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The Honorable Scott Pruitt
Administrator
United States Environmental Protection Agency
EPA Docket Center, Mail Code: 28221T
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Attention: Docket ID Number: EPA–HQ–OAR–2017–0545

Subject: State Guidelines for Greenhouse Gas Emissions from
Existing Electric Utility Generating Units

Dear Mr. Administrator:

This response represents the views of The American Society of Mechanical Engineers (ASME's) Research Committee on Energy, Environment, & Waste (RCEEW) and is not necessarily a position of ASME as a whole. Founded in 1880, ASME is a nonprofit, worldwide educational and technical society. With membership exceeding 130,000, it conducts one of the world's largest technical publishing operations, holds more than 30 technical conferences and 200 professional development courses each year, and sets some 600 industrial and manufacturing standards, many of which have become de facto global technical standards.

These RCEEW Committee comments are offered to assist USEPA in its goals to protect the environment as they relate to air emissions from power plants. Accurate and meaningful collection and analysis of plant efficiency data is necessary as part of this goal. Efficiency is generally referred to as heat rate in the industry and this term will be applied throughout. Decrease in heat rate represents an increase in plant efficiency. Proper application of accurate data will aid in your proposed rulemaking.

The RCEEW Committee encourages the goal of heat rate improvement for all power generating units Electric Generating Units (EGUs) and all fuels employed; including coal, gas, waste, and biomass. While most of RCEEW's comments in this letter are mostly related to coal EGUs, USEPA should address other fuels in future rulemaking. Improvements to heat rate reduce each unit's fuel usage and its emissions, including carbon dioxide (CO₂). Heat rate improvements, if the industry was incentivized to improve heat rate accordingly will result in improved economic power production while reducing environmental impact, which helps both the ultimate consumer and entire country.

Reporting of heat rate is an accepted and important tool used by industry and regulators, for the following:

- To measure overall thermal/electric efficiency.
- As a key metric for dispatch to the electricity grid.
- To measure and monitor fuel use.
- To measure and monitor operating economics.
- To support reporting of emission rates (e.g., pounds per million British thermal units).
- To measure and monitor reduced CO₂ emissions.
- To verify if changes or improvements in operating procedures are beneficial.
- To verify if changes or improvements to equipment and systems are beneficial.

Heat rate, as a measure of operating cost, permits plant and fleet owner/operators to determine which units operate at the appropriate time to achieve the lowest total cost of generation. As the heat rate of a unit increases (worsens), then that unit may drop lower on the dispatch order. Low load operation, cycling, on-and-off operation, and lower capacity factors increase heat rate, resulting in increased operating cost and potentially causing unit shutdown due to economics and/or damage to components.

Significant opportunities exist in the power industry for a better understanding of heat rate and its use to achieve current and future environmental policy goals. This will encourage the power industry to be positively incentivized to achieve those goals as heat rate is already a key parameter in their economic goals.

Several accepted methods of measuring EGU heat rate on an as-tested basis, including both the ASME Performance Test Codes and Electric Power Research Institute (EPRI) procedures exist. These methods are considered consensus methods as defined by American National Standards Institute (ANSI) in that they were developed through substantial agreement among directly and materially affected stakeholders. ASME standards are similarly developed to protect the health and welfare of the public. EPRI focuses on electricity generation, delivery, and use in collaboration with the electricity sector, its stakeholders and others to enhance the quality of life by making electric power safe, reliable, affordable, and environmentally responsible.

RCEEW seeks to assist EPA, and related bodies, to achieve a consensus method of measuring a power plant's heat rate, or performance, on an annual basis. For example, in development of its Clean Power Plan in 2017, the USEPA used a statistical method of determining heat rate measured on a gross basis; in contrast, the U.S. Department of Energy (USDOE), Energy Information Administration (USEIA) reports annual heat rate measured on a net basis, other significant differences in reported heat rate data from USEPA and USDOE also exist. Avoidance of these discrepancies will result in more meaningful and consistent data analysis and aid in developing productive environmental and energy policies.

Opportunities to Improve Heat Rate Reporting

In preparing the Clean Power Plan, the USEPA used a statistical method of calculating annual unit heat rate for coal-fired EGUs using data derived from an EGU's continuous emissions monitoring system (CEMS) velocity probes and fuel F-factors¹. This has been in use on power plants for some time for USEPA reporting. Use of F-factors and velocity probes were of adequate accuracy for USEPA's goals set at the time, but for the goals going forward, they do not meet the need as currently employed. Now that USEPA is addressing CO₂ as a pollutant, the need to measure that stream accurately is more significant. An opportunity exists by which CEMS velocity probes and fuel F-Factors accuracy can be improved today.

¹ Fuel F-factors are used to characterize the products of complete atmospheric combustion for a given amount of heat released; F-factors are generally considered to be consistent, despite the variability of fuel density, ash and moisture. The F-factor represents a ratio of the volume of flue gases generated to the caloric value of the fuel combusted.

Various factors create potential for errors in applying data. Peer reviewed, technical papers exist which discuss the fact that velocity probes are not normally calibrated for cycling operations. Others have questioned and demonstrated the errors associated with using constant F-factors along with variation of fuels on an annual basis. In the “Journal of the Air & Waste Management Association”, 64(1):73–79, 2014, Dr. Jeff Quick reported that “Annual CO₂ emission tallies for 210 coal-fired power plants during 2009 were more accurately calculated from fuel consumption records reported by the USEIA than measurements from CEMS reported by the USEPA. Results from these accounting methods for individual plants vary by +/- 10.8%.”

In June 2017, the United States Department of Commerce, National Institute for Standards and Testing (NIST) reported that CEMS-measured CO₂ emissions versus the USDOE/USEIA calculation method for CO₂ emissions resulted in a -10% to +15% variation in data. One of the primary causes of this variation in data is related to flow measurement by CEMS velocity probes mounted in the stack. USDOE/USEIA reports heat rate using two methods: annual and as-tested. The USDOE/USEIA as-tested data shows improved heat rates and in contrast the USEPA data shows a decline in EGU performance. The USDOE/USEIA data were based on the amount of coal burned and on actual operating conditions.

Dr. Quick reported issues with the USDOE/EIA data, stating that “Limitations of the EIA fuel consumption data are also discussed. Consideration of weighing, sample collection, laboratory analysis, emission factor, and stock adjustment errors showed that the minimum error for CO₂ emissions calculated from the fuel consumption data ranged from +/-1.3% to +/-7.2% with a plant average of +/- 1.6%. This error might be reduced by 50% if the carbon content of coal delivered to U.S. power plants were reported.”

The F-factors used by USEPA remain an important tool in monitoring performance enhancements. As part of its ongoing support, ASME’s RCEEW intends to evaluate development of a “certified F-factor”; and for such an evaluation, RCEEW will need significant technical support from the USDOE, USEPA, ASME’s Committee on PTC-46, NIST, and EPRI. The goal is to develop consensus methods to improve the accuracy and addressing the concerns that have been published to date on F-factors.

ASME’s “PTC-46 Overall Plant Performance Test” Committee is developing plans for measuring annual plant performance and is evaluating existing ASME codes and standards so that performance can be monitored more accurately on a continuous basis.

Opportunities to Create Incentives for Heat Rate Improvement

There is no global solution to improving the heat rate or energy efficiency of an individual EGU. Each EGU’s performance is based on the following performance parameters:

- Plant’s design thermodynamic cycle.
- Fuel composition and quality – with special consideration of moisture and sulfur.
- Plant age and size.
- The types of pollution control equipment installed.
- Operating and maintenance practices.
- Plant equipment design, including steam generator, turbine and cooling/condenser.
- Geographic location and ambient conditions.
- Electric grid dispatch requirements.
- Cycling or base load.

There are technologies available to improve heat rate that could be evaluated by USEPA for potential inclusion in the Best System of Emission Reduction (BSER). These technologies could guide the industry to the best solutions and lead to adoption of incentive-based systems. RCEEW has been investigating various technologies for performance impacts and invites the USEPA to evaluate them for use in BSER.

A vital part of any coal-fired unit is the Fuel Delivery System (FDS), comprising feeders, pulverizers, classifiers, coal piping and burners. ASME investigated three typical 500-MW wall, tangential, and cyclone, fired boilers originally designed for eastern bituminous coal and now firing low sulfur subbituminous Powder River Basin (PRB) coals. The subcommittee reviewed and selected retrofit upgrades for the FDS, determining costs and the potential value of the ensuing benefits. In the case of a 500 MW bituminous wall fired boiler, they concluded that 0.34% improvement in boiler efficiency on a 500 megawatt (MW) wall fired coal boiler costs \$13,600,000 in pulverizer upgrades. USEPA should evaluate this concept.

Recent research developments have been made and test conducted on low load and cycling operations. One of the limiting factors impacting coal-fired EGUs is that at low load conditions the acid dew point can be reached in the air heater. Units can use a steam coil (or similar systems) air preheater to control the cold end temperature of the air-to-gas air heater to mitigate problems. However, this increases heat rate. For units not designed for cycling or low load service, air quality control systems, such as selective catalytic reduction (SCR) systems, pose the first limit to turn down. For example, the economizer exit gas temperature must be maintained high enough for the SCR catalyst to perform as required and to prevent the formation of ammonium salts. If flue gas temperature drops to or below the acid dew point several significant problems can happen. These negative effects include:

- Fouling of the air heater which causes outages,
- High pressure drops with increased plant heat rate
- Increased corrosion in the air heater
- “Blue Plume” and possible emissions violations

Most existing EGUs were not designed to operate at low load or cycling conditions. Acid condensation test can be mitigated by injection of alkaline sorbents upstream of the air heater.

The following is our analysis for specific technical questions asked by USEPA in the Advanced Notice of Proposed Rulemaking (ANPRM).

Load Capacity Factor and Cycling Operations

USEPA has requested input on load capacity and cycling operations. These should be analyzed together. RCEEW used data from 2002 to 2012 to be consistent with the data used by USEPA in developing the Clean Power Plan. Since 2010 there has been a dynamic shift in the power industry primarily driven by the price of natural gas and increased use of renewable energy. Coal-fired EGU capacity factors have declined from about 70% to about 53% today. The reduction in coal-fired dispatch results in increased cycling and plants running at low load conditions leading to higher heat rates (The higher the heat rate, the less efficient the plant).

The following table highlights the recent performance of coal-fired EGUs. The cost of natural gas is directly related to the capacity factors for coal-fired units. Changes in the cost of natural gas in future years will impact the operating cycle of coal units and their heat rate.

Year	Annual Gross Heat Rate Btu/kWh USEPA	Annual Net Heat Rate Btu/kWh USEIA	Actual Tested Net Heat Rate Btu/kWh Full load USEIA	Capacity Factor %	Nat. Gas for Power \$/MMBtu
2002	9,924	10,314		68	
2003	9,886	10,297		69	
2004	9,819	10,331		70	
2005	9,774	10,373		71	
2006	9,743	10,351		70	\$6.94
2007	9,740	10,375	10,158	71	\$7.11
2008	9,643	10,378	10,138	70	\$9.02
2009	9,649	10,414	10,150	62	\$4.74
2010	9,662	10,415	10,142	65	\$5.09
2011	9,708	10,444	10,128	61	\$4.72
2012	9,732	10,498	10,107	53	\$3.42
2013		10,459	10,089	60	\$4.33
2014		10,428	10,080	61	\$5.00
2015		10,495	10,059	55	\$3.23
2016		10,493	10,045	53	\$2.87

On July 25, 2017 USEIA reported “The slight rise in the average operating heat rate in coal-fired generation is attributable to the net result of competing factors. Emissions-control investments, which often create significant station loads (increase in auxiliary power consumption), were made to almost 205,000 MW of coal capacity from 2006 to 2015. These emissions-control measures increased the operating heat rates for coal-fired generation.” The table above indicates a 130 Btu/kWh (≈1.3%) increase over this 10-year period. However, USEIA did not consider the impacts of cycling and low load operations. The result is a misleading picture by not evaluating all the factors that impacted the change in heat rate.

Both the installation of environmental controls and cycling have adversely affected heat rate. Typical effects from environmental equipment installed on a coal-fired subcritical 500 MW gross EGUs can be seen below.

Typical effects: coal-fired subcritical 500 MW gross EGUs		
	High Sulfur Coal	PRB Coal
Initial Heat Rate	10,500 Btu/kWh	10,920 Btu/kWh
Wet Limestone FGD	289 Btu/kWh	191 Btu/kWh
Typical SCR	79 Btu/kWh	82 Btu/kWh
New Heat Rate	10,868 Btu/kWh	11,193 Btu/kWh
Increase in Heat Rate	3.5%	2.5%

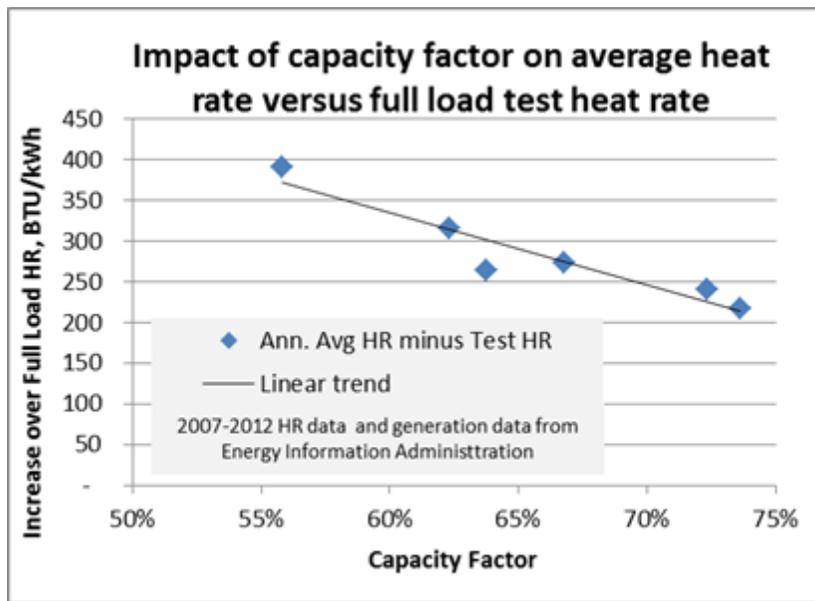
The USEIA data summarized in the table below shows the increased installation of major air pollution equipment on coal-fired EGUs since 2005.

Quantity and Net Summer Capacity of Operable Environmental Equipment, 2005 - 2015

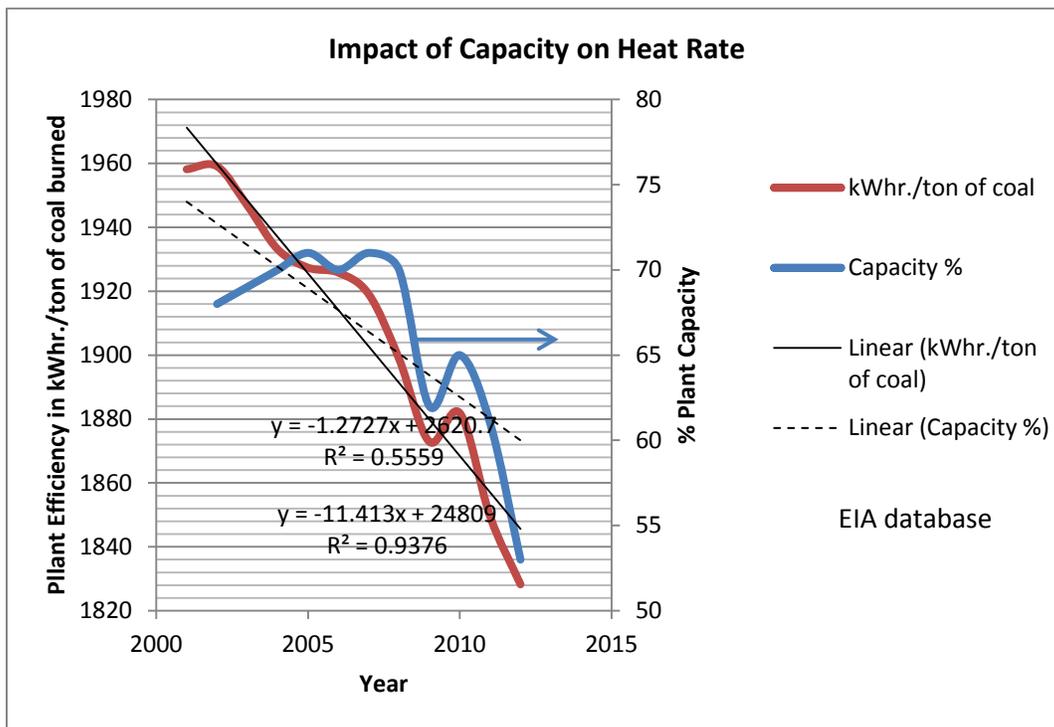
Year	Flue Gas Desulfurization Systems		Electrostatic Precipitators		Baghouses		Select Catalytic and Non-Catalytic Reduction Systems		Activated Carbon Injection Systems		Direct Sorbent Injection Systems	
	No.	Associated Net Summer Capacity (MW)	No.	Associated Net Summer Capacity (MW)	No.	Associated Net Summer Capacity (MW)	No.	Associated Net Summer Capacity (MW)	No.	Associated Net Summer Capacity (MW)	No.	Associated Net Summer Capacity (MW)
2005	555	113,573	1,542	324,511	528	58,033	1,068	236,689	128	4,693	47	6,765
2006	554	116,899	1,494	317,408	539	60,641	1,151	255,923	139	6,859	55	7,333
2007	582	130,815	1,494	317,296	556	65,672	1,186	264,851	141	7,735	56	7,407
2008	629	150,835	1,469	316,356	576	68,442	1,238	276,010	169	17,391	59	7,506
2009	669	174,090	1,454	313,902	597	73,863	1,311	298,441	227	39,546	62	8,047
2010	708	200,368	1,408	310,031	610	83,407	1,348	313,656	262	54,183	63	8,527
2011	721	210,878	1,364	306,511	633	98,507	1,396	329,676	274	59,057	72	8,783
2012	716	218,285	1,286	297,880	629	101,593	1,438	343,233	287	63,709	80	10,424
2013	691	218,121	1,209	288,210	635	104,226	1,445	349,727	260	61,160	93	12,740
2014	689	222,626	1,163	282,968	619	105,885	1,459	356,920	277	68,697	98	15,918
2015	680	222,919	1,027	263,848	620	110,073	1,464	358,007	361	105,860	115	22,418

It is obvious from the data above that both annual gross and net heat rates and the capacity factor have all declined during this period while the tested heat rate (full load) has improved. Why is there a difference? The answer is clear when one reviews the operating capacity for the same period. There is a direct relationship in the decline of the heat rates as related to the capacity factor. The average full load test heat rate improved over the period by roughly 0.50%. Despite an improvement in full load heat rate over the period, average annual heat rates deteriorated because of the decrease in capacity factor over the period.

The estimated impact of capacity factor on average annual heat rate over those years can be obtained by subtracting the average full load test heat rate from the average annual heat rate for the fleet. When the results are plotted, a very strong correlation arises as shown below. The average annual heat rate will exceed the full load test heat rate as that design point is usually set for the optimum efficiency. The data below demonstrates a clear trend of deteriorating heat rate relative to full load at lower capacity factors.



The graph below using USDOE/USEIA data shows the strong relationship between the decrease in EGU plant efficiency and plant capacity factors.



Research work has demonstrated that in low load condition coal-fired EGUs can operate at optimum air heater conditions if they inject alkaline sorbents before the air heater. If a plant can lower air heater temperature by 40 °F while mitigating acid deposition they could improve their heat rate by 1%.

Many of the older, originally designed, base loaded units now operate as summer peaking power plants (peakers), so their availability and performance only matter during those 3-4 months. They have 8+ months every year to prepare the unit for the peak period. They focus more on heat rate maintenance

versus heat rate improvement. Another factor on annual heat rate is the impact of increased unplanned (forced) outages due to increased boiler tube creep stress for baseload units in cycling operation.

The share of total electricity supplied by natural gas-fired power plants is expected to average 33% in 2018 and 34% in 2019, up from 32% in 2017. USEIA expects the share of generation from coal, which had been the predominant electricity generation fuel for decades, to average 30% in 2018 and 28% in 2019, compared with 30% in 2017.

USEIA expects the cost of natural gas for electricity generation to remain relatively competitive with coal-fired electricity over the next two years. The average cost of natural gas delivered to generators in 2018 is forecast to fall 2%, while the forecast delivered cost of coal rises 5%. These relative price changes should increase the share of natural gas generation in 2018 causing coal EGUs to cycle more and to increased operations at low loads. This will have a negative impact on heat rate. The as tested (full load) net heat rate of coal EGUs continues to improve over the past ten years. USEIA data from its 2016 Electric Power Annual Report shows this improvement in net heat rate in following table.

Improvement in Net Heat Rate		
Year	Coal, Btu/kWh	Nat. Gas Combined Cycle, Btu/kWh
2007	10,158	7,577
2008	10,138	7,642
2009	10,150	7,605
2010	10,142	7,619
2011	10,128	7,603
2012	10,107	7,615
2013	10,089	7,667
2014	10,080	7,658
2015	10,059	7,655
2016	10,045	7,652
<i>As tested full load net heat rate</i>		

This improvement in the coal-fired units can be attributed to; improvements made by operators and or closure of the smaller less efficient units. It is interesting to note that the natural gas combined cycle unit heat rates have not improved even as the new more efficient units have come on line.

The reasons for the increase in annual heat rates are complex and are result of a combination of many factors including cycling and low load operations, installation of air pollution control equipment and fuel changes over the past ten years.

On February 7, 2018 USEIA reported; “The mix of fuels used to generate electricity in the United States has changed in response to differences in the relative costs of electricity-generating technologies and, for those technologies that consume fuel, the cost of fuel. Several cases in EIA’s Annual Energy Outlook 2018 (AEO2018) show how projected generation and capacity could continue to be affected by fuel price patterns, particularly for the price of natural gas. In a sensitivity case with low natural gas prices, natural gas ultimately provides more than half of all United States electricity generation by the mid-2040s.

Natural gas recently surpassed coal as the main fuel used to generate electricity in the United States. In the AEO2018 Reference case, natural gas remains the leading source of electricity generation through 2050. By 2050, natural gas accounts for 35% of total electricity generation, a slight increase from its 2017 share of 31%.” This will impact the cycling and low load operations of the coal fleet and their respective heat rates.

Subcategories for Coal-Fired EGUs

RCEEW recommends a minimum of three subcategories for coal-fired EGUs, based on the type of coal: lignite, bituminous and subbituminous. USEPA may also want to consider a subcategory for waste coals fuel and plants with fluidized bed boilers. RCEEW does not have sufficient data to recommend if fluidized bed units need their own category. USEPA should evaluate any EGU source type which accounts for more than 5% of the total grid energy input to be a category. USEPA may also consider a category for plants that blend subbituminous and bituminous coal, and the few plants that blend lignite and subbituminous coal. Significant variations of blending rates and fuel rank affect operation and heat rate. Plants that blend fuel could be near 50/50, or anywhere from 100% bituminous to 100% subbituminous within several days of operation. It's also not appropriate/accurate to compare the performance of a lower-moisture subbituminous unit with a PRB coal-fired unit since it skews the results.

Combined effect of fuel moisture content and boiler or combustion technologies may improve heat rate in one case and not have the same benefits in another. The boiler/combustion system is only one component but a significant one of plant performance. Steam turbine and balance of plant operation are independent of how the steam was generated or the fuel used, and only dependent on steam temperature, flow rate, and pressure. On the other hand, the air pollution control equipment used in each plant is directly affected by the fuel type and constituents.

Typical heating values and coal moistures			
	Bituminous	Subbituminous	Lignite
Heat Value HHV, Btu/lb	11,700	8,700	6,500
% Moisture	8 to 12%	≈25%	≈ 50%

The fuel used also controls the air heater design and performance as the fuel used affects the acid dew point, available heat sink, and air heater operation are different. The sulfur and moisture content of the fuel determine the acid dew point which is the primary design factor for the operating temperature of air heaters. When evaluating heat rate improvements, modifications to the air heater is one of the most significant areas where improvements can be made. Typically, the air heater gas outlet is maintained at 20-30 °F above the sulfuric acid dew point to prevent corrosion of cold-end baskets. Injection of sorbents such as Trona™ or hydrated lime can be used to lower the dew point. Local ambient conditions and turbine cycle design (final feedwater temperature) can also limit the minimum practical air heater exit gas temperature. Depending on the sizing of the air heater, it may need to be modified to optimize the lower outlet temperature. The capital costs can range from \$1.5-18 M for heat rate reductions of 50-120 Btu/kWh.

Fuel switch to PRB has created operational issues for plants designed for other fuels. In addition to the fouling of boiler walls, the lower heat value of PRB fuel results in higher flue gas volumes, increasing auxiliary power for material handling and other equipment. The additional moisture reduces boiler efficiency. Plants that have converted to PRB from other fuel may have few heat rate improvement options.

Coal Type	Total coal moisture, (% weight)	H ₂ O in flue gas, (% volume)	Saturation temperature (F)
Bituminous	8	7.31	104.2
Washed Illinois	20	9.07	111.6
Powder River Basin (PRB)	25	10.73	117.5
Lignite	40	16.95	134.3

Other impacts on the balance of plant also influence performance. More units firing bituminous coal have wet flue gas desulfurization (FGD) systems also called scrubbers and larger power consumption than PRB units with dry FGD. In addition, regulations such as the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Industry (ELG) will have greater impact on bituminous based units again due to presence of wet FGD systems. PRB units are trending to dry FGD which will not have the same requirements. There will be greater impacts on the net heat rates based on these fuel differences.

Fuel impacts on unit performance can be seen in the table below; this data was developed from the EPRI Vista fuel quality impact analysis program. The model data for new 650 MW supercritical and subcritical boilers with SCR & Wet FGD demonstrates how the fuel impacts performance.

EPRI Vista Fuel Quality Impact Analysis Program: Model Data for New 650 MW Supercritical and Subcritical Boilers with SCR & Wet FGD					
Parameter	Units	Powder River Basin Coal (PRB)	Northern Appalachian Coal (NAPP)	Central Appalachian Coal (CAPP)	Illinois Basin Coal (ILB)
Supercritical Demo Unit					
Coal Heating Value, HHV	Btu/lbm	8,763	13,052	12,250	11,830
Coal Heating Value, LHV	Btu/lbm	8,514	13,005	12,190	11,310
Gross Output	MW	650.00	650.00	650.00	650.00
Net Output	MW	604.69	605.67	607.97	601.58
Boiler Efficiency, (HHV Basis)	%	86.70	90.06	90.30	89.12
Boiler Efficiency, (LHV Basis)	%	89.24	90.39	90.74	93.22
Net Turbine Heat Rate	Btu/kWh	7,401	7,400	7,400	7,400
Net Plant Heat Rate (HHV Basis)	Btu/kWh	9,175	8,819	8,762	8,973
Net Plant Heat Rate (LHV Basis)	Btu/kWh	8,915	8,787	8,719	8,578
Coal Burn Rate	ton/hr	316.6	204.6	217.4	228.1
Coal Burn Rate (HHV Basis)	MBtu/hr	5,548	5,341	5,327	5,398
Coal Burn Rate (LHV Basis)	MBtu/hr	5,391	5,322	5,301	5,160
Subcritical Demo Unit					
Coal Heating Value, HHV	Btu/lbm	8,763	13,052	12,250	11,830
Coal Heating Value, LHV	Btu/lbm	8,514	13,005	12,190	11,310
Gross Output	MW	650.00	650.00	650.00	650.00
Net Output	MW	604.79	606.50	608.72	601.91
Boiler Efficiency, (HHV Basis)	%	86.63	90.00	90.22	89.05
Boiler Efficiency, (LHV Basis)	%	89.16	90.32	90.67	93.14
Net Turbine Heat Rate	Btu/kWh	8,151	8,151	8,151	8,151

EPRI Vista Fuel Quality Impact Analysis Program: Model Data for New 650 MW Supercritical and Subcritical Boilers with SCR & Wet FGD					
Parameter	Units	Powder River Basin Coal (PRB)	Northern Appalachian Coal (NAPP)	Central Appalachian Coal (CAPP)	Illinois Basin Coal (ILB)
Net Plant Heat Rate (HHV Basis)	Btu/kWh	10,112	9,706	9,646	9,884
Net Plant Heat Rate (LHV Basis)	Btu/kWh	9,825	9,671	9,599	9,450
Coal Burn Rate	ton/hr	348.9	225.5	239.7	251.5
Coal Burn Rate (HHV Basis)	MBtu/hr	6,115	5,887	5,872	5,949
Coal Burn Rate (LHV Basis)	MBtu/hr	5,942	5,865	5,843	5,688

Improvements regarding heat rate will be governed by the type of fuel, the boiler design and balance of plant, including air pollution control equipment. The table below comes from the USEIA database. It shows the distribution of net heat rates by fuel and boiler type. Values shown are net heat rate in. This table clearly shows the impacts of fuel, boiler design, and balance of plant on heat rate. Further investigations are needed to determine if additional subcategories should be considered.

Impact by Fuel, Boiler Technology & Boiler Size				
	Subcritical		Supercritical	
Size Range	Bituminous	Subbituminous	Bituminous	Subbituminous
100-200 MW	10,663	11,051		
200-500 MW	10,470	10,642	10,364	
500+ MW	10,121	10,374	9,868	10,582
Lignite	11,091			

Performance Averaging Time

USEPA requested information regarding an emission standard that is based on a unit-specific emission limitation consistent with each modified unit’s best 1-year historical performance and can be met through a combination of best operating practices and equipment upgrades. RCEEW believes that a unit’s performance improvements cannot be determined since we do not have an acceptable or proven base for comparison. A single, 1-year period is too short an evaluation period with the load changing variations from year to year caused by fuel prices, weather and dispatch conditions.

The year following a high-pressure steam turbine upgrade, which typically provides the largest one-time heat rate improvement back closer to original design, if coupled with a high capacity factor for that unit will provide a lower heat rate. This improved heat rate usually cannot be matched as the turbine performance degrades over time. RCEEW recommends using a three-year rolling average, which will skew the results toward periods of time with higher capacity factors and “as-new” or recently replaced equipment.

Another factor to consider in setting the averaging period is the capacity and cycling rates of the units. As presented elsewhere in this letter the heat rate is impacted by the load factor and cycling. USEIA forecasts that the coal-fired generation factor will be increasing therefore the heat rate will also be changing; this is shown in the table below. A one-year averaging is not practical based on USEIA’s forecast.

Generation by Capacity		
	Coal	Natural Gas
2010	44.8%	23.9%
2011	42.3%	24.7%
2012	37.4%	30.3%
2013	38.9%	27.7%
2014	38.6%	27.5%
2015	33.2%	32.7%
2016	30.4%	33.8%
2017	30.1%	31.7%
2018	29.6%	33.1%
2019	28.1%	34.3%
<i>Source: EIA Short-Term Energy Outlook, January 2018.</i>		

Useful Life impacts

Reductions in plant operating time, which further degrades heat rate, and creates declining value for a plant. Heat rate degradation is well demonstrated in our discussion on cycling and low load operations. EPRI has recently published the results of research describing the longevity of heat rate improvements and the steps to maintain those benefits longer. Many of those actions are essential basics, e.g. continuous performance monitoring, timely maintenance actions, maintaining operations within industry or original equipment manufacturer (OEM) guidelines. RCEEW suggests a review of EPRI’s report “Range and Applicability of Heat Rate Improvements”.

BSER Focused on Technological or Operational Measures That Can Be Applied to or At a Single Source

RCEEW offers to work with USEPA and USDOE to establish work practice standards. Our experience leads us to believe that establishment of specific or generic heat rate improvement standards are problematic. Unintended consequences can result due to various factors cited in this response. Each plant’s ability to achieve heat rate improvements are based on the following:

- Unit’s design thermodynamic cycle.
- Fuel composition and quality with moisture and sulfur as prime interests.
- Unit age and size.
- The type of pollution control equipment installed.
- Operating and maintenance practices.
- Unit equipment design, including steam generator, and cooling/condenser
- Geographic location and ambient conditions.
- Electric grid dispatch requirements.
- Cycling or base load.

Work practice standards would include operating and maintenance practices. Many specific recommendations can be made to include correction of casing leaks, air pre-heater (APH) leaks, use of boiler optimization software, furnace cleanliness efforts, and others. USEPA used the term “best practices” for those units that they believed were better performers and did not need as much improvement. A work practice standard needs to look at older base loaded units operating as summer

peakers. These plants may only operate during those 3-4 months and require focus on heat rate maintenance versus heat rate improvement.

However, one of the major opportunities that USEPA, USDOE, and industry have is that we can develop a consensus definition of annual heat rate and a method of measuring annual heat rate. With a consensus approach, the USEPA will be able to evaluate what improvements in EGUs are effective and what incentives could be used to drive the industry to improve. Both USEPA and USDOE/USEIA report annual heat rates and as we have demonstrated, there are significant differences in reporting and calculation. Industry needs to have a consensus-based and consistent method of calculation and reporting. Understanding that regulatory agencies and the utility industry have different needs and application of heat rate data a need for consistency remains.

USDOE has asked ASME's RCEEW to report on the conflicts between USEPA and USDOE's reporting on annual heat rate. As mentioned, one concept that RCEEW will investigate is creation of a "certified or calibrated F-factor" which will blend USEPA's approach, ASME's Performance Test Codes and USDOE's calculation method.

RCEEW considers that the North Carolina proposed rule 15A NCAC 02D .2701 "STANDARDS OF PERFORMANCE FOR EXISTING ELECTRIC UTILITY GENERATING UNITS UNDER CLEAN AIR ACT SECTION 111(d)" could be a useful model to developing a BSER unit-level heat rate improvement work practice standards. A unit specific work practice needs to reflect the local conditions and the operating parameters we have outlined.

Gross vs. Net Heat Rate

Both gross and net heat rates are important and can be reported and properly identified. Unfortunately, many documents published do not clearly state if they are referring to gross or net heat rate. USEPA's Clean Power Plan analysis uses gross heat rate and USDOE generally reports net annual heat rates. USDOE also reports as tested full load net heat rates. Industry needs to report both to capture a full understanding of unit performance. If USEPA were to propose new rules for heat rate improvements RCEEW recommends that the Net Heat Rate be the baseline. USEPA should also consider the additional comments in this letter.

Reporting of net heat rate can show improvements in performance as EGUs implement operational improvements. EPRI has outlined operational improvements in their document "Range and Applicability of Heat Rate Improvements" and some utilities have started to make these improvements. Utilities are interested in overall plant performance; net power should be a key economic focus.

However, to measure the impact on performance of new rules, ELG for example, one needs to look at both the gross and net heat rates.

F-factor and Other Flow Measurements and CEMS in General.

Historically, stoichiometric calculations have been used to design and size combustion equipment and air pollution control systems. Numerous conference papers published compare flue gas volumes developed from established procedures such as ASME's Performance Test Codes to determine flue gas volumes and stack testing methods. Most reports comparing acceptance test results with stack CEMS, or the stack pitot tube method, show a 10-20% variation, and typically the Pitot tube provides higher gas volumes.

It is a relatively simple matter to calculate boiler duty (heat output) and boiler efficiency using the energy balance (formerly heat loss) method using typical plant, calibrated, instrumentation – heat input is then determined from boiler heat output divided by efficiency. Depending upon the quality of the feedwater/steam flow measurement the uncertainty in calculated fuel input is estimated to be in the 2-6% range.

The USEPA reference methods for flow rate determination (Methods 2, 2F, 2G, 2H) are not stringent in terms of precision, and results typically vary from documented calculated values. Even when Method 2F (3D velocity probe) is used to account for non-axial velocity vectors (yaw and pitch angles), the method specifications for field instrumentation can cause reporting of heat rate and emissions to be imprecise. This also applies to the 3D probe calibrations performed in the laboratory. These calibrations can have significant uncertainty depending on the number of calibration points and the accuracy of the lab instrumentation. EPRI's Program 77 (for CEMS) is currently investigating these issues in collaboration with NIST. Execution of in-situ traverses with 3D probes faces other difficulties including plugging.

At an NIST conference, Improving Measurement for Smokestack Emissions, held in June of 2017, NIST reported that CEMS measurement compared to USEIA Calculated CO₂ Emission for 2005 varied by -15% to +20%. They stated "distorted, swirling profiles: stack flows will have significant "installation effects" on flow meters". The Fc factor for some fuels, especially western fuels, is much more inconsistent than for eastern fuels. Moreover, many plants blend eastern and western fuels, which impacts the precision with the Fc factor. (Fc = fuel-specific carbon dioxide based F-factor, dry basis, from Method 19 [scf / 106 Btu])

The F-factor becomes more difficult to estimate with plants that blend fuels, especially those that blend PRB with bituminous, or those that regularly switch fuels, of which there are many. Dr. Staudt in his paper at the 2016 Mega Symposium showed a fairly wide variation in F factor for subbituminous fuels and less of a variation for bituminous fuels. Moreover, when you consider blending (especially PRB and bituminous, which have widely different F-factors), and the varying degrees of accuracy for blending between different plants, blending can introduce some real challenges for the F-factor method as the relationship between gas flow rate and heat input will vary too much for any single F factor to be useful. It would probably be impractical to have a "dynamic" F-factor that changes F-factor in the CEMS daily since that might impact the relative accuracy test audit (RATA).

Authors Quick and Staudt have also pointed out the significant variations between calculated emissions and emissions measured by F-factor and CEMs. As mentioned earlier, and repeated here for easier reference, Dr. Jeff Quick in Journal of the Air & Waste Management Association, 64(1):73-79, 2014 reported the following:

"Annual CO₂ emission tallies for 210 coal-fired power plants during 2009 were more accurately calculated from fuel consumption records reported by the USEIA than measurements from CEMS reported by the USEPA. Results from these accounting methods for individual plants vary by +/- 10.8%. Although the differences systematically vary with the method used to certify flue-gas flow instruments in CEMS, additional sources of CEMS measurement error remain to be identified."

Dr. Quick also reported that there are other issues related with the USDOE/USEIA reporting of data. In the same article he reported:

"Limitations of the USEIA fuel consumption data are also discussed. Consideration of weighing, sample collection, laboratory analysis, emission factor, and stock adjustment errors showed that the minimum error for CO₂ emissions calculated from the fuel consumption data ranged from +/- 1.3% to +/-7.2% with a plant average of +/- 1.6%. This error might be reduced by 50% if the carbon content of coal delivered to U.S. power plants were reported."

Dr. Staudt in his paper "Examination of Uncertainty in Heat Rate Determinations" presented at "MEGA" Symposium August 16-18, 2016, compared USEPA's Air Market Program Data (AMPD) with calculations based on USEIA data for 232 coal-fired plants. Dr. Staudt found the following:

- AMPD heat input and heat input estimated from USEIA Form 923 fuel use data are within 5% in only about 55% of the plants

- AMPD heat input and heat input estimated from USEIA Form 923 fuel use data are within 10% in only about 85% of the plants
- The maximum amount that AMPD was lower than that determined by Form 923 was 100%.
- The maximum amount that AMPD was greater than that determined by USEIA Form 923 was 34.3%

We have attached an additional analysis by Dr. Quick for USEPA's consideration.

It is clear that these two approaches to determine heat rate can have substantial differences. The USEIA Form 923 data is entered and submitted to USEIA each year. There is the risk of data entry errors. Also, there may be inconsistencies in the approach to measuring heating value of the fuel.

Calculations based on fuel consumption measurements is the standard method to count CO₂ emissions from stationary sources within the European Union, Emission Trading Scheme (EU ETS). Notably, where CO₂ tallies from CEMS are used, EU rules require annual verification of the CEMS measurements using results from fuel consumption calculations. The EU rules also allow a hybrid method where the measured carbon content of the flue gas is used with flue-gas flow volumes that are calculated from fuel consumption measurements.

USDOE/USEIA measurement of fuel consumption measurements for US power plants are collected in the USEIA-923 survey. The feasibility of using USEIA-923 fuel consumption data to calculate heat rate depends on the specific EIA-923 data elements that might be used; the amount and heating value of coal and other fuels are listed in three places in the USEIA 923 spreadsheet. For the amount of plant-level fuel the most comprehensive data are reported on the USEIA-923 "Generation and Fuels" page. For the coal heating values, the best data are listed on the "Fuel Receipts and Cost" page. However, for coal-fired plants <50 MW the delivered quality is not reported. For these plants it is best to use the coal quality (heating value, ash content, Sulfur content) reported with the "Boiler Fuel Data." There are also a few large power plants that do not report all coal shipment data. In these instances, the amount and quality of delivered coal is reported by a transfer station, which then distributes the coal to client plants. USEIA is aware of this and has been making good progress in recent years to reduce these "unreported distributions." The accuracy of measurements from commercial scales and stockpile surveys is well established. USEIA uses results from these measurements to confirm the reported coal consumption. Following are comments are some of the measurement methods for coal delivery and use.

Coal tons measured at delivery/custody transfer. The delivered coal ton measurements are reported on the "Fuel Receipts and Cost" page of the USEIA-923 spreadsheet. These measurements are made using commercial scales where the tons of coal delivered to power plants are measured to within $\pm 0.5\%$ (95% confidence) following a SI-traceable protocol; this protocol is mandated by state law in 49 of the 50 States. Note that state agencies follow the NIST method to certify the accuracy of these commercial scales.

Measurement of coal tons in the stockpile. These data are reported in section 4a of the USEIA-923 form but are not publicly released. As noted in section 4a, coal consumption must balance where: Consumption = Delivered coal, minus changes in coal stocks. Where periodic stockpile surveys show an imbalance, the correction is applied to the current month coal consumption. This can introduce significant error (bias) for the month when the correction is applied but improves the accuracy of the annual consumption tally. The best stockpile survey measurement possible is about $\pm 2\%$. However, Dr. Quick has reported the precision varies according to the nature of the stockpile and other factors, such that the error is typically near $\pm 3\%$, and as much as $\pm 5\%$.

Measurement of coal flow to the boilers. This information is reported each month on the "Generation and Fuels" and "Boiler Fuel Data" pages of the USEIA-923 spreadsheet. These measurements are difficult to ensure (verify) on a continuous basis. Possibly, some of these scales could be certified to meet commercial standards. However, many of the belts feeding power plant boilers are too steep and short to accommodate commercial-grade scales. Even where these scales

might be installed, their periodic calibration following the NIST handbook 44 protocol would require the belts to stop and the plant to necessarily shut down.

The accuracy of coal quality of measurements for coal delivered to power plant is also well established; see “Limitations of the USEIA Fuel Consumption Data” in <http://dx.doi.org/10.1080/10962247.2013.83> . These data are reported on the “Fuel Receipts and Cost” pages of the EIA-923 spreadsheet. Note also that measurements of the quality of coal in the stockpile are not reported in the USEIA data; such measurements are widely considered to be unreliable because it is rarely possible to collect a representative sample from a coal stockpile. Although USEIA collects and reports monthly coal quality values for coal fed to the boilers, the pedigree of the values is uncertain.

All the methods used to measure or predict flue gas flow rate have certain levels of uncertainty. In using ASME’s heat output method, improvement in the measurement of feed water flow is being investigated by ASME’s PTC-46. We also see where improvements can be made in USEIA’s reporting of annual heat rate.

Combined Heat and Power Plants

Combined heat and power plants (CHPs) play an important environmental, social, and economic role. In the future they can play a more significant position in emission reduction and economic development. There is no consensus definition of CHPs or method of reporting heat rate for CHPs. ASME would encourage USEPA to work with ASME and the USDOE Southeast CHP Technical Assistance Partnership at NC Clean Energy Technology Center (www.nccleantech.ncsu.edu) to develop a heat rate reporting system for CHPs. CHPs need to be in their own subcategory in any future rulemaking.

ASME’s Performance Test Code Committee PTC-46 Overall Plant Performance is working on definitions and heat rate measurement methods.

Summary

ASME RCEEW is pleased to have this opportunity to assist USEPA by addressing several of the technical inputs USEPA requested. We look forward to working with USEPA in addressing these issues as you develop your rulemaking.

There is opportunity for significant improvements in the measurement of flue gas flow rate and F-factors as USEPA moves forward in efforts to optimize heat rates. We believe that a “calibrated or certified F-factor” can be developed using a combination of the energy balance method using typical plant instrumentation. Heat input is then determined from boiler heat output divided by efficiency, and a modified RATA testing process. This should result in reduction of uncertainty and improve precision. One significant reason when employing the F-factors concept used by USEPA is that it provides hourly and daily information and RCEEW agrees it should be preserved.

RCEEW has provided technical responses to several of USEPA’s request for technical input. There are many factors that impact heat rate in EGUs including fuels, cycling and low load operations, ambient conditions, and the design of the plant. All these factors need to be addressed in a rulemaking related to heat rate improvements.

Sincerely,

Robert Sommerlad

Chair, ASME Research Committee on Energy, Environment, & Waste (RCEEW)

Attachments:

- Measuring Heat Rate at Fossil Fuel-Fired EGUs
- References

Members of the RCEEW Heat Rate Committee

Mr. Robert Sommerlad, P.E., Consultant, Chair RCEEW

Mr. Dave Wheeler, P.E., Clean Air Engineering, Inc.

Dr. Keith Kirkpatrick, McHale & Associates, Inc. Chair ASME PTC-46

Mr. Steve Scavuzzo, Babcock & Wilcox, Chair ASME PTC-4

Ms. Una Catherine Nowling, P.E., M.Sc. Black & Veatch

Dr. Jeffrey Quick, P.G. Utah Geological Survey

Dr. James Staudt, Andover Technology Partners

Dr. Tim Sharobem, Consultant

Mr. Mark Sankey, Mark R. Sankey & Associates

Mr. Anthony Licata, Licata Energy & Environmental Consultants, Inc. Heat Rate Subcommittee Chair

Determining the power plant (or unit) heat rate (Btu/kWh) requires measurement of the electric generation (kWh) and the heat input (Btu). The heat input can be determined in two different ways, namely: (1) according to the amount and quality of fuel burned reported to the DOE, or (2) according to the volume and composition of the combustion flue gas reported to the EPA. Figure 1 shows that the heat rates obtained by these two methods differ by $\pm 11\%$.

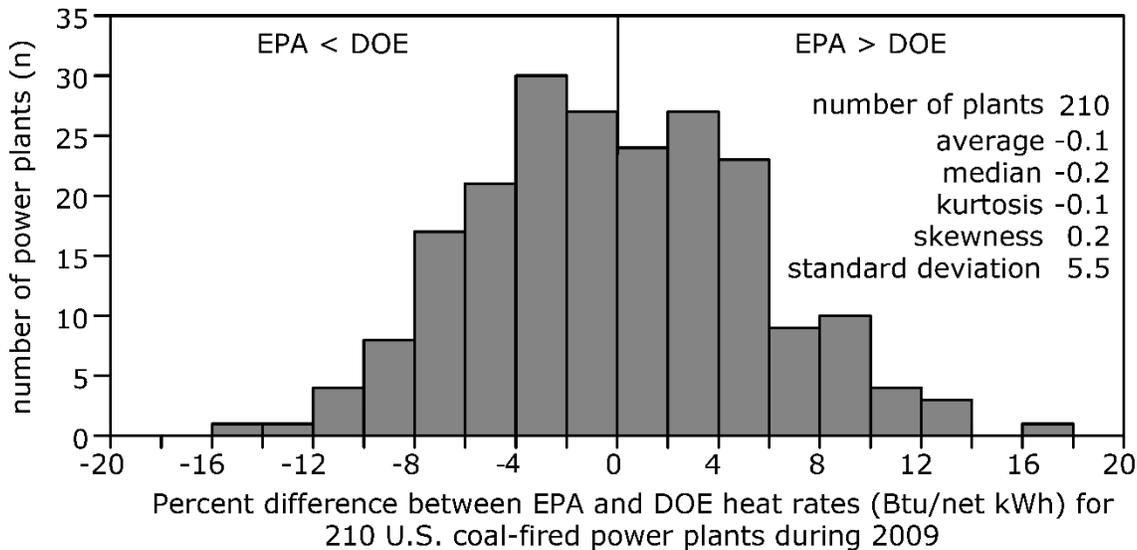


Figure 1. The differences between heat rates determined from flue gas measurements (EPA data) and fuel consumption measurements (DOE data) differ by $\pm 11\%$ (two times the standard deviation) for 210 U.S. coal-fired power plants during 2009. The percent difference was calculated according to: $100 \times (\text{EPA} - \text{DOE}) / \text{maximum (EPA or DOE)}$. Data are from Quick (2014, supporting information) and EPA (2018).

Examination of figure 1 shows that the differences are normally distributed (Anderson-Darling test statistic = 0.30, $P=0.60$) around a mean near zero. This distribution is consistent with random measurement error. Figure 2(b) shows attenuation bias (diminished slope and standard error) where the EPA heat rate is the independent variable that is used to predict the DOE heat rate. As noted by Hutcheon and others (2010), attenuation bias results from random measurement error associated with the independent variable. Accordingly, the heat rate is more reliably determined from the amount and quality of fuel reported by DOE, than the amount and composition of flue gas reported to the EPA. The minimum uncertainty of the DOE heat rate determination is near $\pm 1\%$, based on the uncertainty of the coal heating value determination ($\pm 0.8\%$ to $\pm 1.7\%$), sample collection error ($\pm 0.6\%$ to $\pm 1.4\%$), number of coal shipments (up to 300), and stockpile measurement error ($\pm 5\%$). Conservatively doubling the minimum DOE uncertainty to $\pm 2\%$, requires a corresponding EPA uncertainty greater than $\pm 10\%$ to explain the $\pm 11\%$ variation shown in figure 1. These results are consistent with Staudt (2014, 2017) who also found that the heat input reported by DOE was substantially more reliable than the heat input reported by EPA. Staudt (2016) compared 2014 EPA reported annual heat input for 232 coal-fired plants against EIA reported fuel data and found similar results as Quick (2014), except that in addition to random error around a mean near zero there was apparently systematic error, likely reporting errors, reflected in a small number of cases with very large differences (ie. “fat tail”).

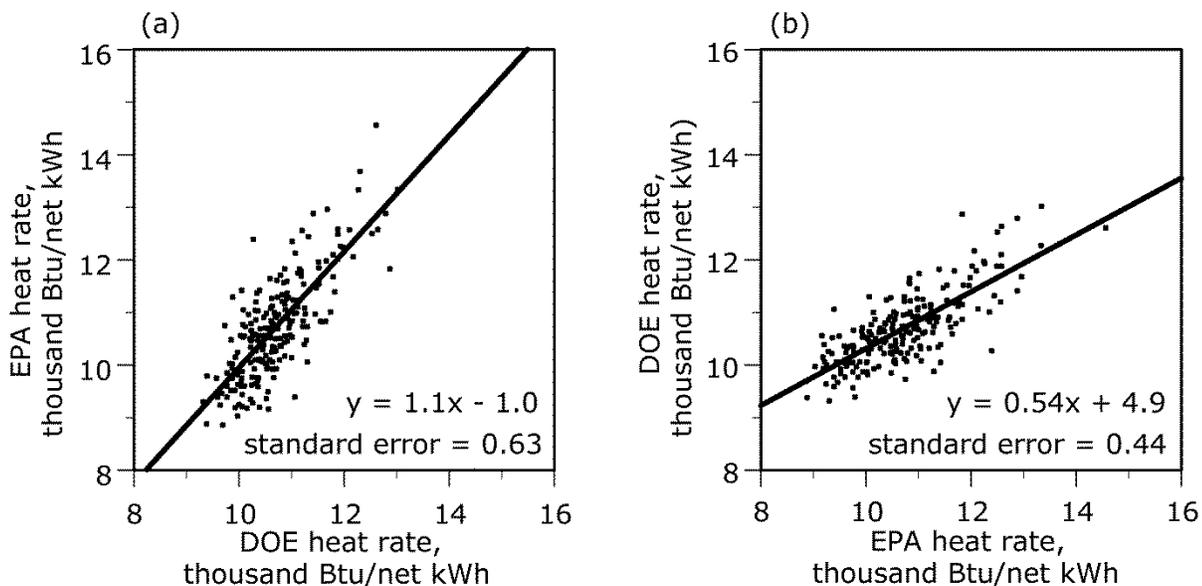


Figure 2. Attenuation bias due to EPA measurement error is shown in (b) where the EPA heat rate is used to predict the DOE heat rates. Points show annual (2009) plant-level heat rates. Data are from Quick (2014, supporting information) and EPA (2018).

As discussed above, the uncertainty of plant-level heat rates calculated from flue gas flow and composition is near $\pm 10\%$. Unit-level heat rates calculated from flue-gas flow and composition are less reliable. Seventy one of the 210 plants examined have only one CEMS system. Comparison of EPA and DOE heat rates for these 71 plants also shows a normal distribution of differences (Anderson-Darling test statistic = 0.26, $P=0.72$) and the same attenuation bias where the EPA heat rate is used to predict the DOE heat rate. However, the standard deviation of the differences for plants with only one CEMS system is 6.4, which indicates that the uncertainty of a single CEMS system is about $\pm 12\%$.

The better precision of the annual fuel-based emission tallies can be largely attributed to the reliability of commercial scales where the tons of coal shipped to power plants are measured to within $\pm 0.5\%$ following an SI-traceable protocol (NIST, 2012) in 49 of 50 U.S. States (NIST, 2014). Causes of the relatively poor precision of the EPA tallies are less certain, but factors related to the flue gas volume determination (for example, pitot tube type and calibration, asymmetrical flow in the stack, stack diameter measurement, and certification protocol for installed flow monitors) appear to be most important (Bryant and others, 2014, 2015; Johnson and others, 2015).

Less appreciated, is the error associated with the Fc factor (scf CO₂/MMBtu) which is used to calculate EPA heat input from the measured CO₂ volume in the flue gas (Staudt, 2016). Although Fc factors for coal can be calculated from the C, H, N, O, and S content of the coal, Fc factors are more commonly assigned according to the coal rank, where lignite, subbituminous, bituminous, and anthracite coals are assigned Fc factors of 1910, 1840, 1800, and 1970 scf CO₂/MMBtu respectively. Staudt (2016) calculated Fc factors and found that western coals had greater variation in Fc factor than eastern coals. Quick (2010) showed that for some western USA coals the EPA Fc factors introduced a $\pm 2.1\%$ uncertainty, which could be reduced 10 to 40% by using plant-specific Fc factors that are calculated from DOE data (coal tons, ash yield, S content, heating value, and county of origin). Additional data for commercial coal from the Eastern, Interior, and Gulf Coast provinces are needed to better evaluate the potential utility of plant-specific Fc factors. A practical consideration with regard to Fc factor is when plants blend eastern and western coals or change coals and the Fc factor reflected in the CEMS data acquisition system does not reflect the change in coal characteristics.

The uncertainty of heat rates for natural gas plants can also be evaluated by comparing results from EPA and DOE data. Figure 3 shows the differences between EPA and DOE heat rates for 559 power plants during 2013 where natural gas accounted for more than 90% of the plant fuel consumption. With

a few exceptions, both EPA and DOE calculate heat input to natural gas plants from the amount of natural gas consumed and the reported heating value of the gas. The use of the same calculation method explains the better agreement between the EPA and DOE heat rates for gas-fired plants (figure 3) compared to coal-fired plants (figure 1). Indeed, the EPA and DOE heat rates for gas-fired plants agree within $\pm 2\%$ for half of the plants (figure 3). Nonetheless, the agreement is less than what might be expected given that both the EPA and DOE heat rates were calculated for the same natural gas volumes and heating values. Moreover, the fat-tailed, non-Gaussian distribution in figure 3 indicates that systematic differences, rather than random measurement errors, are likely responsible for the larger differences. Lacking a Gaussian distribution, it is not possible to empirically estimate the uncertainty of the EPA or DOE heat rates for gas-fired power plants. Additional work to identify these systematic differences is required.

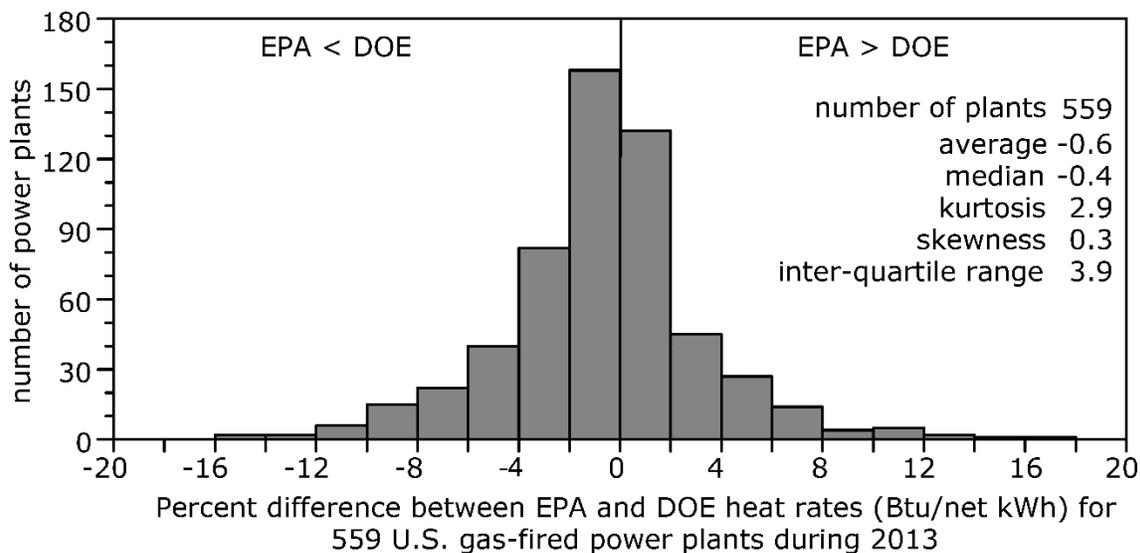


Figure 3. The differences between heat rates determined from flue gas measurements (EPA data) and fuel consumption measurements (DOE data), show a non-Gaussian (fat-tailed) distribution for 559 U.S. natural gas-fired power plants during 2013. The percent difference was calculated according to: $100 \times (\text{EPA} - \text{DOE}) / \text{maximum (EPA or DOE)}$.

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