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**DATE:** August 20, 2008

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**SUBJECT:** Emissions Factors for Condensable Particulate Matter Emissions from Electric Generating Units

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#### Introduction

Accurate emissions factors are needed to model the effect of condensable emissions on regional haze in the MANE VU region. Particulate matter smaller than 2.5 micrometers in diameter (PM<sub>2.5</sub>) emitted from stationary sources has two components, particles that are solid regardless of stack temperature (filterable) and gases that condense shortly after exiting the stack (condensable). For electric generating units (EGUs) burning oil or natural gas, condensable particulate matter (CPM) emissions can be greater than filterable emissions. However, there is a great deal of uncertainty about the best way to measure condensable emissions. Essentially all CPM emissions factors in EPA's WebFIRE (the database containing AP-42 emissions factors) and CPM emissions data collected recently were measured using EPA Reference Method 202. In Method 202, an effluent gas stream, after passing through a filter to remove solid particulate, is bubbled through a series of impingers to collect CPM. In measuring CPM from combustion of fuels containing sulfur, it has been shown by EPA that SO<sub>2</sub> collected in the impingers can be oxidized to sulfate and produce a variable sulfate artifact that results in overestimation of condensable emissions. In this example, if impingers are not purged with nitrogen, errors associated with the sulfate artifact may be inflated. The emissions factors in WebFIRE were developed from source test data that are more than 10 years old and may not represent newer refinements to Method 202. See the following link for more information on Method 202 and the nitrogen purge: <http://www.epa.gov/ttn/emc/methods/method202.html>.

Because of these and other uncertainties, condensable emissions were not calculated uniformly across all states in the MANE-VU region in the 2002 emissions inventory. For the future year MANE VU (2009, 2012, and 2018) emissions inventories, MARAMA has requested that MACTEC evaluate available data on condensable emissions from EGUs and recommend emissions factors to be used for the future year inventories.

### Summary of Existing AP-42 CPM Emissions Factors

To establish a baseline for the condensable emissions factors used in the 2002 MANE VU emissions inventory and to compare the existing AP-42 emissions factors with emissions factors developed from recent source tests, we first reviewed EPA's FIRE (version 6.25) to identify all EGU source/fuel/control device combinations for which AP-42 emissions factors and other factors are provided for CPM and PM<sub>2.5</sub>. These emissions factors are attached in an ACCESS database (Attachment 1). The attached database contains all 121 CPM and 51 PM<sub>2.5</sub> emissions factors that are in the most recent version of FIRE (version 6.25). FIRE 6.25 contains all emissions factors published in AP-42 prior to October 2004. This includes the most recent updates to AP-42 Chapters 1 and 3, which contain all the external and internal combustion emissions factors associated with EGUs and other large combustion sources. The 121 CPM and 51 PM<sub>2.5</sub> EGU emissions factors in FIRE 6.25 are based on only 16 unique emissions factors (14 from AP-42 and 2 others). The 172 emissions factors were assigned by assuming that each unique factor can be applied to a large number of source classification codes (SCCs) similar to the one for which the factor was actually developed.

The 121 CPM EGU emissions factors represent 14 unique emissions factors from the following AP-42 sections (number of unique emission factors in parentheses):

- AP-42 Section 1.1: Bituminous and Subbituminous Coal Combustion (3)
- AP-42 Section 1.2: Anthracite Coal Combustion (1)
- AP-42 Section 1.3: Fuel Oil Combustion (2)
- AP-42 Section 1.4: Natural Gas Combustion (1)
- AP-42 Section 1.6: Wood Residue Combustion in Boilers (1)
- AP-42 Section 1.7: Lignite Combustion (3)
- AP-42 Section 3.1: Stationary Gas Turbines (2)
- AP-42 Section 3.2: Natural Gas-fired Reciprocating Engines (1)

For those factors for which information was provided, each FIRE 6.25 emissions factor was calculated from data reported in from 2 to 36 test reports. In some cases, no information was provided on the number of tests forming the basis for the CPM factor. In addition to the 14 unique emissions factors from AP-42, there are 2 CPM emissions factors in FIRE 6.25 from single independent test reports (not included in AP-42). The assigned quality ratings of the factors vary from grade "A" to "E", with some quality ratings designated as "U" for "Unknown". The A ratings are likely due to the large number of tests conducted for some factors. It appears that the data were graded on the number of tests that were conducted to measure PM or PM<sub>10</sub>, and then the corresponding grade was associated with the CPM emissions factors as well. The 14 unique emission factors were then assigned to many related SCCs, resulting in the 121 CPM emissions factors in FIRE 6.25. This information is reflected in the attached database, which contains identical emissions factors associated with many SCCs.

In addition, for each CPM emissions factor, Attachment 1 also contains the following information:

- SCC
- SCC Description
- Control description (if applicable)
- Fuel heat content (assumed value, based on type of fuel and used to convert factors from a mass basis to an energy basis)
- Notes, reference information, formulae, factor identification number, date and description of any assumptions associated with the emissions factor.

The data in Exhibits 1 and 2 summarize the FIRE 6.25 information in Attachment 1. The exhibits list the emissions factors for coal, natural gas, and oil as they have been assigned in FIRE 6.25, by fuel type. Because unique emissions factors were assigned multiple times to many SCCs associated with the same fuel, we have only represented each unique emission factor one time per fuel. In this way, we have prevented the average emissions factors from becoming biased due to the number of assignments. We have indicated the emissions factors that have been calculated from FIRE 6.25 formulae with fuel sulfur content as the variable. Investigation of typical sulfur values for the different grades of coal showed that the sulfur content is best represented as a range for all the coal types except for lignite coal. We calculated the emissions factors based on established ranges of sulfur content for anthracite, bituminous, and subbituminous coal. We then averaged the high and low range value to calculate the emissions factor. Please refer to Attachment 1 for additional details on these emissions factors.

Exhibit 1: FIRE 6.25 Unique CPM Emissions Factors by Coal Type

Coal Type (units)	Anthracite (lb/MMBtu)	Bituminous (lb/MMBtu)	Subbituminous (lb/MMBtu)	Lignite (lb/MMBtu)
	0.0385 <sup>(1)</sup>	0.225 <sup>(1)</sup>	0.125 <sup>(1)</sup>	0.01 <sup>(2)</sup>
	0.049 <sup>(1)</sup>	0.02 <sup>(3)</sup>	0.02 <sup>(3)</sup>	0.02 <sup>(3)</sup>
		0.04 <sup>(3)</sup>	0.04 <sup>(3)</sup>	0.04 <sup>(3)</sup>
			0.026	
<b>AVERAGE</b>	0.044	0.095	0.053	0.023

- (1) Emissions factor value was calculated by averaging the low and high range CPM emission estimate that resulted from the assignment of a high and low sulfur value in the emissions factor formula.
- (2) Emissions factor value was calculated by assigning a single value (no range) to the sulfur variable in the emissions factor formula.
- (3) Emissions factors applicable to bituminous, subbituminous, and lignite.

Exhibit 2: FIRE 6.25 CPM Emissions Factors for Natural Gas and Fuel Oil

Fuel Type (units)	Natural Gas (lb/MMBtu)	Fuel Oil (lb/MMBtu)
	0.0059	0.01
	0.0047	0.0093
	0.00991	0.0072
<b>AVERAGE</b>	0.0068	0.0088

Updated CPM Emissions Factors from Recent Emissions Test Reports

To develop CPM emissions factors from recent compliance tests, MACTEC evaluated source test reports beginning in 2002 for PM and CPM emissions from utility boilers and turbines firing coal, oil, or natural gas from six states: Delaware, Minnesota, New Jersey, North Carolina, Pennsylvania, and Wisconsin. We reviewed 162 tests from 83 test reports to obtain CPM test data. Additional test reports were reviewed, but did not contain CPM data. [Note that each FIRE 6.25 emissions factor consists of data from 2 to 36 test reports.]. All tests for CPM were conducted using EPA Method 202 which, as described above, uses water-filled impingers to collect condensable gases and aerosols after the filter. A key discriminator of artifact formation in Method 202 is the use of a nitrogen gas purge after sample collection to drive out excess SO<sub>2</sub> before oxidation to sulfate. Thus, in addition to extracting condensable emissions data and process information from each test report, we collected whatever details were provided on the application of Method 202. MACTEC extracted data from the 162 tests and entered the data in the WebFIRE data template (with emphasis on the use of the nitrogen purge). For each test we calculated the emissions factor from the emissions data and the process information. The condensable emissions factors were sorted by SCC and compared to the condensable emissions factors in WebFIRE.

Exhibit 3 is a breakdown of the number of test reports by state and fuel. Exhibit 4 further breaks down the coal test reports by type of coal. As noted above, a key difference in CPM measured by EPA Method 202 is whether or not the impingers were purged with nitrogen, Exhibit 5 provides a summary of the number of tests where impingers were purged, not purged, or not specified.

Exhibit 3: Tests by State and Fuel Type

State/Fuel	Coal	Oil	Gas
Delaware	3	0	0
Minnesota	16	0	1
New Jersey	10	0	0
North Carolina	27	1	1
Pennsylvania	23	18	19
Wisconsin	32	8	3
Total	111	27	24

Exhibit 4: Tests by State and Type of Coal

State/Fuel	Coal*	Bituminous	Subbituminous
Delaware	3	0	0
Minnesota	7	0	9
New Jersey	7	3	0
North Carolina	26	1	0
Pennsylvania	14	9	0
Wisconsin	32	0	0
Total	89	13	9

(\*) Type of coal unspecified.

Exhibit 5: Tests by State and Nitrogen Purge

State/Purge	Purged	Not purged	Not specified
Delaware	3	0	0
Minnesota	15	2	0
New Jersey	0	0	10
North Carolina	29	0	0
Pennsylvania	1	25	34
Wisconsin	28	6	9
Total	76	33	53

Exhibits 6 through 9 summarize the results of the CPM and FPM data collected from the 162 tests. The data extracted from the reports and the analyses used to generate the graphs in Exhibits 6 through 9 are available in Attachment 2 to this memorandum. Exhibit 6 shows the average emissions factors for each fuel from all test reports. The average coal CPM emissions factor is  $0.023 \pm 0.006$  lb/MMBtu (95% confidence interval for 111 data points). Most of the test reports did not specify the type of coal fired, but based on DOE monthly coal-use data for the United States, the majority of coal burned in the United States is either bituminous or subbituminous. The average fuel oil CPM emissions factor is  $0.013 \pm 0.006$  lb/MMBtu (95% confidence interval for 27 data points), and the average natural gas CPM emissions factor is  $0.005 \pm 0.001$  lb/MMBtu (95% confidence interval for 24 data points).

The effect of the nitrogen purge can be seen from comparison of the CPM emissions factor results in Exhibits 7 through 9. CPM results from tests for which no nitrogen purge was done are noticeably higher than the results from the tests for which the purge was done. A comparison of Exhibits 7 and 8 demonstrates the magnitude of the sulfate artifact. The average of the CPM emissions resulting from the non-purged tests are 3 times higher than the results of the purged tests for coal based on the comparison of 11 non-purged and 66 purged data points. The average of the CPM emissions resulting from the non-purged tests are twice the results of the purged tests for fuel oil based on the comparison of 12 non-purged and 6 purged data points. For natural gas, average CPM emissions resulting from non-purged tests are 3 times higher than the purged tests based on comparison of 12 non-purged and 6 purged data points.

Exhibit 6: Average Emission Factors By Fuel – All Tests

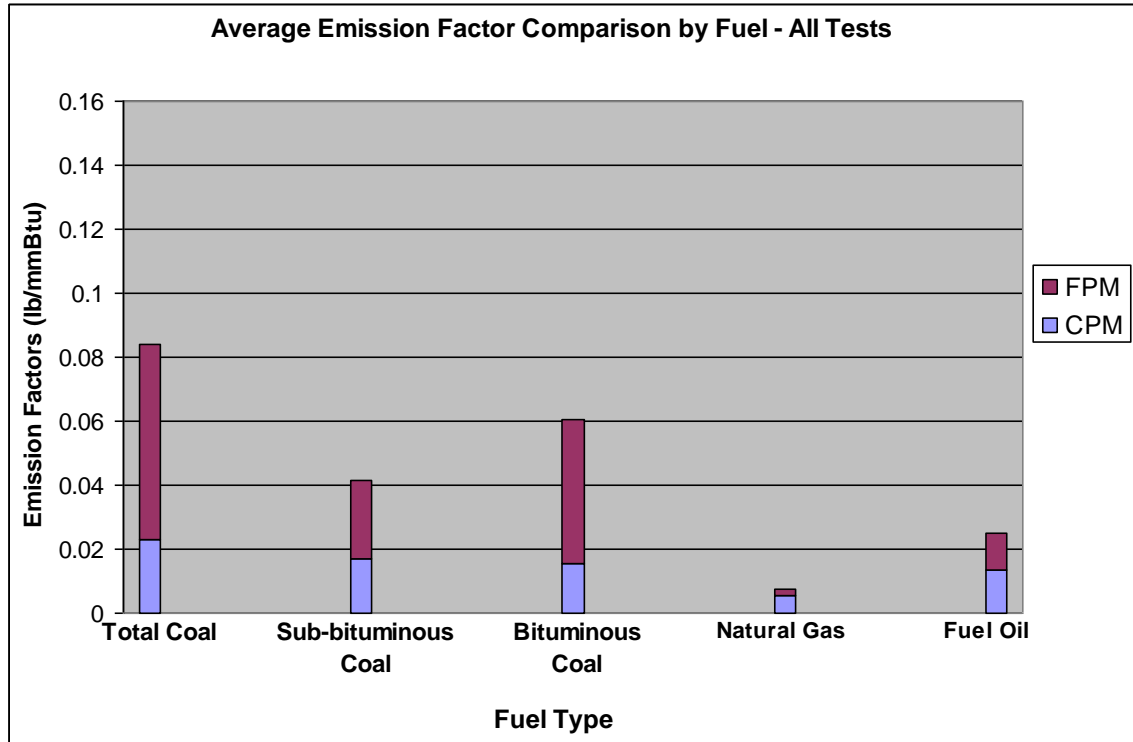


Exhibit 7: Emission Factor Comparisons, Purged

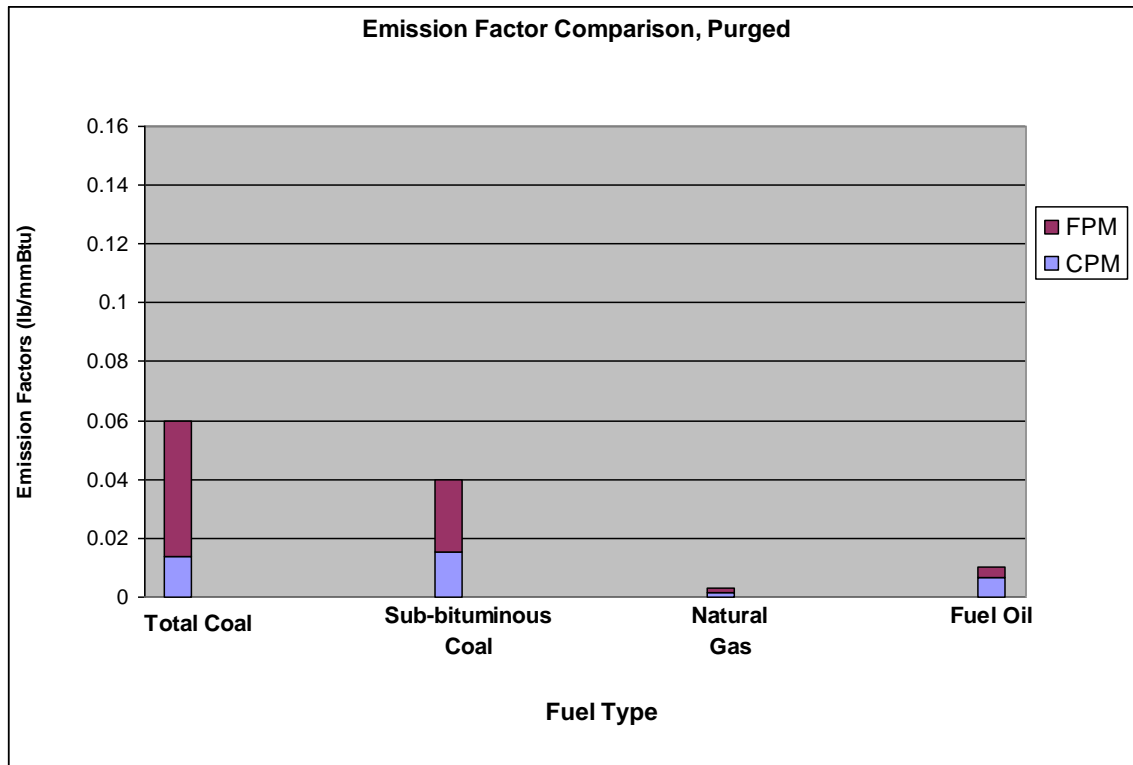


Exhibit 8: Emission Factor Comparisons, Non-Purged

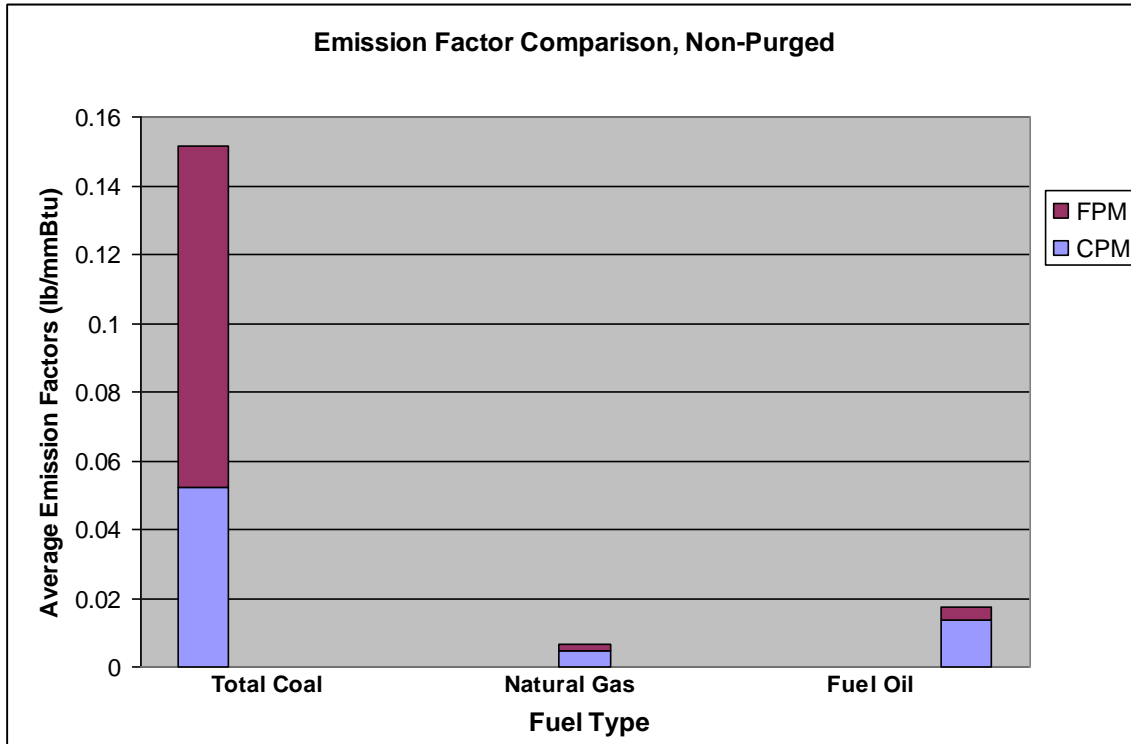
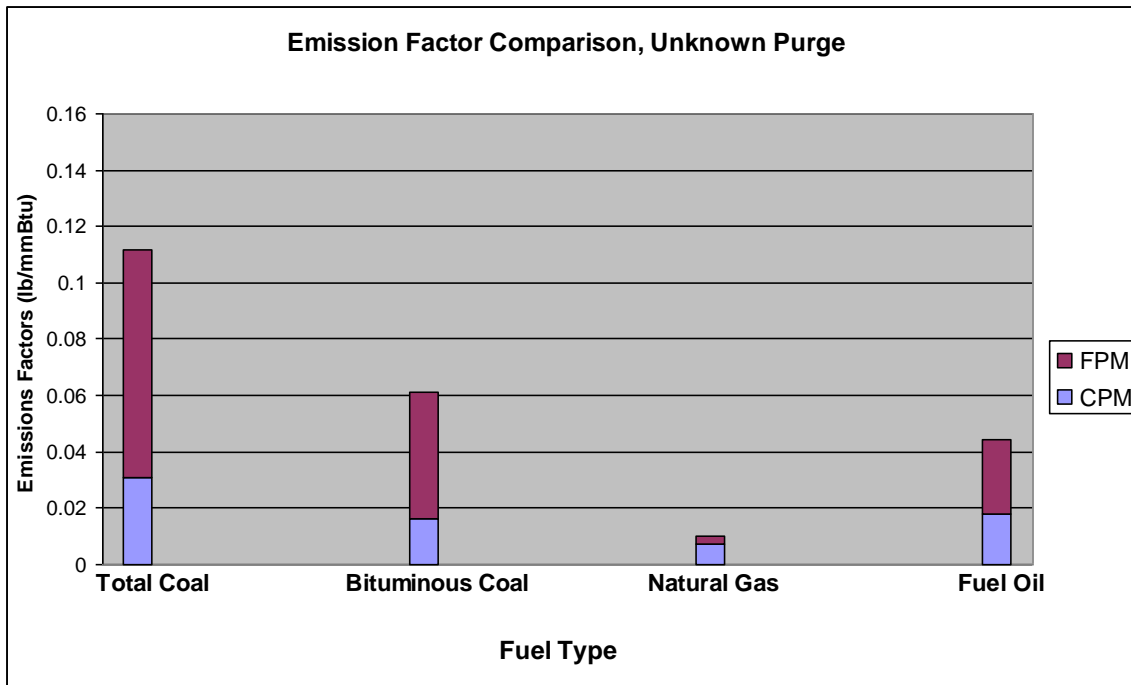


Exhibit 9: Emission Factor Comparisons, Unknown Purge



In addition to categorization by fuel type, we reviewed the available information for each of the 162 tests, and made assignments of the data points to SCCs for direct comparison to existing AP-42 emissions factors. Using the available information and considering the limited number of data points (162 total), we decided that the most effective analysis would result from assignment of the data points to the 6-digit SCC level. Assignment at the SCC 8-digit level was not possible for most test data because the information supplied in most test reports did not indicate the specific boiler/turbine type. After the assignments were made, additional calculations were completed to calculate the emissions factors by 6-digit SCC. Exhibit 10 contains a summary of these data, and the assignments. Complete calculations are provided in Attachment 3 to this memorandum.

Exhibit 10: Summary of CPM Emissions Factors by SCC (6-digit)

SCC (6-digit)	SCC (6-digit) Description	Number of Tests	Average CPM Emissions Factor (lb/MMBtu)	95% Confidence Interval (lb/MMBtu)
1-01-001	Boiler / EGU / Anthracite Coal	1	0.0084	N/A
1-01-002 – all tests	Boiler / EGU / Bituminous/Subbituminous Coal	102	0.022	± 0.006
1-01-002 (purged only)	Boiler / EGU / Bituminous/Subbituminous Coal	63	0.013	± 0.002
1-01-003 – all tests	Boiler / EGU / Lignite	6	0.039	± 0.029
1-01-005 – all tests	Boiler / EGU / Fuel Oil	10	0.014	± 0.007
1-01-006 – all tests	Boiler / EGU / Natural Gas	1	0.00249	N/A
1-01-008 – all tests	Boiler / EGU / Petroleum Coke	2	0.05	± 0.03
2-01-001 – all tests	Internal Combustion Engine / EGU/ Fuel Oil	17	0.013	± 0.005
2-01-001 (purged only)	Internal Combustion Engine / EGU/ Fuel Oil	3	0.010	± 0.004
2-01-002 – all tests	Internal Combustion Engine / EGU/ Natural Gas	23	0.005	± 0.001
2-01-002 (purged only)	Internal Combustion Engine / EGU/ Natural Gas	3	0.0015	± 0.0002

Summary of Results from Emissions Factors Data Analysis

In accordance with EPA guidance that CPM emissions determined from Method 202 tests that apply nitrogen purging are more reliable than results from tests where purging was not used, we will only consider categories where purging was used. Based on the high level of agreement among the 63 test data points for the nitrogen purged tests for SCC “1-01-002” in Exhibit 10 (third row), the CPM emissions factor of  $0.013 \pm 0.002$  lb/MMBtu for bituminous and/or subbituminous coal is considered to be a high quality estimate of the CPM emissions factor in EGU boilers and we recommend its use. One should be careful in comparing the emissions factors in Exhibit 10 with those in Exhibit 1 because the emissions factors in Exhibit 1 for coal combustion are averaged over a range of fuel sulfur content and the factors in Exhibit 10 are averaged over tests without regard to fuel sulfur. Nevertheless, it should be noted that the nitrogen purged CPM emissions factor in Exhibit 10 for combustion of bituminous and subbituminous coal are lower than the older emissions factors in FIRE 6.25 by a factor of about 7 and 4 for bituminous and subbituminous coal, respectively. Additionally, because nearly all coal fired in the United States is bituminous or subbituminous coal, application of this emissions factor for all combustion of bituminous and/or subbituminous coal should greatly improve emissions estimates from EGUs.



Based on the small sample size of nitrogen purged tests for anthracite and lignite coals, natural gas and fuel oil as shown in Exhibit 10, we do not recommend any revisions to FIRE 6.25 emissions factors. It should be noted that while these data have been shared with EPA, EPA has not yet added the data to WebFIRE.

Comments from state agency review of this technical memorandum

This technical memorandum was circulated to state agency staff for their review. A number of technical changes were made as a result of those comments. In addition, Pennsylvania provided the following comments:

- Pennsylvania DEP is requiring EGU owners/operators in Pennsylvania to conduct source testing by June 30, 2009 to determine actual condensable PM emission.
- The measurement method for CPM has now been updated. EPA's recently developed dry impinger method (OTM-028) was not used in the tests used in this study, rather the method that was used (Method 202) produces results that are biased high.
- A follow-up study would be desirable to determine if testing methods affect the CPM/TPM ratio.

APPENDIX A

Delaware

NRG Indian River Generating Station, Unit 4, October 31, 2002

NRG Indian River Generating Station, Unit 2, October 16, 2002

NRG Indian River Generating Station, Unit 1, October 16, 2002

Minnesota

Otter Tail Power Company's Hoot Lake Facility, No. 1 Boiler, Fergus Falls, MN, December 19, 2006

Minnesota Power's Boswell Energy Center, Unit 4, Cohasset, MN, August 26-28, 2002

Xcel Energy's Riverside Generating Plant, Units 6, 7 and 8, Minneapolis, MN, October 3-4, 2006

Xcel Energy Sherburne County Generating Plant, Unit 1/2 Common Stack, Becker, MN, June 15-16, 2004

Xcel Energy Sherburne County Generating Plant, Boilers 1 and 2 Common Stack/EP #001, Becker, MN, August 28, 2001

Xcel Energy Sherburne County Generating Station, Unit #3 Exhaust Stack, Becker, MN, September 28, 2005

Xcel Energy Sherburne County Generating Plant, EU001 & EU002/SV001, Becker, MN, April 27, 2007

Minnesota Power Laskin Energy Center, Boilers 1 and 2, Hoyt Lakes, MN, February 27, 2007 and July 24, 2007

Otter Tail Power Company's Hoot Lake Facility, Unit 3 Boiler, Fergus Falls, MN, December 20, 2006

Otter Tail Power Hoot Lake Facility, Unit 3 Boiler, Fergus Falls, MN, August 24, 2006

Xcel Energy Black Dog Unit #5 Repowering Project, Combustion Turbine #5, Burnsville MN, June 26-July 2, 2002

North Carolina

Carolina Power & Light Lee Plant, Unit 1, Goldsboro, NC, May 2, 2002

Carolina Power & Light Lee Plant, Unit 3, Goldsboro, NC, May 1, 2002

Carolina Power & Light Mayo Plant, Unit 1, Roxboro, NC, May 9, 2002

Carolina Power & Light L.V. Sutton Steam Electric Plant, Unit No. 1, Wilmington, NC, June 15, 2002

Carolina Power & Light L.V. Sutton Steam Electric Plant, Unit No.2, Wilmington, NC, June 16, 2002

Carolina Power & Light L.V. Sutton Steam Electric Plant, Unit No.3, Wilmington, NC, June 13, 2002

Carolina Power & Light Roxboro Plant, Unit 1, Roxboro, NC, July 23, 2002

Carolina Power & Light Roxboro Plant, Unit 2, Roxboro, NC, May 22, 2002

Carolina Power & Light Roxboro Plant, Unit 3, Roxboro, NC, July 24, 2002

Carolina Power & Light WH Weatherspoon Plant, Units 1 & 2, Lumberton, NC, February 13-14, 2002

Carolina Power & Light WH Weatherspoon Plant, Unit3, Lumberton, NC, March 6, 2002

Carolina Power & Light WH Weatherspoon Plant, Unit3, Lumberton, NC, September 24, 2002

Duke Energy Allen Steam Station, Unit 1, Gaston County, NC, August 13, 2002

Duke Energy Allen Steam Station, Unit 3, Gaston County, NC, August 14, 2002

Duke Energy Allen Steam Station, Unit 4, Gaston County, NC, August 15, 2002

Duke Energy Riverbend Steam Station, Unit 4 Boiler 7, Gaston County, NC, October 8, 2002

Duke Energy Riverbend Steam Station, Unit 5 Stacks A & B, Gaston County, NC, October 9, 2002

Duke Power Company, Buck Steam Station, Unit No. 3, Spencer, NC, September 11, 2003

Duke Power Company, Buck Steam Station, Unit No. 5, Spencer, NC, September 10, 2003

Duke Power Company, Cliffside Steam Station, Unit No. 5, Rutherford County, NC, August 1, 2002

Duke Power Company Dan River Steam Station, Unit 2, Eden, NC, May 1, 2002

Duke Power Company Dan River Steam Station, Unit 1, Eden, NC, April 30, 2002

Progress Energy Carolina's Mayo Plant, Unit 1, Roxboro, NC, June 16, 2004

Progress Energy Asheville Generating Station, Unit T4, Asheville, NC, May 6-9, 2008

Carolina Power and Electric Roxboro Electric Generating Plant, Unit 1, Roxboro, NC, October 16, 2001

Pennsylvania

Allegheny Energy Supply Company Hatfield's Ferry Power Station, Stacks 1 & 2, Masontown, PA, March 23 and 26, 2007

Allegheny Energy Supply Company Hatfield's Ferry Power Station, Stacks 1 & 2, Monongahela Township, PA, June 12, 2007

Reliant Energy Newcastle Plant, Boilers 3 & 5, Taylor Township, PA, March 22, 2005

Reliant Energy Newcastle Plant, Boiler 4, Taylor Township, PA, May 18, 2005

Reliant Energy Newcastle Plant, Boilers 3, 4 & 5, Taylor Township, PA, February 27, 2007

Northampton Generating Company, Northampton, PA, August 23-24, 2005

PPL Brunner Island, Unit 3 ESP, East Manchester Twp., PA, January 10, 2007

PPL Brunner Island S.E.S., Unit 1 Exhaust Stack, York Haven, PA, May 15, 2007

Reliant Energy Elrama Power Plant, Boilers 1-4, Elrama, PA, August 3, 2005

Reliant Energy Elrama Power Plant, Baghouse Stack, Elrama, PA, November 18, 2005

Reliant Energy Elrama Power Plant, Elrama, PA, April 12 & 16, 2007

Reliant Energy Elrama Power Plant, Boilers 1-4, Union Township, PA, December 17, 2007

PPL Martins Creek Station, Northampton County, 2007

PPL Generation Montour Steam Electric Station, Boiler 1, Washingtonville, PA, May 16, 2006

PPL Generation Montour Steam Electric Station, Boiler 2, Washingtonville, PA, April 4, 2007

Reliant Energy Mid-Atlantic Power Seward Station, Boilers 1 & 2, East Wheatfield Twp., PA, December 5, 2004

Conectiv Bethlehem, Combined Cycle Electric Generation Facility, Combustion Turbines 1-3, Bethlehem and Lower Saucon Twp., PA, January 29-March 26, 2003

Conectiv Bethlehem, Combined Cycle Electric Generation Facility, Combustion Turbines 1-3, Bethlehem and Lower Saucon Twp., PA, May 20-June 2, 2003

Conectiv Energy Bethlehem Power Plant, Units 2 & 3, Bethlehem, PA, February 3, 4, 7, 8 & 10, 2003

Conectiv Energy Bethlehem Power Plant, Unit 2, Bethlehem, PA, May 27-29, 2003

Conectiv Energy Bethlehem Power Plant, Unit 3, Bethlehem, PA, May 30, 31 & June 2, 2003

Conectiv Energy Bethlehem Power Plant, Unit 1, Bethlehem, PA, January 28-30, 2003

Conectiv Energy Bethlehem Power Plant, CT 2, Bethlehem & Lower Saucon Twp., PA, December 30, 2003

Conectiv Energy Bethlehem Power Plant, Unit 5, Bethlehem & Lower Saucon Twp., PA, March 22, 24 2003

Conectiv Energy Bethlehem Power Plant, CT 3, Bethlehem & Lower Saucon Twp., PA, February 8, 10, 2003

Conectiv Energy Bethlehem Power Plant, CT 7, Bethlehem & Lower Saucon Twp., PA, September 25-26, 2003

Conectiv Energy Bethlehem Power Plant, Unit 5, Bethlehem & Lower Saucon Twp., PA, September 15-17, 2003

Reliant Energy Did Atlantic Power Holding Portland Station, Combustion Turbine #5, Upper Mt. Bethel Township, PA, September 24, 2002

Conectiv Energy Bethlehem Power Plant, CT 6, Bethlehem & Lower Saucon Twp., PA, September 22-23, 2003

#### New Jersey

Carney's Point Generating Plant, Boilers 1 & 2 Carney's Point, NJ, January 19-29, 2004

PSEG Hudson Generating Station, Unit No. 2, Hudson, NJ, June 20 & 23, 2003

Logan Generating Station, Swedesboro, NJ, October 27-28, 2004

#### Wisconsin

Dairyland Power Cooperative Genoa 3 Station, No. 1 Boiler, Genoa, WI, August 3, 2004

Dairyland Power Cooperative J.P. Madgett Station, No. 1 Boiler, Alma, WI, April 9, 2002

Dairyland Power Cooperative J.P. Madgett Station, No. 1 Boiler, Alma, WI, May 18, 2006

Dairyland Power Cooperative J.P. Madgett Station, Baghouse Stack (Main Boiler B25, S11), Alma, WI, December 18-19, 2007

Wisconsin Public Service Corporation J.P. Pulliam Power Plant, Units 3/4 Common Stack, Green Bay, WI, July 7, 2004

Madison Gas and Electric Company Blount Generating Station, Unit 7 Outlet Duct, Madison, WI, November 6, 2003

Madison Gas and Electric Company Blount Generating Station, Unit 8 Precipitator Outlet, Madison, WI, April 15, 2004

Manitowoc Public Utilities MPU Power Plant, Boilers B25 and B28, Manitowoc, WI, June 10 and July 9, 2003

Manitowoc Public Utilities MPU Power Plant, Boilers B25 and B28, Manitowoc, WI, March 6-9, 2006

Wisconsin Electric Power Company Valley Power Plant, Boilers 1 and 2 Inlet and Outlet Ducts, October 24 and 26, 2001

Wisconsin Public Service Corporation Weston Power Plant, Unit 1 Stack, Rothschild, WI, December 21, 2005

We Energies Oak Creek Station, Unit 8 Precipitator Outlet, East and West Inlets, Oak Creek, WI, September 4, 2003

We Energies Valley Power Plant, Boilers 3 and 4 Inlet and Outlet Ducts, Milwaukee, WI, July 28 and 29, 2003

Alliant Energy Columbia Station, Unit 1 Stack, Pardeeville, WI, September 4, 2003

Dairyland Power Alma Station, No. 105 Boiler Stack, Alma, WI June 1, 2006

Dairyland Power Cooperative Genoa 3 Station, No. 1 Boiler Baghouse Stack, Genoa, WI, July 24-25, 2007

We Energies Pleasant Prairie Power Plant, Unit 1 FGD Scrubber Stack, Pleasant Prairie, WI, January 24 and 25, 2007

We Energies Pleasant Prairie Power Plant, Unit 2 FGD Scrubber Stack, Pleasant Prairie, WI, May 23 and 24, 2007

Northern Wisconsin Center, #3 Boiler Exhaust Stack, Chippewa Falls, WI, March 15, 2005

Wisconsin Public Service Corporation Weston Power Plant, Unit 4 Auxiliary Boiler Stack,  
November 27, 2007

Alliant Energy Edgewater Generating Station, Unit 4 Outlet Duct, Sheboygan, WI, March 19,  
2002

Mendota mental Health heating Plant, #2 Boiler Exhaust, Madison, WI, March 21, 2003

Wisconsin Power and Light Nelson Dewey Generation Station Cassville, Units 1 and 2,  
Cassville, WI, February 22 and 24, 2005

Manitowoc Public Utilities Custer Plant, Combustion Turbine Stack, Manitowoc, WI, October 2-  
5, 2001

We Energies Port Washington Power Plant, Combustion Turbine 21, Port Washington, WI,  
October 10-11, 2005

Wisconsin Public Service Corporation Weston Power Plant, Combustion Turbine 32 South  
Stack, Rothschild, WI, December 29-30, 2005

Madison Gas and Electric Company West Campus Cogeneration Facility, Unit 2, Madison, WI,  
April 11, 12, 15,16, 2005

Madison Gas and Electric Company West Campus Cogeneration Facility, Unit 1 and the Diesel  
Engine Backup Generator, Madison, WI, February 21 and 22, 2006

Wisconsin Public Service Corporation Petenwell Dam Hydro Site, Simple Cycle Combustion  
Turbine, Necedah, WI, September 2-5, 2003

Arcadia Municipal Electric Utility, No. 7 Diesel Engine Outlet, Arcadia, WI, July 31, 2002

Wisconsin Public Service Corporation Weston Power Plant, Unit 4 Main Diesel Fire Pump,  
Rothschild, WI, January 23, 2007

Wisconsin Public Service Corporation Weston Power Plant, Unit 4 Diesel Booster Fire Pump,  
February 26, 2008