

Chapter 2: Calculations

Table of Contents

2.1 Overview	2
2.2 Regulatory Differences in Calculations	2
2.2.1. New Source Review/Prevention of Significant Deterioration (NSR/PSD)	2
2.2.2. Minnesota Rules	6
2.2.3. New Source Performance Standards (NSPS)	7
2.2.4. National Emission Standards for Hazardous Air Pollutants Part 63 (Part 63 NESHAP). 7	
2.3 Components of an Air Emission Calculation	8
2.3.1. Calculation Methods	8
2.3.2. Emission Factors	10
2.3.3. Process Variables	16
2.3.4. Control Efficiencies	17
2.4 Documentation of Emission Calculations	21

Chapter 2

Calculations

2.1 Overview

When contemplating making a physical or operational change to a facility, you need to quantify the changes in emissions to the atmosphere that will result. The magnitude of the emissions change will, in part, determine the type of permit amendment you need. This chapter provides guidance on how to calculate and document changes in air emissions for air permitting purposes.

2.2 Regulatory Differences in Calculations

The first step is to identify the calculation method to use. Applicable rules dictate the calculation method in several ways. For example:

- The federal **New Source Review – Prevention of Significant Deterioration (NSR-PSD) rules at 40 CFR 52.21 (a)(2)(iv)(b)-(f) and (b)(3)** specify how to calculate emission increases for the purposes of this regulatory program.
- **Minn. R. 7007.1200** specify how to calculate emission changes in preparing applications for permit amendments (including non-Title I and Title I modifications).
- **NSPS, 40 CFR 60** specify how to calculate emissions to determine whether an emission unit or source is subject to NSPS requirements, and
- **NESHAP, 40 CFR 63** specify how to calculate emissions to determine whether a source is a major HAP source.

2.2.1. New Source Review/Prevention of Significant Deterioration (NSR/PSD)

NSR/PSD rules are triggered when the net emissions increase following a modification exceeds pollutant-specific thresholds detailed in the rules (See 40 CFR § 52.21). The net emission increase is the difference in emissions after the modification and before the modification. Calculating this difference, and calculating the “before” and “after” emissions, can be complex and is broken down in this section.

Minnesota Rules (Minn. R. 7007.1200, Subps. 1 and 2, and Minn. R. 7007.0100) specify the use of the federal rules for a Title I modification subject to NSR/PSD.

7007.1200 Calculating Emission Changes for Permit Amendments.

Subpart 1. **How to calculate emission changes.** When this part is required to be used, the method of calculation in subpart 2 must be used to determine first whether a modification is a title I modification.

Subpart 2. **Calculation methods to determine if the proposed change is a Title I modification.** To determine if a modification is a Title I modification, the applicable federal calculation method must be used. To determine the applicable methods to calculate emission changes for a Title I modification, the permittee must refer to the federal regulations listed in part 7007.0100, subpart 26.

7007.0100 Definitions.

Subp. 26. Title I modification. "Title I modification" means any change that constitutes any of the following:

...

B. A new source review modification: major modification as defined in Code of Federal Regulations, title 40, section 52.21(b)(2) or 51.165(a)(1)(v), as amended, or any other rules adopted by the administrator under part C or D of the act.

"Before" Or Baseline Emissions – Existing Units

Emissions "before" the change (usually called pre-modification or baseline actual emissions) can be calculated one of two ways, depending on the type of facility. Electric Utility Steam Generating Units (EUSGUs) may use the average emissions of any 24 consecutive months during the past 5 years of operation. Non EUSGUs may use the average emissions of any 24 consecutive months during the past 10 years of operation.

Although the choice of which 24-month period to use is up to the source, there are a few things to consider. First, the period must be 24 consecutive months. Second, you must actually have operating data for the 24 months you wish to use. Third, you should use a 24-month period that is typical of "normal" operations; it is not in your best interest to choose periods when equipment was shut down due to lack of demand, for example. In such a case, the baseline emissions would be less, which would ultimately result in a larger difference between baseline and post-change emissions.

For each pollutant, the same 24-month period must be chosen. You cannot, for example, choose the years 1996-1997 for the boiler and 1999-2000 for the diesel generator when calculating emissions of PM₁₀. However, you may choose a different set of years for different pollutants. You may, for example, use 1996-1997 for NO_x and 1999-2000 for VOC.

Note that not just the criteria pollutants are included as pollutants regulated by PSD. As is seen in Table A of Form CH-04a, fluorides, sulfuric acid mist, a variety of reduced sulfur compounds, hydrogen sulfide, Municipal Waste Combustion (MWC) emissions and Municipal Solid Waste (MSW) landfill gas emissions must be calculated as well.

Some adjustments may need to be made to the baseline actual emissions if other changes have occurred between the chosen baseline period and the present. If a new regulation has imposed limits on existing units between the 24-month period and the present, the effect of those limits must be reflected as reductions in the emissions. To do this, you must determine the effect on the emissions. Three examples:

1. The new emission limitation is a pound/hour limit. Determine the number of hours that the emission unit actually operated during the 24-month period, and apply the emission limitation to the actual hours the emission unit operated. If the calculated emissions based on the new emission limit are lower than the actual emissions, substitute the result of this calculation for the actual emissions of that unit.
2. The new emission limitation is a pound/unit of production limit (e.g. lb/MM Btu). Determine the actual production during the 24-month period and apply the emission limitation to the actual production during that period. If the calculated emissions based on the new emission limit are lower than the actual emissions, substitute the result of this calculation for the actual emissions of that unit.
3. The new emission limitation is a work practice (e.g. tanks must be equipped with floating roofs, seals and gaskets, or process fugitive emissions [e.g. leaks from pump seals or valves] must be controlled through a leak detection program). Determine the effect of the work practice on emissions from the operations during the 24-month period and if the calculated emissions based on the work practice requirement are lower than the actual emissions, substitute the result of this calculation for the actual emissions of that unit.

In cases where the actual emissions were lower during the 24-month period than they would have been required to be with the new emission limitations in place, you should use the actual emissions.

Similarly, actual emissions must be adjusted downward to exclude any non-compliant emissions that occurred during the baseline period.

Baseline actual emissions need to also include fugitive emissions and any emissions that occurred due to startups, shutdowns, and malfunctions, to the extent that they are quantifiable, unless these emissions were not compliant with an enforceable limit. There are additional restrictions and qualifications on determining "before" or baseline emissions. Consult 40 CFR § 52.21(a)(2)(iv)(c) through (f) for details.

The emissions from the baseline period must be included on Table A of Form CH-04a. A separate Table A needs to be prepared for each emission unit which is being changed, including not only emission units labeled as "emission units" but also fugitive sources (FS units), and tanks (TK units). If more than three units are being changed, a duplicate Table A is needed.

All baseline actual emissions adjustments for each existing emission unit affected by the change/project and for all pollutants emitted by that unit should be documented, either in an attachment to Form CH-04a, or in records at the source. These calculations need to be repeated for each emission unit and for each pollutant affected by the change/project. For example, if a change is made in a combustion unit (e.g., new larger burners installed), emissions increases for all of the combustion pollutants need to be calculated (e.g. NO_x, CO, SO₂, PM₁₀ and VOC).

“After” Emissions – Existing Units

Emissions after the change can be calculated either by: (1) using potential to emit of the changed unit, or (2) using projected actual emissions of the changed unit. As noted in 40 CFR § 52.21(b)(4):

“Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.”

When using potential to emit (PTE), only certain facilities need to include fugitive emissions. These include sources on the list of 28 for which 100 tons per year is the threshold for classification as a major PSD source (found in Form CH-04 Determination of New Source Review Status), those that were regulated as of August 7, 1980 by a New Source Performance Standard in effect at the time, or those that were regulated by a NESHAPs standard as of August 7, 1980. All other sources do not need to include fugitive emissions. (See *New Source Review Workshop Manual*, October, 1990, pages A.9 and A.10 and 40 CFR § 52.21(b)(1)(c)(3).)

When using projected actual emissions, fugitive emissions must be included “to the extent they are quantifiable” and must also include emissions from startup, shutdown, and malfunctions, in accordance with 40 CFR § 52.21(b)(41). In most cases, a source will want to include these emissions in the “before” emissions as well, provided sufficient documentation is available to quantify fugitive and startup, shutdown, and malfunction emissions. If insufficient documentation is available, such emissions should not be included in the “before” emissions.

Certain emissions can be excluded from projected actual emissions, as noted in the 40 CFR § 52.21(b)(41)(ii)(c):

“In determining the projected actual emissions under paragraph (b)(41)(i) of this section (before beginning actual construction), the owner or operator of the major stationary source: ...
(c) Shall exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (b)(48) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth;”

For some facilities (e.g. electric utility steam generating utilities [EUSGUs]), it may be relatively easy to determine the exclusion, as capacity and demand are predicted on a regular basis for other regulatory programs. For other facilities, quantifying these exclusions may be more difficult.

Also, using projected actual emissions will involve recordkeeping requirements on all facilities and reporting requirements on EUSGUs, whereas using the potential to emit will not impose these

requirements. You should consider the cost and potential compliance liability that those requirements may impose. If projected actual emissions are used, include those requirements on Form CD-01.

Increases From New Units

For new units, the “before” or baseline emissions are zero, and the “after” emissions, by rule, are equal to the potential to emit, which may be restricted either by an applicable rule or voluntarily in order to reduce the emissions increase (Note that units that are less than two years old are treated differently).

2.2.2. Minnesota Rules

Similarly, Minnesota Rules (Minn. R. 7007.1200, Subps. 1 and 2, and Minn. R. 7007.0100) specify the calculation procedures for determining the type of permit amendment required.

7007.1200 Calculating Emission Changes For Permit Amendments.

Subp. 3. Calculation method for modifications that are not title I modifications. Emissions changes for a modification must be calculated by comparing the hourly emission rate of the stationary source, at maximum physical capacity, before and after the proposed physical or operational change. The emission rate shall be expressed as pounds per hour of any regulated air pollutant. Items A to C shall be used to determine emission changes for modifications that are not title I modifications.

A. When calculating emissions before and after the physical and operational change, physical and operational limitations and emission decreases will be considered only if they:

- (1) are or will be automatically required by an applicable requirement including parts 7011.0060 to 7011.0080;
- (2) are or will be automatically required by an existing permit;
- (3) are integral to the process;
- (4) are proposed as a permit term and condition in the application for a minor, moderate, or major modification under part 7007.1450 or 7007.1500; or
- (5) are calculated in records kept at the stationary source where reductions rendered the modification insignificant under part 7007.1250.

B. In cases where use of emission factors or related calculation methods clearly demonstrates whether or not the change will increase the emission level, the emission factors as defined in part 7005.0100, subpart 10a, shall be used.

C. Material balances, continuous monitor data, or manual emissions tests may be used in cases where use of emission factors or related calculation methods under item B does not clearly demonstrate, to the agency's satisfaction, whether or not the change will increase the emission level, or where a permittee demonstrates to the agency's satisfaction that there are reasonable grounds to dispute the result obtained under item B. These methods may be used only to establish premodification emission rates from which postmodification emission rates may be calculated. Tests shall be conducted under such conditions as the agency shall specify. At least three valid test runs must be conducted. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

In other words, for determining the type of Minnesota permit amendment required—major, moderate or minor—the PTE before is compared to the PTE after, and the difference compared to the thresholds in Minn. R. 7007.1450.

2.2.3. New Source Performance Standards (NSPS)

NSPS rules are triggered at an emissions unit to which an NSPS is applicable when either a new unit is constructed, when an existing unit is reconstructed (as defined in 40 CFR 60.15) or when an existing unit is modified and there is **any** emissions increase associated with the modification. Note that this differs from the NSR/PSD triggers in that there are no pollutant-specific thresholds specified in the rules: “any” emissions increase occurring as the result of a modification triggers the applicability of the NSPS.

Minnesota Rules (Minn. R. 7007.1200, Subps. 1 and 2, and Minn. R. 7007.0100) specify the use of the federal rules for a Title I modification subject to NSPS. (A copy of the rules is included in section 2.2.1.)

“Reconstruction” of an existing unit consists of economic tests, rather than emissions tests, and is discussed in Chapter 3.

For a “modification” of an existing unit, calculate and compare the hourly emission rate (lb/hr) at maximum capacity before and after the change for each unit. This calculation is different than under NSR/PSD applicability, where the calculations are generally based on an annual average and expressed in tons/year. Also unlike NSR/PSD applicability, there is no threshold in NSPS applicability. Any increase in emissions, even a fraction of a pound per hour, triggers NSPS. Be careful with significant digits in calculations. If you really know an emission factor or production variable to 0.01 pounds per hour, than calculate it at that level. If you only know the value to the nearest 0.1 or 1 pound per hour, calculate it at that level.

Another important recognition under NSPS is that an enforceable limit to restrict actual emissions cannot be taken to avoid NSPS applicability. For example, if a grandfathered boiler with a heat input design capacity of 50 MM Btu/hr undergoes a change that increases its capacity to 60 MM Btu/hr, you cannot accept a limit on actual hourly NOx emissions such that there is no emissions increase. Rather, the NOx emissions increase must be calculated based on the new heat input capacity minus the existing heat input capacity. Unless the source installs control technology to lower the NOx emissions, it is likely that the NOx emissions increase will be greater than zero, thus subjecting the boiler to NSPS.

2.2.4. National Emission Standards for Hazardous Air Pollutants Part 63 (Part 63 NESHAP)

Unlike NSR/PSD or NSPS, the applicability of a Part 63 NESHAP (or Maximum Achievable Control Technology [MACT] standard) is not triggered by a change at a particular emission unit. Rather, there are standards for new and existing units at major HAP sources. A major HAP source is defined at 40 CFR § 63.2.

40 CFR PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES
Subpart A—General Provisions

§ 63.2 Definitions.

Major source means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants, unless the Administrator establishes a lesser quantity, or in the case of radionuclides, different criteria from those specified in this sentence.

Thus, in determining whether or not a source is a major HAP source, you must calculate the potential of the entire source (including all emission units) to emit more than 10 tons/year of any individual HAP or more than 25 tons/year of any combination of HAPs. If a source has the potential to emit HAPs in excess of those thresholds, and there is a MACT standard which applies to a particular emission unit or units at that source, then the MACT standard (Part 63 NESHAP) is applicable to those emission units—standards for new units for new or reconstructed units, and standards for existing units.

Unlike NSPS, limitations on the potential to emit HAPs can be taken to avoid applicability of Part 63 NESHAP. These are discussed in Chapter 3.

2.3 Components of an Air Emission Calculation

2.3.1. Calculation Methods

Calculating emissions from complex combustion and manufacturing sources can seem like an overwhelming task. However, there is much guidance provided by state and federal rules (as noted above) as well as industry-specific or process-specific guidance documents prepared by the EPA or trade groups, or from other relevant sources.

For some sources, such as tanks, USEPA has developed computer programs (e.g. the "TANKS" program) which calculates emissions based upon the design of the tank, the materials stored, and other information. Similarly, for fugitive dust emissions, USEPA and others have developed emission calculation procedures, based on the size and shape of the pile, the type and particle size of material stored, moisture content, wind speed and other parameters. And, for fugitive emissions of volatile organic compounds (VOCs) and volatile organic hazardous air pollutants (VHAPs), USEPA and trade organizations have developed emission calculation procedures based on the number of components which may leak (e.g. valves, pump seals), the rate of leakage, the material flowing through those components and the chemical and physical properties of those materials. Finally, for batch processes, USEPA and others have developed emission calculation procedures based on the size and configuration of the equipment, the materials processed, the processing time, operational conditions and other variables.

However, for many emission sources, calculation methods can be expressed as:

$$\text{Emissions} = \text{Emission Factor (EF)} \times \text{Process Variable (PV)} \times [1 - \text{Control Efficiency (CE)}]$$

Section 2.3.2

Section 2.3.3

Section 2.3.4

Note that the PV's unit of measurement should correspond to that of the EF. Typically, you may need to manipulate the PV to obtain units that correspond to those in which the EF is expressed. The emissions should be expressed in pounds of pollutant per hour (lb/hr) and/or tons of pollutant per year (tons/yr). If there is an applicable standard expressed in different units, the emissions should also be expressed in those units. Control efficiency is dictated by the level of emissions that are captured and subsequently destroyed or recovered.

An Example: VOC Emissions from a Painting Operation

EF = lb VOC/gallon of paint (from the label on the paint can or from the paint's Material Safety Data Sheet [MSDS])

PV = gallons/hr of paint used (from the design rating of the spray gun used to apply the paint)

CE = None (assume VOC emissions are uncontrolled)

The MSDS reports that the VOC content of the paint ranges from 1.0 to 1.6 lb VOC/gallon of paint, and the paint spray gun manufacturer's specifications indicate that paint can be applied at a rate of up to 20 gallons/hr. The high end of the range of VOC content reported on the paint's MSDS (1.6 lb VOC/gallon) may be used to calculate emissions:

$$\text{Emissions} = 1.6 \text{ \{lb VOC/gallon paint\}} \times 20 \text{ \{gallons paint/hr\}} = 32 \text{ \{lb VOC/hr\}}$$

If the MSDS reports that the VOC content of the paint is 0.20 lb/lb of paint, we will need to know the density of the paint (the MSDS reports it to be 8.0 lb/gallon):

$$\begin{aligned} \text{Emissions} &= 0.20 \text{ \{lb VOC/lb paint\}} \times [20 \text{ \{gallons paint/hr\}} \times 8.0 \text{ \{lb paint/gallon paint\}}] \\ &= 0.20 \text{ \{lb VOC/lb paint\}} \times 160 \text{ \{lb paint/hr\}} \\ &= 32 \text{ \{lb VOC/hr\}} \end{aligned}$$

This hourly emission rate may be converted to an annual rate as follows, assuming a worst-case, year-round operation of 8,760 hours/year (24 hours/day, 365 days/year):

$$\begin{aligned} \text{Emissions} &= 32 \text{ \{lb VOC/hr\}} \times 24 \text{ \{hrs/day\}} \times 365 \text{ \{days/yr\}} / 2,000 \text{ \{lb/ton\}} \\ &= 140 \text{ \{tons VOC/yr\}} \end{aligned}$$

Note that even if the permittee typically operates the spray guns for a single 8-hour shift, 5 days per week, 50 weeks per year (equivalent to 2,000 hours per year), the potential emissions must be calculated assuming 8,760 hours/year unless the permittee is willing to take an enforceable limit on the annual operating hours.

Implications of the calculation method for the compliance determination form (Form CD-01)

It is important to carry over from the emission calculations into the compliance plan form (Form CD-01) any assumptions you made; they should be proposed as limitations or monitoring requirements along with a proposal of how to demonstrate compliance. For example, such assumptions may include:

- an assumed limited annual throughput to limit annual potential to emit. (Unless otherwise specified, the federal definition assumes facility operation at capacity, 24 hours per day, 365 days per year)
- an applicable emission limit imposed by a standard. (Such a limit should be used in the calculation of potential to emit unless no control is required to meet the limit. The permittee is free to choose a lower limit but that lower limit will be set as a permit condition)
- a BACT limit imposed by NSR-PSD. (The BACT limit should be used in the calculation of potential to emit)
- an assumed limited hourly, monthly, or annual throughput due to emission projections used in environmental analyses.

When choosing the calculation method, think ahead to what you intend to monitor. For example, will you be tracking the usage of raw materials, the rate of production of an intermediate or finished product, or actual emissions (via a CEMS)? Often several choices are available. Selecting the best one may depend on:

- what is already being measured (such as for production purposes or to comply with performance standards)
- the relative costs associated with each option, and
- the degree of difficulty in measuring the alternatives.

2.3.2. Emission Factors

These may come from direct measurements such as CEMS data, performance tests, or monitoring of specific operating parameters (e.g., oxygen concentration) in combination with performance tests, or acceptable published sources such as USEPA's AP-42, FIRE database, AIRS database or "Locating and Estimating ..." documents, documents published by other regulatory agencies (such as the Texas DEQ), or documents prepared by trade groups. Emission limits set in standard. Since these are federally enforceable, they are considered the maximum allowable emissions. Again, as stated above, the facility operator is free to choose a lower limit than that set in standard, but that limit will be set in the permit.

Note

"AP-42" refers to the EPA's "Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources" (see <http://www.epa.gov/ttn/chief/ap42/index.html>). AP-42 is organized by industry sector or emission unit type. It is important to check EPA's website for the latest version of AP-42 since it is frequently updated.

(continued)

"FIRE" refers to the Factor Information Retrieval Data System which is a database containing EPA's emission estimation factors for criteria and hazardous air pollutants in an easy to use PC-based format (see <http://www.epa.gov/ttn/chief/software/fire/index.html>). The latest version is 6.24, released March 9, 2004. A useful way to query FIRE for emission factor data is by source classification code (SCC), which corresponds to a particular type of emissions source (see <http://www.epa.gov/ttn/chief/codes/index.html>).

"AIRS" refers to the EPA's Aerometric Information Retrieval System Facility Subsystem Source Classification Codes and Emission Factor Listing for Criteria Air Pollutants, EPA, 450/4-90-003, March 1990.

"Locating and Estimating ..." documents refer to a EPA report series, titled "Locating and Estimating Air Toxic Emissions from Sources of (source category or substance)" (see <http://www.epa.gov/ttn/chief/le/index.html>). These reports characterize the source categories for which emissions of approximately 30 toxic substance have been identified. These volumes include general descriptions of the emitting processes, identifying potential release points and emission factors.

Other excellent emission factor resources are available from the Texas Natural Resource Conservation Commission (TNRCC) through its Technical Guidance documents (see http://www.tnrcc.state.tx.us/permitting/airperm/nsr_permits/guidedoc.htm) and the California Air Resources Board (CARB) through its California Air Toxics Emission Factor (CATEF) II database (see <http://www.arb.ca.gov/emisinv/catef/catef.htm>).

It is very important that you document where or how you obtained the emission factor that you used, and why you chose to use it above other available information. This saves the MPCA permit writer time that he/she may otherwise have to spend verifying your calculations.

Sources of Acceptable Emission Factors

Minn. R. 7005.0100, subpart 10a (<http://www.revisor.leg.state.mn.us/arule/7005/0100.html>)

"Emission factor" means the most accurate and representative emission data available from one of the following sources:

- A. For criteria pollutants, the emission factor listed in the Compilation of Air Pollutant Emission Factors (AP-42), fifth edition, United States Environmental Protection Agency, Technical Support Division, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711, January 1995, which is incorporated by reference and is available through the Minitex interlibrary loan system. It is subject to frequent change. Where more than one emission factor is listed in AP-42, "emission factor" means the one approved by the commissioner using best engineering judgment and based on one or more of the considerations in item C, subitem (2).

- B. For hazardous air pollutants (HAPs), the emission factor listed in Factor Information Retrieval (FIRE) Data System, EPA-454/C-94-032, United States Environmental Protection Agency, Technical Support Division, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27111, October 1994, which is incorporated by reference and is available through the Minitex interlibrary loan system. Where more than one emission factor is listed, emission factor means the one approved by the commissioner using best engineering judgment and based on one or more of the considerations in item C, subitem (2). It is not subject to frequent change.

C. (1) Where no emission factor is available in one of the documents described in item A or B, or where a more representative emission factor is available under this item, emission factor means an emission factor developed or approved by the commissioner and derived from the following sources:

- (a) the AIRS Facility Subsystem Source Classification Codes and Emission Factor Listing for Criteria Air Pollutants, EPA, 450/4-90-003, United States Environmental Protection Agency, Technical Support Division, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711, March 1990, which is incorporated by reference and is available at the Minnesota state law library and through the Minitex interlibrary loan system; it is not subject to frequent change;
- (b) other EPA publications including, but not limited to, Locating and Estimating documents, Control Technology Center documents, the preamble and background information documents for New Source Performance Standards or National Emission Standards for Hazardous Air Pollutants;
- (c) EPA databases and computer programs;
- (d) engineering publications;
- (e) performance test data from the same or a similar emission unit at the same or a similar facility;
- (f) manufacturer's performance tests; or
- (g) emission data developed by the regulated party using the best engineering judgment criteria listed in subitem (2).

(2) The commissioner shall develop or approve an emission factor using best engineering judgment and based on one or more of the following considerations:

- (a) the precision and accuracy of the data;
- (b) the design and operational similarity between the emission units tested and the emission units to which the emission factor is to be applied;
- (c) the number of emission units tested in developing the emission factor under consideration;
- (d) the availability of emission data of equal or greater quality;
- (e) the emission unit operating conditions under which the tests were conducted; and
- (f) the data analysis procedures.

An Example: Evaluating Sources for CO Emission Factors for a 125 mm Btu/hr Natural Gas-Fired Boiler

AP-42 Table 1.4-1 (7/98) reports an emission factor of 84 lb/10⁶ scf for a large (> 100 mm Btu/hr) wall-fired boiler.

FIRE version 6.23: A search by pollutant for CO and by SCC for 1-01-006-01 reports the same emission factor of 84 lb/10⁶ scf.

AIRS: Page 20 reports an emission factor of 40 lb/million cubic feet burned scf for a SCC of 1-01-006-01 (Boilers > 100 mm Btu/hr except tangential).

There is no relevant "Locating and Estimating" document for CO. The potentially relevant NSPS (40 CFR 60, subpart D) does not regulate CO emissions. The potentially relevant NESHAP (40 CFR 63, subpart DDDDD) imposes the following "work practice" limit on CO from gaseous-fueled boilers:

"400 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MM Btu/hr or greater, 3-run average for units less than 100 MM Btu/hr)"

It should be noted that even if there were an NSPS standard, the standard would (like the NESHAP standard presented above) represent a limit, not an emission factor. As such, it would represent the maximum allowed emissions. An emission factor would still be needed to predict whether the standard is likely to be met.

There are no USEPA databases or computer programs that include CO emission factors from natural gas-fired boilers. No emission factors reported in engineering publications are being proposed for evaluation.

Performance test data from the specific emission unit at the specific facility.

A performance test at the boiler exhaust stack conducted two years ago gave an average CO emission rate of 10 lb/hr with an average natural gas-firing rate of 135,000 standard cubic feet per hour (scf/hr). The average heating value of the fuel was measured to be 1,050 mm Btu/mm scf. The emission factor derived from this test would be:

$$\text{Emission Factor} = 10 \text{ \{lb CO/hr\}} / 0.135 \text{ \{mm scf/hr\}} = 74 \text{ \{lb CO/mm scf\}}$$

Performance test data from a similar emission unit at a similar facility:

A test conducted four years ago at a nearby facility on a 240 mm Btu/hr natural gas-fired boiler gave an average CO emission rate of 14 lb/hr with an average fuel feed rate of 200,000 scf/hr. The emission factor derived from this test would be:

$$\text{Emission Factor} = 14 \text{ \{lb CO/hr\}} / 0.2 \text{ \{mm scf/hr\}} = 70 \text{ \{lb CO/mm scf\}}$$

Performance guarantee test data from the manufacturer of the emission unit:

The manufacturer has provided a CO performance guarantee of less than 80 lb/mm scf for this type of natural gas-fired boiler.

Which Emission Factor to Use?

The available CO emission factors are:

- 40 lb/mm scf AIRS
- 70 lb/mm scf Test data from similar boiler
- 74 lb/mm scf Test data from specific boiler
- 80 lb/mm scf Boiler manufacturer performance guarantee
- 84 lb/mm scf FIRE
- 84 lb/mm scf AP-42

The factor from AIRS should be discarded. The AIRS document dates from 1990 and appears to significantly underestimate emissions compared to the other data sources. Using this emission factor would almost certainly lead to compliance demonstration problems, especially given the result of the stack test on the specific boiler.

Using the factor derived from testing on a similar (but 60 % larger) boiler is risky, given the higher emission factor resulting from a test performed on the specific boiler. Typically, larger boilers are more efficient in terms of CO emissions than smaller boilers, as evidenced in the AP-42 documents where

emission factors are reported for different sized units, so applying an emission factor from a large boiler to a smaller boiler is generally not advisable.

It is tempting to use the 74 lb/mm scf emission factor that was measured on the specific boiler. After all, what could be more appropriate than a measurement taken on the actual boiler? Before adopting this factor, consider whether the boiler was being operated at its maximum design capacity during the test. Knowing the fuel feed rate and the heating value of the fuel during the test, we can calculate the heat input to the boiler:

$$\text{Heat Input} = 1,050 \{mm \text{ Btu/mm scf}\} \times 0.135 \{mm \text{ scf/hr}\} = 141.75 \{mm \text{ Btu/hr}\}$$

This is 94.5 % of the boiler's rated design capacity of 150 mm Btu/hr. What if conditions during the next compliance test correspond to 102% of the boiler's rated design capacity? If a permit condition of 10 lb CO/hr was imposed based on the results of the last test, then re-testing at a higher heat input could result in an exceedance of the limit. On the other hand, if a permit limit of 74 lb/mm scf was imposed based on the results of the last test, then re-testing at a higher heat input may not result in an exceedance. Clearly, the choice of emission factor must consider the method of compliance demonstration and the form of any likely permit conditions.

Whether or not the MPCA will set a pollutant emission factor used in the calculations as an emission limit in the permit depends on several factors:

- Whether or not the source would exceed any emission thresholds if emissions were actually higher
- Whether or not the source's emissions are predicted to cause ambient concentrations that are close to any ambient standards or health based recommended maximum concentrations (NAAQS, MAAQS, or Health Benchmarks)
- Whether or not control equipment is used to meet the assumed emission rate
- Discrepancy/variability in different sources of emission estimates and
- Amount of data available to substantiate assumptions.

As an example, for an existing boiler, the potential emissions should be calculated based on the following:

For any pollutant for which a standard sets an emission limit, the emission limit should be used for potential emissions calculations if the unit could exceed the associated limit without control. This may include PM, SO₂, NO_x, and with the newly promulgated NESHAP, HCl, CO, and mercury. For VOCs and the rest of the HAP emissions (listed in AP-42), the AP-42 emission factor is acceptable, or any source specific emission testing. Controlled emission factors are acceptable if your permit requires control.

Another point to consider before using the test data from the specific boiler is the degree of variability inherent in any performance testing. Although the last test reported a CO emission rate of 10 lb/hr at a fuel feed rate of 135,000 scf/hr, it is unlikely that a future test under the exact same operating conditions would produce the exact same result. A simple way to estimate the variability between tests is to look at the variability between the three runs in the last test. For this reason, it is common for permittees to add

a safety margin to emission factors derived from performance tests when using the factors in permit applications.

Adjusting the 74 lb/mm scf emission factor derived from the last test to reflect the unit's design capacity of 150 mm Btu/hr and to include a safety margin of 10%, gives:

$$\text{Emission Factor} = 74 \text{ \{lb CO/mm scf\}} \times (150/141.75) \times 110 \% = 86 \text{ \{lb CO/mm scf\}}$$

This is more in line with the 84 lb/mm scf emission factor reported in AP-42 and FIRE. At this point, the permittee may conclude that it's a wash between the source-specific test data and AP-42 and decide to use the AP-42 factor to avoid the hassle of having to gain agency approval of the test-derived emission factor. This logic may stem from permittees mistakenly assuming either that the AP-42 emission factors are 'conservative', while their specific units are 'average,' or that the AP-42 emission factors are 'average', while their specific units are 'better than average.' Actually, USEPA, in its introduction to AP-42, states that:

Use of these (AP-42) factors as source-specific permit limits and/or as emission regulation compliance determinations is not recommended by USEPA. Because emission factors essentially represent an average of a range of emission rates, approximately half of the subject sources will have emission rates greater than the emission factor and the other half will have emission rates less than the factor. As such, a permit limit using an AP-42 emission factor would result in half of the sources being in noncompliance.

For this particular example, the permittee may be advised to adopt an emission factor of 86 lb/mm scf, slightly higher than the AP-42 value.

Although not included in this example (because it is unlikely that CO emissions from a boiler would be continuously monitored), any available CEMS data should be closely examined when deciding which emission factor to use. CEMS data represents actual emissions measured over an extended period and may be useful in putting the one-time test data into context.

Finally, the detailed discussion provided above of how an emission factor was derived is a good example of the level of documentation that could be included in a permit application.

Implications of the selection of emission factor for the compliance determination form (Form CD-01)

When using direct measurements, do the CEMS or performance test data reflect the "worst case" emissions, or are there other operating modes which should be reflected? You should also anticipate the degree of variability in any directly measured value and incorporate an appropriate safety factor. For example, using an emission factor derived from a performance test consisting of three runs may not adequately reflect the variation in emissions that may result from repeating the test under identical conditions the next time a compliance demonstration is required.

When using published emission factors (e.g. AP-42), be sure to read the background document on the development of the factor. Also, some emission factors are expressed as a range. If possible, use the upper end of the range to maximize operational flexibility and minimize compliance liability.

When developing empirical formulas for emission factors, consult with the permitting agency regarding the QA/QC for the measurements upon which the emission factor is being based.

Remember, you may be held to the value of the emission factor as a condition of the resulting permit.

2.3.3. Process Variables

These typically come from

- process information systems
- material handling systems
- purchasing systems
- manufacturer specifications, or
- performance tests.

An Example: Identifying Sources for Process Variables for a Multiple-Fuel Boiler

Process Information System: It is not unusual for the rate at which natural gas is fed to a boiler to be monitored as part of the boiler's process control system. The system could consist of a flow meter and an automatic valve to control the flow of gas. The monitoring is likely to be continuous so that the instantaneous flow rate in scf/min is displayed and recorded in the control room.

Material Handling System: The rate at which coal is fed to a boiler could be measured by an in-line weigh scale installed downstream of the day bin but upstream of any pulverization equipment and the boiler itself. The monitoring is likely to be continuous so that the instantaneous flow rate in lb/hr is displayed and recorded in the control room.

Purchasing System: A small utility may track coal usage with purchasing records. In developing the throughput to be used in calculating emissions, the permittee must pay attention to the correlation between when coal is purchased, when it is delivered and when it is combusted in the boiler.

For calculating annual emission rates, the distinctions between these three example parameters are probably minimal; however, for calculating hourly emission rates, the distinctions are likely to be significant. For example, the utility may have a long-term (five year) contract with a coal supplier. The terms of the contract may specify an approximate quantity of coal to be purchased over the life of the contract, and possibly on an annual basis. In practice, the utility and coal supplier may have an understanding that, during the winter months, seven 25-ton truckloads of coal will be delivered daily. If the utility finds that excessive power demand from its customers is causing the boiler to be run closer to capacity for a few days, then the utility may call in an additional truckload of coal to be delivered that same day or the following day.

Over the course of a year, the amounts of coal ordered by the utility, delivered by the supplier and combusted in the boiler are likely to be in close agreement. On a daily basis, the amounts of coal delivered and combusted are likely to be very similar but the amount of coal ordered may be off by a truckload or two. On an hourly basis, the amount of coal combusted is likely to be close to the amount of coal delivered over a 24-hour period, if the latter is averaged over the number of hours the boiler operated during that 24-hour period. There is likely to be little correlation between the amount of coal combusted each hour and the amount of coal ordered each hour.

Manufacturer Specifications: A boiler manufacturer may provide a specification sheet that states the amount of various fuels that the specific boiler is able to combust on an hourly basis. However, such data is likely to be based on an assumed heating value of the fuel and possibly on other parameters that may vary between installations (for example, the supply pressure of natural gas, or the temperature of distillate fuel oil). The permittee should carefully consider such caveats before using a manufacturer-specified throughput in an emission calculation. Most boilers are rated by the manufacturer in units of mm Btu/hour.

Performance Tests: A performance test is typically conducted at or as close as possible to the maximum design capacity of the unit. As such, the throughput measured during the test may be an appropriate value to use in a potential emission calculation. As with test-derived emission factors, test-derived throughputs may need to be adjusted to reflect the unit's design capacity relative to the test conditions and to include a safety margin to account for variability between tests.

When choosing the value of the process variable to use in the emission calculations, consider whether the throughput reflects the process operating at its maximum capacity. If operated in any other mode, could higher emissions result? This is critical because the resulting permit could hold you to the process rate (units/hour or units/year or hours/year) used in the calculations. As with emission factors, it is preferable to use the upper end of the possible range of throughputs to maximize operational flexibility and minimize compliance liability.

2.3.4. Control Efficiencies

Similar to emission factors, control efficiencies may come from performance tests, or acceptable published sources such as USEPA's "AP-42", "Locating and Estimating ..." documents, or documents prepared by trade groups. They may also be defined by rule — for example, Minn. R. 7011.0070, subpart 1, Table A. There are also many control efficiencies listed in Form GI-05A

Minn. R. 7007.1200, subparts 2 and 3 (www.revisor.leg.state.mn.us/arule/7007/1200.html) allows the use of the control efficiencies listed in Minn. R. 7011.0070, subpart 1, Table A, shown below (www.revisor.leg.state.mn.us/arule/7011/0070.html). However, if no control efficiency is listed in Table A, or if a more representative control efficiency is available under Minn. R. 7011.0070 Subp. 2 of the rule, then the rule allows the use of control efficiencies derived from the sources listed in this item, subject to approval by the MPCA.

Table 2-1.

**Minn. R. 7011.0070, subpart 1, Table A:
Listed Control Equipment And Control Equipment Efficiencies**

ID #	Control Equipment Description	Pollutant	Control Efficiency	
			Total Enclosure	Hood
PM Control Category - Cyclones means a device where airflow is forced to spin in a vortex through a tube				
007	Centrifugal Collector (cyclone) - high efficiency means: a cyclonic device with parameters stated in drawing 1 and table 1	PM, PM-10	80%	64%
008	Centrifugal Collector (cyclone) - medium efficiency means: a cyclonic device with parameters stated in drawing 1 and table 1	PM, PM-10	50%	40%
009	Centrifugal Collector (cyclone) - low efficiency means: a cyclonic device with parameters stated in drawing 1 and table 1	PM, PM-10	10%	8%
076	Multiple Cyclone without Fly Ash Reinjection means: a cyclonic device with more than one tube where fly ash is not reinjected	PM, PM-10	80%	NA
077	Multiple Cyclone with Fly Ash Reinjection means: a cyclonic device with more than one tube where fly ash is reinjected	PM, PM-10	50%	NA
085	Wet Cyclone Separator or Cyclonic Scrubbers means: a cyclonic device that sprays water into a cyclone	PM, PM-10	50%	40%
PM Control Category - Electrostatic Precipitators means: a control device in which the incoming particulate matter receives an electrical charge and is then collected on a surface with the opposite electrical charge				
012	- assumed efficiency for boiler fly ash control - assumed efficiency for other applications	PM-10	40% 70%	NA 56%
PM Control Category – Other Controls				
016, 017, 018	Fabric Filter means: a control device in which the incoming gas stream passes through a porous fabric filter forming a dust cake	PM, PM-10	99%	79%
052	Spray Tower means: a control device in which the incoming gas stream passes through a chamber in which it contacts a liquid spray	PM, PM-10	20%	16%
053	Venturi Scrubber means: a control device in which the incoming gas stream passes through a venturi into which a low pressure liquid is introduced	PM, PM-10	90%	72%
055	Impingement Plate Scrubber means: a control device in which the incoming gas stream passes a liquid spray and is then directed at high velocity into a plate	PM, PM-10	25%	20%
058A, 058B	HEPA and Wall Filter means: a control device in which the exiting gas stream passes through	PM, PM-10	92%	74%

ID #	Control Equipment Description	Pollutant	Control Efficiency	
			Total Enclosure	Hood
	a panel of coarse fibers. Other Wall Filters means removable panels for cleaning and replacement, or liquid curtains for particulate removal that provide little resistance to air flow			
VOC Control Category				
019	Afterburners (thermal or catalytic oxidation) means: a device used to reduce VOCs to the products of combustion through thermal (high temperature) oxidation or catalytic (use of a catalyst) oxidation in a combustion chamber	VOC	95%	57%
023	Flaring or Direct Combustor means: a device in which air, combustible organic waste gases, and supplementary fuel (if needed) react in the flame zone (e.g., at the flare tip) to destroy the VOCs	VOC	98%	59%

An Example: Control Efficiencies for Xylene Emitted from a MSW Landfill and Controlled by a Flare

This example assumes that landfill gas (LFG, of which xylene is a component) generated by the decomposition of municipal solid waste is collected and routed to an enclosed flare. Note that xylene is a volatile organic compound (VOC), a non-methane organic compound (NMOC), a hazardous air pollutant (HAP), and that it is non-halogenated. The possible sources of relevant control efficiencies are:

Minn. R. 7011.0070, subpart 1, Table A: Control device category 023 has a listed control efficiency of 98% for VOC, assuming a total enclosure (which better approximates the landfill situation than collection by a hood). It should be noted that Minn. R. 7011.0070, subp. 2 states that a control efficiency listed in Table A may be used for a HAP if the control efficiency has been verified by a performance test approved by the commissioner under parts 7017.2001 to 7017.2060.

The potentially relevant "Locating and Estimating" document for xylene (Locating And Estimating Air Emissions From Sources of Xylene, USEPA-454/R-93-048, March 1994) does not address xylene emissions from MSW landfills.

The potentially relevant NSPS (40 CFR § 60, subp. WWW) regulates NMOC emissions and requires that an enclosed flare either reduce NMOC by 98 weight percent or reduce the outlet NMOC concentration to less than 20 parts per million by volume, dry basis as hexane at 3 percent oxygen.

The potentially relevant NESHAP (40 CFR § 63, subp. AAAA) defers to the NSPS for required control efficiencies.

AP-42: Table 2.4-3 (11/98) reports a control efficiency of 99.2% (90 to > 99%) for NMOC and 99.7% (38 to > 99%) for non-halogenated NMOC for an enclosed flare burning LFG.

There are no EPA databases or computer programs that include xylene control efficiencies from LFG flares. No emission factors reported in engineering publications are being proposed for evaluation.

Performance test data from the specific emission unit at the specific facility: Assume that a performance test conducted two years ago in accordance with MPCA procedures gave an average xylene control efficiency of 99.2% for the flare.

Performance test data from a similar emission unit at a similar facility: Assume that a test conducted four years ago at a smaller landfill owned by the same permittee gave an average xylene control efficiency of 98.5% for the flare.

Performance test data from the flare manufacturer: Assume that the manufacturer has provided a xylene control efficiency of 99.0% for this particular type of enclosed flare.

Which Control Efficiency to Use?

The available xylene control efficiencies, ranked from lowest to highest, are:

98.0%	Minn. R. 7011.0070, subp. 1, Table A for VOC
98.0%	NSPS (40 CFR § 60, subpart WWW) for NMOC
98.5%	Test data from similar flare
99.0%	Test data from flare manufacturer
99.2%	Test data from specific flare
99.7%	AP-42, Table 2.4-3 (11/98) for non-halogenated NMOC

The permittee could conclude that the control efficiency to be used in the emission calculations should be no lower than 98% because this is the minimum level required by the applicable rules (both Minn. R. 7011.0070 and 40 CFR § 60, subp. WWW). However, these requirements apply to the collective category of pollutants called VOC or NMOC. The rules do not require a 98% control efficiency for each and every individual VOC or NMOC.

The most relevant control efficiency would appear to be the 99.2% resulting from the source-specific test. If this test has been done in accordance with MPCA procedures and the results verified and approved by the MPCA, this value would seem to be preferable to the 99.7% reported in AP-42 because there is no evidence to suggest that a future test would demonstrate compliance with the higher AP-42 value if that were to be adopted as a permit limit. Also, it should be noted that the AP-42 value is based on an underlying range of values corresponding to a wide variety of different (but unspecified) individual pollutants. However, before deciding to use the source-specific test value of 99.2%, the permittee should consider the variability in this number (in the same way as this was considered for test-derived emission factors above). This includes reviewing the operating conditions in effect during the test and the variability between individual runs. Make sure the MPCA has a copy of the full test report from the test demonstrating the 99.2% efficiency, and that they have approved the methods and results. Don't forget

to propose how the 99.2% efficiency will be maintained, remembering that the frequency of performance testing may also be impacted by the level of control efficiency chosen.

2.4 Documentation of Emission Calculations

To facilitate the processing of an application for a permit amendment, emission calculations must be fully documented by the permittee. This includes clearly specifying the calculation methods and their bases, any conversion factors used to manipulate units of measurement, and the sources of all supporting information.

One way to provide this documentation is by completing the emission calculation (EC) forms that the MPCA has prepared for a variety of emission sources (see <http://www.pca.state.mn.us/air/permits/forms.html#1d-emission>).

An Example: Evaluating Sources for CO Emission Factors for a 125 mm Btu/hr Natural Gas-Fired Boiler

Using Form EC-02, and considering only CO emissions as was done above, note that the instructions to the form (pages 10 through 13) provide emission factors. The emission factor for gas fired boilers > 100 mm BTU/hr is given as 76 lbs/mm scf, which differs from the emission factor found in the example above. If the source chooses to use that emission factor and accepts a permit limitation based on that factor, then no further discussion would be needed.

However, based on the above analysis, the source has chosen an emission factor which is higher than that provided in the form, for reasons discussed above. A brief explanation for the use of a different factor should be provided as an attachment, as shown in Figure 2-1.

Another way to provide documentation is by providing an electronic copy of the emission calculations spreadsheet you use for your calculations. While a spreadsheet is more sophisticated than what the MPCA typically would require, it can include all of the information necessary to expedite MPCA review of your calculations. Several features of a spreadsheet are worth pointing out:

- The spreadsheet presents the emission calculations for each emission unit in turn, following the source numbering system used in the permit.
- A spreadsheet allows calculations to be made using maximum hourly, maximum annual, actual annual, and limited annual emission rates.
- All throughputs for a given combination of emission unit and pollutant can use the same basic unit of measurement (e.g. "mm BTU" for criteria pollutants emitted from EU 001, "gallons of diesel" for HAPs emitted from EU 001, and "VMT" for particulate matter emitted from FS 001).
- All emission factors are expressed in lb per basic unit of throughput measurement (e.g., lb pollutant/mm BTU), and the source of the emission factor is listed.
- Documentation of why an emission factor was chosen, if there are several alternative factors available.
- The emission factors for can be based on several variables and the derivation of the emission factors is presented on a supporting page of the spreadsheet.

- Footnotes documenting the source of each throughput, emission factor and control efficiency can be linked to cells in the emission calculations table.
- All calculations are performed using formulae in the relevant spreadsheet cells. This allows a reviewer to follow the logic of any calculations and to quickly identify points of disagreement without going through a lengthy process of additional informational requests. These formulae may be printed out and submitted to the MPCA or the permittee may choose to submit an electronic version of the spreadsheet to the MPCA to expedite the review process, even though, at this time, the MPCA only requires hard-copy submittals of a permit application.

Figure 2-1: Example Form EC-02 Showing CO Emission Calculations & Documentation for Simple Facility



MINNESOTA POLLUTION CONTROL AGENCY
 AIR QUALITY
 520 LAFAYETTE ROAD
 ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **EC-02**
EXTERNAL COMBUSTION (BOILER) CALCULATION FORM
 10/27/03

- 5) Maximum Rated Boiler Capacity: 150 million BTU/hr
- 6) Control Equipment: None
- 7) Fuel Parameters

7a) Fuel Type	7b) % Sulfur	7c) % Ash	7d) Heat Value	Units	7e) Fuel Consumption Rate	Units
Natural Gas	0	0	1,050	Btu/scf	143,000	cf/hr

When calculating Potential Emissions, use items 8a, 8b, 8d, 8e, 8g, 8h, and 8i (if a limit is proposed in item 12).
 When calculating Actual Emissions, use items 8a, 8b, 8c, 8f, 8g, and 8j.

8) Calculations Summary - Primary Fuel: Potential Emissions

8a Pollutant	8b Emission Factor (lbs/tmm scf.)	8c Actual Annual Fuel Use (tons, gallons, cf, etc.)	8d Emission Rate (lbs/hr)	8e Maximum Uncontrolled Emissions (tons/yr)	8f Actual Uncontrolled Emissions (tons/yr)	8g Pollution Control Efficiency (%)	8h Maximum Controlled Emissions (tons/yr)	8i Limited Controlled Emissions (tons/yr)	8j Actual Controlled Emissions (tons/yr)
CO	86		12.3	53.9		0	53.9	53.9	

Notes on choice of Emission Factor

The available CO emission factors are:

40 lb/mm scf	AIRS
70 lb/mm scf	Test data from similar boiler
74 lb/mm scf	Test data from specific boiler
80 lb/mm scf	Boiler manufacturer performance guarantee
84 lb/mm scf	FIRE
84 lb/mm scf	AP-42

Adjusting the 74 lb/mm scf emission factor derived from the last test to reflect the unit's design capacity of 150 mm Btu/hr and to include a safety margin of 10%, gives:

$$\text{Emission Factor} = 74 \{lb\ CO/mm\ scf\} \times (150/141.75) \times 110\ \% = 86 \{lb\ CO/mm\ scf\}$$

This is more in line with the 84 lb/mm scf emission factor reported in AP-42 and FIRE.