NO_X COMPLIANCE
UNDER THE NO_X SIP CALL AND SECTION 126 RULES

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ABSTRACT:
This paper provides an overview of the NO_x trading program requirements established by 40 CFR Part 96, the NO_x SIP Call rule and 40 CFR Part 97, the Section 126 rule. The paper also provides an introduction to 40 CFR Part 75, which serves as the cornerstone for the monitoring, recordkeeping and reporting requirements specified in Parts 96 and 97.

I. INTRODUCTION

Over the past several years, the Environmental Protection Agency (EPA) has become increasingly concerned with perceived increases in ground-level ozone, especially in the Eastern United States. EPA has determined that nitrogen oxide (NO_x) emissions from certain States significantly contribute to ozone nonattainment in downwind States. Based on the success of EPA's Acid Rain Program in reducing sulfur dioxide (SO_2) emissions, EPA has introduced legislation designed to establish a national NO_x trading program as a means to reduce NO_x emissions. These regulations affect both electric generating units (EGUs) and non-electric generating units (non-EGUs) located in the Eastern United States. This paper provides an introduction to the compliance issues associated with the NO_x budget programs.

II. REGULATORY OVERVIEW

40 CFR 96 -NOx Budget Trading Program for State Implementation Plans

In 1998, EPA issued the NO_x SIP Call rule, *NO_x Trading Program for State Implementation Plans* - 40 CFR Part 96, which was designed to reduce long range transport of ozone. The requirements of the NO_x SIP Call rule were based on an extensive analysis of ozone transport conducted by the Ozone Transport Assessment Group (OTAG). Part 96 required 23 jurisdictions (referred to as "States" in Part 96 and herein) to submit revisions to their State Implementation Plans (SIPs) to ensure that NO_x emissions from sources within the States do not significantly contribute to nonattainment of the 1-hour ozone national ambient air quality standards (NAAQS) in a downwind State. The 23 affected States were: Alabama, Connecticut, Delaware, District of Columbia, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, Missouri, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island,

South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin. Part 96 established an ozone-season (May 1 through September 30) NO_x budget for each affected State, as well as a State implemented and Federally enforced NO_x trading program.
After the promulgation of Part 96, certain affected states and industry-labor groups sued EPA in the U.S. Court of Appeals and in May 1999, the Court issued a stay of the original NO_x SIP submission deadlines specified in the rule. Later in a surprising ruling on March 3, 2000, the Court upheld the merits of the NO_x SIP Call rule. As a result of this favorable ruling, in April 2000 EPA requested that the U.S. Court of Appeals lift its stay of the NO_x SIP rule. In this request, EPA removed Wisconsin, Georgia and South Carolina from the SIP Call. On June 22, 2000, the U.S. Court of Appeals lifted its stay of EPA's NO_x SIP Call and the 19 affected States were required to submit their Phase I SIPs by September 1, 2000. However, in response to subsequent litigation, the U.S. Court of Appeals ruled that EPA must postpone the May 1, 2003 compliance deadline until May 31, 2004 in order to provide States with the 43-month compliance period specified in Part 96. Monitoring systems are required to be installed and provisionally certified no later than May 1, 2003.

Currently, seven affected states have filed two separate briefs requesting that the Supreme Court review the U.S. Court of Appeals March 3, 2000 decision. It is anticipated that the Supreme Court will determine whether to accept this case in early 2001.

40 CFR 97 – Federal NOx Budget Program
As a second thrust, on January 18, 2000, EPA published 40 CFR Part 97, *Federal NOx Budget Trading Program*, also referred to as the Section 126 rule. EPA established this rule after determining that the Section 126 petitions filed by eight northeastern states demonstrated that specific upwind EGUs and non-EGUs significantly contributed to nonattainment or maintenance problems in the petitioning States. Appendix A of 40 CFR Part 97 identifies the EGUs and non-EGU's affected by the regulation. These sources are located in Delaware, Indiana, Kentucky, Maryland, Michigan, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Virginia, Washington, D.C. and West Virginia. Part 97 establishes the Federal NO_x Budget Trading Program as a control remedy for sources affected by this rule. Numerous sources are currently affected by both the Part 96 and 97 requirements. However, EPA has stated that it will withdraw the Section 126 requirements for a State after approving both phases of the State's SIP Call. In August 2000, EPA published the *Small Entity Compliance Guide* to provide owners and operators with guidance for complying with the Part 97 requirements.

For Part 97, a NO_x Budget Program Application must be submitted no later than November 1, 2001 and monitoring systems must be installed and provisionally certified by May 1, 2002. Compliance with the Federal NO_x Budget Trading Program begins May 1, 2003. Although legal maneuvering is certainly underway, at this juncture, the Part 97 May 1, 2003 compliance date has not been postponed to coincide with the NO_x SIP deadline. Attachment 1 provides a summary of the Part 97 notifications and submittals.

40 CFR Part 75 – Continuous Emission Monitoring

Although Parts 96 and 97 establish the framework of the NO_x trading program, the requirements specified in 40 CFR Part 75 serve as the foundation of each rule's monitoring, record-keeping, reporting and quality assurance/quality control (QA/QC) procedures. Originally promulgated in January 1993, Part 75 established the CEM requirements for electric utilities subject to the Acid Rain Program. In contrast to 40 CFR Part 60, Part 75 established rigorous certification requirements, stringent QA/QC performance tests, missing data procedures for periods when CEM data are unavailable or invalid, and extensive recordkeeping and reporting requirements. These new regulations necessitated substantial changes to electric utility CEM programs.

Since 1993, Part 75 has undergone several extensive revisions. Most recently, EPA published major changes to Part 75 on May 25, 1999. These revisions included the incorporation of Subpart H that defines the NO_x mass emission provisions for those units subject to State or federal NO_x reduction programs. Although Part 75 is designed to provide a definitive set of monitoring requirements, it continues to be a highly complex, evolving and ambiguous regulation. In recognition of this confusion, in March 1993 EPA issued a companion document to Part 75, the *Acid Rain CEM (Part 75) Policy Manual*, now referred to as the *Acid Rain Program Compliance Manual*. The manual includes over 350 questions and answers designed to clarify the requirements of the Acid Rain Program. Since 1993, EPA has issued thirteen "updates" to this manual, incorporating new policy as well as revising and or retiring existing questions. Unfortunately, each revision to Part 75 has fostered another set of policy questions and clarifications.

A second companion document to 40 CFR Part 75 is the reporting instructions, currently *EDR Version 2.1 Reporting Instructions*, for submitting the quarterly electronic data reports (EDR). The reporting instructions provide detailed information concerning both the format and the content of EDRs. Several EDR software vendors have acknowledged that the development of the initial EDR software required over 20,000 man-hours. Since 1993, EPA has issued four versions of the EDR, each requiring additional significant programming implementation and training efforts. EPA uses the information provided in the EDRs to track emission allowances. At a minimum, two quarterly EDRs will be required for each ozone season. However, as the NO_x trading program matures, it is anticipated that sources will be required to submit EDRs for each calendar quarter.

The Acid Rain Program is administered by EPA's Clean Air Markets Division (CAMD), formerly the Acid Rain Division. The Division's name change in 2000 reflects that CAMD has been charged with implementing the NO_x Budget Program.

III. NO_x TRADING PROGRAM

Both Part 96 and Part 97 establish a "cap-and-trade" allowance program founded on the experience of the SO_2 Allowance Trading Program. As opposed to the traditional command and control regulatory method, the trading program is design to provide an affected source with greater flexibility in complying with emissions limits. The program is also designed to provide sources with the opportunity to determine the most cost-effective approach to compliance.

Each affected source receives an annual allocation of NO_x allowances. One allowance is equal to one ton of NO_x emissions. Allowances can be bought, sold and/or banked. In general terms, each affected source must hold sufficient allowances to cover NO_x emissions during an ozone season (i.e., May 1 through September 30). Allowance allocations are based on a "control limit" of 0.15 lb/mmBtu for EGUs and 0.17 lb/mmBtu for non-EGUs. Potential compliance options include fuel switching, allowance trading, combustion modifications and post-combustion NO_x controls.

Each source must select an Authorized Account Representative (AAR) that serves as the source's legal representative for the program. EPA then establishes an account for the affected source in the NO_x Allowance Tracking System administered by EPA's CAMD. If a source has more than one affected unit, an overdraft account is also established. After the allowance transfer deadline of November 30 of each year, EPA deducts allowances corresponding to reported emissions. If a source does not hold sufficient allowances, then the source is assessed an automatic penalty for each ton of excess emissions. In this instance, EPA deducts three allowances for each ton of excess NO_x emissions from the compliance account for the subsequent year. The source may also be subject to additional enforcement actions (e.g., monetary fines).

The rules include provisions for obtaining allowances for new units or newly affected units. Allowances allocations will be updated periodically for future compliance periods. Each compliance period consists of five calendar years. Currently, NO_x allowances are allocated based on unit heat input. However, there is a strong desire within the regulatory community to base future NO_x allocations on unit output. The primary reason for this change is EPA's belief that this would encourage unit efficiency. The incorporation of non-EGUs into the program poses challenges to accurately measuring unit output.

IV. MONITORING REQUIREMENTS

The "cap-and-trade" program's "flexibility" is in stark contrast to the rigid set of monitoring and reporting requirements required by 40 CFR Parts 96 and 97. However, it is EPA's contention that this consistency for monitoring and reporting emissions is essential to the credibility of the program. As previously mentioned, Subpart H to Parts 96 and 97 state that affected sources must comply with the monitoring requirements specified in Subpart H of 40 CFR Part 75. 40 CFR Part 75 specifies three general monitoring approaches that may be used to determine NO_x mass emissions. However, these monitoring strategies can be further complicated when units share common stacks with other affected or non-affected units. For each monitoring approach, data must be collected using a certified continuous emissions monitoring system (CEMS) equipped with a data acquisition and handling system (DAHS).

1. For coal-fired units, install and certify a NO_x/diluent (i.e., an oxygen (O_2) or carbon dioxide (CO_2) analyzer) CEMS that also includes a volumetric flow monitoring system.

2. For gas- and oil-fired units, (1) install and certify a CEMS as detailed in Item 1 above or (2) install and certify a NO_x/diluent CEMS and certified fuel flow meters for each fuel combusted to determine unit heat input. Each fuel flow meter must be installed, certified and maintained in accordance with Appendix D of Part 75.

3. For gas- and oil-fired peaking units, (1) install and certify a CEMS as detailed in Items 1 and 2 above or (2) install certified fuel flow meters and use the NO_x correlation procedures specified in Appendix E of Part 75 to determine NO_x emissions (in lb/mmBtu). A peaking unit is defined as a unit that is expected to have an average capacity factor of no more than 10.0% average over any three consecutive years following unit startup or a capacity of no more than 20.0% during any one of these calendar years. If a unit exceeds either of the two peaking unit requirements, then a continuous NO_x emission monitoring system is required to be installed and certified.

Parts 96 and 97 provide one rather unattractive exemption to the CEM requirements that may be used by a few select sources. An affected unit may become exempt by obtaining a federally enforceable permit that limits NO_x emissions to 25 tons during the ozone season. This emission restriction is achieved by limiting unit operating hours. The unit operating hour limit is determined by multiplying the unit's maximum hourly heat input times the very conservative default NO_x emission rates provided in Section 75.19 (40CFR75) to determine the unit's maximum potential hourly NO_x mass emission rate. The 25-ton limit is then divided by the maximum potential hourly NO_x emission rate to determine the unit operating time limit. For a natural gas-fired boiler rated at 250 mmBtu/hr, this equates to an operating limit of 5.5 days during an ozone season. Unfortunately, this is extremely restrictive and will probably not be a viable alternate for most affected sources. Moreover, violating the permit would leave the source vulnerable to fines and penalties.

Part 75 also provides affected units with the option of petitioning EPA for approval of an alternate monitoring system (e.g., a parametric emission monitoring system (PEMS)). However, since 1993 EPA has not approved any alternate monitoring systems under Subpart E to Part 75.[1]

Unfortunately, Part 75 was written for utility boilers and turbines and the application of the specified monitoring approaches to unique industrial sources has proven to be challenging. Conditions such as high exhaust gas temperatures and unique unit configurations present difficulties for the application of Part 75's "standardized" monitoring strategies.

V. CEM SYSTEM OVERVIEW

There are three basic types of sample acquisition methods employed by CEMS: (1) dilution-extractive, (2) straight extractive and (3) in-situ systems. Each of the three CEM sampling technologies has distinct advantages and disadvantages, especially when applied to site-specific applications. Developing a sound understanding of the regulatory requirements as well as current CEM technologies is essential for establishing a successful CEM program. A brief summary of each of these CEMS technologies is presented below.

Dilution-extractive CEMS
Dilution-extractive CEMS dilute the effluent sample with dry contamination-free air, thereby eliminating the need for moisture condensing systems. Dilution-extractive CEMS use either in-stack or out-of-stack dilution probes. Pollutant and diluent monitors operate at or near ambient concentration levels to analyze the diluted sample. In the Acid Rain Program, approximately 82% of the affected sources use dilution-extractive CEMS to meet the Part 75 monitoring requirements.[2] For affected units using volumetric flow monitors to determine heat input, dilution-extractive CEMS offer the advantage of avoiding the need to include a moisture analyzer.

Extractive CEMS
Straight extractive CEMS remove an effluent sample using a probe and use an extensive conditioning system to remove particulate and moisture. Analyzers measure pollutant concentrations on a dry basis. Given the challenges of sampling a hot, wet, particulate-laden effluent (especially for coal-fired units), only about 14% of the Part 75 affected sources operate straight extractive CEMS.[2] Under a rigorous preventive maintenance program, extractive CEMS can provide highly accurate emissions data. However, because these systems typically have more mechanical components exposed to the exhaust gases, they generally require more maintenance than dilution-extractive or in-situ CEMS.

In-situ CEMS
As opposed to extractive CEMS, in-situ CEMS measure effluent pollutant concentrations directly in the stack or duct. Because an in-situ CEMS is mounted directly on the stack or duct, the system does not require a sample umbilical. Path and point systems are the two types of in-situ CEMS currently available. Path in-situ CEMS analyze the effluent passing through a measurement path of greater than 10% of the stack/duct diameter. The measurement path for point in-situ CEMS is less than or equal to 10% of the equivalent diameter. Currently, only about 5% of the Part 75 affected sources employ in-situ CEMS and many are in the process of being replaced.[2]

Data Acquisition and Handling System
An automated DAHS is required to collect and report CEMS data as well as any specified process data. A programmable logic controller (PLC) or data logger is typically used as the interface between the analyzers and personal computer (PC) workstation. In most applications, the DAHS is integrated into the source's internal network. In addition to the recordkeeping and reporting functions, the DAHS controls CEMS functions such as daily calibration error tests and system purge frequencies, and missing data substitution routines. The DAHS is used to generate the required quarterly EDRs.

VI. CEM PROGRAM IMPLEMENTATION

Experience shows that establishing a sound CEM program requires a significant personnel and monetary investment during a fairly concentrated time period. Tasks associated with establishing a CEM program include, but are not limited to: developing a detailed CEMS/DAHS procurement specification and selecting a vendor, performing required modifications to the source (e.g., installing ports, platforms, elevators, etc.), and certifying the CEMS. During this process, an affected source must also develop a Quality Assurance Plan, Monitoring Plan, certification test protocol and certification application.

However, the level of effort and cost required to maintain a successful CEM program is often underestimated. Because allowances are of significant monetary value, it is imperative that each CEMS operate reliably and accurately. When hourly data from a particular monitor is unavailable or invalid, missing data substitution procedures specified in Part 75 must be used to provide data for that hour. Consistent with Part 75, missing data becomes increasingly punitive as monitor availability falls below the 95%, 90%, and 80% thresholds.

The operator of a CEMS consisting of a NO_x, diluent, and volumetric flow monitors should budget approximately 1.0 to 2.0 man-days per week to maintain the system in accordance with Part 75. A similar amount of time should be budgeted to comply with the extensive recordkeeping and reporting requirements specified in Part 75. Additionally, each CEMS must meet stringent ongoing quality assurance/quality control (QA/QC) tests. These QA/QC tests include daily calibration error tests, quarterly linearity checks for gaseous monitors, and annual relative accuracy test audits (RATAs).

Finally, EPA has also developed procedures to be used by EPA and State air quality agencies when auditing affected sources. Audit procedures are detailed in the *Acid Rain Program CEMS Field Audit Manual*. Criteria for selecting a unit for an audit include: (1) low monitor availability, (2) frequently failed QA tests, (3) source compliance history and (4) reporting problems.

VII. CONCLUSION

Given the various pending and anticipated legal challenges to 40 Parts 96 and 97, many affected sources are taking a "wait-and-see approach" for establishing a monitoring program. This is understandable in light of the costs associated with developing a CEM program. However, experience with EPA's Acid Rain Program shows that establishing a CEM program is an involved and challenging process. Unfortunately, many Part 75 affected sources procrastinated CEMS procurement and program development. As vendor backlogs increased, CEMS costs escalated and compliance deadlines were jeopardized.

Moreover, the CEM industry has been prone to peaks and valleys. For example, established firms increased staff resources to meet the demand created by Part 75. The demand was also substantial enough to give rise to fledgling companies. However, lacking sufficient market share and no immediate new market, several smaller CEMS and DAHS vendors shortly went out of business. For this reason, within a fairly short period of time numerous utilities were forced at a substantial cost to replace DAHS and/or CEMS due to a lack of ongoing technical support.

Although it may be prudent to await the outcome of the legal challenges, it may also be beneficial to begin laying the groundwork for the monitoring program. If, for example, the Section 126 deadlines are upheld in the first quarter of 2001, sources would have just over one year to procure, install and certify a CEMS. Unfortunately, the stage is set for potential mistakes similar to those observed in the Acid Rain Program.

VIII. REFERENCES

1. United States Environmental Protection Agency, Small Entity Compliance Guide, EPA 430-R-00-008, August, 2000.

2. "Continuous Emission Monitoring Guidelines – 1999 Update," Electric Power Research Institute, Palo Alto, CA, Report No. TR-111165, November, 1999.

ATTACHMENT 1

Part 97 Notifications/Submittals

Action/Event	When Required
Submit Certificate of Representation	Prior to all other submittals
Submit NO_x Budget Program Application	No later than November 1, 2001
Submit Certification Test Schedule	45 days prior to certification testing
Notify EPA of Changes to Scheduled Certification/Recertification Test Date	At least 7 days prior to first scheduled day of testing (via written notice or telephone)
Notify EPA of Recertification Testing Under Emergency Conditions	Within 2 business days following the date when testing is scheduled (via telephone)
Develop Quality Assurance Plan	No specified deadline. Recommend prior to completion of certification testing.
Submit Monitoring Plan & Test Protocol	45 days prior to certification testing
Complete Certification Tests	No later than April 30, 2002
Submit Certification Application	No later than 45 days after testing
Submit Quarterly EDRs	No later than 30 days following the end of the calendar quarter (July 30 and October 30).
NO_x Allowance Transfer Deadline	No later than midnight on November 30 of each calendar year
Submit NO_x Compliance Report	No later than November 30 of each calendar year (during or after the year of 2003)