Permit Compliance Monitoring for the Power Generation Industry

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INTRODUCTION

The Clean Air Act Amendments (CAAA) of 1990 authorized EPA to develop regulations requiring facilities to monitor the adequacy of emission control equipment and plant operations. Furthermore, under the CAAA, EPA is required to issue regulations to require owners and operators of large industrial facilities to enhance air pollution monitoring and certify compliance with air pollution regulations.

The fossil-fueled power generation industry has been targeted with the promulgation of the Acid Rain Program regulations of 40 CFR 72, and the Continuous Emissions Monitoring requirements of 40 CFR 75. The Part 75 regulations, with a few exceptions, establish requirements for monitoring, recordkeeping, and reporting of sulfur dioxide, nitrogen oxides, and carbon dioxide emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program. Depending upon the type of unit and location, other applicable emission limitations may apply for particulate emissions (both total and PM-10), carbon monoxide, volatile organic compounds and sulfuric acid mist.

In the August 2, 1996, draft of the EPA's Compliance Assurance Monitoring (CAM) rule, the main components of the CAM rule generally affecting power generation are:

- Establishes criteria that define what monitoring is necessary to provide a reasonable assurance of compliance with emission limits not already addressed in 40 CFR 75 (EPA feels that the Acid Rain Monitoring requirements under 40 CFR 75 already establish all appropriate compliance assurance monitoring).

- Proposes Title V compliance certification language in order to use compliance assurance monitoring data in establishing compliance status with permit terms.

- For emission units with control equipment, the draft rule requires a source to develop a CAM plan and comply with that plan. The CAM plan must include operating indicator ranges for the control equipment which, if maintained, will represent normal operation that provides a reasonable assurance of compliance. Conversely, excursions beyond these indicator ranges would trigger corrective actions due to the potential for noncompliances.

- For sources that utilize other forms of emission controls, such as work practices, fuel usage rates, or content limitations (e.g., fuel sulfur content in oil), improved recordkeeping and reporting practices would be required.

The Title V operating permit application and review process, including the applicant's initial compliance certification and compliance plan obligations, add another tool for assuring that sources have adopted the proper control measures for achieving compliance. The second step of CAM is to ensure that control measures, once installed or employed, are operated in a manner so that they do not deteriorate to levels resulting in noncompliances.

There is a great deal of overlap between the draft CAM rule and pollution control management practices already in use by the electric utility industry. Until the final CAM rule is promulgated, the exact degree of overlap will not be known. Regardless of the overlap, this paper discusses the various methods available for coal-fired power plants and gas turbine installations to demonstrate a reasonable assurance of facility compliance with emission limitations, and ensure that control measures are operated and maintained in a manner consistent with best air pollution control management practices.

The major emission sources associated with fossil-fueled power generation include boilers (steam electric generating units), auxiliary boilers (steam generation only), gas turbines (simple and combined-cycle), duct burners in combined-cycle applications, diesel generators, coal storage piles, coal handling operations, ash handling operations, fuel handling (oil), lube-oil vents, oil storage tanks, and roadways/parking areas. What does it really take to demonstrate that a power generation facility is in compliance with its applicable regulatory limits? What are some of the best management practices to control air pollution from these emission sources?

Demonstrations of Compliance

The generally accepted methods for demonstration of compliance with emission limitations in the power generation industry are:

- Periodic source testing using EPA reference test methods.
- Continuous emissions monitoring (CEM) systems.
- Predictive, parametric, or alternative emissions monitoring systems.
- Monitoring of control device operating parameters to ensure that control equipment is operated properly and maintained so that performance does not deteriorate.
- Use of pollution control management practices to minimize air pollution (e.g., dust control measures for fugitive dust from coal piles).

Periodic source testing is performed using EPA Reference Test Methods (40 CFR 60, Appendix A; 40 CFR 51, Appendix M), or state equivalents. These “reference methods” are the primary methods for directly determining whether or not a source is meeting its permitted emission limits, and for validation of CEM, predictive, parametric, and alternative monitoring systems. If a source fails the reference method test, or the monitoring system does not pass minimum relative accuracy criteria, the source can be considered out of compliance. The most commonly used reference test methods for power plants are given in Table 1.

Continuous emissions monitoring systems are required for Part 75 units. In general, the Part 75 CEM regulations require the monitoring, recordkeeping, and reporting of sulfur dioxide, nitrogen oxides, carbon dioxide, volumetric flow, and opacity data from affected units under the Acid Rain Program. These CEM systems must pass rigorous certification test procedures and maintain a strict quality assurance program, plus account for missing data in the event the CEM system is out of service.

The Part 75 regulations also allow for the use of alternative emissions monitoring systems to determine the average hourly emissions data for nitrogen oxides, sulfur dioxide, and/or volumetric flow by demonstrating that the alternative monitoring system has the same, or better, precision, reliability, accessibility, and timeliness as that provided by a CEM system. To demonstrate the precision of a predictive emissions monitoring (PEM) system for NO_x, the source must conduct and pass an F-test, a correlation analysis, and a t-test for bias over 30-days of hourly predicted emissions data compared to NO_x from a certified CEM system. This alternative monitoring technique is more suitable for gas turbine installations where the operating conditions and fuel flow can be accurately measured, and where the fuel quality is very consistent. Volumetric flow rate for gas turbines can also be easily predicted based upon a manufacturer’s mathematical algorithms relating gas turbine operating conditions and ambient meteorology to volumetric flow rate.

Appendix D of 40 CFR 75 is an optional SO_2 emissions protocol for gas-fired and oil-fired units. The parametric approach is utilized whereby fuel sulfur content, fuel heating value, and fuel flow are used to calculate SO_2 emissions. This protocol requires the certification of fuel flow meters at three operating loads. Assuming that one molecule of sulfur in the fuel converts to one molecule of SO_2, and the molecular weights of sulfur and SO_2 are 32 and 64, respectively, one pound of sulfur in the fuel converts to two pounds of SO_2 as shown below.

Example: Given .. 3,525 gal/hr oil flow, fuel density of 7.05 lb/gal, and 0.043% sulfur by weight

SO_2 (lb/hr) = 0.043% S/100 * 2.0 lb SO_2/lb S * 3525 gal/hr * 7.05 lb/gal
= 21.37 lb/hr

Appendix E of 40 CFR 75 is an optional NO_x emissions estimation protocol for gas-fired peaking units and oil-fired peaking units. Peaking units are defined as operating with less than 10% capacity factor. Units are tested for NO_x at four equally spaced load points, including the minimum and maximum operating load. A plot is developed relating NO_x (lb/million Btu) versus heat input (million Btu/hr) as shown in Figure 1. For each load condition, a minimum of four operating parameters indicative of the unit's NO_x formation characteristics are monitored and compared to the recommended ranges for each of these parameters at each tested load point. For instance, in gas turbine applications using water injection for NO_x control, the four parameters will include water injection rate, fuel flow, unit load (MW), and gas turbine inlet temperature. The source then keeps records of the hourly operating parameters to demonstrate that it has operated within the expected range that corresponds to the NO_x versus heat input graph.

For some pollutants, such as particulate emissions, the source does not continuously monitor particulate emissions. Compliance with particulate emissions are determined via periodic reference method emissions testing. During the remainder of the year, opacity may be monitored as an indicator of particulate emissions compliance as well as a demonstration of compliance with the applicable opacity limit. But in order to rely on periodic particulate test results, the source must operate under a program of regular evaluations of emission control conditions and follow-up on necessary corrective actions. Should the emission control equipment operate outside of the normal operating range, such as a precipitator section trip, then immediate corrective action is necessary to mitigate the situation. These procedures will be discussed in more detail later in this paper.

Alternative monitoring techniques are also available for particulate emissions. In exactly the same manner as in 40 CFR 75, Appendix E, for generating NO_x prediction curves, particulate emissions can be determined and plotted. As shown in Figure 2 for a hypothetical oil-fired boiler without particulate emission controls, particulate emission rates (lb/million Btu) measured at various load points could be used to calculate particulate emissions (lb/hr) with simple multiplication. This approach requires accurate fuel flow metering, as well as an evaluation of the unit operating parameters that may affect particulate emissions. In this example, even though the emission rate (lb/million Btu) was slightly higher at part load, the particulate emission level (lb/hr) associated with part load operation was significantly less than the level corresponding to full load due to the lower fuel heat input.

For coal-fired units with electrostatic precipitators (ESP) for particulate control, computer programs have been developed to determine allowable load (MW) versus emissions (lb/million Btu) in the event that there is a malfunction of the control equipment. For example, on a unit with an ESP configuration 4 cells deep by 8 sections wide, the calculation may show that the loss of one section will still allow the unit to operate at full load and remain in compliance with the particulate limit, but the loss of two sections would require a unit derating until the malfunction condition was repaired.

In November, 1993, the Electric Power Research Institute (EPRI) published the Electrostatic Precipitator Performance Model (ESPM) that evaluates the collection efficiency of precipitators based upon various input parameters. When the values of all input parameters are accurately known, ESPM is considered to be highly accurate. It is used by many utilities to obtain a rough estimate of the effect of different coal characteristics on the removal efficiencies of an electrostatic precipitator.

For fugitive emissions or particulates or volatile organic compounds that are not tested periodically, the use pollution control management practices to minimize air pollution is recommended. These practices, discussed later, include dust control measures for fugitive dust from coal piles and roadways.

COAL-FIRED POWER PLANT WITH ELECTROSTATIC PRECIPITATORS

This section demonstrates the compliance management activities related to a coal-fired power plant that uses electrostatic precipitators for control of particulates.

Periodic Emissions Testing

The air permit for these affected units (boilers) requires periodic emissions testing for total suspended particulates, PM-10, NO_x, SO_2, and opacity. Testing is performed at the maximum load for each unit, using the worst case coal supply. Since these units typically obtain coal from several sources, worst case coal is defined as the coal with the highest ash and moisture contents.

Units that fire low-sulfur coal with sulfur contents typically less than 0.6% by weight do not require the use of flue gas desulfurization equipment.

Continuous Emissions Monitoring

The steam-electric generating units (boilers) have continuous emissions monitoring systems for NO_x, SO_2, CO_2, volumetric flow, and opacity. The data acquisition and handling system generates electronic data reports for submittal to state and federal regulatory agencies, and has the capability to perform data substitution in accordance with EPA procedures. The CEM systems undergo quarterly cylinder gas audits, plus annual Part 75 relative accuracy test audits to demonstrate that the systems are operating properly. Plant instrument technicians follow a strict CEM quality assurance routine for daily, weekly, monthly, and quarterly maintenance checks.

The annual relative accuracy audit consists of testing at three load conditions—a frequently used low operating level selected within the range of minimum load and 50% load, a high operating load between 80% and 100% of full load, and the normal operating level or a level midway between high and low if the normal operating range is within 10% of either the high or low load point.

Daily Emissions Compliance

Compliance with the SO_2 emission limit is based solely upon the fuel sulfur content, and therefore, there is no immediate corrective action for units without flue gas desulfurization other than fuel blending to reduce the SO_2 emissions. In addition to continuous emissions monitoring, the source may also utilize daily composite fuel sampling and analysis to obtain daily calculated fuel sulfur contents.

Direct emission measurements of SO_2 at coal-fired units with SO_2 analyzers, in conjunction with exhaust flow rate monitors, will often result in SO_2 emissions (lb/hr) that are 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 SO_2 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 SO_2). If the actual sulfur conversion was 97%, then 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 SO_2 emission rate should agree with the 4,313 lb/hr rate determined from the fuel analysis. But if the exhaust flow monitor reads 7% high, the CEM system would erroneously calculate an SO_2 emission rate of 4,614 lb/hr. At the EPRI CEM Users Group Meeting in May, 1996, a paper by Cashin et al. addressed the issue of differences between mass balance calculations and CEM emission rate calculations. When it comes to stack emissions measurement, the “true value” can only be estimated due to uncertainty in all of the measurements used to calculate emission rates.

When SO_2 emissions monitoring is required, especially for units affected by the Acid Rain Program, it is advisable to continue evaluation of the CEM readings in comparison to the fuel sampling and analysis alternative.

To maintain NO_x compliance, the CEM system provides the operator with an instantaneous and hourly average NO_x level. The operator will make adjustments to the boiler firing (low excess air, overfire air) to lower NO_x levels in the event of elevated readings.

For particulate emissions, the operator has access to continuous opacity readings but not a direct reading of particulate emission levels. To ensure compliance with the particulate emission limits at all times, the facility must follow a particulate emissions compliance program to evaluate control equipment operating conditions and perform any necessary corrective actions. In day to day operations, the facility must ensure that the units are operated in a manner similar to the day of reference method compliance testing. Situations of equipment malfunctions or off-normal operation may affect operations to the extent that particulate emissions may exceed regulatory limits. When these situations occur, they must be identified as soon as possible and correction actions must be initiated to bring emissions back into compliance.

The focal point for action are shift advisors (or shift engineers) who are responsible for unit operation around the clock. It is the advisor’s responsibility to be aware of air pollution control equipment performance and condition. Information is routed to the shift advisor from all areas of the plant for his or her evaluation, and initiation of corrective action (if necessary). The shift advisor is also responsible for notifying the compliance specialist of any conditions resulting in possible excess emissions.

The primary particulate control devices are electrostatic precipitators, but also includes other ancillary equipment that affects precipitator performance, such as ash handling to the extent that ash must be removed from precipitator hoppers. The performance level of a precipitator can generally be determined by evaluation of the precipitator electrical readings, precipitator physical conditions, trouble alarms, hopper conditions, and stack exit opacity readings.

Procedurally, any trouble alarm for the precipitator must be responded to immediately. If the operator is unable to correct the trouble, the shift advisor is notified in an attempt to resolve the situation. All actions related to possible excess emissions are recorded in the shift log.

In addition to inspections made to investigate trouble alarms, operators inspect the precipitator electrical control equipment on a daily basis. Operating data is recorded on an inspection form such as the one shown in Figure 3. Operators attempt to re-energize any sections which are found tripped out. Completed data forms are submitted to the shift advisor for review and initiation of any required corrective operation or maintenance actions.

An accurate evaluation of the operating performance of precipitator rappers and vibrators can only be determined from an inspection of precipitator internal components. This type of inspection is limited to periods of boiler outages. However, an external inspection of rappers and vibrators can be made to determine whether or not they are operating. For rappers, the sound of impact and movement of the plunger (where visible) can indicate normal operation. For vibrators, the sound of vibration, duration of vibration, and indication of loose or missing bolts, nuts, etc. can provide a valuable indication of acceptable operating conditions.

The internal conditions of each precipitator are inspected once every six months during an outage of sufficient length to allow safe access. In addition, an internal inspection is performed at the first available opportunity following an abnormal operating condition of the precipitator. The internal inspection includes an evaluation of the following items:

- Rappers—boots, rod welds, insulators
- Vibrators—insulators
- Plate build up—color, consistency, thickness
- Wire build up
- Plates—hanger bolts, plate supports, mounting bolts
- Wires—hanger bolts, arcing shields, bushings, hangers
- Damaged or broken wires—location, probable cause
- High voltage insulators
- Penthouse insulation
- Inlet/outlet ducts—dust conditions, leaks
- Anti-sway bars—brackets
- Inlet perforated plates
- Duct and vane blowers
- Hoppers—cracks, buildup, divider doors
- Transformer set conditions

Precipitator ash hoppers require a shift inspection. A malfunction of ash removal equipment, such as hopper vibrator failure, can cause ash to hang up on hopper sidewalls. Internal physical obstructions, such as broken wires or other precipitator parts, can cause ash to build up in the hoppers as well. The ash level can quickly rise to the plates and wires, and result in grounding of precipitator sections. To minimize these occurrences, operators perform an evaluation of the ash hoppers to determine whether or not ash is being removed from the hoppers in a normal manner.

In the event of elevated opacity levels as indicated by the continuous opacity monitors, annuciator alarms notify the operator of high opacity conditions. Alert levels below the actual opacity limit help to identify possible problems for corrective action in advance of an actual exceedance. Upon notification of an alarm condition, the operator checks boiler conditions, oxygen levels, operation of soot blowers, load conditions (swinging, stable), precipitator trouble alarms, mill or cyclone operation, and precipitator hopper dust levels. The operator makes adjustments, when applicable, to remedy the high opacity condition before it becomes an exceedance. Any excess opacity conditions are logged with a cause and corrective action.

In the event of an opacity monitor outage, instrument technicians immediately respond to the situation. For certain situations, such as the loss of purge air flow, it is essential that the optical head of the opacity monitor be pivoted away from the stack until such time that the purge air is restored. When the opacity monitor is out of service for more than two hours, certified visual emission readers perform Method 9 observations during daylight hours, weather conditions permitting. These readings are scheduled every four hours after the first reading, or until the opacity monitor is returned to service. However, if there is a known malfunction condition or situation resulting in elevated opacity levels, visual emission readings continue until corrective action results in lower opacity levels.

The control of fugitive dust levels on plant property is by means of dust suppression programs which includes treatment of storage piles, treatment of roads and grounds, and control measures applied to coal handling and ash handling facilities. The fugitive dust regulations state that no person shall cause or allow the emissions of fugitive particulate matter from any process including any material handling or storage activity, that is visible by an observer looking generally towed the zenith at a point beyond the property line. The limits do not apply in some states when wind speeds are in excess of 25 miles per hour.

For coal pile management, the coal stacker is equipped with a telescopic chute. The chute is operated to maintain the minimum practicable free-fall distance of coal onto the pile. In the event that the telescopic chute malfunctions, repairs are made as soon as possible to restore the chute to service.

The coal pile is treated according to whether the area of the pile is active or inactive. An active pile area is one that is frequently being worked or disturbed by the action of coal pile vehicles and equipment. An inactive pile area is one which remains relatively undisturbed for more than several days. Active pile areas are treated with water sprays from a mobile water wagon. On days when coal handling vehicles are operating or anticipated to be operated, the pile is sprayed with water as needed to control fugitive dust emissions but no less frequently than once per day. On days when coal handling vehicles are not operational or not anticipated to be operation, the pile is sprayed only as necessary to control fugitive dust emissions. Water spray treatments are not performed on those areas of the coal pile which are considered to be excessively wet.

Water spray treatments are suspended for up to 24 hours subsequent to a precipitation event of 0.1 inches or greater. A precipitation gauge is maintained at each station site.

During the period December 1 through the end of February, water spraying is suspended due to the potential for freezing. In addition, cessation of spraying also takes place during any period of time that the temperatures are expected to drop below 32 °F. Water sprays treatments will also be suspended when malfunction of the water wagon and/or fill facilities occur, but repairs are given a high priority.

Inactive areas of the coal piles are treated with water or a chemical binding agent. A binding agent puts a film on the surface of the coal to minimize dust levels. A log is kept for all water spray treatments and/or application of chemical binding agents.

For coal handling operations, bag filters are used to control fugitive dust from coal loading points, such as conveyor transfers, rail car dumpers, coal bunker loading points, and transfer towers. The performance level of this equipment is determined by observations of emissions and the physical condition of the equipment. A daily inspection program is established for each bag filter system. An operator performs a visual inspection of the fan discharge for the presence of any visible emissions. A quarterly inspection is also performed only as needed to detect, identify, and correct abnormal conditions. During the inspection, each unit is taken out of service and opened up for visual bag inspections. All torn, loose, fallen or dust blinded bags are reported to the shift advisor. The condition of all gasket seals on the inspection doors is also recorded on the report. When the unit is returned to service, the pulse air pressure, range, and frequency of pulses is recorded. All other deviations from standard operating levels is reported to the shift advisor.

Proper flyash handling is necessary to minimize the potential for fugitive dust. Flyash is unloaded to tank trucks through telescopic chutes. The flyash unloading operator manages unloading activities so as to minimize spills and activates clean-up actions in the case of spills. The flyash silos vent through bag filters. The performance level of this equipment is determined by observations of emissions and the physical condition of the equipment. A daily inspection program is established for each bag filter system. An operator performs visual inspection of the fan discharges and reports any visual emissions to the shift advisor. Quarterly baghouse inspections are also performed for flyash handling baghouses.

The final fugitive dust program relates to the roads and grounds. Paved areas are swept as need to minimize fugitive dust emissions, but no less frequently than once per week. Sweeping is suspended during the period of December 1 through the end of February, or when the anticipated ambient temperature drops below freezing. Road sweeping is also suspended up to 24 hours following a precipitation event or 0.1 inches or greater. All normally traveled unpaved roads and unpaved parking areas are treated with water spays or chemical dust suppressants.

Dust and debris collected during street sweeping is stored on site in dust retention bins. The bin is enclosed on three sides by a cyclone fence with wind screens, and on the fourth side there is a ramp leading from local grade level to the top of the bin. The street sweeper will mix sweepings with water and will discharge them into the bin as a moistened mixture. The contents of the bin are re-wetted as necessary to control dust levels.

GAS TURBINE COMBINED-CYCLE POWER PLANT

This section demonstrates the compliance management activities related to a natural gas-fired (low-sulfur distillate oil backup) combined-cycle power plant that uses steam injection plus selective catalytic reduction for the control of NO_x emissions. For purposes of this discussion, the source includes a natural gas-fired auxiliary boiler (40 CFR 60, subpart Db) for use when the generating units are off line.

Periodic Emissions Testing

The air permit for these affected units (gas turbines, auxiliary boiler) requires that the units undergo annual emissions testing for total suspended particulates, PM-10, NO_x, SO_2, CO, sulfuric acid mist, volatile organic compounds, and opacity. Testing for NO_x is performed at four operating loads, including the minimum and maximum loads for each unit, on both fuels. When firing natural gas, particulate testing is not required due to the fact that the particulate levels are below the detectable limit for the reference test methods. The demonstration of SO_2 compliance is based upon fuel sampling and analysis. Volatile organic compounds (VOC) and carbon monoxide (CO) testing is performed at the maximum operating load. Since there is no applicable ammonia slip limit in the operating permit, ammonia testing is not required.

The auxiliary boiler fires natural gas and qualifies as a 40 CFR 60, Subpart Db, industrial boiler requiring an initial 30-day NO_x compliance test. During the unit commissioning, the boiler underwent development of a predictive emissions monitoring (PEM) system in accordance with the Subpart Db regulations.

Continuous Emissions Monitoring

The combined-cycle stacks have continuous emissions monitoring systems for NO_x, O_2, and CO. Volumetric flow is determined based upon algorithms from the gas turbine manufacturer. Continuous monitoring for opacity is not required due to the low number of operating hours on oil fuel. The determination of SO_2 is based upon fuel sampling and analysis. The data acquisition and handling system generates electronic data reports for submittal to state and federal regulatory agencies, and has the capability to perform data substitution in accordance with EPA procedures. Just as in the case of the coal-fired units, the CEM systems undergo quarterly cylinder gas audits, plus annual Part 75 relative accuracy test audits to demonstrate that the systems are operating properly. Plant instrument technicians follow a strict CEM quality assurance routine for daily, weekly, monthly, and quarterly maintenance checks. The annual relative accuracy audit is virtually identical to the coal-fired units discussed earlier.

Since the facility utilizes selective catalytic reduction (SCR), the CEM system includes measurement of inlet NO_x levels upstream of the ammonia injection grid. This allows for a direct calculation of NO_x removal efficiency, plus the determination of how much ammonia to inject into the grid.

In order to comply with the New Source Performance Standards for Stationary Gas Turbines, 40 CFR 60, Subpart GG, the CEM system also monitors and records steam injection rates, fuel flow, and steam/fuel ratio in addition to the monitored NO_x level (even though an exception from the steam/fuel ratio could be granted by EPA for a unit equipped with a NO_x monitoring system).

Predictive NO_x Emissions for the Auxiliary Boiler

The auxiliary boiler is rated at 210 million Btu/hr and qualifies as a 40 CFR 60, Subpart Db, industrial boiler. In accordance with the Subpart Db regulations, the unit has a predictive NO_x emissions monitoring system to predict NO_x emissions (ppmvd at 3% O_2 and lb/million Btu), and calculate 30-day rolling average NO_x levels (lb/million Btu). For periods of start-ups and shutdowns, the boiler uses a substitution routine to insert a constant NO_x emission rate determined during the initial test period. A separate prediction routine is utilized for use when operating on low-sulfur distillate oil fuel.

Daily Emissions Compliance

Compliance with the SO_2 emission limit is based solely upon the use of natural gas, plus low-sulfur distillate oil as a backup fuel. Calculated SO_2 emissions are performed by the CEM data acquisition and handling system. To control NO_x, CO, and VOC emissions, the gas turbine controls automatically determine the appropriate steam injection and ammonia injection rates. To avoid excessive steam injection at any given load (which would increase the CO and VOC emissions), the control system uses the inlet NO_x signal to trim steam injection, and then determines the appropriate ammonia injection feed rate for the SCR system. Blade path spread is also monitored by the gas turbine control system to avoid damage to the gas turbines, and to ensure that CO/VOC emissions are not affected by excessively high spread temperatures.

Since there are no coal storage piles, and no coal handling operations, fugitive particulate emissions is not an issue. The facility does not require a fugitive dust control program.

EXCESS EMISSIONS, MONITORING EQUIPMENT DOWNTIME, AND MISCELLANEOUS REPORTING

In accordance with Title V operating permit conditions, a special form is used to report to the regulatory agency situations resulting in excess emissions, downtime for emissions monitoring equipment, and miscellaneous incidents of possible noncompliance of applicable requirements.

For excess emissions, the reporting form includes general information related to the source, a contact person, identification of the emission unit(s), identification of applicable standards, magnitude of the excess emissions, duration, date of the exceedance, description of corrective action, and a description of the subsequent actions taken to prevent future exceedances.

For unpermitted downtime of monitoring equipment, the form requires identification of the malfunctioning equipment, the affected emission unit(s), date, duration, suspected cause, corrective actions, and subsequent actions to be taken to prevent future exceedances.

For miscellaneous incidents, the source describes the incident, the affected emission unit(s), control equipment involved, rules violated (if applicable), date, duration, a description of the type and amount of emissions that occur during the incident, suspected cause of the incident, corrective action, and subsequent actions to be taken in the future.

For all of these notifications, the form is signed by a responsible corporate official (plant manager) that certifies under penalty of law that the information included in the notification is true, accurate, and complete.

CONCLUSION

A question was posed earlier. What does it really take to demonstrate that a power generation facility is in compliance with its applicable emission limits? The answer is that in order to demonstrate that a source is in compliance with its regulatory requirements with a reasonable level of assurance, it takes more than just "stack testing" and continuous emissions monitoring. It is essential that power plant operators closely follow prescribed air pollution control management programs. Not all emission sources are covered by source testing or emissions monitoring. Fugitive dust is a prime example.

Compliance requires a dedicated, concerted effort by responsible personnel to follow station procedures. They must respond quickly to situations, such as control equipment malfunctions and instrumentation alarms, and implement corrective actions in a timely manner. Early identification of equipment problems, through the use of routine inspection procedures and warning alarm levels, will help mitigate or eliminate compliance problems before they arise. For reoccurring problems, each facility must consider subsequent quality improvement actions that could be taken to minimize potential problems in the future.

REFERENCES

1 40 CFR 51, Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Appendix M, Recommended Test Methods for State Implementation Plans.

2 40 CFR 60, Standards of Performance For New Stationary Sources, Appendix A, Reference Test Methods.

3 40 CFR 70, State Operating Permit Programs.

4 40 CFR 72, Permits Regulation.

5 Cashin, M.G., Love, J. E., Muller, J.D. 1996. "Resolving the Difference--Mass Balance vs. CEM Air Emissions Estimates," presented at the EPRI CEM Users Group Meeting, May 8-10.

6 Electric Power Research Institute, 1993. Electrostatic Precipitator Performance Model, AP-101592,Palo Alto, California, November.

7 Environmental Protection Agency, 1996. Compliance Assurance Monitoring (CAM) Rule Discussion and Rulemaking (8/2/96 Draft, 40 CFR Parts 654, 70, 71).

Table 1. Primary Reference Test Methods for Demonstrating Emissions Compliance.

Parameter	Method	Comment
Flow Rate	Method 2	In order to determine the emission rate on a lb/hr basis, the stack gas velocity and volumetric flow rate is determined. Velocity pressures are determined by traversing the test locations with an S-type pitot tube. Temperatures are measured using a K-type thermocouple with a calibrated digital temperature indicator. The molecular weight and moisture content of the gases are determined to permit the calculation of the volumetric flow rate. Sampling points utilized are determined using Method 1, 40CFR60.
Oxygen and carbon dioxide	Method 3 or 3A	In Method 3, samples are collected in a grab or integrated manner and analyzed using a Hays Orsat gas analyzer. Several passes of the gas are made during each run to ensure a stable reading. Mandatory leak checks are performed prior to and following each use. Chemicals are changed frequently and inspected for reactivity prior to each use. On a continuous basis, oxygen and carbon dioxide can be determined with continuous analyzers in Method 3A. The oxygen analyzer has an electrochemical cell or paramagnetic-based detector and operates in the range of 0-25% O_2. The carbon dioxide (CO_2) analyzer has a nondispersive infrared-based detector and operates in a range of 0-10 or 0-25% CO_2, depending upon the source. Calibrations are performed using certified standard gases prior to and between each test run.
Moisture	Method 4 or Alternate Method	Moisture determinations are necessary to accurately calculate flow rates in dry standard cubic feet per minute, and for the conversion of emissions in ppm, wet basis, to ppm, dry basis.
Nitrogen oxides	Method 7E (boilers) or Method 20 (gas turbines)	Both methods utilize the same instrumentation, but differ in the sample durations and time. Method 7E for boilers is conducted at full load, whereas Method 20 is conducted at four loads, including the minimum, maximum, and two interim load conditions. A gas sample is continuously extracted from the gas stream through a heated sampling probe and a gas conditioning system to remove moisture. A portion of the sample stream is conveyed via a sampling line to gas analyzers for determination of NO_x content. Prior to emissions sampling, the nitric oxide (NO)/NO_x analyzer is zeroed and calibrated. High-range, mid-range, and zero gases are introduced into the NO_x sampling system. The chemiluminescent reaction of NO and ozone (O_3) provides the basis for this instrument operation. Specifically: $NO + O_3 \rightarrow NO_2 + O_2 + h_v$ where: h_v = light. Light emission results when electronically excited nitrogen dioxide

Table 1. Primary Reference Test Methods for Demonstrating Emissions Compliance.

Parameter	Method	Comment
		(NO_2) molecules revert to their ground state. To measure NO concentrations, the gas sample to be analyzed is blended with O_3 in a reaction chamber. The resulting chemiluminescence is monitored through an optical filter by a high-sensitivity photomultiplier positioned at one end of the chamber. The filter/photomultiplier combination responds to light in a narrow-wavelength band unique to the above reaction (hence, no interference). The output from the photomultiplier is linearly proportional to the NO concentration. To measure NO_x concentrations (i.e., NO plus NO_2), the sample gas flow is diverted through a NO_2-to-NO converter. The chemiluminescent response in the reaction chamber to the converted effluent is linearly proportional to the NO_x concentration entering the converter. The instrument is operated in the NO_x mode during all tests and calibrations. For Method 20 (gas turbines), a preliminary O_2 traverse is performed to locate the lowest O_2 concentrations. The O_2 traverse is performed at the lowest percentage of peak load operation included in the test program. The lowest eight points are determined and used for emissions sampling.
Sulfur dioxide	Method 6C (solid fuel) or fuel analysis (gas and oil fuels)	A gas sample is continuously extracted from the stream through a heated probe and gas conditioning system to remove moisture. A portion of the gas stream is conveyed to the gas analyzer for determination of SO_2 content. Prior to sampling, the SO_2 analyzer is zeroed and calibrated with high-range, mid-range, and zero gases. Between each test run, zero and mid-range calibration gases are introduced to check calibration. For units firing natural gas, distillate oil, or residual oil, fuels sampling and analysis for sulfur content and heating value is preferred. Accurate fuel flow measurements in accordance with 40 CFR 75, Appendix D, are required.
Particulates less than 10 microns aerodynamic equivalent (PM-10)	Method 201A/202	These reference methods are found in 40 CFR 51, Appendix M. Method 201A is the front half filter catch, and Method 202 is the condensable portion. A gas sample is extracted at a constant flow rate through an in-stack sizing device that is used to separate particulate matter greater than PM_{10}. A glass microfibre filter exhibiting a 99.97% efficiency is used to collect the PM_{10}. The particulate mass is determined gravimetrically after removal of uncombined water. With the exception of the PM_{10} sizing device and in-stack filter, the sampling train is the same as a standard Method 5 train. The sizing device is a cyclone that meets all the requirements and design specifications of the test method. The PM_{10} emissions are calculated from the gravimetric analyses of the cyclone exit acetone wash and in-stack filter. Method 202 applies to the determination of condensable particulate

Table 1. Primary Reference Test Methods for Demonstrating Emissions Compliance.

Parameter	Method	Comment
		matter (CPM) emission from stationary sources. It is intended to represent condensable matter as material that condenses after passing through an in-stack filter and as measured by this method. The CPM is collected in the impinger portion of the sampling train. The impinger contents are immediately purged after the run with nitrogen (N_2) to remove dissolved sulfur dioxide (SO_2) gases from the impinger contents. The impinger solution is then extracted with methylene chloride ($MeCl_2$). The organic and aqueous fractions are then taken to dryness and the residues weighed. A correction is made for any sulfates or chlorides present in the impingers. The total of both fractions represents the CPM.
Total suspended particulates (TSP)	Method 5 (stack) and Method 17 (inlet to particulate control equipment)	The Method 5 isokinetic sampling method for all particle sizes is similar to PM-10, with the exception that a cyclone separator is not used at the end of the sample probe. All sample contact surfaces of the train are washed with reagent-grade acetone. These washes are placed in sealed and marked containers for analysis. The total sample weight is a combination of the filter catch, plus probe wash. For higher particulate loadings present at the inlet of control devices, Method 17 is used. Method 17 employs the use of ceramic thimbles to collect particulates in the ductwork.
Sulfuric Acid Mist	Method 8	This test procedure is used to determine the sulfur trioxide (SO_3) concentrations in conjunction with Method 5 particulate testing. Sulfuric acid (H_2SO_4) mist and SO_3 are separated from the SO_2 emissions and measured by the barium-thorin titration method. Barium ions react preferentially with sulfate ions in solution to form a highly insoluble precipitate. When the barium has reacted with all of the sulfate ions, the excess barium reacts with the thorin indicator to form a metal salt of the indicator, resulting in a color change. The gas is isokinetically extracted through a glass-lined probe heated sufficiently to prevent condensation. The H_2SO_4 sample is collected in the probe wash and on the filter. Any SO_3 present is collected in an initial bubbler containing an 80% isopropanol solution and a crossover filter on the outlet to entrain water-soluble SO_3 molecules and sulfuric acid mist. The remaining impingers contained a 3%-10% hydrogen peroxide (H_2O_2) solution which is recovered and analyzed as the SO_2 fraction. The impingers are placed in an ice bath to maintain the exit gas from the last impinger containing silica gel below 68°F in order to increase the efficiency of the silica gel in drying the metered gas.
Opacity	Method 9	Visual emission determinations are performed in accordance with Method 9. The method specifies that the qualified observer stand at a distance sufficient to provide a clear view of the emissions with the sun oriented in the 140° sector to his back. As much as possible, the line of

Table 1. Primary Reference Test Methods for Demonstrating Emissions Compliance.

Parameter	Method	Comment
		vision will be approximately perpendicular to the plume direction. Opacity observations are made at the point of greatest opacity in the portion of the plume where condensed water vapor is not present. Observations are made at 15-second intervals for the duration of the time period.
Carbon monoxide	Method 10	A continuous gas sample is extracted from a sampling point and analyzed for CO content using a nondispersive infrared analyzer (NDIR). The gas stream is conditioned by condensing moisture and filtering particulate prior to the analyzer. This instrument employs an internal gas correlation filter wheel which eliminates potential detector interference. Instruments so equipped do not require the use of an interference removal trap. After an appropriate warm up time, the analyzer is calibrated using certified calibration gases at concentrations corresponding to approximately 30, 60, and 90% of the applicable instrument range of 100 ppm, with a CO free calibration gas used as a zero gas.
Volatile organic compounds (VOC)	Method 25A (total HCs) in conjunction with Method 18 (methane, ethane)	In Method 25A, a gas sample is extracted from the stack through a heated Teflon sample line to the heated flame ionization detector (FID) that provides direct reading of total hydrocarbons on a wet basis. Calibration gases are typically propane or methane, with the ppm results being reported "as propane" or "as methane." To determine methane and ethane fractions (for subtraction from the total hydrocarbon value), integrated bag samples are collected in accordance with the sampling procedure of Method 18, with analysis later performed using a gas chromatography.

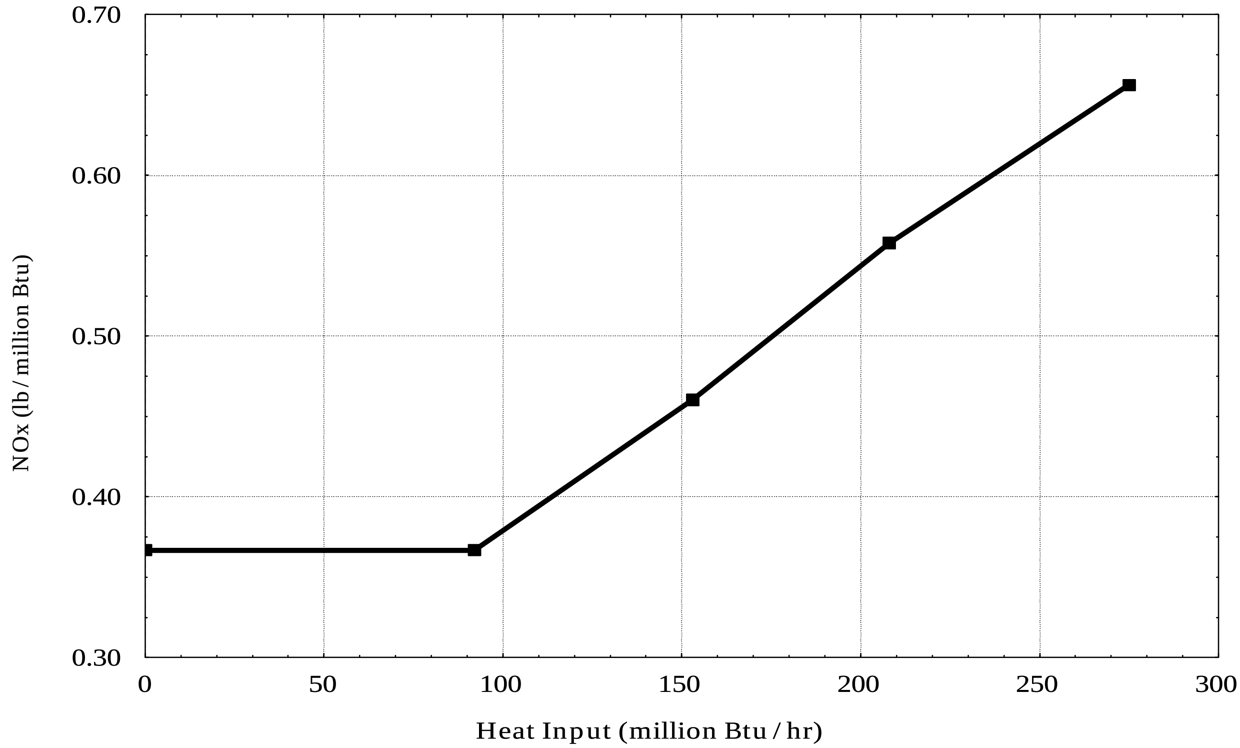

Figure 1. Graph of NOx (lb/million Btu) versus Heat Input (million Btu/hr) for a Peaking Unit Firing Natural Gas to Comply with Appendix E of 40 CFR 75.

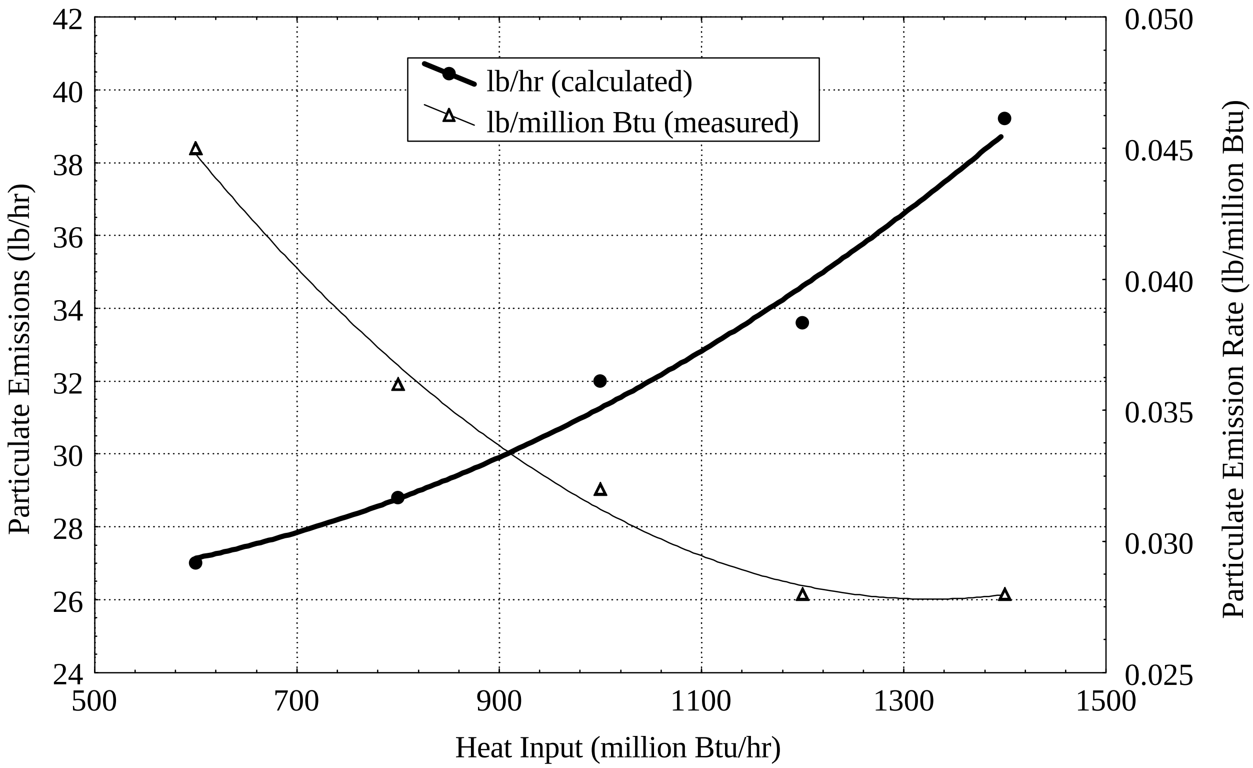

Figure 2. Plot of Particulate Emissions (lb/hr [left axis]; lb/million Btu [right axis]) versus Heat Input (million Btu/hr) for an Oil-Fired Peaking For Use in a Parametric Monitoring System to Continuously Calculate Particulate Emission Rates.

Daily Precipitator Report

Unit: ___________ **Operator:** _____________________________________

Unit Load: ___________ **MW**

Date: ___________ **Time:** ____________

	AC Amps	***AC Volts***	***DC Milliamps***	***DC Kilovolts***	***Sparks/ Minute***	***KVA***	***Auto or Manual***	***OOS Ground***
01								
02								
03								
04								
05								
06								
07								
08								
09								
10								
11								
12								

Rapper/Vibrator Microprocessor Status: ______ **ON** _______ **OFF** ______ **MALFUNCTION**

Comments:

Operator Signature: ____

Figure 3. Sample Precipitator Daily Inspection Form.