Reg. at 80481.

We request EPA to confirm that data collected by CMRA and BPA, as national trade associations, can be relied upon by combustors of C&D wood. These data represent the results of the processing practices described in this letter. We understand that any finding by EPA will be based the facts presented in this letter. However, we believe that individual combustors can meet their obligations under the CISWI and Boiler MACT Rules to show that C&D wood is not a solid waste by keeping the following records:

- a. A copy of an EPA letter agreeing that C&D wood both meets the legitimacy criteria and is adequately processed when it is managed consistent with the facts set forth herein.
- b. A copy of a contract, purchase order, or other document that requires a supplier of C&D wood to process and manage C&D wood consistent with the practices described herein or a certification from the supplier that the practices described herein were followed.

Allowing combustors to rely on these records to demonstrate that C&D wood is not a waste is consistent with how EPA proposes to implement its non-waste determination for tires from established tire collection programs. Units that combust tires are allowed to rely on certifications that the tires that are combusted are from established tire collection programs and were not discarded. 40 C.F.R. 60.2740(v). EPA recognizes that such a certification can be based on a contractual arrangement and is proposing to define established tire collection program to include “a contractual arrangement that ensures that scrap tires are not discarded and are handled as valuable commodities through arrival at the combustion facility.” 76 Fed. Reg. at 80484 and proposed 40 C.F.R. 241.2. Once that certification is made, EPA does not intend to require the combustor to have perfect knowledge of the source of a secondary fuel and does not require the combustor to test that fuel. “Rather, it is sufficient that the ultimate user verify that it is obtaining tires from an established tire collection program, which program can provide the user with reasonable assurance that it manages tires carefully from point of collection to point of burning and which does not receive tires which have been abandoned in landfills or otherwise.” 76 Fed. Reg. 28318, 28322 (May 17, 2011).

Please confirm that the records identified above are sufficient to meet any burden of proof a combustor may have to show that a fuel is not a waste and that these records meeting the requirements of 40 C.F.R. 60.2740 (u) and 40 C.F.R. 60.7555(d)(2).

Conclusion

Suzanne Rudzinski

October xx, 2012

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We believe that this letter demonstrates that C&D wood is processed into a non-waste fuel through the removal of contaminants and the appropriate sizing, C&D wood is a valuable commodity that is bought and sold in the market place and is managed as such by both processors and combustors, C&D wood has meaningful heating value, and C&D wood has contaminant levels that are comparable to or lower than traditional fuels that could otherwise be combusted by the biomass to electricity sector. Accordingly, we request EPA to provide a letter agreeing with these conclusions.

Thank you for your attention to this matter.

Sincerely,

Susan Parker Bodine

cc: Jim Berlow
George Faison

June 8, 2012

The Honorable Mathy Stanislaus
Assistant Administrator
Office of Solid Waste and Emergency Response
U.S. Environmental Protection Agency
Ariel Rios Federal Building
1200 Pennsylvania Ave., NW
Washington, DC 20460

Re: The Regulatory Status of Gases that are not Contained in a Container

Dear Assistant Administrator Stanislaus:

We would like to bring to your attention an issue of significant concern to all of the undersigned representatives of manufacturing facilities, energy generation facilities, waste management facilities, and wastewater treatment plants. We recently learned that EPA is refusing to advise state regulators that gases that are not contained in a container are not solid wastes, notwithstanding the Agency's long-standing position that such gases are not solid wastes; the April 13, 2011, letter from Suzanne Rudzinski, Director, Office of Resource Conservation and Recovery to Tim Hunt, American Forest & Paper Association; and the preamble discussion of this issue in the December 23, 2011, Reconsideration and Proposed Amendments to the Commercial and Industrial Solid Waste Incineration (CISWI) Rule and the Non-Hazardous Secondary Materials (NHSM) Rule.

EPA created confusion over the regulatory status of gases that are not contained in a container in a response to comments document accompanying the March 2011 NHSM Rule. Realizing its mistake, EPA clarified the status of such gases in both the April 13, 2011 letter and the December 23, 2011, preamble. In these documents, EPA affirmatively states that the "burning of gaseous material, such as in fume incinerators (as well as other combustion units, including air pollution control devices that may combust gaseous material) does not involve treatment or other management of a solid waste (as defined in RCRA section 1004(27))."

Following release of the April 13, 2011 letter, the regulated community thought the issue of what is a contained gas was settled. However, we now learn that it may not be. Notwithstanding this letter, it is our understanding that EPA has refused to clarify to North Carolina air pollution control regulators that the burning of gaseous fuel derived from landfill gas and the combustion of gases in flares is not the burning of a solid waste. As a result, North Carolina has determined that such burning may be the combustion of a solid waste, suggesting that a flare would have to meet CISWI standards and a gaseous fuel would have to meet the processing and legitimacy criteria of the NHSM Rule.

For example, in addition to confusion over permits for landfills, we are aware of one title V permit application for a flare in North Carolina that has been halted over this issue. The subject permit application is for temporary short-term incineration of HVLC gases (2-3 weeks). Without an alternative source of control during this one-time maintenance event, the facility would have to cease operation and the cost of lost production revenue could be as much as \$6 million. Add to that the repercussions of potential loss of customers looking elsewhere for product when the manufacturing facility is down and the effects could be permanent. Further, if the state extends its new interpretation of “contained gaseous materials” to the primary units that control these types of gases, then facilities all over the state may have to shut down. Finally, if this state and others apply the same interpretation to all combustion of gases, the implications across all manufacturing sectors will be enormous. See the attached email exchanges with North Carolina regulators.

Also attached is a May 2, 2012 Questions and Answers document that is posted on the North Carolina web site. As you can see from this document, North Carolina relies on both an August 5, 2011, letter from Suzanne Rudzinski to Sue Briggum of Waste Management, as well as the response to comments document accompanying the March 21, 2011 Non-Hazardous Secondary Materials Rule to reach the conclusion that gases that are not contained in a container may still be solid wastes. The attached documents highlight the importance of clarifying that *all* gases are not solid wastes unless combusted while in a container. EPA needs to clarify that this is the position of the Agency not only under the Clean Air Act, but also under RCRA.

Please be aware that EPA’s unwillingness to provide clarification to state regulators regarding the RCRA status of gaseous materials is an issue that goes far beyond landfill gas. As demonstrated by the reaction of North Carolina regulators, discussed above, a statement by EPA that one gas that is not contained in a container is a solid waste brings into question the status of all such gases, and the regulatory status of the units in which they are combusted.

It is our understanding that some at EPA have attempted to distinguish landfill gas from other uncontained gases by referencing the attached March 6, 1986, letter from Marcia Williams, Director, Office of Solid Waste, to Mr. Lanier Hickman, Executive Director, Governmental Refuse Collection and Disposal Association. However, that letter provides no basis for an EPA determination that landfill gas is a solid waste when combusted. In fact, in Volume U of the RCRA Definition of Solid Waste Compendium, this letter is included in the subtopic “un-contained gases” so it is clear that EPA has not interpreted this letter as authority for determining that landfill gas is solid waste.

Instead, the 1986 letter responds to a question regarding the regulation of gaseous emissions from both hazardous and non-hazardous waste landfills. The letter asserts the authority to regulate such emissions, relying on 3004(n) and 4004(a) of RCRA.

Section 3004(n) is stand-alone authority for EPA to promulgate regulations controlling air emissions from hazardous waste treatment, storage, and disposal (TSD) facilities. This section of RCRA does not identify such emissions as solid wastes and the authority granted under this

The Honorable Mathy Stanislaus

June 8, 2012

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section of the statute is completely independent of EPA's authority over solid wastes. EPA regulations promulgated under this authority do not purport to identify gases as solid wastes.

Section 4004(a) is stand-alone authority for EPA to promulgate regulations establishing criteria for sanitary landfills. This section of RCRA does not discuss gaseous emissions, much less identify them as solid wastes. EPA regulations promulgated under this section of RCRA require the control of explosive gases and compliance with the Clean Air Act. They do not purport to identify gases as solid wastes. If EPA now believes that this section of RCRA represents a determination that gases generated in landfills are solid wastes, then landfills would have to cease flaring methane gas, unless the flares comply with the 2000 CISIW Rule.

This issue has enormous consequences for the undersigned sectors of our nation's economy. Thousands of facilities are operating today based on EPA's interpretation of the definition of contained gaseous material in the April 13, 2011, letter to Tim Hunt. This interpretation is now being called into question and EPA cannot let the present ambiguity continue. Should EPA define a gas that is not in a container a solid waste, then EPA will shut down significant portions of the manufacturing sector, disrupt the management of sanitary landfills and wastewater treatment plants, and potentially eliminate the future ability of communities and facilities to derive energy from landfill gas as well as biogas generated during wastewater treatment. The same consequences will result from EPA inaction and refusal to clarify what constitutes a contained gas.

Given the fact that this issue is impacting pending permit applications, we respectfully urge you to immediately make it clear to state regulators and the regulated community in the forthcoming CISWI and NHSM rules that, for all gases, neither a combustion device nor a conveyance such as a pipe or duct that delivers gas to a combustion device constitutes a container, and that a gas that is not contained in a container cannot be considered a solid waste under RCRA and is not subject to regulation under the Clean Air Act Section 129 incinerator rules when combusted.

Thank you for your consideration of this issue.

Sincerely,

American Chemistry Council
American Coke and Coal Chemicals Institute
America Forest & Paper Association
American Foundry Society
American Iron and Steel Institute
American Petroleum Institute
American Wood Council
Brick Industry Association
Celanese Corp.
Council of Industrial Boiler Owners
Delaware Solid Waste Authority

The Honorable Mathy Stanislaus

June 8, 2012

Page 4

KapStone Paper and Packaging Corporation
Manufacturers and Chemical Industry Council of North Carolina
National Association of Clean Water Agencies
National Solid Wastes Management Association
Portland Cement Association
Rubber Manufacturers Association
The County Sanitation Districts of Los Angeles County
Utility Solid Waste Activities Group
Waste Management

cc: Robert Perciasepe, EPA
Suzanne Rudzinski, EPA
James Berlow, EPA
Peter Tsirigotis, EPA
David Cozzie, EPA
Kevin Neyland, OMB
Dominic Mancini, OMB
Kevin Bromberg, SBA

Attachments:

NC Email on Landfill Gas, April 26, 2012 from Sheila Holman
NC Landfill Gas Q&A, May 2, 2012
NC Email on Flares, June 1, 2012 from Donald Vandervaart



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JUN 25 2012

OFFICE OF
SOLID WASTE AND
EMERGENCY RESPONSE

Mr. Paul Noe
Vice President for Public Policy
American Forest and Paper Association
1111 19th Street, NW, Suite 800
Washington, D.C. 20036

Dear Mr. Noe:

Thank you and the other industry representatives for your letter of June 8, 2012, in which you expressed significant concerns regarding EPA's interpretation of what constitutes a "contained gaseous material" and how that might affect the regulation of industrial gaseous emissions, such as landfill gas.

As indicated in your letter, the Agency addressed the contained gas issue in the May 13, 2011 letter to Tim Hunt, American Forest and Paper Association, and the landfill gas issue in the August 5, 2011 letter to Sue Briggum, Waste Management, as well as in the preamble to the December 23, 2011 Commercial and Industrial Solid Waste Incineration (CISWI)/Non-Hazardous Secondary Materials (NHSMs) proposed rule issued on December 23, 2011. In those letters, and in the preamble to the proposed rule, we made it clear that the Agency was not changing any previous positions regarding contained gas or landfill gas. For example, in the preamble to the proposed rule, it states, "However, our response seems to have caused confusion about whether the Agency was changing its prior interpretations regarding the burning of gaseous materials, for example in fume incinerators, and whether or not such burning is considered to be treatment of a solid waste by burning. The response does not change any previous EPA positions. We clarify here that the Agency's previous statements and interpretations remain effective. Thus, burning of gaseous material, such as in fume incinerators (as well as other combustion units, including air pollution control devices that may combust gaseous material) does not involve treatment or other management of a solid waste (as defined in RCRA section 1004(27)). Thus, we are stating again in the preamble to today's proposed rule that we are not changing any of our previous interpretations as it relates to whether "contained gaseous material" is a solid waste."

EPA regrets any confusion that may have been created since those letters were issued. However, to ensure that there is no further confusion, I want to strongly reaffirm that those letters and preamble statement express EPA's position. As noted in the preamble, the Agency did not take comment on those statements, and thus, we did not open the

letters for public comment. You also asked that we address this issue in the forthcoming CISWI and NHSM final rules. It is our intention to address this issue in those rulemakings.

Again, thank you for your letter. If you have any questions, please contact me at (202) 566-0200.

Sincerely,



Mathy Stanislaus
Assistant Administrator

cc: Robert Perciasepe, EPA
Suzanne Rudzinski, EPA
James Berlow, EPA
Peter Tsirigotis, EPA
Kevin Neyland, OMB
Dominic Mancini, OMB
Kevin Bromberg, SBA
Association of State and Territorial Solid Waste Management Officials



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

MAR 13 2012

OFFICE OF
ENFORCEMENT AND
COMPLIANCE ASSURANCE

Kate Williams
Alaska Oil and Gas Association
121 W. Fireweed Lane, Ste. 207
Anchorage, Alaska 99503-2035

Randy Rawson
American Boiler Manufacturer's Association
8221 Old Connecticut Rd., Ste. 202
Vienna, VA 22182

Leslie Hulse
American Chemistry Council
700 Second St., NE
Washington, DC 20002

David Darling
American Coatings Association
1500 Rhode Island Avenue NW
Washington, DC 20005

Tim Hunt
American Forest & Paper Association
1111 19th St., NW #800
Washington, DC 20036-3652

Bill Perdue
American Home Furnisher's Association
317 W. High Ave., 10th Floor
High Point, NC 27260

Pete Pagano
American Iron and Steel Institute
1140 Connecticut Ave., NW, Ste. 705
Washington, DC 20036

Matt Todd and John Wagner
American Petroleum Institute
1220 L St., NW
Washington, DC 20005-4070

Debra Jezouit
Class of '85 Regulatory Response Group
Baker Botts L.L.P.
1299 Pennsylvania Ave., NW
Washington, DC 20004

Robert Bessette
Council of Industrial Boiler Owners
6801 Kennedy Rd., Ste 102
Warrenton, VA 20187

Felix Mestey
Department of Defense
1000 Navy Pentagon
Washington, DC 20350-1000

Grif Bond
Environmental Health & Safety
Communications Panel
14111 Capital Boulevard
Wake Forest, NC 27587

David Buff
Florida Sugar Industry
6026 NW 1st Place
Gainesville, FL 32607

Dan Bosch
National Federation of Independent Business
1201 F St. NW #200
Washington, DC 20004

Jennifer Youngblood
National Tribal Air Association
4520 Montgomery Blvd. NE, Suite 3
Albuquerque, NM 87109

Daniel Moss
Society of Chemical Manufacturers & Affiliates
1850 M Street, NW Suite 700
Washington, DC 20036-5810

Renee Lesjak Bashel
National Steering Committee
Small Business Ombudsman / Small Business
Environmental Assistance Programs
101 South Webster (AM/7)
Madison, WI 53703

Re: No Action Assurance Regarding Certain Work Practice or Management Practice Standard Deadlines in the March 2011 Area Source Boiler Rule

Dear Sir/Madam:

Today, the EPA is providing a no action assurance (No Action Assurance) to all owners and/or operators of existing industrial boilers and commercial and institutional boilers at area sources that are subject to the requirement to conduct a tune-up by March 21, 2012 in the final rule discussed below. This No Action Assurance is being issued in response to a request from Assistant Administrator for Air and Radiation Gina McCarthy. As explained more fully below, this No Action Assurance addresses provisions of the final rule to regulate industrial boilers and commercial and institutional boilers at area sources of hazardous air pollutant emissions (the "Area Source Boiler Rule"), 76 Fed. Reg. 15,554 (March 21, 2011). Specifically, this No Action Assurance establishes that the EPA will exercise its enforcement discretion to not pursue enforcement action for failure to complete a tune-up required by a work practice or management practice standard by the compliance date of March 21, 2012 established in 40 C.F.R. § 63.11196(a)(1), subject to certain specified terms and conditions.

Under the Area Source Boiler Rule, area sources that fall into two subcategories of boilers – existing or new coal units with heat input capacity of less than 10 million Btu per hour, and existing or new biomass or oil units – are required to comply with work practice or management practice standards that consist of undergoing biennial tune-ups. 40 C.F.R. § 63.11201(b) (requiring compliance with the work practice or management practice standards specified in Table 2 to Subpart JJJJJ of Part 63 of the C.F.R.); 40 C.F.R. Part 63, Subpart JJJJJ, Table 2 (listing requirements by boiler subcategory). For existing affected boilers, the Area Source Boiler Rule established that the first of these tune-ups must be completed by March 21, 2012. 40 C.F.R. § 63.11196(a)(1).

Over 180,000 existing area source boilers are required to do tune-ups under the Area Source Boiler Rule. However, many facilities with older affected boilers have indicated that it is not possible to meet the March 21, 2012 compliance date. Entities particularly affected include those with large numbers of facilities with affected boilers, such as in the telecommunication sector; those with a large number of affected boilers, such as military installations; and those with seasonal boilers, such as the sugar cane industry and facilities in Alaska. These industries' representatives have identified specific problems with testing required to comply with the tune-up requirement in the final rule. Specifically, the final rule requires stack testing to measure carbon monoxide and oxygen as a component of the tune-up. 40 CFR 63.11223(b)(5). The rule further requires that combustion be optimized consistent with manufacturers'

specifications. 40 CFR 63.11223(b)(3). However, many facilities with area source boilers have indicated that they are not equipped to measure carbon monoxide and oxygen, and must undergo alterations such as the installation of a sampling port or platform before stack testing would be possible. Other facilities with older affected boilers have noted that many boilers will need to be repaired before they will be able to meet manufacturer specifications, such as the proper air-to-fuel ratio, and be ready to undergo the testing needed to comply with the tune-up requirements. Given the limited number of individuals qualified to conduct and complete these repairs, industry representatives assert that they are unable to schedule and complete the repairs, in addition to scheduling and completing the tune-ups, during the one-year initial compliance period specified in the final rule. At this time, the EPA continues to evaluate these assertions and observations. While we have not concluded that each of these points is valid, the Agency has sufficient concern at this time about these issues to question whether compliance by March 21, 2012 is feasible for a significant number of parties.

In addition, the EPA recently published a proposed reconsideration of the Area Source Boiler Rule that would adjust the relevant initial compliance date for compliance with work practice or management practice standards from March 21, 2012, to March 21, 2013, which would provide affected sources subject to the tune-up requirement with an additional year to demonstrate initial compliance with that requirement. National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers; Proposed Rule; Reconsideration of Final Rule, 76 Fed. Reg. 80,532 (Dec. 23, 2011). The regulated community is aware of the EPA's proposed extension to the compliance date, and this has caused confusion and uncertainty in the regulated community. The EPA stated that this change was proposed in part because the EPA recognized that some sources – particularly those with large numbers of affected boilers or seasonal boilers – cannot timely complete the testing needed to comply with the tune-up requirements. 76 Fed. Reg. at 80,535.

Finally, the only way for sources to avoid being in noncompliance if they cannot meet the tune-up compliance date would be for sources to stop operating their boilers until the tune-up can be completed. However, the affected categories of sources include many for which shutdown would be problematic and possibly dangerous, such as hospitals, clinics, nursing homes, and schools. It would not be in the public interest for such sources to shut down.

For the reasons discussed above, this No Action Assurance establishes that the EPA will exercise its discretion not to pursue enforcement for violations of the deadline to complete an initial tune-up identified in 40 C.F.R. § 63.11196(a)(1). This No Action Assurance applies only to the timeliness of the tune-up, and I note that nothing in this No Action Assurance affects any other provisions in the Area Source Boiler Rule.


This exercise of discretion is subject to the following conditions:

- The No Action Assurance is to remain in effect until either (1) 11:59 PM EDT, October 1, 2012, or (2) the effective date of a final rule addressing the proposed reconsideration of the Area Source Boiler Rule, whichever occurs earlier. The EPA has proposed new deadlines for initial tune-ups in its proposed reconsideration of the Area Source Boiler Rule, and, if the Agency takes final action to adopt those proposed deadlines, they will control.
- The EPA reserves the right to revoke or modify this No Action Assurance.

The issuance of a No Action Assurance for this period of time is in the public interest to ensure all existing sources have sufficient time to complete their initial tune-ups. I believe this action is consistent with the protections afforded under the proposed reconsideration of the Area Source Boiler Rule.

If you have any further questions regarding this matter, please contact Sara Froikin of my staff at (202) 564-3187 or froikin.sara@epa.gov.

Sincerely,

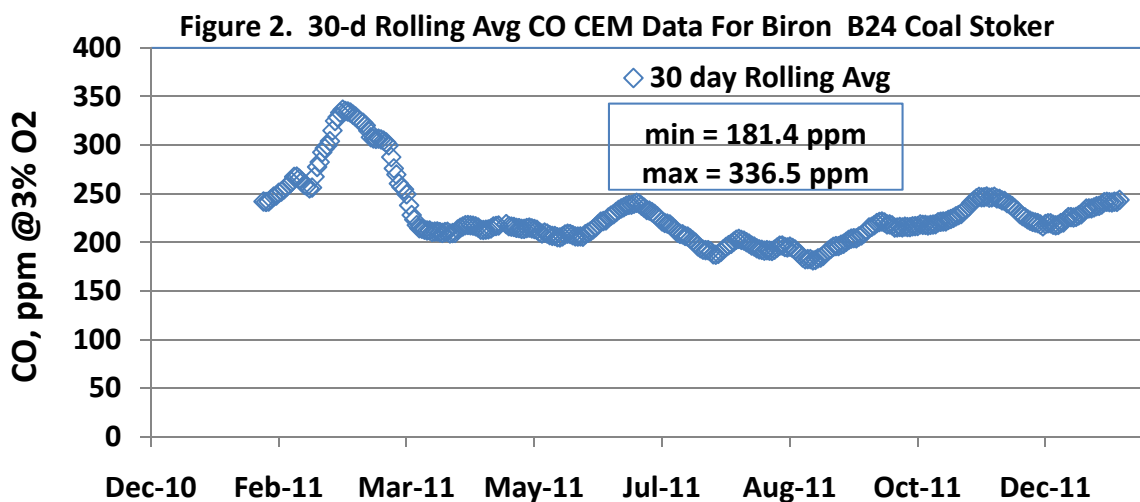
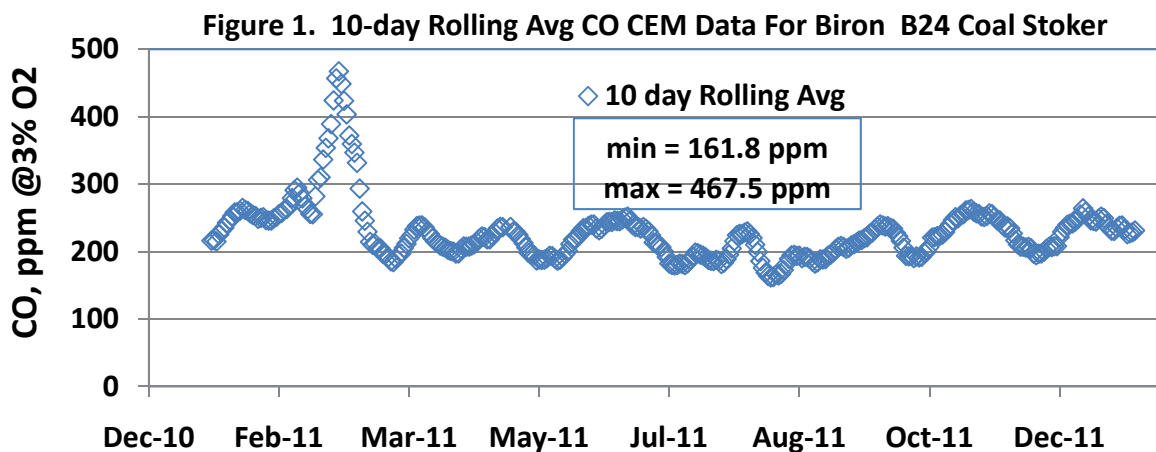


Cynthia Giles
Assistant Administrator

Cc: Gina McCarthy
Steve Page
Peter Tsirigotis
Robert Wayland

Why Coal And Biomass Boiler CEM-Based CO Limits Should Be Based On Year Long Data Sets And 30-Day Averages

In response to a request by EPA, NewPage Corporation recently provided EPA a year's worth of CEM CO data on their Biron Mill B24¹ boiler, a stoker unit that predominantly burned western sub-bituminous coal. Figures 1 and 2 show plots of the 10- and 30-day rolling average (RA) CO emissions for this boiler, respectively, during the calendar year 2011. The data plotted exclude a small amount of data that were clearly identified by the mill as "startup and shutdown periods". 10-day RAs are the current proposed EPA procedure for determining CEM-based limits for many boiler categories.



These plots show quite clearly how this boiler's CO emissions were somewhat elevated during a 15 to 20 day window in February of 2011. The mill reported to EPA¹ that these elevated CO

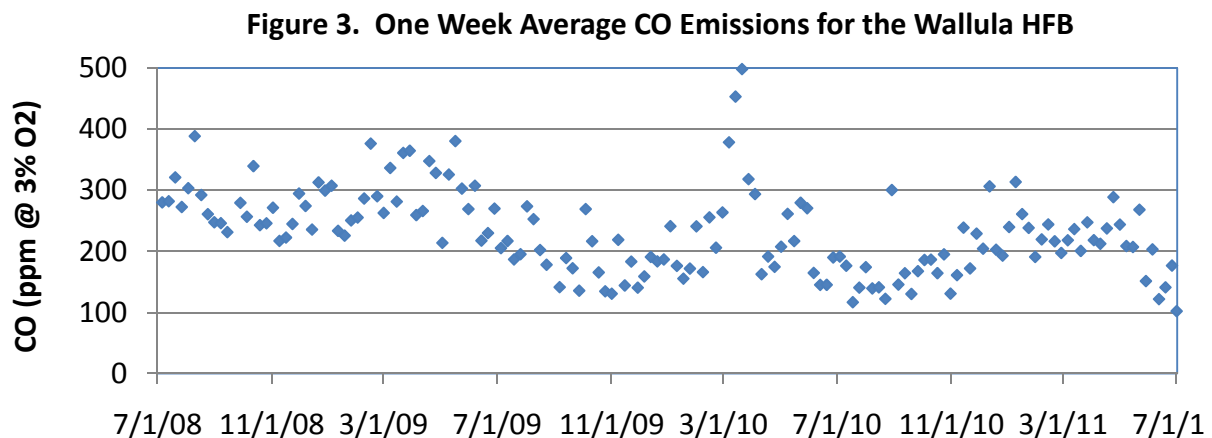
¹ Email with attachment from Annabeth Reitter to Amanda Singleton, August 3, 2012

emission levels were most likely a result of wet coal being processed during that time (likely snow-related). The data in EPA's database for coal stoker units², prior to the submittal of the NewPage data, is of much shorter duration and misses normal variability in stoker emissions such as higher moisture fuel during various seasons. The data for the Biron B24 boiler clearly demonstrate how a minimum of a year's duration of CEM data is critical for setting limits for boilers equipped with CO CEMs and how a 30-day average limit would then be the superior averaging period and consistent with averaging periods for other boiler types. Thus, we believe the Biron boiler data is the best performing stoker coal boiler with sufficient data to set the appropriate CO CEMs limit.

Long-Term CO CEM Data for Several Biomass Stokers

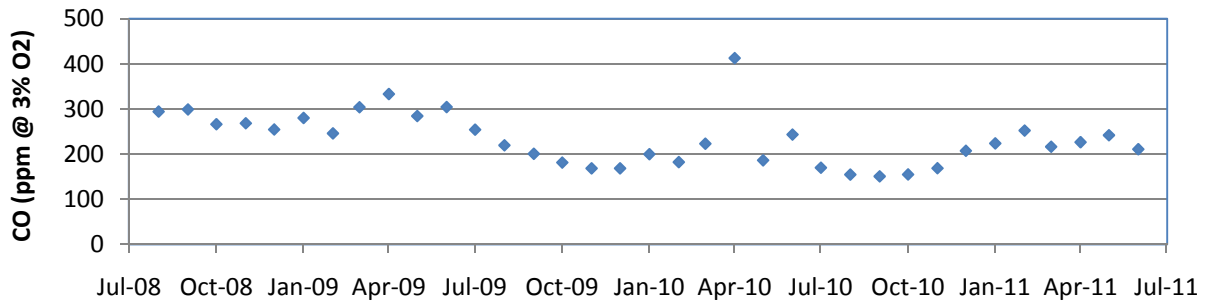
In the past, NCASI has also looked at long-term CO CEMS data for several biomass stoker units and found that seasonal variations in CO emissions from a boiler are significant and should be considered when setting CEM-based long-term average CO limits. At least a year's worth of data would be needed to accurately reflect the potential variations in CO emissions across all four seasons.

Figures 3 and 4 show the 7-day (1 week) and 30-day average CO emission profile for the Boise, Wallula, WA hog fuel boiler (stoker) over a three year period (data already submitted to EPA). Note that 7-day averages and 10-day averages would be expected to show similar trends.



² A 30 day CEM-based CO data set for the WVDuPontWashingtonWorks coal stoker unit is currently being used to propose a 10-day rolling average CO limit for coal stokers.

Figure 4. Monthly Average CO Emissions for the Wallula HFB



Figures 3 and 4 demonstrate how 7-day and 30-day averages would have been quite different depending on which 30-day duration one chose to estimate a 10-day rolling average limit.

Figures 5 and 6 show the 7-day and 30-day average CO emission profile for the Genessee, Flint, MI electric generating unit over a one year period (data already submitted to EPA). Again, these figures demonstrate how 7-day and 30-day averages would have been quite different depending on which 30-day duration one chose to analyze to obtain a 10-day rolling average limit.

Figure 5. Weekly Average CO Emissions for the Genessee EGU

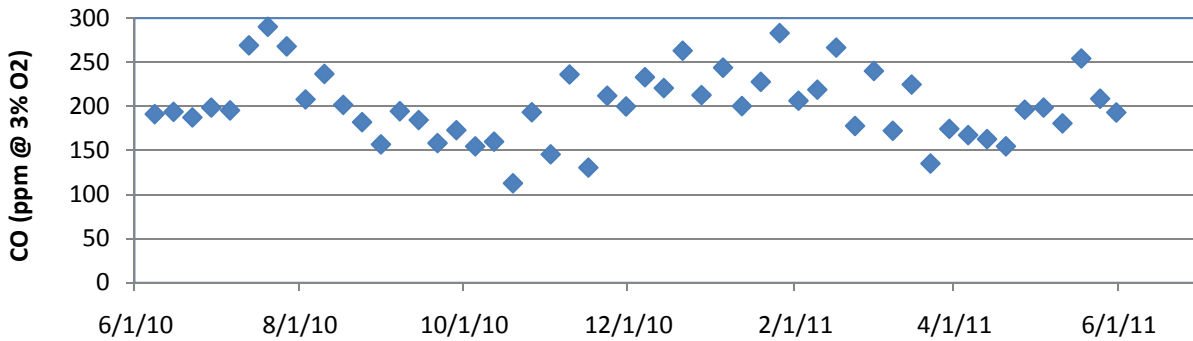
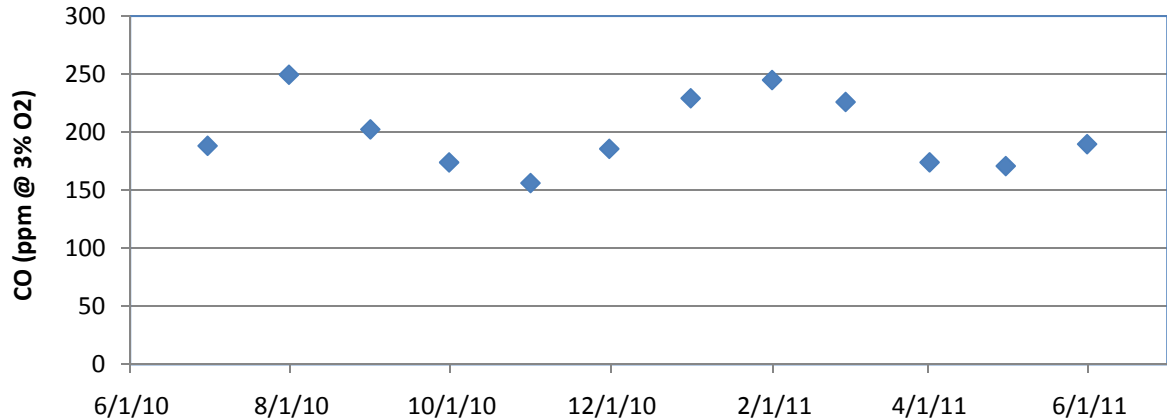


Figure 6. Monthly Average CO Emissions for the Genessee EGU



Figures 7 and 8 show the 7-day and 30-day average CO emission profile for the Mill I boiler over a one year period. This wood products mill stoker unit fired 100% biomass during the one year period. Again, these figures demonstrate that when data is available for a longer period of time, it captures variability that would be missed when relying solely on short duration data sets and thus should be used when available in setting a CEM-based limit.

Figure 7. Weekly Average CO Emissions for the Mill I WFB

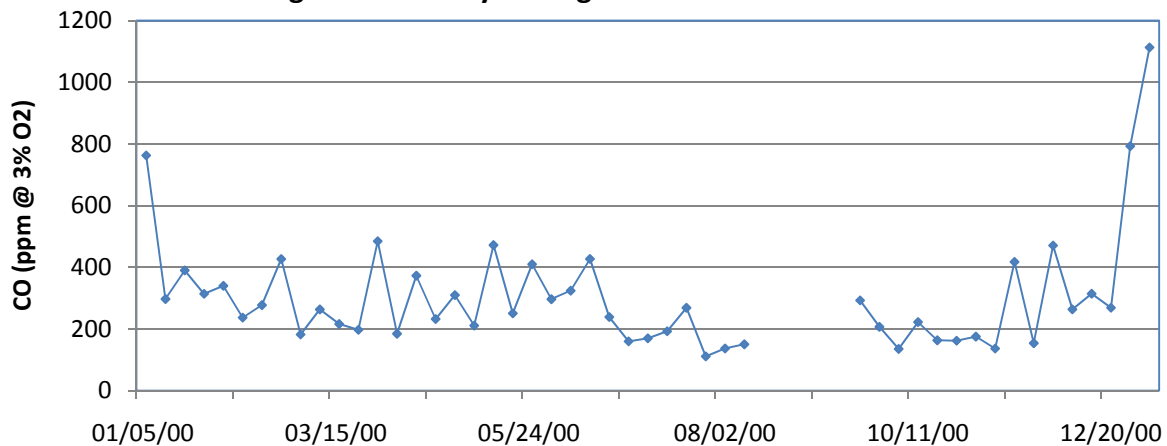
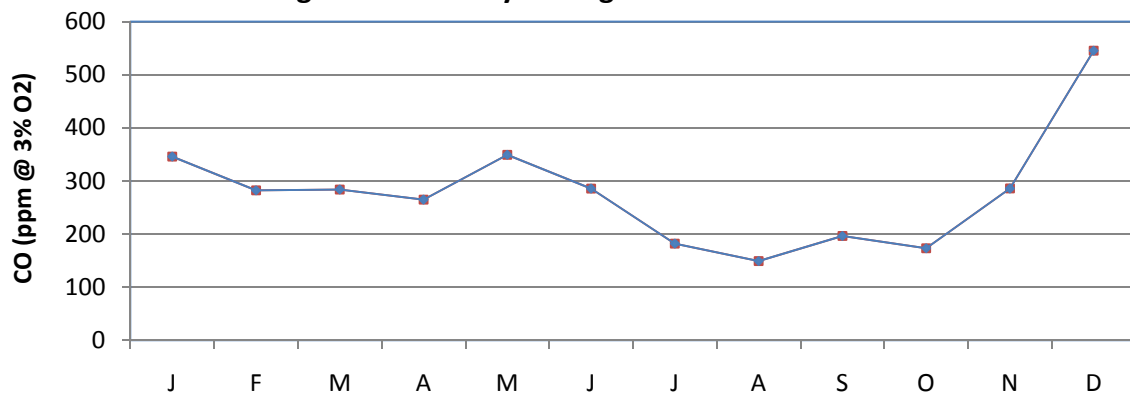
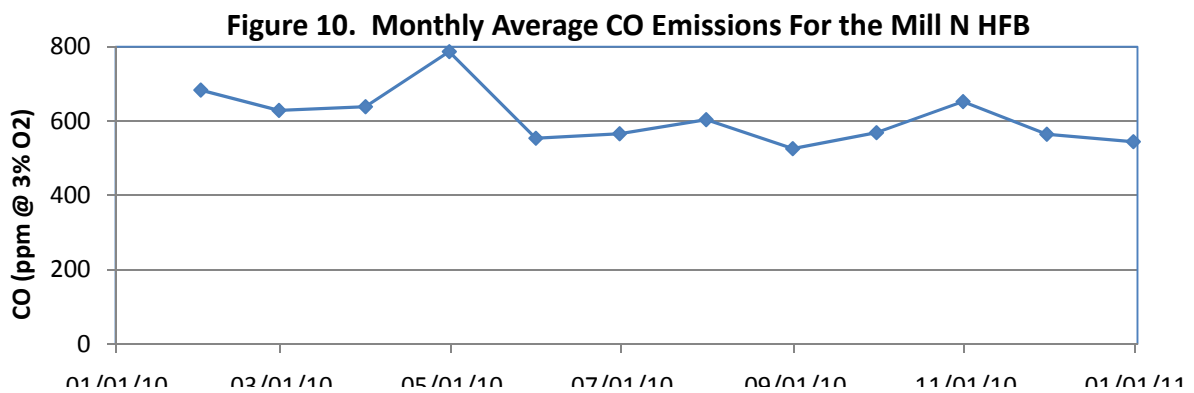
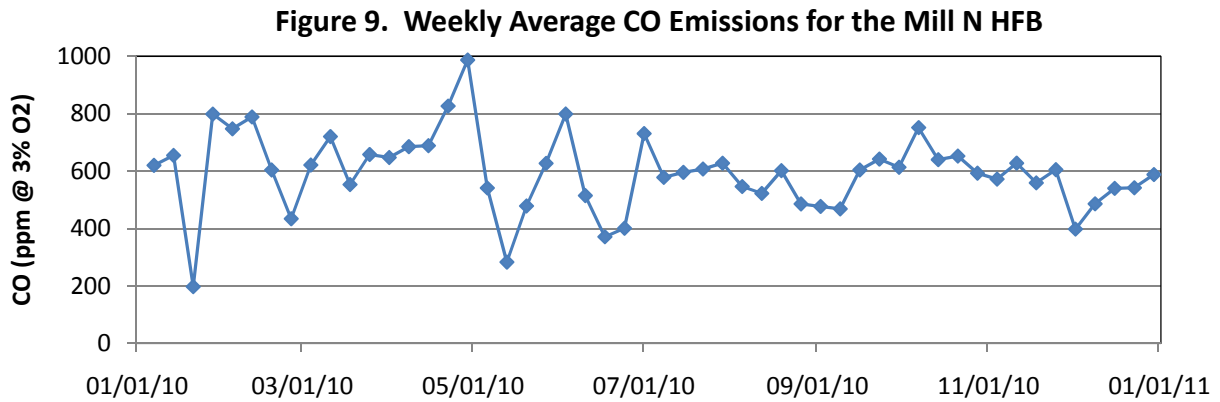


Figure 8. Monthly Average CO Emissions For the Mill I WFB



Finally, Figures 9 and 10 show the 7-day and 30-day average CO emission profile for the Mill N pulp mill hog fuel boiler over a one year period. On average, this boiler fired 97.5% biomass (bark and some sludge) and a small amount (2.5%) natural gas over the one year period. Once again, the variability shown in at least a year's duration of data highlights the importance of these data sets in setting a CEM-based limit.



Conclusion

NCASI plotted the 7-, 10- or 30-day averages from several year-long CEM CO data for coal or biomass-fired boilers and found significant seasonal variation in the boiler's emissions profile. When at least a year's worth of CEM data are available, preference should be given to a longer term CEM-based CO limit for such boiler types since the data would reflect the seasonal effect of fuel quality on boiler CO emissions. In the case of stoker coal fired boilers, EPA should use the New Page Biron CEM data to set the 30-day CEM-based limit. Finally, there is a long history of EPA setting 30-day rolling average standards for boilers and EPA should use this approach to simplify reporting and reflect the variability of performance.

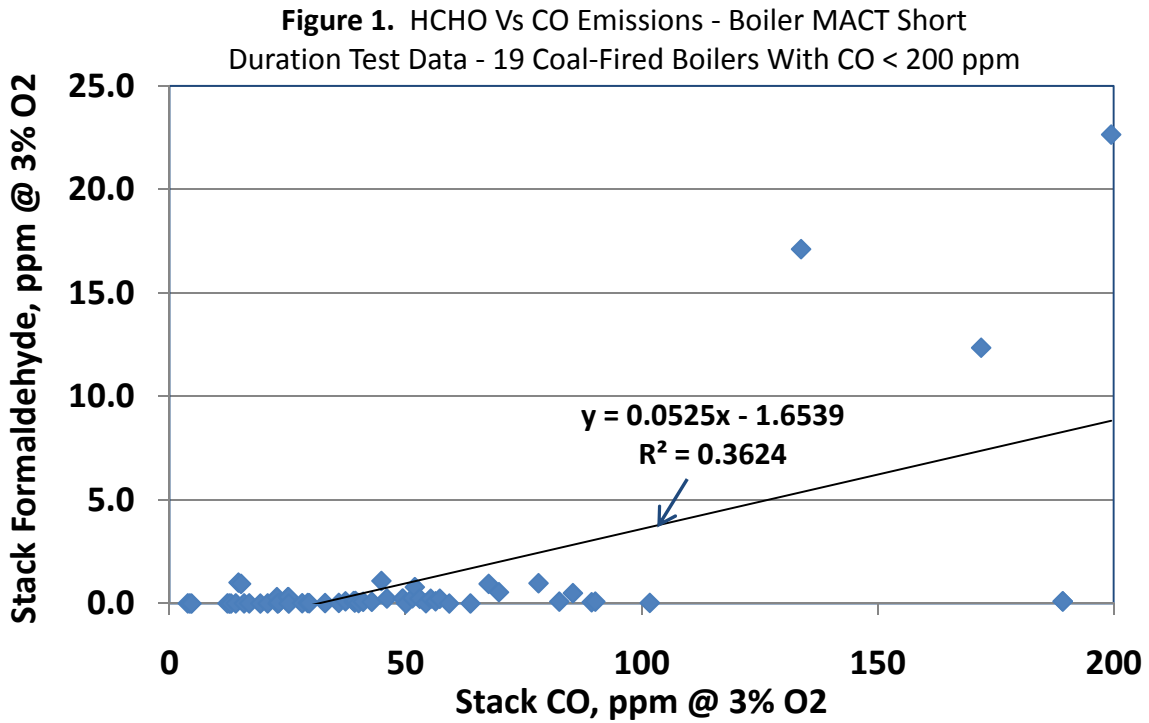
HAP Emissions Vs. CO for Coal-Fired Industrial Boilers – Analysis of Short Duration BM Test Data¹

An earlier document prepared by NCASI (Formaldehyde Vs CO For Coal-Fired Industrial Boilers with Less Than 100 ppm CO), dated June 9, 2012 and submitted to EPA showed how formaldehyde emissions were uncorrelated with corresponding stack CO emissions for 21 different coal-fired industrial boilers, data for which were extracted from EPA's Boiler MACT database. A subsequent document titled "RELATIONSHIP BETWEEN CO AND THCS AT LOW CO LEVELS FOR COAL-FIRED INDUSTRIAL BOILERS" (dated June 19, 2012), also submitted to EPA, showed how total hydrocarbon emissions were also quite uncorrelated with stack CO emissions for coal-fired units below about 200 ppm. However, it has been argued that even though a THC-CO relationship may not exist for coal-fired boilers, the relationship between CO and HAPs is perhaps more relevant and this should be investigated. In the presentation by Nick Hutson of EPA titled "Hazardous Air Pollutant (HAP) Emissions Testing in the EPA Pilot-Scale Combustion Research Facility" (35th Annual EPA-A&WMA Information Exchange at EPA Campus, Research Triangle Park, NC) it was shown that there indeed existed a linear relationship between PAH and CO emissions even at very low levels of CO (below 100 ppm). For this study, a pilot-scale testing facility (4 MMBtu/hr) in EPA's Multipollutant Control Research Facility was used and multiple tests using a variety of coal ranks and air pollution technology configurations were carried out. Although the pilot scale study may have demonstrated a correlation between one particular HAP species (PAH) and CO, the following plots generated from data currently existing in EPA's own Boiler MACT database show how this relationship between several different HAPs and stack CO as measured in full scale coal-fired industrial boilers demonstrate once again (just as for THCs) that CO is not a good surrogate for HAPs at low levels of CO (<200 ppm), especially when it comes to coal-fired industrial boilers.

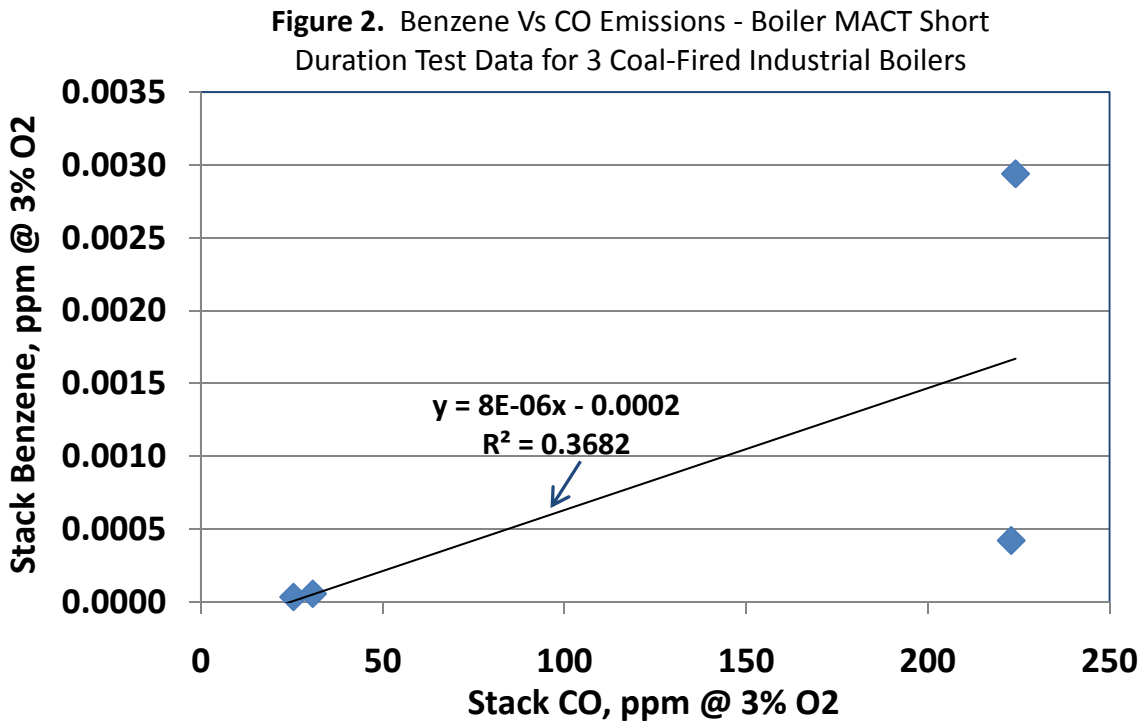
Figure 1 is a plot of CO versus formaldehyde emissions as measured on 19 coal-fired industrial boilers, data for which were extracted from EPA's Boiler MACT database. Essentially 100% coal was combusted in these units during the tests. These pairs of tests (HCHO vs CO) corresponded to typically 3 short duration tests. Only data corresponding to CO emissions of <200 ppm are shown, although this corresponded to the bulk of the data (76 of a total of 84 data points). Based on the low coefficient of regression², r^2 , it is clearly seen that below about 200 ppm CO, there is very little correlation between HCHO and CO. Further, it can also be seen that below about 100 ppm CO, there is simply NO CORRELATION between stack HCHO and CO emissions, with formaldehyde levels remaining practically unchanged at CO levels between 0 ppm and 100 ppm.

¹ Prepared by the National Council for Air and Stream Improvement

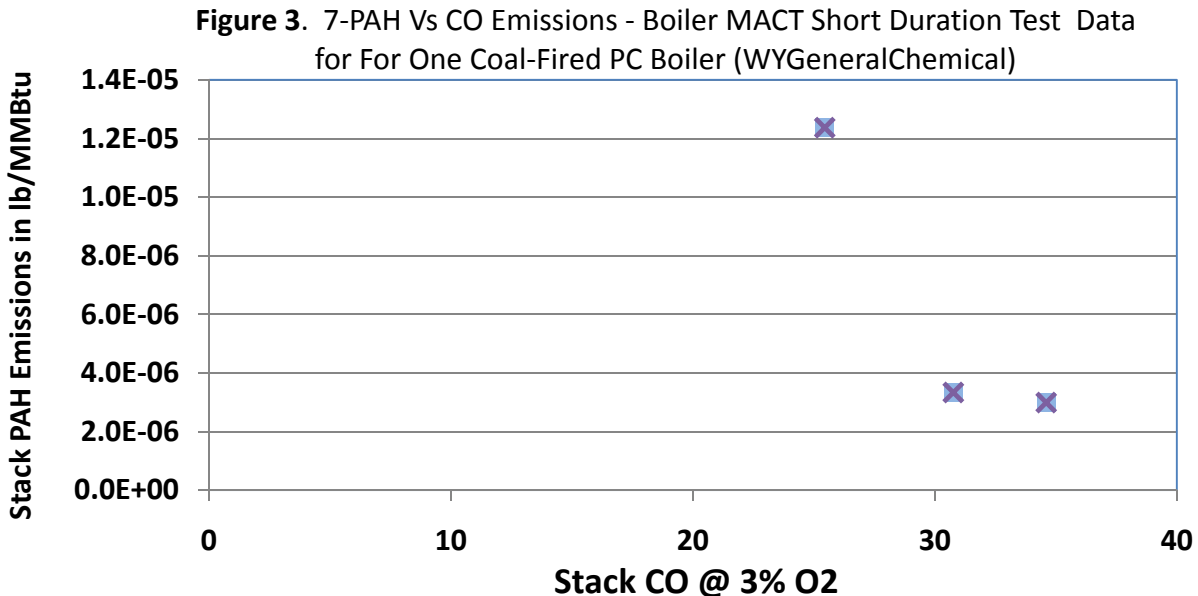
² A correlation coefficient r^2 of between 0.0 and 0.04 implies slight to almost negligible correlation; from 0.04 to 0.16 it implies low, quite small correlation; from 0.16 to 0.50 it implies moderate correlation; from 0.50 to 0.80 it implies high correlation; and from 0.80 to 1.00 it implies very high correlation.



A limited amount of data for CO versus benzene emissions as measured on 3 coal-fired industrial boilers are shown plotted in Figure 2. Once again, at CO emission levels below about 100 ppm CO (only 2 data points), there appears to be NO CORRELATION between stack benzene and CO emissions.



A limited amount of data for CO versus 7-PAH emissions as measured on just one PC-fired industrial boiler are shown plotted in Figure 3. The 3 runs for PAH emissions on this boiler do not appear to correlate with stack CO emissions.



Figures 4 and 5 are plots of CO versus acetaldehyde and toluene emissions as measured on 4 PC-fired industrial boilers at one pulp mill. The low coefficients of regression, r^2 , suggest once again that there is no correlation between emissions of these two HAPs and CO, at least for CO < 100 ppm. For instance, the spread of acetaldehyde and toluene emission data around 20 ppm CO further illustrates that the surrogacy is nonexistent at these levels.

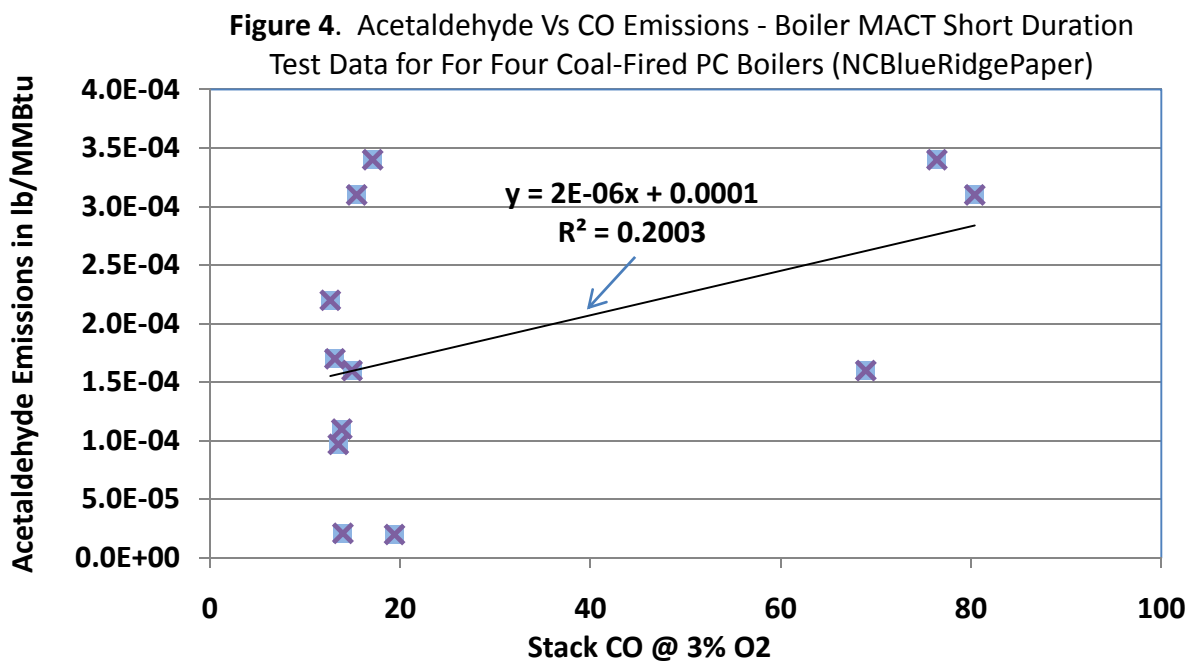
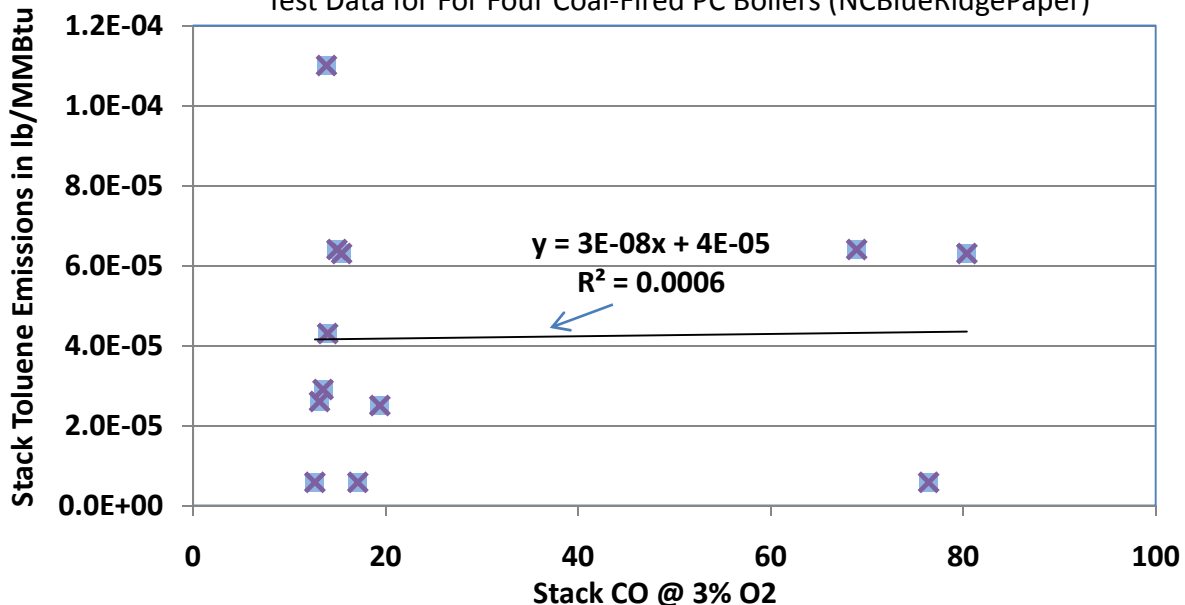
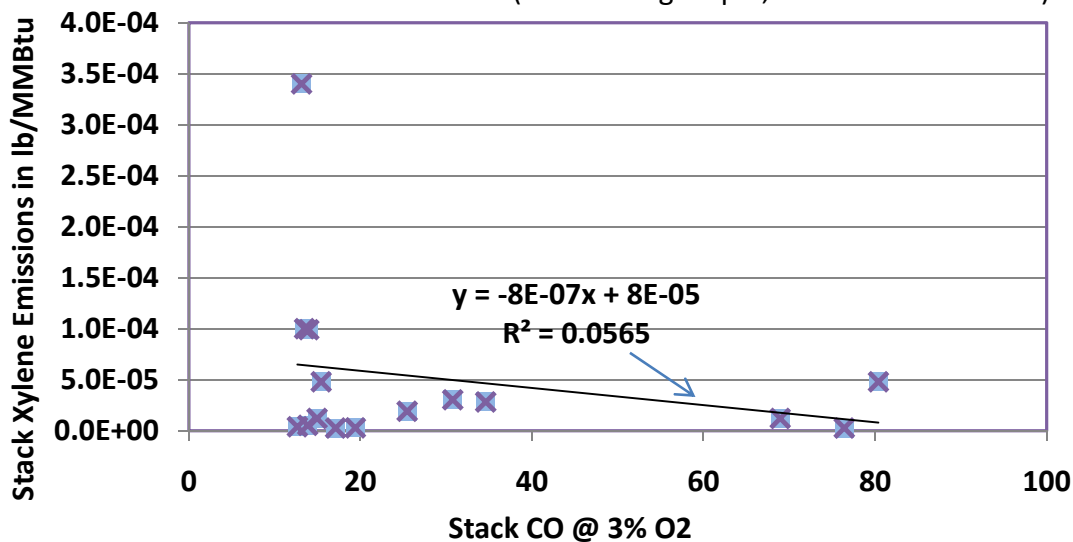


Figure 5. Toluene Vs CO Emissions - Boiler MACT Short Duration Test Data for For Four Coal-Fired PC Boilers (NCBlueRidgePaper)



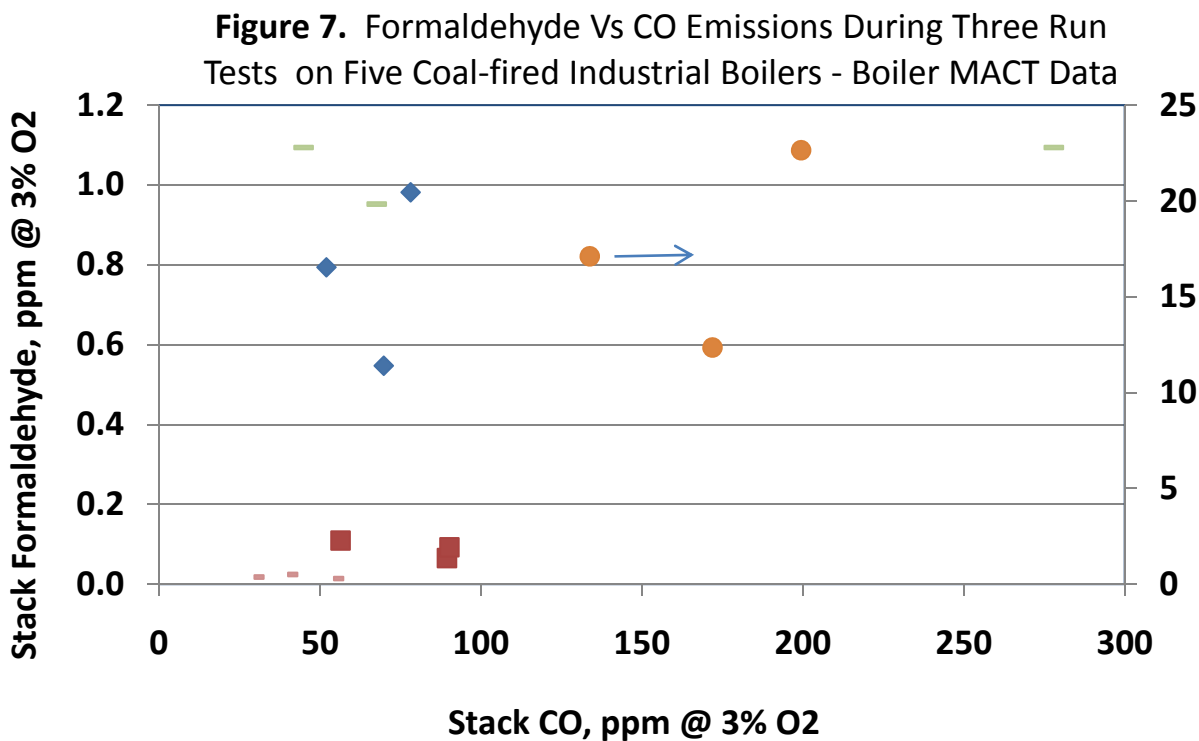
Finally, Figure 6 is a plot of CO versus xylene emissions as measured on 5 PC-fired industrial boilers, including the 4 pulp mill boilers at NCBlueRidgePaper. The low coefficient of regression, r^2 , suggests no correlation exists between emissions of this HAP and CO, at least for CO < 100 ppm. Once again, the spread of xylene emission data around 20 ppm CO illustrates that the surrogacy is nonexistent at these levels.

Figure 6. Xylene Vs CO Emissions - BM Short Duration Test Data for Five Coal-Fired PC Boilers (NCBlueRidgePaper, WYGeneralChemical)



Formaldehyde Variability With CO Within 3 Run Short-Duration Tests - Five Coal Boilers

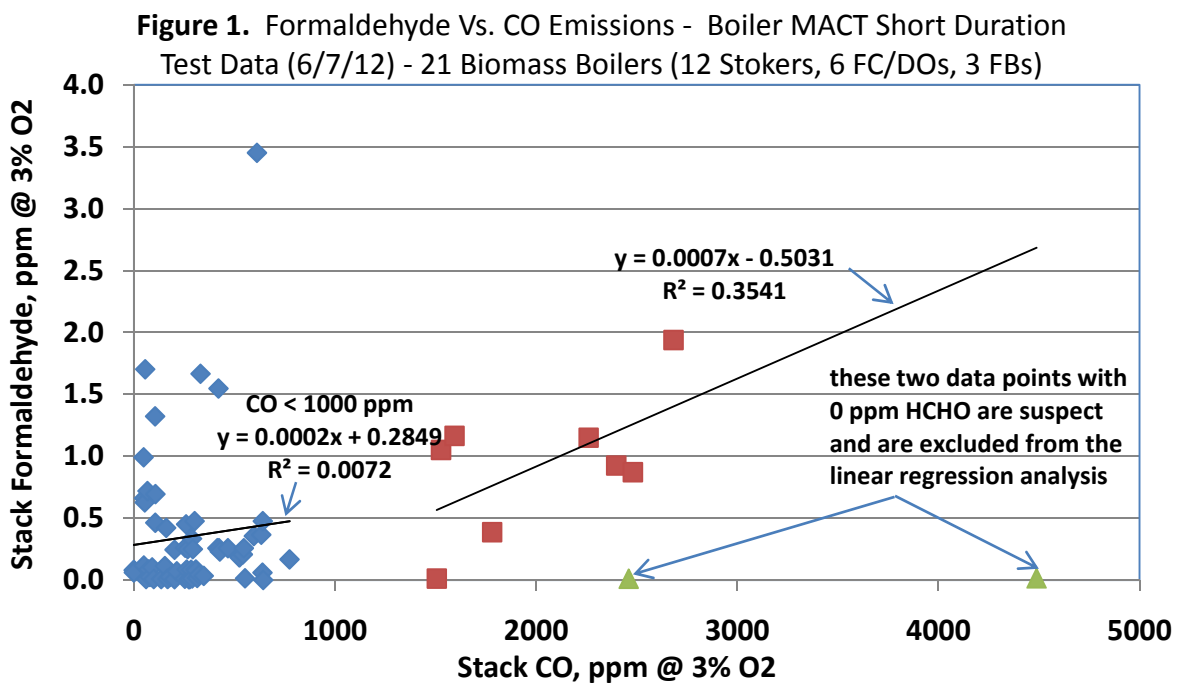
Figure 7 is a plot of HCHO vs stack CO emissions measured during 3 consecutive runs for five different coal-fired boilers. These data are a subset of the HCHO-CO data sets for 19 coal-fired boilers presented earlier in Figure 1. The HCHO-CO data pairs for these five boilers were chosen for further scrutiny as unlike the other 14 boilers the CO emission levels for these five appeared to vary somewhat from run to run. The 3 individual runs are shown plotted separately for each of the five boilers. This plot shows quite clearly how for each of the 5 boilers the HCHO emissions were unrelated to the corresponding stack CO emissions. In fact, the CO emission levels for one boiler ranged from 45 to 278 ppm while the corresponding HCHO emissions remained almost constant around 1.1 ppm.



Analysis of CO vs. Formaldehyde Emissions For Biomass (Wood and Bagasse), Oil and Gas-Fired Industrial Boilers Based on Short Duration Boiler MACT Test Data¹

Formaldehyde is the most frequently tested and likely the most dominant HAP among those tested during the ICR. In a separate document submitted to EPA², short duration formaldehyde (HCHO) and CO stack test data for 19 coal-fired boilers in the December 2011 Boiler MACT database were plotted to show that no clear relationship existed between HCHO and CO for coal-fired boilers below CO levels of 100 to 150 ppm. Additional short duration coal-fired boiler test data for CO and HCHO were available in the 6/7/12 Boiler MACT database. A reanalysis of the combined data sets once again shows that for coal-fired boilers short duration test HCHO emissions exhibit very poor correlation with corresponding stack CO at lower CO levels. Unfortunately, insufficient data exists for coal boilers at higher CO levels to understand the relationship with HCHO so we turn to other fuels to study this relationship. This paper looks at the relationship between short duration test data (6/7/12 Boiler MACT database) for HCHO and CO in boilers that exclusively burned wood residues, bagasse, oil or gas.

Figure 1 is a plot of CO vs. HCHO emissions for 21 wood-fired biomass units (12 Stokers, 6 Fuel Cell/Dutch Ovens, 3 Fluidized Beds), 3 run data extracted from the 6/7/12 Boiler MACT database. Up to about 800 ppm CO, the correlation between HCHO and CO is seen to be rather weak. Two of the data points at high CO levels (2600 and 4500 ppm) had corresponding zero ppm HCHO (non-detect), which is implausible, and thus have been excluded. Excluding these two points, the remaining data show a reasonable trend of increasing HCHO with increasing levels of CO at the higher CO levels.



¹ Prepared by the National Council for Air and Stream Improvement

² HAP Emissions Vs. CO for Coal-Fired Industrial Boilers – Analysis of Short Duration BM Test Data” document dated July 11, 2012 submitted by AF&PA to EPA.

Figure 2 looks at 3 run data for five biomass suspension boilers burning bagasse (sugar industry). Here, a reasonably strong correlation is seen between HCHO and CO emissions even at these much higher levels.

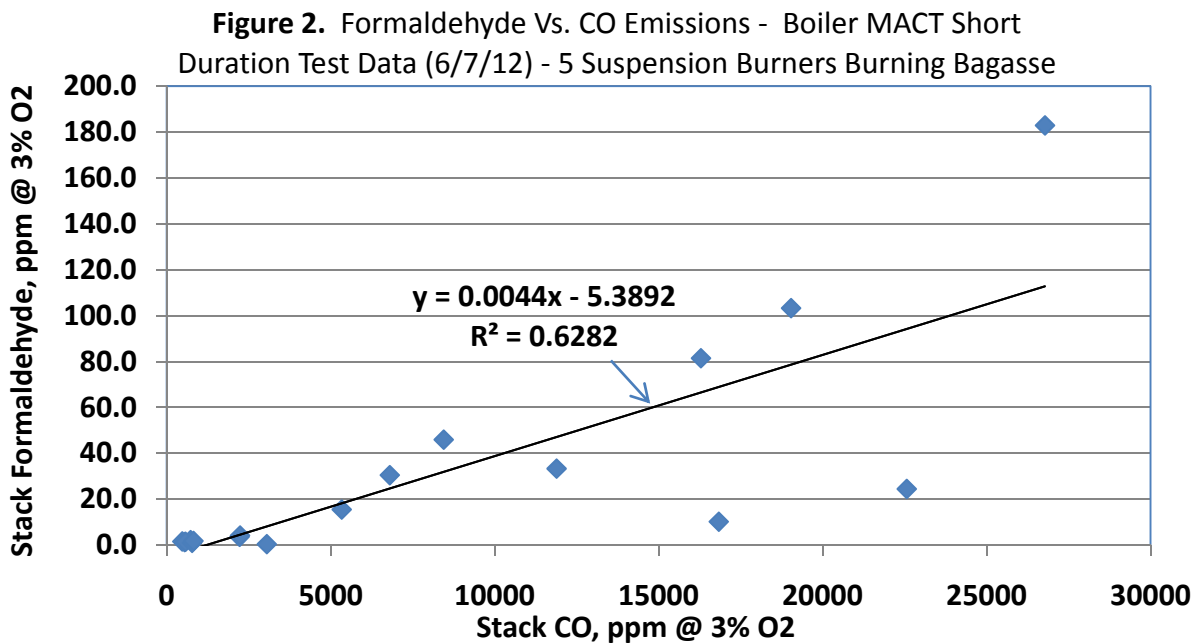
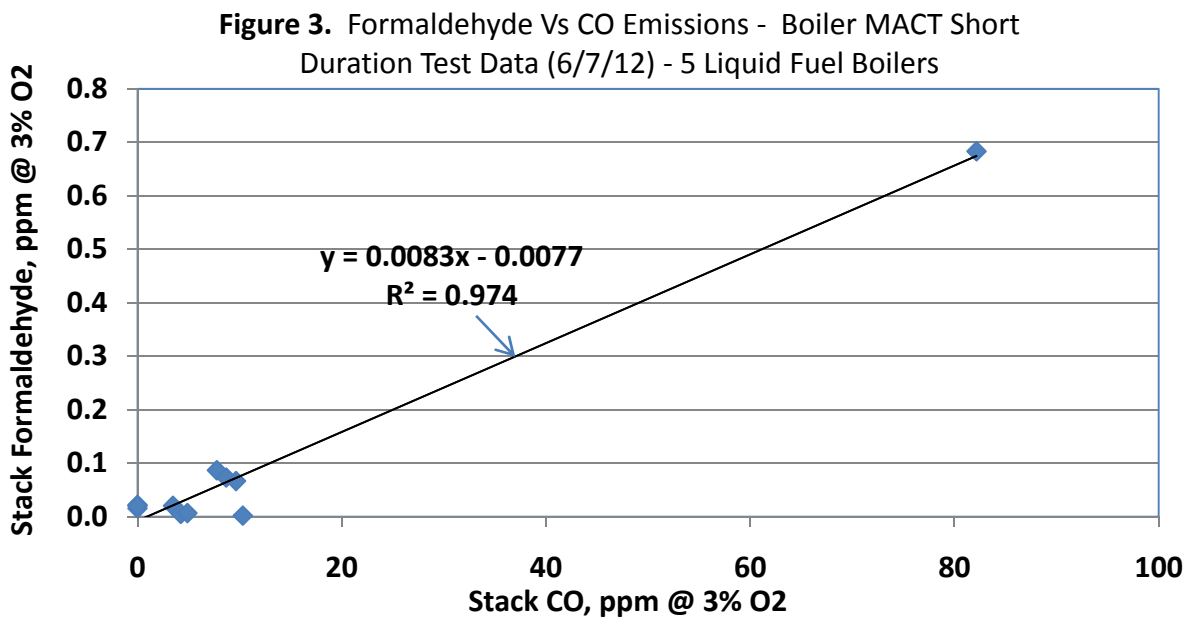
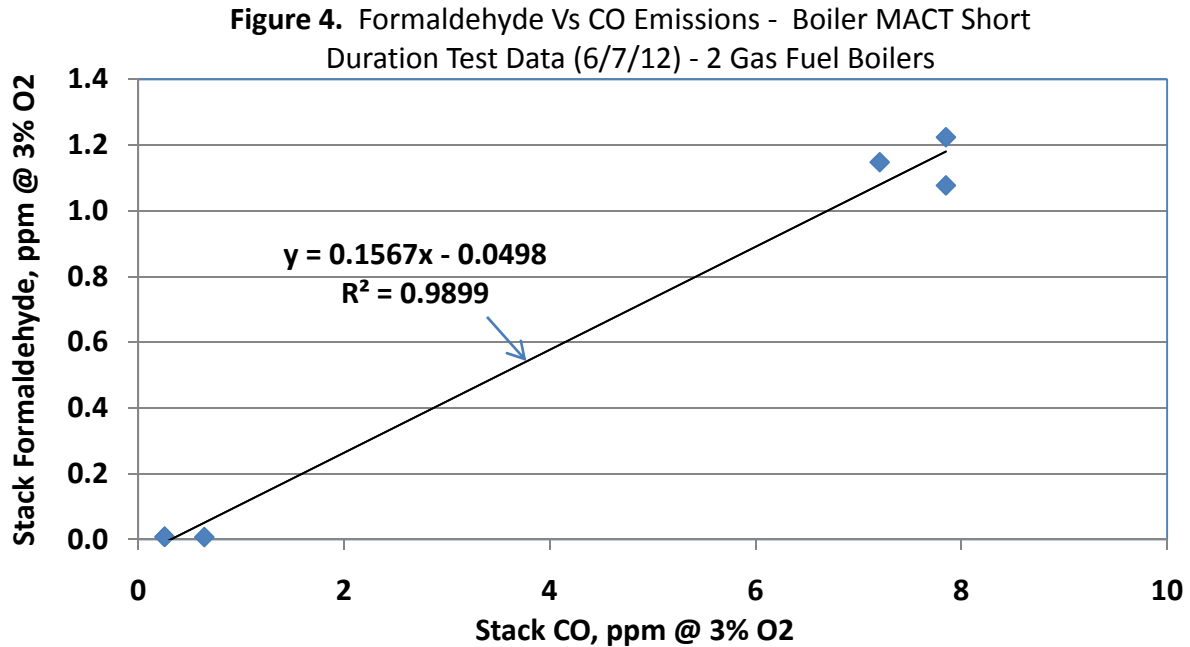


Figure 3 looks at 3 run data for five boilers burning liquid fuels (heavy and light oil). A good correlation is observed between CO and HCHO. However, it should be noted this relationship is almost entirely influenced by a singular data point for the MNGPDuluth unit at 80 ppm CO.



Finally, Figure 4 looks at 2 sets of data (3 runs each) for two boilers burning gaseous fuels (Gas 1). A good relationship between CO and HCHO is observed. However, this relationship is influenced almost totally by the data for one boiler at around 8 ppm CO.



Conclusion

Formaldehyde is the most common and dominant HAP tested during the ICR. The data for wood-fired boilers show no correlation exists between HCHO and CO when stack CO levels are below about 800 ppm, similar to what was found with coal fired boilers. A reasonable correlation between CO and HCHO becomes apparent at higher levels of CO in wood-fired boilers. Reasonable correlations between HCHO and CO also are apparent when data for several boilers exclusively burning bagasse, oil or gas are analyzed. This shows that CO is still a good surrogate for HAPs at high CO levels. At lower levels, the relationship does not exist between CO and HCHO suggesting that at a minimum a cutoff should be established for fossil fuel boilers in the range of 200 ppm for both stack and CEM-based limits. Alternatively, the data shows that HCHO (and by analogy HAPs in general) are not present under the good combustion conditions typical of fossil fuel boilers supporting the use of work practices for these fossil fuel boilers.³

While this paper focuses on formaldehyde and CO, our earlier paper shows that CO and total hydrocarbons (THC) from coal-fired boilers exhibit that same positive linear relationship at higher CO levels⁴. These data sets should not be ignored in the overall analysis. Further analysis on the relationship between Total Non-Methane Hydrocarbons (TNMHCs) and CO is also available. This analysis reinforces the THC findings and the need for a cutoff or work practice.

³ Emission limits are still justified for biomass-fired boilers given their different combustion dynamics.

⁴ "Relationship Between CO and THCs at Low CO Levels Coal Boilers", July 19, 2012 document submitted by NCASI to EPA.

Applicability of PM CEMS and its Use As Parametric Monitors On Biomass Boilers And Multi-Fuel Boilers Co-Firing Biomass (from NCASI 2/27/12 comments to EPA)

In the proposed regulation, EPA has specified that PM CPMSs are not required on boilers smaller than 250 MMBtu per hour heat input rate and on boilers complying with the alternative total select metal limit. NCASI supports this decision. We are, however, concerned about the requirements in section 63.7525 (b) where EPA has proposed that all boilers with an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or residual oil and demonstrating compliance with the PM limit, must install, certify, maintain, and operate a PM CPMS. This requirement inadvertently includes biomass units that burn at least 10 percent biomass or bio-based solids on an annual heat input basis, in combination with solid fossil fuels, liquid fuels, or gaseous fuels. Based on rationale and language presented in section D (2) of the preamble, it is our understanding that EPA intended to not require PM continuous emission monitors on biomass units. We, therefore, recommend that:

1. EPA should clarify the rule by stating that the requirement to install and use PM CPMS does not apply to boilers in the biomass category.
2. EPA should not require the use of a PM CPMS on any multi-fuel boiler.

The above recommendations are based on the findings of a recent study carried out by Georgia-Pacific and NCASI (Attachment 1). This study consisted of installing PM CEMS, operating on the light scattering principle, on multi-fuel boilers at two different facilities. During this study, calibration testing was performed for both PM CEMS, and a follow-up Relative Response Audit (RRA) was also carried out on both PM CEMS. Two different fuel mixtures were burned during the calibration testing for each PM CEMS, and fuel mixtures burned during the RRA were slightly different than those combusted during the calibration testing. Although the two monitoring systems worked reasonably well and required minimal routine maintenance, the study identified two major problems with the backscattering monitoring system:

1. The relationship between stack gas PM concentration as measured by the PM CEMS and the manual reference method varied when the fuel mixtures were changed. This resulted in several different calibration equations for different fuel combinations.
2. The PM monitoring system also failed to meet EPA's relative response audit criteria when the monitoring system was tested three months after the initial installation and calibration.

In addition to the PM monitoring instrument calibration issue, the study also identified significant challenges associated with (a) calibrating stack PM monitors when a source is operating at very low stack gas PM concentrations, and (b) reporting stack PM emissions as lb/MMBtu heat input. These challenges include:

1. High variability in EPA Method 5 measured values observed during tests when dual sampling trains are used simultaneously on a stack with low PM concentrations.
2. Difficulty associated with determining instantaneous flow rates of individual fuels in multi-fuel boilers due to the time delay between monitoring fuel flow rate and its firing in the boiler.
3. Integrating, maintaining, and calibrating ancillary monitoring equipment required for determination of PM emission rates.
4. Complexity of converting stack gas PM concentration to the PM mass emission rate in lb/MMBtu when burning multiple fuels at varying rates.

The findings of this study support EPA's conclusion that the currently available stack gas PM monitors are not capable of being used as compliance monitors on biomass boilers. The study results also show that because the relationship between stack gas PM concentration and instrument response varies with fuel mix, in order to develop a parameter which would indicate that the source was in compliance with the

PM standards, the facility would have to carry out PM CPMS calibration tests using every possible fuel combination and fuel ratio. This would require months of testing with varying fuel mixes and would be very expensive and disruptive to a facility's operation. Even after carrying out such a study, the facility would not be able to establish a parameter not to be exceeded during routine operations to ensure compliance with the PM emission standards, thus eliminating the feasibility of using such monitors as CPM devices.

The results of the G-P/NCASI study also raise significant doubts regarding the feasibility of installing and calibrating a PM CPMS on coal-fired boilers which burn other fuels such as petroleum coke, sludge, OCC rejects, TDF, and biomass.

We therefore recommend that EPA should modify the requirement to install PM CPMS and make it applicable only to fossil fuel boilers burning only one kind of fossil fuel. The requirements should not apply to biomass boilers or multi-fuel fossil-fuel boilers due to the difficulty in developing a stack parameter which could be used as the threshold for maintaining compliance with the standard.

EPA Should Adjust its Procedures for Setting New Source Numerical Limits (from AF&PA 2/27/12 comments to EPA)

Some of the new source and existing source limits are the same (for example, the solid fuel HCl limit) because the 99 UPL for the new unit data is higher than the 99 UPL for the existing unit data. If the emissions data for the top performing unit exhibits more variability than the emissions data for the existing units, EPA cannot ignore this fact. It is arbitrary to choose the calculated existing unit limit as the standard that both types of units must meet. EPA should instead set both the existing and new unit standards at the new unit 99 UPL in order to adequately reflect variability and acknowledge the capabilities of the top performer to meet a standard.

Many of the new source limits are set using one 3-run stack test. EPA could further consider variability by using the UL instead of the UPL statistical calculation and using a 99.9 percent confidence level instead of a 99 percent confidence level, since sources will be required to meet the new source limits at all times. In addition, fuel variability data should be collected for all units setting new source floors and factored into the calculated emission limits. Industrial boilers operate over a variety of conditions and fire a variety of fuels, so adequate consideration of variability is important in setting achievable emission limits. EPA continues to use a pollutant-by-pollutant approach instead of a source-based approach to setting new unit limits, so maximum consideration of variability is imperative.