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Ethanol Plants

Associated Permitting and Compliance Activities

by Jessica A. Karras-Bailey and Kenneth J. Skipka

Ethanol is a word heard with increasing frequency. It is on the evening news, in the local paper, and probably posted on the gas pump you recently pulled next to. Ethanol, also known as ethyl alcohol, is used in many industries, including manufacturing, cosmetics, and beverage. Ethanol can be produced in many ways, including via natural fermentation.

Ethanol manufacturing plants are being constructed at a record pace throughout the United States, with a distinct concentration in America's Heartland. The increase in ethanol production can be linked to the decreased use of methyl tertiary butyl ether (MTBE). MTBE as a fuel additive has been banned in several States and is being phased out in many others. However, the Clean Air Act requirements that necessitate the need for MTBE or similar constituent have not changed. MTBE is an oxygenator added to gasoline to increase octane and improve combustion and decrease pollutants. Ethanol is increasingly being used as a replacement for MTBE and gas pumps all over the country have signs indicating 10% ethanol. In addition, the Renewable Fuel Standard under the Energy Bill is expected to increase the need for ethanol.

As few as ten years ago individuals scoffed and proclaimed that ethanol would never be a viable industry. Now it is a booming industry, based on corn, milo and other renewable resources as feedstocks. Ethanol production results in the generation of two additional co-products; carbon dioxide and animal feed. If the carbon dioxide is captured, it can be sold for beverages as well as for large scale,

industrial freezing operations (frozen foods, etc.). The animal feed has historically been used for cattle, but pilot programs have been conducted to determine the feasibility as feed for poultry, pigs, and fish.

As one might expect, economics also have had a major effect on the ethanol industry. A plant with the production capacity of 40 million gallons per year is expected, at current market, to generate about \$2 million per month, not to mention the increased economic benefits to the local community. Typical construction costs for a plant of this size are about \$60 million and the economics in the industry are improving, as co-products such as animal feed and carbon dioxide improve the bottom line. In addition, continued improvements in plant design and production efficiencies, such as improved yield and co-generation, also improve ethanol manufacturing economics. According to the Renewable Fuels Association, there are currently 81 plants generating about 3.4 billion gallons of ethanol in the United States and 14 more ethanol plants under construction.

Ethanol plants, like all manufacturing facilities, are subject to several environmental regulations. The regulations require that a facility obtain permits and complete numerous compliance activities associated with the Clean Air and Clean Water Acts, as well as RCRA, CERCLA, EPCRA, and others. It can be difficult and somewhat daunting to determine what regulations, permits and compliance needs are required not to mention developing a schedule to meet the needs for project development. The following summary will

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provide additional insight as to the typical environmental issues faced when building and/or operating an ethanol plant.

It is suggested that project developers contact Federal, State, and Local agencies early in the project stages. In many cases it is also helpful to work with an environmental consultant to assist with obtaining and complying with all of the necessary environmental regulations. Often environmental permits are required prior to groundbreaking activities. Many banks and other financial institutions require that, at a minimum, permit applications have been applied for to move forward with loans or other grant approval processes. The following provides general environmental requirements and typical timing; however, each project is different and should be assessed on a case-by-case basis.

Preliminary Site Assessment

RTP suggests that several activities associated with obtaining pertinent site specific data be initiated as early in project development as possible. It is prudent to obtain information with respect to land use and potential types of environmental permits and/or clearances that may be involved in locating an industrial development project in the specific locality. It is important to obtain information to determine potential constraints associated with a project site. This preliminary information will be beneficial to both site development decisions as well as future permitting application needs.

Specifically, the preliminary information obtained should include archaeological or historical sites, cemeteries/gravesites; attainment/non-attainment and/or Class I areas and local air quality; CERCLA or Superfund and RCRA sites; dams, impoundments or retention ponds; geologic conditions and existing soils; location of community wellhead protection areas; aquifer characteristics; nearby sensitive receptors; fish, wildlife and

ecologically sensitive resources; stream flows and floodplains; and wetlands. In the event that one or more of these areas indicates the need for additional information or investigation, the project team can consider options at the beginning of project start-up and if necessary, develop and initiate remediation or mitigation activities as soon as possible. By having this information early on, the project can avoid costly delays or the need to retrofit facility designs all together or select a different site.

Air Permit Application Activities

Most States require the submission and approval of an air construction permit application prior to the initiation of construction activities of an air emissions source. In some states, two air permits are required for an ethanol plant. The first is associated with construction and the second with operation. The development and submission of an air permit application package necessary for construction of the proposed ethanol plant is the critical path permit for plant development, while the operating permit can be finalized later (after plant start-up) in those states that require separate operating permits.

Most ethanol plants are being constructed and operated as synthetic minor sources. Simply put, this means that the facility opts to limit emissions through enforceable limitations on production and/or the use of add-on control technology to maintain total facility air emissions below major source thresholds. The applicable major source thresholds for an ethanol plant are generally 100 tons per year (tpy) of any pollutant that is subject to regulation under the Federal Clean Air Act, with the exception that lower thresholds apply for Hazardous Air Pollutants (HAPs - 10 tpy for an individual HAP or 25 tpy for all HAPs in the aggregate) and for nonattainment pollutants for plants that are located in areas in which one or more of the National Ambient Air Quality





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Gary McCutchen, Instructor

New Orleans, Louisiana..... September 12-16, 2005

Standards (NAAQS) have not been met. Depending upon the nonattainment pollutant and the particular nonattainment area, these thresholds can be as low as 10 tpy.

Application packages for construction of air contamination sources are usually comprised of a standardized set of permit application forms, emissions calculations representing the facility Potential-to-Emit, as well as supporting documentation regarding applicable regulatory requirements. In addition, many States require that air dispersion modeling be performed to provide documentation of compliance with National and State Ambient Air Quality Standards (NAAQS/SAAQS).

In addition to the above, ethanol plants are subject to some of the New Source Performance Standards (NSPS). These standards are also set forth under the air quality regulations under 40 CFR Part 60. NSPS requirements often applicable at an ethanol plant include Subparts Db or Dc which relate to steam boilers, Subpart Kb which applies to certain storage tanks for ethanol and denaturant, as well as Subpart VV which regulates piping, valves and other connections in VOC service and requires a Leak Detection and Repair (LDAR) program for such equipment. Other NSPS requirements may also be triggered, depending on the proposed plant design.

Storm Water Permit Application Activities

Requirements of storm water permits are outlined in each State's water quality regulations. Storm water permits for construction activities are usually issued under a general permit. The general permit requires implementation of a Storm Water Pollution Prevention Plan (SWPPP) Associated with Construction, which must incorporate any required pollution control measures.

Typically, General Storm Water permits associated with construction require the

submission of an application to obtain coverage. The application or registration is often called a Notice of Intent (NOI). In addition, as a condition of application approval and authorization issuance, a Storm Water Pollution Prevention Plan (SWPPP) must be completed prior to submitting the application.

A NOI, SWPPP and supporting documentation for a proposed project site will require site-specific information concerning the location and physical characteristics of the site and surrounding areas. In addition, facility design information is necessary for preparation and implementation of a SWPPP. It should be noted that SWPPPs often require on-site inspections and employee training, which are conducted by on-site representatives.

An ethanol plant usually requires two storm water permits for facility development - one to cover construction activities and another to cover industrial (manufacturing) activities once operations commence. As with the air permit, storm water approvals related to the construction of the plant are more critical and the second permit associated with industrial activities can be completed at a later date, but prior to facility start-up. Typically, a General Storm Water Permit satisfies applicable requirements for most ethanol plant construction.

Initiation of NPDES Utility Water Discharge Permitting

National Pollution Discharge Elimination System (NPDES) permits allow the discharge of process, non-contact or utility waters, or other industrial discharges. Although these permits are not typically required until the facility starts operation, RTP believes it is important to start the NPDES permit process as soon as possible. The basis for this recommendation is related to our past ethanol plant experience and that such permits often take six months or longer for agency review and approval. Since this permit is necessary upon start-up, it is often not initiated until

after plant construction begins. However, waiting until construction begins can lead to delays in obtaining the permit from the agency as well as increases in project development costs. It is prudent to initiate NPDES permitting activities to provide the greatest amount of flexibility to site development while considering project costs.

Additional Regulatory Compliance Activities

The activities outlined herein will provide an ethanol plant applicant with the necessary information and environmental permits to initiate construction, however, additional activities will be required. The following text describes additional permitting and environmental compliance activities that are typically associated with an ethanol plant, but that are not necessarily "critical path" for the initiation of plant construction.

As noted previously, an air operating permit for an emission source must be obtained. This permit will allow and regulate the manufacturing activities associated with the ethanol plant associated with air emissions. In addition, it is anticipated that stack testing will be a requirement of an air permit and is usually required within

six months or less of plant start-up. Ethanol plants are typically subject to 40 CFR 112(r), Risk Management Plans (RMP) as well as Process Safety Management (PSM) under OSHA. A Leak Detection and Repair (LDAR) program will also be required as part of facility operations under the Federal NSPSs.

Other permitting requirements will include the preparation of a SWPPP Associated with Industrial Activities and a Spill Prevention, Control and Countermeasure (SPCC) Plan. Aboveground storage tank (AST) registrations are commonly required as part of tank construction and operation. AST testing often require that the facility obtain a hydrostatic testing water discharge permit. The plant will also need to complete Tier II/III reporting, Toxic Release Inventories (TRI) and emissions inventories in the future.

As noted above, RTP firmly believes in initiating permitting activities early on in the planning process because of the knowledge gained about the site, permit requirements, and overall project feasibility. Also, the permitting requirements for an ethanol plant are similar to most industrial process or manufacturing facilities.

ABOUT THE AUTHORS

Jessica Bailey is a Sr. Environmental Scientist in RTP's New York office. She has a B.S. in Natural Resources from Cornell University and is a Master's Candidate in Restoration



Ecology, Rangeland Ecosystem Science at Colorado State University. Jessica has over 10 years of environmental consulting experience. She also has extensive experience in the ethanol industry. She has worked on over 25 plants in at least 8 states, which in total supported over 530 million gallons of annual ethanol production. Currently, she is providing environmental consulting services for 5 ethanol plants and working as a senior technical advisor with the industry.

Ken Skipka is a Principal and Manager of RTP's New York office. He holds an undergraduate degree in Natural Sciences from Long Island University and a graduate degree in Meteorology from



Cornell University, and is a Certified Consulting Meteorologist (CCM). Ken has over 35 years of environmental consulting experience, with a special emphasis in air permitting and compliance, environmental impact statements and assessments, air quality and meteorological monitoring programs, air dispersion modeling, air toxics, indoor air quality, and regulatory compliance. He is working with Jessica to develop and expand RTP's ethanol services.

Should you require any of the environmental consulting services discussed in this article, RTP would be pleased to provide additional information or to discuss individual projects or concerns.



The New Boiler MACT How Does It Apply to You?

by Daniel E. Taylor

40 CFR 63 Subpart DDDDD

Maximum Achievable Control Technology (MACT) refers to EPA's National Emission Standards for Hazardous Air Pollutants for specific source categories. The "Boiler MACT" addresses the National Emission Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters (40 CFR 63 Subpart DDDDD). The regulation was signed February 26, 2004 and promulgated September 13, 2004.

The Boiler MACT is presented in greater detail on our website www.rtpenv.com.

Click on the "Newsletter" link to download the RTP Reporter issue for May-Aug 2005 (Issue 6) in .pdf format to help you determine the specifics for your particular situation. Our website **BOILER MACT** aide also contains Tables 1 through 8 of 40 CFR 63 Subpart DDDDD that present control equipment information, testing and monitoring guidelines as well as "Alternative Total Selected Metals Emission Limits."

The first question to ask:

**IS THE FACILITY A MAJOR SOURCE OF HAP EMISSIONS?
IF YES,** then there are a few things you need to know.

Is Your Unit Existing or New?

Existing Boiler

Units constructed prior to January 13, 2003

New Boiler

New or reconstructed boilers or process heaters are those which commenced construction after January 13, 2003.

Compliance Dates

- ① If you have a **new or reconstructed boiler or process heater**, you must comply with this subpart by November 12, 2004 or upon start-up of your boiler or process heater, whichever is later.
- ② If you have an **existing boiler or process heater**, you must comply with this subpart no later than September 13, 2007.
- ③ Any **existing boiler or process heater** at the existing facility must be in compliance with this subpart within 3 years after the facility becomes a major source.

Notification Requirements

- ① If you start-up your affected source before November 12, 2004, you must submit an Initial Notification not later than 120 days after November 12, 2004.
- ② If you start-up your new or reconstructed affected source on or after November 12, 2004, you must submit an Initial Notification not later than 15 days after the actual date of start-up of the affected source.

The "Boiler MACT" does not apply to:

- Municipal waste combustors



- Hospital/medical/infectious waste incinerators
- Electric utility steam generating units that are fossil fuel combustion units of more than 25 megawatts that produce electricity for sale
- Commercial and industrial solid waste incineration units that are subject to other Clean Air Act requirements
- Boilers and process heaters used for research and development
- Low pressure and low volume hot water heaters
- Blast furnace stoves
- Blast furnace gas-fired boilers and process heaters
- Boilers that are designed to be moved or carried from one location to another and which remain located at a particular location for less than 180 days
- Boilers and process heaters specifically listed as affected sources in other standards under 40 CFR Part 63 (NESHAP)

The air pollutants of concern are the HAPs emitted by combustion processes.

These compounds are:

- Hydrogen chloride
- Hydrogen fluoride
- Arsenic
- Beryllium
- Cadmium
- Nickel
- Mercury

The following pollutants are surrogates for the above HAPs:

- Particulate matter
- Hydrogen chloride
- Carbon monoxide
- Mercury

MACT Boilers Are Subdivided Into 3 Primary Categories:

First, determine whether your source is considered **NEW** or **EXISTING** (definition, page 5). Next, choose your source type and size.

Choose Your Source Type

- **Solid fuel units (SFU).** Units burning coal, wood, biomass, tires, plastics, or other non-fossil solid materials.
- **Liquid fuel units (LFU).** Units burning distillate oil, residual oil, waste oil, or process liquids.
- **Gaseous fuel units (GFU).** Units burning only natural gas, process gas, landfill gas, coal derived gas, refinery gas, or biogas.

Each MACT Category is Further Classified According to Size:

- **Large (l).** Rated capacity greater than 10 MM Btu/hour heat input and an annual capacity factor greater than 10%
- **Limited Use (lu).** Rated capacity greater than 10 MM Btu/hour heat input and an annual capacity factor less than 10%
- **Small (s).** Rated capacity less than or equal to 10 MM Btu/hour heat input (FYI, fire tube boilers considered small)



Solid Fuel Units Large (SFU-I)

Existing Sources

| Emission Limits | Monitoring Requirements | Recordkeeping & Reporting | Notification Requirements |
|---|--|--|---|
| Particulate Matter 0.07 lbs/mil Btu of heat input OR 0.001 lbs/mil Btu of heat input for total selected metals Hydrogen Chloride 0.09 lbs/mil Btu of heat input Mercury 0.000009 lbs/mil Btu of heat input | Compliance testing must be performed for particulates or total selected metals Hydrogen chloride and mercury emissions must also be monitored | Submit performance testing reports; semi-annual compliance reports and information on start-up, shut-down, or malfunctions that were not performed in a manner consistent with facility's start-up, shut-down, or malfunction plan | If you start-up your affected source before Nov. 12, 2004 you must submit an Initial Notification not later than 120 days after Nov. 12, 2004 |

Solid Fuel Units Large (SFU-I)

New or Reconstructed Sources

| Emission Limits | Monitoring Requirements | Recordkeeping & Reporting | Notification Requirements |
|--|---|--|---|
| Particulate Matter 0.025 lbs/mil Btu of heat input OR 0.0003 lbs/mil Btu of heat input for total selected metals Hydrogen Chloride 0.02 lbs/mil Btu of heat input Mercury 0.000003 lbs/mil Btu of heat input Carbon Monoxide 400 ppm (corrected to 7% oxygen) | Particulate matter, hydrogen chloride, and mercury emissions must be monitored Carbon monoxide emission monitoring | Submit initial performance testing reports; semi-annual compliance reports and information on start-up, shut-down, or malfunctions that were not performed in a manner consistent with facility's start-up, shut-down, or malfunction plan | If you start-up your new or reconstructed affected source on or after November 12, 2004 you must submit an Initial Notification not later than 15 days after the actual date of start-up of the affected source |



Solid Fuel Units Limited Use (SFU-*lu*)

Existing Sources

| Emission Limits | Monitoring Requirements | Recordkeeping & Reporting | Notification Requirements |
|---|--|--|---|
| Particulate Matter 0.21 lbs/mil Btu of heat input OR 0.004 lbs/mil Btu of heat input for total selected metals | Compliance testing must be performed for particulates or total selected metals | Submit performance testing reports; semi-annual compliance reports and information on start-up, shut-down, or malfunctions that were not performed in a manner consistent with facility's start-up, shut-down, or malfunction plan | If you start-up your affected source before November 12, 2004 you must submit an Initial Notification not later than 120 days after November 12, 2004 |

Solid Fuel Units Limited Use (SFU-*lu*)

New or Reconstructed Sources

| Emission Limits | Monitoring Requirements | Recordkeeping & Reporting | Notification Requirements |
|--|---|--|---|
| Particulate Matter 0.025 lbs/mil Btu of heat input OR 0.0003 lbs/mil Btu of heat input for total selected metals Hydrogen Chloride 0.02 lbs/mil Btu of heat input Mercury 0.000003 lbs/mil Btu of heat input Carbon Monoxide 400 ppm (corrected to 7% oxygen) | Particulate matter, hydrogen chloride, and mercury emissions must be monitored Carbon monoxide emission monitoring | Submit initial performance testing reports; semi-annual compliance reports and information on start-up, shut-down, or malfunctions that were not performed in a manner consistent with facility's start-up, shut-down, or malfunction plan | If you start-up your new or reconstructed affected source on or after November 12, 2004 you must submit an Initial Notification not later than 15 days after the actual date of start-up of the affected source |



Solid Fuel Units Small (SFU-s)

Existing Sources

| Emission Limits | Monitoring Requirements | Recordkeeping & Reporting | Notification Requirements |
|--------------------|--|---------------------------|---------------------------|
| No emission limits | No compliance testing is necessary to ensure initial or continuous compliance with the limitations | None | None |

Solid Fuel Units Small (SFU-s)

New or Reconstructed Sources

| Emission Limits | Monitoring Requirements | Recordkeeping & Reporting | Notification Requirements |
|---|--|--|---|
| Particulate Matter 0.025 lbs/mil Btu of heat input OR 0.0003 lbs/mil Btu of heat input for total selected metals Hydrogen Chloride 0.02 lbs/mil Btu of heat input Mercury 0.000003 lbs/mil | Particulate matter, hydrogen chloride, and mercury emissions must be monitored | Submit initial performance testing reports; semi-annual compliance reports and information on start-up, shut-down, or malfunctions that were not performed in a manner consistent with facility's start-up, shut-down, or malfunction plan | If you start-up your new or reconstructed affected source on or after November 12, 2004 you must submit an Initial Notification not later than 15 days after the actual date of start-up of the affected source |

Gaseous Fuel Units Large (GFU-l)

Existing Sources

| Emission Limits | Monitoring Requirements | Recordkeeping & Reporting | Notification Requirements |
|--------------------|-------------------------|---|---|
| No emission limits | No Monitoring | Notify the appropriate air pollution control agency that the unit is subject to the requirements of the "Boiler MACT" No additional reporting/recordkeeping requirements have been established | If you start-up your affected source before November 12, 2004 you must submit an Initial Notification not later than 120 days after November 12, 2004 |



Gaseous Fuel Units Large (GFU-*l*)

New or Reconstructed Sources

| Emission Limits | Monitoring Requirements | Recordkeeping & Reporting | Notification Requirements |
|---|--|--|---|
| Carbon Monoxide 400 ppm (corrected to 3% oxygen) | Carbon monoxide emission monitoring | Submit initial performance testing reports; semi-annual compliance reports and information on start-up, shut-down, or malfunctions that were not performed in a manner consistent with facility's start-up, shut-down, or malfunction plan | If you start-up your new or reconstructed affected source on or after November 12, 2004 you must submit an Initial Notification not later than 15 days after the actual date of start-up of the affected source |

Gaseous Fuel Units Limited Use (GFU-*lu*)

Existing Sources

| Emission Limits | Monitoring Requirements | Recordkeeping & Reporting | Notification Requirements |
|--------------------|-------------------------|---|---|
| No emission limits | No Monitoring | Notify the appropriate air pollution control agency that the unit is subject to the requirements of the "Boiler MACT" No additional reporting/recordkeeping requirements have been established | If you start-up your affected source before November 12, 2004 you must submit an Initial Notification not later than 120 days after November 12, 2004 |



Gaseous Fuel Units Limited Use (GFU-*lu*)

New or Reconstructed Sources

| Emission Limits | Monitoring Requirements | Recordkeeping & Reporting | Notification Requirements |
|---|--|--|---|
| Carbon Monoxide 400 ppm (corrected to 3% oxygen) | Carbon monoxide emission monitoring | Submit initial performance testing reports; semi-annual compliance reports and information on start-up, shut-down, or malfunctions that were not performed in a manner consistent with facility's start-up, shut-down, or malfunction plan | If you start-up your new or reconstructed affected source on or after November 12, 2004 you must submit an Initial Notification not later than 15 days after the actual date of start-up of the affected source |

Gaseous Fuel Units Small (GFU-*s*)

Existing Sources

| Emission Limits | Monitoring Requirements | Recordkeeping & Reporting | Notification Requirements |
|--------------------|-------------------------|---------------------------|---------------------------|
| No emission limits | No monitoring | None | None |

Gaseous Fuel Units Small (GFU-*s*)

New or Reconstructed Sources

| Emission Limits | Monitoring Requirements | Recordkeeping & Reporting | Notification Requirements |
|--------------------|-------------------------|---------------------------|---------------------------|
| No emission limits | No monitoring | None | None |



Liquid Fuel Units Large (LFU-1)

Existing Sources

| Emission Limits | Monitoring Requirements | Recordkeeping & Reporting | Notification Requirements |
|--------------------|-------------------------|---|---|
| No emission limits | No Monitoring | Notify the appropriate air pollution control agency that the unit is subject to the requirements of the "Boiler MACT" No additional reporting/recordkeeping requirements have been established | If you start-up your affected source on or after November 12, 2004 you must submit an Initial Notification not later than 15 days after the actual date of start-up |

Liquid Fuel Units Large (LFU-1)

New or Reconstructed Sources

| Emission Limits | Monitoring Requirements | Recordkeeping & Reporting | Notification Requirements |
|---|-------------------------|---|---|
| Particulate Matter 0.03 lbs/mil Btu of input heat Hydrogen Chloride 0.0005 lbs/mil Btu of heat input Carbon Monoxide 400 ppm (corrected to 3% oxygen) | No Monitoring | Maintain records that demonstrate that only fossil fuels are used during the reporting period | If you start-up your affected source before November 12, 2004 you must submit an Initial Notification not later than 120 days after November 12, 2004 |



Liquid Fuel Units Limited Use (LFU-*lu*)

Existing Sources

| Emission Limits | Monitoring Requirements | Recordkeeping & Reporting | Notification Requirements |
|--------------------|-------------------------|--|--|
| No emission limits | No Monitoring | <p>Notify the appropriate air pollution control agency that the unit is subject to the requirements of the "Boiler MACT"</p> <p>No additional reporting/recordkeeping requirements have been established</p> | <p>If you start-up your affected source before November 12, 2004 you must submit an Initial Notification not later than 120 days after November 12, 2004</p> |

Liquid Fuel Units Limited Use (LFU-*lu*)

New or Reconstructed Sources

| Emission Limits | Monitoring Requirements | Recordkeeping & Reporting | Notification Requirements |
|--|-------------------------|---|---|
| <p>Particulate Matter 0.03 lbs/mil Btu of heat input</p> <p>Hydrogen Chloride 0.0009 lbs/mil Btu of heat input</p> <p>Carbon Monoxide 400 ppm (corrected to 3% oxygen)</p> | None | Maintain records that demonstrate that only fossil fuels are used during the reporting period | <p>If you start-up your affected source on or after November 12, 2004 you must submit an Initial Notification not later than 15 days after the actual date of start-up of the affected source</p> |

Liquid Fuel Units Small (LFU-*s*)

Existing Sources

| Emission Limits | Monitoring Requirements | Recordkeeping & Reporting | Notification Requirements |
|--------------------|-------------------------|---------------------------|---------------------------|
| No emission limits | No monitoring | None | None |



Liquid Fuel Units Small (LFU-s)

New or Reconstructed Sources

| Emission Limits | Monitoring Requirements | Recordkeeping & Reporting | Notification Requirements |
|---|-------------------------|---|---|
| Particulate Matter 0.03 lbs/mil Btu of input heat (residual oil only) | No Monitoring | Maintain records that demonstrate that only fossil fuels are used during the reporting period | If you start-up your affected source on or after November 12, 2004 you must submit an Initial Notification not later than 15 days after the actual date of start-up |
| Hydrogen Chloride 0.0009 lbs/mil Btu of heat input (residual oil only) | | | |



ABOUT THE AUTHOR - DANIEL E. TAYLOR

Dan Taylor is a Principal and Manager of RTP's South Carolina office. He holds degrees in geology and environmental engineering, and specializes in developing permitting strategies encompassing a wide variety of environmental issues. Dan has devoted the past 29 years assisting industry with optimizing environmental compliance and facility operation.

Review of Ammonia Emissions Effect on a Southern California Project

by Paul E. Neil

RTP recently defended a project in Southern California from a California State agency's assessment that the project's ammonia emissions had a potential significant adverse effect to the local air quality, especially with regard to increased PM10/PM2.5 concentrations. With the adoption of the PM2.5 standards, the issue of ammonia's role in particulate formation has come to the forefront. While ammonia is not currently listed in air regulations or policies as a precursor of PM10/PM2.5, the accepted scientific knowledge provides evidence that ammonia can play

a significant role under certain conditions.

One of the interesting aspects of very fine particulate (PM2.5) is that it is generated primarily as a secondary pollutant. The gases significant to formation are the acid gases, nitrogen oxides, sulfur dioxide, and ammonia. Studies have shown that nitrogen oxides can form nitrate in a polluted environment at a rate of 10 to 30 percent per hour, and subsequently combine with ammonia to generate fine particulate ammonia nitrate. While the emissions of nitrogen oxides have been regulated by the



air agencies for some time, ammonia emissions have not. In fact, there are still a lack of data and significant gaps in knowledge regarding natural and anthropogenic ammonia emissions. EPA and the California Air Resources Board (CARB), along with local air quality control districts, have been preparing inventories of ammonia emissions sources because of the non-attainment of the federal and state fine particulate standards in many areas of California and the United States. Two areas that have experienced significant ammonia nitrate formation - Denver, Colorado and the San Joaquin Valley in California - have conducted extensive studies to understand the aspects of fine particulate formation. The chemistry of the reactions is complex, and dependent upon such factors as concentration, humidity and temperature. Nonetheless, high humidity and low temperatures favor the generation of very fine particulate.

Sulfur dioxide also plays a role similar to nitrogen oxides, except that in the western United States sulfur dioxide emissions are a minor part of total acid gases. In the eastern United States the roles are reversed and sulfur dioxide is normally the significant contributor to fine particulate formation.

For this Southern California project, that issue was addressed in the initial submissions by noting that the significance of ammonia emissions with regard to particulate conversion is dependent upon the chemical makeup of the local air quality. Ammonia emissions in a highly acidic (ammonia lean) environment can potentially produce particulate matter, while ammonia emissions in a basic (ammonia rich) environment can potentially produce no additional particulate. The application stated that the area around the project was ammonia rich and therefore only the acid gases from the project would be generating particulate matter. An estimate of these emissions (fine particulate from the project's acid gases) was provided. However, because the project's ammonia emis-

sions were over 500 times those of its acid gas emissions, the agency staff focused on the project's ammonia emissions. Their assessment noted that

- ❶ the applicant neglected the transport of pollutants from the surrounding urban air basins and that these emissions were not likely to be ammonia rich;
- ❷ there was no information to prove the project area was ammonia rich; and
- ❸ even if the area was ammonia rich, the formation reaction was reversible, which was construed to mean that increasing the concentrations of a reactant in a reversible chemical balance would automatically increase the concentrations of the products.

First RTP had to resolve the question of whether the local air basin could truly be considered ammonia rich. EPA deems the Western United States to be ammonia rich and CARB considers the rural counties of California (the project is located in just such a rural county) to be ammonia rich. However, published data were lacking to confirm such an assumption in this case. Thus, RTP obtained the most recent annual basin inventories of acid gases and the best estimate from the local agencies of the actual ammonia emissions. With the units in tons per year, a conversion to mole-ton per year was made and a comparison to determine available moles was made. It requires one mole of ammonia and one mole of nitrogen dioxide to form ammonia nitrate. It requires two moles of ammonia and one mole of sulfur dioxide to form ammonia sulfate. Employing this type of review, it was possible to conclude that the local air quality was ammonia rich. The same calculations were also made for the nearby urban air basins. Except for one, these air basins were noted to be ammonia rich. The one air basin that was an exception was apparently ammonia lean and was located at a distance of over 100 miles away from the project. With a 10 to 30 percent conversion of this basin's nitrogen dioxide to nitrate, and with sub-



sequent fallout by dry/wet deposition, it was determined that this nearby urban air basin's acid gases would not be a significant source of acid gases for the air quality in the project's locality.

With regard to the agency's concern regarding the reversibility of the formation reaction, RTP contacted the Project Managers of the Denver and San Joaquin Valley studies. These studies had also reviewed the effect of controlling ammonia emissions to resultantly control particulate matter formation. Both of the studies were conducted in localities that were in ammonia rich basins. This made the results of these studies particularly appropriate for this comparison. The conclusions from the Denver and San Joaquin Valley studies were that only in ammonia lean areas would control of ammonia emissions affect particulate matter formation. In areas with ammonia rich conditions, the control of acid gases was the only way to reduce the formation of very fine particulate matter.

Ultimately, the State agency's decision was to accept the evidence presented and concur with the applicant's position with regard to the application and reject the agency's staff assessment that the project's ammonia emissions had a potential significant adverse effect to the local air quality, especially with regard to increased PM10/PM2.5 concentrations. Thus, accepted scientific knowledge does provide evidence that ammonia can play a significant role under certain conditions, but as this project's experience proved, the factors going into the determination must be fully analyzed.

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