

ADDRESSING MEASUREMENT UNCERTAINTY IN POWER PLANT AIR QUALITY PERMITTING AND ONGOING REGULATORY COMPLIANCE

by

Joseph J. Macak III
Principal Consultant
Mostardi Platt ~~Environmental~~
~~1520 Kensington Drive—Suite 204~~888 N. Industrial Drive
~~Oak Brook~~Elmhurst, Illinois ~~60523~~60126

Phone: (630) 993-2127 Email: jmacak@mostardiplattenv.com jmacak@mp-mail.com

ABSTRACT

Ongoing regulatory compliance with emission limitations imposed in air quality permits continues to be a major problem for fossil fuel-fired power plants. As emission limitations become more stringent, it is essential that measurement uncertainty be appropriately factored into the air quality permit during the permitting stage, and subsequent permit modifications. Addressing the issues early will help avoid compliance monitoring problems in the future. Too often sources, in a rush to obtain an air permit quickly, accept permit limits that will inevitably result in non-compliances in the future.

This paper addresses measurement uncertainty for both combustion turbine power plants and coal-fired power plant boilers. A strategy for dealing with the various sources of uncertainty will be presented. Air pollutants evaluated will include nitrogen oxides, sulfur dioxide, carbon monoxide, volatile organic compounds, and particulates. Topics to be covered include fuel flow measurements, stratification in the exhaust gases, accuracy of calibration gases, accuracy of analytical instruments, variability in fuel composition, effect of atmospheric conditions on emissions, control equipment efficiency, impacts of control equipment on emissions or other air pollutants (i.e., control equipment for one pollutant may alter the emissions for another air pollutant), operating margin, operating ranges, averaging periods, and manufacturer's emission guarantees.

Environmental engineers need to understand the complexities related to permit limits in order to operate with sufficient operational flexibility.

INTRODUCTION

The construction of a new power plant requires an extensive permitting process called Prevention of Significant Deterioration (PSD) and/or Non-Attainment New Source Review, depending upon the status of the ambient air quality in the area of the proposed project. Although it is beyond the scope of this paper to discuss the permit application process, this paper addresses

one of the essential components of the permit application—emission rates. As part of the permitting process, sources must demonstrate that they are using the Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) in which they are compared to other emission sources in their source category (e.g., natural gas-fired combustion turbines). In the rush to obtain an air permit, too often sources agree to emission rates that cause compliance trouble after the source becomes operational.

Once a major emission source becomes operational, the source must operate under a Title V operating permit which requires continuous compliance to all permit conditions, and requires a semi-annual or annual compliance certification by a designated representative certify under penalty of law that the submittal is accurate and complete. Furthermore, any deviations from permit conditions must be fully documented as possible exceptions to compliance. Typical certification language is:

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gathered and evaluated the information submitted. Based on my inquiry of the person or persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

The emission rates for permit applications generally come from manufacturer's performance data. For example, combustion turbine engine performance data is provided at various ambient temperatures and load conditions, albeit at typical (but not worst case) humidity and barometric pressures. A sample profile for mass emissions and concentration (ppmvd at 15% O₂) is given in Figure 1. This figure shows that while the concentration limit (often used as the BACT or LAER) limit stays constant, the mass emissions vary as a function of temperature.

The engine and emissions performance data is generally warranted by the manufacturer for those specific conditions and fuel supply, and is too often used directly in permitting without adjustment for measurement uncertainty, fuel variations, and changes in meteorological¹ conditions.

Continuous emissions monitoring (CEM) systems for combustion turbines and boilers are generally extractive systems. Extractive systems are either straight-extractive or dilution-extractive systems. For gas and oil fuels with lower emission rates, monitoring is typically dry-based straight-extractive whereby flue gas samples are pulled continuously from the stack or duct, filtered, transported, conditioned (i.e., dried) and presented to a gas analysis system. Gas concentrations are measured, recorded and stored as data. The data is used to generate reports,

¹ Note: ambient humidity and temperature will affect emission rates from combustion sources, especially with combustion turbines. It is beyond the scope of this analysis to examine meteorological effects on the emission data. It is assumed that emissions data used for this analysis utilizes worst case meteorological conditions for permitting. This paper addresses the measurement and uncertainty due to the calculation inputs of the various input parameters.

alarms or control some aspect of the boiler operations. Dry-basis straight extractive systems offer the advantages of choosing the most appropriate analysis technique for the desired components and concentration ranges.

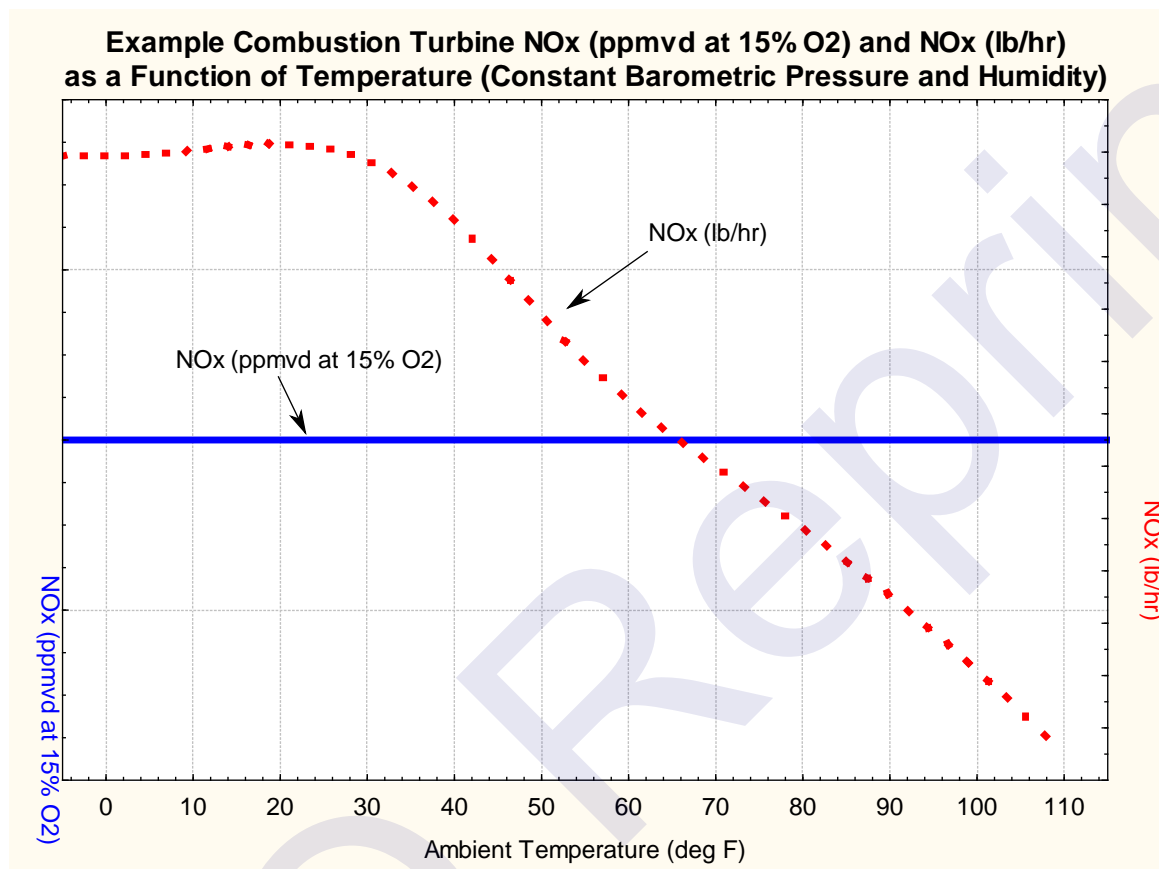


Figure 1. Example NO_x Emission Profile Across The Ambient Temperature Range.

The layout of a typical extractive CEM system is shown in Figure 2.

Dilution extractive systems are more common for solid fueled boilers such as the large coal-fired boilers used in the power industry. The flue gases are diluted 25:1, 50:1, 100:1, or even 200:1 with instrument air prior to measurement with no requirement for gas conditioning before analysis. Therefore, the gases are analyzed on a wet-basis requiring no correction for moisture content. After measurement by the various analyzers, the gas concentrations are multiplied by the dilution ratio to get back to the original concentration.

An advantage of a dilution-based system for a coal-fired boiler is that these units typically utilize flow monitoring for the calculation of mass emission rates. Measurement of both gaseous components and flue gas flow rate is on a wet-basis, so calculations can be completed without regard to moisture content in the flue gas.

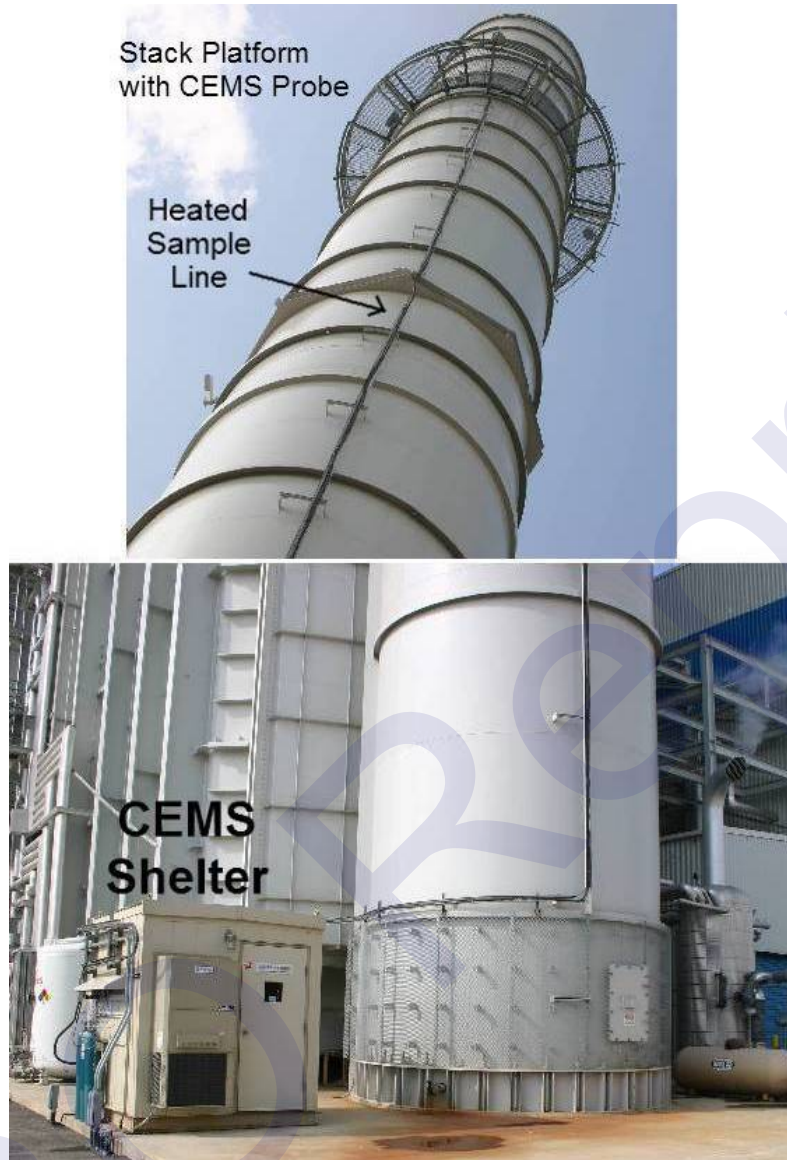


Figure 2. Typical Straight-Extractive Continuous Emissions Monitoring System.

To calculate emission rates from dry-based extractive systems (e.g., combustion turbine plant), the monitored pollutant concentration (ppmvd ... parts per million by volume on a dry basis) also requires a diluent (oxygen in dry based systems, carbon dioxide in wet based dilution systems) to calculate the emission rates in lb/million Btu. For combustion turbine plants that utilize clean fuels of a consistent composition, and can accurately monitor fuel flow, the sources may calculate the mass emission rate (lb/hr) by multiplying the emission rate in lb/million Btu by the heat input (million Btu/hr). For dilution-based coal-fired boiler applications, the mass emission concentration is determined along with the mass flow using a flow monitor, and the mass emissions are calculated directly.

An example calculation for NO_x emissions for a combustion turbine follows. To calculate the NO_x emission rate in lb/million Btu (HHV) from the monitor data, the following equation derived from 40 CFR 60, Appendix A, Method 19, is used:

$$(A) \text{ NO}_x \text{ (lb / million Btu)} = \frac{(\text{NO}_x \text{ (ppmvd)} * F_d * K_{\text{NO}_x} * 20.9)}{(20.9 - \% \text{ O}_2, \text{ dry basis})}$$

where:

NO_x (ppmvd) = NO_x concentration from continuous analyzer

F_d = Dry basis fuel factor equivalent to 8710 dscf/million Btu for natural gas (EPA default factor, or fuel specific equivalent)

K_{NO_x} = Conversion factor for ppm (NO_x) to lb/scf, which is equivalent to the value 1.194E-07 for NO_x

O₂ = Percent by volume of oxygen as measured on a dry basis with continuous analyzer.

To calculate fuel heat input to the combustion turbine, fuel flow (kscfh) is monitored and a direct calculation of heat input is performed.

$$(B) \text{ Heat Input (million Btu/hr)} = \text{fuel flow} \left(\frac{\text{kscf}}{\text{hr}} \right) * 1015 \left(\frac{\text{Btu}}{\text{scf}} \right) * 1000 \left(\frac{\text{scf}}{\text{kscf}} \right) * 10^{-6} \left(\frac{\text{million Btu}}{\text{Btu}} \right)$$

To calculate lb/hr, the lb/million Btu values are multiplied by the fuel heat input to the boiler (million Btu/hr) as follows:

$$(C) \text{ NO}_x \text{ (lb/hr)} = \text{NO}_x \text{ (lb/million Btu)} * \text{Heat Input (million Btu/hr)}$$

The dry basis fuel factor (F_d) in equation (A) can be adjusted from the default version using 40 CFR 60, Appendix A, Method 19, using the following equation:

$$(D) F_d = 10^6 * [3.64(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)] / \text{GCV}$$

SOURCES OF ERROR AND UNCERTAINTY

Using NO_x emissions from a natural gas-fired combustion turbine as an example, the following looks at the various sources of error and uncertainty related to the calculation of NO_x emission rates (lb/hr).

NO_x Measurement – The accuracy of the NO_x analyzer is typically +/- 1 percent of scale, plus the accuracy could be skewed based on the accuracy of the NO_x calibration gas (often +/- 2 %). If the analyzer's calibration gas is actually 1 ppm lower than the published certificate value, the NO_x CEMS will be reading approximately 1 ppm higher when it begins to read stack gas versus calibration gas.

Oxygen Measurement – The accuracy of the O₂ analyzer is typically +/- 0.25% O₂, plus calibration gas is also used for daily calibrations. Similar to NO_x, any error in the calibration gas will translate into an erroneous calibration and subsequent O₂ readings in the stack gas.

Fuel Flow Meter – A fuel flow meter must be accurate across the full operating range, and the stated accuracy is generally +/- 2.0 or 2.5% of range if they are maintained properly. The readings must be temperature and pressure compensated.

Heating Value in the Fuel – Using fuel flow readings in the CEMS, the software calculates heat input (million Btu/hr) using a fuel heating value (Btu/scf). This heating value is typically a constant entered on a monthly basis, although the heating value actually varies throughout the month by approximately +/- 20 Btu/scf. A fuel controller will adjust as necessary to ensure there are adequate Btu's of fuel as called upon by the process control computer, so if the heating value actually drops below the stated value in the CEMS software, the fuel flow reading to the CEMS may be higher than expected as the controller asks for more fuel to compensate for lower Btu's in the fuel supply.

Fuel Factor F_d – As shown in Equation (C), the dry basis fuel factor, F_d , can be calculated from the fuel analysis data. Just as the fuel heating value can vary, so to can the fuel factor. Use of a skewed fuel factor will throw off the calculation of the emission rate (lb/million Btu), and thus, affect the calculation of mass emissions, lb/hr.

Performance Data – The engine performance and operating data provided by manufacturer's may vary based on whether or not the data is used for warranty purposes, for permitting purposes, or for information only. The performance data will be subject to some degradation over time as the unit ages, thereby having the potential to affect the emissions data.

Stratification in the Stack – Emissions monitoring in a stack occurs through an extractive probe, approximately 3 to 5 feet inside the stack. Emissions testing by a testing contractor is more accurate, extracting samples from several locations in the stack. Data has shown that the concentration profile across the stack can vary from a few tenths of a ppm, to several ppm, depending upon the type of source, monitoring location, stack diameter, and flow characteristics.

Coal-fired sources generally have even more stratification across the stack due to the large stack diameters involved, and more variability in the combustion process.

In general, with proper engineering, design, operation, and maintenance, the CEM systems currently being used in industry today are reliable. But some of the other sources of bias and system uncertainty that should be considered when developing emission rate margins include:

- Probe location
- Contaminants in the flue gas and blinding (probe tip gets sealed)
- Condensation (may affect gas concentrations)
- Analyzer flow rates (sample flow rate through the analyzers could vary outside specs, resulting in over or under reporting of results)
- Instrument drift
- CEM shelter temperature variations
- Audit gas injection pressurization
- Leakage in the CEM system
- Vibration
- Moisture (in dry based systems)
- Gas adsorption and absorption

ANALYSIS OF UNCERTAINTY

Regulators require compliance with published permit limits, and generally allow rounding to the units of the permit limit. For instance, if a permit limit is 9 ppmvd at 15% O₂, a value of 9.4 ppmvd @ 15% O₂ would be considered in compliance. However, if the permit limit was listed as 9.0 ppmvd @ 15% O₂, the 9.4 value would be out of compliance. The same holds for mass emissions in lb/hr.

The controlling factor in an air permit for a combustion turbine is generally the concentration limit, which has been defined as the BACT or LAER limit in the permit. While controlling to the concentration limit, a source is not allowed to simply meet the concentration limit while at the same time exceed the mass emission limit.

To evaluate the uncertainty in the mass emission calculation, an analysis was conducted for 100,000 data runs of the emission calculation. The set-up of the data file is given in Table 1. The study examines how much uncertainty could be found in a 9 ppmvd NO_x emission concentration, with 14.5 % O₂, a fuel factor of 8685, fuel flow of a reported 1800 kscfh, and fuel heating value of 1015 Btu/scf. The reported +/- values are representative of the expected ranges of uncertainty that this particular combustion turbine source will experience during its operation.

Table 1. Analysis Conditions for CEMS Emission Calculation.

	Actual Value	+/- Value	Minimum	Maximum	Std. Dev.
NO _x	9	1.25	7.75	10.25	0.417
O ₂	14.5	0.75	13.75	15.25	0.250
Fuel Factor, F _d	8685	25	8660	8710	8.333
Fuel Flow, kscfh	1800	30	1770	1830	10.000
Fuel Heating Value, Btu/scf	1015	20	995	1035	6.667
Calculated by CEMS					
Heat Input (million Btu/hr)	1827		1761.2	1894.1	
NO _x (lb/million Btu)	0.03048		0.02342	0.03943	
NO _x (lb/hr)	55.68		41.25	74.69	

The column labeled “actual value” indicates the value that would be calculated by the manufacturer—0.03048 lb/million Btu and 55.68 lb/hr for the 9 ppm NO_x case. Assuming all uncertainty worked towards the minimum and maximum directions, the calculated emission rate could drop to as low as 41.25 lb/hr (74.1% of expected), or as high as 74.69 lb/hr (134.14% of expected). However, the likelihood of all uncertainty working towards one direction or the other is quite remote. Therefore, one must decide how much margin should reasonably be applied to the mass emission rate to ensure that ongoing compliance will not be affected by measurement uncertainty.

Using *Statistica* Release 7.1, a dataset of 100,000 cases of CEMS calculation runs were produced using the RNDNORMAL function, using the standard deviations from Table 1. The values were then added to the Actual values for each parameter. For instance, to generate normally distributed NO_x concentrations around the actual value 9 +/- the uncertainty, the variable command was:

$$\text{NO}_x (\text{case } 1 \dots 100,000) = \text{RNDNORMAL}(0.417)+9$$

Similar variables were generated for the other calculation input parameters, and then the heat input, NO_x (lb/million Btu), and NO_x (lb/hr) values were calculated for each case.

Table 2 shows the descriptive statistics for each of the values, and the histogram of Figure 3 shows that the NO_x (lb/hr) values were normally distributed. Similar histograms were generated to show that all input parameters were also normally distributed.

Figure 4 shows the range of correction factors that could be used to adjust the mass emission rates to reflect the various degrees of uncertainty (i.e., percentile level). As shown in Figure 4, the 90th percentile correction factor is a nominal 1.09, and 1.11 for 95th percentile.

Table 2. Descriptive Statistics of Input and Calculated Parameters.

Parameter	# of cases	Mean	Median	Min	Max		
NO _x (ppmvd)	100000	9.00	9.00	7.09	10.89		
O ₂ (% , dry)	100000	14.50	14.50	13.47	15.55		
F _d	100000	8685.0	8685.0	8649.4	8720.1		
Fuel Flow (kscfh)	100000	1800.0	1800.0	1757.6	1841.8		
Fuel Heating Value (Btu/scf)	100000	1015.0	1015.1	985.4	1045.4		
NO _x (lb/million Btu)	100000	0.0305	0.0305	0.0232	0.0401		
Heat Input (million Btu/hr)	100000	1827.1	1827.0	1758.0	1894.9		
NO _x (lb/hr)	100000	55.77	55.69	42.14	73.96		

Parameter	# of cases	Percentile Values					
		65%	75%	80%	95%	99%	99.70%
NO _x (ppmvd)	100000	9.16	9.28	9.35	9.69	9.97	10.15
O ₂ (% , dry)	100000	14.60	14.67	14.71	14.91	15.08	15.18
F _d	100000	8688.2	8690.6	8692.0	8698.8	8704.5	8708.0
Fuel Flow (kscfh)	100000	1803.8	1806.8	1808.5	1816.5	1823.5	1827.7
Fuel Heating Value (Btu/scf)	100000	1017.6	1019.6	1020.7	1026.0	1030.4	1033.2
NO _x (lb/million Btu)	100000	0.0312	0.0317	0.0321	0.0337	0.0351	0.0360
Heat Input (million Btu/hr)	100000	1833.1	1837.7	1840.3	1853.0	1863.6	1871.0
NO _x (lb/hr)	100000	57.01	58.02	58.61	61.57	64.17	65.75

COAL-FIRED APPLICATIONS

For coal-fired boilers, the same issues relating to monitoring uncertainty are present, only magnified. The use of continuous flow monitoring devices have the most uncertainty, and quite often the relative accuracy comparison of flow monitoring data to emissions testing flow traverses shows that significant adjustment may be necessary to get the monitors back into a valid range.

To alleviate some monitoring concerns, many sources utilize alternative monitoring of sulfur dioxide (SO₂) through fuel sampling/analysis and fuel consumption. These facilities calculate SO₂ emission rates from fuel flow, fuel heating value, and fuel sulfur contents. Since the molecular weight of sulfur is 32, and the molecular weight of sulfur dioxide is 64, every pound of sulfur contained in the fuel is theoretically converted to two pounds of SO₂. Therefore, to determine daily and annual SO₂ emissions using fuel sampling and analysis, representative fuel samples can be collected and analyzed daily.

Direct emission measurements of SO₂ at coal-fired units with SO₂ analyzers, in conjunction with exhaust flow rate monitors, will often result in SO₂ emissions (lb/hr) that are significantly higher than the theoretical values calculated from fuel sampling and analysis. This discrepancy is typically related to inaccuracies in continuous exhaust flow measurement techniques, rather than the SO₂ analyzers. For example, if the fuel sulfur content of the coal supply is 0.65% by weight,

with a heating value of 9,650 Btu/lb (HHV), a heat input of 3300 million Btu/hr would result in a maximum emission rate of 4,446 lb/hr (using 100% conversion of sulfur to SO₂). Assuming the actual sulfur conversion rate (S→SO₂) was 97%, the corresponding emission rate would be 4,313 lb/hr. If the CEM system and exhaust flow rate monitor were operating without error, the measured SO₂ emission rate should agree with the 4,313 lb/hr rate determined from the fuel analysis. But if the exhaust flow monitor was reading 10% high, the CEM system would erroneously calculate an SO₂ emission rate of 4,744 lb/hr.

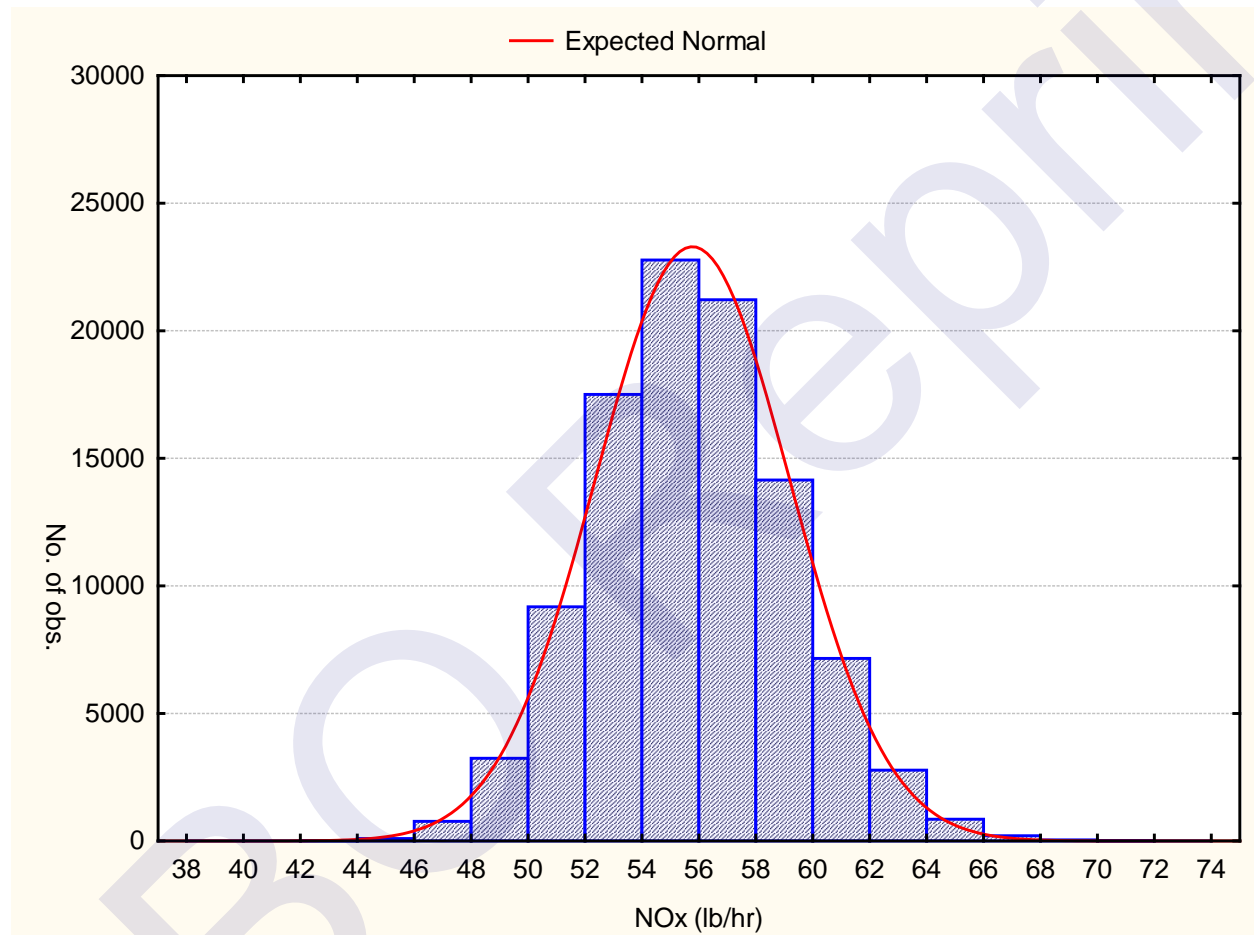


Figure 3. Histogram of Calculated NO_x (lb/hr) ... Normally Distributed.

Due to the physical constraints of some coal-fired generating units, the proximity of the stack monitoring location to the duct breaching and flow disturbances can cause significant problems with stratification. While attempting to site a stack probe location, sources often undergo stratification test profiles to determine the most appropriate location for the stack probe. The problem comes in when that load testing is conducted at only one or two load conditions, rather than across the load range of the unit. As volumetric flow through the boiler varies, the flow profiles in the stack could change as well, leading to increased uncertainty.

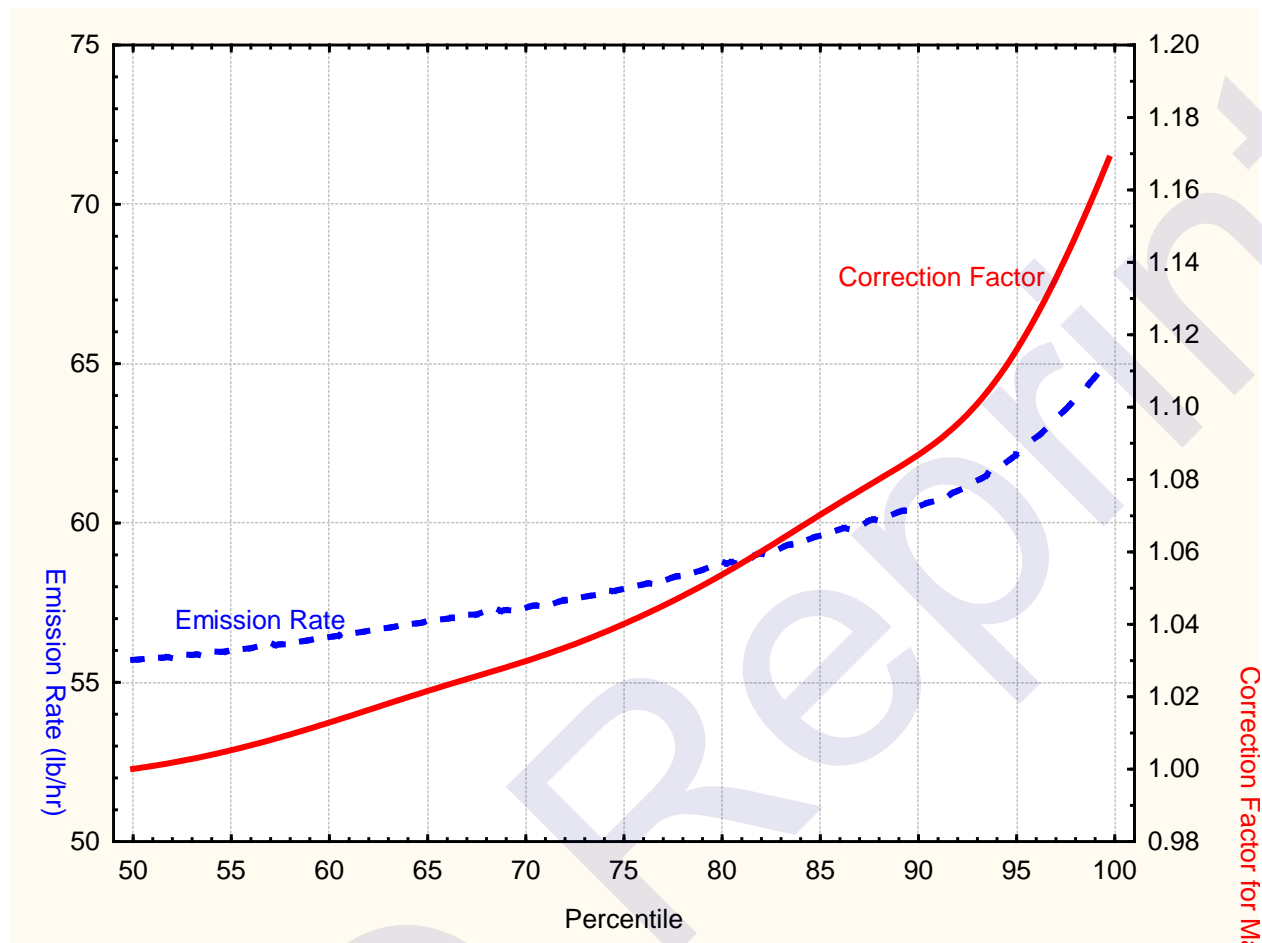


Figure 4. Mass Emission Correction Factor vs. Percentile for Combustion Turbine Plant.

AVERAGING PERIODS

For ongoing emissions compliance, longer term emissions averaging is generally recommended to allow the source a longer time period to “return to compliance” in the event that monitored emissions begin to show the potential for non-compliance. Hourly emission limits leave little time for reaction, and sources often have no indication of a potential mass emission exceedance until after it has already occurred (i.e., CEMS DAS or plant process computer displays the ppm values, without projecting the mass emission rate).

SUMMARY AND CONCLUSION

This study has identified some causes of measurement uncertainty that needs to be taken into account when permitting power plants. Most regulators will advise the permittee to “permit for

uncertainty” upfront since you will not be allowed to “subtract uncertainty” from monitored values that show an exceedance.

One cannot rely solely on manufacturer’s performance data without applying a reasonable margin to the mass emissions. For the example given in this paper, it was shown that at worst case conditions for parameters within their expected range of uncertainty, the mass emissions could be 134% of the theoretical calculation that could lead to compliance problems. However, simply adding a multiplier of 1.34 to all mass emissions would face some scrutiny by regulators, plus create the need for more emission allowances and higher permit fees.

What level is reasonable? In this example, the 1.34 multiplier was a very extreme case, and should be unnecessary. A margin level corresponding to the 90th or 95th percentile levels is reasonable, and for the example provided, the mass emission adjustment would be a 1.09 to 1.11 multiplier, respectively, for use in permitting and ongoing compliance. Each proposed emission source should be evaluated for its own conditions (i.e., prepare table similar to Table 1) and then the permittee should generate an uncertainty analysis to determine source-specific corrections for mass emissions.

For coal-fired boilers, the inaccuracy ranges may be much greater, requiring an even higher level of margin. Once again, the uncertainty for all parameters used in the calculations should be addressed on a case-by-case basis. Where monitoring alternatives are available (e.g., coal sampling and analysis), sources should evaluate all available data on an ongoing basis as part of the QA/QC checks.

To alleviate the effects of uncertainty, sources should not simply rely on correction factors to provide compliance margin. Rather, sources should continue to operate with very stringent QA/QC programs that ensure monitored readings are as accurate as possible.