How Reliable are GHG Combustion Calculations and Emission Factors?

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INTRODUCTION

The number of Greenhouse Gas (GHG) reporting programs and protocols is increasing every year. Many of these protocols rely on calculations or emission factors to quantify GHG emissions rather than direct measurement. Research has shown that the data validating the accuracy of some of these calculations and factors is incomplete or in some cases, entirely absent. This leads to questions regarding the reliability of the calculation approach to quantifying GHG emissions.

This paper examines the data comparing calculated CO_2 emissions from fossil-fueled boilers (primarily coal-fired utility boilers) versus actual measured CO_2. The focus is to examine the data quality resulting from the use of these two techniques, not to advocate for the exclusive use of one technique over the other. This comparison is done within the context of three GHG programs each with their own protocol. These are:

1) The European Union Emission Trading Scheme (EU-ETS)[1]

2) The proposed US Environmental Protection Agency GHG Reporting Protocol (EPA)[2], and

3) The Climate Registry's Electric Power Sector Protocol (TCR-EPS)[3].

The data show significant differences in results when using calculations vs. measurement to report CO_2 from combustion sources. This paper examines the data quality requirements in each protocol, presents examples from five actual plants, and discusses the ability of the third-party verification process to address the issue of data quality.

MAIN BODY

Most GHG reporting protocols recognize that the quality of data used to report GHG emissions varies. These protocols have developed quality levels or "tiers" that classify the quality of data submitted to the greenhouse gas program. A description of the quality tiers for the three programs referenced in this presentation is shown in Table 1. The tiers are presented in descending order of presumed quality.

Table 1. Quality tier levels for various greenhouse gas programs.

Proposed EPA		**EU-ETS***		**TCR-EPS (Draft)**	
Tier 4	Certified CEMS	Tier 4	1.5% uncertainty	Tier A	Certified CEMS or calculated from measured fuel carbon content
Tier 3	Calculated from measured fuel carbon content	Tier 3	2.5 % uncertainty		
Tier 2	Calculated from measured fuel heat content	Tier 4	5.0% uncertainty	Tier B	Calculated from measured fuel heat content and default carbon content
Tier 1	Default generic emission factors	Tier 1	7.5% uncertainty	Tier C	Default generic emission factor and default fuel heat content

*Note: Direct measurement (e.g. CEMS) is allowed only with permission.

In the EU-ETS program the direct measurement of GHG emissions can only be used with permission from the "competent authority" and only if comparison with calculated data shows equal or less uncertainty. It is important to note that uncertainty as it is used here has nothing to with accuracy (i.e. closeness to "truth" or lack of bias). The uncertainty calculations used in the EU-ETS program deal only with the precision or repeatability of the data.

The idea implicit in these tier structures is that the higher the tier level, the more accurate or reliable the data. The top tier, in effect, defines the "gold standard" of data quality. Based on the above comparison, it is clear that we have three differing approaches to defining this gold standard. As can be seen by Table 1, the US EPA believes that measured data represents the gold standard. The Europeans have taken a statistical uncertainty approach, but believe that calculated data represents the gold standard[4]. And The Climate Registry EPS Draft, again from Table 1, takes the position that the two are equivalent.[1]

Approaches to Determining CO_2 Emissions

So the question is who is right? We can begin to answer that question by first understanding the mechanics of each approach. Next we can look at data comparing the two approaches. And finally, we can look at the quality of the input data such as stack gas flow and fuel flow measurements (i.e. garbage in, garbage out).

[1] When the data from this report was presented to TCR, the response was to completely eliminate all quality rankings from the final version of the protocol. The TCR protocol is, therefore, the only GHG protocol of which we are aware that has no quality criteria. Anything goes. Essentially TCR's position is that all techniques are equally reliable. This of course means that data collected under this protocol is of unknown quality.

Direct Measurement Approach
The direct measurement approach relies on two pieces of input data to determine CO_2 emissions – stack concentration and stack gas flow. These are related to stack CO_2 emissions by the following equation:

$$CO_{2_{tpy}} = \frac{\text{tons } CO_2}{\text{volume gas emitted}} \times \frac{\text{volume gas emitted}}{\text{year}}$$

Eq. 1

This is simply a CO_2 concentration times a gas flow rate. There are many variations of this equation depending on the units used and the measurement intervals.

Each of these input values is measured by validated reference methods or performance specifications. The CO_2 concentration is measured by a certified continuous emission monitoring system (CEMS). The uncertainty of this measurement is typically <1%[5]. The gas flow rate may be measured either manually by accredited emission testers or by a certified gas flow CEMS. The uncertainty of this measurement is typically <5%[5].

Calculation Approach Using Fuel Use and Fuel Quality Data
The calculation approach does not directly measure CO_2 emissions. Rather, it relies on measurements of fuel flow and fuel carbon content to estimate CO_2 emissions based on combustion stoichiometry. These emissions are typically calculated as follows (example from TCR EPS):

$$CO_{2_{tpy}} = \sum_{i=1}^{12} Fuel_i \times CC_i \times 3.664$$

Eq. 2

Where:

$Fuel_i$ = The monthly mass of fuel combusted

CC_i = The monthly carbon content analysis

3.664 = conversion factor for carbon to carbon dioxide

In some versions of this approach, an additional oxidation factor is used to account for unburnt carbon. The carbon content of the fuel can be typically measured to <1% by ASTM D5373 or other consensus standard method. Most of the uncertainty of this approach is found in the measured fuel flow. Belt scales and gravimetric feeders used for coal flow rate measurement need constant maintenance and calibration and are in general considered unreliable[6]. Estimates of the uncertainty of data from this equipment are scarce but some have estimated that they can be as much as 20% in error[7]. If the carbon input to a boiler cannot be determined to within 20%, the carbon output (in the form of CO_2) can certainly not be determined more reliably.

The accuracy of coal scales or gravimetric feeders would be much higher if proper maintenance and calibration could be provided. However, because these scales are inline, they are in continuous use during plant operation requiring maintenance and calibration to wait until the plant is operating at a reduced load or during an outage. The drift in calibration during this time span can, in some cases, be several percent. This problem has been further intensified due to declining coal quality which necessitates units being run with all pulverizers operating to maintain the unit near its rated load.

Even when the plant takes great care, it is difficult to keep this gravimetric equipment within manufacturer's specifications. In one plant, coal mass flow measurements drifted by almost 5% in just 4 months[8]. Many plants have abandoned coal flow measurements entirely for critical process determinations such as heat input and instead rely on other process data (e.g. steam flow, drum pressure, etc.) sometimes in conjunction with thermodynamic modeling.

Another calculation approach for estimating CO_2 emissions uses the heat content (Higher Heating Value or HHV) of the fuel, as well as the mass of fuel consumed during a given reporting period. This approach requires the use of a generic emission factor (e.g. kg CO_2/Btu). Using this approach, CO_2 emissions are calculated as follows (example from TCR EPS):

$$\mathrm{CO}_{2tpy} = \sum_{i=1}^{n} Fuel_i \times HHV_i \times EF \times 0.001 \qquad \text{Eq. 3}$$

Where:

n	= frequency of heat content measurements over each year
$Fuel_i$	= The monthly mass of fuel combusted
$HHVi$	= Higher Heating Value (MMBtu/mass)
EF	= Default CO_2 emission factor (e.g. 93.46 kg CO_2/MMBtu for bituminous coal)
0.001	= Conversion factor for kg to metric tons

The shortcomings of this approach are similar to those for the carbon mass balance approach with additional uncertainty introduced by the use of a generic emission factor. The use of generic emission factors introduces additional uncertainty due to the following factors: 1) different ranks of coal, and regional differences (i.e. state-to-state variations) will produce different effluent concentrations thus different average CO_2 emissions from base assumptions; and 2) many low Btu coals found in the Powder River Basin in the United States may have significant natural limestone in its fuel's mineral matter, thus producing effluent CO_2 not addressed by the default CO_2 emission factor;).

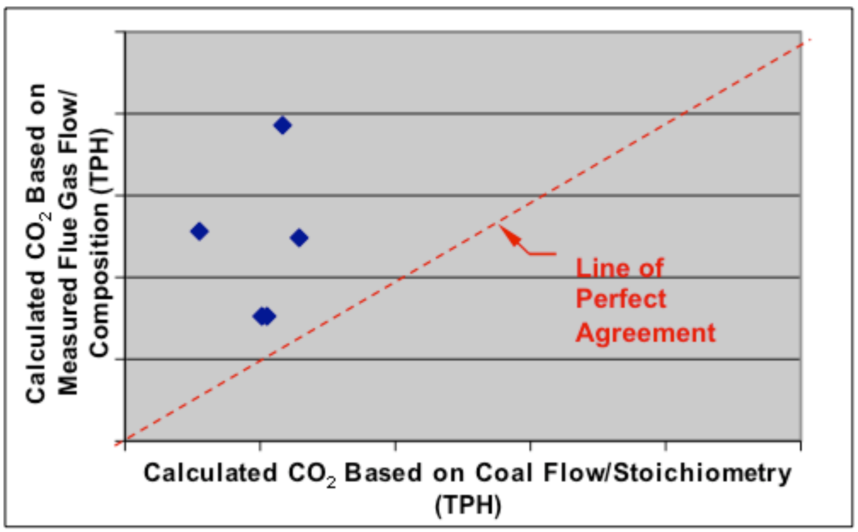
Comparison of Approaches

Clean Air Engineering has conducted an in-house survey of test data from units where both coal flow/composition and flue gas CO_2 emissions were both available. Our research has shown that there are significant discrepancies between measured and calculated CO_2 from coal-fired power plants. To illustrate these discrepancies, data from five plants are presented below. Note that the underlying base data for some of these plants have been redacted due to client confidentiality issues, however the results can still be clearly seen.

Plant # 1 – 500 MW bituminous-fired boiler

The calculated vs. measured CO_2 differed by as much as 15%. The calculated results use Eq. 2 based on carbon content. The results from a series of 5 tests are plotted in Figure 1. (Note: Actual values are not shown on the axes for reasons of client confidentiality).

Figure 1. Comparison of calculated vs. measured CO_2 from Plant #1



Even without the actual values, it can clearly be seen that not only are there significant differences between the two methods, but also, in this case, there is not even a correlation between calculated and measured CO_2. Note that the measured CO_2 is consistently higher than the calculated CO_2. This was a consistent pattern in all the data we reviewed.

This difference amounts to almost a half-million tons of CO_2 per year for this boiler based on an 80% capacity factor.

Plant #2 – >500 MW bituminous-fired boiler

Calculated vs. measured results differed by 26% in one test and 21% in a second test. Again, calculated results were lower. In this case, the calculated values used Eq. 3 based on the HHV of the fuel.

This difference amounts to 1,200,000 tons of CO_2 per year for this boiler based on an 80% capacity factor.

Plant #3 - <500 MW natural gas/fuel oil fired boiler

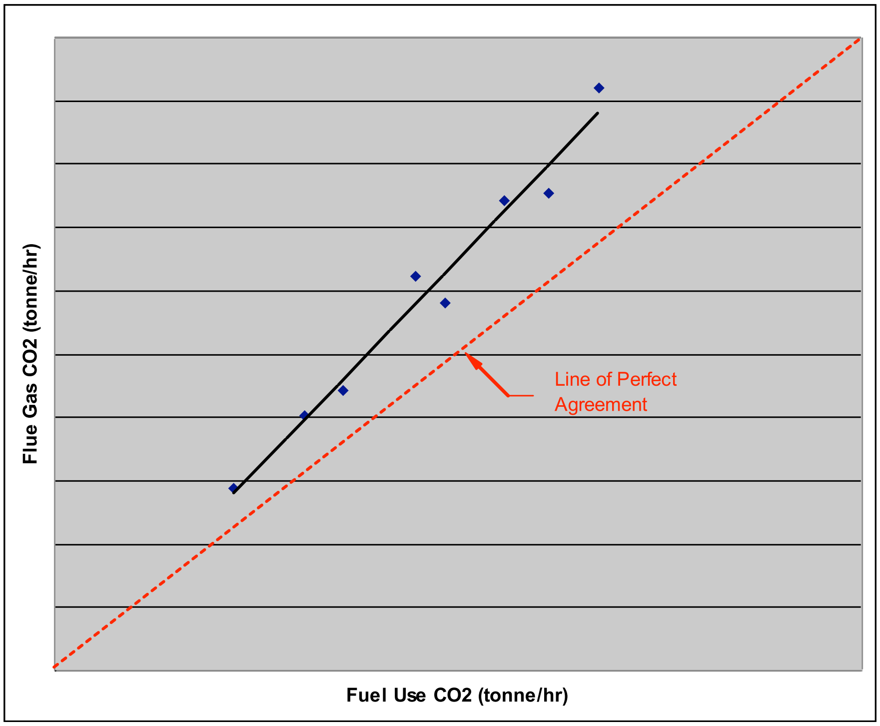
There has been some speculation that this problem is less pronounced in gas or oil-fired boilers. While the body of data is not as large for these boilers as it is for coal-fired boilers, some preliminary data indicates the problem may be just as severe. Table 2 shows data from natural gas and fuel oil combustion at a variety of loads.

Table 2. Differences in calculated vs. measured CO_2 from NG/FO boiler

Fuel Type	Load	% Lower than Direct Measurement
Natural gas	100%	-20.9
Natural gas	75%	-18.3
Natural gas	50%	-21.7
Natural gas	25%	-25.7
Fuel oil	100%	-30.7
Fuel oil	75%	-28.5
Fuel oil	50%	-33.0
Fuel oil	25%	-26.3

In this instance, we can see correlation between measured and calculated flow although the correlation is not 1:1. Figure 2, below, illustrates this. Note that the base data has been redacted due to client confidentiality concerns.

Figure 2. Comparison of calculated vs. measured CO_2 from Plant #3



Plant #4 - < 500 MW bituminous-fired boiler

The next example is interesting in that we found a much higher discrepancy calculated and measured values than was expected. These results are based on the carbon content of the fuel and are presented in Table 3.

Table 3. Differences in calculated vs. measured CO_2 from bituminous-fired boiler.

Test	% Lower than Direct Meas.
1	-73.1
2	-77.0
3	-73.2
4	-76.0
5	-64.7
6	-54.6
7	-65.6
8	-67.2

After some investigation, it was determined that the coal flow data was in error. Since the plant does not rely on coal flow data for process critical applications, this situation was not detected as part of routine plant operating procedures.

Plant #5 - 480 MW Sub-bituminous fired boiler

In this case, nine one-hour runs were conducted. The results are shown in Table 4.

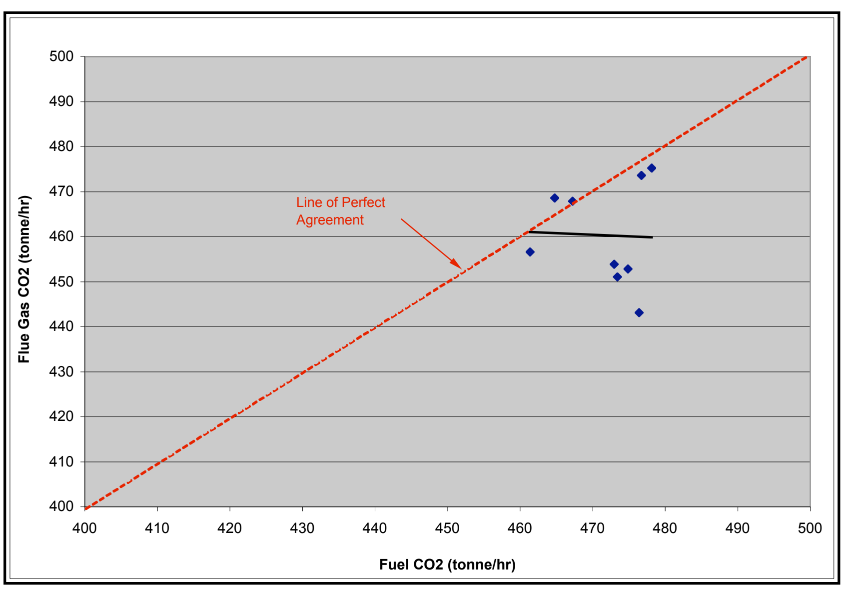
Table 4. Differences in calculated vs. measured CO_2 from sub-bituminous-fired boiler.

Run	Fuel CO_2 (tonne/hr)	CEMS CO_2 (tonne/hr)	% Difference
1	473.0	453.9	-4.1
2	478.1	475.3	-0.6
3	476.7	473.6	-0.7
4	461.4	456.6	-1.0
5	467.2	467.9	0.1
6	464.8	468.6	0.8
7	473.4	451.1	-4.8
8	476.4	443.1	-7.2
9	474.9	452.9	-4.7
Avg	**471.8**	**460.3**	**-2.5**

The results from this plant seem different in several respects from the previous four examples. First, in this case, the CEM data is lower than the calculated data rather than higher as in the previous cases. Second, the data is much closer -- only 2.5% difference between calculated and measured CO_2.

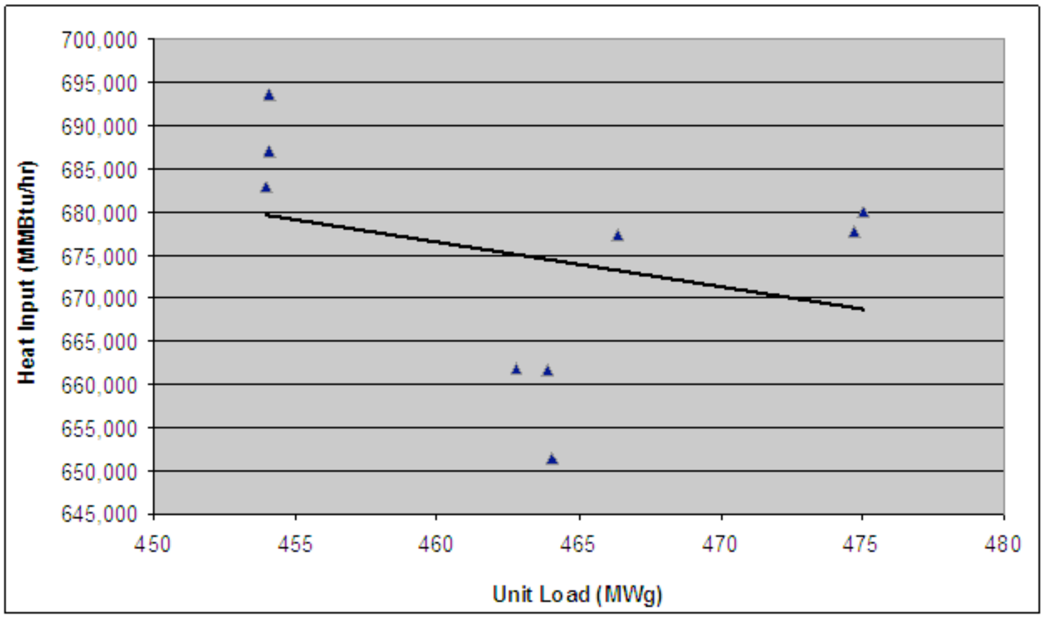
However, when the data is examined in more depth, one can see problems. First, there is no correlation between the calculated and measured CO_2 values. This can be seen in Figure 3.

Figure 3. Comparison of calculated vs. measured CO_2 from Plant #5



More importantly, when the heat input (based on coal flow) is plotted against unit load, the graph shows that as heat input increased, unit load decreased. See Figure 4.

Figure 4. Unit Load vs. Heat Input from Plant #5



This leaves us with two possible explanations:

1. The boiler is operating in violation of the First Law of Thermodynamics, or
2. There is something wrong with the coal flow data.

I leave it to the reader to determine which is more likely explanation. Upon further discussion with the plant, it was determined that coal flow is delivered with a rotary feeder and coal flow is measured by the number of revolutions per unit of time. To the best knowledge of plant personnel, this rotary feeder had never been calibrated and even if it had, the accuracy of such an approach is unknown. The plant does not rely on coal flow data for heat input determination, but instead calculates heat input based on steam parameters.

In summary, the calculated CO_2 values from this plant are essentially meaningless and the closeness of the calculated vs.measured values are purely coincidental.

A Broader Assessment

A recent report by Ackerman from the U. S. Geological Survey[9], looked at CO_2 emissions from 828 coal-fired power plants. Ackerman compared two databases – the Department of Energy, Energy Information Administration (DOE/EIA) database of fuel data from individual plants and the US EPA eGrid database that contains directly measured CO_2. In this study, Ackerman found that the average absolute difference between calculated and measured CO_2 was 17.1%. Overall, directly measured data was higher than calculated data.

The results of this broader study confirm what we have found in the smaller group of plants that we have examined – there are consistent and significant differences between calculated and measured CO_2 from large industrial and electric utility boilers.

A Word About Gas Flow Measurement

As mentioned above, it is necessary to measure stack gas flow in order to determine the CO_2 mass emission rate (e.g. tons/yr). Some critics of the measurement approach make the claim that stack gas flow measurements are inaccurate when swirling or cyclonic flow is present. As evidence, they cite studies from the Electric Power Research Institute (EPRI) and others. What they fail to state is that these studies were performed almost two decades ago. Furthermore, as a result of these studies, U.S. EPA established new test methods (i.e. Methods 2F, 2G and 2H) that addressed this inaccuracy.

Virtually all electric power plants in the U.S. are subject to the Acid Rain emission trading program which requires measurement of stack gas flow to determine mass emissions of SO_2 and NOx. Since the participants in this program must buy and sell credits under this program, flow is money. Accurate gas flow measurement is a key concern for these plants. Needless to say, there is great attention focused on the reliability of these measurements.

What Does This Mean?

It is clear based on available data, that the two techniques – calculated and measured – produce significantly different results. They cannot be equivalent as TCR claims in the Draft Electric Power Sector Protocol. The question then becomes – "Which one is right?"

This question can be answered by examining the confidence one has in the reliability of the data from each technique – in other words, the quality of the data. For reliable data, we expect the quality to be both known and documented.

Table 4 shows the differences in data quality between calculated and measured data. The calculated data evaluation uses the TCR Draft Electric Power Sector Protocol specifications.

Table 4. Comparison of data quality between calculated and measured CO_2 data

Measured Data	**Calculated Data**
NIST traceable calibrations on all equipment	No calibrations required on any equipment
Periodic QA/QC of the measurement system	No QA/QC required at any time
Validated test methods used	Unvalidated sampling procedures used even when validated procedures are available
Accredited test personnel often with state observation of testing	No personnel competency requirements and no oversight. No requirements for competency of laboratories performing analysis.
Data of known and documented quality	Data of unknown and undocumented quality

The credibility of any reporting program depends on the reliability of the data reported. From the data presented in Table 4 and elsewhere in this report, it is evident that direct measurement results in reliable data that can be confidently reported. While both the U.S. EPA and EU-ETS protocols require known quality and reliability (at least in the top tier data), the calculation approach taken by TCR produces data of unknown quality and reliability.

A word should be said here regarding the European reporting protocol – EU-ETS. As described above, the EU-ETS protocol also has a bias toward calculated data (to which these authors take issue). However, the European approach requires that data reliability and quality be documented. For example, under EU-ETS the uncertainty of coal flow data must be determined and reported. The degree of uncertainty dictates the quality tier of the data. This is worth noting -- the EU-ETS recognizes that different sets of calculated results, <u>even when using the same calculations</u>, may have different levels of quality depending on the quality of input data. This contrasts sharply with the TCR approach which lumps all calculated data together as equivalent quality with no thought whatsoever of the quality of input data.

What About Verification?

It has been argued by some that the requirements for third-party verification contained in most reporting protocols will address this problem and ensure reliable data. This argument can be addressed in two parts. First, if the underlying reporting protocol does not require the reporter to provide information on data quality, there is no information for any third-party to assess. When this issue was raised with TCR, the response was that the role of the verifier was simply to ensure that the reporting protocol had been followed and if the calculation methodology used by the reporter was consistent with the protocol, that is all the verifier need be concerned with. Obviously under this scenario, the verifier is bound strictly by the protocol and plays no role in independently assessing data quality and reliability.

Second, the technical aspects of the measurement process are not addressed in verifier training requirements. There is at least one organization that currently offers "certification" of third-party verifiers. One of the authors of this paper has taken and passed this certification exam and can report that not one single question addressed the verifier's knowledge of CO_2 or other GHG measurement issues. ANSI is currently operating a pilot program for verification bodies. The authors of this paper are participating in this pilot and can report that ANSI has no specific requirements that verifiers be knowledgeable about the measurement of CO_2 or other GHGs. Each of these organizations focuses exclusively on the accounting aspects of GHG reporting and ignores the technical aspects. If a GHG reporting body does have a third party verifier that is knowledgeable about measurement issues, it is by coincidence, not by design.

While the verification process may play an important role in verifying ownership of GHG emissions, it plays very little, if any, role in assuring the reliability of the reported emissions if reliability is not addressed specifically in the reporting protocol.

To Prove the Case for Calculation…

Despite the tenor of this paper, it is not the intention of the authors to argue for the exclusive use of direct measurement over calculations. We believe that the calculation approach has its place. This paper presents an argument based on the data quality of the two approaches focusing on the TCR Draft Electric Power Sector Protocol. We are not opposed to the use of calculations if they are presented with data to support their reliability.

To prove the case for calculation, there are two requirements:

1. Show that the input data (e.g. fuel flow, sampling, analysis) are reliable and repeatable in real-world situations; and,
2. Explain the low bias in calculated CO_2 data.

The first requirement is achieved with QA/QC for the input data. In particular, the following are required:

1. The measurement process must be defined.
2. Those using the measurement process to generate data must be trained.
3. Measurement equipment must be calibrated to NIST traceable standards
4. The calibration must be checked on a periodic basis to ensure continuing reliability
5. Laboratories used for fuel analysis must be accredited
6. Only validated sampling and analysis methods (e.g. ASTM, ASME) must be used.
7. A written quality assurance plan must be generated
8. Adherence to the quality assurance plan must be documented

These are the same requirements that are already in place for those generating measured data. If a claim for equivalency to measured data is to be made, it can only be made once the quality of each dataset is known.

The second requirement may resolve itself once good QA/QC is achieved for the calculated data. If not, this issue must be investigated. If significant differences remain, it is certainly not possible to claim the two approaches are equivalent.

Other Issues

None of the three protocols take recent technological advances into consideration that could improve the overall reliability of GHG emission data. For example, while all protocols reference Continuous Emission Monitoring Systems (CEMS) for direct measurement, none mentions the possibility of using Predictive Emission Monitoring Systems (PEMS). In the U.S. PEMS are subject to the same rigorous QA/QC requirements as CEMS. In fact, U.S. EPA has recently finalized a Performance Specification that establishes strict PEMS performance criteria[10]. While PEMS are not suitable for every application, allowing the use of PEMS where appropriate may provide some plants with a means of generating reliable data without the need for a CEMS.

Both TCR and EU-ETS rely on fuel flow to determine the boiler heat input. As stated above, many plants are moving away from this approach due to the lack of reliability in fuel flow data. These plants are using other process parameters in combination with thermodynamic modeling to calculate heat rate (See, for example, References 7 and 11) which can, in turn, be used to quantify CO_2 emissions. None of the three protocols allow this approach, although it is potentially more accurate than the fuel flow measurement approach. It is our belief that thermodynamic modeling for heat input coupled with a site-specific CO_2 emission factor determination (i.e. no use of generic factors) could potentially provide data rivaling a CEMS in reliability.

Summary

The data are clear and convincing that significant differences exist between calculated and measured CO_2 emissions from power plants. This fact alone argues against any presumption that these two techniques are equivalent as claimed in the TCR Draft Electric Power Sector Protocol.

The conflicting presumptions between the EPA Protocol and the EU-ETS regarding which approach is more reliable, can only be resolved if the data quality of each approach is known and documented. EPA has chosen direct measurement as the more reliable approach based on over a decade of experience in emissions trading. While the EU-ETS approach contains an unfortunate bias against direct measurement, the structure of the program with its requirement to ascertain and report the quality of all input data, at least gives measurement a chance to be utilized. However, as long as significant differences exist, it will be difficult to implement a measurement approach in Europe due the requirement to validate the measurement against calculated data.

It is critical that GHG reporting protocols pay as much attention to the quality of the actual GHG emission data as they do to the accounting aspects of the GHG program. To use a financial analogy, it doesn't matter how good your accounting system is -- if you are dealing with sub-prime assets, you're still broke.

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