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NESHAP SSM Exemption Vacatur Mandated by the DC Circuit

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The National Emission Standards for Hazardous Air Pollutants (NESHAP), codified in 40 Code of Federal Regulations (CFR) Part 63, set emission standards and monitoring, recordkeeping, and reporting requirements for specific source categories that emit HAPs. NESHAP Subpart A, the *General Provisions*, includes general requirements for NESHAP subject facilities, including provisions for startup, shutdown, or malfunction (SSM) events. Subpart A previously stipulated that facilities minimize emissions during SSM events but did not require that the emission source achieve emission levels (during SSM events) that are required by the relevant NESHAP Subpart during normal operation.[1] This allowance during SSM events is also referred to as the "SSM exemption." On October 16, 2009, the United States Court of Appeals for the District of Columbia Circuit (DC Circuit) issued the mandate vacating the SSM exemption from Subpart A of the NESHAPs.

On December 19, 2008 in *Sierra Club versus (v.) the Environmental Protection Agency (EPA)*, the DC Circuit vacated the SSM exemption of Subpart A, concluding that even during periods of SSM, an affected source must comply with the applicable emission standard required by the relevant source category subpart. Since this finding, there have been numerous stays on the determination but the SSM vacatur was ultimately mandated on October 16, 2009. The effects on industry will be significant, as each subject source will be required to demonstrate compliance with applicable emission standards even during SSM events.

Note that the SSM exemption vacatur only affects source categories subject to the SSM requirements by virtue of incorporating Subpart A by reference. If a particular NESHAP explicitly exempts applicable sources from meeting emission limits during SSM events, then the SSM exemption in that subpart will continue to apply regardless of the Subpart A vacatur. As the Subpart A vacatur was mandated, industry should also expect challenges to any SSM exemptions specific to an individual NESHAP. EPA intends to evaluate each of the source category-specific SSM provisions in light of the court's decisions.[2]

History of the SSM Exemption

In 1994, EPA adopted the SSM exemption and required that subject facilities develop and implement an SSM plan. Note that this is a current requirement in Subpart A per 40 CFR 63.6(e)(3). The purpose of the SSM plan is to require a source to "demonstrate how it will do its reasonable best to maintain compliance with the standards, even during SSM."[3] EPA also required that the facility's Title V permit incorporate the SSM plan by reference. The reason for inclusion of the SSM plan into the Title V permit was so that EPA, the state agency, and the general public would be able to review and comment on the plan. It is important to note that the Sierra Club did not challenge the SSM exemption at this juncture.

In 2002, the EPA removed the requirement that the SSM plan be included by reference in a facility's Title V permit but instead required that the Title V permit include a condition that the SSM plan must be in place at the respective facility.[4] In 2003, the EPA updated the procedure for public review such that a concerned party could request a copy of the SSM plan from the state agency, who would then request a copy of the SSM plan from the specific source.[5] The Sierra Club challenged the SSM exemption legitimacy during the 2002 and 2003 rule updates.

In 2006, EPA further determined that a facility was not required to implement its SSM plan during an SSM event because facilities are already required to minimize emissions during these scenarios under the "general duty" clause. Additionally, EPA removed the requirement that the public be provided a copy of the SSM plan upon request to the delegating agency; instead, if the delegating agency has a copy of the relevant SSM plan, the agency is required to provide the public with a copy of the plan.[6] In the 2006 revisions, the Coalition for a Safe Environment challenged the EPA regarding the 2006 rule changes.

Summary of Court Findings

In its December 2008 ruling, the DC Circuit determined that the SSM exemption should be vacated by reasoning that the SSM exemption violates the Clean Air Act (CAA) Section 112 requirement that the NESHAP must apply continuously. Under the CAA Section 112(d)(2), EPA must set "emission standards that require the maximum degree of reduction in emissions …." CAA Section 302(k) defines an emission standard as "a requirement established by the State or the EPA which limits the quantity, rate, or concentration of emissions of air pollutants on a **continuous basis** …." The DC Circuit therefore concluded that the emission standard required during normal operation in conjunction with the general duty to minimize emissions during an SSM event does not constitute continuous application of an emission standard.[7]

EPA argued that the Sierra Club was required to petition the SSM exemption when the rule was initially incorporated into Subpart A with the 1994 rulings, since the CAA requires that "petition for review … shall be filed within 60 days from the date notice

[1] Parts of 40 CFR 63.6(e)(1)(i), 40 CFR 63.6(f)(1); 40 CFR 63.6(h)(1).

[2] EPA letter titled "Re: Vacatur of Startup, Shutdown, and Malfunction (SSM) Exemption (40 CFR 63.6(f)(1) and 63.6(h)(1))" by Adam M. Kushner, Director of the Office of Civil Enforcement, dated July 22, 2009.

[3] 59 Federal Register 12423.

[4] 67 Federal Register 16582.

[5] 68 Federal Register 32586.

[6] 71 Federal Register 20446.

[7] 40 CFR 63.6(e)(1)(i).

… appears in the Federal Register." EPA also interprets 40 CFR 63.6(e)(1)(i) to be the relevant standard during SSM events, and that the specific emission standard listed in each subpart applies during normal operation, unless otherwise specified in the relevant subpart.

Currently, the vacatur of the SSM exemption has not yet been mandated by the DC Circuit and the SSM exemption remains in effect for subject sources. The DC Circuit did approve EPA's request for a 60-day stay on September 23, 2009.

How Does The Potential SSM Exemption Vacatur Affect Your Facility?

Facilities subject to a NESHAP Subpart should determine whether or not their operations are covered by the SSM provisions of Subpart A or SSM provisions from a specific NESHAP. As an example, gas turbines subject to NESHAP Subpart YYYY will not be immediately affected by the SSM exemption vacatur because Subpart YYYY, 63 CFR 6105(a) includes the following language, "You must be in compliance with the emission limitations and operating limitations which apply to you at all times except during SSM." However, combustion sources at pulp mills will be impacted by the vacatur because NESHAP Subpart MM does not include specific provisions regarding SSM events and the provisions of Subpart A, including the SSM exemption at 40 CFR 63.6, is incorporated by reference. Table 1, which is not comprehensive, shows a sampling of NESHAP Subparts and the effect the SSM exemption vacatur will have on the particular source category.

If you determine that the Subpart A SSM exemption does not apply to your facility, then the current DC Circuit ruling will have no immediate effect on site operations. However, as discussed earlier, the likelihood exists that if the SSM exemption vacatur is upheld, individual NESHAP regulations that allow an SSM exemption may be challenged or revised by EPA in the future.

If you determine that a mandate would affect site operations, your company should begin strategic planning as soon as possible to determine how it will address future *(Continued on page 14)*

Table 1. Effects of the SSM Exemption Vacatur on a Sampling of Specific NESHAP Subparts

40 Part 63	Subpart A General Duty Clause currently applies	Subchapter Specific SSM Requirements
Subparts F, G, H Synthetic Organic Chemical Manufacturing		X
Subpart S Pulp and Paper Industry	X, dependent on emission limit	X, dependent on emission limit
Subpart GG Aerospace Manufacturing	X	
Subpart MM Combustion Sources at Pulp Mills	X	
Subpart GGG Pharmaceutical Production		X
Subpart LLL Portland Cement Manufacturing	X	
Subpart AAAA Municipal Solid Waste Landfills	X	
Subpart DDDD Plywood and Composite Wood Products		X
Subpart YYYY Gas Turbines		X

Milestones Related to the SSM Exemption Vacatur

- **September 12, 2008** – *Sierra Club v. the EPA* was argued before the DC Circuit[8].
- **December 19, 2008** – the DC Circuit vacated the SSM exemption.
- **January 28, 2009** – the DC Circuit granted EPA a 60-day extension to file for rehearing of *Sierra Club v. EPA* and the SSM exemption vacatur was stayed during this 60-day period.
- **April 3, 2009** – the American Chemistry Council requested a rehearing of *Sierra Club v. EPA* and the SSM exemption vacatur was stayed until the DC Circuit decides if the case will be reheard.
- **May 29, 2009** – EPA issued a brief that opposed industry requests for the DC Circuit to reconsider its decision in the *Sierra Club v. the EPA* case.
- **July 22, 2009** – Mr. Adam M. Kushner, Director of Civil Enforcement for EPA, issued a guidance letter titled "Re: Vacatur of SSM Exemption (40 CFR 63.6(f)(1) and 63.6(h)(1)".
- **July 30, 2009** – the DC Circuit denied the American Chemistry Council request for a rehearing.
- **August 5, 2009** – EPA filed a motion seeking a 60-day stay on the mandate to vacate the SSM exemption.
- **August 6, 2009** – industry interveners filed a motion to stay the mandate pending appeal of the decision to the United States Supreme Court.
- **September 23, 2009** - the DC Circuit granted EPAs request and denied the industry intervenors motion. The DC Circuit can issue the mandate to vacate the SSM exemption as early as October 6, 2009, which is approximately 60 days from EPAs request dated August 5, 2009.

[8] Case No. 02-1135.

Navigating NSPS Subpart Db for Boilers: A Case Study

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Over the past year, Trinity assisted a chemical company with the permitting and installation of a new 220 MMBtu/hr package boiler. The new natural gas-fired boiler replaces coal-fired units that were installed in the 1940s. Navigating through the numerous, and at times conflicting, regulatory requirements applicable to such a unit has been challenging. With careful planning and implementation, the project resulted in a successful and compliant start-up of the new unit.

Project Background

For more than 60 years, steam needed for process and comfort heating, as well as electricity generation at the facility, was provided by boilers primarily fired by coal with No. 6 fuel oil as backup. Electrostatic precipitators (ESPs) were used to control particulate matter and the main boiler stack was equipped with a continuous opacity monitoring system (COMS). Additionally, the facility's Title V permit required extensive and labor-intensive monitoring which included field verification of ESP operating parameters, sampling and analyses for verification of the sulfur content in the coal burned, operation and maintenance of a local sulfur dioxide ambient air monitoring station, and monitoring of boiler operating parameters for parametric determination of nitrogen oxides (NO_x) emissions.

The new boiler is fired primarily with natural gas and is capable of burning No. 2 fuel oil as backup. The boiler is equipped with low NO_x burner technology, flue gas recirculation, and Selective Catalytic Reduction (SCR) technology for the reduction of NO_x emissions when burning natural gas. The SCR system uses a vanadium/titanium catalyst with anhydrous ammonia as the reductant. The reductant is injected immediately downstream of the boiler flue gas outlet where the temperature range is approximately 500 to 700° F for maximum NO_x conversion. The system is designed to reduce NO_x emissions by at least 90% during normal operation.

The boiler exhaust stack is equipped with a NO_x Continuous Emissions Monitoring System (CEMS) to measure and record NO_x emissions. This is the primary NO_x CEMS. Additionally, a sample line of stack exhaust gas is directed to a small oxidizer which converts residual ammonia from the SCR to nitrogen monoxide. The converted gas sample is then analyzed in a secondary NO_x CEMS and the difference between the NO_x readings of the primary and secondary CEMS is calculated by the Data Acquisition and Handling System (DAHS) to determine ammonia slip. The DAHS also receives data from the facility's distributed control system so that boiler operators can monitor other operating parameters related to the boiler's performance on the DAHS display screen.

> *Initial compliance with NSPS Db can be challenging, even for a boiler with a relatively clean fuel firing scenario...*

Regulatory Requirements and Compliance Considerations

The new boiler meets the definition of an affected facility under the NSPS for industrial, commercial, and institutional steam generating units contained in 40 CFR 60, Subpart Db (NSPS Db). These requirements are fuel dependent and, for a unit firing natural gas and "very low sulfur fuel" (containing 0.30 weight percent sulfur or less), include limits on NO_x at all times and opacity during fuel oil firing. The No. 2 fuel oil used as a backup meets the requirements of "very low sulfur fuel." Such units are exempt from NSPS Db limitations on particulate matter and sulfur dioxide emissions but must maintain fuel records certifying compliance with the very low sulfur fuel criteria.

NSPS Db limits opacity to 20% based on a six-minute average except for one six-minute period per hour not to exceed 27% opacity. The new boiler is also subject to a State Implementation Plan (SIP) opacity standard of 20%, based on a three-minute average in any one hour or fifteen minutes in any 24-hour period. These similar, but not identical opacity requirements, were both considered in determining the facility's compliance strategy.

NSPS Db allows for the implementation of a site-specific opacity monitoring plan in lieu of installing a COMS for units fired with natural gas and very low sulfur fuel oil. In developing the site-specific monitoring plan, Trinity presented two options for the client's consideration.

Option 1: Method 22/Method 9 Tiered Frequency Approach

Option 1 was based on the alternate monitoring options added to NSPS Db in the January 2009 revision (outlined in 40 CFR §60.48b(a)). Affected facilities meeting certain requirements may choose the alternate monitoring option in lieu of installing a COMS. This approach provides for the use of Method 9 and Method 22 opacity determinations for sources that are expected to have no significant visible emissions. The required duration and frequency for these determinations is based on the results of the most recent observations. For example, if the most recent Method 9 opacity determination yielded a result of 10% or less, a 10-minute Method 22 observation may be conducted daily when the affected unit fires fuel for which an opacity standard is applicable to demonstrate that the sum of the occurrences of any visible emissions does not exceed 5% of the observation period. That is, visible emissions are observed for less than 30 seconds during a 10-minute observation period. If the sum of visible emissions occurrences exceeds the 5% threshold, then

a 30-minute Method 22 observation must be conducted immediately. If the sum of the occurrences of visible emissions is again greater than the 5% threshold (i.e., visible emissions are observed for 90 seconds or more during the 30-minute observation period) then a new Method 9 determination must be performed within 24 hours. On the other hand, if no visible emissions are observed for 30 operating days during which an opacity standard is applicable, Method 22 observations may be reduced to once every seven applicable operating days. If any visible emissions are observed during the once per seven day schedule, then daily observations must be resumed.

Option 2: Method 9 Regular Frequency Approach

The second site-specific monitoring plan option was based on a review of letters previously issued by EPA with respect to acceptable alternate monitoring plans for NSPS Db opacity requirements contained in the Applicability Determination Index database. The second option requires performing a 6-minute Method 9 observation daily during periods of No. 2 fuel oil firing when the opacity standard is applicable.

Both options would require an alternate monitoring plan approved by the regulatory authority. Although the second approach requires the client to obtain Method 9 certification for several employees, it was chosen over the first option because it is a less complex approach and the facility does not anticipate burning No. 2 fuel oil very often. Further, since the Method 9 determinations are based on six-minute observations, compliance with the SIP opacity requirement based on three-minute observations can be confirmed as well.

The new boiler is subject to the NSPS Db NO_x emissions limit of 0.20 lb/MMBtu based on a 30-day rolling average which applies at all times, whether burning natural gas or fuel oil, and including periods of startup, shutdown, and malfunction. The boiler's construction permit also contains a SIP NO_x limit of 5 ppmvd (corrected to 3% oxygen) based on a three-hour rolling average basis. Unlike the NSPS Db limit, the SIP limit only applies when firing natural gas. Recognizing the need for the SCR to achieve a specified minimum temperature in order to efficiently remove NO_x, the SIP limit does not apply during periods of boiler cold start. As such, this requirement led to the inclusion of a definition for cold start in the permit, limiting cold start duration to a certain number of hours per year, in order to clarify compliance requirements per year. Compliance with both NO_x limits is determined based on hourly block averages calculated from the NO_x values measured by the CEMS analyzer. However, the difference in averaging times and applicable operating conditions between the two limits complicated the programming of the DAHS. The data is classified or "tagged" with process and monitoring codes that indicate the specific operating conditions at the time it is obtained (e.g., data is tagged as cold startup, warm startup, normal operation, shutdown, malfunction, etc.) based on digital signals received from the plant DCS, the CEMS sample system, or manually input by boiler operators. Similarly, the fuel type being burned at the time a given data point is collected is also determined from signals received from the DCS. The DAHS is programmed to evaluate these process and monitoring codes in conjunction with the data validation criteria required by NSPS Db to determine what data should be included in the calculation of the three-hour and 30-day average NO_x emissions values for comparison against the applicable limitation. Given these complexities, great care was taken to ensure that the DAHS vendor and plant operations team properly programmed the system before initial startup of the unit.

Additional Challenges

In addition to the aforementioned implementation challenges, there were a myriad of regulatory requirements for installing and operating a CEMS. The NO_x CEMS is required to meet the requirements of 40 CFR Part 60 which includes the performance specifications in Appendix B and the quality assurance procedures in Appendix F. These requirements include regular calibration of the analyzers and quarterly audit testing – Relative Accuracy Test Audits (RATAs) and Cylinder Gas Audits (CGAs). Additionally, a new CEMS must be certified initially for compliance with the applicable federal performance specifications. The required timing for this initial certification, which involves a RATA and 7-day calibration drift test, is not specifically addressed in the construction permit.

(Continued on page 14)

Class I Area Impact Analyses – Recent Guidance and Updates

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As recommended in Appendix W of 40 Code of Federal Regulations (40 CFR) Part 51 (Guideline on Air Quality Models), the CALPUFF modeling system has been widely used for long-range transport dispersion modeling analyses, especially for applications related to Class I Area analyses (e.g., regional haze evaluation and Class I Prevention of Significant Deterioration (PSD) increment analysis). As U.S. EPA, Federal Land Managers (FLMs), and state agencies have become more knowledgeable on the use of CALPUFF for Class I Area impact analyses, regulators have made case-by-case determinations regarding when analyses are required and what user-defined model inputs are appropriate. However, requirements for Class I Area analyses remain widely disparate across the U.S.

At the 2009 Regional, State, and Local Modelers Workshop, held on May 11–14, 2009 in Philadelphia, Pennsylvania, the FLMs provided an update including topics related to the application of CALPUFF for Class I Area impact analyses and the Draft 2008 Federal Land Managers' Air Quality Related Values Work Group (FLAG 2008) guidance. The update addressed many issues applicants have been facing in recent submittals including how a site can screen out of a Class I Area impact analysis, selection of user-defined input parameters for CALMET data preparation, and acceptable methods for post processing. On August 31, 2009, the EPA posted a clarification memo, [*EPA-FLM Recommended Settings for CALMET*], on the Support Center for Regulatory Atmospheric Modeling (SCRAM) website. Each of these topics is addressed in more detail below.

When Should a Class I Impact Analysis Be Conducted?

FLAG 2008 guidance incorporates findings from recent scientific studies and methodologies for conducting visibility analyses based on experience gained through implementation of the Regional Haze Rule. The most substantial change to the guidelines is the setting of a threshold ratio of emissions to distance, below which AQRV review is not required. Specifically, if

Q (tpy)/d (km) < 10, no AQRV analysis is required

Where,

- Q is the emissions increase of sulfur dioxide (SO_2), oxides of nitrogen (NO_X), particulate matter less than 10 microns (PM_{10}), and sulfuric acid mist (H_2SO_4), combined in tons per year (tpy)
- d is the nearest distance to a Class I Area in kilometers (km)

This proposed screening approach (10 D Rule) was discussed at the 2009 Workshop with a note that applicants must convert maximum 24-hour emissions (lb/hr) of SO_2 + sulfates (SO_4) + NO_X + PM Coarse (PMC) + PM Fine (PMF) + secondary organic aerosols (SOA) + Elemental Carbon (EC) into tons per year (tpy) before applying the 10 D Rule. If Q/d is less than 10 for a Class I Area, then presumptively, there is no adverse impact and a project "screens out" of a Class I AQRV analysis. If Q/d results in a value above 10, a Class I analysis is required. Once FLAG 2008 is finalized, this new screening approach will assist applicants in determining if a Class I AQRV analysis is required. However, there may still be instances when an AQRV analysis is not required, but a Class I increment analysis is still requested by EPA.

Meteorological Data Preparation

A primary concern regarding input meteorological data preparation using CALMET is the user selection of non-default values. Some of the parameters most scrutinized recently are the horizontal receptor grid spacing, radius of influence (RMAX 1, RMAX 2), and the weighting

provided in the Step 1 wind field (R1 and R2) when an applicant is preparing CALMET data using the Diagnostic Wind Module.

The developer of the CALPUFF modeling system has provided guidelines for determining these values, and recently, BART protocols have included requirements for particular regions of the country. Despite these resources, FLMs can have varying opinions on these issues, especially in the case of PSD analyses. The meteorological data setup is highly contingent on the modeler with respect to selection of appropriate RMAX 1, RMAX 2, R1 and R2 values. Modelers should not select input values just because they were used by a previous applicant. In addition, the FLMs have communicated that CALPUFF-ready data sets provided by regional planning organizations is not acceptable for PSD modeling. Rather, an applicant can use existing BART-related MM5 data sets along with the settings for RMAX 1, RMAX 2, R1 and R2 detailed in EPA Clearinghouse memos to create a CALMET data set for a specific project.

Post-Processing Methods

There are numerous methods available in the CALPOST post-processing module to calculate background light extinction using the original FLM background extinction equation. The Interagency Workgroup on Air Quality Models (IWAQM) Phase 2 guidance recommends "Method 2," which uses hourly relative humidity adjustment applied to background and modeled sulfate and nitrate with the relative humidity factor (f(RH)) capped at 95 percent to compute visibility impairment in terms of percent change of the light extinction coefficient (b_{ext}) from modeled pollutant concentrations.

An alternative approach, "Method 6," computes b_{ext} using a monthly average relative humidity adjustment particular to each Class I Area applied to background and modeled sulfate and nitrate. Because a monthly average is used, no cap on f(RH) is necessary since the function is not used in Method 6 and the results tend to be smoothed out since peak short-term humidity events are not considered. In addition, the Interagency Monitoring of

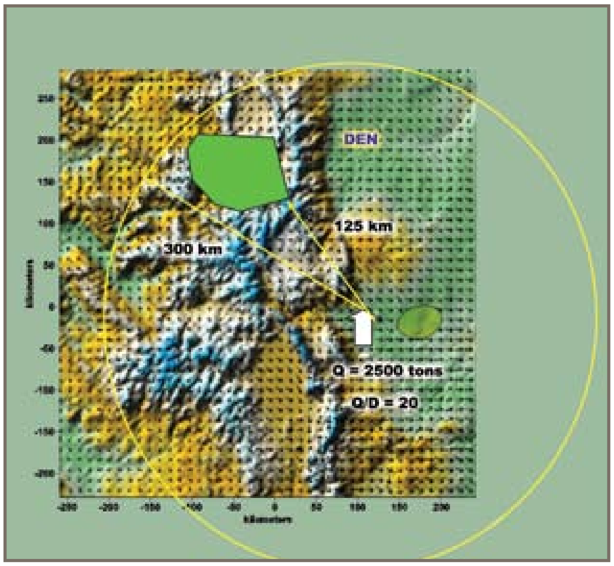

Illustration of the proposed Q/d screening approach for Class 1 area AQRV analysis.

Protected Visual Environments (IMPROVE) workgroup proposed a more robust equation that was used for some BART projects. The Eastern regional planning organization, VISTAS, developed an initial revised IMPROVE algorithm spreadsheet for an applicant to manually calculate light extinction by entering the results from the CALPOST Method 6 output file, along with NO_x concentration data and several other parameters specific to the location of the project in the U.S., resulting in a newly calculated light extinction value. Values for the natural background conditions at Class I Areas to be modeled can be obtained on an annual average basis from EPA's *Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule*. This algorithm is now available in CALPOST as "Method 8."

Recently, applicants have been requested by FLMs to follow the historical method of post-processing (Method 2) and include the two newer methods (Method 6 and Method 8) as supplemental results. Until FLAG 2008 is approved, Method 2 is required for all PSD projects. If any other methods are submitted, they are reviewed as supplemental information. The thresholds for determining a no-impacts determination varies greatly between these methods.

FLAG 2008 proposes to compare the 98th percentile of the daily values per year to the threshold, allowing for seven days per year, to exceed the threshold before additional review of impacts is warranted. This method was reconfirmed at the 2009 Workshop. Applicants should be advised this is not the 21st high or a 3-year average. If one year exceeds the 98th percentile, it fails the FLAG 2008 test. This new guidance will help remove subjectivity from visibility analyses for Class I Area impact analyses.

Under FLAG 2008, if an adverse impact is determined, additional refined analyses can be conducted using hourly (instead of daily) data and fundamental aerosol and visibility theory to assess impacts when an adverse impact is predicted using the standard prescribed methods. These analyses should be conducted in close consultation with the reviewing authority.

Although requirements for dispersion modeling for Class I Area analyses continue to be somewhat variable in different geographies, the FLMs, EPA, and state regulators are working to standardize guidance to the extent possible. However, facilities that must conduct Class I Area Impact analyses using CALPUFF should continue to work closely with pertinent regulatory personnel in order to verify modeling requirements. ◈

Preparing for EPA's Mandatory Reporting of Greenhouse Gases Rule

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Recent action by the US EPA to finalize the Mandatory Reporting of Greenhouse Gases (GHG) Rule means that environmental managers must now seriously examine whether they are fully prepared to address the imminent requirements. This article provides some assistance by summarizing key points regarding the final versus proposed rule, providing clarification on key questions that have arisen since the rule was proposed, and recommending action items that should be completed now to help ensure compliance.

Mandatory Reporting of Greenhouse Gases Rule Passed

On September 22, the EPA Administrator signed the final Mandatory Reporting of Greenhouse Gases Rule. Although there had been some discussion about EPA potentially delaying the reporting of GHG emissions for one year, **EPA did not revise the reporting schedule in the final rule.** The final rule requires annual reporting, with the first reports due on March 31, 2011 for calendar year 2010 emissions. This means that monitoring, reporting and recordkeeping activities must begin on January 1, 2010 at subject facilities.

The final GHG reporting rule contains some slightly modified requirements compared to the proposed rule. Most notably, the final rule excludes several sectors from reporting at this time, including the following:

- Electronics manufacturing
- Oil and natural gas systems
- Ethanol production
- SF_6 from electrical equipment
- Fluorinated GHG production
- Underground coal mines
- Food processing
- Wastewater treatment
- Industrial landfills
- Suppliers of coal
- Magnesium production

In addition, similar to the flexibility allowed under the California Air Resources Board (ARB) AB 32 GHG reporting requirements, EPA will allow facilities to exit the reporting program if they invest in reducing GHG emissions, as follows:

- Cease reporting after 5 consecutive years of emissions below 25,000 metric tons CO_2e/year
- Cease reporting after 3 consecutive years of emissions below 15,000 metric tons CO_2e/year
- Cease reporting if the GHG-emitting processes or operations are shut down

Other significant revisions and clarifications to the rule include the following:

Emissions Calculations: The use of the Tier 2 calculation method for CO_2 emissions was expanded to include units greater than 250 MMBtu/hr that combust only pipeline natural gas and/or distillate oil.

Exemptions: EPA added exemptions for unconventional fuels, flares, hazardous wastes, and emergency equipment.

Aggregation: More facilities will be able to report aggregate emissions from smaller units rather than report emissions for each individual unit. The proposed rule limited the aggregation of any one group to a combined maximum capacity of 250 <MMBtu/hour heat input. The final rule allows grouping of any units that individually are less than 250 MMBtu/hour heat input.

Fuel Sampling: The fuel sampling frequency for Tiers 2 and 3 was reduced for fuels that are homogeneous or delivered in shipments or lots. Averaging of fuel sampling results is also permitted in certain circumstances. Finally, fuel sampling (as provided by the fuel supplier) as well as the use of fuel billing records to quantify fuel consumption is permissible.

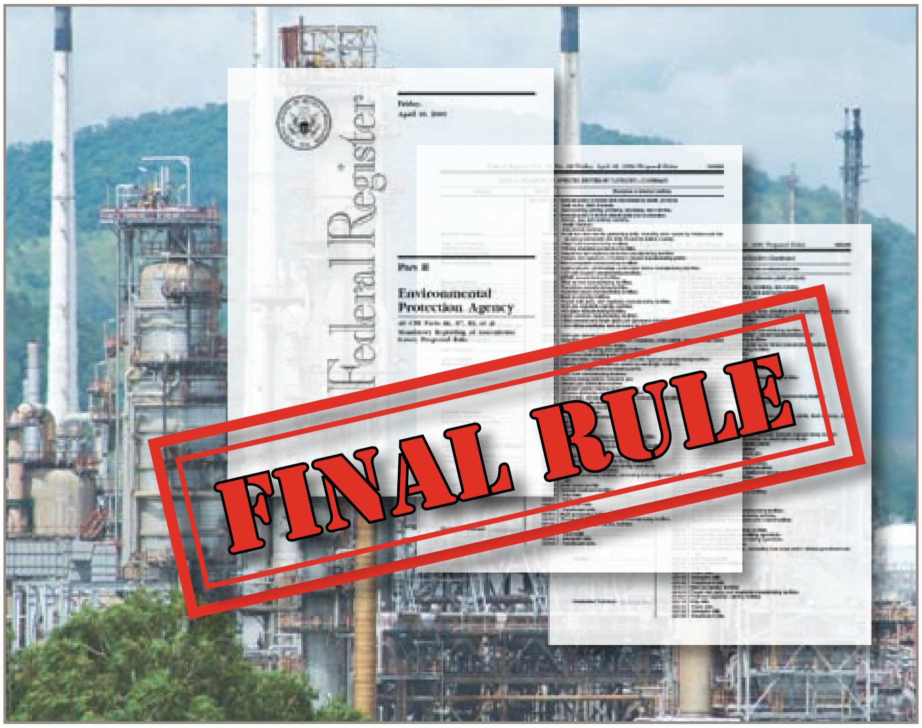
Missing Data: The final rule provides additional clarification and flexibility regarding missing heating value, carbon content, and molecular weight data.

Monitoring: EPA added a provision to allow use of best available monitoring methods in lieu of required monitoring methods for January - March 2010; extensions for this flexibility beyond March 2010 will be considered but will not be granted after 2010. EPA also added monitoring provisions that allow engineering calculation estimates to preclude the need for new monitor installation.

Verification: To better allow EPA to verify reported emissions, more data must be reported rather than kept as facility records.

Electricity Indirect Emissions: Both the proposed and final rules do not require submittal of emissions or usage data regarding electricity purchased.

The final rule will go through a congressional 60-day review period because it is a major rule and must comply with Congressional Review Act (CRA). During this review period, the major rule will be suspended and Congress will either allow the rule to take effect or provide recommendations. There is a chance that passage of the final rule could be challenged, but that would take both houses of Congress to pass a Joint Resolution of Disapproval which must then be signed by the President. If the President vetoes the Resolution, Congress would then have 30 session days to override the rule and prevent it from becoming effective. This is an unlikely scenario given that the final rule stemmed from the congressional Consolidated Appropriations Act.



Q&A Related to the Mandatory Reporting of Greenhouse Gases Rule

As with most Clean Air Act regulations, questions have inevitably arisen on the Mandatory Reporting of Greenhouse Gases Rule concerning key applicability provisions – specifically, the universe of equipment at affected facilities that may be subject and the emissions calculation methodologies that should be applied. Trinity has an in-depth understanding of the questions that many industry sectors have raised on various portions of the rule. Since the proposed GHG reporting rule appeared in the Federal Register in early April, Trinity has provided training to nearly 1,000 environmental professionals on all aspects of the rule in a series of webinars and workshops. Based on this interaction, we have observed some common themes in the questions that we have heard.

Question: If my facility is subject to a certain subpart of the rule, am I required to report my emissions from other subparts?

Answer: The short answer is that many facilities may very well need to report emissions from numerous source categories covered by multiple subparts in the rule. The extent to which a facility must address multiple subparts depends upon which criteria (from Subpart A - General Provisions) trigger rule applicability. Facilities are subject to the rule if they meet specific criteria under sections 98.2 (a)(1), 98.2(a)(2), 98.2(a)(3), or 98.2 of Subpart A. These "doorways" into the rule determine whether or not your facility will need to report emissions using methodologies specified in one or more of the source category subparts B through PP.

If your facility is subject to 98.2(a)(4) for suppliers of fuel and industrial GHG's, then you must report the GHG emissions that cover all applicable products for which calculation methodologies are provided in subparts KK through PP. If your facility is subject due to exceeding 25,000 MT CO_2e from combustion sources as specified in 98.2(a)(3), then you need only report emissions from stationary combustion sources, and you are not required to report under any other source category. If your facility is subject due to exceeding the 25,000 MT CO_2e threshold specified in 98.2(a)(2), then you must report the GHG emissions from all source categories for which calculation methodologies are provided in subparts C through JJ. Lastly, if your facility meets one of the source category definitions listed in 98.2(a)(1), then you must report all sources in any source category for which calculation methodologies are provided in subparts C through JJ.

Question: What subparts should I be looking at when determining applicability if I'm subject to sections 98.2(a)(1) and 98.2(a)(2)?

Answer: As discussed above, facilities should first determine which "doorway" triggers rule applicability for their operations. Once a facility has determined that it is subject to the rule, subparts C through JJ should be thoroughly examined. That is, the source categories listed in 98.2(a)(1) and 98.2(a)(2) are an aggregated list of industry types that may have emissions from equipment covered under a number of subparts in the rule. For example, if you are responsible for a Glass Production facility, your facility would be subject to Subpart N, Glass Production. However, your facility may also be required to report emissions addressed under Subpart U, Miscellaneous Use of Carbonates. The only way to determine applicability is to examine each subpart and to determine if your facility meets its applicability definitions. Similarly, a facility subject to the Petrochemical provisions in Subpart X should also evaluate the possible reporting requirements addressed in Subpart C (Stationary Source Combustion) and Subpart D (Electric Generating Units).

Table 2 in the preamble to the rule provides a guide for a facility to consider which ancillary subparts to review, in addition to reviewing the main subpart which triggered applicability for that facility.

Question: What is considered a biogenic fuel?

Answer: Ethanol, animal waste used as fuel, biogas, and many other types of biogenic fuels must be reported if a facility exceeds the reporting threshold. Biogenic CO_2

means carbon dioxide emissions generated as the result of biomass combustion from combustion units for which emission calculations are required. Biomass means non-fossilized and biodegradable organic material originating from plants, animals or microorganisms, including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material.

It is important to note that emissions from the combustion of biogenic fuels from down-stream emitters would not be included in the initial baseline emissions calculations – but if a facility exceeds the minimum threshold and combusts biogenic fuels – those emissions would be reportable. For the final rule, EPA decided not to apply the same approach to suppliers of CO_2. The preamble to the final rule states that EPA has concluded that data on capture of biogenic CO_2 would be useful and informative because biogenic CO_2 can potentially be stored in geological sequestration sites, or displace fossil CO_2 applications. Thus, a facility that captures CO_2 from biomass and otherwise meets the applicability test is covered under 40 CFR Part 98, Subpart PP and is required to report all CO_2 supplied along with the percentage of that supply that is biomass-based.

Question: Are emissions from "other" types of stationary combustion sources such as control devices, emergency generators, and flares required to be reported?

Answer: The final rule clarifies the applicability of several "other" types of stationary combustion sources. The final rule defines stationary combustion sources and specifies the types of stationary combustion equipment that are exempt under Subpart 98.30. Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters.

Sources that are exempt from the rule include:

- Portable equipment
- Emergency generators and emergency equipment
- Irrigation pumps at agricultural operations
- Flares, unless otherwise required by provisions of another subpart of 40 CFR Part 98
- Electricity generating units that are subject to Subpart D
- Units that combusts hazardous waste unless either of the following conditions apply:
  - Continuous emission monitors (CEMS) are used to quantify CO_2 mass emissions
  - Any fuel listed in Table C-1 of the rule is also combusted in the unit

In addition, EPA has determined that units larger than 250 mmBtu/hour heat input that combust miscellaneous, non-traditional fuels such as refinery gas, process gas, vent gases, waste liquids, and others must report only if CEMS are used or if these fuels contribute 10 percent or more of the annual unit heat input to the unit. With this exclusion, EPA has concluded that devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment would report **only** GHG emissions from the firing of supplemental fossil fuels.

Question: Will my facility be required to install a CEMS?

Answer: The rule requires direct measurement of emissions from certain units that already are required to collect and report data using CEMS under other programs (e.g., ARP, NSPS, NESHAP, SIPs). In some cases, this may require upgrading existing CEMS that currently monitor criteria pollutants to also monitor CO_2 or add a volumetric flow meter. For facilities with units that do not have CEMS installed, reporters may either install and operate CEMS to directly measure emissions or use facility-specific GHG calculation methods. The measurement and calculation methods for each source category are specified in each subpart. As policies and programs evolve and/or particular calculation or monitoring equipment improves, EPA will evaluate whether or not to update the methodologies in the rule. EPA has made changes to individual subparts of 40 CFR Part 98 to clarify when CEMS and CEMS upgrades are required and has made other changes to reduce the monitoring burden.

Sources that have all of the necessary CEMS installed and are certified by January1, 2010 must use Tier 4 in 2010. However, sources that need additional time to upgrade their CEMS can use a lower tier calculation methodology for 2010 and begin to use CEMS on January 1, 2011.

Question: How will existing GHG registries interact with the EPA rule?

Answer: Reporters may not provide data submitted to another registry in lieu of the EPA rule mechanisms. For example, at this time, EPA will not allow an organization to submit GHG emissions data to The Climate Registry (TCR) in lieu of reporting to the EPA using EPA's reporting requirements. EPA has stated that it is developing an electronic reporting system, but it has not been released yet.

The rule preamble notes that EPA extensively reviewed existing mandatory and voluntary programs to ensure that, to the extent possible, similar methodologies could be used. Nevertheless, EPA developed a reporting rule that is focused on direct emissions and stationary sources, so there are some differences between EPA's rule and existing GHG registries. While there are many similarities between EPA's rule and other methodologies (e.g., IPCC, TCR), companies must follow the guidelines provided within the EPA rule and report emissions via the reporting system that EPA will develop.

Recommended Path Forward

Because EPA chose to maintain the schedule of initial required reporting in March 2011, based on 2010 monitoring data, prudent environmental managers have begun to establish their recordkeeping and reporting structure.

Trinity recommends several key steps to organizations for establishing a GHG Reporting Rule compliance structure:

- Analyze existing GHG inventory and determine whether the facility is subject (documenting non-applicability as appropriate)
- Compare existing GHG calculation methodologies versus requirements in the Rule
- Compare current monitoring and record keeping practices versus requirements in the Rule
- Develop a plan for closing the gaps between existing methodologies/ practices and the Rule requirements
- Understand and outline the elements of he required Quality Assurance Performance Plan (QAPP)

With these steps completed, your facility will be well on the way toward sound compliance with the Reporting Rule and better positioned to address the GHG mitigation programs that may lie ahead. For assistance with determining applicability and complying with this significant new rule, contact Katherine Blue, Climate Change Practice Leader at (404) 256-1919 or *kblue@trinityconsultants.com*. ❖

Trinity Receives Accreditation to Perform California AB 32 GHG Verification

Trinity Consultants was recently approved as an accredited verification body by the California Air Resources Board (ARB) to perform verification of greenhouse gas (GHG) reporting under the California Global Warming Solutions Act of 2006 (AB 32). Under the regulation, affected organizations must measure, calculate, report, and verify their GHG emissions if they are in affected industry sectors (cement, electricity, petroleum refineries, cogeneration, and hydrogen plants) or if they are a general stationary combustion source that generates at least 25,000 metric tons of CO_2 in a calendar year.

AB 32 requires that affected organizations have their GHG reports verified by accredited verifiers. Accreditation involves successful completion of training and testing by California ARB. Trinity has three accredited verifiers, with approval in all accreditation categories—General, Cement, Refinery, and Electricity Transaction.

In June 2009, subject facilities were required to submit their 2008 GHG inventory and annually thereafter. Verification is optional for all sources for the 2008 GHG inventory and required for all sources for the 2009 GHG inventory and thereafter. Verification opinions are due to ARB six months after submission of the GHG inventory.

Trinity's consultants are particularly well suited to provide these services due to extensive expertise with air emissions quantification, local understanding of the AB 32 regulatory requirements, familiarity with affected industrial sector operations, and auditing knowledge. According to Lead Verifier and Trinity's Irvine, California office manager, Vineet Masuraha, "We are pleased that we will be able to assist the approximately 800 affected facilities who will be required to verify their GHG emissions reports under AB 32." Facilities needing GHG verification assistance can contact the Irvine office at (949) 296-4100 or by email at *vmasuraha@trinityconsultants.com*. ❖

BREEZE Software Releases AERMOD/ISC Version 7.1

BREEZE Software releases its first update to AERMOD/ISC Version 7, first introduced in early 2009. The 7.1 Version includes enhancements requested by current users. We will explore four of these new features.

ISCST3 Integration

BREEZE has integrated both the AERMOD and ISCST3 model into the same graphical user interface (GUI). Users can run the standard U.S. EPA models of ISCST3 and ISCPrime. To switch between AERMOD and ISC, simply choose the desired model in the application options form. This feature is accessed through the blue "b" icon in the upper left corner of the application and next selecting the Options button. ISCST3 integration is available in our Pro and Pro Plus editions.

Roadway Tool for Volume Sources

The roadway tool was added to assist in the creation of roadways made up of volume sources. Simply draw the roadway, enter the vehicle height, adjusted roadway width, emission rate, and choose whether or not you want the roadway to be represented as adjacent or separated volume sources, and that's it! The roadway tool is available in our Pro and Pro Plus editions.

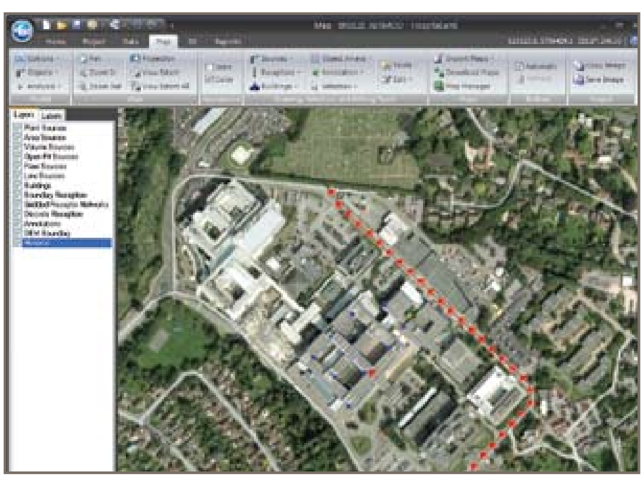
Sensitive Receptors

The sensitive receptor option allows users to flag discrete receptors as being "sensitive". *BREEZE* AERMOD will create a separate grouping of receptors that can be viewed in the ASCII AERMOD output file and in an HTML report file. This option allows for easy identification of selected concentration results from AERMOD model runs.

Heightmaps and Shaded Relief Maps

Heightmaps and shaded relief maps are compatible with the 09040 version of AERMAP. This feature was only available in the 06341 version of AERMAP previously.

Maintenance users will receive *BREEZE* AERMOD/ISC Version 7.1 download instructions via email. Contact us today at (972) 661-8881 to purchase software maintenance to receive software support and the Version 7.1 update.



The new roadway tool allows users to create roadways made up of volume sources. Available in BREEZE *AERMOD/ISC version 7.1.*

BREEZE AERMOD is available in three editions allowing users to choose the level of functionality they need. Download *BREEZE* AERMOD Standard for free at **breeze-software.com/freeaermod!** Learn more about *BREEZE* Software and view video demonstrations at **breeze-software.com.** ✥

Fine-Tuning EH&S Performance with Technology

HUNG-MING (SUE) SUNG, PH.D
DIRECTOR, QUALITY & TECHNOLOGY —DALLAS

Despite challenging economic circumstances, environmental compliance is a business obligation that cannot be ignored. However, regulatory compliance is not the only aspect of environmental management that should be considered. Careful environmental management is a growing concern among consumers and the public image of a company is greatly influenced by how the company handles its environmental responsibilities. In virtually all organizations, there are also opportunities to improve efficiency by analyzing and streamlining environmental information management. One possibility for addressing all of these issues and adding value to the company is through the implementation of an EH&S management information system (EMIS).

Benefits of EMIS

Efficiently maintaining environmental compliance is not possible without developing a careful process to ensure that all permit requirements are met. Manual methods that rely on informal paper processes can result in duplication of tasks and inconsistencies in reporting, as well as a considerable margin for error. Countless labor hours are wasted trying to maintain records of hundreds of tasks. This overwhelming load cannot be effectively managed by any single individual and is often too costly to spread among several staff. Increasing the number of staff involved is costly and adds to the complexity of the system, raising the likelihood of compliance demonstration difficulties.

While manual compliance management is expensive and can reduce levels of compliance, implementation of a technology-based EMIS can help ensure that all environmental compliance requirements are met in the most cost-effective way. An EMIS provides the means to centralize control of all compliance tasks while eliminating the burden and costs of maintaining countless spreadsheets that can easily be overlooked, as well as the other negative impacts of a distributed system. An EMIS will considerably reduce the time spent gathering the data required to demonstrate compliance while providing greater accuracy through validation of data inputs.

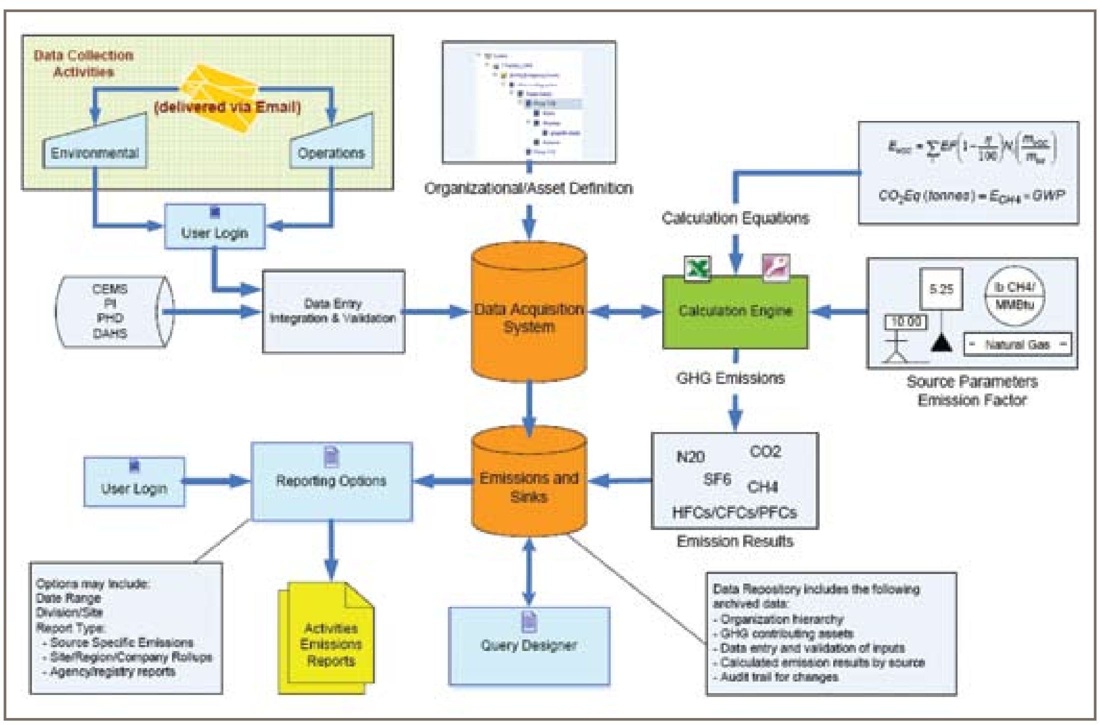
Reporting efficiency is improved through the utilization of a single, centralized system. Considerable savings can be realized by submitting required information electronically rather than providing paper reports, eliminating paper costs and contributing to a positive influence on the public perception of the company's approach toward the environment.

Financial gains that result from an EMIS are not the only available benefits that a company can realize. Risk is reduced through access to data that can be relied upon for accuracy and availability. The EMIS provides a way to look at historical information and to make projections regarding the future so that measures can be taken to better deal with potential risks. Communication channels also benefit from the EMIS by ensuring that the appropriate staff receives the notifications that are critical to their job functions, enabling them to be more productive and have easier access to the information they need, when they need it. Improved channels of communication also lead to more efficient use of the company's invaluable asset of its collective knowledge. Ensuring that all of the right information gets to the right person at the right time is an enormous benefit. It increases productivity and creates a better working environment by eliminating the chaos associated with an unmanaged knowledge base.

The Bottom Line

Ultimately, a company must be profitable and the functions of the environmental program must contribute to that profitability. Without an EMIS in place to accurately gather and report information, measuring such value is not possible. The EMIS gives business managers the tools and information needed to analyze the impact that environmental programs have on the company's financials. By creating goals that can be tracked and demonstrated through the EMIS, managers have an observable and concrete basis to make decisions and identify areas for improvement.

An EMIS can deliver tremendous benefits to organizations, both tangible and intangible. The company can save money as the result of a more efficient process that reduces the amount of hours required to perform tasks that can be automated. Staff will be more efficient as they are freed from performing routine duties and allowed to focus on the critical aspects of their job functions. The image of the company will be improved by demonstrating a commitment to enhancing its compliance with environmental regulations as well as taking steps to identify and mitigate potential risks. Corporate knowledge will be effectively managed and the disorder associated with a decentralized system will be molded into an efficient, effective, and accurate information system. ❖



An integrated EMIS enables streamlined emissions management, recordkeeping and reporting including GHG emissions data.

NESHAP SSM Exemption Vacatur Mandated by the DC Circuit *(Continued from page 3)*

compliance issues if compliance cannot be achieved or determined during SSM events. EPA has not indicated whether it will exercise enforcement discretion for violations or whether significant penalties will immediately ensue.

Industry and/or EPA will likely question the validity of each emission standard set by EPA, as it is likely that emissions during SSM events were not considered when setting the current emission standards. Industry may request that EPA evaluate emissions that would occur during reasonably foreseeable SSM events and establish appropriate maximum achievable control technology (MACT) standards for such events. CAA Section 112(d)(3) describes that MACT for existing sources should be determined by either the "average emission limitation achieved by the best performing 12 percent of the existing sources… of 30 or more sources" or "the average emission limitation achieved by the best performing five sources …with fewer than 30 sources." Therefore, it would be necessary to determine what the emissions were during SSM events to accurately determine what the emission standard should be for each NESHAP subpart.

Begin planning now on how to comply with NESHAP emission standards during SSM events or consider obtaining legal advice as to how to mitigate the ramifications of potential noncompliance events if continuous compliance during SSM cannot be achieved. ❖

Navigating NSPS Subpart Db for Boilers: A Case Study *(Continued from page 5)*

Performance Specification 2 in NSPS Appendix B indicates that the NO_x CEMS should be certified at the time of installation or soon after and whenever specified in the regulations. NSPS Subpart A indicates that it should be performed at the time of the required initial performance testing of the emissions unit or within 30 days of such testing. However, NSPS Db requires such performance testing be conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the boiler. This could potentially delay the CEMS certification to up to 210 days or seven months after the boiler begins normal operations. Since the CEMS is relied on for process control of the SCR, the project team decided that the CEMS certification should be conducted as soon after installation as possible.

NSPS Appendix F requires the development and implementation of a QA/QC plan for operating and maintaining the CEMS. Trinity assisted in the development of this plan which provides step-by-step procedures for calibrating and auditing CEMS performance, summarizes the data recording, calculations and reporting requirements, and provides preventative maintenance (PM) schedules and corrective actions for system malfunctions. Trinity recommended that the facility obtain a maintenance contract for at least the first year to have an outside contractor with specific CEMS expertise perform quarterly PM and to be on call in the event of a system breakdown. By doing so, the site maintenance personnel, who are also becoming familiar with the maintenance routines for the new boiler and SCR equipment, will have assistance and a resource for CEMS maintenance. Since NSPS requires the facility have emissions data for a minimum of 75% of the operating hours in any day that the boiler operates, or in at least 22 out of 30 operating days, it is imperative that the facility be prepared to repair a malfunctioning CEMS in a timely manner.

To monitor ammonia slip, the use of a primary and secondary NO_x CEMS with an ammonia converter prior to the secondary unit was accepted by the state regulatory agency as an alternative to installing a direct ammonia analyzer. This regulatory acceptance was contingent on the system being certified, however there are no performance specifications available for such a system. Absent any federal or state performance specification, the proposed certification strategy was to confirm the accuracy of the secondary NO_x CEMS via a CGA, both initially and quarterly going forward. Additionally, discrete stack testing for ammonia via EPA Conditional Test Method 027 was proposed for the initial certification of the ammonia monitoring system. Stack testing will also be performed annually to provide data to adjust the correction factor for the calculation of ammonia slip as needed.

Project Outcomes

Initial compliance with NSPS Db can be challenging, even for a boiler with a relatively clean fuel firing scenario of natural gas and No. 2 fuel oil. The new boiler is subject not only to the requirements specific to boilers in NSPS Subpart Db, but also to the general provisions of Subpart A, the performance specifications of Appendix B, the quality control requirements of Appendix F and applicable SIP regulations (including project specific construction permit requirements). However, careful planning and implementation (including assessing compliance risks during the state construction permit issuance process) paid off with a permit that provides methods for continous compliance demonstration with maximum operational flexibility and minimum compliance burdens on the facility ❖

STAFF SPOTLIGHT

20-Year EH&S Veteran Helps Companies & Professionals Improve

With a track record that includes positions in both industry and consulting, Rhonda Grigg, P.E., CPEA is a senior EH&S professional that can do it all. Since completing her B.S. degree in Chemical Engineering from Texas A&M University, Rhonda has held EH&S roles in the defense, computer manufacturing, and food processing industries, in addition to consulting.

In each role, Rhonda added to her well-rounded and extensive knowledge of EH&S regulatory requirements affecting industry. Since joining Trinity's Dallas office in 2001, Rhonda has worked on many compliance-related projects and recently, has been largely focused on performing EH&S compliance audits and teaching several of Trinity's professional training courses, for which she is consistently rated among Trinity's top instructors.

Among Rhonda's latest achievements was her accreditation by the California Air Resources Board (ARB) as a lead verifier under the Global Warming Solutions Act of 2006 (AB 32). Rhonda was among the few verifiers who were accredited in all four areas – General, Cement, Refining, and Electricity. Rhonda is enthusiastic about providing this service to organizations in California and neighboring states, saying, "I am excited to be working with Trinity's top-notch GHG verification services team and our customers on these critical first-round baseline reports." Her extensive knowledge of environmental regulatory requirements combined with her auditing experience makes Rhonda a natural to provide this service.

Robert Liles, manager of Trinity's Dallas office, is glad to have Rhonda in his corner. "It's a pleasure to have such a strong leader in our group. Rhonda is both technically strong and a great mentor to junior staff. And most importantly, clients are always well-pleased to have Rhonda on their project," he said.

Contact Rhonda at rgrigg@trinityconsultants.com. ✥

Trinity Launches Redesigned Web Site

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- **Lake Michigan State Section of A&WMA Annual Conference** — November 12 — Downer's Grove, IL

UPCOMING WEBINARS

- **EPA Mandatory GHG Reporting – An Overview of the Final Rule** — November 5 — 12:00 pm - 1:30 pm EDT
- **EPA Mandatory GHG Reporting – An Overview of the Final Rule** — November 12 — 12:00 pm - 1:30 pm EDT

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