Updated: December 22, 2014

Attached are written comments and questions that EPA has received on the emissions factors proposed on August 19, 2014.

#	Page #	From
1	3	Dave Coffin
2	6	Sparsh Khandeshi, Environmental Integrity Project
3	8	Laurel Kearns, Drew University
4	9	Gary Fischman, Allegheny County Health Department
5	13	Sparsh Khandeshi, Environmental Integrity Project
6	26	Michael Zeilstra, Kinder Morgan
7	27	Mohammad
8	28	Matthew Todd, API
9	33	Sparsh Khandeshi, Environmental Integrity Project
10	158	Cathe Kalisz, API
11	159	Cathe Kalisz, API
12	160	Gurinder Saini, RTP Environmental
13	162	Cathe Kalisz, API
14	164	Sparsh Khandeshi, Environmental Integrity Project
15	165	Lisa Beal, INGAA
16	167	David Chetkowski, P.E., Monroe Energy, LLC
17	174	Russell Wozniak, The Dow Chemical Company
18	180	Danielle Nesvacil, Texas Commission on Environmental Quality
19	185	Steve Gossett, Eastman Chemical Company
20	189	David Friedman, American Fuel & Petrochemical Manufacturers
21	191	Gary Fischman, Allegheny County Health Department
22	194	Paul Morris, Air Products and Chemicals, Inc.
23	197	Anne Germain, Waste & Recycling Technology
24	201	Amy Van Kolken Banister, Waste Management
25	207	Georgette Reeves, Trinity Consultants
26	220	Stephen Holcomb, NiSource
27	223	Anne Germain, Waste & Recycling Technology
28	230	Angela Marconi, P.E., BCEE, Delaware Solid Waste Authority
29	238	Angela Marconi, P.E., BCEE, Delaware Solid Waste Authority
30	246	Lee Vail, Louisiana Chemical Association
31	252	Khalid Al-Binali, Aramco
32	253	Anthony Stratton, Eastmount Environmental Services, LLC
33	259	Jay Leduc, Sprague Resources GP LLC
34	263	Daniel DeArment, CB&I
35	267	Gail Tonnesen, EPA Region 8
36	270	Anthony Guiliani, Momentum Energy Group
37	273	Alice Prior, Dominion Environmental Services
38	277	Erin Bartlett, Gas Processors Association

#	Page #	From
39	281	Vicente Martinez, Dakota Gasification Co.
40	286	Lucinda Legel, Flint Hills Resources
41	327	Josh Nall, Wyoming Department of Environmental Quality
42	330	Liz Ulrich, Montana Department of Environmental Quality
43	334	Loren Anderson, Marcellus Shale Coalition
44	337	Angie Adams, Texas Pipeline Association
45	339	Anthony Giuliani, Ohio Oil and Gas Association
46	341	David Callahan, MarkWest Energy Partners
47	344	Andrea Grant, Independent Fuel Terminal Operators Association
48	348	Nathan Wheldon, MarkWest Energy Partners
49	351	Lisa Beal, INGAA
50	364	Lorraine Gershman, P.E., American Chemistry Council
51	368	Larry Conner, Perennial Energy
52	370	Nathan Wheldon, MarkWest Energy Partners
53	376	Jacob Fournier, Marathon Petroleum Company
54	414	Andriy Shvab, American Fuel & Petrochemical Manufacturers
55	432	Niki Westenberg, Republic Services, Inc.
56	441	Cathe Kalisz, P.E., American Petroleum Institute
57	546	Errol Villegas, San Joaquin Valley Air Pollution Control District
58	550	Sparsh Khandeshi, Environmental Integrity Project

From: Dave Coffin <davecoffinpe96@gmail.com>
Sent: Wednesday, August 20, 2014 1:26 PM
To: RefineryFactor
Subject: Re: Missing Proposed Revision Document

Thank you for the reply,

I see that it is there know which is good. Just so you know I would not have troubled anyone but I only decided to comment as it was showing when clicking on the link there around 6pm EDT last night so I assume I just saw webpage before it was updated.

thanks again.

On Wed, Aug 20, 2014 at 10:57 AM, RefineryFactor <RefineryFactor@epa.gov> wrote:

> **Dear Mr. Coffin.**
>
> **Thank you for your comment. Actually, the redline/strikeout version for Chapter 13.5 is posted on the webpage. If you look at the following link: http://www.epa.gov/ttn/chief/ap42/ch13/index.html#13.5 it's the third bullet under 13.5. Here's a direct link to the file if you're still having difficulty accessing it (http://www.epa.gov/ttn/chief/ap42/ch13/final/dc13s05rlso_8-19-14.pdf)**
>
> **Emission Factor Team**
>
> **From:** Dave Coffin [mailto:davecoffinpe96@gmail.com]
> **Sent:** Wednesday, August 20, 2014 9:53 AM
> **To:** RefineryFactor
> **Subject:** Missing Proposed Revision Document
>
> FYI to whom it may concern:

There is a web content posting error related to the announcement of TTN consent decree (below) and following the link, which is the suggested way by which a person gains access the proposed revision of **AP-42 Chapter 13: Miscellaneous Sources Section 13.5 Industrial Flares.**

The consent decree index webpage link (highlighted in **orange** below) for Industrial Flares goes to relevant section of section of AP-42 but the section **does not have the redlined version posted.** This is **unlike** the other two links for Petroleum Refining and Sulfur Recovery source categories, **which both have posted** the redlined documents.

As the industrial flare section is used by many other industries beyond the Petroleum Refining and Inorganic Chemical sectors and will require many other stakeholders to review and need additional time to provide comment; I request that the comment closing date be extended from October 19, 2014, preferably 60 days but at a minimum the number of days that it will take the agency to address this website error related to access to proposed revisions to the stakeholders.

> *"August 19, 2014 - EPA is proposing new and revised emissions factors for flares and new emissions factors for certain refinery process units. We are also proposing revisions to the refinery protocol document and proposing no changes to VOC emissions factors for tanks and wastewater treatment systems. We seek your comments on all aspects of these proposed actions regarding new and revised emissions factors for flares, proposed revisions to the refinery protocol document, as well as on the newly proposed emission factors for certain process units at refineries. We also seek your comments on our proposed determination that revisions to the VOC emission factors for tanks and wastewater treatment systems are not necessary. The proposed revisions and supporting documentation can be accessed at the following link: http://www.epa.gov/ttn/chief/consentdecree/index_consent_decree.html.*
>
> *Please submit your written comments on the above referenced documents and the proposed actions to AP-42 by October 19, 2014."*

> ***extracted from "consentdecree/index_consent_decree.html" webpage***
>
> *"We are proposing revisions for three sections of AP-42 to incorporate the revised/new factors. These proposed revisions can be accessed at the following links:*
>
> - *AP-42 Chapter 5: Petroleum Industry Section 5.1 Petroleum Refining*
> - *AP-42 Chapter 8: Inorganic Chemical Industry Section 8.13 Sulfur Recovery*
> - ***AP-42 Chapter 13: Miscellaneous Sources Section 13.5 Industrial Flares*** *"*

Respectively yours,

Dave Coffin, PE*
***Licensed in Louisiana**
Midlothian, VA
davecoffinpe96@gmail.com

Garwood, Gerri

From: Garwood, Gerri on behalf of RefineryFactor
Sent: Thursday, August 21, 2014 9:24 AM
To: skhandeshi@environmentalintegrity.org
Subject: FW: Emission Factor Question for flares

Sparsh,

Thank you for bringing this to our attention. The short answer is that it depends on the what pollutant you are interested in.

Keff uses CE (combustion efficiency) for pollutants like SO_2, but if this equation is being applied to SO_2, you need to add a mole number factor in the equation to account for compounds with 2 S atoms (like CS_2).

Keff uses DE (destruction efficiency) for hydrocarbons.

We hope that this clarification answers your question.

Sincerely,
The Emissions Factor Team

From: Sparsh Khandeshi [mailto:skhandeshi@environmentalintegrity.org]
Sent: Wednesday, August 20, 2014 2:51 PM
To: Shine, Brenda
Cc: Jennifer Duggan
Subject: Emission Factor Question for flares

Brenda,

For variable Keff in equation 6-1 of the Emission Estimation Protocol, does EPA intend for facilities to use the combustion efficiency or the destruction efficiency to calculate emissions?

The proposed revision to the Emission Estimation Protocol and AP-42 emission factors makes a distinction between “combustion efficiency” and “destruction efficiency.” EPA states that combustion efficiency of a properly operated flare is 96.5% and the destruction efficiency is 98%.

Thank you for any clarification.

Best,
Sparsh Khandeshi
Attorney
Environmental Integrity Project
1000 Vermont Ave., NW
Eleventh Floor
Washington DC, 20005
Phone: 202-263-4446
Fax: 202-296-8822

From: Laurel Kearns <lkearns@drew.edu>
Sent: Sunday, August 24, 2014 5:11 PM
To: RefineryFactor
Subject: comments on new refinery rules

As a social scientist, I have interviewed many in fence lines communities, and heard first hand what living near an oil refinery means in terms of quality of life and health. Not only do the emissions from oil refineries pose serious environmental justice issues, they also have broader environmental impacts that the EPA is charged with protecting.

We have heard the claims time and again from industry about how costly a regulation will be..I just think of smokestack scrubbers and mpg standards. The list could go on…and rarely does the cost to the human and ecological community get factored in if old standards are allowed to stand when new technology is available.

I feel increasingly like we live in a corporate run government and not a democracy, but the EPA always gives me hope. I heard Gina McCarthy speak, and felt that a new era could be dawning. I hope that is true, and that you will listen to the concerns of citizens.

Thank you.

Laurel

--
Laurel D. Kearns
Associate Professor, Sociology of Religion and Environmental Studies
Drew Theological School and the
Graduate Division of Religion
Drew University
Madison, NJ 07940
973 408 3009

Green Seminary Initiative www.greenseminaries.org

From:	Garwood, Gerri
Sent:	Tuesday, September 09, 2014 10:17 AM
To:	Fischman, Gary
Subject:	RE: Proposed AP-42 Flaring NOx Factor

Mr. Fischman,

Upon reviewing your calculations, I have discovered that your calculations do not follow the calculations we provided in the factor development report. I noted the following discrepancies:

- The CO2 you used was at the 2k wavelength instead of following the procedure we used for averaging the 765 and 2k wavelengths.
- Your C_inlet calculation does not follow ours at all. (Please see the factor development report for the equation we used. You can also follow the calculation in the “Flare Calculation” spreadsheet located in the Draft Background Documents zip file.)
- The vent gas heating value used is the average instead of the minute-by-minute value.

We chose to use the unweighted CE where it was available.

We are accepting comments on the equations used and the variables used at refineryfactor@epa.gov.

Thank you,
Gerri G. Garwood, P.E.

U.S. Environmental Protection Agency
OAR/OAQPS/SPPD
Measurement Policy Group
Ph: 919-541-2406 Fax: 919-541-3207

From: Fischman, Gary [mailto:GFischman@achd.net]
Sent: Monday, September 08, 2014 4:16 PM
To: Garwood, Gerri
Subject: RE: Proposed AP-42 Flaring NOx Factor

Ms. Garwood,

I actually got a lower number when doing a minute-by-minute average. I got 2.7 lb/mmbtu that way. This was using the weighted CE%s as the “IF” clause. However, when I selected on unweighted CE > 96.5% and did a minute-by-minute average, the result was 11.6 lb/mmbtu. The unweighted CE’s are substantially greater than the weighted CE’s. Therefore, using the unweighted CE’s included two minutes with extremely low CO2, driving the average up. One of these, 10/26/2010 17:28:00; Run ID 24, Condition AU-C, Run 3.7 (1), resulted in NOx = 3874.8 lb/mmbtu. The other minute, 10/26/2010 12:23:00; Run ID 21; Condition AU-C, Run 1.0 (1) resulted in 1987.7 lb/mmbtu. CO2 concentrations were 101.2 ppm for the highest NOx minute and 486.5 ppm for the second-highest minute, compared to an average of 13,047.5 ppm CO2 for all runs with CE>96.5%. Both of these minutes were excluded if the weighted CE’s are used for the filter.

Averaging by columns using the unweighted CE's, however, gives 2.9 lb/mmbtu. Since NOx concentrations are averaged this way, the high values resulting from extremely low CO2 are never calculated. For this reason, I believe averaging the concentrations is the best approach. Such low CO2 concentrations are highly suspect, especially given that the C_inlet concentrations for these minutes are well within one standard deviation of the average over all test minutes.

I still haven't been able to replicate the calculation of 16 lb/mmbtu.

I attached my revised spreadsheet showing minute-by-minute NOx lb/mmbtu calculations. I sorted the data by descending NOx. The highest NOx emission factor is just after all the "#DIV/0" rows. The NOx emission factors are in column CA.

Gary

From: Garwood, Gerri [mailto:Garwood.Gerri@epa.gov]
Sent: Monday, September 08, 2014 3:08 PM
To: Fischman, Gary
Subject: RE: Proposed AP-42 Flaring NOx Factor

Mr. Fischman,

Am I correct in that you have averaged the values per column to do the calculation?

To do the calculation, we actually performed the calculation for each minute of data to get the lb/mmBtu value, and then we averaged the lb/mmBtu value over all of the minutes. This may be where the difference in results lies.

Sincerely,
Gerri G. Garwood, P.E.

U.S. Environmental Protection Agency
OAR/OAQPS/SPPD
Measurement Policy Group
Ph: 919-541-2406 Fax: 919-541-3207

From: Fischman, Gary [mailto:GFischman@achd.net]
Sent: Monday, September 08, 2014 2:26 PM
To: Garwood, Gerri
Subject: RE: Proposed AP-42 Flaring NOx Factor

Ms. Garwood:

I'm a little confused by your response to item 1. I believe I actually did use the raw data files. I have attached the file with my calculations. Using all data with CE >=96.5% (all of the 1163 data points had steam present), including the zero-emission data, I calculated a NOx emission factor of 3.1 lb/mmbtu. My calculations are below the data. I used multiple subsets of the data; however, the calculations using weighted CE >=96.5% are at the top of this section and are in boldface.

Gary Fischman
Allegheny County Health Department
Air Quality Program
phone: (412) 578-8141
fax: (412) 578-8144
gfischman@achd.net

From: Garwood, Gerri [mailto:Garwood.Gerri@epa.gov]
Sent: Monday, September 08, 2014 11:59 AM
To: Fischman, Gary
Cc: RefineryFactor
Subject: RE: Proposed AP-42 Flaring NOx Factor

Mr. Fischman,

I hope that these responses answer your questions:

1. The draft background documents posted under Section 13.5 contains the compressed data file that we used in the factor calculation. The raw data files that were used and which did not come up as outliers are listed as references in the AP-42 section. The references are hyperlinked, and you can access the documents by clicking on their name from either the “clean” draft version or the red-line/strike-out draft version. There is a crosswalk document in the draft background documents that matches file names and AP-42 reference names to help with the process of locating these data. The flare data were limited to times when the CE was >= 96.5% (using normal rounding conventions), CO2 > 0, and steam was present.
2. We used the log transformed data in the outlier test because that is what the emissions factors procedures dictate. Please see Section 1.0 of Appendix C of the procedures document: http://www.epa.gov/ttn/chief/efpac/procedures/procedures81213.pdf
3. We included the zeros as we believe that they represent actual measurements, similar to how other instrumental methods will fall to zero or below zero (because of instrument drift) at times.

We would be interested in any comments that you may have on the calculation of the factor. Please provide comments to refineryfactor@epa.gov. Please provide as much detail as possible in your comments. You may contact me directly with any further questions.

Sincerely,
Gerri G. Garwood, P.E.

U.S. Environmental Protection Agency
OAR/OAQPS/SPPD
Measurement Policy Group
Ph: 919-541-2406 Fax: 919-541-3207

From: Fischman, Gary [mailto:GFischman@achd.net]
Sent: Monday, September 08, 2014 11:09 AM

To: Garwood, Gerri
Subject: Proposed AP-42 Flaring NOx Factor

Gerri:

The proposed NOx factor for industrial flares, 2.9 lb/mmbtu, is over 40 times the current factor of 0.068 lb/mmbtu. The factor is skewed upward by a single test, the Port Arthur Chemicals 2010 test on the AU Flare, which gave a factor of 16 lb/mmbtu. Using a Dixon's Q test on the logarithms of the six emission factors (the current factor plus six test results), the Port Arthur test was shown not to be an outlier. If either the Dixon's Q or the Grubbs test is run on the untransformed values, the Port Arthur test is identified as an outlier.

In addition, I calculated average NO_x emissions for the Port Arthur AU Flare using the filter specified in the background section, control efficiency >= 96.5%. Instead of limiting the selection to $CO_2 > 0$, I used the average of NO_2 where $NO_2 > 0$ and of NO where NO > 0. This gave the maximum NO_x emissions. I used the average control efficiency for values > 96.5%, resulting in 98.7%. I used the formula given on page 38 of the background document to calculate the emission rate in lb/hr. I also calculated the average net heating value and vent gas flow for CE >= 96.5% and used these values to convert the emission rate to an emission factor. My result was 10.3 lb/mmbtu.

My questions are:

1) Can EPA provide live Excel spreadsheet calculations of the emission factors from the test data which would indicate exactly which data were used in the calculation?
2) What is the rationale for performing the outlier test on the logarithms of the emission factors rather than the emission factors themselves?
3) Do the zero values for NO_2 and NO, where the CO_2 and vent gas flow were not zero, represent actual measurements or missing data?

The calculation spreadsheets and additional information will be helpful to us in determining the comments we will submit, if any.

Thank you for your assistance in this matter.

Gary Fischman
Allegheny County Health Department
Air Quality Program
phone: (412) 578-8141
fax: (412) 578-8144
gfischman@achd.net

From:	Shine, Brenda
Sent:	Tuesday, September 09, 2014 10:50 AM
To:	Sparsh Khandeshi
Cc:	Garwood, Gerri
Subject:	RE: Refernece Document from Emission Factor Proposal
Attachments:	Memo_Hourly TANKS emissions estimates_12-29-08.doc

Hi Sparsh---

Here it is in word format; We will be uploading to Gerri's emission factor website (probably as a PDF) this week.

From: Sparsh Khandeshi [mailto:skhandeshi@environmentalintegrity.org]
Sent: Monday, September 08, 2014 4:42 PM
To: Shine, Brenda
Subject: Refernece Document from Emission Factor Proposal

Brenda,

I am having trouble tracking down this document. Do you have easy access to it and can you share it with me? It is listed as a reference in Section 7 of the Emission Factor Proposal.

Coburn, J., and M. Icenhour. 2008. Preliminary Analysis of Short-term Variability in Storage Vessel Emissions. Memorandum from Jeff Coburn and Melissa Icenhour, RTI International, to Brenda Shine, EPA/OAQPS/SPPD. December 29, 2008.

Thanks.

Best,
Sparsh Khandeshi
Attorney
Environmental Integrity Project
1000 Vermont Ave., NW
Eleventh Floor
Washington DC, 20005
Phone: 202-263-4446
Fax: 202-296-8822

RTI INTERNATIONAL
3040 Cornwallis Road ▪ PO Box 12194 ▪ Research Triangle Park, NC 27709-2194 ▪ USA
Telephone 919 541-6000 ▪ Fax 919 541-5985 ▪ www.rti.org

TO: Brenda Shine, EPA/SPPD

FROM: Jeff Coburn and Melissa Icenhour

DATE: December 29, 2008

SUBJECT: Preliminary Analysis of Short-term Variability in Storage Vessel Emissions

I. Purpose

The purpose of this task was to evaluate the variability in the short-term emission rates for petroleum refinery storage vessels and to determine if the use of annual meteorological data in the TANKS model biases the emission estimates as compared to using hourly meteorological data.

II. Background

In a study documented in "Refinery Demonstration of Optical Technologies for Measurement of Fugitive Emissions and for Leak Detection" (Chambers and Strosher, 2006), volatile organic compound (VOC) emission measurements determined using Differential Absorption LIDAR (DIAL) suggested that the emissions from storage vessels were approximately 30 times greater than projected by the facility using the TANKS emission model. The American Petroleum Institute (API) submitted a letter (Watkins and Ritter, 2006) asserting that the short-term measurements reported in the DIAL study (Chambers and Strosher, 2006) are not indicative of the annual average emissions. API noted that there may have been maintenance issues with storage vessels, but they also outlined a number of reasons why short-term (on the order of 1 to 3 hours) emissions conducted in the summer (at higher than average temperatures) and during the day (when vessel loading activity and wind levels are higher), would be higher than the annual average emissions. API also cited a CONCAWE report (Smithers, et al, 1995) indicating that the TANKS model equations accurately estimated the emissions measured during a longer DIAL measurement study (90 hours). However, hourly input data were used in the TANKS model to estimate the storage vessel emissions during the CONCAWE study. This raised a question as to whether the use of hourly input data for a storage vessel would yield similar annual average emission estimates as the use of annual average meteorological data.

III. Summary of Results

Based on an analysis of the variability in meteorological data, the following observations regarding storage vessel emission estimates were made:

1. Based on annual average meteorological conditions, emissions estimates can vary by 25 percent or more due to variability in meteorological conditions from year to year.

2. For the single hourly average data set evaluated, using hourly average input data resulted in emission estimates that were 16 to 18 percent higher than those estimated using annual average meteorological input data.

3. Peak hourly average emission rates can be a factor of 5 to 10 higher than the annual average emission rates.

4. Use of an annual average liquid temperature in the monthly output feature of TANKS is likely to underestimate the seasonal variability of the emissions from the storage tank.

IV. Preliminary Analysis

For this analysis, a medium-sized model external floating roof tank (EFRT) and a medium-sized model internal floating roof tank (IFRT) were evaluated for gasoline storage. The model EFRT was configured according to Table 1 and the model IFRT was configured according to Table 2. The TANKS model default liquid properties for gasoline with a Reid Vapor Pressure (RVP) of 7 were used for the model tank analysis. For the hourly analysis, 1992 meteorological data for a single city (Houston, Texas) were used because there are many refineries in this area or in areas with similar climates.

In the preliminary analysis, a batch program was written that allows the TANKS model to be run thousands of times (using the hourly meteorological data) and to compile the results. The hourly temperature and wind speed were read into TANKS as the annual average wind speed and temperature, and the model was run for annual emissions output. The hourly average temperature was used for both the liquid and the air temperature. While this approach may exaggerate the influence of temperature since the liquid temperature will not fluctuate as readily as the air temperature, this approach provides a simple means of evaluating the potential variability in the emission estimates without significant re-writing of TANKS code.

After evaluating the meteorological data for Houston, two months were chosen for modeling using the hourly average input data set. July was chosen because it contains days with the highest temperatures and also days with the highest winds. January was chosen as the second month because it contains days with the lowest temperatures and also days with the calmest winds.

Using the hourly TANKS program, the emissions over time were graphed. Figure 1 shows the influence of wind on the total emissions for the model EFRT during January and July. Figure 2 shows the influence of temperature on total EFRT emissions during January and July. As seen in Figures 1 and 2, the emissions from EFRT are strongly influenced by wind speed, and are also influenced by temperature. For an EFRT, temperature appears less likely to cause peak storage vessel emissions than wind speed. The peak emissions that occurred in January appear to be primarily driven by high wind. While the emissions increase with increasing temperature, wind speed appears to be the primary factor influencing short-term emission variations from EFRT.

Table 1. Tank parameters for EFRT

City:	Houston, TX	
Diameter:	100	ft
Volume:	840,000	gal
Turnovers:	180	Q
Color:	white	
Condition:	Good	
Shell:	Lt rust	
Construction:	Welded	
Primary seal:	Mech shoe	
Secondary seal:	Shoe mounted	
Deck:	pontoon	
Fittings:	Typical	

Fitting Description	***No. of Fittings***
Vacuum Breaker (10 inch diameter), gasketed	1
Unslotted guide pole well, ungasketed sliding cover	1
Roof leg, adjustable, pontoon area, ungasketed	17
Roof leg, adjustable, center area, ungasketed	16
Rim vent, weighted mechanical actuation, gasketed	1
Gauge-Hatch / Sample Well (8 inch diameter), weighted mechanical actuation, gasketed	1
Automatic gauge float well unbolted cover, ungasketed	1
Access Hatch (24 inch diameter), bolted cover, gasketed	1

Tank Contents:		Gasoline (RVP-7)	
Antoine Coefficients -			
	A:	11.83315935	
	B:	5500.595807	
	C:		
Vapor molecular weight:		68	
RVP:		7	
Liquid molecular weight:		92	
ASTM slope:		3	
Density:		5.6	lb/gal at 60F

Table 2. Tank parameters for IFRT

City:	Houston, TX	
Diameter:	75	ft
Volume:	1,000,000	gal
Turnovers:	30	Q
Color:	white	
Condition:	Good	
Shell:	Lt rust	
Primary seal:	Liquid	
Secondary seal:	None	
Deck:	welded	
Columns:	1	
Fittings:	Typical	

Fitting Description	***No. of Fittings***
Vacuum Breaker (10 inch diameter), gasketed	1
Sample pipe, 10%open	1
Deck leg, adjustable	22
Ladder Well, ungasketed	1
Column well, ungasketed	1
Automatic Gauge Float Well, unbolted cover, ungasketed	1
Access Hatch, unbolted cover, ungasketed	1

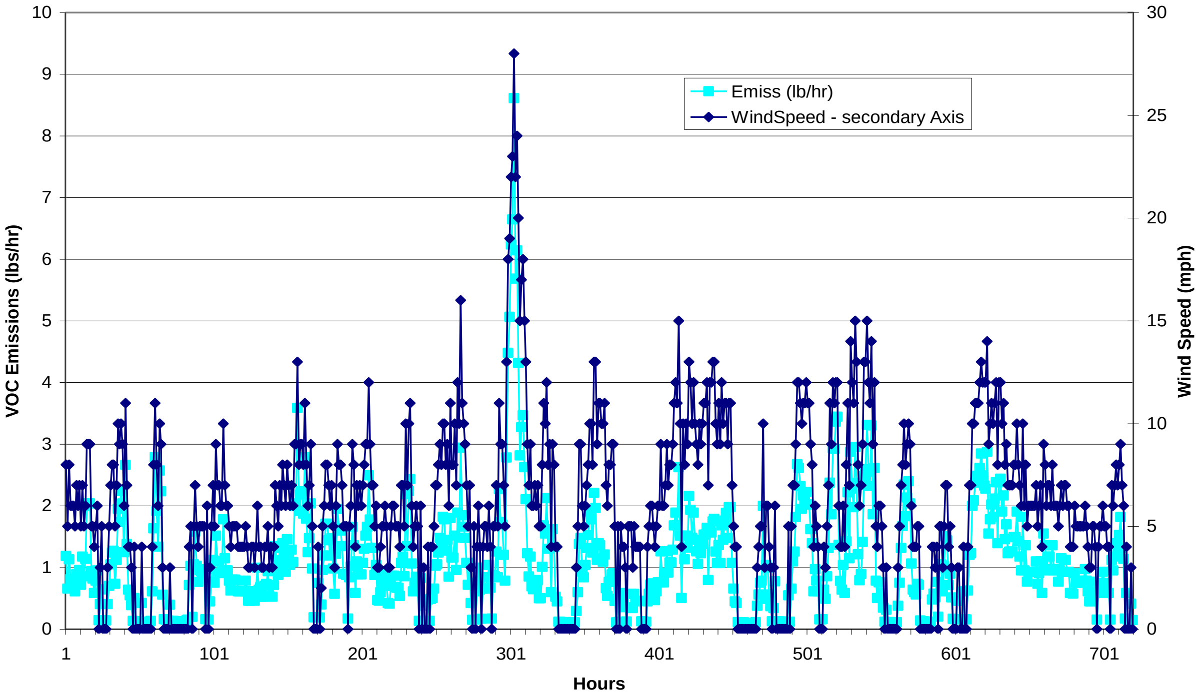
Contents:	Gasoline (RVP-7)	
Vapor molecular weight:	68	
RVP:	7	
Liquid molecular weight:	92	
ASTM slope:	3	
Component: benzene	3	percent

Wind speed does not affect the calculated emissions from an IFRT (at least based on the TANKS model calculations). Therefore, temperature is the primary meteorological variable affecting storage vessel emissions. Figure 3 shows the total emissions for the IFRT tank during January and July. As seen in this figure, the IFRT emissions are closely correlated with temperature.

V. Detailed Analysis of EFRT

The model EFRT described in Table 1 was further evaluated to assess the uncertainty and variability of input assumptions on the calculated emissions. The detailed analysis entailed using validation spreadsheets containing the basic AP-42 equations for the TANKS program. These Excel spreadsheets had been prepared during the development of the TANKS program as a check of the TANKS results, and they provide identical output results as the TANKS model when using the same input data. A macro was written to allow the validation spreadsheets to be run thousands of times, which allowed an evaluation of hourly meteorological data as well as other input data on the variability of the calculated emissions.

January EFRT, Wind



July EFRT Wind Speed

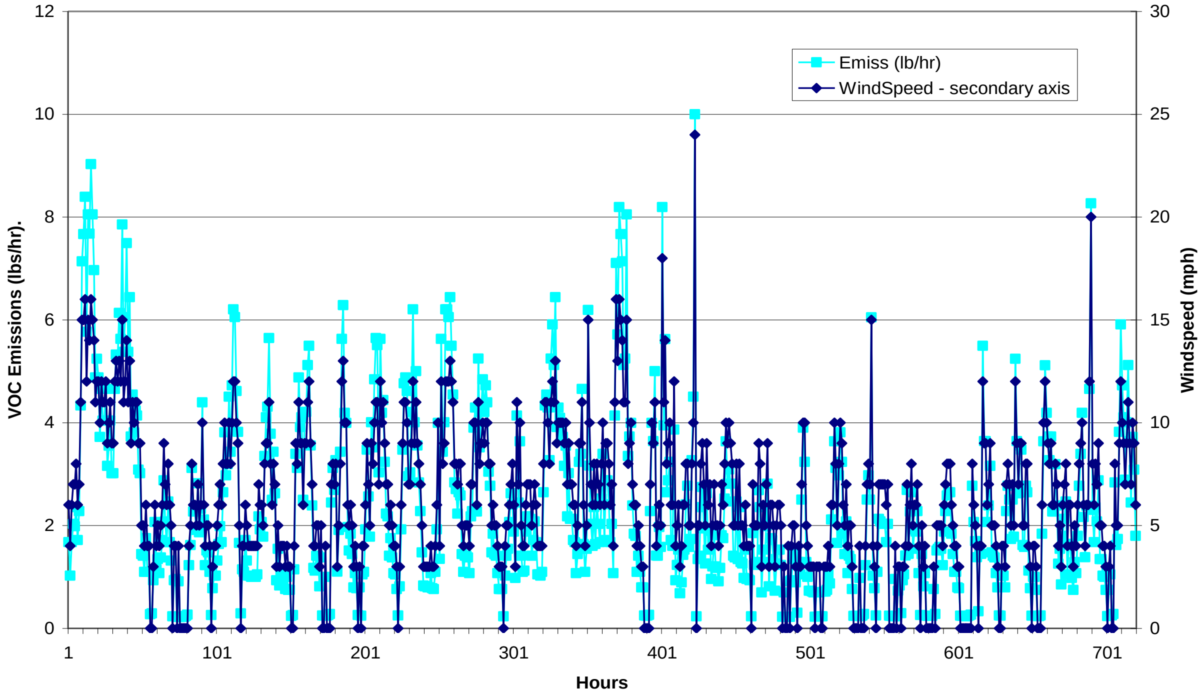
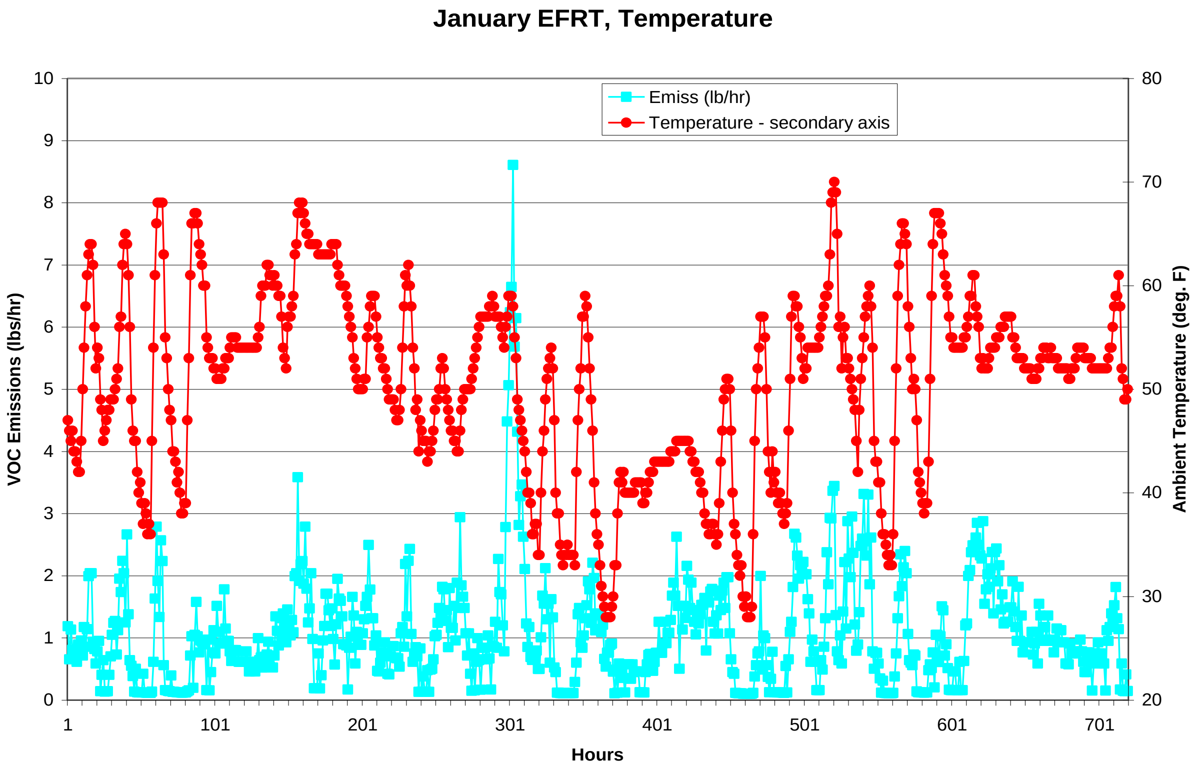


Figure 1. Effect of wind on VOC emissions from an external floating roof tank (EFRT).


January EFRT, Temperature

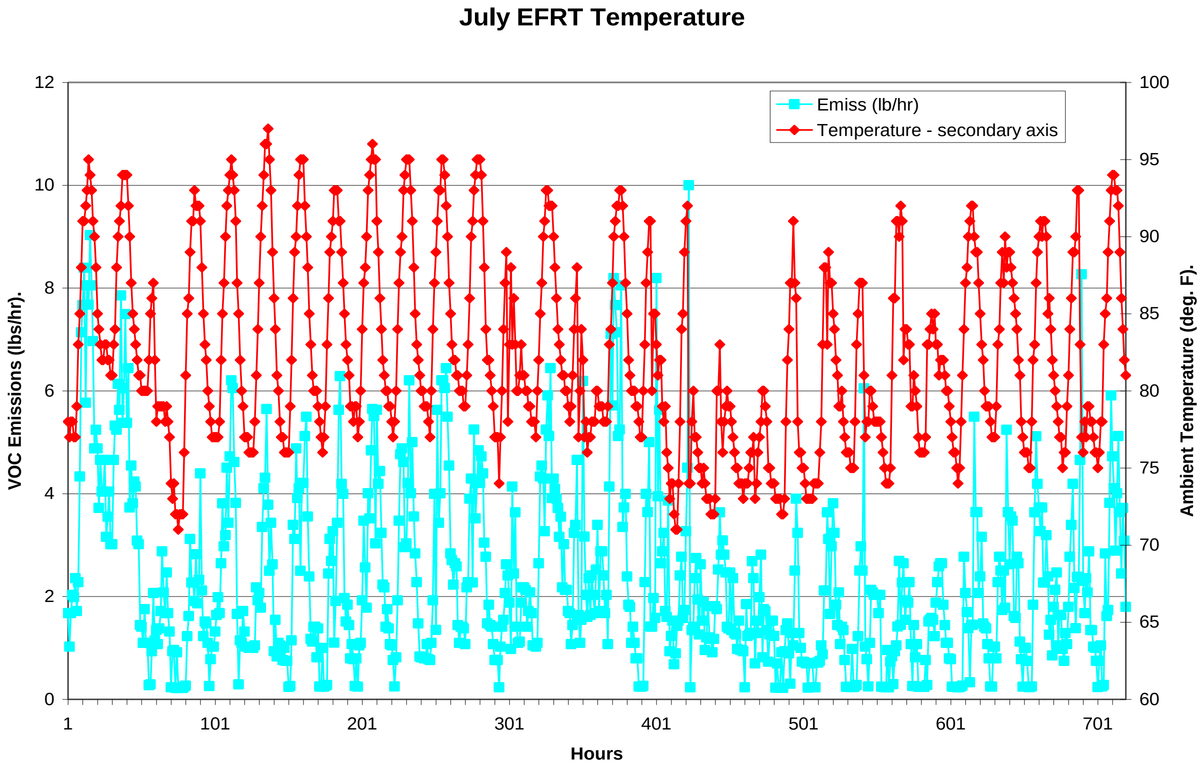
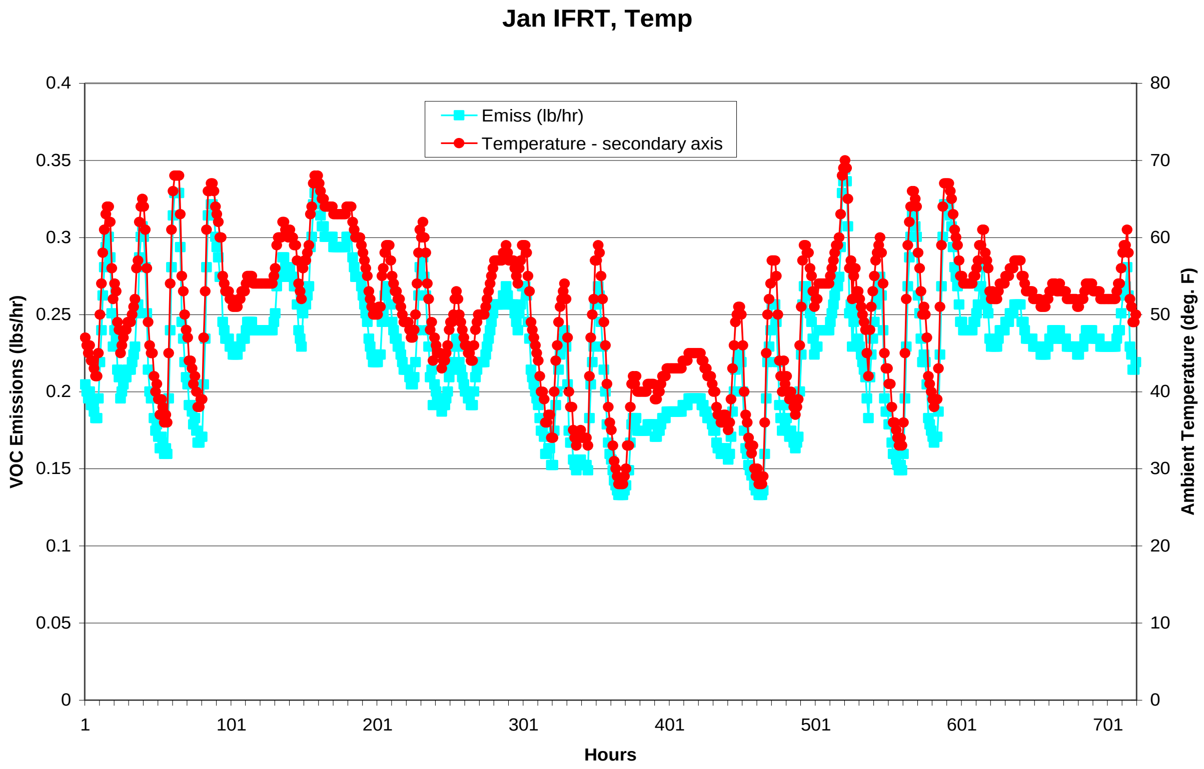

July EFRT Temperature

Figure 2. Effect of temperature on external floating roof tank (EFRT) VOC emissions.



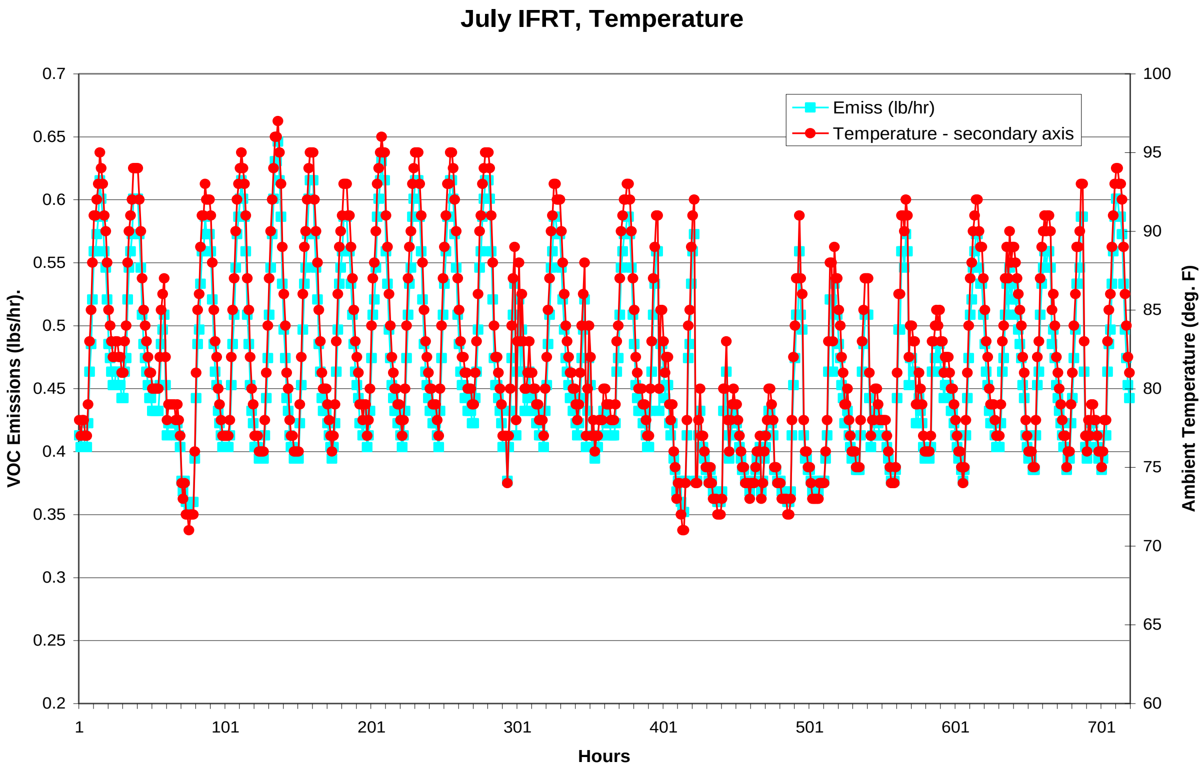


Figure 3. Effect of temperature on internal floating roof tank (IFRT)VOC emissions.

Uncertainty in Calculated Annual Average Emissions

The annual average emissions were calculated four different ways. First, the TANKS program was run directly using the default meteorological data for Houston. Second, the validation spreadsheet was used with the annual average meteorological conditions for Houston in1992 (the year for which the hourly meteorological data were available). This method allows an analysis of the average emissions variations from year to year due to normal variability in average annual meteorological conditions. It also provides a more direct comparison of the model runs using hourly meteorological input data. The third estimate for annual average emissions (Method 3) was calculated using the hourly average meteorological data for air temperature and wind speed. The liquid temperature was calculated using a rolling 336-hour (14-day) average. Monthly solar insolation factors from the TANKS model for Houston were used for all hours within a month, and turnover rates were kept constant for all hours of the year. The fourth model analysis was similar to Method 3, except that diurnal variations were also included. The solar insolation factors during the day (7AM to 7 PM) were set to twice the monthly average and the solar insolation factors for the other hours were set to zero. The turnover rate for the tank was also assumed to be higher during the day than at night. The average turnover rate was 180 turnovers per year for all hours in Method 3. For Method 4, the turnover rate during the day was assumed to be 270 while at night it was assumed to be 90. This analysis was performed to see what affect these diurnal variations have on the estimated annual emissions.

The annual average emissions calculated by the different methodologies are summarized in Table 3. Method 1b is provided simply to demonstrate that the spreadsheet model provides identical emissions to the TANKS program when using the same input data. Because the average annual temperature and wind speed for Houston in 1992 were lower than the average annual temperature and wind speed included in the TANKS program's database, the emissions calculated using the 1992 meteorological data were less than the default TANKS program output for the model EFRT in Houston, Texas.

When the hourly average temperature data are used (with the liquid temperature varying with the 336-hour rolling average), the emissions increased compared to using the annual average data for the same meteorological dataset (Method 3 compared to Method 2). Including diurnal activity data variations also increased the emissions, but not by very much. Using Method 2 as the reference method, using hourly average data to estimate the annual emissions resulted in an emission estimate that was 16 percent higher than using the annual average value. Including diurnal activity variations (Method 4) only led to a slight emissions increase over Method 3, and it resulted in an emission estimate that was 18 percent higher than calculated using the annual average values for all inputs.

These changes are not very significant compared to the variability in the emissions due to normal variations in the weather. The default meteorological data in the TANKS program for Houston yielded emissions that were 24 percent higher than using the annual average meteorological conditions for Houston in 1992. Thus, it appears that the variability in the annual temperatures and wind speed introduces as much uncertainty in the calculated annual average emissions rate as do differences in the calculation methodology. For this location and meteorological data set evaluated, the TANKS default led to higher annual average emissions, but it is just as reasonable to expect that, for other locations or other years, the annual average emissions could be underestimated by 25 or 30 percent using the TANKS default data as compared to the actual data for that year and location.

Table 3. Evaluation of Different Calculation Methods in Estimating Annual Emissions from an External Floating Roof Tank.

Calculation Methodology	Annual VOC Emissions (lbs/yr)
1a. TANKS program using TANKS default meteorological data[1]	16,389
1b. Validation spreadsheet using TANKS default meteorological data[1]	16,389
2. Validation spreadsheet using annual average 1992 meteorological data[1]	13,172
3. Validation spreadsheet using hourly average 1992 meteorological data[1]	15,319
4. Validation spreadsheet using hourly average 1992 meteorological data[1] plus additional diurnal activity variations	15,543

[1] All meteorological data is for Houston, Texas.

Uncertainty in Calculated Monthly Average Emissions

The monthly average emissions rate in January and July were evaluated in a manner similar to the evaluation of the annual emissions rates. Note, however, that the TANKS program always assumes the liquid temperature is at the annual average temperature even when run using the monthly output function. While the liquid temperature will not vary as significantly as the ambient air temperature, the average temperature of the liquid stored during the summer months will generally be higher than during the winter months. The temperature of some stored fluids may be driven by the operating temperature of the upstream process, but these will require over-riding the default temperature in any event. In calculation Methods 3 and 4, a 336 rolling hour average was calculated for the liquid temperature. For this analysis, there were two different variations on Method 2. In Method 2a, the liquid temperature was assumed to be constant at the 1992 annual average value, so that the calculation mimics the TANKS program except that different meteorological data were used. In Method 2b, the monthly average temperature was used for both the air and liquid temperatures.

The results of the monthly emissions analysis are provided in Table 4. For more direct comparison with the annual emissions reported in Table 3, the emission rates in Table 4 are reported in terms of pounds per year (lbs/yr) assuming the emissions calculated for the month continued all year long.

Table 4. Evaluation of Different Calculation Methods in Estimating Monthly Emissions from an External Floating Roof Tank.

Calculation Methodology	VOC Emissions Rate (lbs/yr) for:	
	January	July
1a. TANKS program using TANKS default meteorological data and monthly output option[1]	14,473	16,605
1b. Validation spreadsheet using TANKS default meteorological data[1]	14,473	16,605
2a. Validation spreadsheet using annual average temperature for liquid and monthly average 1992 meteorological data for other inputs[1]	9,055	14,918
2b. Validation spreadsheet using monthly average 1992 meteorological data for all inputs[1]	7,620	17,267
3. Validation spreadsheet using hourly average 1992 meteorological data[1]	9,025	19,736
4. Validation spreadsheet using hourly average 1992 meteorological data[1] plus additional diurnal activity variations	9,077	20,142

[1] All meteorological data is for Houston, Texas.

The TANKS program shows little difference between January and July emissions for two reasons. First, as discussed previously, it uses the annual average emissions rate for the liquid regardless of the month for which the calculations are being made. The second reason is simply a matter of the default meteorological data in the TANKS program. The monthly average wind speed in the default TANKS data for January is slightly higher than the annual average and the monthly average wind speed in the default TANKS data for July is slightly lower than the annual average. Given the significance of wind speed on the emissions rate for an EFRT, these slight variations in wind speed help to off-set the variations in temperatures. For the 1992 Houston, Texas, meteorological data set, the monthly average wind speed for January is slightly lower than the monthly average wind speed for July (although both are lower than the annual average wind speed). Therefore, the 1992 data set provides a much more significant variation in the monthly emissions because both wind speed and temperatures are lower in January than in July.

When the liquid temperature is allowed to fluctuate with the monthly or 336-hour rolling average ambient temperature (Methods 2b, 3, and 4), the monthly average emissions vary by ±30 to 40 percent compared to the annual average emissions rate. These variations are estimated by comparing the monthly emissions in Table 4 with the annual average monthly emissions for the same calculation methodology in Table 3. As this is the variability seen for one year for one meteorological station, it is likely that higher variability could be seen for certain years or for other locations.

Uncertainty in Short-term Measured Emissions

The CONCAWE report (Smithers, et al, 1995) provides evidence that the TANKS model equations can accurately estimate short-term emissions when the appropriate short-term input data are used. The preliminary runs indicate that emissions during certain July days were as high as 8 lbs/hr (see Figure 1). The annual average emissions rate for this same meteorological data set suggests that annual average emissions would have been 1.5 lbs/hr (from Table 3: 13,172 lbs/yr /365/24). These data suggest that the short-term emissions may be a factor of 5 or so higher than the annual average. However, this preliminary analysis used the hourly average temperature for the liquid temperature and is likely to exaggerate the temperature fluctuation of the stored liquid. The model runs using Method 3 or 4 provide a much more reasonable estimate of the potential fluctuations in liquid temperatures. Additionally, Methods 3 and 4 provide hourly emission estimates that can be directly evaluated. Table 5 provides a summary of the variability in the hourly emission rates as compared to the annual average emissions estimated by TANKS using the 1992 dataset.

Table 5. Variability in Hourly Average Emission Rates an External Floating Roof Tank.

Calculation Methodology	VOC Emissions Rate (lbs/hr)	Ratio to Annual Average Emission Rate from Method 2
2. Average annual emissions rate for TANKS program using annual average data from the 1992 meteorological data set[1]	1.50	1.00
3. Annual average emissions rate using Method 3	1.75	1.16
3a. Highest hourly average emissions rate	11.25	7.48
3b. 99th percentile hourly average emissions rate	5.75	3.82
3b. 98th percentile hourly average emissions rate	5.11	3.40
4. Annual average emissions rate using Method 4	1.77	1.18
4a. Highest hourly average emissions rate	11.96	7.95
4b. 99th percentile hourly average emissions rate	6.04	4.01
4b. 98th percentile hourly average emissions rate	5.37	3.57

[1] All meteorological data is for Houston, Texas

As the Alberta DIAL testing (Chambers and Strosher, 2006) was conducted during the summer months during the day during periods of sustained (constant) wind (constant wind is needed to quantify the plume), it is expected that the emissions would be indicative of the 98th percentile or higher hourly average emissions rate (warmest 60 days/yr; warmest 6 hours/day; top 50% wind speeds = testing during top 180 hours of 8,760 hours per year). While it is unlikely that testing occurred during the very single hour of highest emissions, it is quite likely that the testing occurred during the 98th or 99th percentile hourly average emissions rate. The data in Table 5 suggest that a short-term emissions test could easily yield an emission rate that is 4 to 5 times higher than the annual average emissions rate. As this analysis was conducted for only one year at one location, more extreme variability may be seen at other locations or for this location during other time periods. Based on the comparison of the annual average emissions rates for the TANKS default and 1992 dataset, emissions could vary by an additional 25 percent or more due to variations in meteorological data from year to year. As such, a factor of 8 to 10 variation in the hourly average emissions and the annual average emissions appears to be a reasonable estimate of the short-term variability in emissions from storage tanks. As the input data used to develop the inventory emission estimates for the Alberta tanks are not available, and the contents and condition of the tank were unknown during the DIAL testing, variability in the types of liquids stored, incorrect modeling assumptions (like the use of annual ambient temperature for tank receiving hot liquids or the use of "typical" fittings selection when uncontrolled slotted guide poles are used), and other factors could give rise to higher differences between the estimated and measured emissions rates. Due to the lack of data for this study, no definitive conclusions can be made. However, this hourly TANKS analysis does indicate that a significant amount of variability in storage vessel emissions is expected during short time periods, but even with this variability, the use of annual average tank conditions does appear to yield very similar emission estimates as more detailed modeling using hourly average meteorological conditions.

VI. Next Steps

The analysis performed here considered one meteorological station and data for only one year. Many meteorological datasets contain hourly data for several years. Additional meteorological data, both in terms of additional locations and longer data series, could be used to further characterize the variability in short-term tank emissions. Different sized model tanks with different types of fittings could be used. It is possible, for example, that emissions from slotted guide poles vary more dramatically with meteorological conditions than other types of fittings. While many tanks are in dedicated service, some tanks may store different types of liquids at different times of the years. Consequently, for mixed services storage vessels, liquid properties can also cause significant variability in the emission from the tank. As such, model runs using different types of liquids could also be useful in characterizing the variability in emissions from storage vessels.

VII. References

Chambers, A. and M. Strosher. 2006. "Refinery Demonstration of Optical Technologies for Measurement of Fugitive Emissions and for Leak Detection," Alberta Research Council Inc. (ARC) Project No. CEM 9643-2006 for Environment Canada, March 31, 2006, revised May 23, 2006.

Watkins, P. and K. Ritter.. 2006. Letter from Paula Watkins and Karin Ritter of the American Petroleum Institute (API) to Michael Ciolek of the U.S. Environmental Protection Agency (EPA), dated August 9, 2006, regarding the Alberta Research Council (ARC) DIAL study (Chambers and Strosher, 2006).

Smithers, B.; McKay, J.; Van Ophem, G.; Van Parijs, K.; White, L., "VOC Emissions from External Floating Roof Tanks: Comparison of Remote Measurements by Laser with Calculation Methods," prepared for CONCAWE Air Quality Mgt. Group, Report No. 95/52, Brussels, January 1995.

From:	Zeilstra, Michael <Michael_Zeilstra@kindermorgan.com>
Sent:	Tuesday, September 09, 2014 11:52 AM
To:	RefineryFactor
Subject:	Flare NOx Emission Factor Change

To whom it may concern,

my comment is in reference to the test results on Table 21 of the Draft Document. The test result that showed a result of 16 lbNOx/MMBtu is obviously an outlier, and therefore should not be represented in the average to determine the new NOx emission factor. It does not make sense that the NOx emission factor is increasing by almost 5,000%.

Thanks, Michael

From: Mohammad AL- <sting86@hotmail.com>
Sent: Wednesday, September 10, 2014 3:12 PM
To: Garwood, Gerri
Subject: Re: Proposed new and revised emission factors

Thanks for your feedback.

Best regards,
Mohammad

Sent from my iPhone

On Sep 10, 2014, at 3:10 PM, "Garwood, Gerri" <Garwood.Gerri@epa.gov> wrote:

> Mohammad,
>
> The August 19 proposal is open for comment for 60 days; there will be no changes to the proposed factors during this time period. After October 19, we will consider the comments received and determine if any revisions are necessary.
>
> Sincerely,
> Gerri G. Garwood, P.E.
> ---
> U.S. Environmental Protection Agency
> OAR/OAQPS/SPPD
> Measurement Policy Group
> Ph: 919-541-2406 Fax: 919-541-3207
> -----Original Message-----
> From: Mohammad AL- [mailto:sting86@hotmail.com]
> Sent: Wednesday, September 10, 2014 2:03 PM
> To: Garwood, Gerri
> Subject: Proposed new and revised emission factors
>
> Dear Gerri,
>
> Do you have any new updates regarding the proposed new and revised emission factors for flares ? I read the august 2014 draft and was wondering if you have anything recent?
>
> Regards,
> Mohammad
>
> Sent from my iPhone

From: Matthew Todd <ToddM@api.org>
Sent: Thursday, September 11, 2014 3:22 PM
To: McCabe, Janet; RefineryFactor
Cc: Tsirigotis, Peter; Lassiter, Penny; Shine, Brenda; Garwood, Gerri
Subject: API Comments on Proposed Emission Factor Revisions
Attachments: 2014 09 11 FINAL API Comment Letter to EPA on Emission Factor Revision.pdf

Dear Ms. McCabe:

API respectfully submits the attached comment letter in response to the Proposed Revisions to Sections 5.1, 8.13, and 13.5 of AP-42 including proposed changes to the Emission Estimation Protocol for Petroleum Refineries.

Matthew Todd

Matthew Todd
API
202.682.8319

Matthew Todd

Regulatory and Scientific Affairs

1220 L Street, NW
Washington, DC
20005-4070 USA
Telephone: 202-682-8319
Email: ToddM@api.org
www.api.org

September 11, 2014

Honorable Janet McCabe
Acting Assistant Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, D.C. 20460

refineryfactor@epa.gov

RE: Proposed Revisions to Sections 5.1, 8.13, and 13.5 of AP-42 and the Draft Emission Estimation Protocol for Petroleum Refineries - Version 3.0 posted August 19, 2014

Dear Acting Assistant Administrator McCabe:

On August 19, 2014, in response to its consent decree with Air Alliance Houston et al.[1] (Consent Decree), EPA posted a notice on its TTN Chief website proposing to revise the AP-42 emission factors for industrial flares and to make no changes to existing factors for liquid storage tanks and wastewater treatment systems. In addition to the emission factors for these three specific emission types required to be reviewed per the Consent Decree, EPA also proposed to add or revise certain AP-42 emission factors for petroleum refinery Fluid Catalytic Cracking Units, Hydrogen Plants, Sulfur Recovery Units, Catalytic Reforming Units , and Delayed Coker Units. Concurrently with the proposed AP-42 revisions, EPA posted an updated version (Draft Version 3) of the Emissions Estimation Protocol for Petroleum Refineries (Protocol), which incorporates the proposed AP-42 emission factor revisions and also changes the function of the Protocol document from a Petroleum Refining Information Collection Request (ICR) tool for industry to now “provide guidance and instructions to petroleum refinery owners and operators *and to federal, state, and local agencies* [emphasis added] for the purpose of improving emission inventories.”

The American Petroleum Institute (API) represents over 600 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America’s energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and, since 2000, has invested nearly $2 trillion in U.S. capital projects to advance all forms of energy, including alternatives. API members own and operate flares, tanks,

---

[1] Air Alliance Houston, et al. v. McCarthy, No. 1:13-cv-00621-KBJ (D.D.C.)

wastewater treatment systems and refining process units that would be directly impacted by any new or revised emission factors, particularly since EPA is under a parallel consent decree timetable to propose and finalize amendments to refinery NESHAP rules and those amendments address emissions from these same sources, among others.

API has significant concerns with EPA's proposed schedule for revising emission factors and with its proposed reclassification of the ICR Protocol to a broader industry and federal, state, and local agency guidance document. In order to meet the CAA requirements for full public participation, to avoid prejudicing the Refinery Sector Rulemaking, to avoid finalizing out-of-date emission factors, and to prevent conflicts among EPA's recommended emission factors in the future API requests that EPA do the following:

- <u>Provide a minimum of 180 days for public review and comment on the proposed revisions to AP-42 and the Emissions Estimation Protocol for Petroleum Refineries (Draft Version 3) after the Refinery Sector Rule is Finalized.</u>

  EPA's notice on its TTN Chief website indicates that comments on the two referenced documents are due on October 19, 2014. As discussed in API's May 27, 2014 comments on EPA's proposed Consent Decree (attached for reference), a 60-day comment period does not allow the public sufficient time to carefully evaluate the proposed emission factors, their impacts, and provide meaningful comment. The flare source category in particular has broad impacts - revised flare emission factors will affect industries who utilize flares, flare manufacturers, and state and local regulators that may have done flare emissions testing or modeling and developed their own emissions factors or have different situations than the narrow basis (i.e., primarily data on steam-assisted refinery flares) used for this proposal. All stakeholders need adequate time to assess EPA's proposed revisions.

  Furthermore, in developing their comments on this emission factor proposal, all potentially impacted sources should be given time to review and consider relevant stakeholder comments submitted on the proposed Refinery Sector Rule (RSR). The comment period for the proposed RSR closes on October 28, 2014. API and others are expected to submit extensive comments on the EPA's emission estimates and models for petroleum refinery flares and some refinery process units and this information could significantly impact comments on the emission factor proposal.

- <u>Delay finalization of any revisions to AP-42 and the Emissions Estimation Protocol until one year after the Refinery Sector Rule is promulgated and incorporate NSPS Ja and Sector rule impacts into the new emission factors.</u>

EPA's Consent Decree with Air Alliance Houston et al. currently requires that revisions to emission factors for flares, tanks or wastewater treatment systems be finalized by December 19, 2014 or that a no revision decision be made. EPA is under a separate consent decree to issue the final RSR by April 17, 2015. If EPA proposes new emission factors for flares that utilize the same underlying assumptions as those used in the Refinery Sector rulemaking, it prejudices the evaluation of comments on the refinery rulemaking since the new emission factors would be finalized prior to finalizing the Refinery Sector Rule.

Even more importantly, any change in emission factors should reflect both NSPS Ja, which will impact virtually all refinery flares and has a compliance deadline of November 15, 2015, and the RSR rule, which will have compliance deadlines from 2015 to 2018. It is arbitrary and unreasonable to revise emission factors for refinery processes, and particularly refinery flares, when those emission factors are known by EPA to reflect operations for which EPA has proposed changes and, as such, will be out-of-date as soon as they are finalized.

Therefore, to avoid prejudicing the Refinery Sector rulemaking and to propose emission factors that are reflective of the timeframes in which they will be used (i.e., after the RSR rule is finalized), EPA should not finalize any changes to AP-42 or the Emissions Estimation protocol until one year after the final RSR.

- <u>Keep the Estimation Protocol for Petroleum Refineries as an ICR tool and do not Link AP-42 to the Protocol</u>

  The Estimation Protocol was intended to provide for consistent estimation of refinery emissions as part of an ICR data collection effort and many of the emissions factors and estimation methods contained therein were not developed using the rigorous methods set out by EPA's recommended procedures for developing emissions factors.[2] For this reason, EPA should not repurpose the Protocol as a broader industry and government agency guidance document, and AP-42 should not reference the Protocol. For example, the proposed revisions to AP-42 Section 5.1.2.3.2 for Coking Units reference the Protocol for estimating emissions from Coker venting and subsequent decoking steps. Furthermore, the Protocol includes recommendations for emission factors for equipment leaks, storage vessels, wastewater, combustion devices and other general types of equipment that are separately addressed in AP-42. This assuredly will result in two different EPA recommendations of emission factors for refinery equipment, most likely an updated AP-42 factor and an out-of-date Protocol factor. Aside from the concern with referencing Protocol emission factors not subject to the

---

[2] See Eastern Research Group, Inc., *Recommended Procedures for Development of Emissions Factors and Use of the WebFIRE Database*, EPA-453/D-13-001, August 2013

same quality standards as AP-42, linking AP-42 and the Protocol document would forever require simultaneous updates to avoid inconsistent documents.

Thank you for your consideration of the above requests. If you have any questions, or would like to discuss further, please contact me at toddm@api.org or at 202-682-8319.

Sincerely,

/s/

Matthew Todd

Cc: Peter Tsirigotis, EPA
Penny Lassiter, EPA
Brenda Shine, EPA
Gerri Garwood, EPA

Garwood, Gerri

From:	Garwood, Gerri
Sent:	Thursday, September 11, 2014 4:49 PM
To:	Sparsh Khandeshi
Cc:	RefineryFactor
Subject:	FW: Emission Factor Proposal
Attachments:	MAy 14 1991 memo.pdf

Sparsh,

We were able to obtain a copy of the memo you requested, as well as the attachment to the memo. I am attaching the memo to this email. Due to size limitations, the attachment will follow separately.

Sincerely,

Gerri G. Garwood, P.E.

--

U.S. Environmental Protection Agency
OAR/OAQPS/SPPD
Measurement Policy Group
Ph: 919-541-2406 Fax: 919-541-3207

From: Sparsh Khandeshi [mailto:skhandeshi@environmentalintegrity.org]
Sent: Friday, September 05, 2014 2:11 PM
To: Garwood, Gerri
Subject: Emission Factor Proposal

Gerri,

I am looking for the Office of Air Quality and Planning and Standards May 14, 1991 memorandum detailing the results of the office's efforts to comply with the CAA Amendments' requirement to review and revise emission factors. This document is referenced by the OIG's 1996 report, http://www.epa.gov/oig/reports/1996/emisrept.pdf#introduction, at page 8 in the linked file. Do you have easy access to this document, or would it be best to submit a FOIA to try and obtain a copy.

Thank you for your assistance.

Best,
Sparsh Khandeshi
Attorney
Environmental Integrity Project
1000 Vermont Ave., NW
Eleventh Floor
Washington DC, 20005
Phone: 202-263-4446
Fax: 202-296-8822

Emission Inventory Survey
EIKABS-24-0020

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

MAY 14 1991

MEMORANDUM

SUBJECT: Implementation of Section 804 of the Clean Air Act Amendments

FROM: William G. Laxton, Director
Technical Support Division (MD-14) William G. Laxton

TO: Director, Air, Pesticides and Toxics, Regions I, IV & VI
Director, Air and Waste Management Division, Region II
Director, Air Management Division, Region III
Director, Air and Radiation, Region V
Director, Air and Toxics Division, Regions VII-X

Section 804 of the Clean Air Act Amendments of 1990 requires the U.S. Environmental Protection Agency (EPA) to do four things. These are: (1) review and revise all volatile organic compound (VOC), carbon monoxide (CO), and nitrogen oxides (NO_x) emission factors within 6 months of passage, (2) fill any gaps in emission factors, (3) repeat this activity each 3 years, and (4) establish a public participation process whereby EPA is required to review and reject or approve alternative emission factors that are submitted and subjected to a public review. The latter element does not have a specific stated time limit but is assumed to be within a reasonable time.

For the first requirement, we have made a good faith effort to evaluate the contents of AP-42 for completeness, accuracy, and quality and make as many revisions in the short term as possible. We have done this through independent review of each section and process and by compiling comments from staff and inquiry logs that were already maintained. From this, we prepared revisions or recommendations for all sections that we believe require attention. We also mailed notices in early February to approximately 600 organizations including all State/local agencies, several environmental groups, and over 200 trade associations, soliciting their input.

We have combined the revisions that we have been able to make in this time period with other Sections that were already under preparation into a draft Supplement D to AP-42, a review copy of which is attached. We request any comments be sent to us by June 30, 1991 so that we may publish the final supplement in a timely manner.

Sections that we have not been able to address in Supplement D due to time and resource constraints are being placed in a section-by-section critique and data base which we will utilize to prioritize further revisions and testing for emission factor development in the 3-year review cycle. An internal report will be prepared on this work this summer with recommendations for action utilizing fiscal year 1992 through 1994 funding. We will continue AP-42 supplements targeted annually, but will summarize our revisions, to comply with the Act, in May 1994.

The public participation requirement will be addressed in draft procedures which we plan to circulate in August. We will finalize these and plan to publish them as "Notice" in the Federal Register by late fall.

This memo and a notice to the approximately 600 organizations from whom comments were solicited are done in fulfillment of the 6-month review requirement for stationary sources.

Please send any comments or questions you have to James H. Southerland of my staff (Mail Drop 14). His telephone number is (FTS) 629-5523 or (919) 541-5523.

Attachment

cc: Chief, Technical and Program Support Branch, Region I
Chief, Air Programs Branch, Regions II-IV, VI, VIII-X
Chief, Air Branch, Region VII
Chief, Air and Radiation Branch, Region V
Ozone Inventory Contacts, Regions I-X
John Calcagni, AQMD
Bruce Jordan, ESD
William Rosenburg (ANR-443)
John Seitz, OAQPS
Lydia Wegman, OAQPS

Garwood, Gerri

From: Garwood, Gerri
Sent: Thursday, September 11, 2014 4:52 PM
To: Sparsh Khandeshi
Cc: RefineryFactor
Subject: RE: Emission Factor Proposal
Attachments: Attachment to Memo.pdf

Sparsh,

This is the attachment.

Sincerely,

Gerri G. Garwood, P.E.

U.S. Environmental Protection Agency
OAR/OAQPS/SPPD
Measurement Policy Group
Ph: 919-541-2406 Fax: 919-541-3207

From: Sparsh Khandeshi [mailto:skhandeshi@environmentalintegrity.org]
Sent: Friday, September 05, 2014 2:11 PM
To: Garwood, Gerri
Subject: Emission Factor Proposal

Gerri,

I am looking for the Office of Air Quality and Planning and Standards May 14, 1991 memorandum detailing the results of the office's efforts to comply with the CAA Amendments' requirement to review and revise emission factors. This document is referenced by the OIG's 1996 report, http://www.epa.gov/oig/reports/1996/emisrept.pdf#introduction, at page 8 in the linked file. Do you have easy access to this document, or would it be best to submit a FOIA to try and obtain a copy.

Thank you for your assistance.

Best,
Sparsh Khandeshi
Attorney
Environmental Integrity Project
1000 Vermont Ave., NW
Eleventh Floor
Washington DC, 20005
Phone: 202-263-4446
Fax: 202-296-8822

Attachment

TABLE OF CONTENTS
AP-42 SUPPLEMENT D
May 1991 DRAFT

Minor Editorial Revisions

New Sections or Technical Revisions

7 new or technically revised revisions (from volume 1)

C, 9, a p.3

TABLE 1.4-1. UNCONTROLLED EMISSION FACTORS FOR NATURAL GAS COMBUSTION[a]

Furnace size & type (10^6 Btu/hr heat input)	Particulate[b]		Sulfur dioxide[c]		Nitrogen oxide[d,e]		Carbon monoxide[f,g]		Volatile Organics			
									Nonmethane		Methane	
	kg/10^6m^3	lb/10^6 ft^3	kg/10^6m^3	lb/10^6 ft^3	kg/10^6m^3	lb/10^6 ft^3	kg/10^6m^3	lb/10^6 ft^3	kg/10^6m^3	lb/10^6 ft^3	kg/10^6m^3	lb/10^6 ft^3
Utility Boilers (> 100)	16 - 80	1 - 5	9.6	0.6	8800[h]	550[h]	640	40	23	1.4	4.8	0.3
Industrial boilers (10 - 100)	16 - 80	1 - 5	9.6	0.6	2240	140	560	35	44	2.8	48	3
Domestic and commercial boilers (< 10)	16 - 80	1 - 5	9.6	0.6	1600	100	320	20	84	5.3	43	2.7

[a] Expressed as weight/volume fuel fired.

[b] References 15-18.

[c] Reference 4. Based on avg. sulfur content of natural gas, 4600 g/10^6 Nm^3 (2000 gr/10^6 scf).

[d] References 4-5, 7-8, 11, 14, 18-19, 21.

[e] Expressed as NO_2. Tests indicate about 95 weight % NO_x is NO_2.

[f] References 4, 7-8, 16, 18, 22-25.

[g] References 16, 18. May increase 10 - 100 times with improper operation or maintenance.

[h] For tangentially fired units, use 4400 kg/10^6 m^3 (275 lb/10^6 ft^3). At reduced loads, multiply factor by load reduction coefficient in Figure 1.4-1. For potential NO_x reductions by combustion modification, see text. Note that NO_x reduction from these modifications will also occur at reduced load conditions.

C. 9.a p.4

1.9 RESIDENTIAL FIREPLACES

1.9.1 General[1-2]

Fireplaces are primarily used for supplemental heating and for aesthetic effects in homes, lodges, etc. Wood is the most common fuel for fireplaces, but, coal, compacted wood waste "logs", paper and rubbish may also be burned. Fuel is intermittently added to the fire by hand.

Fireplaces can be divided into two broad categories, 1) masonry, generally brick and stone, assembled on site, and integral to a structure and 2) prefabricated, usually metal, installed on site as a package with appropriate ductwork.

Masonry fireplaces typically have large fixed openings to the firebed and dampers above the combustion area in the chimney to limit room air and heat losses when the fireplace is not being used. Some masonry fireplaces are designed or retrofitted with doors and louvers to reduce the intake of combustion air during use.

Prefabricated fireplaces are commonly equipped with louvers and glass doors to reduce the intake of combustion air, and some are surrounded by ducts through which floor level air is drawn by natural convection and is heated and returned to the room. Many varieties of prefabricated fireplaces are now available on the market. One general class is the freestanding fireplace. The most common freestanding fireplace models consist of an inverted sheet metal funnel and stovepipe directly above the fire bed. Another class is the "zero clearance" fireplace, an iron or heavy gauge steel firebox lined with firebrick on the inside and surrounded by multiple steel walls with spaces for air circulation.

Some zero clearance fireplaces can be inserted into existing masonry fireplace openings, thus they are sometimes called "inserts". Some of these units are equipped with close fitting doors and have operating and combustion characteristics similar to wood stoves (see Section 1.10, Residential Wood Stoves).

Masonry fireplaces usually heat a room by radiation, with a significant fraction of the combustion heat lost in the exhaust gases or through the fireplace walls. Moreover, some of the radiant heat entering the room must go toward warming the air that is pulled into the residence to make up for the air drawn up the chimney. The net effect is that masonry

C.9.a p.5

fireplaces are usually inefficient heating devices. Indeed, in cases where combustion is poor, where the outside air is cold, or where the fire is allowed to smolder (thus drawing air into a residence without producing appreciable radiant heat energy), a net heat loss may occur in a residence from use of a fireplace. Fireplace heating efficiency may be improved by a number of measures that either reduce the excess air rate or transfer some of the heat back into the residence that would normally be lost in the exhaust gases or through the fireplace walls. As noted above, such measures are commonly incorporated into prefabricated units. As a result, the energy efficiencies of prefabricated fireplaces are slightly higher than those of masonry fireplaces.

1.9.2 Emissions[1-12]

The major pollutants of concern from fireplaces are unburnt combustibles, including carbon monoxide, gaseous organics and particulate matter (i.e., smoke). Significant quantities or unburnt combustibles are produced because fireplaces are inefficient combustion devices, because of high uncontrolled excess air rates and the absence of any sort of secondary combustion. The latter is especially important in wood burning because of its high volatile matter content, typically 80 percent on a dry weight basis. In addition to unburnt combustibles, lesser amounts of nitrogen oxides and sulfur oxides are emitted.

Polycyclic organic material (POM), a minor but potentially important component of wood smoke, is a group of organic compounds which includes potential carcinogens such as benzo(a)pyrene (BaP). The POM results from the combination of free radical species formed in the flame zone, primarily as a consequence of incomplete combustion. Under reducing conditions, radical chain propagation is enhanced, allowing the buildup of complex organic material such as POM. The POM is generally found in or on smoke particles, although some sublimation into the vapor phase is probable.

Another important constituent of wood smoke is creosote. This tar-like substance will burn if the fire is sufficiently hot, but at lower temperatures, it may deposit on cool surfaces in the exhaust system. Creosote deposits are a fire hazard in the flue, but they can be reduced if the exhaust ductwork is insulated to prevent creosote condensation or the exhaust system is cleaned regularly to remove any buildup.

C9op.b

Fireplace emissions are highly variable and are a function of many wood characteristics and operating practices. In general, conditions which promote a fast burn rate and a higher flame intensity will enhance secondary combustion and thereby lower emissions. Conversely, higher emissions will result from a slow burn rate and a lower flame intensity. Such generalizations apply particularly to the earlier stages of the burning cycle, when significant quantities of combustible volatile matter are being driven out of the wood. Later in the burning cycle, when all of the volatile matter has been driven out of the wood, the charcoal that remains burns with relatively few emissions.

Emission factors and corresponding factor ratings for wood combustion in residential fireplaces are given in Table 1.9-1.

TABLE 1.9-1. EMISSION FACTORS FOR RESIDENTIAL FIREPLACES

Pollutant	Wood		Emission Factor Ratings
	g/kg	lb/ton	
Particulate[a]	9.4	18.8	C
Sulfur oxides[b]	0.2	0.4	A
Nitrogen oxides[c]	0.9	1.8	C
Carbon monoxide[d]	61.1	122.2	C
VOC[e]			
Methane	--	--	
Nonmethane	13	26	D
Total Hydrocarbons[f]	95.1	191.2	D
POM[f]	0.8	1.6	F
PAH[f]	0.5	1.0	D
Aldehydes[f]	1.2	2.4	D

[a] References 2-7. Includes condensible organics (back half catch of EPA Method 5 or similar test method), which alone accounts for 54 - 76% of tile total mass collected by both the front and back half catches (Reference 8). POM is carried by suspended particulate matter and has been found to range from 0.017 - 0.044 g/kg (References 2, 8) which may include BaP of up to 1.7 mg/kg (Reference 2).
[b] References 1 and 8.
[c] Expressed as NO_2. References 2-11.
[d] References 2-12.
[e] References 2-12.
[f] Reference 2-7. Dash = no data available.

C.9.a p.7

References for Section 1.9

1. D. G. DeAngelis, et al., Source Assessment: Residential Combustion of Wood, EPA-600/2-80-042b, U.S. Environmental Protection Agency, Washington, DC, March 1980.

2. W. D. Snowden, et al., Source Sampling of Residential Fireplaces for Emission Factor Development, EPA-450/3-76-010, U.S. Environmental Protection Agency, Research Triangle Park, NC, November 1975.

3. J. W. Shelton and L. Gay, Colorado Fireplace Report, Colorado Air Pollution Control Division, Denver, CO, March 1987.

4. Jean M. Dash, "Particulate and Gaseous Emissions from Wood-Burning Fireplaces", Environmental Science and Technology, 16(10): 643-67, October 1982.

5. Source Testing for Fireplaces, Stoves, and Restaurant Grills in Vail, Colorado, EPA Contract No. 68-01-1999, PEDCO Environmental, Inc., Cincinnati, OH, December 1977.

6. Written Communication from Robert C. McCrillis, U.S. Environmental Protection Agency, Research Triangle Park, NC, to Neil Jacquay, U.S. Environmental Protection Agency, Region 9, San Francisco, CA, November 19, 1985.

7. Development of AP-42 Emission Factors for Residential Fireplaces, EPA Contract No. 68-D9-0155, Advanced Systems Technology, Inc., Atlanta, GA, January 11, 1990.

8. D. G. DeAngelis, et al., Preliminary Characterization of Emissions from Wood Fired Residential Combustion Equipment, EPA-600/7-80-040, U.S. Environmental Protection Agency, Washington, DC, March 1980.

9. P. Kosel, et al., "Emissions from Residential Fireplaces", CARB Report C-80-027, California Air Resources Board, Sacramento, CA, April 1980.

10. L. Clayton, et al., "Emissions from Residential Type Fireplaces", Source Tests 24C67, 26C, 29C67, 40C67, 41C67, 65C67 and 66C67, Bay Area Air Pollution Control District, San Francisco, CA, January 31, 1968.

11. J. L. Muhlbaier, "Gaseous and Particulate Emissions from Residential Fireplaces," Publication GMR-3588, General Motors Research Laboratories, Warren, MI, March 1981.

C.9.a p.8

12. A. C. S. Hayden and R. W. Braaten, "Performance of Domestic Wood Fired Applicances", Presented at the 73rd Annual Meeting of the Air Pollution Control Association, Montreal, Canada, June 1980.

C.9.a p.9

1.10 RESIDENTIAL WOOD STOVES

1.10.1 General[1-3]

Wood stoves are commonly used as space heaters in residences to supplement conventional heating systems. They are increasingly found as the primary source of residential heat.

Because of differences in both the magnitude and the composition of emissions from wood stoves, four different categories of stoves should be considered when estimating emissions:

- the conventional noncatalytic wood stove,
- the noncatalytic low emitting wood stove,
- the pellet fired noncatalytic wood stove, and
- the catalytic wood stove.

Among these categories, there are many variations in wood stove design and operation characteristics.

The conventional stove category comprises all stoves without catalytic combustors not included in the other noncatalytic categories. Stoves of many different airflow designs, such as updraft, downdraft, crossdraft, and S-flow, may be in this category.

"Noncatalytic low emitting" wood stoves are those units properly installed, having no catalyst and meeting EPA certification standards as of July 1, 1990.[1]

Pellet fired stoves are those fueled with pellets of sawdust, wood products, and other biomass materials pressed into manageable shape and size. These stoves have a specially designed or modified grate to accommodate this type of fuel.

Catalytic stoves are equipped with a ceramic or metal honeycomb device, called a combustor or converter, that is coated with a noble metal such as platinum or palladium. The catalyst material reduces the ignition temperature of the unburned hydrocarbons and carbon monoxide in the exhaust gases, thus augmenting their ignition and combustion at normal stove operating temperatures. As these components of the gases burn, the temperature inside the catalyst increases to a point where the ignition of the gases is essentially selfsustaining. The particulate emissions data in Table 1.10-1 represent the field operation emissions expected from properly installed wood heaters.

C.9.a p80

1.10.2 Emissions

The combustion and pyrolysis of wood in wood stoves produce atmospheric emissions of particulate, carbon monoxide, nitrogen oxides, organic compounds, mineral residues, and to a lesser extent, sulfur oxides. The quantities and types of emissions are highly variable and depend on a number of factors, including the stages of the combustion cycle. During initial stages of burning, after a new wood charge is introduced, emissions increase dramatically and are primarily volatile organic compounds (VOC). After the initial period of high burn rate, there is a charcoal stage of the burn cycle, characterized by a slower burn rate and decreased emission rates. Emission rates during this stage are cyclical, characterized by relatively long periods of low emissions with shorter episodes of emission spikes.

Particulate emissions are defined in this document is the total catch measured by the EPA Method 5H (Oregon Method 7) sampling train.[1] A small portion of wood stove particulate emissions includes "solid" particles of elemental carbon and wood. The vast majority of particulate emissions is condensed organic products of incomplete combustion equal to or less than 10 micrometers in aerodynamic diameter (PM_{10}). The particulate emission values shown in Table 1.10-1 represent estimates of emissions produced by wood heaters expected to be available over the next few years as cleaner, more reliable wood stoves are manufactured to meet the New Source Performance Standards.[1] These emission values are derived entirely from field test data on studies of the best available wood stoves. Still, there is a potential for higher emissions from some wood stove models.

Control devices on wood stoves may exhibit reduced control efficiency over a period of operation. Control degradation for any stoves, including low-emitting noncatalyst wood stoves may also occur, as a result of deteriorated seals and gaskets, misaligned baffles and bypass mechanisms, broken refractory, or other damaged functional components. The increase in emissions resulting from such control degradation has not been quantified.

Although reported particle size data are scarce, one reference states that 95 percent of the particles in the emissions from a wood stove were less than 0.4 micrometers in size.[4]

Sulfur oxides are formed by oxidation of sulfur in the wood. Nitrogen oxides are formed by oxidation of fuel and atmospheric nitrogen. Mineral constituents, such as potassium and sodium compounds, are released from the wood matrix during combustion. The high levels of organic

C.9.a p.11

TABLE 1.10-1 EMISSION FACTORS FOR COMBUSTION IN RESIDENTIAL WOOD STOVES

Stove Type	Particulate ≤10μm[a,b,c]			Carbon Monoxide[b]			Nitrogen Oxides[b]	Sulfur Oxides[b]	Volatile Organics[d]	
	All Stoves	Pre-Phase II	Phase II	All Stoves	Pre-Phase II	Phase II			Methane	Nonmethane
Catalytic	10.8 (21.6)	10.5(21.0)	11.1(22.2)	44.7(89.4)	45.9(91.8)	40.6(81.2)	1.0(2.0)	0.2(0.4)	13.0(26.0)	8.6(17.2)
Noncatalytic										
Conventional	16.9(33.8)	16.9(33.8)	---	114.9(229.8)	114.9(229.8)	---	1.4(2.8)[e]	0.2(0.4)	32.0(64.0)	14.0(28.0)
Low-emitting	10.0(20.0)	12.2(24.4)	7.5(15.0)	77.7(155.4)	---	82.8(165.6)	---	0.2(0.4)	---	---
Pellet-fired	1.6(3.2)	---	1.6(3.2)	19.7(39.4)	---	19.7(39.4)	6.9(13.8)[f]	0.2(0.4)	---	---

[a] Pre-phase II stoves are those stoves not certified to 1990 EPA emission standards. Phase II stoves are those stoves certified to 1990 EPA emission standards. Units are g/kg (lb/ton) of dry wood burned. Dash = no data.

[b] References 5-13. Emission Factor Rating for particulate, CO, and SO_x: B; for NO_x: E.

[c] Reference 1. Defined as equivalent to total catch by EPA Method 5H train.

[d] References 14 and 15. Emission Factor Rating of E. Calculated by adding the estimated mass of simple hydrocarbon material C1-C7 data to total chromatographic organics.

[e] References 16 and 17. Emission Factor Rating: C.

[f] Reference 14. Based on a single data point.

C.9.a p.92

compound and carbon monoxide emissions result from incomplete combustion of the wood.

Organic constituents of wood smoke vary considerably in both type and volatility. These constituents include simple hydrocarbons of carbon number 1 through 7 (C1 - C7), which exist as gases or which volatilize at ambient conditions, and complex low volatility substances that condense at ambient conditions. These low volatility condensible materials generally are considered to have boiling points below 300°C (572°F).

Polycyclic organic matter (POM) is an important component of the condensible fraction of wood smoke. POM contains a wide range of compounds, including organic compounds formed by the combination of free radical species in the flame zone through incomplete combustion. This group contains some potentially carcinogenic compounds, such as benzo(a)pyrene.

Emission factors and their ratings for wood combustion in residential wood stoves are presented in Table 1.10-1.

As mentioned, particulate emissions are defined as the total emissions equivalent to that collected by EPA Method 5H. This method employs a heated filter followed by three impingers, an unheated filter, and a final impinger. Particulate and carbon monoxide emissions data used to develop the factors in Table 1.10-1 are totally from data collected during field testing programs, and they are presented as values equivalent to that collected with Method 5H.[8] Conversions are employed, as appropriate, for data collected with other methods. See Reference 2 for detailed discussions of EPA Methods 5H and 28. Other emission factors shown in Table 1.10-1 have been developed from data collected during laboratory testing programs.

References for Section 1.10

1. <u>Standards of Performance for New Stationary Sources: New Residential Wood Heaters</u>, 53 FR 5860, February 26, 1988.

2. G. E. Weant, <u>Emission Factor Documentation for AP-42 Section 1.10. Residential Wood Stoves</u>, EPA-450/4-89-007, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1989.

3. R. Gay and J. Shah, <u>Technical Support Document for Residential Wood Combustion</u>, EPA-450/4-85-012, U. S. Environmental Protection Agency, Research Triangle Park, NC, February 1986.

C.9.a p.13

4. J. A. Rau and J. J. Huntzicker, "Composition and Size Distribution of Residential Wood Smoke Aerosols". Presented at the 21st Annual Meeting of the Air and Waste Management Association, Pacific Northwest International Section, Portland, OR, November 1984.

5. C. A. Simons, *et al.*, *Whitehorse Efficient Woodheat Demonstration*, The City of Whitehorse, Whitehorse, Yukon, September 1987.

6. C. A. Simons, *et al.*, *Woodstove Emission Sampling Methods Comparability Analysis and In-situ Evaluation of New Technology Woodstoves*, EPA-600/7-89-002, U. S. Environmental Protection Agency, Research Triangle Park, NC, January 1989.

7. S. G. Barnett, *Field Performance of Advanced Technology Woodstoves in Glens Falls, N.Y. 1988-1989.*, Vol. 1, New York State Energy Research and Development Authority, Albany, NY, October 1989.

8. P. G. Barnett, *The Northeast Cooperative Woodstove Study*, Volume 1, EPA-600/7-87-026a, U. S. Environmental Protection Agency, Research Triangle Park, NC, November 1978.

9. D. R. Jaasma and M. R. Champion, *Field Performance of Woodburning Stoves in Crested Butte During the 1989-90 Heating Season*, Town of Crested butte, Crested Butte, CO, September 1990.

10. D. R. Jaasma and M. R. Champion, *Field Performance of Woodburning Stoves in Crested Butte During the 1989-90 Heating Season*, Town of Crested Butte, Crested Butte, CO, September 1990.

11. S. Dernbach, *Woodstove Field Performance in Klamath Falls, OR*, Wood Heating Alliance, Washington, DC, April 1990.

12. C. A. Simons and S. K. Jones, *Performance Evaluation of the Best Existing Stove Technology (BEST) Hybrid Woodstove and Catalytic Retrofit Device*, State of Oregon Department of Environmental Quality, Portland, OR, July 1989.

13. S. G. Barnett and R. B. Roholt, *In-home Performance of Certified Pellet Stoves in Medford and Klamath Falls, OR*, U. S. Department of Energy Report No. PS407-02, July 1990.

C.9.a p.14

14. R. C. McCrillis and R. G. Merrill, "Emission Control Effectiveness of a Woodstove Catalyst and Emission Measurement Methods Comparison". Presented at the 78th Annual Meeting of the Air and Waste Management Association, Detroit, MI, 1985.

15. K. E. Leese and S. M. Harkins, Effects of Burn Rate, Wood Species, Moisture Content and Weight of Wood Loaded on Woodstove Emissions, EPA 600/2-89-025, U. S. Environmental Protection Agency, Cincinnati, OH, May 1989.

16. J. M. Allen and W. M. Cooke, Control of Emissions from Residential Wood Burning by Combustion Modification, EPA-600/7-81-091, U. S. Environmental Protection Agency, Cincinnati, OH, May 1981.

17. D. G. Deangelis, *et al.*, Preliminary Characterization of Emissions from Wood-fired Residential Combustion Equipment, EPA-600/7-80-040, U. S. Environmental Protection Agency, Cincinnati, OH, March 1980.

C.9.a p.15

TABLE 2.1-3. UNCONTROLLED EMISSION FACTORS FOR INDUSTRIAL/COMMERCIAL REFUSE COMBUSTORS[a]

EMISSION FACTOR RATING: A

Incinerator Type	Particulate		Sulfur oxides[b]		Carbon Monoxide		Volatile organics[c]		Nitrogen oxides[d]	
	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton
Multiple chambers[e]	3.5	7	1.25	2.5[f]	5	10	1.5	3	1.5	3
Single Chambers[g]	7.5	15	1.25	2.5[f]	10	20	7.5	15	1	2
Trench[h]										
Wood	6.5	13	0.05	0.1[j]	NA	NA	NA	NA	2	4
Rubber tires	69	138	NA	NA	NA	NA	NA	NA	NA	NA
Municipal refuse	18.5	37	1.25	2.5[f]	NA	NA	NA	NA	NA	NA
Flue fed										
Single chamber[k]	15	30	0.25	0.5	10	20	7.5	15	1.5	3
Modified[m]	3	6	0.25	0.5	5	10	1.5	3	5	10
Domestic single chamber										
Without primary burner[n]	17.5	35	0.25	0.5	150	300	50	100	0.5	1
With primary burner[p]	3.5	7	0.25	0.5	Neg	Neg	1	2	1	2
Pathological[q]	4	8	Neg	Neg	Neg	Neg	Neg	Neg	1.5	3

[a] Factors are averages based on EPA procedures for incinerator stack testing. NA = not available. Neg = negligible.

[b] Expressed as SO_2.

[c] Expressed as methane.

[d] Expressed as NO_2.

[e] References 6, 10-13.

[f] Based on municipal incinerator data.

[g] References 6, 10-11, 13.

[h] Reference 12.

[j] Based on data for wood combustion in conical burners.

[k] References 6, 11-15.

[m] With afterburners and draft controls. References 6,13-14.

[n] References 10-11.

[p] Reference 10.

[q] References 6, 16.

C.9.a p.16

2.1.2.1 Process Description[8-12]

Industrial/commercial Combustors - The capacities of these units cover a wide range, generally between 22.7 and 1800 kilograms (50 and 4000 pounds) per hour. Of either single- or multiple-chamber design, these units are often manually charged and intermittently operated. Some industrial combustors are similar to municipal combustors in size and design. Better designed emission control systems include gas-fired afterburners, scrubbers, or both.

Trench Combustors - A trench combustor is designed for the combustion of wastes having relatively high heat content and low ash content. The design of the unit is simple. A U-shaped combustion chamber is formed by the sides and bottom of the pit, and air is supplied from nozzles (or fans) along the top of the pit. The nozzles are directed at an angle below the horizontal to provide a curtain of air across the top of the pit and to provide air for combustion in the pit. Low construction and operating costs have resulted in the use of this combustor to dispose of materials other than those for which it was originally designed. Emission factors for trench combustors used to burn three such materials are included in Table 2.1-3.

Domestic Combustors - This category includes combustors marketed for residential use. Fairly simple in design, they may have single or multiple chambers and usually are equipped with an auxiliary burner to aid combustion.

Flue-fed Combustors - These units, commonly found in large apartment houses, are characterized by the charging method of dropping refuse down the combustor flue and into the combution chamber. Modified flue-fed incinerators utilize afterburners and draft controls to improve combustion efficiency and reduce emissions.

Pathological Combustors - These are combustors used to dispose of animal remains and other organic material of high moisture content. Generally, these units are in a size range of 22.7 to 45.4 kilograms (50 to 100 pounds) per hour. Wastes are burned on a hearth in the combustion chamber. The units are equipped with combustion controls and afterburners to ensure good combustion and minimal emissions.

2.1.2.2 Emissions And Controls[8,13]

Operating conditions, refuse composition, and basic combustor design have a pronounced effect on emissions. The manner in which air is supplied to the combustion chamber or chambers has a significant effect on the quantity of particulate emissions. Air may be introduced from beneath the chamber, from the side, or from the top of the combustion chamber. As underfire air is increased, an increase in fly-ash emissions occurs. Erratic refuse charging causes a disruption of the combustion bed and a subsequent release of large quantities of particulates. Large quantities of uncombusted particulate matter and carbon monoxide are also emitted for an extended period after charging of batch-fed units because of interruptions in the combustion process. In continuously fed units, furnace particulate emissions are strongly dependent upon grate type. The use of a rotary kiln and reciprocating grates results in higher particulate emissions than the use of a rocking or traveling grate. Emissions of oxides of sulfur are dependent on the sulfur content of the refuse. Carbon monoxide and unburned hydrocarbon emissions may be significant and are caused by poor combustion resulting from improper combustor design or operating conditions. Nitrogen oxide emissions increase with an increase in the temperature of the combustion zone, an increase in the residence time in the combustion zone before quenching, and an increase in the excess air rates to the point where dilution cooling overcomes the effect of increased oxygen concentration.

C.9.a p.17

References for Section 2.1

1. Municipal Waste Combustion Industry Profile - Facilities Subject To Section 111(d) Guidelines, Radian Corporation, Research Triangle Park, NC, prepared for U. S. Environmental Protection Agency, September 16, 1988.
2. Municipal Waste Combustion Study - Combustion Control Of Organic Emissions, EPA/530-SW-87-021-c, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1987, p. 6-2.
3. Municipal Waste Combustion Retrofit Study (Draft), Radian Corporation, Research Triangle Park, NC, prepared for U. S. Environmental Protection Agency, August 5, 1988, p. 6-4.
4. Air Pollution Control At Resource Recovery Facilities, California Air Resources Board, Sacramento, CA, May 24, 1984.
5. Control of NO_x Emissions from Municipal Waste Combustors, Radian Corporation, Research Triangle Park, NC, prepared for U. S. Environmental Protection Agency, February 3, 1989.
6. H. Vogg and L. Stieglitz, Chemosphere, Volume 15, 1986.
7. Emission Factor Documentation for AP-42 Section 2.1.1: Municipal Waste Combustion, EPA-450/4-90-016, U. S. Environmental Protection Agency, Research Triangle Park, NC, August 1990.
8. Air Pollutant Emission Factors, APTD-0923, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1970.
9. Control Techniques For Carbon Monoxide Emissions From Stationary Sources, AP-65, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1970.
10. Air Pollution Engineering Manual, AP-40, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1967.
11. J. DeMarco. et al., Incinerator Guidelines 1969, SW. 13TS, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1969.
12. J. O. Brukle, J. A. Dorsey, and B. T. Riley, "The Effects Of Operating Variables And Refuse Types On Emissions From A Pilot-scale Trench Incinerator", Proceedings Of The 1968 Incinerator Conference, American Society Of Mechanical Engineers, New York, NY, May 1968.
13. Walter R. Nessen, Systems Study Of Air Pollution From Municipal Incineration, Contract Number CPA-22-69-23, Arthur D. Little, Inc. Cambridge, MA, March 1970.
14. C. V. Kanter, R. G. Lunche, and A. P. Fururich, "Techniques For Testing Air Contaminants From Combustion Sources", Journal Of The Air Pollution Control Association, 6(4): 191-199, February 1957.
15. J. L. Stear, Municipal Incineration: A Review Of Literature, AP-79, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1971.
16. E. R. Kaiser, Refuse Reduction Processes In Proceedings Of Surgeon General's Conference On Solid Waste Management, PHS 1729, Public Health Service, Washington, DC, 1967.
17. Unpublished source test data on incinerators, Resources Research, Incorporated, Reston, VA, 1966-1969.

C.9.a p.18

18. E. R. Kaiser, et al., Modifications To Reduce Emissions From A Flue-fed Incinerator, Report Number 552.2, College of Engineering, New York University, June 1959, pp. 40 and 49.

19. Communication between Resources Research, Incorporated, Reston, VA, and Division of Air Quality Control, Maryland State Department Of Health, Baltimore, MD, 1969.

20. Unpublished data on incinerator testing, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1970.

C.9.a p.19

Orchard crops[d,l,m]										
Unspecified	3	6	26	52	1.2	2.5	4	8	3.6	1.6
Almond	3	6	23	46	1	2	3	6	3.6	1.6
Apple	2	4	21	42	0.5	1	1.5	3	5.2	2.3
Apricot	3	6	24	49	1	2	3	6	4	1.8
Avocado	10	21	58	116	3.8	7.5	12	25	3.4	1.5
Cherry	4	8	22	44	1.2	2.5	4	8	2.2	1.0
Citrus (orange, lemon)	3	6	40	81	1.5	3	5	9	2.2	1.0
Date palm	5	10	28	56	0.8	1.7	3	5	2.2	1.0
Fig	4	7	28	57	1.2	2.5	4	8	4.9	2.2
Nectarine	2	4	16	33	0.5	1	1.5	3	4.5	2.0
Olive	6	12	57	114	2	4	7	14	2.7	1.2
Peach	3	6	21	42	0.6	1.2	2	4	5.6	2.5
Pear	4	9	28	57	1	2	3.5	7	5.8	2.6
Prune	2	3	21	42	0.4	0.7	1	2	2.7	1.2
Walnut	3	6	24	47	1	2	3	6	2.7	1.2
Forest Residues[n]										
Unspecified	8	17	70	140	2.8	5.7	9	19	157	70
Hemlock, Douglas Fir, cedar[p]	2	4	45	90	0.6	1.2	2	4		
Ponderosa pine[q]	6	12	98	195	1.7	3.3	5.5	11		

[a] Expressed as weight of pollutant emitted/weight of refuse material burned.

[b] Reference 12. Particulate matter from most agricultural refuse burning has been found to be in the submicrometer size range.

[c] References 10-13, 15-17. Data indicate that VOC emissions average 22% methane, 7.5% other saturates, 17% olefins, 15% acetylene, 38.5% unidentified. Unidentified VOC are expected to include aldehydes, ketones, aromatics, cycloparaffins.

[d] References 12-13 for emission factors, Reference 14 for fuel loading factors.

[e] For these refuse materials, no significant difference exists between emissions from headfiring or backfiring.

[f] Factors represent emissions under typical high moisture conditions. If ferns are dried to <15% moisture, particulate emissions will be reduced by 30%, CO emissions 23%, VOC 74%.

[g] Reference 11. When pineapple is allowed to dry to <20% moisture, as it usually is, firing technique is not important. When headfired at 20% moisture, particulate emissions will increase to 11.5 kg/Mg (23 lb/ton) and VOC will increase to 6.5 kg/Mg (13 lb/ton).

[h] Factors are for dry (15% moisture) rice straw. If rice straw is burned at higher moisture levels, particulate emissions will increase to 14.5 kg/Mg (29 lb/ton), CO emissions to 80.5 kg/Mg (181 lb/ton), and VOC emissions to 11.5 kg/Mg (23 lb/ton).

[i] Reference 20. See Section 8.12 for discussion of sugar cane burning. The following fuel loading factors are to be used in the corresponding states: Louisiana, 8 - 13.6 Mg/hectare (3 - 5 ton/acre); Florida, 11 - 19 Mg/hectare (4 - 7 ton/acre); Hawaii, 30 - 48 Mg/hectare (11 - 17 ton/acre). For other areas, values generally increase with length of growing season. Use the larger end of the emission factor range for lower loading factors.

[j] See text for definition of headfiring.

[k] See text for definition of backfiring. This category, for emission estimation purposes, includes another technique used occasionally to limit emissions, called into-the-wind strip lighting, which is lighting fields in strips into the wind at 100 - 200 m (300 - 600 ft) intervals.

[l] Orchard prunings are usually burned in piles. There are no significant differences in emissions between burning a "cold pile" and using a roll-on technique, where prunings are bulldozed onto the embers of a preceding fire

[m] If orchard removal is the purpose of a burn, 66 Mg/hectare (30 ton/acre) of waste will be produced.

[n] Reference 10. NO_x emissions estimated at 2 kg/Mg (4 lb/ton).

[p] Reference 15.

[q] Reference 16.

C.9.a p.20

TABLE 2.5-1. EMISSION FACTORS FOR SEWAGE SLUGE INCINERATORS[a]

		Multiple hearth			Fluidized bed			Electric infrared		
Pollutant	Cut diameter, microns	Uncontrolled, kg/Mg (lb/ton)[b]	After scrubber, kg/Mg (lb/ton)[b]	Emission Factor Rating	Uncontrolled, kg/Mg (lb/ton)[b]	After scrubber, kg/Mg (lb/ton)[b]	Emission Factor Rating	Uncontrolled, kg/Mg (lb/ton)[b]	After scrubber, kg/Mg (lb/ton)[b]	Emission Factor Rating
Particulate	0.625	0.30 (0.60)	0.07 (0.14)[c]	E	NA	0.08 (0.16)[d]	E	0.50 (1.0)	0.30 (0.60)[e]	E
	1.0	0.47 (0.94)	0.08 (0.16)			0.15 (0.30)		0.60 (1.2)	0.35 (0.70)	
	2.5	1.1 (2.2)	0.09 (0.18)			0.18 (0.36)		1.0 (2.0)	0.50 (1.0)	
	5.0	2.1 (4.2)	0.10 (0.20)			0.20 (0.40)		1.7 (3.4)	0.70 (1.4)	
	10.0	4.1 (8.2)	0.11 (0.22)			0.22 (0.44)		3.0 (6.0)	1.0 (2.0)	
	15.0	6.0 (12)	0.12 (0.24)			0.23 (0.46)		4.3 (8.6)	1.2 (2.4)	
Total particulate		42 (84)	0.89 (1.8)[e]	C	NA	0.33 (0.66)[e]	C	4 (8)	1 (2)[e]	E
Lead		0.05 (0.10)	0.02 (0.04)[e]	C	NA	0.003 (0.006)[e]	D	NA	NA	
Sulfur dioxide[f]		10 (20)	2 (4)[e]	D	10 (20)	2.0 (4.0)[e]	D	10 (20)	2.0 (4.0)[e]	D
Nitrogen oxides		5.5 (11)	2.5 (5.0)[e]	C	NA	2.2 (4.4)[e]	D	4 (8)	3 (6)[e]	E
Carbon monoxide		36 (72)	2 (4)[e]	C	NA	2 (4)[e]	E	NA	NA	
Volatile organics										
Methane		NA	2.3 (4.6)[e]	D	NA	1 (2)[e]	E	NA	NA	
Nonmethane		0.85 (1.7)	0.85 (1.7)[e]	D	NA	NA		NA	NA	

---

[a] Reference 4. NA = not available.
[b] Expressed in units of dried sludge. Particulate figures in parentheses are cumulative.
[c] Impingement scrubber.
[d] Venturi scrubber.
[e] Impingement, venturi and/or cyclone scrubbers.
[f] Because data were limited, an average for all three types of incinerators is presented.

C.9.a p.21

TABLE 2.5-2. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR SEWAGE SLUDGE INCINERATORS[a]

Particle size, microns	Cumulative mass % ≤ stated size						Cumulative emission factor, kg/Mg (lb/ton)					
	Uncontrolled			Controlled			Uncontrolled			Controlled		
	MH[b]	FB[c]	EI[d]	MH[b]	FB[c]	EI[d]	MH[b]	FB[c]	EI[d]	MH[b]	FB[c]	EI[d]
15	15	NA	43	30	7.7	60	6.0 (12)	NA	4.3 (8.6)	0.12 (0.24)	0.23 (0.46)	1.2 (2.4)
10	10	NA	30	27	7.3	50	4.1 (8.2)	NA	3.0 (6.0)	0.11 (0.22)	0.22 (0.44)	1.0 (2.0)
5.0	5.3	NA	17	25	6.7	35	2.1 (4.2)	NA	1.7 (3.4)	0.10 (0.20)	0.20 (0.40)	0.70 (1.4)
2.5	2.8	NA	10	22	6.0	25	1.1 (2.2)	NA	1.0 (2.0)	0.09 (0.18)	0.18 (0.36)	0.50 (1.0)
1.0	1.2	NA	6.0	20	5.0	18	0.47 (0.94)	NA	0.60 (1.2)	0.08 (0.16)	0.15 (0.30)	0.35 (0.70)
0.625	0.75	NA	5.0	17	2.7	15	0.30 (0.60)	NA	0.50 (1.0)	0.07 (0.14)	0.08 (0.16)	0.30 (0.60)
TOTAL	100	100	100	100	100	100	40 (80)	NA	10 (20)	0.40 (0.80)	3.0 (6.0)	2.0 (4.0)

[a] Reference 4. NA = not available.
[b] MH = multiple hearth.
[c] FB = fluidized bed.
[d] EI = electric infrared.

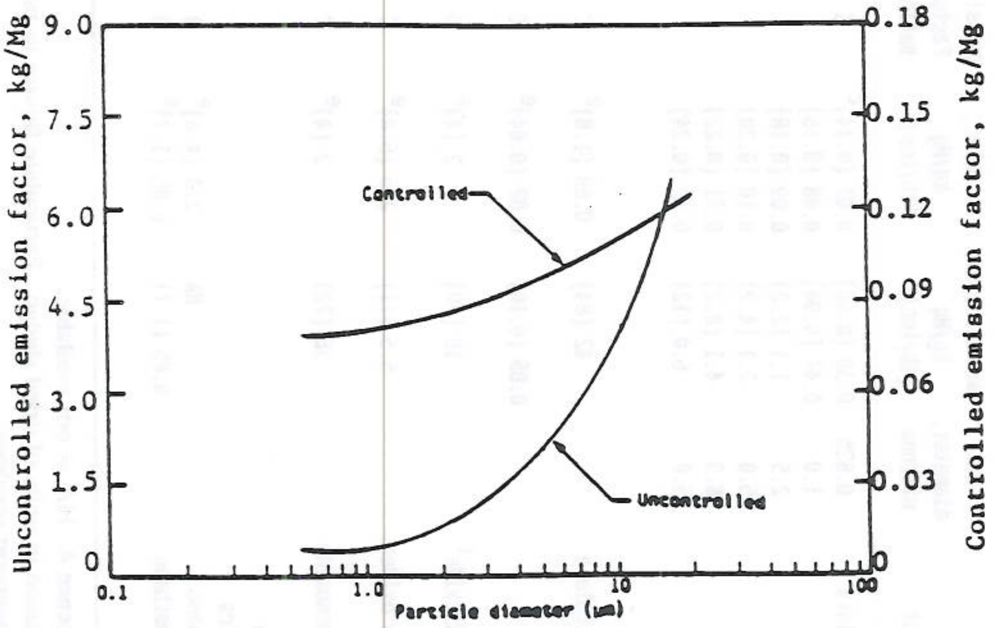


Figure 2.5-5. Cumulative particle size distribution and size-specific emission factors for multiple-hearth incinerators.

C.9.a p.22

4.2 SURFACE COATING

Surface coating operations involve the application of paint, varnish, lacquer or paint primer, for decorative or protective purposes. This is accomplished by brushing, rollings, spraying, flow coating and dipping operations. Some industrial surface coating operations include automobile assembly, job enameling, and manufacturing of aircraft, containers, furniture, appliances and plastic products. Nonindustrial applications of surface coatings include automobile refinishing and architectural coating of domestic, industrial, government and institutional structures, including building interiors and exteriors and exteriors and signs and highway markings. Nonindustrial Surface Coating is discussed below in Section 4.2.1, and Industrial Surface Coating in Section 4.2.2.

Emissions of volatile organic compounds (VOC) occur in surface coating operations because of evaporation of the paint vehicle, thinner or solvent used to facilitate the application of coatings. The major factor affecting these emissions is the amount of volatile matter contained in the coating. The volatile portion of most common surface coatings averages about 50 percent, and most, if not all, of this is emitted during the application of coatings. The compounds released include aliphatic and aromatic hydrocarbons, alcohols, ketones, esters, alkyl and aryl hydrocarbon solvents, and mineral spirits. Table 4.2-1 presents emission factors for general surface coating operations.

TABLE 4.2-1. EMISSION FACTORS FOR GENERAL SURFACE COATING APPLICATIONS[a]

EMISSION FACTOR RATING: B

Coating Type	Emissions[b]	
	kg/Mg	lb/ton
Paint	560	1,120
Varnish and Paint	500	1,000
Lacquer	770	1,540
Enamel	420	840
Primer (zinc chromate)	660	1,320

[a] Reference 1.
[b] Reference 2. Nonmethane VOC.

References for Section 4.2

1. Products Finishing, 41(6A):4-53, March 1977.

2. Air Pollution Engineering Manual, Second Edition, AP-40, U.S. Environmental Protection Agency, Research Triangle Park, NC, May 1973. Out of Print.

4.2.2 INDUSTRIAL SURFACE COATING

4.2.2.1 General Industrial Surface Coating[1-5]

Process Description - Surface coating is the application of decorative or protective materials in liquid or powder form to substrates. These coatings normally include general solvent type paints, varnishes, lacquers and water thinned paints. After application of coating by one of a variety of methods such as brushing, rolling, spraying, dipping and flow coating, the surface is air and/or heat dried to remove the volatile solvents from the coated surface. Powder type coatings can be applied to a hot surface or can be melted after application and caused to flow together. Other coatings can be polymerized after application by thermal curing with infrared or electron beam systems.

Coating Operations - There are both "toll" ("independent") and "captive" surface coating operations. Toll operations fill orders to various manufacturer specifications, and thus change coating and solvent conditions more frequently than do captive companies, which fabricate and coat products within a single facility and which may operate continuously with the same solvents. Toll and captive operations differ in emission control systems applicable to coating lines, because not all controls are technically feasible in toll situations.

Coating Formulations - Conventional coatings contain at least 30 volume percent solvents to permit easy handling and application. They typically contain 70 to 85 percent solvents by volume. These solvents may be of one component or of a mixture of volatile ethers, acetates, aromatics, cellosolves, aliphatic hydrocarbons and/or water. Coatings with 30 volume percent of solvent or less are called low solvent or "high solids" coatings.

Waterborne coatings, which have recently gained substantial use, are of several types: water emulsion, water soluble and colloidal dispersion, and electrocoat. Common ratios of water to solvent organics in emulsion and dispersion coatings are 80/20 and 70/30.

Two part catalyzed coatings to be dried, powder coatings, hot melts, and radiation cured (ultraviolet and electron beam) coatings contain essentially no volatile organic compounds (VOC), although some monomers and other lower molecular weight organics may volatilize.

Depending on the product requirements and the material being coated, a surface may have one or more layers of coating applied. The first coat may be applied to cover surface imperfections or to assure adhesion of the coating. The intermediate coats usually provide the required color, texture or print, and a clear protective topcoat is often added. General coating types do not differ from those described, although the intended use and the material to be coated determine the composition and resins used in the coatings.

Coating Application Procedures - Conventional spray, which is air atomized and usually hand operated, is one of the most versatile coating methods. Colors can be changed easily, and a variety of sizes and shapes can be painted under

C.9.a p.24

References for Section 4.2.2.1

1. Controlling Pollution from the Manufacturing and Coating of Metal Products: Metal Coating Air Pollution Control, EPA-625/3-77-009, U. S. Environmental Protection Agency, Cincinnati, OH, May 1977.

2. H. R. Powers, "Economic and Energy Savings through Coating Selection", The Sherwin-Williams Company, Chicago, IL, February 8, 1978.

3. Air Pollution Engineering Manual, Second Edition, AP-40, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1973. Out of Print.

4. Products Finishing, 41(6A):4-54, March 1977.

5. Control of Volatile Organic Emissions from Existing Stationary Sources - Volume II: Surface Coating of Cans, Coils, Paper, Fabrics, Automobiles, and Light-Duty Trucks, EPA-450/2-77-008, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1977.

C.9.a p.25

TABLE 4.2.2.14-4. EMISSION FACTORS FOR VOC FROM SURFACE COATING OPERATIONS TO APPLY DECORATIVE/EXTERIOR COATINGS[a,b]

		Volatile Organics	
Plant configuration and control technique	kg/m² coated	kg/yr	kg/hr
Small			
Baseline coating mix[c]	0.84	8,122	2.0
Low solids SB coating[d]	1.14	11,096	2.8
Medium solids SB coating[e]	0.54	5,221	1.3
High solids SB coating[f]	0.36/0.22[h]	3,481/2,176[h]	0.87/0.54[h]
WB Coating[g]	0.18	1,778	0.44
Medium			
Baseline coating mix[c]	0.84	64,986	16.2
Low solids SB coating[d]	1.14	88,825	22.2
Medium solids SB coating[e]	0.54	41,800	10.4
High solids SB coating[f]	0.36/0.22[h]	27,867/17,417[h]	7.0/4.4[h]
WB Coating[g]	0.18	14,234	3.6
Large			
Baseline coating mix[c]	0.84	162,463	40.6
Low solids SB coating[d]	1.14	222,076	55.5
Medium solids SB coating[e]	0.54	104,506	26.1
High solids SB coating[f]	0.36/0.22[h]	69,671/43,544[h]	17.4/10.9[h]
WB Coating[g]	0.18	35,589	8.9

C.9.a p.26

TABLE 4.2.2.14-4 (Cont.)

[a] Assumes values given in Table 4.2.2.14-2, using the following equation: E = LDV.

where:

E = VOC emission factors from surface coating operations (kg/yr)
L = Volume of coating sprayed (l)
D = Density of coating sprayed (kg/l)
V = Volatile content of coating, including dilution solvents added at plant (weight fraction).

[b] Assumes all VOC present is emitted. Values have been rounded off. Does not address EMI/RFI shielding coatings. Assumes annual operating schedule of 4,000 hours. SB = solventborne. WB = waterborne.

[c] Based on use of the baseline coatig mix in Table 4.2.2.14-2.

[d] Based on use of a solvent base coating containing 32 volume % solids at the gun.

[e] Based on use of a solvent base coating containing 50 volume % solids at the gun.

[f] Based on use of a solvent base coating containing 60 volume % solids at the gun.

[g] Based on use of a waterborne coating containing 37 volume % solids and 12.6 volume % organic solvent at the gun.

[h] Use higher factor for spraying equipment with a 25% transfer efficiency and lower factor for those with a 40% transfer efficiency.

(19, a p.2)

TABLE 4.6-2. SOLVENT LOSS EMISSION FACTORS FOR DEGREASING OPERATIONS

EMISSION FACTOR RATING: C

Type of Degreasing	Activity Measure	Uncontrolled organic emission factor[a]	
All[b]	Solvent consumed	1,000 kg/mg	2,000 lb/ton
Cold cleaner			
Entire unit[c]	Units in operation	0.30 Mg/yr/unit	0.33 tons/yr/unit
Waste solvent loss		0.165 Mg/yr/unit	0.18 tons/yr/unit
Solvent carryout		0.075 Mg/yr/unit	0.08 tons/yr/unit
Bath and spray evaporation		0.06 Mg/yr/unit	0.07 tons/yr/unit
Entire unit[f]	Surface area and duty cycle[d]	0.4 $kg/hr/m^2$	0.08 $lb/hr/ft^2$
Open top vapor			
Entire unit	Units in operation	9.5 Mg/yr/unit	10.5 tons/yr/unit
Entire unit[f]	Surface area and duty cycle[e]	0.7 $kg/hr/m^2$	0.15 $lb/hr/ft^2$
Conveyorized, vapor			
Entire unit	Units in operation	24 Mg/yr/unit	26 tons/yr/unit
Conveyorized, nonboiling			
Entire unit	Units in operation	47 Mg/yr/unit	52 tons/yr/unit

[a] 100% nonmethane VOC.

[b] Solvent consumption data will provide much more accurate emission estimates than any of the other factors presented.

[c] Emissions generally would be in higher for manufacturing units and lower for maintenance units.

[d] Reference 4, Appendix C-6. For trichloroethane degreaser.

[e] For trichloroethane degreaser. Does not include waste solvent losses.

[f] The area refers to the dimension of the open area at the condenser coils or the open area at the cold water jacket where the vapor condensation occurs.

C.9.a p.28

Vapor recovery or collection methods employed include condensation, adsorption and absorption. Technical feasibility of the method chosen depends on the solvent's miscibility, vapor composition and concentration, boiling point, reactivity, and solubility, as well as several other factors.

Condensation of solvent vapors is accomplished by water cooled condensers and refrigeration units. For adequate recovery, a solvent vapor concentration well above 0.009 grains per cubic foot (20 mg/m^3) is required. To avoid explosive mixtures of a flammable solvent and air in the process gas stream, air is replaced with an inert gas, such as nitrogen. Solvent vapors that escape condensation are recycled through the main process stream or recovered by adsorption or absorption.

Activated carbon adsorption is the most common method of capturing solvent emissions. Adsorption systems are capable of recovering solvent vapors in concentrations below 0.002 grains per cubic foot (4 mg/m^3) of air. Solvents with boiling points of 392°F (200°C) or more do not desorb effectively with the low pressure steam commonly used to regenerate the carbon beds. Figure 4.7-2 shows a flow diagram of a typical fixed bed activated carbon solvent recovery system. The mixture of steam and solvent vapor passes to a water cooled condenser. Water immiscible solvents are simply decanted to separate the solvent, but water miscible solvents must be distilled, and solvent mixtures must be both decanted and distilled. Fluidized bed operations are also in use.

Absorption of solvent vapors is accomplished by passing the waste gas stream through a liquid in scrubbing towers or spray chambers. Recovery by condensation and adsorption results in a mixture of water and liquid solvent, while absorption recovery results in an oil and solvent mixture. Further reclaiming procedures are required, if solvent vapors are collected by any of these three methods.

Initial treatment of liquid waste solvents is accomplished by mechanical separation methods. This includes both removing water by decanting and removing undissolved solids by filtering, draining, settling, and/or centrifuging. A combination of initial treatment methods may be necessary to prepare waste solvents for further processing.

4.7.1.3 Distillation - After initial treatment, waste solvents are distilled to remove dissolved impurities and to separate solvent mixtures. Separation of dissolved impurities is accomplished by simple batch, simple continuous, or steam distillation. Mixed solvents are separated by multiple simple distillation methods, such as batch or continuous rectification. These processes are shown in Figure 4.7-3.

In simple distillation, waste solvent is charged to an evaporator. Vapors are then continuously removed and condensed, and the resulting sludge or still bottoms are drawn off. In steam distillation, solvents

C.9.a/.29

not more than 1000°F (480 - 540°C) to prevent warping of the drum. Emissions are vented to an afterburner or secondary combustion chamber, where the gases are raised to at least 1400°F (760°C) for a minimum of 0.5 seconds. The average amount of material removed from each drum is 4.4 lb (2 kg).

TABLE 4.8-2. EMISSION FACTORS FOR TANK TRUCK CLEANING[a]

EMISSION FACTOR RATING: D

	Chemical Class		Total emissions	
Compound	Vapor pressure	Viscosity	lb/truck	g/truck
Acetone	high	low	0.686	311
Perchloroethylene	high	low	0.474	215
Methyl methacrylate	medium	medium	0.071	32.4
Phenol	low	low	0.012	5.5
Propylene glycol	low	high	0.002	1.07

[a] Reference 1. One hour test duration.

4.8.2 Emissions and Controls

4.8.2.1 Rail Tank Cars and Tank Trucks - Atmospheric emissions from tank car and truck cleaning are predominantly volatile organic chemical vapors. To achieve a practical but representative picture of these emissions, the organic chemicals hauled by the carriers must be broken down into classes of high, medium and low viscosities and high, medium and low vapor pressures. This is because high viscosity materials do not drain readily, affecting the quantity of material remaining in the tank, and high vapor pressure materials volatilize more readily during cleaning and tend to lead to greater emissions.

Practical and economically feasible controls on atmospheric emissions from tank car and truck cleaning do not exist, except for containers transporting commodities that produce combustible gases and water soluble vapors (such as ammonia and chlorine). Gases which are displaced as tanks are filled are sent to a flare and burned. Water soluble vapors are absorbed in water and sent to the wastewater system. Any other emissions are vented to the atmosphere.

Tables 4.8-1 and 4.8-2 give emission factors for representative organic chemicals hauled by tank cars and trucks.

4.8.2.2 Drums - There is no control for emissions from steaming of drums. Solution or caustic washing yields negligible air emissions, because the drum is closed during the wash cycle. Atmospheric emissions from steaming or washing drums are predominantly organic chemical vapors.

C.9.a/.30

Air emissions from drum burning furnaces are controlled by proper operation of the afterburner or secondary combustion chamber, where gases are raised to at least 1400°F (760°C) for a minimum of 0.5 seconds. This normally ensures complete combustion of organic materials and prevents the formation, and subsequent release, of large quantities of NO_x, CO and particulates. In open burning, however, there is no feasible way of controlling the release of incomplete combustion products to the atmosphere. Conversion of open cleaning operations to closed cycle cleaning and elimination of open air drum burning seem to be the only control alternatives immediately available.

Table 4.8-3 gives emission factors for representative criteria pollutants emitted from drum burning and cleaning.

TABLE 4.8-3. EMISSION FACTORS FOR DRUM BURNING[a]

EMISSION FACTOR RATING: E

Pollutant	Total Emissions			
	Controlled		Uncontrolled	
	lb/drum	g/drum	lb/drum	g/drum
Particulate	0.02646	12[b]	0.035	16
NO_x	0.0004	0.18	0.002	0.89
VOC	negligible		negligible	

[a] Reference 1. Emission factors are in terms of weight of pollutant released per drum burned, except for VOC, which are per drum washed.

[b] Reference 1, Table 17 and Appendix A.

Reference for Section 4.8

1. T. R. Blackwood, et. al., Source Assessment: Rail Tank Car, Tank Truck, and Drum Cleaning, State of the Art, EPA-600/2-78-004g, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1978.

C.9.a p131

TABLE 4.12-2. EMISSION FACTORS FOR UNCONTROLLED POLYESTER RESIN PRODUCT FABRICATION PROCESSES[a]

(100 x mass of VOC emitted/mass of monomer input)

Process	Resin		Emission Factor Rating	Gel Coat		Emission Factor Rating
	NVS	VS[b]		NVS	VS[b]	
Hand layup	5 - 10	2 - 7	C	26 - 35	8 - 25	D
Spray layup	9 - 13	3 - 9	B	26 - 35	8 - 25	B
Continuous lamination	4 - 7	1 - 5	B	c	c	--
Pultrusion[d]	4 - 7	1 - 5	D	c	c	--
Filament winding[e]	5 - 10	2 - 7	D	c	c	--
Marble casting	1 - 3	1 - 2	B	f	f	--
Closed molding[g]	1 - 3	1 - 2	D	c	c	--

[a] Reference 9. Ranges represent the variability of processes and sensitivity of emissions to process parameters. Midpoint of the given ranges should be used for unknown process parameters. NVS = nonvapor-suppressed resin. VS = vapor-suppressed resin.

[b] Factors are 30-70% of those for nonvapor-suppressed resins.

[c] Gel coat is not normally used in this process.

[d] Resin factors for the continuous lamination process are assumed to apply.

[e] Resin factors for the hand layup process are assumed to apply.

[f] Factors unavailable. However, when cast parts are subsequently sprayed with gel coat, hand and spray layup gel coat factors are assumed to apply.

[g] Resin factors for marble casting, a semiclosed process, are assumed to apply.

TABLE 4.12-3. TYPICAL RESIN STYRENE PERCENTAGES

Resin Application	Resin Styrene Content[a] (wgt. %)
Hand layup	43
Spray layup	43
Continuous lamination	40
Filament winding	40
Marble casting	32
Closed molding	35
Gel coat	35

[a] May vary by at least ±5 percentage points.

C 9.a /.32

4.13 WASTEWATER COLLECTION, TREATMENT, AND STORAGE

4.13.1 Process Description

Many different industries generate wastewater streams that contain organic compounds. Nearly all of these wastewater streams undergo collection, contaminant treatment, and/or storage operations before they are finally discharged into a receiving body of water or a municipal treatment plant for further treatment. During some of these operations, the wastewater is in direct contact with the atmosphere and volatile organic compounds (VOC) may be emitted from the wastewater into the air.

Industrial wastewater operations can range from pretreatment to full-scale treatment processes. In a typical pretreatment facility, process and/or sanitary wastewater and/or storm water runoff is collected, equalized, and/or neutralized and then discharged to a municipal wastewater plant, also known as a publicly owned treatment works (POTWs), where it is then typically treated further by biodegradation.

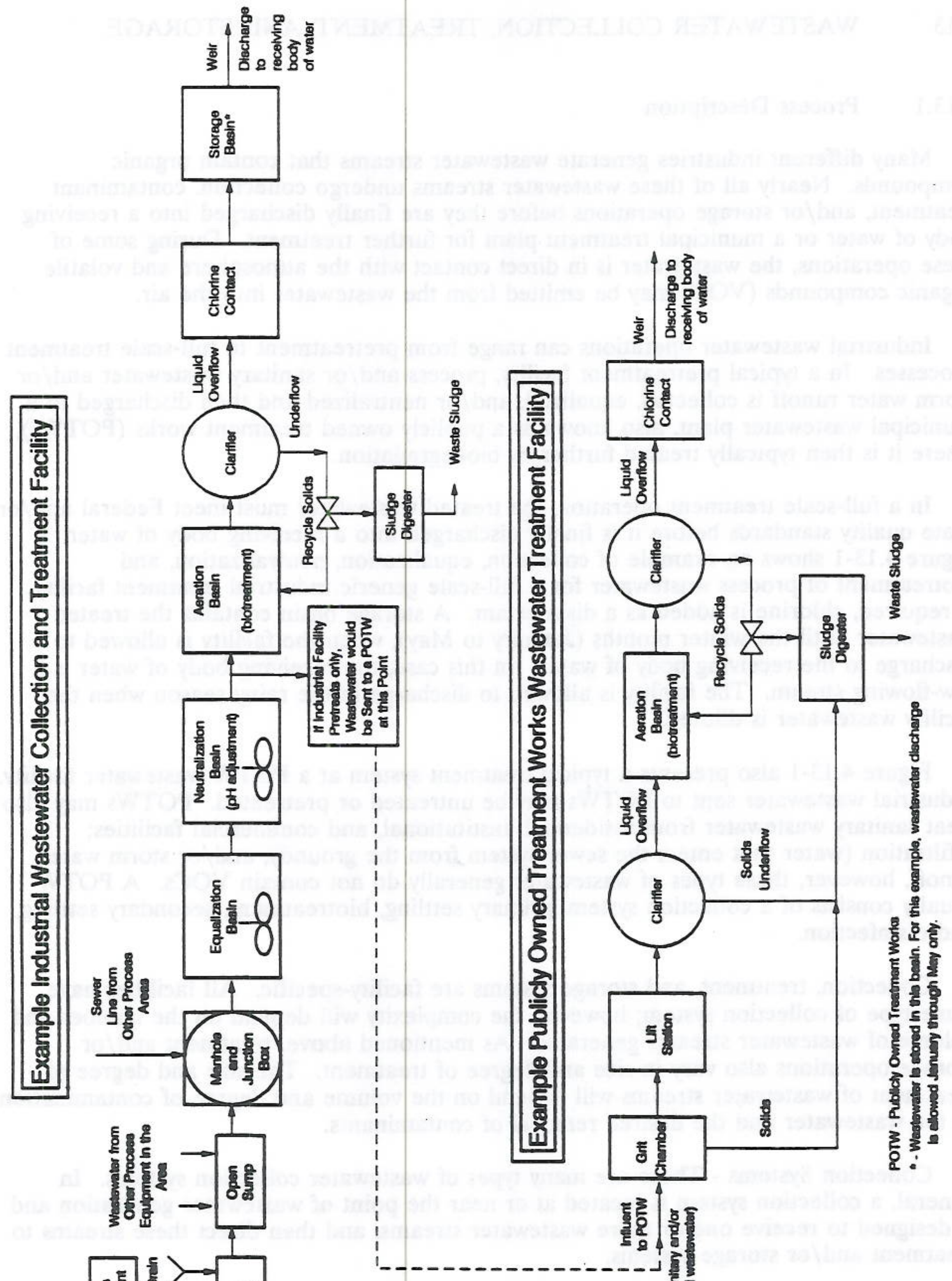
In a full-scale treatment operation, the treated wastewater must meet Federal and/or State quality standards before it is finally discharged into a receiving body of water. Figure 4.13-1 shows an example of collection, equalization, neutralization, and biotreatment of process wastewater for a full-scale generic industrial treatment facility. If required, chlorine is added as a disinfectant. A storage basin contains the treated wastewater until the winter months (January to May), when the facility is allowed to discharge to the receiving body of water. In this case, the receiving body of water is a low-flowing stream. The facility is allowed to discharge in the rainy season when the facility wastewater is diluted.

Figure 4.13-1 also presents a typical treatment system at a POTW wastewater facility. Industrial wastewater sent to POTWs may be untreated or pretreated. POTWs may also treat sanitary wastewater from residential, institutional, and commercial facilities; infiltration (water that enters the sewer system from the ground); and/or storm water runoff, however, these types of wastewater generally do not contain VOCs. A POTW usually consists of a collection system, primary settling, biotreatment, secondary settling, and disinfection.

Collection, treatment, and storage systems are facility-specific. All facilities have some type of collection system; however, the complexity will depend on the number and volume of wastewater streams generated. As mentioned above, treatment and/or storage operations also vary in size and degree of treatment. The size and degree of treatment of wastewater streams will depend on the volume and degree of contamination of the wastewater and the desired removal of contaminants.

Collection Systems - There are many types of wastewater collection systems. In general, a collection system is located at or near the point of wastewater generation and is designed to receive one or more wastewater streams, and then direct these streams to treatment and/or storage systems.

C.9.a p.83



POTW: Publicly Owned Treatment Works
* - Wastewater is stored in the basin. For this example, wastewater discharge is allowed January through May only.

Figure 4.13-1. Example Wastewater Collection and Treatment Systems for Industrial and Municipal Facilities

C,9,a p,34

A typical industrial collection system may include drains, manholes, trenches, junction boxes, sumps, lift stations, and/or weirs. Wastewater streams from different points throughout the industrial facility normally enter the collection system through drains open to the atmosphere, with individual drains usually being connected directly to a main sewer line; however, the streams may also enter the system through trenches. Junction boxes, sumps, trenches, lift stations, and weirs are usually located wherever wastewater transport from one area or treatment process to another is required.

A typical POTW facility collection system consists of a lift station, trenches, junction boxes, and manholes. Wastewater is received into the facility collection system through open sewer lines that reach to all sources of influent wastewater. As mentioned previously, these sources may discharge sanitary, pretreated or untreated industrial, and/or storm water runoff wastewaters.

The following paragraphs present a brief description of some of the most common types of wastewater collection system components found in industrial and POTW facilities. Because the arrangement of collection system components is facility-specific, the order in which the collection system descriptions are presented is somewhat arbitrary.

Wastewater streams are normally introduced into the collection system through individual or area drains, which can be open to the atmosphere or sealed to prevent the wastewater from contacting the atmosphere. Individual drains are dedicated to a single source or piece of equipment in industry. Area drains serve several sources and are located centrally between the sources or pieces of equipment that they serve.

Manholes are service entrances into sewer lines that permit inspection and cleaning of the line. They also may be located where sewer lines intersect or where there is a significant change in direction, grade, or sewer line diameter. The lower portion of the manhole is usually cylindrical and tapers to a smaller diameter opening at, or slightly above, ground level.

Trenches can be used to transport industrial wastewater from the point of generation to collection units such as junction boxes and lift stations; from one process area of an industrial facility to another, or from one treatment unit to another. Trenches are also used at POTWs to transport wastewater from one treatment unit to another. Trenches may be open, or covered with a grating for safety.

Junction boxes typically serve several process sewer lines. Process sewer lines meet at the junction box to combine multiple wastewater streams into one stream. Junction boxes are normally square or rectangular and are sized based on the total flow rate of the entering streams.

Sumps are typically used for collection and equalization of wastewater flow from trenches or sewer lines prior to treatment or storage. They are usually quiescent and open to the atmosphere.

Lift stations are usually the last collection unit prior to the treatment system and can accept wastewater from one or several sewer lines. The main function of the lift station is to lift the collected wastewater to the treatment and/or storage system, usually by pumping or through the use of a hydraulic lift, such as a screw lift.

Weirs can act as dams to open channels, or they can be used to discharge cleaner effluent from a settling basin, such as a clarifier. When used as a dam, the weir face is normally aligned perpendicular to the bed and walls of the channel. Water from the channel normally flows over the weir and falls to the receiving body of water; in some cases, the water may pass through a notch or opening in the weir face. With this type of weir, flow rate through the channel can be measured. The weir height (i.e., the distance the water falls) is usually no more than 2 meters. A typical clarifier weir is designed to allow settled wastewater to overflow to the next treatment process. The weir is generally placed around the outside perimeter of the settling basin but can also be placed towards the middle. The clarifier weir height is usually only about 0.1 meters.

Treatment and Storage Systems - Treatment and/or storage systems are designed to hold liquid wastes or wastewater for treatment, storage, or disposal. They are usually composed of various types of earthen and/or concrete-lined basins, known as surface impoundments. Storage systems are typically used for accumulating wastewater before ultimate disposal or for temporarily holding batch (intermittent) streams before treatment.

Wastewater treatment systems are divided into three categories, depending on their design, operation, and application: primary, secondary, and tertiary. In primary treatment systems, physical operations are used to remove floatable and settleable solids. In secondary treatment systems, biological and chemical processes are used to remove most of the organic matter in the wastewater. In tertiary treatment systems, additional processes are used to remove constituents that could not be removed by secondary treatment.

Examples of primary treatment include oil/water separators, primary clarification, equalization basins, and primary treatment tanks. The first process in an industrial wastewater treatment plant is often the removal of heavier solids and lighter oils by means of oil/water separators. Oils are usually removed continuously with a skimming device, while solids can be removed with a sludge removal system.

In primary treatment, clarifiers are typically located near the beginning of the treatment process and are used to settle and remove settleable or suspended solids contained in the influent wastewater. Figure 4.13-2 presents an example design of a clarifier. Clarifiers are generally cylindrical in shape and are sized based on the settling rate of the suspended solids and thickening characteristics of the sludge. Floating scum is typically skimmed continuously from the top of the clarifier, while sludge is typically removed continuously from the bottom of the clarifier.

Equalization basins are used to reduce fluctuations in the wastewater flow rate and organic content before the wastewater is sent to downstream treatment processes. Equalization of wastewater flow rate results in a more uniform effluent quality in downstream settling units such as clarifiers. Biological treatment performance can also benefit from the damping of concentration and flow fluctuation. This damping protects biological processes from upset or failure due to shock loadings of toxic or treatment-inhibiting compounds.

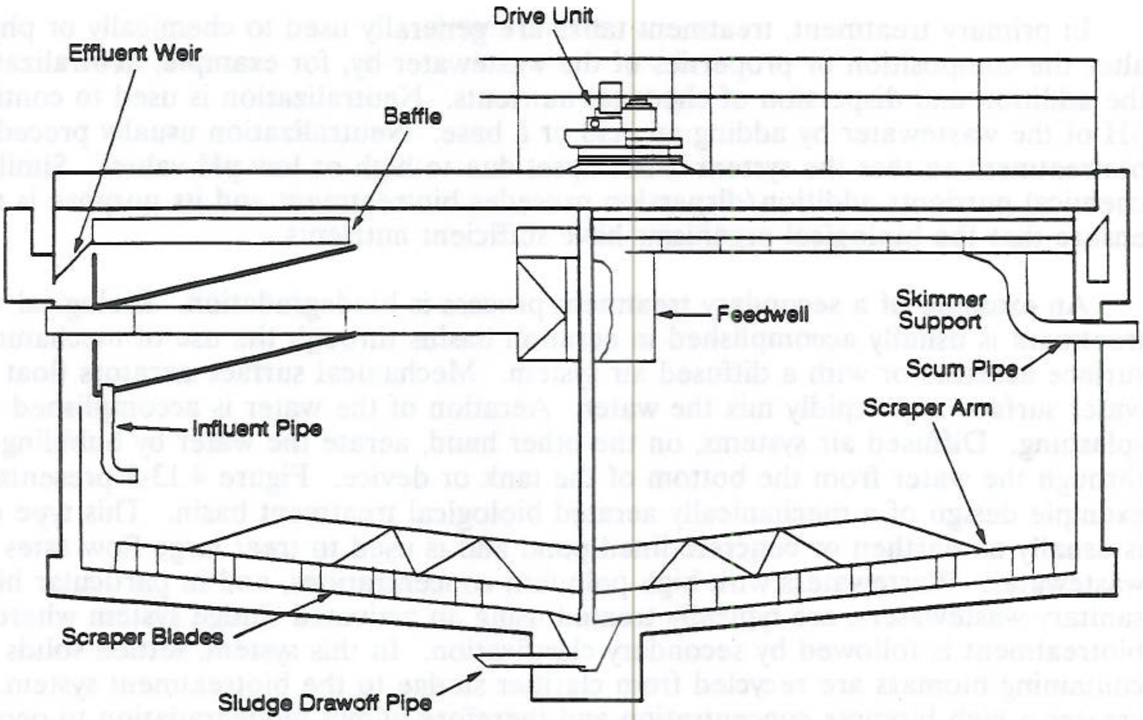


Figure 4.13-2. Example Clarifier Configuration

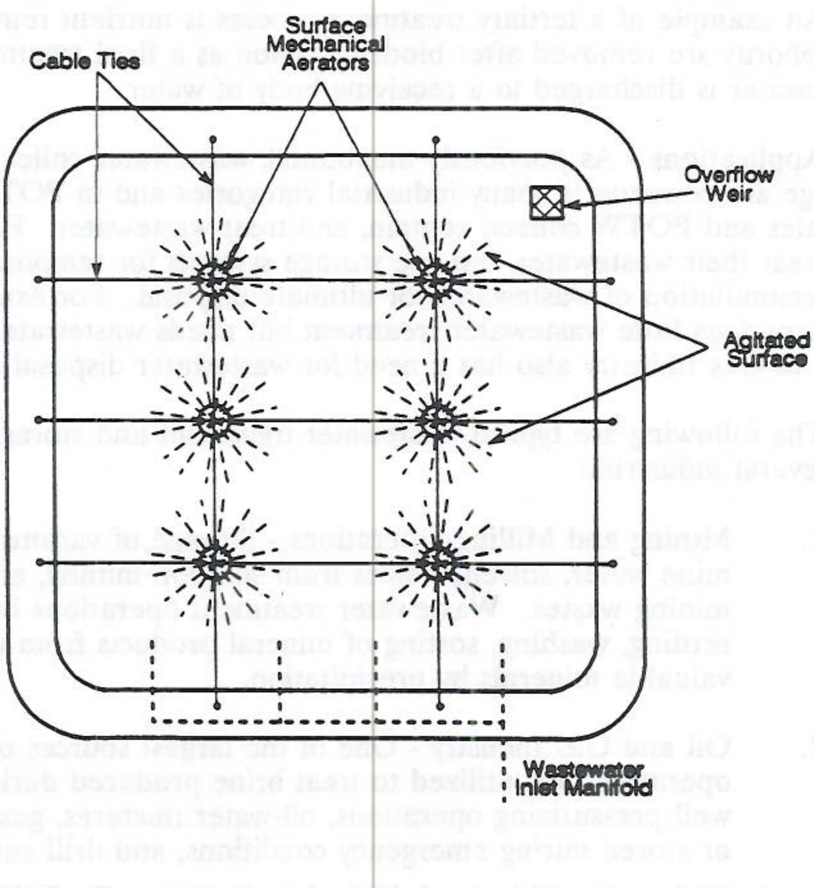


Figure 4.13-3. Example Aerated Biological Treatment Basin

C.9.a p.37

In primary treatment, treatment tanks are generally used to chemically or physically alter the composition or properties of the wastewater by, for example, neutralization and the addition and dispersion of chemical nutrients. Neutralization is used to control the pH of the wastewater by adding an acid or a base. Neutralization usually precedes biotreatment so that the system is not upset due to high or low pH values. Similarly, chemical nutrients addition/dispersion precedes biotreatment and its purpose is to ensure that the biological organisms have sufficient nutrients.

An example of a secondary treatment process is biodegradation. Biological waste treatment is usually accomplished in aeration basins through the use of mechanical surface aerators or with a diffused air system. Mechanical surface aerators float on the water surface and rapidly mix the water. Aeration of the water is accomplished through splashing. Diffused air systems, on the other hand, aerate the water by bubbling oxygen through the water from the bottom of the tank or device. Figure 4.13-3 presents an example design of a mechanically aerated biological treatment basin. This type of basin is usually an earthen or concrete-lined pond and is used to treat large flow rates of wastewater. Wastewaters with high pollutant concentrations, and in particular high flow sanitary wastewaters, are typically treated using an activated sludge system where biotreatment is followed by secondary clarification. In this system, settled solids containing biomass are recycled from clarifier sludge to the biotreatment system. This creates a high biomass concentration and therefore allows biodegradation to occur over a shorter residence time.

An example of a tertiary treatment process is nutrient removal. Nitrogen and phosphorus are removed after biodegradation as a final treatment step before wastewater is discharged to a receiving body of water.

Applications - As previously mentioned, wastewater collection, treatment, and storage are common in many industrial categories and in POTW. Most industrial facilities and POTW collect, contain, and treat wastewater. However, some industries do not treat their wastewater, but use storage systems for temporary wastewater storage or for accumulation of wastewater for ultimate disposal. For example, the Agricultural Industry does little wastewater treatment but needs wastewater storage systems, while the Oil and Gas Industry also has a need for wastewater disposal systems.

The following are typical wastewater treatment and storage applications identified for several industries:

1. Mining and Milling Operations - Storage of various wastewaters such as acid mine water, solvent wastes from solution mining, and leachate from disposed mining wastes. Wastewater treatment operations include separation via settling, washing, sorting of mineral products from tailings, and recovery of valuable minerals by precipitation.

2. Oil and Gas Industry - One of the largest sources of wastewater. Treatment operations are utilized to treat brine produced during oil extraction and deep-well pressurizing operations, oil-water mixtures, gaseous fluids to be separated or stored during emergency conditions, and drill cuttings and drilling muds.

3. Textile and Leather Industry - Wastewater treatment and sludge disposal. Organic species treated or disposed of include dye carriers such as

C.4.a
p.38

halogenated hydrocarbons and phenols. Heavy metals treated or disposed of include chromium, zinc, and copper. Tanning and finishing wastes may contain sulfides and nitrogenous compounds.

4. Chemical and Allied Products Industry - Process wastewater treatment and storage, and sludge disposal. Waste constituents are process-specific and include organics and organic phosphates, fluoride, nitrogen compounds, and assorted trace metals.

5. Other Industries - Treatment and storage operations are found at petroleum refining, primary metals production, wood treating, and metal finishing facilities. Various industries store and/or treat air pollution scrubber sludge and dredging spoils sludge (i.e., settled solids removed from the floor of a surface impoundment).

4.13.2 Emissions

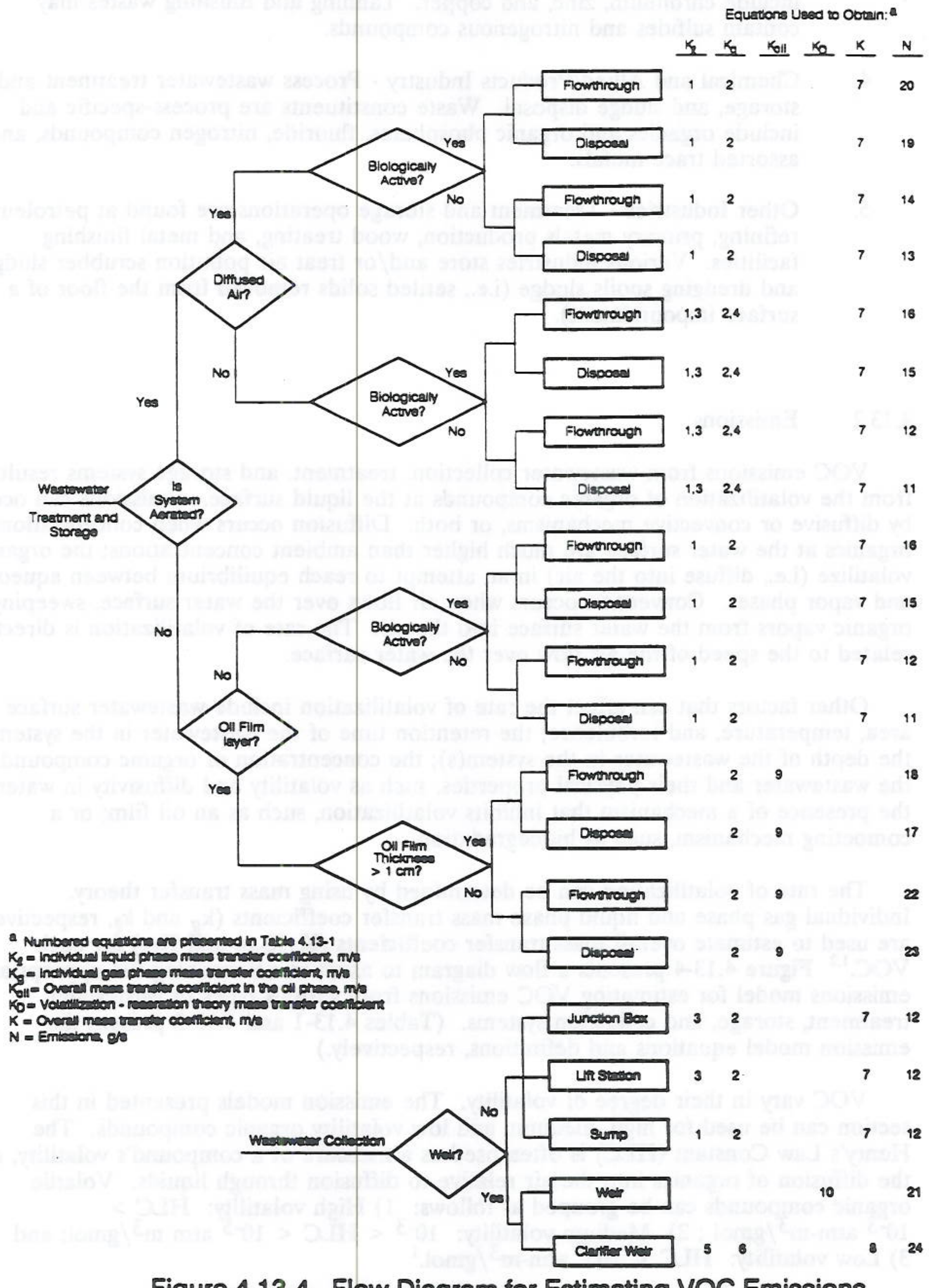
VOC emissions from wastewater collection, treatment, and storage systems result from the volatilization of organic compounds at the liquid surface. Emissions can occur by diffusive or convective mechanisms, or both. Diffusion occurs when concentrations of organics at the water surface are much higher than ambient concentrations; the organics volatilize (i.e., diffuse into the air) in an attempt to reach equilibrium between aqueous and vapor phases. Convection occurs when air flows over the water surface, sweeping organic vapors from the water surface into the air. The rate of volatilization is directly related to the speed of the air flow over the water surface.

Other factors that can affect the rate of volatilization include wastewater surface area, temperature, and turbulence; the retention time of the wastewater in the system(s); the depth of the wastewater in the system(s); the concentration of organic compounds in the wastewater and their physical properties, such as volatility and diffusivity in water; the presence of a mechanism that inhibits volatilization, such as an oil film; or a competing mechanism, such as biodegradation.

The rate of volatilization can be determined by using mass transfer theory. Individual gas phase and liquid phase mass transfer coefficients (k_g and k_ℓ, respectively) are used to estimate overall mass transfer coefficients (K, K_{oil}, and K_D) for each VOC.[1,2] Figure 4.13-4 presents a flow diagram to assist in determining the appropriate emissions model for estimating VOC emissions from various types of wastewater treatment, storage, and collection systems. (Tables 4.13-1 and 4.13-2 present the emission model equations and definitions, respectively.)

VOC vary in their degree of volatility. The emission models presented in this section can be used for high, medium, and low volatility organic compounds. The Henry's Law Constant (HLC) is often used as a measure of a compound's volatility, or the diffusion of organics into the air relative to diffusion through liquids. Volatile organic compounds can be grouped as follows: 1) High volatility: HLC > 10^{-3} atm-m^3/gmol ; 2) Medium volatility: 10^{-3} < HLC < 10^{-5} atm m^3/gmol; and 3) Low volatility: HLC < 10^{-5} atm-m^3/gmol.[1]

C.9.a / .39



[a] Numbered equations are presented in Table 4.13-1
K_ℓ = Individual liquid phase mass transfer coefficient, m/s
K_g = Individual gas phase mass transfer coefficient, m/s
K_{oil} = Overall mass transfer coefficient in the oil phase, m/s
K_O = Volatilization - reaeration theory mass transfer coefficient
K = Overall mass transfer coefficient, m/s
N = Emissions, g/s

Figure 4.13-4. Flow Diagram for Estimating VOC Emissions from Wastewater Collection, Treatment, and Storage Systems

C.9. a p.40

TABLE 4.13-1. MASS TRANSFER CORRELATIONS AND EMISSIONS EQUATIONS

Equation No. — Equations

Individual Liquid and Gas Phase Mass Transfer Coefficients (k_ℓ, and k_g, respectively)

1 $k_\ell\ (m/s) = (2.78 \times 10^{-6})(D_w/D_{ether})^{2/3}$

For: $0 < U_{10} < 3.25$ m/s and all F/D ratios

$k_\ell\ (m/s) = [(2.605 \times 10^{-9})(F/D) + (1.277 \times 10^{-7})](U_{10})^2(D_w/D_{ether})^{2/3}$

For: $U_{10} > 3.25$ m/s and $14 < F/D < 51.2$

$k_\ell\ (m/s) = (2.61 \times 10^{-7})(U_{10})^2(D_w/D_{ether})^{2/3}$

For: $U_{10} > 3.25$ m/s and $F/D > 51.2$

$k_\ell\ (m/s) = 1.0 \times 10^{-6} + 144 \times 10^{-4}\ (U^*)^{2.2}\ (Sc_L)^{-0.5};\ U^* < 0.3$

$k_\ell\ (m/s) = 1.0 \times 10^{-6} + 34.1 \times 10^{-4}\ U^*\ (Sc_L)^{-0.5};\ U^* > 0.3$

For $U_{10} > 3.25$ m/s and $F/D < 14$

where:

$U^*\ (m/s) = (0.01)(U_{10})(6.1 + 0.63(U_{10}))^{0.5}$

$Sc_L = \mu_L/(\rho_L D_w)$

$F/D = 2\ (A/\pi)^{0.5}$

2 $k_g\ (m/s) = (4.82 \times 10^{-3})(U_{10})^{0.78}\ (Sc_G)^{-0.67}\ (d_e)^{-0.11}$

where:

$Sc_G = \mu_a/(\rho_a D_a)$

$d_e(m) = 2(A/\pi)^{0.5}$

3 $k_\ell\ (m/s) = [(8.22 \times 10^{-9})(J)(POWR)(1.024)^{(T-20)}(O_t)(10^6) * (MW_L)/(Va_v \rho_L)](D_w/D_{O2,w})^{0.5}$

where:

$POWR\ (hp) = (\text{Total Power to aerators})(V)$

$Va_v\ (ft^2) = (\text{fraction of area agitated})(A)$

4 $k_g\ (m/s) = (1.35 \times 10^{-7})(Re)^{1.42}\ (P)^{0.4}\ (Sc_G)^{0.5}\ (Fr)^{-0.21}(D_a\ MW_a/d)$

where:

$Re = d^2\ w\ \rho_a/\mu_a$

$P = [(0.85)(POWR)(550\ ft\text{-}lb_f/s\text{-}hp)/N_I]\ g_c/(\rho_L(d^*)^5 w^3)$

$Sc_G = \mu_a/(\rho_a D_a)$

$Fr = (d^*)w^2/g_c$

C.9.a p.41

TABLE 4.13-1. MASS TRANSFER CORRELATIONS AND EMISSIONS EQUATIONS (continued)

Equation No.	Equations

5 k_{ℓ} (m/s) = $(f_{air,\ell})(Q)/[3600 \text{ s/min } (h_c)(\pi d_c)]$

where:

$f_{air,\ell} = 1 - 1/r$

$r = \exp[0.77(h_c)^{0.623}(Q/\pi d_c)^{0.66}(D_w/D_{O2,w})^{0.66}]$

6 k_g (m/s) = $0.001 + (0.0462(U^{**})(Sc_G)^{-0.67})$

where:

U^{**} (m/s) = $[6.1 + (0.63)(U_{10})]^{0.5}(U_{10}/100)$

$Sc_G = \mu_a/(\rho_a D_a)$

Overall Mass Transfer Coefficients for Water and Oil Phases (K and K_{oil}, Respectively, and for Weirs (K_D)

7 $K = (k_{\ell}\ Keq\ k_g)/(Keq\ k_g + k_{\ell})$

where:

$Keq = H/(RT)$

8 K (m/s) = $[[MW_L/(k_{\ell}\rho_L{*}(100 \text{ cm/m})] + [MW_a/(k_g\rho_a H{*}\ 55{,}555(100 \text{ cm/m}))]]^{-1}\ MW_L/[(100 \text{ cm/m})\rho_L]$

9 $K_{oil} = k_g Keq_{oil}$

where:

$Keq_{oil} = P^{*}\rho_a MW_{oil}/(\rho_{oil}\ MW_a\ P_o)$

10 $K_D = 0.16h\ (D_w/D_{O2,w})^{0.75}$

Air Emissions (N)

11 N(g/s) = $(1 - Ct/Co)\ V\ Co/t$

where:

$Ct/Co = \exp[-K\ A\ t/V]$

12 N(g/s) = $K\ C_L\ A$

where:

$C_L(g/m^3) = Q\ Co/(KA + Q)$

13 N(g/s) = $(1 - Ct/Co)\ V\ Co/t$

C.19.4 p42

TABLE 4.13-1. MASS TRANSFER CORRELATIONS AND EMISSIONS EQUATIONS (continued)

Equation No.	Equations
	where: $Ct/Co = \exp[-(KA + KeqQ_a)t/V]$
14	$N(g/s) = (KA + Q_aKeq)C_L$ where: $C_L(g/m^3) = QCo/(KA + Q + Q_aKeq)$
15	$N(g/s) = (1 - Ct/Co)\ KA/(KA + Kmax\ b_i\ V/K_s)\ V\ Co/t$ where: $Ct/Co = \exp[-Kmax\ b_i\ t/K_s - K\ A\ t/V]$
16	$N(g/s) = K\ C_L\ A$ where: $C_L(g/m^3) = [-b + (b^2 - 4ac)^{0.5}]/(2a)$ and $a = KA/Q + 1$ $b = K_s(KA/Q + 1) + Kmax\ b_i\ V/Q - Co$ $c = -K_sCo$
17	$N(g/s) = (1 - Ct_{oil}/Co_{oil})V_{oil}Co_{oil}/t$ where: $Ct_{oil}/Co_{oil} = \exp[-K_{oil}\ t/D_{oil}]$ and: $Co_{oil} = Kow\ Co/[1 - FO + FO(Kow)]$ $V_{oil} = (FO)(V)$ $D_{oil} = (FO)(V)/A$
18	$N(g/s) = K_{oil}C_{L,oil}A$ where: $C_{L,oil}(g/m^3) = Q_{oil}Co_{oil}/(K_{oil}A + Q_{oil})$ and: $Co_{oil} = Kow\ Co/[1 - FO + FO(Kow)]$ $Q_{oil} = (FO)(Q)$
19	$N(g/s) = (1 - Ct/Co)(KA + Q_aKeq)/(KA + Q_aKeq + Kmax\ b_i\ V/K_s)\ V\ Co/t$

C,9,a p,45

TABLE 4.13-1. MASS TRANSFER CORRELATIONS AND EMISSIONS EQUATIONS (continued)

Equation No.	Equations
	where: $Ct/Co = \exp[-(KA + KeqQ_a)t/V - Kmax\ b_i\ t/K_s]$
20	$N(g/s) = (KA + Q_aKeq)C_L$ where: $C_L(g/m^3) = [-b + (b^2 - 4ac)^{0.5}]/(2a)$ and: $a = (KA + Q_aKeq)/Q + 1$ $b = K_s[(KA + Q_aKeq)/Q + 1] + Kmax\ b_i\ V/Q - Co$ $c = -K_sCo$
21	$N\ (g/s) = (1 - \exp[-K_D])Q\ Co$
22	$N(g/s) = K_{oil}C_{L,oil}A$ where: $C_{L,oil}(g/m^3) = Q_{oil}(Co_{oil}{}^*)/(K_{oil}A + Q_{oil})$ and: $Co_{oil}{}^* = Co/FO$ $Q_{oil} = (FO)(Q)$
23	$N(g/s) = (1 - Ct_{oil}/Co_{oil}{}^*)(V_{oil})(Co_{oil}{}^*)/t$ where: $Ct_{oil}/Co_{oil}{}^* = \exp[-K_{oil}\ t/D_{oil}]$ and: $Co_{oil}{}^* = Co/FO$ $V_{oil} = (FO)(V)$ $D_{oil} = (FO)(V)/A$
24	$N\ (g/s) = (1 - \exp[-K\pi\ d_c\ h_c/Q])Q\ Co$

[a]All parameters in numbered equations are defined in Table 4.13-2.

C.9.a p44

TABLE 4.13-2. PARAMETER DEFINITIONS FOR MASS TRANSFER CORRELATIONS AND EMISSIONS EQUATIONS

Parameter	Definition	Units	Code[a] or Value
A	Wastewater surface area	m^2 or ft^2	A
b_i	Biomass concentration (total biological solids)	g/m^3	B
C_L	Concentration of constituent in the liquid phase	g/m^3	D
$C_{L,oil}$	Concentration of constituent in the oil phase	g/m^3	D
Co	Initial concentration of constituent in the liquid phase	g/m^3	A
Co_{oil}	Initial concentration of constituent in the oil phase considering mass transfer resistance between water and oil phases	g/m^3	D
Co_{oil}^*	Initial concentration of constituent in the oil phase considering no mass transfer resistance between water and oil phases	g/m^3	D
Ct	Concentration of constituent in the liquid phase at time = t	g/m^3	D
Ct_{oil}	Concentration of constituent in the oil phase at time = t	g/m^3	D
d	Impeller diameter	cm	B
D	Wastewater depth	m or ft	A,B
d^*	Impeller diameter	ft	B
D_a	Diffusivity of constituent in air	cm^2/s	C
d_c	Clarifier diameter	m	B
d_e	Effective diameter	m	D
D_{ether}	Diffusivity of ether in water	cm^2/s	(8.5×10^{-6})[b]
$D_{O2,w}$	Diffusivity of oxygen in water	cm^2/s	(2.4×10^{-5})[b]
D_{oil}	Oil-film thickness	m	B
D_w	Diffusivity of constituent in water	cm^2/s	C
$f_{air,\ell}$	Fraction of constituent emitted to the air considering zero gas resistance	dimensionless	D

C.9.a
p.45

TABLE 4.13-2. PARAMETER DEFINITIONS FOR MASS TRANSFER CORRELATIONS AND EMISSIONS EQUATIONS (continued)

Parameter	Definition	Units	Code[a] or Value
F/D	Fetch to depth ratio, d_e/D	dimensionless	D
FO	Fraction of volume which is oil	dimensionless	B
Fr	Froude number	dimensionless	D
g_c	Gravitation constant (a conversion factor)	$lb_m\text{-ft/s}^2\text{-lb}_f$	32.17
h	Weir height (distance from the wastewater overflow to the receiving body of water)	ft	B
h_c	Clarifier weir height	m	B
H	Henry's Law Constant of constituent	$\text{atm-m}^3\text{/gmol}$	C
J	Oxygen transfer rating of surface aerator	$\text{lb O}_2\text{/(hr-hp)}$	B
K	Overall mass transfer coefficient for transfer of constituent from liquid phase to gas phase	m/s	D
K_D	Volatilization-reaeration theory mass transfer coefficient	dimensionless	D
Keq	Equilibrium constant or partition coefficient (concentration in gas phase/concentration in liquid phase)	dimensionless	D
Keq_{oil}	Equilibrium constant or partition coefficient (concentration in gas phase/concentration in oil phase)	dimensionless	D
k_g	Gas phase mass transfer coefficient	m/s	D
k_ℓ	Liquid phase mass transfer coefficient	m/s	D
Kmax	Maximum biorate constant	g/s-g biomass	A,C
K_{oil}	Overall mass transfer coefficient for transfer of constituent from oil phase to gas phase	m/s	D
Kow	Octanol-water partition coefficient	dimensionless	C
K_s	Half saturation biorate constant	g/m^3	A,C
MW_a	Molecular weight of air	g/gmol	29

C.9.a
v.46

TABLE 4.13-2. PARAMETER DEFINITIONS FOR MASS TRANSFER CORRELATIONS AND EMISSIONS EQUATIONS (continued)

Parameter	Definition	Units	Code[a] or Value
MW_{oil}	Molecular weight of oil	g/gmol	B
MW_L	Molecular weight of water	g/gmol	18
N	Emissions	g/s	D
N_I	Number of aerators	dimensionless	A,B
O_t	Oxygen transfer correction factor	dimensionless	B
P	Power number	dimensionless	D
P^*	Vapor pressure of the constituent	atm	C
P_o	Total pressure	atm	A
POWR	Total power to aerators	hp	B
Q	Volumetric flow rate	m^3/s	A
Q_a	Diffused air flow rate	m^3/s	B
Q_{oil}	Volumetric flow rate of oil	m^3/s	B
r	Deficit ratio, ratio of the difference between the constituent concentration at solubility and actual constituent concentration in the upstream and the downstream	dimensionless	D
R	Universal gas constant	atm-m^3/gmol-K	8.21×10^{-5}
Re	Reynold's number	dimensionless	D
Sc_G	Schmidt number on gas side	dimensionless	D
Sc_L	Schmidt number on liquid side	dimensionless	D
T	Temperature of water	^oC or Kelvin (K)	A
t	Residence time of disposal	s	A
U^*	Friction velocity	m/s	D
U^{**}	Friction velocity	m/s	D
U_{10}	Windspeed at 10 m above the liquid surface	m/s	B
V	Wastewater Volume	m^3 or ft^3	A

C.9.a
P.41

TABLE 4.13-2. PARAMETER DEFINITIONS FOR MASS TRANSFER CORRELATIONS AND EMISSIONS EQUATIONS (continued)

Parameter	Definition	Units	Code[a] or Value
Va_v	Turbulent surface area	ft^2	B
V_{oil}	Volume of oil	m^3	B
w	Rotational speed of impeller	rad/s	B
ρ_a	Density of air	g/cm^3	$(1.2x10^{-3})^b$
ρ_L	Density of water	g/cm^3 or lb/ft^3	1^b or 62.4^b
ρ_{oil}	density of oil	g/m^3	B
μ_a	Viscosity of air	g/cm-s	$(1.81x10^{-4})^b$
μ_L	Viscosity of water	g/cm-s	$(8.93x10^{-3})^b$

[a] Code

A = Site specific parameter
B = Site-specific parameter, however, default values are available (see Table 4.13-3)
C = Parameter can be obtained from literature data (see Attachment 1 for a list of ~150 compound chemical properties at T = 25°C (298°K)).
D = Calculated value

[b] Reported values at 25°C (298°K).

C.9.6
p.48

Collection, treatment, and storage system arrangement and design are facility-specific. Testing provides the most accurate wastewater emissions estimate from a facility (i.e., tracer studies or direct measurement of emissions from openings). However, if actual data is unavailable, the emission models provided in this section can be used.

Although default values are available for some emission model input parameters, it is recommended that site-specific information always be used if available. The models are most sensitive to system design and the constituent profile (i.e., concentrations). A completely characterized system will provide the most accurate estimate when these models are used. In addition, for systems with biodegradation, the accuracy of the rate of biodegradation is improved if site-specific compound biorates are provided.[3] Reference 3 contains information on a test method for measuring site-specific biorates. (Attachment 1 presentsr estimated biorates for approximately 150 compounds.)

To estimate an emissions rate (N), the first step is to calculate individual gas phase and liquid phase mass transfer coefficients k_g and k_ℓ. These individual coefficients are then used to calculate the overall mass transfer coefficient, K. Exceptions to this procedure are the calculation of overall mass transfer coefficients in the oil phase, K_{oil}, and the overall mass transfer coefficient for a weir, K_D (K_{oil} requires only k_g and K_D does not require any individual mass transfer coefficients). The overall mass transfer coefficient is then used to calculate the emissions rates. The following discussion describes how to use Figure 4.13-4 to determine an emission rate and an example calculation is presented in Section 4.13.2.1.

Figure 4.13-4 is divided into two sections: 1) Wastewater Treatment and Storage Systems, and 2) Wastewater Collection Systems. Wastewater treatment and storage systems are further segmented by aerated/nonaerated systems, biologically active systems, oil film layer systems, and whether the surface impoundment is flowthrough or disposal. In flowthrough systems, wastewater is treated and discharged to a POTW or receiving body of water, such as a river or stream. All wastewater collection systems are flowthrough by nature. Disposal systems, on the other hand, do not discharge any wastewater.

Figure 4.13-4 includes information needed to estimate air emissions from junction boxes, lift stations, sumps, weirs, and clarifier weirs. Sumps are considered quiescent, while junction boxes, lift stations, and weirs are considered turbulent in nature. Junction boxes and lift stations are considered turbulent because incoming flow is normally above the water level in the component, which creates some splashing. Wastewater falls or overflows from weirs and creates splashing in the receiving body of water (both weir and clarifier weir models). In addition, wastewater from weirs can be aerated by falling over steps (usually only the weir model).

Assessing VOC emissions from drains, manholes, and trenches is also important for determining the total facility emissions from wastewater. As these sources can be open to the atmosphere and closest to the point of wastewater generation (i.e., where wastewater temperatures and pollutant concentrations are greatest), emissions can be significant. Currently, there are no well established emission models for these collection system types. However, work is being performed to obtain accurate models for these emission sources.

C.9.a
p.49

Preliminary emission models of VOC from wastewaste collection system units have already been developed and are presented in Appendix B of an U.S. EPA Background Information Document[4]. The emission equations presented in Reference 4 are used with standard collection system parameters to estimate the fraction of the constituents released as the wastewater flows through each unit. The fraction released from several units are estimated for high, medium, and low volatility compounds. The units used in the estimated fractions included open drains, manhole covers, open trench drains, and covered sumps.

The emission equations presented in Appendix B of Reference 4 have been used in a computer program to perform a Monte Carlo computer simulation of a model plant to estimate the site specific emissions of benzene.[5] The magnitude of the air emissions of benzene varied from 11 to 55 percent of the initial benzene in the waste entering the collection system, with an average value of 33 percent.

The numbers under the columns for k_ℓ, k_g, K_{oil}, K_D, K, and N in Figure 4.13-4 refer to the appropriate equations in Table 4.13-1. Definitions for all parameters that appear in these equations are given in Table 4.13-2. Table 4.13-2 also supplies the units that must be used for each parameter and codes to help locate input values. If the parameter is coded with the letter A, a site-specific value is required. Code B also requires a site-specific parameter, however defaults are available. These defaults are typical or average values and are presented in Table 4.13-3 by specific systems.

Code C means the parameter can be obtained from literature data. Attachment 1 contains a listing of approximately 150 chemicals and their physical properties needed for calculating emissions from wastewater using the correlations presented in Table 4.13-1. All properties are at 25°C. (A more extensive although somewhat incomplete, chemical properties database is contained in Appendix C of Reference 1.) Finally, Code D is a calculated value.

Calculation of air emissions from wastewater collection, treatment, and storage systems is a complex procedure, especially if several systems are present. Performing the calculations by hand may result in errors and will be time consuming. A personal computer program called the Surface Impoundment Modeling System (SIMS) is now available for estimation of air emissions. The program is menu driven and can estimate air emissions from all surface impoundment models presented in Figure 4.13-4 on an individual basis or in series. The program requires, as a minimum input for each collection, treatment, or storage system component, the wastewater flow rate and component surface area. All other inputs are provided as default values. However, any available site-specific information should be entered in place of these defaults, as the most characterized system will provide the most accurate emissions estimate.

The SIMS program and supporting documentation (User's Manual and background technical document) can be obtained through State agencies and through the

---

[*] All emission model systems presented in Figure 4.13-4 imply a completely mixed or uniform wastewater concentration system. Emission models for a plug flow system, or system in which there is no axial, or horizontal mixing, are too extensive to be covered in this document. (An example of plug flow might be a high wastewater flow in a narrow channel.) However, information on emission models of this type is contained in Reference 1.

C,9,a
p.50

Environmental Protection Agency's Office of Air Quality, located in Research Triangle Park, North Carolina [CTC HOTLINE (919) 541-0800 or FTS 629-0800]. It is recommended that the User's Manual and Technical background document be obtained to produce meaningful results.

In addition, the program and User's Manual can be downloaded from the Clearinghouse for Inventories and Emission Factors (CHIEF) electronic bulletin board system (BBS). The CHIEF BBS is accessed through the Technical Support Division (TSD) BBS, and is open to all persons involved in air emission inventories. To access the BBS, a computer, modem, and communication package capable of communicating at 1200, 2400, or 9600 baud, 8 data bits, 1 stop bit, and no parity (8-N-1) are needed.

C, 9, a
v, 81

TABLE 4.13-3. SITE-SPECIFIC DEFAULT PARAMETERS[1]

Default[a] Parameter	Definition	Default Value
General		
T	Temperature of water	298°K
U_{10}	Windspeed	4.47 m/s
Biotreatment Systems		
b_i	Biomass concentration (for biologically active systems)	
	Quiescent treatment systems	50 g/m^3
	Aerated treatment systems	300 g/m^3
	Activated sludge units	4000 g/m^3
POWR	Total power to aerators (for aerated treatement systems) (for activated sludge)	 0.75 hp/1000 ft^3 (V) 2 hp/1000 ft^3 (V)
W	Rotational speed of impeller (for aerated treatment systems)	126 rad/s(1200 rpm)
d(d*)	Impeller diameter (for aerated treatment systems)	61 cm(2 ft)
Va_v	Turbulent surface area (for aerated treatment systems) (for activated sludge)	 0.24 (A) 0.52 (A)
J	Oxygen transfer rating to surface aerator (for aerated treatment systems)	3 lb O_2/hp•hr
O_t	Oxygen transfer correction factor (for aerated treatment systems)	0.83
N_I	Number of aerators	POWR/75
Diffused Air Systems		
Q_a	Diffused air volumetric flow rate	0.0004(V) m^3/s

C.9.a
p152

TABLE 4.13-3. SITE-SPECIFIC DEFAULT PARAMETERS (continued)[1]

Default Parameter	Definition	Default Value
Oil Film Layers		
MW_{oil}	Molecular weight of oil	282 g/gmol
D_{oil}	Depth of oil layer	0.001 (V/A) m
V_{oil}	Volume of oil	0.001 (V) m^3
Q_{oil}	Volumetric flow rate of oil	0.001 (Q) m^3/s
ρ_{oil}	Density of oil	0.92 g/cm^3
FO	Fraction of volume which is oil	0.001[b]
Junction Boxes		
D	Depth of Junction Box	0.9 m
N_I	Number of aerators	1
Lift Station		
D	Depth of Lift Station	1.5 m
N_I	Number of aerators	1
Sump		
D	Depth of sump	5.9 m
Weirs		
d_c	Clarifier weir diameter	28.5 m[c]
h	Weir height	1.8 m
h_c	Clarifier weir height	0.1 m[d]

[a] As defined in Table 4.13-2.

[b] Reference 4.

[c] Reference 2.

[d] Reference 5.

C, 9, a
p, 53

The TSD BBS telephone numbers are:

1) (919) 541-5742 (1200 or 2400 baud), and

2) (919) 541-5384 (9600 baud).

First-time users must register before access is allowed.

The emissions estimates of SIMS are based on mass transfer models developed by the Emissions Standards Division (ESD) of EPA during the evaluations of TSDFs and VOC emissions from industrial wastewater. As a part of the TSDF project, a Lotus 123 (TM) spreadsheet program called CHEMDAT7 was developed for estimating VOC emissions from wastewater land treatment ysstems, open landfills, closed landfills, and waste storage piles, as well as various types of surface impoundments. For more information about CHEMDAT7 contact the Chemicals and Petroleum Branch, USEPA, Office of Air Quality Planning and Standards, Mail Drop 13,
Research Triangle Park, N.C. 27711.

4.13.2.1 Example Calculation

An example industrial facility operates a flowthrough, mechanically aerated biological treatment impoundment that receives wastewater contaminated with benzene at a concentration of 10.29 g/m^3.

The following format is used for calculating benzene emissions from the treatment process:

I. Determine Which Emission Model to Use
II. User-Supplied Information
III. Defaults
IV. Pollutant Physical Property Data and Water, Air, and Other Properties
V. Calculate Individual Mass Transfer Coefficient
VI. Calculate the Overall Mass Transfer Coefficients
VII. Calculate VOC Emissions

I. Determine Which Emission Model to Use - Following the flow diagram in Figure 4.13-4, the emission model for a treatment system that is aerated, but not by diffused air, is biologically active, and is a flowthrough system contains the following equations:

Parameter	Definition	Equation Nos. from Table 4.13-1
k_ℓ	Individual liquid phase mass transfer coefficient, m/s	1,3
k_g	Individual gas phase mass transfer coefficient, m/s	2,4

C.9,6
p.54

K	Overall mass transfer coefficient, m/s	7
N	VOC Emissions, g/s	16

II. User-Supplied Information - Once the correct emission model is determined, some site-specific parameters are required. As a minimum for this model, site-specific flow rate, wastewater surface area, and depth, and pollutant concentration should be provided. For this example, these parameters have the following values:

Q = Volumetric flow rate = 0.0623 m^3/s

D = Wastewater depth = 1.97 m

A = Wastewater surface area = 17,652 m^2

Co = Initial benzene concentration in the liquid phase = 10.29 g/m^3

III. Defaults - Defaults for some emission model parameters are presented in Table 4.13-3. Generally, if these parameters are easily obtained, site-specific values should be used. For this facility, all available general and biotreatment system defaults from Table 4.13-3 were used:

U_{10} = Windspeed at 10 m above the liquid surface = e = 4.47 m/s

T = Temperature of water = 25°C (298°K)

b_i = Biomass concentration for aerated treatment systems = 300 g/m^3

J = Oxygen transfer rating to surface aerator = 3 lb O_2/hp-hr

POWR = Total power to aerators = 0.75 hp/1,000 ft^3 (V)

O_t = Oxygen transfer correction factor = 0.83

Va_v = Turbulent surface area = 0.24 (A)

d = impeller diameter = 61 cm

d* = impeller diameter = 2 ft

w = rotational speed of impeller = 126 rad/s

N_I = number of aerators = POWR/75 hp

IV. Pollutant Physical Property Data and Water, Air, and Other Properties - For each pollutant, specific physical properties needed by this model are listed in Attachment 1. Water, air, and other property values are given in Table 4.13-2.

A. Benzene (from Attachment 1)

$D_{w,benzene}$ = Diffusivity of benzene in water = 9.8 x 10^{-6} cm^2/s

C, 9, a
p, 55

$D_{a,benzene}$ = Diffusivity of benzene in air = 0.088 cm2/s

$H_{benzene}$ = Henry's Law Constant for benzene = 0.0055 atm-m^3/gmol

$Kmax_{benzene}$ = Maximum biorate constant for benzene = 5.28 x 10^{-6} g/g-s

$K_{s,benzene}$ = Half saturation biorate constant for benzene = 13.6 g/m^3

B. Water, Air, and Other Properties (from Table 4.13-3)

ρ_a = density of air = 1.2 x 10^3 g/cm^3

ρ_L = density of water = 1 g/cm^3 (62.4 lb$_m$/ft^3)

μ_a = viscosity of air = 1.81 x 10^{-4} g/cm-s

$D_{O2,w}$ = diffusivity of oxygen in water = 2.4 x 10^{-5} cm^2/s

D_{ether} = diffusivity of ether in water = 8.5 x 10^{-6} cm^2/s

MW_L = molecular weight of water = 18 g/gmol

MW_a = molecular weight of air = 29 g/gmol

g_c = gravitation constant = 32.17 lb$_m$-ft/lb$_f$-s^2

R = Universal gas constant = 8.21 x 10^{-5} atm-m^3/gmol

V. Calculate Individual Mass Transfer Coefficients - Because part of the impoundment is turbulent and part is quiescent, individual mass transfer coefficients are determined for both turbulent and quiescent areas of the surface impoundment.

Turbulent Area of Impoundment - Equation numbers 3 and 4 from Table 4.13-1.

A. Calculate the individual liquid mass transfer coefficient, k_ℓ:

$$k_\ell(m/s) = [(8.22 \times 10^{-9})(J)(POWR)(1.024)^{(T-20)} * (O_t)(10^6)MW_L/(Va_v\rho_L)](D_w/D_{O2,w})^{0.5}$$

The total power to the aerators, POWR, and the turbulent surface area, Va_v, are calculated separately [Note: some conversions are necessary.]:

1) Calculate total power to aerators, POWR (Default presented in III):

POWR (hp) = 0.75 hp/1,000 ft^3 (V)

V = wastewater volume, m^3

C.9.4
p.56

$V\ (m3) = (A)(D) = (17{,}652\ m^2)(1.97\ m)$

$V = 34{,}774\ m^3$

$POWR = (0.75\ hp/1{,}000\ ft^3)(ft^3/0.028317\ m^3)(34{,}774\ m^3)$

$POWR = 921\ hp$

2) Calculate turbulent surface area, Va_v, (Default presented in III):

$Va_v\ (ft^2) = 0.24\ (A)$

$Va_v = 0.24(17{,}652\ m^2)(10.758\ ft^2/m^2)$

$Va_v = 45{,}576\ ft^2$

Now, calculate k_ℓ, using the above calculations and information from II, III, and IV:

$$k_\ell\ (m/s) = [(8.22 \times 10^{-9})(3\ lbO_2/hp\text{-}hr)(921\ hp) * (1.024)^{(25-20)}(0.83)(10^6)(18\ g/gmol)/((45{,}576\ ft^2)(1\ g/cm^3))] * [(9.8 \times 10^{-6}\ cm^2/s)/(2.4 \times 10^{-5}\ cm^2/s)]^{0.5}$$

$k_\ell\ (m/s) = (0.00838)(0.639)$

$k_\ell = 5.35 \times 10^{-3}\ m/s$

B. Calculate the individual gas phase mass transfer coefficient, k_g:

$$k_g\ (m/s) = (1.35 \times 10^{-7})(Re)^{1.42}(P)^{0.4}(Sc_G)^{0.5}(Fr)^{-0.21}(D_a\ MW_a/d)$$

The Reynold's number, Re, power number, P, Schmidt number on the gas side, Sc_G, and Froude's number Fr, are calculated separately:

1) Calculate Reynold's Number, Re:

$Re = d^2\ w\ \rho_a/\mu_a$

$Re = (61\ cm)^2(126\ rad/s)(1.2 \times 10^{-3}\ g/cm^3)/(1.81 \times 10^{-4}\ g/cm\text{-}s)$

$Re = 3.1 \times 10^6$

2) Calculate power number, P:

$P = [(0.85)(POWR)(550\ ft\text{-}lb_f/s\text{-}hp)/N_I]\ g_c/(\rho_L(d^*)^5\ w^3)$

$N_I = POWR/75\ hp$ (default presented in III)

$$P = (0.85)(75\ hp)(POWR/POWR)(550\ ft\text{-}lb_f/s\text{-}hp) * (32.17\ lb_m\text{-}ft/lb_f\text{-}s^2)/[(62.4\ lb_m/ft^3)(2\ ft)^5(126\ rad/s)^3]$$

$P = 2.8 \times 10^{-4}$

3) Calculate Schmidt Number on the gas side, Sc_G:

C.9.a
p.57

$Sc_G = \mu_a/(\rho_a D_a)$

$Sc_G = (1.81 \times 10^{-4}\ g/cm\text{-}s)/[(1.2 \times 10^{-3}\ g/cm^3)(0.088\ cm^2/s)]$

$Sc_G = 1.71$

4) Calculate Froude Number, Fr:

$Fr = (d^*)w^2/g_c$

$Fr = (2\ ft)(126\ rad/s)^2/(32.17\ lb_m\text{-}ft/lb_f\text{-}s^2)$

$Fr = 990$

Now calculate k_g using the above calculations and information from II, III, and IV:

$k_g\ (m/s) = (1.35 \times 10^{-7})(3.1 \times 10^6)^{1.42}(2.8 \times 10^{-4})^{0.4}(1.71)^{0.5}\ \bullet$

$(990)^{-0.21}(0.088\ cm^2/s)(29\ g/gmol)/(61\ cm)$

$k_g = 0.109\ m/s$

Quiescent Surface Area of Impoundment - Equations 1 and 2 from Table 4.13-1

A. Calculate the individual liquid phase mass transfer coefficient, k_ℓ:

$F/D = 2(A/\pi)^{0.5}/D$

$= 2(17{,}652\ m^2/\pi)^{0.5}/(1.97\ m)$

$= 76.1$

$U_{10} = 4.47\ m/s$

For $U_{10} > 3.25$ m/s and $F/D > 51.2$ use the following:

$k_\ell\ (m/s) = (2.61 \times 10^{-7})(U_{10})^2(D_w/D_{ether})^{2/3}$

$k_\ell\ (m/s) = (2.61 \times 10^{-7})(4.47\ m/s)^2[(9.8 \times 10^{-6}\ cm^2/s)/$

$(8.5 \times 10^{-6}\ cm^2/s)]^{2/3}$

$k_\ell = 5.74 \times 10^{-6}\ m/s$

B. Calculate the individual gas phase mass transfer coefficient, k_g:

$k_g = (4.82 \times 10^{-3})(U_{10})^{0.78}(Sc_G)^{-0.67}(d_e)^{-0.11}$

The Schmidt number on the gas side, Sc_G, and the effective diameter, d_e, are calculated separately:

1) Calculate the Schmidt Number on the gas side, Sc_G:

C, 9, a
p. 58

$Sc_G = \mu_a/(\rho_a D_a) = 1.71$ (same as for turbulent impoundments)

2) Calculate the effective diameter, d_e:

$d_e\ (m) = 2(A/\pi)^{0.5}$

$d_e\ (m) = 2(17{,}652\ m^2/\pi)^{0.5}$

$d_e = 149.9\ m$

$k_g\ (m/s) = (4.82 \times 10^{-3})(4.47\ m/s)^{0.78}\ (1.71)^{-0.67}\ (149.9\ m)^{-0.11}$

$k_g = 6.24 \times 10^{-3}\ m/s$

VI. Calculate the Overall Mass Transfer Coefficient. Because part of the impoundment is turbulent and part is quiescent, the overall mass transfer coefficient is determined as an area-weighted average of the turbulent and quiescent overall mass transfer coefficients. (Equation number 7 from Table 4.13-1)

Overall Mass Transfer Coefficient for the Turbulent Surface Area of Impoundment, K_T

$K_T\ (m/s) = (k_\ell Keq k_g)/(Keq k_g + k_\ell)$

$Keq = H/RT$

$Keq = (0.0055\ atm\text{-}m^3/gmol)/[(8.21 \times 10^{-5}\ atm\text{-}m^3/gmol\text{-}^oK)(298^oK)]$

$Keq = 0.225$

$K_T\ (m/s) = (5.35 \times 10^{-3}\ m/s)(0.225)(0.109)/[(0.109\ m/s)(0.225) + (5.35 \times 10^{-6}\ m/s)]$

$K_T = 4.39 \times 10^{-3}\ m/s$

Overall Mass Transfer Coefficient for the Quiescent Surface Area of Impoundment, K_Q

$K_Q\ (m/s) = (k_\ell Keq k_g)/(Keq k_g + k_\ell)$

$K_Q\ (m/s) = (5.74 \times 10^{-6}\ m/s)(0.225)(6.24 \times 10^{-3}\ m/s)/[(6.24 \times 10^{-3}\ m/s)(0.225) + (5.74 \times 10^{-6}\ m/s)]$

$K_Q = 5.72 \times 10^{-6}\ m/s$

Overall Mass Transfer Coefficient, K, Weighted by Turbulent and Quiescent Surface Areas (A_T and A_Q)

$K\ (m/s) = (K_T A_T + K_Q A_Q)/A$

C.9.a
12,59

A_T = 0.24(A) (Default value presented in III: $A_T = Va_v$)

A_Q = (1 - 0.24)A

$K\ (m/s) = [(4.39 \times 10^{-3}\ m/s)(0.24\ A) + (5.72 \times 10^{-6}\ m/s)(1 - 0.24)A]/A$

$K = 1.06 \times 10^{-3}\ m/s$

VII. Calculate VOC Emissions for an Aerated, Biological, Flowthrough Impoundment - Equation number 16 from Table 4.13-1

$N\ (g/s) = K\ C_L\ A$

where:

$C_L\ (g/m^3) = [-b + (b^2 - 4ac)^{0.5}]/(2a)$

and:

$a = KA/Q + 1$

$b = K_s(KA/Q + 1) + Kmax\ b_i\ V/Q - Co$

$c = -K_sCo$

a, b, c, and the concentration of benzene in the liquid phase, C_L, are calculated separately:

1) Calculate a:

$a = (KA/Q + 1) = [(1.06 \times 10^{-3}\ m/s)(17{,}652\ m^2)/(0.0623\ m^3/s)] + 1$

$a = 301.3$

2) Calculate b ($V = 34{,}774\ m^3$ from IV):

$b = K_s\ (KA/Q + 1) + Kmax\ b_i\ V/Q - Co$

$b = (13.6\ g/m^3)[(1.06 \times 10^{-3}\ m/s)(17{,}652\ m^2)/(0.0623\ m^3/s)] +$

$[(5.28 \times 10^{-6}\ g/g\text{-}s)(300\ g/m^3)(34{,}774\ m^3)/(0.0623\ m^3/s)] - 10.29\ g/m^3$

$b = 4{,}084.6 + 884.1 - 10.29$

$b = 4{,}958.46\ g/m^3$

3) Calculate c:

$c = -K_sCo$

$c = -(13.6\ g/m^3)(10.29\ g/m^3)$

$c = -139.94$

C.9.a
p.60

4) Calculate the concentration of benzene in the liquid phase, C_L, from a, b, and c above:

$$C_L\ (g/m^3) = [-b + (b^2 - 4ac)^{0.5}]/(2a)$$

$$C_L\ (g/m^3) = [(4{,}958.46\ g/m^3) + [(4{,}958.46\ g/m^3)^2 - [4(301.3)(-139.94)]]^{0.5}]/(2(301.3))$$

$$C_L = 0.0282\ g/m^3$$

Now calculate N with the above calculations and information from II and V:

$$N\ (g/s) = K\ A\ C_L$$

$$N\ (g/s) = (1.06 \times 10^{-3}\ m/s)(17{,}652\ m^2)(0.0282\ g/m^3)$$

$$N = 0.52\ g/s$$

4.13.3 Controls

The types of control technologies generally used in reducing VOC emissions from wastewater include: steam stripping or air stripping, carbon adsorption (liquid phase), chemical oxidation, membrane separation, liquid-liquid extraction, and biotreatment (aerobic or anaerobic). For efficient control, all control technologies should be placed as close to the point of wastewater generation as possible with all collection, treatment, and storage systems prior to the control technology being covered to suppress emissions. Tightly covered, well maintenanced collection systems can suppress emissions by 95 to 99 percent. However, if there is explosive potential, the components should be vented to a control device, such as an incinerator or carbon adsorber.

The following paragraphs present a brief description and the performance of the control technologies listed above and any secondary controls that may need to be considered for fugitive air emissions.

Steam stripping is the fractional distillation of wastewater to remove volatile organic constituents, with the basic operating principle being the direct contact of steam with wastewater. The steam provides the heat of vaporization for the more volatile organic constituents. Removal efficiencies vary with volatility and solubility of the organic impurities. For highly volatile compounds (HLC greater than 10^{-3} atm-m^3/gmol), average VOC removal ranges from 95 to 99 percent, for medium volatility compounds (HLC between 10^{-5} and 10^{-3} atm-m^3/gmol), average removal ranges from 90 to 95 percent, and for low volatility compounds (HLC $< 10^{-5}$ atm-m^3/gmol), average removal ranges from less than 50 to 90 percent.

Air stripping involves the contact of wastewater with air to strip out volatile organic constituents. By forcing large volumes of air through contaminated water, the surface area of water in contact with air is greatly increased, resulting in an increase in the transfer rate of the organic compounds into the vapor phase. Removal efficiencies vary

C.9.a
p.61

with volatility and solubility of organic impurities. For highly volatile compounds, average removal ranges from 90 to 99 percent, for medium to low volatility compounds, removal ranges from less than 50 to 90 percent.

Steam and air stripping controls most often are vented to a secondary control device such as a combustion device or gas phase carbon adsorber. Combustion devices include incinerators, boilers, and flares. Vent gases can be used as an alternate fuel if the fuel value is high. Typically, vent gas is combined with other fuels such as natural gas and fuel oil. If the fuel value is very low, vent gases can be heated and combined with combustion air. It is important to note that some organics, such as chlorinated hydrocarbons, can emit toxic pollutants when combusted.

Secondary control using gas phase carbon adsorption processes take advantage of compound affinities for activated carbon. The types of gas phase carbon adsorption systems most commonly used for volatile organic compound emission control are fixed-bed carbon adsorbers and carbon canisters. Fixed-bed carbon adsorbers are used for controlling continuous, organic gas streams with flow rates ranging from 30 to over 3,000 m^3/min. Canisters are much simpler and smaller than fixed-bed system and are usually installed for controlling gas flows less than 3 m^3/min.[4] Removal efficiencies depend highly on the type of compound being removed. Pollutant-specific activated carbon is usually required. Average removal efficiency ranges from 90 to 99 percent.

Like gas phase carbon adsorption, liquid phase carbon adsorption takes advantage of compound affinities for activated carbon. Activated carbon is an excellent adsorbent because of its large surface area and because it is usually in granular or powdered form. Two types of liquid phase carbon adsorption are the fixed bed and moving bed systems. The fixed bed system is used primarily for low flow wastewater streams with contact times around 15 minutes and is a batch operation (i.e., once the carbon is spent, the system is taken offline). Moving bed carbon adsorption systems operate in a continuous mode with wastewater typically being introduced from the bottom of the column and regenerated carbon from the top (countercurrent flow). Spent carbon is continuously removed from the bottom of the bed. Liquid phase carbon adsorption is usually used for low concentrations of nonvolatile components and high concentrations of nondegradable compounds.[6] Removal efficiencies are dependent on whether the compound is adsorbed on activated carbon. Average removal efficiency ranges from 90 to 99 percent.

Chemical oxidation involves a chemical reaction between the organic compound and an oxidant such as ozone, hydrogen peroxide, permanganate, or chlorine dioxide. Ozone is usually added to the wastewater through an ultraviolet (UV)-ozone reactor. Permanganate and chlorine dioxide are added directly into the wastewater. It is important to note that addition of chlorine dioxide can form chlorinated hydrocarbons as a side reaction. The applicability of this technology depends on the reactivity of the individual organic compound.

Two types of membrane separation processes are ultrafiltration and reverse osmosis. Ultrafiltration is primarily a physical sieving process driven by a pressure gradient across the membrane. This process separates organic compounds with molecular weights greater than 2,000, depending on the size of the membrane pore. Reverse osmosis is the process by which a solvent is forced across a semi-permeable membrane due to an osmotic pressure gradient. Selectivity is, therefore, based on osmotic diffusion properties of the compound and the molecular diameter of the compound and membrane pores.[4]

C19,u
p.62

Liquid-liquid extraction uses differences in solubility of compounds in various solvents as a separation technique. By contacting a solution containing the desired compound with a solvent in which the compound has a greater solubility, the compound may be removed from the solution. This technology is often used for product and process solvent recovery. Through distillation, the compound of interest is usually recovered, and the solvent reused.

Biotreatment is the aerobic or anaerobic chemical breakdown of organic chemicals by microorganisms. Removal of organics via biodegradation is highly dependent on whether the compound is biodegradable, its volatility, and its ability to be adsorbed onto solids. Removal efficiencies range from almost zero to 100 percent. In general, highly volatile compounds, such as chlorinated hydrocarbons and aromatics, will biodegrade very little because of their high volatility, while alcohols and other compounds soluble in water and low volatility compounds can be almost totally biodegraded in an acclimated system. In an acclimated biotreatment system, the microorganisms easily convert available organics into biological cells, or biomass. This often requires a mixed culture of organisms, where each organism utilizes the food source most suitable to its metabolism. If a system is not acclimated, i.e., the organisms cannot metabolize the available food source, the organisms will starve and the organics will not be biodegraded.

4.13.4 Glossary of Terms

Basin - an earthen or concrete-lined depression used to hold liquid.

Completely mixed - having the same characteristics and quality throughout or at all times.

Disposal - the act of permanent storage. Flow of liquid into, but not leaving, a device.

Drain - a device used for the collection of liquid. This device may be open to the atmosphere or equipped with a seal to prevent emissions of vapors.

Flowthrough - having a continuous flow into and leaving a device.

Plug flow - characteristics and quality are not uniform throughout. These will change in the direction the fluid flows, but not perpendicular to the direction of flow (i.e., no axial movement)

Storage - any device that can accept and retain a fluid for the purpose of future discharge. Discontinuity of flow of liquid into and leaving a device.

Treatment - the act of improving fluid properties by physical means. The removal of undesirable impurities from a fluid.

VOC - Volatile Organic Compounds (VOCs) refers to all organic compounds except the following compounds that have been shown not to be photochemically reactive: methane, ethane, trichlorotrifluoroethane, methylene chloride, 1,1,1,-trichloroethane, trichlorofluoromethane, dichlorodifluoromethane, chlorodifluoromethane, trifluoromethane, dichlorotetrafluoroethane, and chloropentafluoroethane. (See 45 FR 48941, July 22, 1980.)

References for Section 4.13

1. Hazardous Waste Treatment, Storage, and Disposal Facilities (TSDF) - Air Emission Models. U. S. EPA, Office of Air Quality and Standards, Research Triangle Park, NC, 27711. EPA - 450/3-87-026, Draft. April 1989.

2. Wastewater Treatment Compound Property Processor Air Emissions Estimator (WATER7). U. S. Environmental Protection Agency, Office of Air Quality and Standards, Research Triangle Park, NC, 27711. November 1990.

3. Evaluation of Test Method for Measuring Biodegradation Rates of Volatile Organics. U.S. EPA, Emissions Measurement Branch, Research Triangle Park, NC, 27711. Contract No. 68D90055. Draft Final Report. September 1989.

4. Industrial Wastewater Volatile Organic Compound Emissions--Background Information for BACT/LAER Determinations. Revised Draft. U.S. EPA. January 1990.

5. Docket for NESHAP for Benzene Waste Operations. Docket No. A-89-06, Docket Item IV-B-5, Feb. 19 1990.

6. Nyer, Evan K. Ground Water Treatment Technology, Van Nostrand Reinhold Company, New York, NY,1985. (ISBN 0-442-26706-1)

C.9.6
p.64

3. Evaluation of Test Method for Measuring Biodegradation Rates of Volatile Organics. U.S. EPA, Emissions Measurement Branch, Research Triangle Park, NC, 27711. Contract No. 68D90055. Draft Final Report. September 1989.

4. Industrial Wastewater Volatile Organic Compound Emissions -- Background Information for BACT/LAER Determinations. Revised Draft. U.S. EPA. January 1990.

5. Nyer, Evan K. Ground Water Treatment Technology, Van Nostrand Reinhold Company, New York, NY, 1985. (ISBN 0-442-26706-1)

C, 9, a
p. 65

ATTACHMENT 1

SIMS Chemical Property Data File

C, 9, a
p, 66

SIMS PHASE IV
CHEMICAL PROPERTY DATA FILE

CHEMICAL NAME	CAS NUMBER	MOLE WT	VAPOR PRESSURE AT 25 C (mm Hg)	HENRY'S LAW CONSTANT AT 25 (atm-m3/mol)	DIFFUSIVITY OF CHEM IN WATER AT 25 (cm2/s)	DIFFUSIVITY OF CHEM IN AIR AT 25 (cm2/s)	ANTOINE EQ VP COEFF A	ANTOINE EQ VP COEFF B	ANTOINE EQ VP COEFF C	MAX BIODEGRADE RATE CONSTANT (g/g biomass-s)	HALF SATURATE CONSTANT (g/m3)	OCTANOL-WATER PART COEFF AT 25 C
ACETALDEHYDE	75-07-0	44.00	760	.000095	.0000141	.124	8.005	1600.017	291.809	.0000228944	419.0542	2.69153
ACETIC ACID	64-19-7	60.05	15.4	.0627	.000012	.113	7.387	1533.313	222.309	.0000038889	14.2857	.48978
ACETIC ANHYDRIDE	108-24-7	102.09	5.29	.00000591	.00000933	.235	7.149	1444.718	199.817	.0000026944	1.9323	1
ACETONE	67-64-1	58.00	266	.000025	.0000114	.124	7.117	1210.595	229.664	.0000003611	1.1304	.57544
ACETONITRILE	75-05-8	41.03	90	.0000058	.0000166	.128	7.119	1314.4	230	.00000425	152.6014	.45709
ACROLEIN	107-02-8	56.10	244.2	.0000566	.0000122	.105	2.39	0	0	.0000021667	22.9412	.81283
ACRYLAMIDE	79-06-1	71.09	.012	.00000000052	.0000106	.097	11.2932	3939.877	273.16	.00000425	56.2388	6.32182
ACRYLIC ACID	79-10-7	72.10	5.2	.0000001	.0000106	.098	5.652	648.629	154.683	.0000026944	54.7819	2.04174
ACRYLONITRILE	107-13-1	53.10	114	.000088	.0000134	.122	7.038	1232.53	222.47	.000005	24	.12023
ADIPIC ACID	124-04-9	146.14	.0000225	.00000000005	.00000684	.0659	0	0	0	.0000026944	66.9943	1.20226
ALLYL ALCOHOL	107-18-6	58.10	23.3	.000018	.0000114	.114	0	0	0	.0000048872	3.9241	1.47911
AMINOPHENOL(-O)	95-55-6	109.12	.511	.00000367	.00000864	.0774	0	0	0	.00000425	68.1356	3.81533
AMINOPHENOL(-P)	123-30-8	109.12	.893	.0000197	.00000239	.0774	-3.357	699.157	-331.343	.00000425	68.1356	3.81533
AMMONIA	7664-41-7	17.03	7470	.000328	.0000693	.259	7.5547	1002.711	247.885	.00000425	15.3	1
AMYL ACETATE(-N)	628-37-8	130.18	5.42	.000464	.0000012	.064	0	0	0	.0000026944	16.1142	51.10801
ANILINE	62-53-3	93.10	1	.0000026	.0000083	.07	7.32	1731.515	206.049	.0000019722	.3381	7.94328
BENZENE	71-43-2	78.10	95.2	.0055	.0000098	.088	6.905	1211.033	220.79	.0000052778	13.5714	141.25375
BENZO(A)ANTHRACENE	56-55-3	228.30	.00000015	.00000000138	.000009	.051	6.9824	2426.6	156.6	.0000086389	1.7006	407380.2778
BENZO(A)PYRENE	50-32-8	252.30	.00568	.00000000138	.000009	.043	9.2455	3724.363	273.16	.0000086389	1.2303	954992.58602
BENZYL CHLORIDE	100-44-7	126.60	1.21	.000433	.0000078	.075	0	0	0	.0000049306	17.5674	199.52623
BIS(2-CHLOROETHYL)ETHER	111-44-4	143.00	1.4	.000013	.0000075	.0692	0	0	0	.0000029889	20.0021	38.01894
BIS(2-CHLOROISOPROPYL)ETHER	39638-32-9	171.10	.85	.00011	.00000641	.0602	0	0	0	.0000029889	8.3382	380.1894
BIS(2-ETHYLHEXYL)PHTHALATE	117-81-7	390.68	.0000002	.0000003	.0000037	.0351	0	0	0	.0000002139	2.2	199526.2315
BROMOFORM	75-25-2	252.77	5.6	.000584	.0000101	.082	0	0	0	.0000029889	10.653	199.52623
BROMOMETHANE	74-83-9	94.95	1250	.221	.0000146	.114	0	0	0	.0000029889	30.4422	12.58925
BUTADIENE-(1,3)	106-99-0	54.09	2100	.142	.0000108	.249	6.849	930.546	238.854	.0000042534	15.3	74.32347
BUTANOL (ISO)	78-83-1	74.12	10	.0000022	.0000093	.086	7.4743	1314.19	186.55	.0000021667	70.9091	5.62341
BUTANOL-(1)	71-36-3	74.12	6.5	.0000089	.0000093	.08	7.4768	1362.39	178.77	.0000021667	70.9091	5.62341
BUTYL BENZYL PHTHALATE	85-68-7	312.39	.0000086	.0108	.0000048	.0458	0	0	0	.0000086389	14.1364	60255.95861
CARBON DISULFIDE	75-15-0	76.10	366	.0168	.00001	.104	6.942	1169.11	241.59	.0000042534	5.8175	1
CARBON TETRACHLORIDE	56-23-5	153.80	113	.03	.0000088	.078	6.934	1242.43	230	.0000004167	1	524.80746

C19,a
p.67

SIMS PHASE IV
CHEMICAL PROPERTY DATA FILE

CHEMICAL NAME	CAS NUMBER	MOLE WT	VAPOR PRESSURE AT 25 C (mm Hg)	HENRY'S LAW CONSTANT AT 25 (atm-m3/mol)	DIFFUSIVITY OF CHEM IN WATER AT 25 (cm2/s)	DIFFUSIVITY OF CHEM IN AIR AT 25 (cm2/s)	ANTOINE EQ VP COEFF A	ANTOINE EQ VP COEFF B	ANTOINE EQ VP COEFF C	MAX BIODEGRADE RATE CONSTANT (g/g biomass-s)	HALF SATURATE CONSTANT (g/m3)	OCTANOL-WATER PART COEFF AT 25 C
CHLORO(-P)CRESOL(-M)	59-50-7	142.60	.0035	.000000164	.0000076	.0709	0	0	0	.0000029889	5.2902	1258.92541
CHLOROACETALDEHYDE	107-20-0	78.50	60	.000026	.0000115	.099	0	0	0	.0000029889	49.838	3.4405
CHLOROBENZENE	108-90-7	112.60	11.8	.00393	.0000087	.073	6.978	1431.05	217.55	.0000001083	.039	316.22777
CHLOROFORM	67-66-3	119.40	208	.00339	.00001	.104	6.493	929.44	196.03	.0000008167	3.7215	91.20108
CHLORONAPHTHALENE-(2)	91-58-7	162.51	.017	.018	.0000074	.0653	0	0	0	.0000029889	2.167	13182.56739
CHLOROPRENE	126-99-8	88.50	273	.331	.00001	.104	6.161	783.45	179.7	.0000029968	6.3412	1
CRESOL(-M)	108-39-4	108.10	.08	.000000443	.00001	.074	7.508	1856.36	199.07	.0000064472	1.3653	93.32543
CRESOL(-O)	95-48-7	108.10	.24	.0000026	.0000083	.074	6.911	1435.5	165.16	.0000063278	1.34	95.49926
CRESOL(-P)	106-44-5	108.10	.11	.000000443	.00001	.074	7.035	1511.08	161.85	.0000064472	1.3653	87.09636
(RESYLIC ACID	1319-77-3	108.00	.3	.0000017	.0000083	.074	0	0	0	.0000041667	15	1
CROTONALDEHYDE	4170-30-0	70.09	30	.0000154	.0000102	.0903	0	0	0	.0000026944	27.6285	12.36833
CUMENE (ISOPROPYLBENZENE)	98-82-8	120.20	4.6	.0146	.0000071	.065	6.963	1460.793	207.78	.0000086458	16.5426	1
CYCLOHEXANE	110-82-7	84.20	100	.0137	.0000091	.0839	6.841	1201.53	222.65	.0000042534	15.3	338.0687
CYCLOHEXANOL	108-93-0	100.20	1.22	.00000447	.00000831	.214	6.255	912.87	109.13	.0000026944	18.0816	37.74314
CYCLOHEXANONE	108-94-1	98.20	4.8	.00000413	.00000862	.0784	7.8492	2137.192	273.16	.0000031917	41.8921	6.45654
DI-N-OCTYL PHTHALATE	117-84-0	390.62	0	.137	.0000041	.0409	0	0	0	.000000083	.02	141253.7
DIBUTYLPHTHALATE	84-74-2	278.30	.00001	.0000028	.0000079	.0438	6.639	1744.2	113.59	.0000001111	.4	158489.31925
DICHLORO(-2)BUTENE(1,4)	764-41-0	125.00	2.87	.000259	.00000812	.0725	0	0	0	.0000029889	9.8973	242.1542
DICHLOROBENZENE(1,2) (-O)	95-50-1	147.00	1.5	.00194	.0000079	.069	.176	0	0	.0000006944	4.3103	2398.83292
DICHLOROBENZENE(1,3) (-M)	541-73-1	147.00	2.28	.00361	.0000079	.069	0	0	0	.0000017778	2.7826	2398.83292
DICHLOROBENZENE(1,4) (-P)	106-46-7	147.00	1.2	.0016	.0000079	.069	.079	0	0	.0000017778	2.7826	2454.70892
DICHLORODIFLUOROMETHANE	75-71-8	120.92	5000	.401	.00001	.0001	0	0	0	.0000029889	12.0413	144.54398
DICHLOROETHANE(1,1)	75-34-3	99.00	234	.00554	.0000105	.0914	0	0	0	.0000029889	4.6783	61.6595
DICHLOROETHANE(1,2)	107-06-2	99.00	80	.0012	.0000099	.104	7.025	1272.3	222.9	.0000005833	2.1429	61.6595
DICHLOROETHYLENE(1,2)	156-54-2	96.94	200	.0319	.000011	.0935	6.965	1141.9	231.9	.0000029889	6.3294	1
DICHLOROPHENOL(2,4)	120-83-2	163.01	.1	.0000048	.0000076	.0709	0	0	0	.0000069444	7.5758	562.34133
DICHLOROPHENOXYACETIC ACID(2,4)	94-75-7	221.00	290	.0621	.00000649	.0588	0	0	0	.0000029889	14.8934	82.61445
DICHLOROPROPANE(1,2)	78-87-5	112.99	40	.0023	.0000087	.0782	6.98	1380.1	22.8	.0000047222	12.1429	1
DIETHYL (N,N) ANILIN	91-66-7	149.23	.00283	.000000574	.00000587	.0513	7.466	1993.57	218.5	.00000425	27.0047	43.57596
DIETHYL PHTHALATE	84-66-2	222.00	.003589	.0111	.0000058	.0542	0	0	0	.000000753	1.28	1412.537
DIMETHYL FORMAMIDE	68-12-2	73.09	4	.0000192	.0000103	.0939	6.928	1400.87	196.43	.00000425	15.3	1

C.9.a
p.68

SIMS PHASE IV
CHEMICAL PROPERTY DATA FILE

CHEMICAL NAME	CAS NUMBER	MOLE WT	VAPOR PRESSURE AT 25 C (mm Hg)	HENRY'S LAW CONSTANT AT 25 (atm-m3/mol)	DIFFUSIVITY OF CHEM IN WATER AT 25 (cm2/s)	DIFFUSIVITY OF CHEM IN AIR AT 25 (cm2/s)	ANTOINE EQ VP COEFF A	ANTOINE EQ VP COEFF B	ANTOINE EQ VP COEFF C	MAX BIODEGRADE RATE CONSTANT (g/g biomass-s)	HALF SATURATE CONSTANT (g/m3)	OCTANOL-WATER PART COEFF AT 25 C
DIMETHYL HYDRAZINE(1,1)	57-14-7	60.10	157	.000124	.0000109	.106	7.408	1305.91	225.53	.00000425	15.3	1
DIMETHYL PHTHALATE	131-11-3	194.20	.000187	.00000215	.0000063	.0568	4.522	700.31	51.42	.0000006111	.7097	74.13102
DIMETHYLBENZ(A)ANTHRACENE	57-97-6	256.33	0	.0000000027	.00000498	.0461	0	0	0	.0000086389	.3377	28680056.33087
DIMETHYLPHENOL(2,4)	105-67-9	122.16	.0573	.000921	.0000084	.0712	0	0	0	.0000029722	2.2766	263.0268
DINITROBENZENE (-M)	99-65-0	168.10	.05	.000022	.00000764	.279	4.337	229.2	-137	.00000425	29.9146	33.28818
DINITROTOLUENE(2,4)	121-14-2	182.10	.0051	.00000407	.00000706	.203	5.798	1118	61.8	.00000425	19.5233	102.3293
DIOXANE(1,4)	123-91-1	88.20	37	.0000231	.0000102	.229	7.431	1554.68	240.34	.0000026944	24.7001	16.60956
DIOXIN	NOCAS2	322.00	0	.0000812	.0000056	.104	12.88	6465.5	273	.0000029968	6.3412	1
DIPHENYLAMINE	122-39-4	169.20	.00375	.00000278	.00000631	.058	0	0	0	.0000052778	8.4103	1659.58691
EPICHLOROHYDRIN	106-89-8	92.50	17	.0000323	.0000098	.086	8.2294	2086.816	273.16	.0000029968	6.3412	1.07152
ETHANOL	64-17-5	46.10	50	.0000303	.000013	.123	8.321	1718.21	237.52	.0000024444	9.7778	.47863
ETHANOLAMINE(MONO-)	141-43-5	61.09	.4	.000000322	.0000114	.107	7.456	1577.67	173.37	.00000425	223.0321	.16865
ETHYL ACRYLATE	140-88-5	100.00	40	.00035	.0000086	.077	7.9645	1897.011	273.16	.0000026944	39.4119	4.85667
ETHYL CHLORIDE	75-00-3	64.52	1200	.014	.0000115	.271	6.986	1030.01	238.61	.0000029889	22.8074	26.91535
ETHYL-(2)PROPYL-(3) ACROLEIN	645-62-5	92.50	17	.0000323	.0000098	.086	0	0	0	.00000425	15.3	1
ETHYLACETATE	141-78-6	88.10	100	.000128	.00000966	.0732	7.101	1244.95	217.88	.0000048833	17.58	1
ETHYLBENZENE	100-41-4	106.20	10	.00644	.0000078	.075	6.975	1424.255	213.21	.0000018889	3.2381	1412.53754
ETHYLENEOXIDE	75-21-8	44.00	1250	.000142	.0000145	.104	7.128	1054.54	237.76	.0000011667	4.6154	.50003
ETHYLETHER	60-29-7	74.10	520	.00068	.0000093	.074	6.92	1064.07	228.8	.0000026944	17.1206	43.57596
FORMALDEHYDE	50-00-0	30.00	3500	.0000576	.0000198	.178	7.195	970.6	244.1	.0000013889	20	87.09636
FORMIC ACID	64-18-6	46.00	42	.0000007	.00000137	.079	7.581	1699.2	260.7	.0000026944	161.3977	.1191
FREONS	NOCAS3	120.92	5000	.401	.00001	.104	0	0	0	.0000029968	6.3412	1
FURAN	110-00-9	68.08	596	.00534	.0000122	.104	6.975	1060.87	227.74	.0000026944	14.1936	71.37186
FURFURAL	96-01-1	96.09	2	.0000811	.0000104	.0872	6.575	1198.7	162.8	.0000026944	18.0602	37.86047
HEPTANE (ISO)	142-82-5	100.21	66	1.836	.00000711	.187	6.8994	1331.53	212.41	.0000042534	15.3	1453.372
HEXACHLOROBENZENE	118-74-1	284.80	1	.00068	.00000591	.0542	0	0	0	.0000029889	.6651	295120.92267
HEXACHLOROBUTADIENE	87-68-3	260.80	.15	.0256	.0000062	.0561	-.824	0	0	.000003	6.3412	5495.408
HEXACHLOROCYCLOPENTADIENE	77-47-4	272.80	.081	.016	.00000616	.0561	0	0	0	.0000029968	.3412	9772.372
HEXACHLOROETHANE	67-72-1	237.00	.65	.0000249	.0000068	.00249	0	0	0	.0000029889	3.3876	4068.32838
HEXANE(-N)	100-54-3	86.20	150	.122	.00000777	.2	6.876	1171.17	224.41	.0000042534	15.3	534.0845
HEXANOL(-1)	111-27-3	102.18	.812	.0000182	.00000753	.059	7.86	1761.26	196.66	.0000026944	15.2068	59.52851

C.9.a
p.69

SIMS PHASE IV
CHEMICAL PROPERTY DATA FILE

CHEMICAL NAME	CAS NUMBER	MOLE WT	VAPOR PRESSURE AT 25 C (mm Hg)	HENRY'S LAW CONSTANT AT 25 (atm-m3/mol)	DIFFUSIVITY OF CHEM IN WATER AT 25 (cm2/s)	DIFFUSIVITY OF CHEM IN AIR AT 25 (cm2/s)	ANTOINE EQ VP COEFF A	ANTOINE EQ VP COEFF B	ANTOINE EQ VP COEFF C	MAX BIODEGRADE RATE CONSTANT (g/g biomass-s)	HALF SATURATE CONSTANT (g/m3)	OCTANOL-WATER PART COEFF AT 25 C
HYDROCYANIC ACID	74-90-8	27.00	726	.000000465	.0000182	.197	7.528	1329.5	260.4	.0000026944	1.9323	1
HYDROFLUORIC ACID	7664-39-3	20.00	900	.000237	.000033	.388	7.217	1268.37	273.87	.0000026944	1.9323	1
HYDROGEN SULFIDE	7783-06-4	34.10	15200	.023	.0000161	.176	7.614	885.319	250.25	.0000029889	6.3294	1
ISOPHORONE	78-59-1	138.21	.439	.00000576	.00000676	.0623	0	0	0	.00000425	25.6067	50.11872
METHANOL	67-56-1	32.00	114	.0000027	.0000164	.15	7.897	1474.08	229.13	.000005	90	.19953
METHYL ACETATE	79-20-9	74.10	235	.000102	.00001	.104	7.065	1157.63	219.73	.0000055194	159.2466	.81283
METHYL CHLORIDE	74-87-3	50.50	3830	.00814	.0000065	.126	7.093	948.58	249.34	.0000029889	14.855	83.17638
METHYL ETHYL KETONE	78-93-3	72.10	100	.0000435	.0000098	.0808	6.9742	1209.6	216	.0000005556	10	1.90546
METHYL ISOBUTYL KETONE	108-10-1	100.20	15.7	.0000495	.0000078	.075	6.672	1168.4	191.9	.0000002056	1.6383	23.98833
METHYL METHACRYLATE	80-62-6	100.10	39	.000066	.0000086	.077	8.409	2050.5	274.4	.0000026944	109.2342	.33221
METHYL STYRENE (ALPHA)	98-83-9	118.00	.076	.00591	.0000114	.264	6.923	1486.88	202.4	.000008639	11.12438	2907.589
METHYLENE CHLORIDE	75-09-2	85.00	438	.00319	.0000117	.101	7.409	1325.9	252.6	.0000061111	54.5762	17.78279
MORPHOLINE	110-91-8	87.12	10	.0000573	.0000096	.091	7.7181	1745.8	235	.00000425	291.9847	.08318
NAPHTHALENE	91-20-3	128.20	.23	.00118	.0000075	.059	7.01	1733.71	201.86	.0000117972	42.47	1
NITROANILINE(-O)	88-74-4	138.14	.003	.0000005	.000008	.073	8.868	336.5	273.16	.00000425	22.8535	67.6083
NITROBENZENE	98-95-3	123.10	.3	.0000131	.0000086	.076	7.115	1746.6	201.8	.0000030556	4.7826	69.1831
PENTACHLOROBENZENE	608-93-5	250.34	.0046	.0073	.0000063	.057	0	0	0	.0000029889	.4307	925887.02902
PENTACHLOROETHANE	76-01-7	202.30	4.4	.021	.0000073	.066	6.74	1378	197	.0000029889	.4307	925887.02902
PENTACHLOROPHENOL	87-86-5	266.40	.00099	.0000028	.0000061	.056	0	0	0	.0000361111	38.2353	102329.29923
PHENOL	108-95-2	94.10	.34	.000000454	.0000091	.082	7.133	1516.79	174.95	.0000269444	7.4615	28.84032
PHOSGENE	75-44-5	98.92	1390	.171	.00000112	.108	6.842	941.25	230	.00000425	70.8664	3.4405
PHTHALIC ACID	100-21-0	166.14	121	.0132	.0000068	.064	0	0	0	.0000026944	34.983	6.64623
PHTHALIC ANHYDRIDE	85-44-9	148.10	.0015	.0000009	.0000086	.071	8.022	2868.5	273.16	.0000048872	3.9241	.23988
PICOLINE(-2)	108-99-6	93.12	10.4	.000127	.0000096	.075	7.032	1415.73	211.63	.00000425	44.8286	11.48154
POLYCHLORINATED BIPHENYLS	1336-36-3	290.00	.00185	.0004	.00001	.104	0	0	0	.000005278	20	1
PROPANOL (ISO)	71-23-8	60.09	42.8	.00015	.0000104	.098	8.117	1580.92	219.61	.0000041667	200	.69183
PROPIONALDEHYDE	123-38-6	58.08	300	.00115	.0000114	.102	16.2315	2659.02	-44.15	.0000026944	39.2284	4.91668
PROPYLENE GLYCOL	57-55-6	76.11	.3	.0000015	.0000102	.093	8.2082	2085.9	203.5396	.0000026944	109.3574	.33141
PROPYLENE OXIDE	75-66-9	58.10	525	.00134	.00001	.104	8.2768	1656.884	273.16	.0000048872	3.9241	1
PYRIDINE	110-86-1	79.10	20	.0000236	.0000076	.091	7.041	1373.8	214.98	.0000097306	146.9139	4.46684
RESORCINOL	108-46-3	110.11	.00026	.0000000188	.0000087	.078	6.9243	1884.547	186.0596	.0000026944	35.6809	6.30957

C.9.a
p.70

SIMS PHASE IV
CHEMICAL PROPERTY DATA FILE

CHEMICAL NAME	CAS NUMBER	MOLE WT	VAPOR PRESSURE AT 25 C (mm Hg)	HENRY'S LAW CONSTANT AT 25 (atm-m3/mol)	DIFFUSIVITY OF CHEM IN WATER AT 25 (cm2/s)	DIFFUSIVITY OF CHEM IN AIR AT 25 (cm2/s)	ANTOINE EQ VP COEFF A	ANTOINE EQ VP COEFF B	ANTOINE EQ VP COEFF C	MAX BIODEGRADE RATE CONSTANT (g/g biomass-s)	HALF SATURATE CONSTANT (g/m3)	OCTANOL-WATER PART COEFF AT 25 C
STYRENE	100-42-5	104.20	7.3	.00261	.000008	.071	7.14	1574.51	224.09	.0000086389	282.7273	1445.43977
TETRACHLOROETHANE(1,1,1,2)	630-20-6	167.85	6.5	.002	.0000079	.071	6.898	1365.88	209.74	.0000029889	6.3294	1
TETRACHLOROETHANE(1,1,2,2)	79-34-5	167.85	6.5	.00038	.0000079	.071	6.631	1228.1	179.9	.0000017222	9.1176	363.07805
TETRACHLOROETHYLENE	127-18-4	165.83	19	.029	.0000082	.072	6.98	1386.92	217.53	.0000017222	9.1176	398.10717
TETRAHYDROFURAN	109-99-9	72.12	72.1	.000049	.0000105	.098	6.995	1202.29	226.25	.0000026944	20.3702	27.58221
TOLUENE	109-88-3	92.40	30	.00668	.0000086	.087	6.954	1344.8	219.48	.0000204111	30.6167	489.77882
TOLUENE DIISOCYANATE(2,4)	584-84-9	174.16	.08	.0000083	.0000062	.061	0	0	0	.00000425	15.3	1
TRICHLORO(1,1,2)TRIFLUOROETHANE	76-13-1	187.38	300	.435	.0000082	.078	6.88	1099.9	227.5	.0000029889	3.3876	4068.32838
TRICHLOROBENZENE(1,2,4)	120-82-1	181.50	.18	.00142	.0000077	.0676	0	0	0	.0000029889	2.4495	9549.92586
TRICHLOROBUTANE(1,2,3)	NOCAS5	161.46	4.39	4.66	.0000072	.066	0	0	0	.0000029968	6.3412	1450901.06626
TRICHLOROETHANE(1,1,1)	71-55-6	133.40	123	.00492	.0000088	.078	8.643	2136.6	302.8	.0000009722	4.7297	309.02954
TRICHLOROETHANE(1,1,2)	79-00-5	133.40	25	.000742	.0000088	.078	6.951	1314.41	209.2	.0000009722	4.7297	1
TRICHLOROETHYLENE	79-01-6	131.40	75	.0091	.0000091	.079	6.518	1018.6	192.7	.0000010833	4.4318	194.98446
TRICHLOROFLUOROMETHANE	75-69-4	137.40	796	.0583	.0000097	.087	6.884	1043.004	236.88	.000003	6.3412	338.8441
TRICHLOROPHENOL(2,4,6)	88-06-2	197.46	.0073	.0000177	.0000075	.0661	0	0	0	.00000425	58.8462	4897.78819
TRICHLOROPROPANE(1,1,1)	NOCAS6	147.43	3.1	.029	.0000079	.071	0	0	0	.0000029889	10.7719	193.7827
TRICHLOROPROPANE(1,2,3)	96-18-4	147.43	3	.028	.0000079	.071	6.903	788.2	243.23	.0000029889	10.7719	193.7827
UREA	57-13-6	60.06	6.69	.000264	.0000137	.122	0	0	0	.00000425	4.8169	4068.32838
VINYL ACETATE	108-05-4	86.09	115	.00062	.0000092	.085	7.21	1296.13	226.66	.0000026944	31.8363	8.51722
VINYL CHLORIDE	75-01-4	62.50	2660	.086	.0000123	.106	3.425	0	0	.000003	6.3412	1.14815
VINYLIDENE CHLORIDE	75-35-4	97.00	591	.015	.0000104	.09	6.972	1099.4	237.2	.0000029968	6.3412	1
XYLENE(-M)	1330-20-7	106.17	8	.0052	.0000078	.07	7.009	1426.266	215.11	.0000086389	14.0094	1584.89319
XYLENE(-O)	95-47-6	106.17	7	.00527	.00001	.087	6.998	1474.679	213.69	.0000113306	22.8569	891.25094

C.9.a
p.71

5.9.2 Emissions and Controls[1]

Emissions from nitric acid manufacture consist primarily of nitric oxide, nitrogen dioxide (which accounts for visible emissions) and trace amounts of nitric acid mist. By far, the major source of nitrogen oxides is the tail gas from the acid absorption tower (Table 5.9-1). In general, the quantity of NO_x emissions is directly related to the kinetics of the nitric acid formation reaction and absorption tower design.

The two most common techniques used to control absorption tower tail gas emissions are extended absorption and catalytic reduction. The extended absorption technique reduces emissions by increasing the efficiency of the absorption tower. This efficiency increase is achieved by increasing the number of absorber trays, operating the absorber at higher pressures, or cooling the weak acid liquid in the absorber.

In the catalytic reduction process (often termed catalytic oxidation), tail gases are heated to ignition temperature, mixed with fuel (natural gas, hydrogen, carbon monoxide or ammonia) and passed over a catalyst. In the presence of the catalyst, the fuels are oxidized, and the nitrogen oxides are reduced to N_2. The extent of reduction of NO_2 andNO to N_2 is a function of plant design, fuel type operating temperature and pressure, space velocity through the reduction catalytic reactor, type of catalyst, and reactant concentration. See Table 5.9-1.

Two seldom used alternative control devices for absorber tail gas are molecular sieves and wet scrubbers. In the molecular sieve technique, tail gas is contacted with an active molecular sieve which catalyticly oxidizes NO to NO_2 and selectively adsorbs the NO_2. The NO_2 is then thermally stripped from the molecular sieve and returned to the absorber. In the scrubbing technique, absorber tail gas is scrubbed with an aqueous solution of alkali hydroxides or carbonates, ammonia, urea or potassium permanganate. The NO and NO_2 are absorbed and recovered as nitrate or nitrite salts.

Comparatively small amounts of nitrogen oxides are also lost from acid concentrating plants. These losses (mostly NO_2) are from the condenser system, but the emissions are small enough to be controlled easily by inexpensive absorbers.

Acid mist emissions do not occur from the tail gas of a properly operated plant. The small amounts that may be present in the absorber exit gas streams are removed by a separator or collector prior to entering the catalytic reduction unit or expander.

Emissions from acid storage tanks may occur during tank filling. The displaced gases are equal in volume to the quantity of acid added to the tanks.

Nitrogen oxide emissions (expressed as NO_2) are presented for weak nitric acid plants in Table 5.9-1. The emission factors vary considerably with the type of control employed and with process conditions. For comparison purposes, the EPA New Source Performance Standard for both new and modified plants is 3.0 pounds per ton (1.5 kg/MT) of 100 percent acid produced, maximum 3 hour average, expressed as NO_2.

References for Section 5.9

1. Control of Air Pollution from Nitric Acid Plants, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, NC, August 1971. Unpublished.

2. Atmospheric Emissions from Nitric Acid Manufacturing Processes, 999-AP-27, U. S. Department of Health, Education and Welfare, Cincinnati, OH, 1966.

3. Marvin Drabkin, A Review of Standards of Performance for New Stationary Sources - Nitric Acid Plants, EPA-450/3-79-013, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1979.

C.9.a
P.72

4. "Standards of Performance for Nitric Acid Plants", 40 CFR 60. G.

C.9.6
p.73

6.18.2 Emissions and Controls

Ammonium sulfate particulate is the principal pollutant emitted to the atmosphere from the manufacturing plants, nearly all of it being contained in the gaseous exhaust of the dryers. Other plant processes, such as evaporation, screening, and materials handling, are not significant sources of emissions.

The particulate emission rate of a dryer depends on the gas velocity and the particle size distribution. Since gas velocity varies according to the dryer type, emission rates also vary. Generally, the gas velocity of fluidized bed dryers is higher than for most rotary drum dryers, and particulate emission rates are also higher. The smaller the particle, the easier it is removed by the gas stream of either type of dryer.

At caprolactam byproduct plants, volatile organic compounds (VOC) are emitted from the dryers. Emissions of caprolactam vapor are at least two orders of magnitude lower than the particulate emissions.

Wet scrubbers, such as venturi and centrifuge, are most suitable for reducing particulate emissions from the dryers. Wet scrubbers use process streams as the scrubbing liquid. This allows the collected particulate to be recycled easily to the production system.

Table 6.18-1 shows the uncontrolled and controlled emission factors for the various dryer types. The VOC emissions shown in Table 6.18-1 apply only to caprolactam byproduct plants which may use either a fluidized bed or rotary drum dryer.

TABLE 6.18-1. EMISSION FACTORS FOR AMMONIUM SULFATE MANUFACTURE[a]

EMISSION FACTOR RATING: B

	Particulates		Volatile Organic Compounds[b]	
Dryer Type and Controls	kg/Mg	lb/ton	kg/Mg	lb/ton
Rotary dryers				
Uncontrolled	23	46	0.74	1.48
Wet scrubber	0.12	0.24	0.11	0.22
Fluidized bed dryers				
Uncontrolled	109	218	0.74	1.48
Wet scrubber	0.14	0.28	0.11	0.22

[a] Reference 1. Expressed as emissions by weight per unit of ammonium sulfate production by weight.
[b] VOC emissions occur only at caprolactam plants using either type of dryer. The emissions are caprolactam vapor.

C, 9, a
p, 74

from the furnace, and is directed through separate runners to a slag pit adjacent to the casthouse, or into slag pots for transport to a remote slag pit. At the conclusion of the cast, the taphole is replugged with clay. The area around the base of the furnace, including all iron and slag runners, is enclosed by a casthouse. The blast furnace byproduct gas, which is collected from the furnace top, contains carbon monoxide and particulate. Because of its high carbon monoxide content, this blast furnace gas has a low heating value, about 2790 to 3350 joules per liter (75 to 90 BTU/ft^3) and is used as a fuel within the steel plant. Before it can be efficiently oxidized, however, the gas must be cleaned of particulate. Initially, the gases pass through a settling chamber or dry cyclone to remove about 60 percent of the particulate. Next, the gases undergo a one or two stage cleaning operation. The primary cleaner is normally a wet scrubber, which removes about 90 percent of the remaining particulate. The secondary cleaner is a high energy wet scrubber (usually a venturi) or an electrostatic precipitator, either of which can remove up to 90 percent of the particulate that eludes the primary cleaner. Together these control devices provide a clean fuel of less than 0.05 grams per cubic meter (0.02 gr/ft^3). A portion of this gas is fired in the blast furnace stoves to preheat the blast air, and the rest is used in other plant operations.

7.5.1.3 Iron Preparation Hot Metal Desulfurization - Sulfur in the molten iron is sometimes reduced before charging into the steelmaking furnace by adding reagents. The reaction forms a floating slag which can be skimmed off. Desulfurization may be performed in the hot metal transfer (torpedo) car at a location between the blast furnace and basic oxygen furnace (BOF), or it may be done in the hot metal transfer (torpedo) ladle at a station inside the BOF shop.

The most common reagents are powdered calcium carbide (CaC_2) and calcium carbonate ($CaCO_3$) or salt coated magnesium granules. Powdered reagents are injected into the metal through a lance with high pressure nitrogen. The process duration varies with the injection rate, hot metal chemistry, and desired final sulfur content, and is in the range of 5 to 30 minutes.

7.5.1.4 Steelmaking Process - Basic Oxygen Furnaces - In the basic oxygen process (BOP), molten iron from a blast furnace and iron scrap are refined in a furnace by lancing (or injecting) high purity oxygen. The input material is typically 70 percent molten metal and 30 percent scrap metal. The oxygen reacts with carbon and other impurities to remove them from the metal. The reactions are exothermic, i.e., no external heat source is necessary to melt the scrap and to raise the temperature of the metal to the desired range for tapping. The large quantities of carbon monoxide (CO) produced by the reactions in the BOF can be controlled by combustion at the mouth of the furnace and then vented to gas cleaning devices, as with open hoods, or combustion can be suppressed at the furnace mouth, as with closed hoods. BOP steelmaking is conducted in large (up to 400 ton capacity) refractory lined pear shaped furnaces. There are two major variations of the process. Conventional BOFs have oxygen blown into the top of the furnace through a water cooled lance. In the newer, Quelle Basic Oxygen process (Q-BOP), oxygen is injected through tuyeres located in the bottom of the furnace. A typical BOF cycle consists of the scrap charge, hot metal charge, oxygen blow (refining) period, testing for temperature and

C.9.w
1.75

TABLE 9.1-1. EMISSION FACTORS FOR PETROLEUM REFINERIES

Process	Particulates	Sulfur oxides (as SO_2)	Carbon monoxide	Total hydrocarbons	Nitrogen oxides (as NO_2)	Aldehydes	Ammonia	Emission factor rating
Boilers and process heaters								
Fuel Oil				See Section 1.3 - Fuel Oil Combustion				
Natural Gas				See Section 1.4 - Natural Gas Combustion				
Liquefied Petroleum Gas (LPG)				See Section 1.5 - Liquefied Petroleum Gas Combustion				
Fluid catalytic cracking units,[b]								
Uncontrolled								
lb/10^3bbl fresh feed	242 (93 to 340)[c]	493 (100 to 525)	13,700	220	71.0 (37.1 to 145.0)	19	54	B
kg/10^3 liters fresh feed	0.695 (0.267 to 0.976)	1.413 (0.286 to 1.505)	39.2	0.630	0.204 (0.107 to 0.416)	0.054	0.155	B
Electrostatic precipitator and CO boiler								
lb/10^3 bbl fresh fed	45[d] (7 to 150)	493 (100 to 525)	Neg[e]	Neg	71.0[f] (37.1 to 145.0)	Neg	Neg	B
kg/10^3 liters fresh feed	0.128 (0.020 to 0.428)	1.413 (0.286 to 1.505)	Neg	Neg	0.204[j] (0.107 to 0.416)	Neg	Neg	B
Moving-bed catalytic cracking units[g]								
lb/10^3 bbl fresh feed	17	60	3,800	87	5	12	6	B
kg/10^3 liters fresh feed	0.049	0.171	10.8	0.250	0.014	0.034	0.017	B
Fluid coking units[h]								
Uncontrolled								
lb/10^3 bbl fresh feed	523	NA[i]	NA	NA	NA	NA	NA	C
kg/10^3 liters fresh feed	1.50	NA	NA	NA	NA	NA	NA	C
Electrostatic precipitator and CO boiler								
lb/10^3 bbl fresh feed	6.85	NA	Neg	Neg	NA	Neg	Neg	C
kg/10^3 liters fresh feed	0.0196	NA	Neg	Neg	NA	Neg	Neg	C
Delayed coking units	NA	NA	NA	NA	NA	NA	NA	
Compressor engines[j]								
Reciprocating engines								
lb/10^3 ft^3 gas burned	Neg	2s[k]	0.43	1.4	3.4	0.1	0.2	B
kg/10^3 m^3 gas burned	Neg	32s	7.02	21.8	55.4	1.61	3.2	B
Gas turbines								
lb/10^3 ft^3 gas burned	Neg	2s	0.12	0.02	0.3	NA	NA	B
kg/10^3 m^3 gas burned	Neg	32s	1.94	0.28	4.7	NA	NA	B

C.9.1a
p.76

TABLE 9.1-2. FUGITIVE EMISSION FACTORS FOR PETROLEUM REFINERIES[a]

Emission Source	Process Stream Type[b]	Emission Factor Units	Emission Factors		Applicable Control Technology	Emission Factor Rating
			Uncontrolled Emissions[c]	Controlled Emissions		
Pipeline valves[d]	II	lb/hr-source kg/day-source	0.059 (0.030 - 0.110) 0.64 (0.32 - 1.19)	NA	Monitoring and maintenance programs	A
	III	·	0.024 (0.017 - 0.036) 0.26 (0.18 - 0.39)	NA		A
	IV	·	0.0005 (0.0002- 0.0015) 0.005 (0.002 - 0.016)	NA		A
	V	·	0.018 (0.007 - 0.045) 0.20 (0.08 - 0.49)	NA		A
Open-ended valves[d,e]	I	· ·	0.005 (0.0016- 0.016) 0.05 (0.017 - 0.17)	NA	Installation of cap or plug on open end of valve/line	A
Flanges[d,f]	I	·	0.00056 (0.0002- 0.0025) 0.0061 (0.002 - 0.027)	NA	Monitoring and maintenance programs	A
Pump seals[d]	III	· ·	0.25 (0.16 - 0.37) 2.7 (1.7 - 4.0)	NA	Mechanical seals, dual seals, purged seals, monitoring and maintenance programs, controlled degassing vents	A
	IV	· ·	0.046 (0.019 - 0.11) 0.50 (0.21 - 1.2)	NA		A
Compressor seals[d]	II	· ·	1.4 (0.66 - 2.9) 15 (7.1 - 31)	NA	Mechanical seals, dual seals, purged seals, monitoring and maintenance programs, controlled degassing vents	A
	V	· ·	0.11 (0.05 - 0.23) 1.2 (0.5 - 2.5)	NA		A
Process drains[d]	I	·	0.070 (0.023 - 0.20) 0.76 (0.25 - 2.2)	NA	Traps and covers	A
Pressure vessel relief valves (gas service)[d,g]	II	· ·	0.36 (0.10 - 1.3) 3.9 (1.1 - 14)	Negligible	Rupture disks upstream of relief valves and/or venting to a flare	A
Cooling towers	-	lb/10^6 gal cooling water	6	0.70	Minimization of hydrocarbon leaks into cooling water system. Monitoring of cooling water for hydrocarbons	D
		kg/10^6 liters cooling water	0.7	0.083		
		lb/10^3 bbl refinery feed[h]	10	1.2		
		kg/10^3 liters refinery feed	0.03	0.004		
Oil/water separators	-	lb/10^3 gal waste-water	5	0.2	Covered separators and/or vapor recovery systems	D
		kg/10^3 liter waste water	0.6	0.024		
		lb/10^3 bbl refinery feed	200	10		
		kg/10^3 liters refinery feed	0.6	0.03		
Storage		See Section 4.3				
Loading		See Section 4.4				

---

[a] Data from References 2,4, 12 and 13 except as noted. Overall, less than 1% by weight of the total VOC emissions are methane.
NA = not available.

[b] The volatility and hydrogen content of the process streams have a substantial effect on the emission rate of some fugitive emission sources. The stream identification numerals and group names and descriptions are:

Stream Identification Numeral	Stream Name	Stream Group Description
I	All streams	All streams.
II	Gas streams	Hydrocarbon gas/vapor at process conditions (containing less than 50% hydrogen, by volume)
III	Light liquid and gas/liquid streams	Liquid or gas/liquid stream with a vapor pressure greater than that of kerosene (>0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at >20% by volume.
IV	Heavy liquid streams	Liquid stream with a vapor pressure equal to or less than that of kerosene (≤ 0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at > 20% by volume.
V	Hydrogen streams	Gas streams containing more than 50% hydrogen by volume.

[c] Numbers in parentheses are the upper and lower bounds of the 95% confidence interval for the emission factor.

[d] Data from Reference 17.

[e] The downstream side of these valves is open to the atmosphere. Emissions are through the valve seat of the closed valve.

[f] Two flanges coupled or bolted together pipe end to pipe end or a pipe end to a valve are counted as one flange.

[g] Emission factor for relief valves in gas service is for leakage, not for emissions caused by vessel pressure relief.

[h] Refinery rate is defined as the crude oil feed rate to the atmospheric distillation column.

C.9.a
p177

9. B. J. Mullins, et. al., Atmospheric Emissions Survey of the Sour Gas Processing Industry, EPA-450/3-75-076, U. S. Environmental Protection Agency, Research Triangle Park, NC, October 1975.

10. Federal Air Quality Control Regions. Environmental Protection Agency, Research Triangle Park, NC. Publication No. AP-102. January 1972.

11. Assessment of Atmospheric Emissions from Petroleum Refining, Volume 3, Appendix B. EPA 600/2-80-075c, April 1980. pp. 266 and 280.

12. Draft CTG Document, Control of Volatile Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants, June 1981.

13. D. A. DuBose, et. al., Data Analysis Report, Frequency of Leak Occurrence and Emission Factors for Natural Gas Liquid Plants, EMB Report No. 80-FOL-1, U. S. Environmental Protection Agency, Emissions Measurement Branch, Radian Corp. Research Triangle Park, NC, July 1982.

14. W. S. Eaton, et. al., Rockwell Corporation. Fugitive Hydrocarbon Emissions from Petroleum Production Operations. American Petroleum Institute Publication No. 4322. Washington, D.C. March 1980.

15. Organic Chemical Manufacturing, Volume 3: Storage, Fugitive, and Secondary Sources. Report 2, Fugitive Emissions. EPA-450/3-80-025. U. S. Environmental Protection Agency. Office of Air Quality Planning and Standards. Emission Standards and Engineering Division. Research Triangle Park, North Carolina. December 1980.

C.9ia
1.78

10.4 WOODWORKING WASTE COLLECTION OPERATIONS

10.4.1 General[1-2,4-5]

Woodworking, as defined in this section, includes any operation that involves the generation of small wood waste particles (shavings, sanderdust, sawdust, etc.) by any kind of mechanical manipulation of wood, bark, or wood byproducts. Common woodworking operations include sawing, planning, chipping, shaping, moulding, hogging, lathing, and sanding. Woodworking operations are found in numerous industries, such as sawmills, plywood, particleboard, and hardboard plants, and furniture manufacturing plants.

Most plants engaged in woodworking employ pneumatic transfer systems to remove the generated wood waste from the immediate proximity of each woodworking operation. These systems are necessary as a housekeeping measure to eliminate the vast quantity of waste material that would otherwise accumulate. They are also a convenient means of transporting the waste material to common collection points for ultimate disposal. Large diameter cyclones have historically been the primary means of separating the waste material from the airstreams in the pneumatic transfer systems, although baghouses have recently been installed in some plants for this purpose.

The waste material collected in the cyclones or baghouses may be burned in wood waste boilers, utilized in the manufacture of other products (such as pulp or particleboard), or incinerated in conical (teepee/wigwam) burners. The latter practice is declining with the advent of more stringent air pollution control regulations and because of the economic attractiveness of utilizing wood waste as a resource.

10.4.2 Emissions[1-6]

The only pollutant of concern in woodworking waste collection operations is particulate matter. The major emission points are the cyclones utilized in the pneumatic transfer systems. The quantity of particulate emissions from a given cyclone will depend on the dimensions of the cyclone, the velocity of the airstream, and the nature of the operation generating the waste. Typical large diameter cyclones found in the industry will only effectively collect particles greater than 40 micrometers in diameter. Baghouses, when employed, collect essentially all of the waste material in the airstream. The wastes from numerous pieces of equipment often feed into the same cyclone, and it is common for the material collected in one or several cyclones to be conveyed to another cyclone. It is also possible for portions of the waste generated by a single operation to be directed to different cyclones.

Because of this complexity, it is useful when evaluating emissions from a given facility to consider the waste handling cyclones as air pollution sources instead of the various woodworking operations that actually generate the particulate matter. Emission factors for typical large diameter cyclones utilized for waste collection in woodworking operations are given in Table 10.4-1.

Emission factors for wood waste boilers, conical burners, and various drying operations - often found in facilities employing woodworking operations - are given in Sections 1.6, 2.3, 10.2, and 10.3.

C.9.a
p.79

Table 10.4-1 PARTICULATE EMISSION FACTORS FOR LARGE DIAMETER CYCLONES IN WOODWORKING WASTE COLLECTION SYSTEMS[a]

EMISSION FACTOR RATING: D

	Particulate emissions[b,c]			
Types of waste handled	gr/scf	g/Nm^3	lb/hr	kg/hr
Sanderdust[d]	0.055 (0.005-0.16)	0.126 (0.0114-0.37)	5 (0.2-30.0)	2.3 (0.09-13.6)
Other[e]	0.03 (0.001-0.16)	0.07 (0.002-0.37)	2 (0.03-24.0)	0.91 (0.014-10.9)

[a] Typical waste collection cyclones range from 4 to 16 feet (1.2 to 4.9 meters) in diameter and employ airflows ranging from 2,000 to 26,000 standard cubic feet (57 to 740 normal cubic meters) per minute. Note: if baghouses are used for waste collection, particulate emissions will be negligible.

[b] References 1 through 3.

[c] Observed value ranges are in parentheses.

[d] These factors should be used whenever waste from sanding operations is fed directly into the cyclone in question.

[e] These factors should be used for cyclones handling waste from all operations other than sanding. This includes cyclones that handle waste (including sanderdust) already collected by another cyclone.

10.4.3 Fugitive Emission Factors[7]

Since most woodworking operations control emissions out of necessity, fugitive emissions are seldom a problem. However, the wood waste storage bins are a common source of fugitive emissions. Table 10.4-2 shows these emission sources and their corresponding emission factors.

Information concerning size characteristics is very limited. Data collected in a western red cedar furniture factory equipped with exhaust ventilation on most woodworking equipment showed most suspended particles in the working environment to be less than 2 µm in diameter.

C, 9, 6
r, 80

Table 10.4-2. POTENTIAL UNCONTROLLED FUGITIVE PARTICULATE EMISSION FACTORS FOR WOODWORKING OPERATIONS

EMISSION FACTOR RATING: C

Type of operation	Particulates[a]	
	lb/ton	kg/MT
Wood waste storage bin vent[b]	1.0	0.5
Wood waste storage bin loadout[b]	2.0	1.0

[a] Factors expressed as unit per unit weight of wood waste handled.

[b] Engineering judgment based on plant visits.

References for Section 10.4

1. Source test data supplied by Robert Harris, Oregon Department of Environmental Quality, Portland, OR, September 1975.

2. J. W. Walton, et. al., "Air Pollution in the Woodworking Industry", Presented at the 68th Annual Meeting of the Air Pollution Control Association, Boston, MA, June 1975.

3. J. D. Patton and J. W. Walton, "Applying the High Volume Stack Sampler To Measure Emissions from Cotton Gins, Woodworking Operations, and Feed and Grain Mills", Presented at 3rd Annual Industrial Air Pollution Control Conference, Knoxville, TN, March 29-30, 1973.

4. C. F. Sexton, "Control of Atmospheric Emissions from the Manufacturing of Furniture", Presented at 2nd Annual Industrial Air Pollution Control Conference, Knoxville, TN, April 20-21, 1972.

5. A. Mick and D. McCargar, "Air Pollution Problems in Plywood, Particleboard, and Hardboard Mills in the Mid-Willamette Valley", Mid-Willamette Valley Air Pollution Authority, Salem, OR, March 24, 1969.

6. Information supplied by the North Carolina Department of Natural and Economic Resources, Raleigh, NC, December 1975.

7. Lester V. Cralley, et. al., Industrial Environmental Health, The Worker And The Community, Academic Press, New York and London, 1972.

C.9.10
P.81

wind speed and wind direction, relative to roof ridge orientation. Thus, high volume samplers do not provide definitive particle size information for emission factors. However, an effective cutpoint of 30 micrometers aerodynamic diameter is frequently assigned to the standard high volume sampler.

Control techniques for fugitive dust sources generally involve watering, chemical stabilization, or reduction of surface wind speed with windbreaks or source enclosures. Watering, the most common and generally least expensive method, provides only temporary dust control. The use of chemicals to treat exposed surfaces provides longer dust suppression but may be costly, have adverse effects on plant and animal life, or contaminate the treated material. Windbreaks and source enclosures are often impractical because of the size of fugitive dust sources.

Reference for Section 11.2

1. C. Cowherd, Jr., et. al., Development of Emission Factors for Fugitive Dust Sources, EPA-450/3-74-037, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1974.

C 91a
p 182

11.2.4 Heavy Construction Operations[1-3]

11.2.4.1 General - Heavy construction is a source of dust emissions that may have substantial temporary impact on local air quality. Building and road construction are the prevalent construction categories with the highest emissions potential. Emissions during the construction of a building or road are associated with land clearing, blasting, ground excavation, cut and fill operations, and the construction of the particular facility itself. Dust emissions vary substantially from day to day depending on the level of activity, the specific operations, and the prevailing weather. A large portion of the emissions result from equipment traffic over temporary roads at the construction site.

11.2.4.2 Emissions and Correction Parameters - The quantity of dust emissions from construction operations are proportional to the area of land being worked and the level of construction activity. Also, by analogy to the parameter dependence observed for othr similar fugitive dust sources, it is probable that emissions from heavy construction operations are directly proportional to the silt content of the soil (that is, particles smaller than 75 µm in diameter) and inversely proportional to the square of the soil moisture, as represented by Thornwaite's precipitation-evaporation (PE) index.

11.2.4.3 Emission Factor - Based on field measurements of suspended dust emissions from apartment and shopping center construction projects, an approximate emission factor for construction operations is:

1.2 tons per acre of construction per month of activity

This value applies to construction operations with: (1) medium activity level, (2) moderate silt content (~30 percent), and (3) semiarid climate (PE ~50; see Figure 11.2-2). Test data are not sufficient to derive the specific dependence of dust emissions on correction parameters (e.g., soil silt content, surface moisture, activity level).

Construction activity levels were shown to influence emission rates from the sites significantly. However, this variation could not be quantified. The final factor represents emission rates during the period of active construction, including some days with no activity, some with moderate activity, and some with heavy earth-moving equipment and considerable truck traffic. Substantial error may result if the factor is applied to a site during a period of extended inactivity.

The above emission factor applies to particles less than about 30 µm in diameter, which is the effective cut-off size for the capture of construction dust by a standard high-volume filtration sampler[1], based on a particle density of 2.0-2.5 g/cm^3.

11.2.4.4 Control Methods - Watering is most often selected as a control method because water and necessary equipment are usually available at construction sites. The effectiveness of watering for control depends greatly on the frequency of application. An effective watering program (that is, twice daily watering with complete coverage) is estimated to reduce dust emissions by up to 50 percent. Chemical stabilization is not effective in reducing the large portion of construction emissions caused by equipment traffic or active excavation and cut and fill operations. Chemical stabilizers are useful primarily for application on completed cuts and fills at the construction site. Wind erosion emissions from inactive portions of the construction site can be reduced by about 80 percent in this manner, but this represents a fairly minor reduction in total emissions compared with emissions occurring during a period of high activity.

C.9.a
V.i.B

References for Section 11.2.4

1. Cowherd, C., Jr., K. Axetell, Jr., C. M. Guenther, and G. A. Jutze. Development of Emissions Factors for Fugitive Dust Sources. Midwest Research Institute, Kansas City, MO. Prepared for Environmental Protection Agency, Research Triangle Park, NC, under Contract No. 68-02-0619. Publication No. EPA-450/3-74-037. June 1974.

2. Thornthwaite, C. W. Climates of North America According to a New Classification. Geograph. Rev. 21: 633-655, 1931.

3. Jutz, G. A., K. Axetell, Jr., and W. Parker. Investigation of Fugitive Dust-Sources Emissions and Control, PEDCo Environmental Specialists, Inc., Cincinnati, Ohio. Prepared for Environmental Protection Agency, Research Triangle Park, NC, under Contract No. 68-02-0044. Publication No. EPA-450/3-74-036a. June 1974.

C.9.a
D.84

These sampling locations can be considered representative of most large urban areas in the United States, with the possible exception of those in the Southwest. Except for the collector roadway category, the mean silt loadings do not vary greatly from city to city, though the St. Louis mean for major roads is somewhat lower than those of the other four cities. The substantial variation within the collector roadway category is probably attributable to the effects of land use around the specific sampling locations. It should also be noted that an examination of data collected at three cities in Montana during early spring indicates that winter road sanding may produce loadings five to six times higher than the means of the loadings given in Table 11.2.5-3 for the respective road categories.[5]

Table 11.2.5-4 presents the emission factors by roadway category and particle size. These were obtained by inserting the above mean silt loadings into the equation on page 11.2.5-1. These emission factors can be used directly for many emission inventory purposes. It is important to note that the paved road emission factors for TSP agree quite well with those developed from previous testing of roadway sites in the major street and highway category, yielding mean TSP emission factors of 4.3 grams/VKT (Reference 6) and 2.6 grams/VKT (Reference 7).

TABLE 11.2.5-4. RECOMMENDED PARTICULATE EMISSION FACTORS FOR SPECIFIC ROADWAY CATEGORIES AND PARTICLE SIZE FRACTIONS[a]

Roadway Category	Emission Factor							
	TSP		≤ 15 μm		≤ 10 μm		≤ 2.5 μm	
	g/VKT	(lb/VMT)	g/VKT	(lb/VMT)	g/VKT	(lb/VMT)	g/VKT	(lb/VMT)
Local streets	15	(0.053)	5.8	(0.021)	5.2	(0.018)	1.9	(0.0067)
Collector streets	10	(0.035)	4.1	(0.015)	3.7	(0.013)	1.5	(0.0053)
Major streets/highways	4.4	(0.016)	2.0	(0.0071)	1.8	(0.0064)	0.84	(0.0030)
Freeways/expressways	0.35	(0.0012)	0.21	(0.00074)	0.19	(0.00067)	0.16	(0.00057)

[a] Reference 4.

References for Section 11.2.5

1. D. R. Dunbar, Resuspension of Particulate Matter, EPA-450/2-76-031, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1976.

2. M. P. Abel, "The Impact of Refloatation on Chicago's Total Suspended Particulate Levels", Purdue University, Purdue, IN, August 1974.

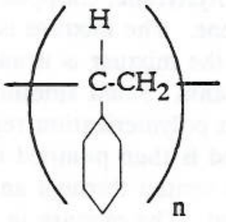
3. C. M. Maxwell and D. W. Nelson, A Lead Emission Factor for Reentrained Dust from a Paved Roadway, EPA-450/3-78-021, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1978.

C, 9, a
P, 85

5.13.3 Polystyrene[1-2]

Styrene readily polymerizes to polystyrene by a relatively conventional free radical chain mechanism. Either heat or initiators will initiate the polymerization. Initiators thermally decompose, thereby forming active free radicals that are effective in starting the polymerization process. Typically initiators used in the suspension process include benzoyl peroxide and di-tert-butyl per-benzoate. Potassium persulfate is a typical initiator used in emulsion polymerizations. In the presence of inert materials, styrene monomer will react with itself to form a homopolymer. Styrene monomer will react with a variety of other monomers to form a number of copolymers.

Polystyrene is an odorless, tasteless, rigid thermoplastic. Pure polystyrene has the following structure.



The homopolymers of styrene are also referred to as general purpose or crystal polystyrene. Due to the brittleness of crystal polystyrene, styrene is frequently polymerized in the presence of dissolved polybutadiene rubber to improve the strength of the polymer. Such modified polystyrene is called high impact or rubber-modified polystyrene. The styrene content of high impact polystyrene varies from about 88 to 97 percent. Where a blowing (or expanding) agent is added to the polystyrene, the product is referred to as an expandable polystyrene. The blowing agent may be added during the polymerization process (as in the production of expandable beads) or afterwards, as part of the fabrication process (as in foamed polystyrene applications.)

Polystyrene is the fourth largest volume thermoplastic. Polystyrene is used in applications in the following major markets (listed in order of consumption): packaging, consumer/institutional goods, electrical/electronic goods, building/construction, furniture, industrial/machinery, and transportation.

Packaging applications that use crystal polystyrene biaxial film include meat and vegetable trays, blister packs, and other packaging where clarity is required for marketing. Extruded polystyrene foam sheet is formed into egg carton containers, meat and poultry trays, and fast food containers where hot or cold insulation is required. Solid polystyrene sheet is formed into drinking cups, lids, and disposable packaging of edibles. Injection molded grades of polystyrene are used extensively in the manufacture of cosmetic and personal care containers, jewelry and photo equipment boxes, and photo film packages. Other polystyrene formed items include refrigerator door liners, audio and video cassette cartridges, toys, flowerpots, picture frames, kitchen utensils, television cabinets, radios, home smoke detectors, computer housings, and profile moldings in the construction/home-building industry.

5.13.3.1 General Purpose and Impact Polystyrene[1-2]

Homopolymers and copolymers can be produced by bulk (or mass), solution (a modified bulk), suspension, or emulsion polymerization techniques. In solution (or modified bulk) polymerization, the reaction takes place as the monomer is dissolved in a small amount of solvent, such as ethylbenzene. suspension polymerization takes place with the monomer suspended in a water phase. The bulk and solution polymerization processes are homogenous (i.e., take place in one phase), whereas the suspension and emulsion polymerization processes are heterogeneous (i.e., take place in more than one phase). The bulk (mass) process is the most widely used process for polystyrene today. The suspension process is also commonly used, especially in the production of expandable beads. The use of the emulsion process for producing homopolymer of styrene has decreased significantly since the mid-1940's.

5.13.3.1.1 Process Descriptions[1-3]

Batch Process - Various grades of polystyrene can be produced by a variety of batch processes. Batch processes generally have a high conversion efficiency, leaving only small amounts of non-reacted styrene to be emitted if the reactor is purged or opened between batches. A typical plant will have multiple process trains, each usually capable of producing a variety of grades of polystyrene.

Figure 5.13-8 is a schematic representation of the polystyrene batch bulk polymerization process. Pure styrene monomer (and comonomer if a copolymer product is desired) are pumped from storage (1) to the feed dissolver (2). For the production of impact grade polystyrene, chopped polybutadiene rubber is added to the feed dissolver, where it is dissolved in the hot styrene. The mixture is agitated for 4 to 8 hours to complete rubber dissolution. From the feed dissolver, the mixture is usually fed to an agitated tank (3), often a prepolymerization reactor, for mixing the reactants. Small amounts of mineral oil (as a lubricant and plasticizer), the dimer of alpha-methylstyrene (as a polymerization regulator), and an antioxidant are added. The blended or partially polymerized feed is then pumped into a batch reactor (4). During the reactor filling process, some styrene vaporizes and is vented through an overflow vent drum (5). When the reactor is charged, the vent and reactor are closed. The mixture in the reactor is heated to the reaction temperature to initiate (or continue) the polymerization. The reaction may also be initiated by introducing a free radical initiator into the feed dissolver (2) along with other reactants. After polymerization is complete, the polymer melt (molten product), which contains some non-reacted styrene monomer, ethylbenzene (an impurity from the styrene feed) and low molecular weight polymers (dimers, trimers, and other oligomers), is pumped to a vacuum devolatilizer (6). In the devolatilizer, the residual styrene monomer, ethylbenzene, and low molecular weight polymers are removed, condensed (7), passed through a devolatizer condensate tank (9), and then sent to the by-product recovery unit. Overhead vapors from the condenser are usually exhausted through a vacuum system (8). Molten polystyrene from the bottom of the devolatilizer, which may be heated to 250 to 280°C, is extruded (10) through a stranding dieplate (a plate with numerous holes forming strands). The extruded strands of polymer are then immersed in a cold water bath. The cooled strands are pelletized (10) and sent to product storage (11).

Continuous Process - As with the batch process, various continuous processes are used to make a variety of grades of polystyrene or copolymers of styrene. The chemical reaction in continuous processes does not approach completion as efficiently as the reaction in batch processes. As a result, a lower percentage of styrene is converted to polystyrene, and larger amounts of non-reacted styrene may be emitted from continuous process sources. A typical plant may contain more than one process line, each producing either the same or different grades of polymer or copolymer.

The bulk (mass) continuous process is represented in Figure 5.13-9. Styrene, polybutadiene (if an impact grade product is desired), mineral oil (lubricant and plasticizer), and small amounts of recycled polystyrene, antioxidants, and other additives, are charged from storage (1) into the feed dissolver mixer (2) in proportions that vary according to the grade of resin to be produced. Blended feed is pumped continuously to the reactor system (3) where it is thermally polymerized to polystyrene. A process line usually employs more than one reactor in series. Some polymerization occurs in the initial reactor, often referred to as the prepolymerizer. Polymerization to successively higher levels occurs in subsequent reactors in the series. Either stirred autoclaves or tower reactors are used. The polymer melt, which contains non-reacted styrene monomer, ethylbenzene (an impurity from the styrene feed) and low molecular weight polymers, is pumped to a vacuum devolatilizer (4). In the devolatilizer, most of the monomer, ethylbenzene, and low molecular weight polymers are removed, condensed (5), and sent to the styrene recovery unit (8 and 9). Noncondensables (i.e., overhead vapors) from the condenser are typically exhausted through a vacuum pump (10). Molten polystyrene from the bottom of the devolatilizer is pumped by an extruder (6) through a stranding dieplate into a cold water bath. The solidified strands are then pelletized (6) and sent to storage (7).

C.9.a
p.87

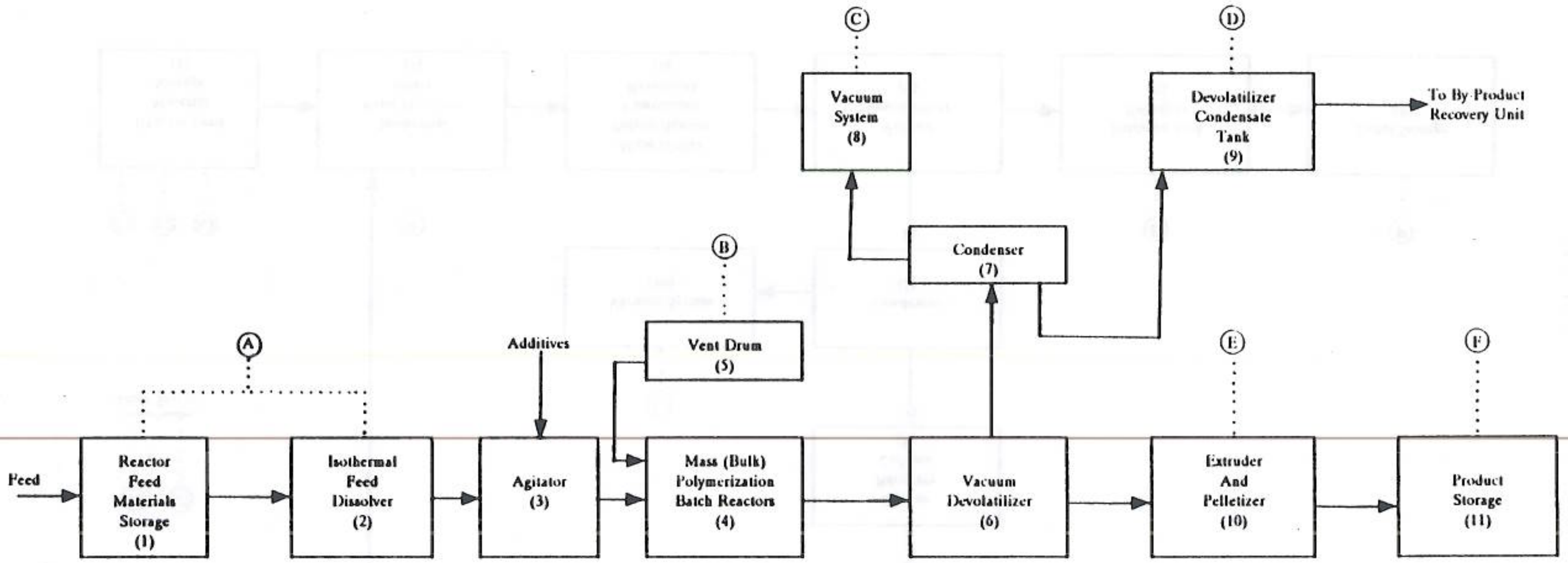


Figure 5.13-8. Simplified Flow Diagram Of Polystyrene Batch Process

C.9.a
p.88

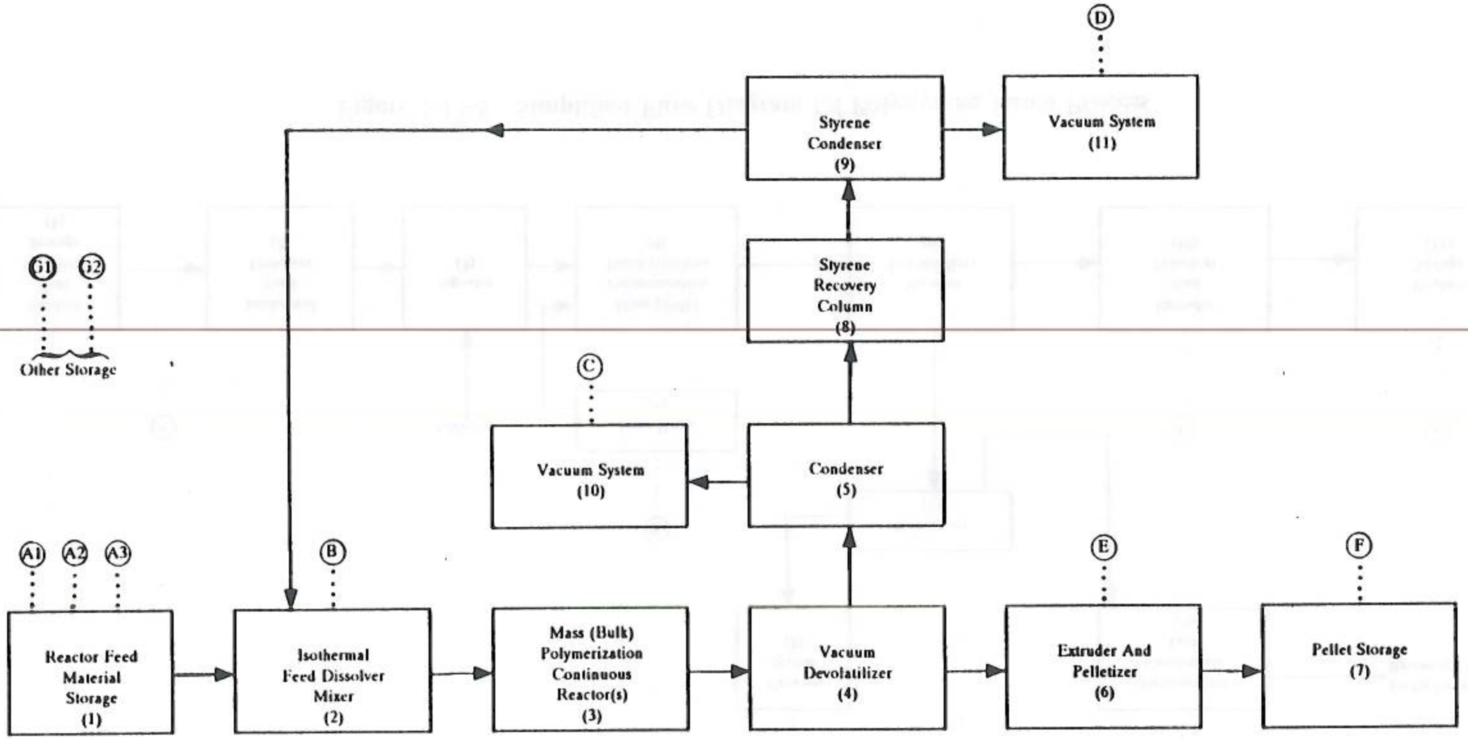


Figure 5.13-9. Simplified Flow Diagram Of Polystyrene Continuous Process.

C.9.a
p.89

In the styrene recovery unit, the crude styrene monomer recovered from the condenser (5) is purified in a distillation column (8). The styrene overhead from the tower is condensed (9) and returned to the feed dissolver mixer. Noncondensables are vented through a vacuum system (11). Column bottoms containing low molecular weight polymers are sometimes used as a fuel supplement.

5.13.3.1.2 Emissions And Controls[3-8]

As seen in Figure 5.13-8, six process emission streams have been identified for batch processes. These are: (1) the monomer storage and feed dissolver vent (Stream A); (2) the devolatilizer condensate tank (Stream B); the reactant vent drum vent (Stream C); (4) the devolatilizer condenser vent (Stream D): (5) the extruder quench vent (Stream E); and (6) product storage emissions (Stream F). Table 5.13-3 summarizes the emission factors for these streams.

The major vent is the devolatilizer condenser vent (Stream D). This continuous offgas vent has an emission rate of 0.25 to 0.75 lbs VOC/1,000 lbs of product. This range of emission factors is associated with the molecular weight of the polystyrene product being produced. The higher emission factor is more likely during the manufacture of lower molecular weight products. The emissions consist of non-reacted styrene, which is flashed from the product polymer in the vacuum devolatilizer, and are extremely diluted in air due to leakage. The stream is exhausted through a vacuum system (i.e., vacuum pump) and then through an oil demister to the atmosphere. The oil demister is used primarily to separate out organic mist.

The second largest vent stream is likely to be the reactor vent drum vent, with an emission rate ranging from 0.12 to 1.35 lbs VOC/1,000 lbs of product. This range of emission factors is associated with the molecular weight of the polystyrene product being produced. The higher emission factor is more likely during the manufacture of lower molecular weight products. These emissions, which are the only intermittent emissions from the process, occur only during reactor filling periods and are vented to the atmosphere. The 0.12 lbs VOC/1,000 lbs of product emission rate was based on a facility that has two batch reactors that are operated on an alternate basis once each per 24 hours.

Stream E, the extruder quench vent, is the third largest emission stream, with an emission rate of 0.15 to 0.3 lbs VOC/1,000 lbs of product. This stream, composed of styrene in water vapor, is formed when the hot, extruded polystyrene strands from the stranding dieplate contact the cold water in the quenching bath. The resulting steam with styrene stream is usually vented through a forced-draft hood located over the water bath and passed through a mist separator or electrostatic precipitator before venting to the atmosphere.

The other emission streams are relatively small continuous emissions. Streams A and B represent emissions from various types of tanks and dissolver tanks. The estimated emissions from these streams are based on fixed roof tanks. Emissions from product storage, Stream F, have been reported to be negligible.

There are no VOC control devices typically used at polystyrene plants employing batch processes. The condenser (7) off of the vacuum devolatilizer (6) is typically used for process reasons (i.e., recovery of non-reacted styrene and other reactants). This condenser reduces VOC emissions and its operating characteristics will affect the quantity of emissions associated with batch processes (Stream D in particular).

Total process uncontrolled emissions are estimated to range from 0.6 to 2.5 lbs VOC/1,000 lbs of product. The higher emission rates are associated with the manufacture of lower molecular weight polystyrene. The emission factor for any given process line will change with changes in the grade of the polystyrene being produced (e.g., with changes in the molecular weight of the product).

Emission factors for the polystyrene continuous process are presented in Table 5.13-4. The types of emissions from the continuous process are similar to those for the batch process, although there is no

C.9.a
p.90

TABLE 5.13-3. EMISSION FACTORS FOR BATCH PROCESS POLYSTYRENE

EMISSION FACTOR RATING: C

Stream Identification	Emission Stream	Nonmethane VOC (lbs VOC/1,000 lbs product)	References
A	Monomer storage and feed dissolver tanks	0.09[a]	3
B	Devolatilizer condensate tank[a]	0.002	3
C	Reactor vent drum vent	0.12-1.35[b]	3,4
D	Devolatilizer condenser vent	0.25-0.75[b]	3,4
E	Extruder quench vent	0.15-0.3[b]	3,4
F	Product storage	negligible	3
Total Plant		0.6 - 2.5	

[a] Based on fixed roof design.

[b] The higher factors are more likely during the manufacture of lower molecular weight products. The emission factor for any given process train will change with product grade. References 2,4.

reactor vent drum vent in the continuous process. The emission streams, all of which are continuous, are: (1) various types of storage (Streams A and G); (2) the feed dissolver vent (Stream B); (3) the devolatilizer condenser vent (Stream C); (4) the styrene recovery unit condenser vent (Stream D); (5) the extruder quench vent (Stream E); and (6) product storage emissions (Stream G).

Industry's experience with continuous polystyrene plants indicates a wide range of emission rates from plant to plant depending, in part, on the type of vacuum system used. Two types of vacuum systems are now used in the industry to generate process vacuums. One relies on steam ejectors; the other, on vacuum pumps. Where steam ejectors are used, the overheads from the devolatilizer condenser vent and the styrene recovery unit condenser vent are composed mainly of steam. Some companies have recently replaced these steam ejectors with mechanical vacuum pumps. Emissions from vacuum pumps are typically lower than emissions from steam ejectors.

It is estimated that the typical total VOC emission rate for plants using steam ejectors is about 3.34 lbs VOC/1,000 product. The largest emission stream being the devolatilizer condenser vent (2.96 lbs VOC/1,000 lbs of product). Emissions from the styrene recovery condenser vent and the extruder quench vent are estimated to be nearly the same (0.13 and 0.15 lbs VOC/1,000 lbs of product, respectively).

For plants that use vacuum pumps, it is estimated that the total VOC emission rate is about 0.21 lbs VOC/1,000 lbs of product. In these plants, emissions from the devolatilizer condenser vent and the styrene recovery condenser vent are estimated to be about the same (0.05 lbs VOC/1,000 lbs of product each). Styrene monomer and other storage emissions can be the largest group of emission sources at such plants (approximately 0.1 lbs VOC/1,000 lbs of product). Some plants combine emissions from the dissolvers with those from the devolatilizer condenser vent. Other plants may combine the dissolver, devolatilizer condenser vent, and styrene recovery condenser vent emissions. One plant uses an organic scrubber to reduce these emissions to 0.004 lbs VOC/1,000 lbs of product.

C.9.a
p.91

TABLE 5.13-4. EMISSION FACTORS FOR CONTINUOUS PROCESS POLYSTYRENE

EMISSION FACTOR RATING: C

Stream Identification	Stream Name	Uncontrolled	Before Control	After Control	References
		Nonmethane VOC Emission Factor (lbs VOC/1,000 lbs product)			
			If Controlled ...		
A1	Styrene monomer storage	0.08			3,5
A2	Additives (GPPS)	0.001			5
	Additives (HIPS)	0.002			5,6
A3	Ethylbenzene storage	0.002			5
B	Dissolvers	0.008			3,5
C	Devolatilizer	0.05[a]		0.04[b]	4,5,6
	condenser vent[f]	2.96[c]			3
D	Styrene recovery unit	0.05[a]			3,6
	condenser vent	0.13[c]			3
C+D		0.024-0.3[d]	--	0.004[e]	4,5,7
E	Extruder quench vent	0.01[a]			5
		0.15[c]			3
F	Pellet storage	negligible			3
G1	Other storage (GPPS)	0.009			3,5
G2	Other storage (HIPS)	0.002			5
Total Plant		0.21[a] 3.34[c]			

[a] For newer plants using vacuum pumps.

[b] Condenser is used downstream of primary process condensers; includes emissions from dissolvers. Plant uses vacuum pumps.

[c] For plants using steam jets.

[d] Lower value based on facility using refrigerated condensers as well as conventional cooling water exchangers; vacuum pumps in use. Higher value for plant using vacuum pumps.

[e] Plant uses an organic scrubber to reduce emissions. Nonsoluble organics are burned as fuel.

[f] Larger plants may route this stream to the styrene recovery section. Smaller plants may find that the expenses do not justify routing this stream to the styrene recovery section. Reference 2.

C.9.a
p.92

Condensers are a critical, integral part of all continuous polystyrene processes. The amount of non-reacted styrene recovered for reuse in the process can vary greatly as the operating parameters for the condensers vary from one plant to another. Lowering the operating temperature of the coolant (e.g., by using chilled or refrigerated coolant) will lower VOC emissions all other things being equal.

Other than the VOC reduction achieved by the process condensers, most plants do not use control devices to achieve additional VOC reductions. There are exceptions, however, and these exceptions can have significant effects on the level of VOC emissions. One company, for example, uses an organic scrubber to reduce VOC air emissions. Another company uses a condenser downstream of the primary process condensers to further reduce emissions.

5.13.3.2 Expandable Polystyrene[1-2,9-10]

The suspension process is a batch polymerization process that may be used to produce crystal, impact, or expandable polystyrene beads. An expandable polystyrene (EPS) bead consists typically of high-molecular weight crystal grade polystyrene (to produce the proper structure when the beads are expanded) and 5 to 8 percent low boiling aliphatic hydrocarbon blowing agent (typically pentane or isopentane although other blowing agents, such as esters, alcohols, and aldehydes, can be used) dissolved in the polymer bead. When used to produce an EPS bead, the suspension process can be adapted in one of two ways for the impregnation of the bead with the blowing agent. One method is to add the blowing agent to a reactor after polymerization. The other method is to add the blowing agent to the monomer prior to polymerization. The former method (which shall be referred to as the "post-impregnation" suspension process) is more common than the latter method (which shall be referred to as the "in-situ" suspension process). Both processes are described below.

EPS beads are generally processed in one of three ways: (1) gravity or air-fed into closed molds and heated to expand up to 50 times their original volume; (2) pre-expanded by heating and then molding in a separate processing operation; and (3) extended into sheets of various thickness. EPS beads are used in a number of foamed polystyrene materials. Extruded foam sheet is formed into egg cartons, meat and poultry trays, and fast food containers. In the building/construction industry, EPS board is used extensively as a low-temperature insulator.

5.13.3.2.1 Process Description[1,9-11]

Post-impregnation Suspension Process - The post-impregnation suspension process is essentially a two-part process using two process lines in series. In the first process line, raw styrene monomer is polymerized and a finished polystyrene bead is produced. The second process line takes the finished bead from the first line, impregnates the bead with a blowing agent, and produces a finished EPS bead. Figure 5.13-10 is a schematic representation of this process.

In the first line, styrene monomer, water, initiator, and suspending agents form the basic charge to the suspension reactor (1). The styrene-to-water ratio varies depending on the type of polystyrene required. A typical ratio is about one-half to one-quarter monomer to water volume. Initiators are commonly used because the reaction temperature is usually too low for adequate thermal initiation of polymerization. Suspending agents are typically protective colloids and insoluble inorganic salts. Protective colloids are added to increase the viscosity of the continuous water phase and insoluble inorganic salts, such as $MgCO_3$, are added to prevent coalescence of the drops upon collision.

In the reactor, the styrene is suspended, through the use of mechanical agitation and suspending agents, in the form of droplets throughout the water phase. The droplet size may range from about 0.1 to 1.0 mm. The reactor is heated to start the polymerization process, which takes place within the droplets. An inert gas, such as nitrogen, is frequently used as a blanketing agent in order to maintain a positive pressure at all times during the cycle and prevent air leaks. Once polymerization starts, temperature control is typically maintained through a water-cooled jacket around the reactor and facilitated by the

C.9.a
p.93

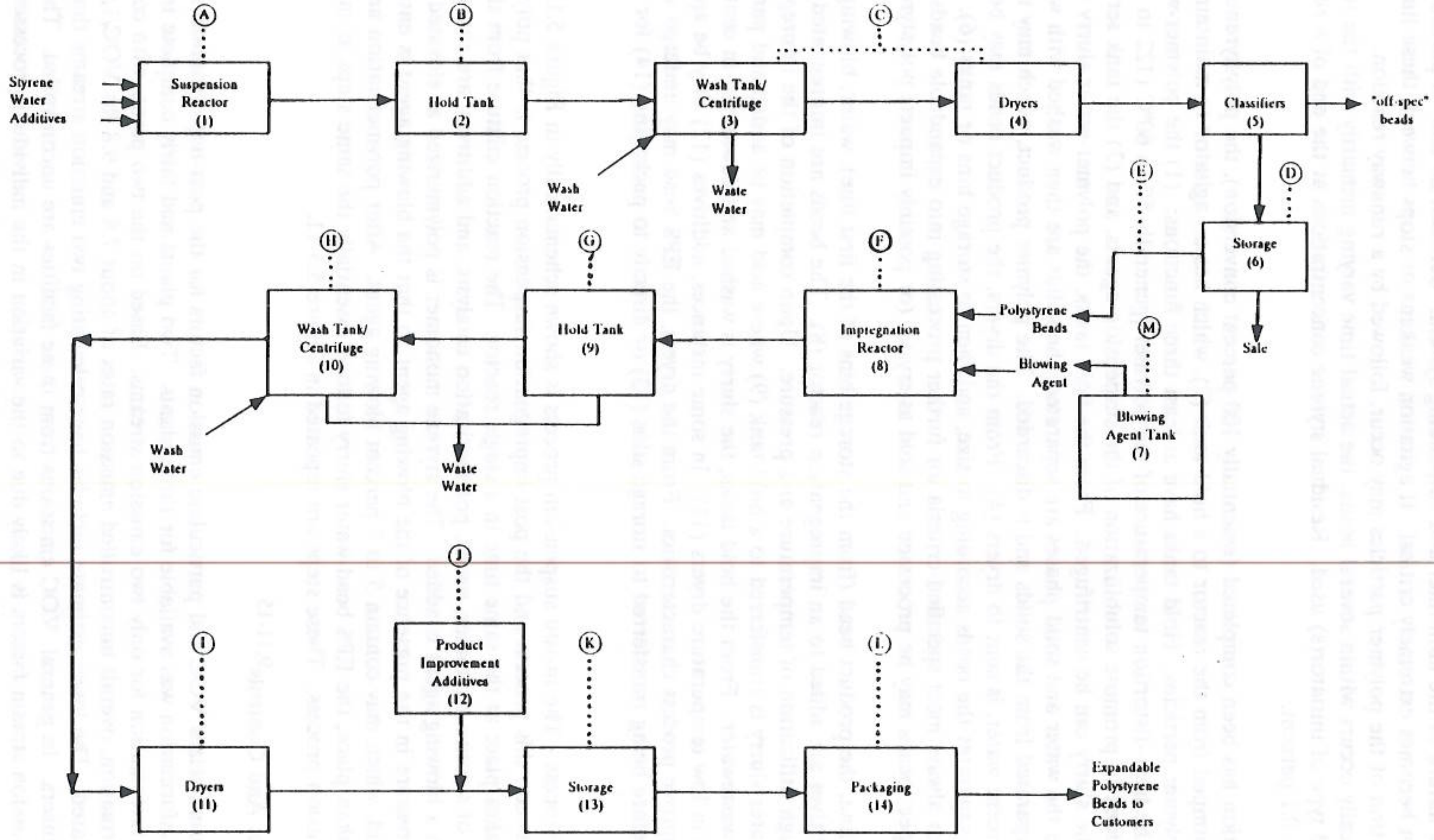


Figure 5.13-10. Simplified Process Block Diagram Of The Expandable Polystyrene Post-impregnation Process.

C.9.a
1.94

added heat capacity of the water in the reactor. The size of the product bead depends on the strength of agitation and on the nature of the monomer and suspending system. Between 20 and 70 percent conversion, agitation becomes extremely critical. If agitation weakens or stops between these limits, excessive agglomeration of the polymer particles may occur, followed by a runaway reaction. Polymerization typically occurs within several hours, the actual time varying primarily with the temperature and the amount and type of initiator(s) used. Residual styrene concentrations at the end of a run are frequently as low as 0.1 percent.

Once the reaction has been completed (essentially 100 percent conversion), the polystyrene-water slurry is normally pumped from the reactor to a hold tank (2), which has an agitator to maintain dispersion of the polymer particles. Hold tanks have at least three functions: (1) the polymer-water slurry is cooled to below the heat-distortion temperature of the polymer [generally 50 to 60°C (122 to 140°F)], (2) chemicals are added to promote solubilization of the suspension agents, and (3) the tank serves as a storage tank until the slurry can be centrifuged. From the hold tanks, the polymer-water slurry is fed to a centrifuge (3) where the water and solid phases are separated, the solids are then washed with water, and the wash water is separated from the solids and is discarded. The polymer product, which may retain between 1 and 5 percent water, is sent to dryers (4). From the dryers, the product beads may be sent to a classifier (5), which separates the beads according to size, and then to storage bins or tanks (6). The product beads do not always meet specified criteria for further processing into expandable beads. In these instances, the "off-spec" beads may be processed and sold as crystal (or possibly impact) polystyrene.

In the second line, the product bead (from the storage bins of the first line), water, blowing agent (7), and any desired additives are added to an impregnation reactor (8). The beads are impregnated with the blowing agent through utilization of temperature and pressure. Upon completion of the impregnation process, the bead-water slurry is transferred to a hold tank (9) where acid may be added and part of the water is drained as wastewater. From the hold tanks, the slurry is washed and dewatered in centrifuges (10) and then dried in low temperature dryers (11). In some instances, additives (12) may be applied to the EPS bead to improve process characteristics. From the dryers, the EPS bead may undergo sizing, if not already done, before being transferred to storage silos (13) or directly to packaging (14) for shipment to the customer.

In-situ Suspension Process - The in-situ suspension process is shown schematically in Figure 5.13-11. The major difference between this process and the post-impregnation suspension process is that polymerization and impregnation takes place at the same time in a single reactor. The reaction mixture from the mix tank (1), composed of styrene monomer, water, polymerization catalysts, and additives, are charged to a reactor (2) to which a blowing agent is added. The styrene monomer is polymerized at elevated temperatures and pressure in the presence of the blowing agent so that the blowing agent is entrapped in the polymerized bead, which may contain 5 to 7 percent blowing agent. After polymerization and impregnation has taken place, the EPS bead-water slurry follows essentially the same steps as in the post-impregnation suspension process. These steps are repeated in Figure 5.3-11.

5.13.3.2.2 Emissions And Controls[9,11-15]

Table 5.13-5 summarizes VOC and particulate emission factors for the post-impregnation suspension process. Emission information was available for three plants. Two plants had fairly complete information; the third plant had information for only two emission streams. Based on the two plants with complete VOC emission information, overall uncontrolled emission rates of about 7.8 and 9.8 lbs VOC/1,000 lbs of product were calculated. The lower estimate includes back-calculating two emission streams that are controlled by condensers. In general, VOC emissions from these facilities are uncontrolled. The variation in the individual emission stream factors is likely due to the variation in the individual processes in terms of how the process reactors are operated, operating temperatures, and reaction time.

Particulate emissions (emissions of fines that occur during pneumatic transfer of the polymer) are typically controlled using either cyclones alone or cyclones followed by baghouses. Overall, controlled

C,9,a
p,98

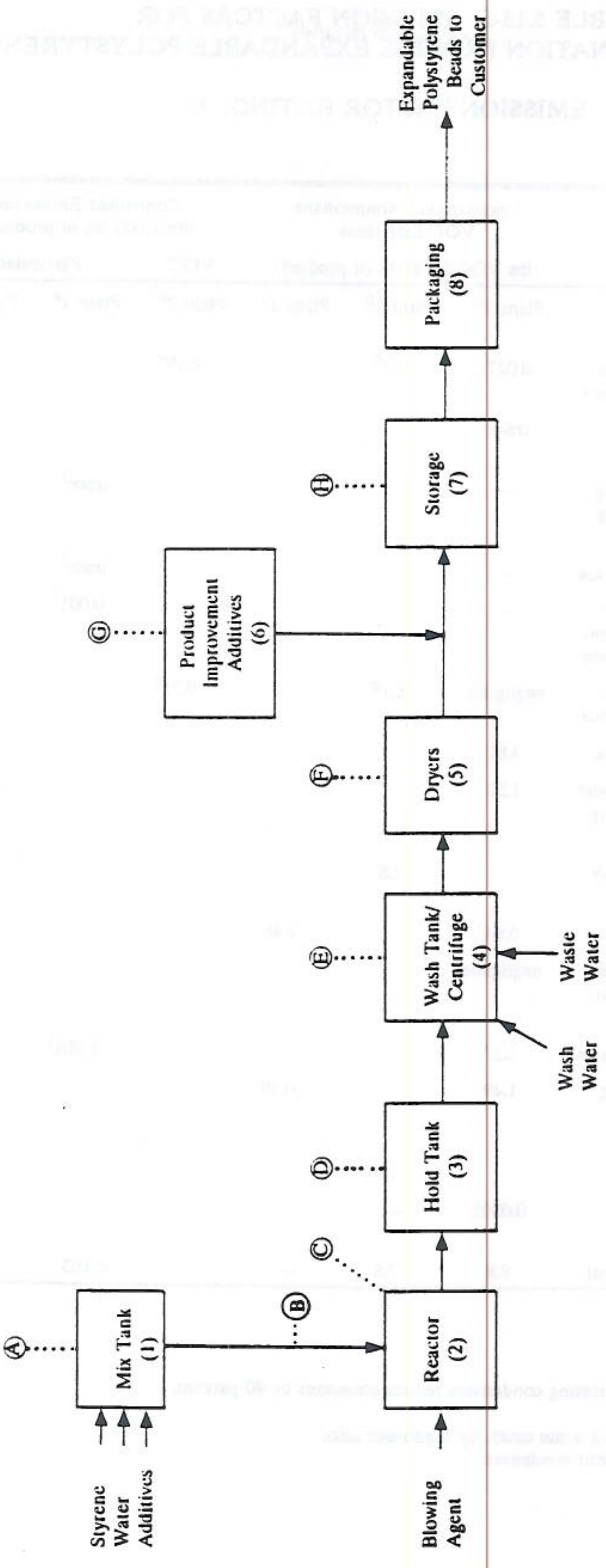


Figure 5.13-11. Simplified Process Block Diagram Of The Expandable Polystyrene In-Situ Suspension Process.

C, 9.a
p.96

TABLE 5.13-5. EMISSION FACTORS FOR POST-IMPREGNATION PROCESS EXPANDABLE POLYSTYRENE

EMISSION FACTOR RATING: C

		Uncontrolled Nonmethane VOC Emissions (lbs VOC/1,000 lbs of product)			Controlled Emissions (lbs/1,000 lbs of product)		
					VOC	Particulate	
Stream Identification	Stream Name	Plant 1[a]	Plant 2[b]	Plant 3[c]	Plant 2[b]	Plant 1[a]	Plant 2[b]
A	Suspension Reactor vent	0.027	1.9[d]		0.19[e]		
B	Holding Tank	trace					
C	Dewatering and Drying System	--				trace[f]	
D	Storage Silos	--				trace[f]	
E	Bag Filter for Pneumatic Conveyor	--				0.001[f]	
F	Impregnation Reactor	negligible	2.1[g]		0.21[b]		
G	Hold Tank	3.81					
H	Washing and Dewatering System	1.52					
G+H	Hold/Wash Tank		2.8				
I	Dryers	0.64		1.48			0.4[f]
J	Product improvement vents	negligible					
K	Storage silos	2.27				0.001[f]	0.001[f]
L	Packaging system Losses	1.49		0.49			
I,J,L	--		1.0				
M	Blowing Agent	0.0002	--				
	Total Plant	9.8	7.8	--		<0.03	0.04

[a] Reference 11.
[b] References 12 and 13.
[c] Reference 14.
[d] Based on information indicating condensers reduce emissions by 90 percent.
[e] Control by condensers.
[f] Control by cyclones and, in some cases, by baghouses also.
[g] Assumes 90 percent efficient condenser.

C.9.a
p.97

particulate emissions are relatively small, being 0.04 lbs/1,000 lbs of product or less. Control efficiencies of 99 percent were indicated. Thus, uncontrolled particulate emissions might be around 0.4 lbs/1,000 lbs of product.

Table 5.13-6 summarizes uncontrolled VOC emissions factors for the in-situ process. These emission factors were based on a single plant. An uncontrolled emission rate of about 5.3 lbs VOC/1,000 lbs of product was estimated for an in-situ suspension process. Most of the emission streams are uncontrolled at this plant. However, the reactor emissions are vented to the boiler as primary fuel and some of the dryer emissions are vented to the boiler as supplemental fuel, thereby resulting in some VOC control.

The blowing agent, which is continually diffusing out of the bead in the manufacturing process and during storage, constitute almost all of the VOC emissions from both processes. A small amount of styrene is emitted from the suspension reactors in the post-impregnation process and from the mix tanks and reactors in the in-situ process.

Due to the continual diffusing of the blowing agent, the EPS bead is unstable for long periods of time. Figure 1 shows the loss of blowing agent as a function of time when beads are stored under standard conditions. This diffusion means that the stock of beads must be rotated. An up-to-date analysis of the blowing agent content (measured as percent volatiles at 212°F) of the beads also needs to be maintained as the blowing agent content determines processing characteristics, ultimate density, and economics. Expandable beads should be stored below 90°F and in full containers (to reduce gas volume space).

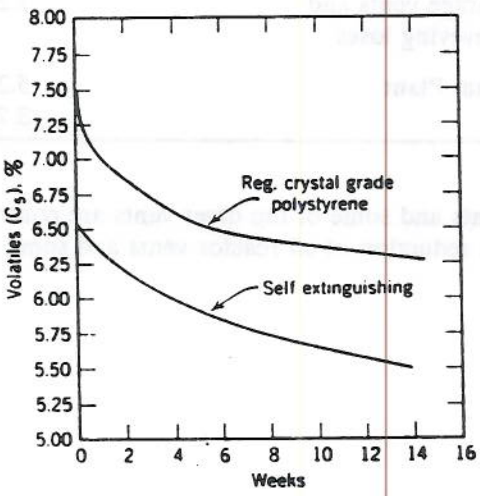


Figure 1. EPS Beads Stored In Fiber Drum at 70-75°F.

Since pentane, a typical blowing agent, forms explosive mixtures, precautionary measures must be taken whenever it is used. For example, after storage containers are opened, a time lag of 10 minutes is suggested to allow fumes or pentane vapors to dissipate out of the containers and care must be exercised to prevent static electricity and sparks from igniting the blowing agent vapors.

C, 9, a
p. 48

TABLE 5.13-6. EMISSION FACTORS FOR IN-SITU PROCESS EXPANDABLE POLYSTYRENE[a]

EMISSION FACTOR RANKING: C

Stream ID	Stream Name	Uncontrolled Nonmethane VOC Emission Factor (lbs VOC/1,000 lbs of product)
A	Mix tank vents	0.3
B	Regranulator hoppers	negligible
C	Reactor vents	1.09[b]
D	Holding tank vents	0.053
E	Wash tank vents	0.023
F	Dryer vents	2.77[b]
G	Product improvement vents	0.008
H	Storage vents and conveying loses	1.2
	Total Plant	5.27 (3.75[c])

[a] Reference 15.

[b] All of the reactor vents and some of the dryer vents are controlled in a boiler.

[c] Assuming 99 percent reduction of all reactor vents and some of the dryer vents.

C.9.0
V.94

References For Section 5.13.3

1. L. F. Albright, Processes for Major Addition-type Plastics And Their Monomers, McGraw-Hill, New York, 1974.

2. Modern Plastics Encyclopedia, 1981-1982, McGraw Hill, New York, 1982.

3. Written communication from E. L. Bechstein, Pullman Kellogg, Houston, TX, to M. R. Clowers, U.S. Environmental Protection Agency, Research Triangle Park, NC, November 6, 1978.

4. Written communication from J. S. Matey, Chemical Manufacturers Association, Washington, DC, to E. J. Vincent, U. S. Environmental Protection Agency, Research Triangle Park, NC, October 19, 1981.

5. Written communication from P. R. Chaney, Mobil Chemical Company, Princeton, NJ, to J. R. Farmer, U. S. Environmental Protection Agency, Research Triangle Park, NC, October 13, 1988.

6. Report of Plant Visit to Monsanto Plastics and Resins Company, Port Plastics, OH, Pacific Environmental Services, September 15, 1982.

7. Written communication from R. Symuleski, Standard Oil Company (Indiana), Chicago, IL, to A. Limpiti, Energy and Environmental Analysis, Inc., Durham, NC, July 2, 1981.

8. Written communication from J. R. Strausser, Gulf Oil Chemicals Company, Houston, TX, to J. R. Farmer, U. S. Environmental Protection Agency, Research Triangle Park, NC, November 11, 1982.

9. Calvin J. Benning, Plastic Foams: The Physics And Chemistry Of Product Performance And Process Technology. Volume I: Chemistry and Physics of Foam Formation, John Wiley and Sons, New York, 1969.

10. S. L. Rosen, Fundamental Principles Of Polymeric Materials, John Wiley and Sons, New York, 1982.

11. Written communication from K. Fitzpatrick, ARCO Chemical Company, Monaca, PA, to D. R. Goodwin, U. S. Environmental Protection Agency, Research Triangle Park, NC, February 18, 1983.

12. Written communication from B. F. Rivers, American Hoechst Corporation, Leominster, MA, to J. R. Farmer, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 4, 1983.

13. Written communication from B. F. Rivers, American Hoechst Corporation, Leominster, MA, to K. Meardon, Pacific Environmental Services, Inc., Durham, NC, July 20, 1983.

14. Written communication from T. M. Nairn, Cosden Oil and Chemical Company, Big Spring, TX, to J. Farmer, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 30, 1983.

15. Written communication from A. D. Gillen, BASF Wyandotte Corporation, Parsippany, NJ, to J. R. Farmer, U. S. Environmental Protection Agency, Research Triangle Park, NC, February 18, 1983.

C, 9, a
p, 100

8.6 PORTLAND CEMENT MANUFACTURING

8.6.1 Process Description

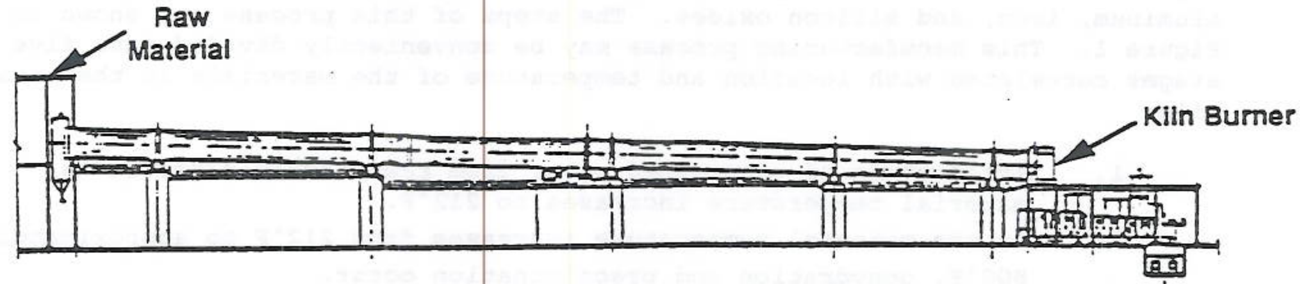
Most of the hydraulic cement in the United States is portland cement. Portland cement, a cementitious, crystalline compound composed of metallic oxides, is produced by a pyroprocess in a rotary kiln from raw materials, e.g., limestone, shale, clay and sand, containing calcium carbonate and aluminum, iron, and silicon oxides. The steps of this process are shown in Figure 1. This manufacturing process may be conveniently divided into five stages correlated with location and temperature of the materials in the rotary kiln:

1. Evaporation of uncombined water from raw materials occurs as material temperature increases to 212°F.
2. As the material temperature increases from 212°F to approximately 800°F, dehydration and precalcination occur.
3. Between 800° and 1650°F, calcination occurs in which carbon dioxide is liberated from the carbonates.
4. Following calcination, sintering of the oxides occurs at temperatures up to 2750°F in the burning zone of the rotary kiln.
5. Following sintering, cement clinker is produced as the temperature of the material decreases from 2750° to 2500°F.

The raw material mix enters the kiln at the elevated end (Figure 8.6-1), and the burner is at the opposite end. The raw materials are then changed into cementitious oxides of metals by a countercurrent, heat-exchange process. The materials are continuously and slowly moved to the lower end by the rotary movement of the kiln. The fuel burned in the kiln is natural gas, oil, or coal. Since 1974, many cement plants have converted to coal but recently supplemental fuels such as waste solvents, chipped rubber, shredded municipal garbage, and coke have been used.

There are three variations in the cement manufacturing process, i.e., wet, dry, and dry preheater/precalciner processes. These processes are essentially identical relative to the manufacture of cement from raw materials. However, the type of process does change the equipment design, the method of operation, and the consumption of fuel. Fuel combustion is different between wet and dry processes and the preheater/precalciner process. In the former, all fuel combustion occurs in the kiln. In the latter, some fuel combustion occurs in a precalcining or calcining vessel before the materials enter the kiln (Figure 8.6-2). Generally speaking, the length of the rotary kiln and the consumption of fuel decrease as the manufacturing process changes from wet to dry to preheater/precalciner equipment for the same mix design of raw materials. However, the relationship is not linear. The Btu/ton significantly decreases as plant configuration changes from wet to dry to preheater/precalciner.

C, 9, a
p, 161



Figures 8.6-1. Conventional kiln.

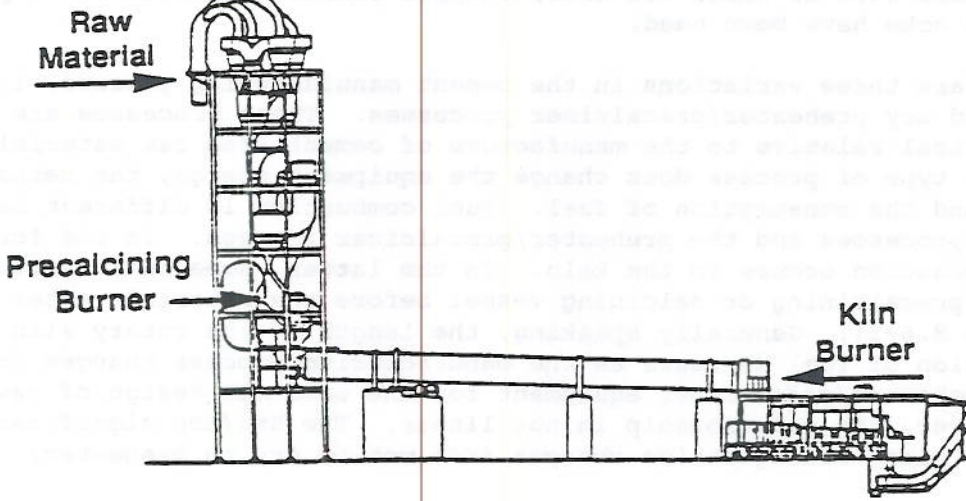


Figure 8.6-2. Preheater/precalciner.

C. 9, a
p. 102

8.6.2 Emissions and Controls

Particulate matter, NO_x and SO_2, CO and CO_2, are the primary emissions in the manufacture of portland cement. But, emissions may also include minute materials form the fuel and raw materials.

Sources of dust at cement plants include (1) quarrying and crushing, (2) raw material storage, (3) grinding and blending (dry process only), (4) clinker production, (5) finish grinding, and (6) packaging (see Figure 8.6-3). The largest source of emissions within cement plants is the kiln operation, which has three units: the feed system, the fuel-firing system, and the clinker-cooling and handling system. The most desirable method of disposing of the collected dust is injection into the burning zone of the kiln and production of clinkers from the dust. If the alkali content of the raw materials is too high, however, some of the dust is discarded or leached before returning to the kiln. In many instances, the maximum allowable cement alkali content of 0.6 percent (calculated as sodium oxide) restricts the amount of dust that can be recycled. Additional sources of dust emissions are raw material storage piles, conveyors, storage silos, and loading/unloading facilities.

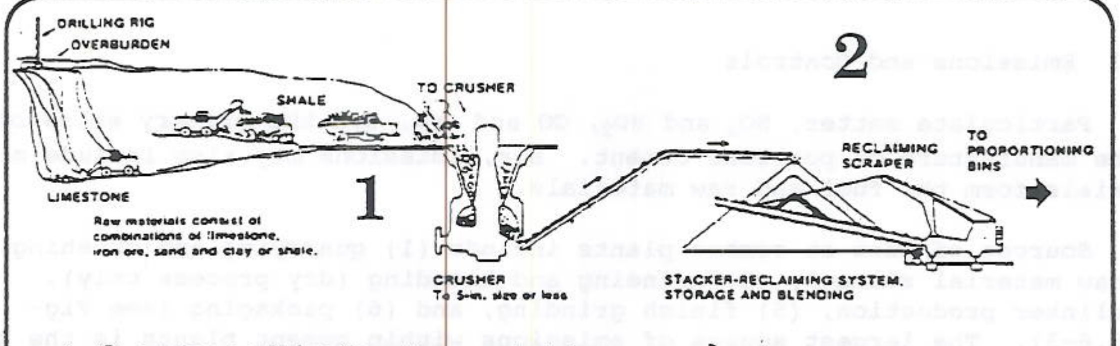
The complications of kiln burning and the large volumes of materials handled have led to the adoption of many control systems for dust collection. Depending upon the emission, the temperature of the effluents in the plant in question, and the particulate emission standards in the community, the cement industry generally uses mechanical collectors, electrical precipitators, fabric filter (baghouse) collectors, or combinations of these devices to control emissions.

Oxides of nitrogen (NO_x) are generated during the fuel combustion by oxidation of chemically bound nitrogen in the fuel and by thermal fixation of nitrogen in the combustion air. As the flame temperature increases, the amount of thermally generated NO_x increases, and the amount of NO_x generated from fuel increases as the quantity of nitrogen in the fuel increases. In the cement manufacturing process, there are two combustion zones in which NO_x may be generated, i.e., the burning zone of the kiln and the burning zone of a precalcining vessel (Figure 1). Also, the type of fuel burned will affect the quantity and type of NO_x generated. Natural gas combustion with a high flame temperature and low fuel nitrogen may generate a different quantity of NO_x than oil or coal, which have higher fuel nitrogen but lower flame temperatures.

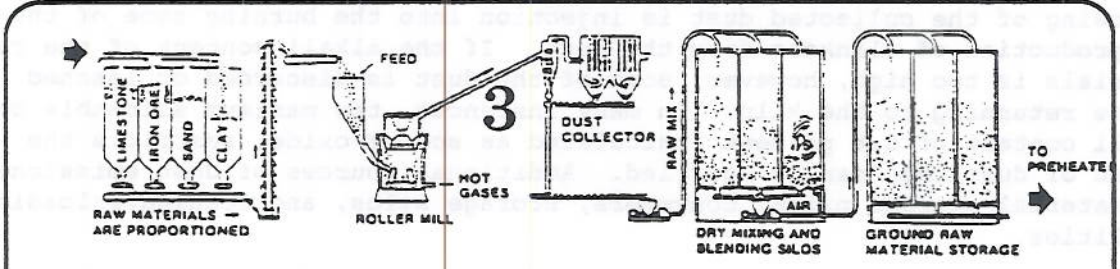
The fuels vary in the cement manufacturing process. Generally, natural gas is used only in the kiln, while coal and oil are used in the kiln and precalcining vessel. Therefore, the generation and emission of NO_x are related to the type of fuel burned and to the extent that fuel affects the flame temperature and contains chemically bound nitrogen.

Presently, there are data to support only two types of reduction of NO_x in the cement industry. First, for conventional wet and dry-process kilns, NO_x emissions are reduced by fuel conversion with coal producing the least amount of NO_x. With new construction, the data are not yet clear. Some preheater/precalciner systems have low emissions; others have high emissions.

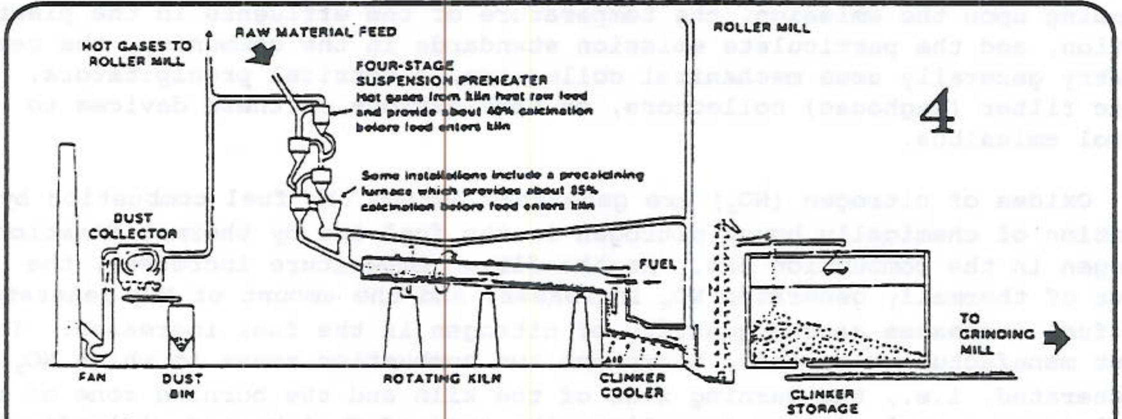
C, 9, a
P, 103



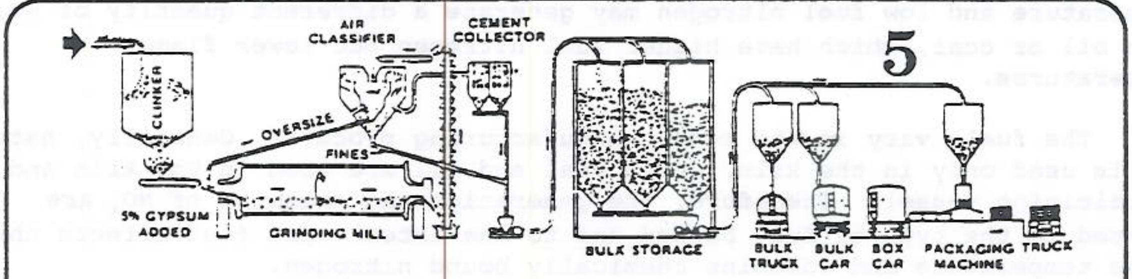
1. Quarrying and blending of raw materials.



2. Proportioning and fine grinding of raw materials.



3. Kiln system. Preheating, burning, cooling and clinker storage.



4. Finish grinding and shipping.

Figure 8.6-3. Steps in the manufacture of portland cement by dry process using preheater.

C19,a
p.104

There is not a single type of preheater/precalciner system used in the cement industry, instead there are at least ten different systems. Each system appears to have unique emissions properties. However, it does appear that for a single system, oil in the calciner produces less NO_x than coal. The No_x emissions from the preheater/precalciner appear to be related to their design. Some have very low emissions and others have emissions in a mid-range of some conventional or wet processes. At the present time, there are insufficient data to choose a NSP system to minimize NO_x emissions.

Sulfur dioxide may be generated from the sulfur compounds in the raw materials, as well as from combustion of fuel. The sulfur content of both raw materials and fuels will vary from plant to plant and with geographic location. The alkaline nature of the cement, however, provides for direct absorption of SO_2 into the product. If a baghouse that allows the SO_2 to come in contact with the cement dust is used, the overall control inherent in the process is approximately 75 percent or greater of the available sulfur in raw materials and fuel. Control, of course, will vary according to the alkali and sulfur content of the raw materials and fuel.

The CO emissions are associated with the efficiency of the combustion process, and the CO_2 is generally a release of 33 percent of the weight of the limestone in the calcining process. Currently, there are no methods available for reducing CO or CO_2 except process control for CO and reduction of production for CO_2.

8.6.3 Emissions Factors

Table 8.6-1 through 8.6-4 give emission factors for cement manufacturing, including factors based on particle size. Size distributions for particulate emissions from controlled and uncontrolled kilns and clinker coolers are also shown in Figures 8.6-4 and 8.6-5.

TABLE 8.6-1. UNCONTROLLED EMISSION FACTORS FOR CEMENT MANUFACTURING[a]--COAL COMBUSTION

Emission Factor Rating: E

Process	Particulate[b]		Sulfur dioxide		Nitrogen oxide		Lead	
	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton
Dry process kiln	128	256	3.5[c]	7.0[c]	2.9[c]	5.7[c]	0.06	0.12
dryer[d]	48	96	–	–	–	–	0.02	0.04
Wet process kiln	120	240	3.0[e]	6.0[e]	4.1[e]	8.2[e]	0.05	0.10
dryer[d]	16	32	–	–	–	–	0.01	0.02
Clunker cooler[f]	4.6	9.2	–	–	–	–	–	–
Preheater kiln	–	–	0.4[e]	0.8[e]	2.8[c]	5.5[c]	–	–
Precalciner kiln	–	–	0.5[c]	1.0[c]	2.4[c]	4.8[c]	–	–

[a] References 1-2. Expressed in terms of units of clinker produced, assuming 5% gypsum in finished cement. Includes fuel combustion emissions, which should not be calculated separately. Dash indicates no data.

[b] Emission Factor Rating: B

[c] Emission Factor Rating: B per Reference 13.

[d] Expressed in terms of units of cement produced.

[e] Emission Factor Rating: C per Reference 13.

[f] Reference 8. Emission Factor Rating: D.

C, 9, h
0.106

TABLE 8.6-2. CONTROLLED PARTICULATE EMISSION FACTORS FOR CEMENT MANUFACTURING[a]

Type of source	Control technology	Particulate		Emission Factor Rating
		kg/Mg clinker	lb/ton clinker	
Wet process kiln	Baghouse	0.57	1.1	C
	ESP	0.39	0.78	C
Dry process kiln	Multiclone	130[b]	260[b]	D
	Multicyclone + ESP	0.34	0.68	C
	Baghouse	0.16	0.32	B
Clinker cooler	Gravel bed filter	0.16	0.32	C
	ESP	0.048	0.096	D
	Baghouse	0.010	0.020	C
Primary limestone crusher[c]	Baghouse	0.00051	0.0010	D
Primary limestone screen[c]	Baghouse	0.00011	0.00022	D
Secondary limestone screen and crusher[c]	Baghouse	0.00016	0.00032	D
Conveyor transfer[c]	Baghouse	0.000020	0.000040	D
Raw mill system[c,d]	Baghouse	0.034	0.068	D
Finish mill system[e]	Baghouse	0.017	0.034	C

[a] Reference 8. Expressed as kg particulate/Mg (lb particulate/ton) of clinker produced, except as noted. ESP = electrostatic precipitator.

[b] Based on a single test of a dry process kiln fired with a combination of coke and natural gas. Not generally applicable to a broad cross section of the cement industry.

[c] Expressed as mass of pollutant/mass of raw material processed.

[d] Includes mill, air separator and weigh feeder.

[e] Includes mill, air separator(s) and one or more material transfer operations. Expressed in terms of units of cement produced.

C,9,a
p.107

TABLE 8.6-3. SIZE SPECIFIC PARTICULATE EMISSION FACTORS FOR CEMENT KILNS[a]

EMISSION FACTOR RATING: D

	Cumulative mass % < stated size[b]						Cumulative emission factor < stated size[c]											
	Uncontrolled				Baghouse		Uncontrolled								Baghouse			
Particle size (µm)	Wet process kiln	Dry process kiln	Dry process kiln with multiclone[d]	Wet process kiln with ESP	Wet process kiln	Dry process kiln	Wet process		Dry process		Dry process with multiclone[d]		Wet process with ESP		Wet process		Dry process	
							kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton
2.5	7.0	18	3.8	64	NA	45	8.4	17	23	46	5.0	10	0.25	0.50	NA	NA	0.075	0.15
5.0	20	NA	14	83	NA	77	24	48	-	-	19	38	0.32	0.64	NA	NA	0.13	0.26
10.0	24	42	24	85	NA	84	29	58	54	108	32	64	0.33	0.66	NA	NA	0.14	0.28
15.0	35	44	31	91	NA	89	43	86	57	114	41	82	0.36	0.72	NA	NA	0.15	0.30
20.0	57	NA	38	98	NA	100	68	136	-	-	49	98	0.39	0.78	NA	NA	0.16	0.32
Total mass emission factor							120[e]	240[e]	128[e]	256[e]	130[f]	260[f]	0.39[f]	0.78[f]	0.57[f]	1.1[f]	0.16[f]	0.32[f]

[a] Reference 8. ESP = electrostatic precipitator. NA = not available. Dash = no data.

[b] Aerodynamic diameter. Percentages rounded to two significant figures.

[c] Expressed as unit weight of particulate/unit weight of clinker produced, assuming 5% gypsum in finished cement. Rounded to two significant figures.

[d] Based on a single test, and should be used with caution.

[e] From Table 8.6-1.

[f] From Table 8.6-2.

C.9.4
P.108

TABLE 8.6-4. SIZE SPECIFIC EMISSION FACTORS FOR CLINKER COOLERS[a]

EMISSION FACTOR RATING: E

Particle size[b] (µm)	Cumulative mass % < stated size[c]		Cumulative emission factor < stated size[d]			
	Uncontrolled	Gravel bed filter	Uncontrolled		Gravel bed filter	
			kg/Mg	lb/ton	kg/Mg	lb/ton
2.5	0.54	40	0.025	0.050	0.064	0.13
5.0	1.5	64	0.067	0.13	0.10	0.20
10.0	8.6	76	0.40	0.80	0.12	0.24
15.0	21	84	0.99	2.0	0.13	0.26
20.0	34	89	1.6	3.2	0.14	0.28
Total mass emission factor			4.6[e]	9.2[e]	0.16[f]	0.32[f]

[a] Reference 8.

[b] Aerodynamic diameter.

[c] Rounded to two significant figures.

[d] Unit weight of pollutant/unit weight of clinker produced. Rounded to two significant figures.

[e] From Table 8.6-1.

[f] From Table 8.6-2.

C, 9, a
p. 109

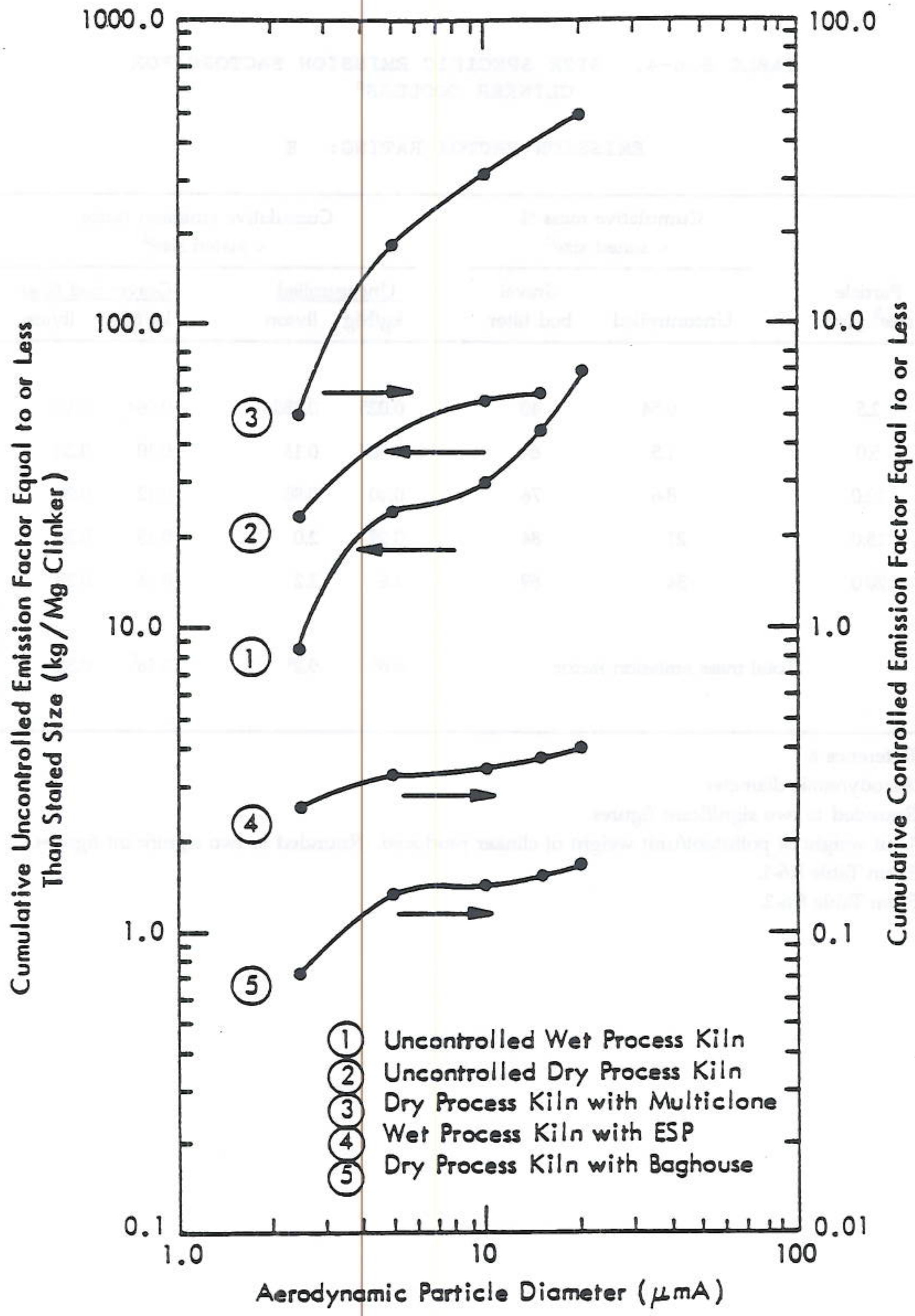


Figure 8.6-4. Size specific emission factors for cement kilns.

C.1.9.6
p.110

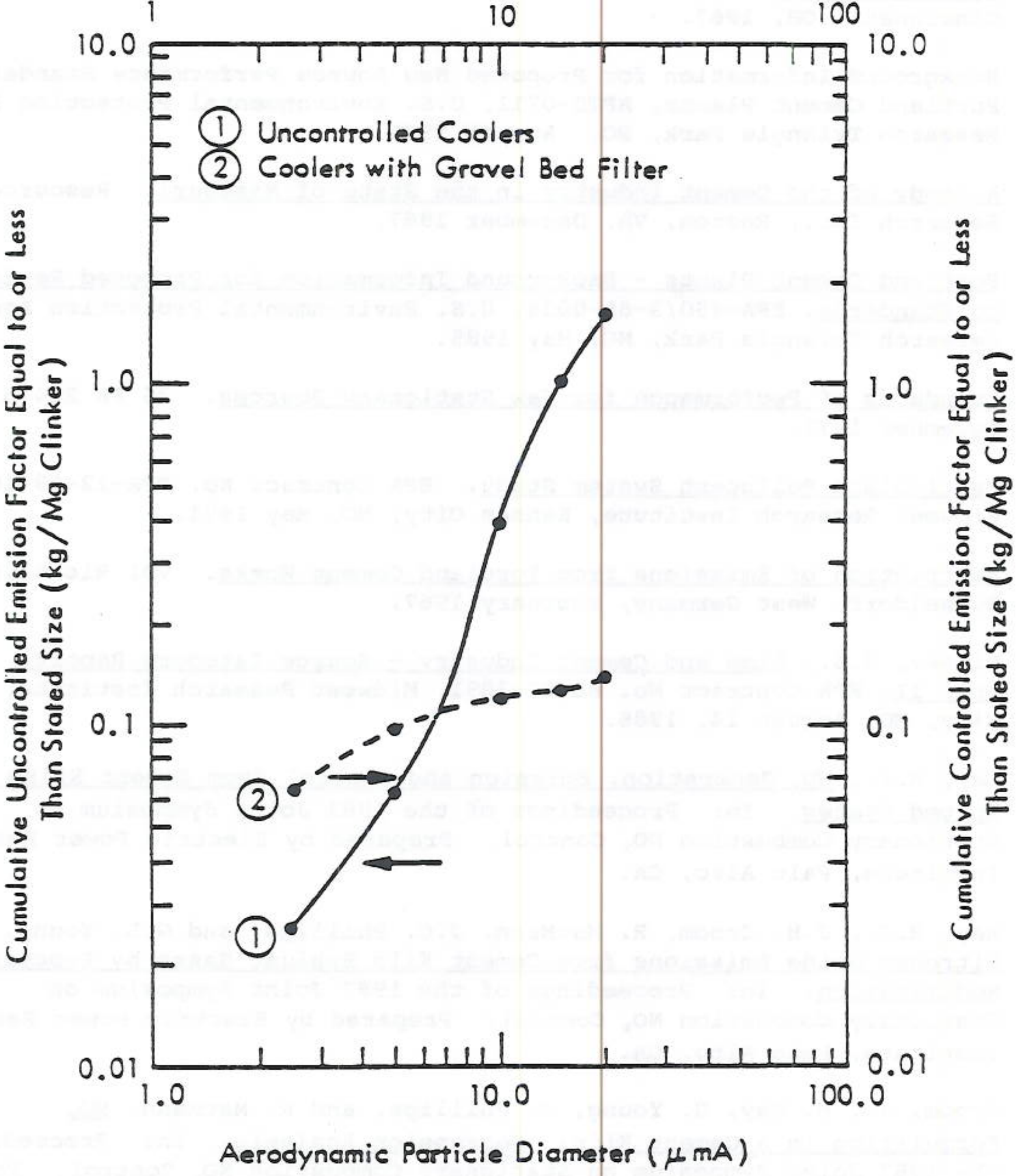


Figure 8.6-5. Size specific emission factors for clinker coolers.

C, 9, a
1.111

REFERENCES

1. Kreichelt, T.E., et al., Atmospheric Emissions from the Manufacture of Portland Cement, 999-AP-17, U.S. Environmental Protection Agency, Cincinnati, OH, 1967.
2. Background Information for Proposed New Source Performance Standards: Portland Cement Plants, APTD-0711, U.S. Environmental Protection Agency, Research Triangle Park, NC. August 1971.
3. A Study of the Cement Industry in the State of Missouri. Resources Research Inc., Reston, VA, December 1967.
4. Portland Cement Plants - Background Information for Proposed Revisions to Standards, EPA-450/3-85-003a, U.S. Environmental Protection Agency, Research Triangle Park, NC, May 1985.
5. Standards of Performance for New Stationary Sources. 36 FR 28476, December 1971.
6. Particulate Pollutant System Study. EPA Contract No. CPA-22-69-104, Midwest Research Institute, Kansas City, MO, May 1971.
7. Restriction of Emissions from Portland Cement Works. VDI Richtlinien. Dusseldorf, West Germany, February 1967.
8. Kinsey, J.S., Lime and Cement Industry - Source Category Report, Vol. II, EPA Contract No. 68-02-3891, Midwest Research Institute, Kansas City, MO, August 14, 1986.
9. May, M.S., NO_x Generation, Emission and Control from Cement Kilns in the United States. In: Proceedings of the 1982 Joint Symposium on Stationary Combustion NO_x Control. Prepared by Electric Power Research Institute, Palo Alto, CA.
10. May, M.S., J.M. Croom, R. MacMann, J.C. Phillips, and G.L. Young, Nitrogen Oxide Emissions from Cement Kiln Exhaust Gases by Process Modification. In: Proceedings of the 1987 Joint Symposium on Stationary Combustion NO_x Control. Prepared by Electric Power Research Institute, Palo Alto, CA.
11. Croom, J., M. May, G. Young, C. Phillips, and R. MacMann, NO_x Formulation in a Cement Kiln: Regression Analysis. In: Proceedings of the 1987 Joint Symposium on Stationary Combustion NO_x Control. Prepared by Electric Power Research Institute, Palo Alto, CA.
12. Methodology for Development of SO_x/NO_x Emission Factor, PSM International, Inc., Dallas, TX, July 26, 1990.

C.9.a
p.1112

13. Bergman, F., <u>Review of Proposed Revision to AP-42 Section 8.6, Portland Cement Manufacturing</u>, EPA Contract No. 68-02-4395, Midwest Research Institute, Kansas City, MO, September 30, 1990.

C.9.a
p.113

11.4 WET COOLING TOWERS

11.4.1 Process Overview[1]

Cooling towers are heat exchangers which are used to dissipate large heat loads to the atmosphere. They are used as an important component in many industrial and commercial processes which need to dissipate heat. Cooling towers may range in size from less than $5(10)^6$ Btu/h ($5.3(10)^6$ kJ) for small air conditioning cooling towers to over $5{,}000(10)^6$ Btu/h ($5{,}275(10)^6$ kJ/h) for large power plant cooling towers.

Although cooling towers can be classified several ways, the primary classification is into dry towers or wet towers. However, some hybrid wet-dry combinations exist. Subclassifications can include the type of draft and/or the location of the draft relative to the heat transfer medium, the type of heat transfer medium, the relative direction of air movement, and the type of distribution system.

When water is used as the heat transfer medium, wet or evaporative cooling towers may be used. Wet cooling towers rely on the latent heat of evaporation of water to exchange heat between the process and the air passing through the cooling tower. The cooling water may be an integral part of the process or provide cooling via heat exchangers.

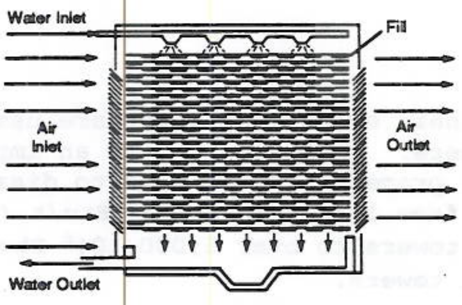
In wet cooling towers, the heat transfer is measured by the decrease in the process temperature and a corresponding increase in the moisture content and wet bulb temperature of the air passing through the cooling tower. (There may also be a change in the sensible or dry bulb temperature; however, its contribution to the heat transfer process is very small and is typically ignored when designing wet cooling towers.) Wet cooling towers typically have a wetted media called "fill" to promote evaporation by providing a large surface area and/or by creating many water drops with a large cumulative surface area.

Cooling towers can be categorized by: the type of heat transfer; the type of draft and location of the draft relative to the heat transfer medium; the type of heat transfer medium; the relative direction of air and water contact; and the type of water distribution system. Since evaporative cooling towers are the predominant type and also generate air pollutants, this section is devoted to this type of tower. Diagrams of the various tower configurations are shown in Figures 11.4-1 and 11.4-2.

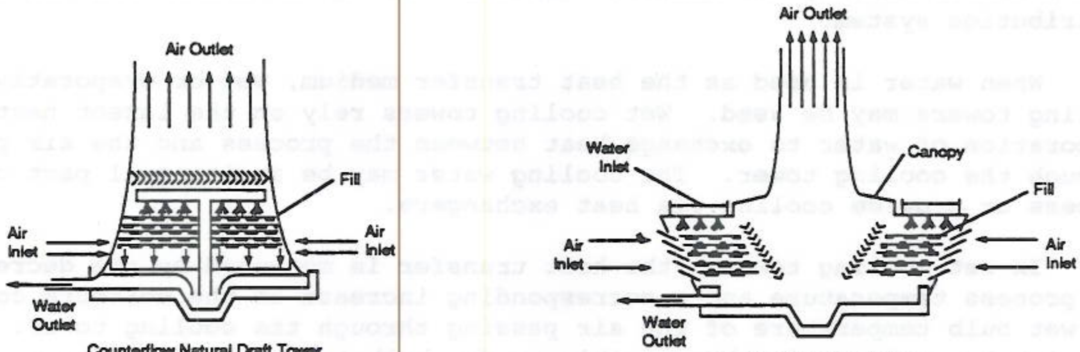
11.4.2 Emissions and Controls[1]

Because wet cooling towers have direct contact between the cooling water and the air passing through the tower, some of the liquid water may be entrained in the air stream and carried out of the tower as "drift" droplets. Therefore, the constituents of the drift droplets may be classified an environmental emission source (i.e., particulate matter).

C.9.a
p.114

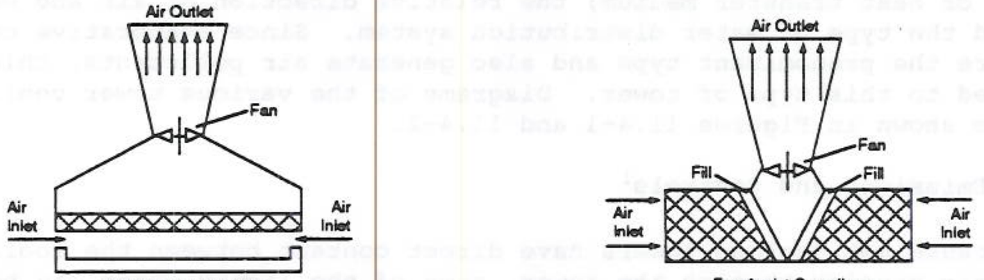


Atmospheric Tower



Counterflow Natural Draft Tower

Crossflow Natural Draft Tower



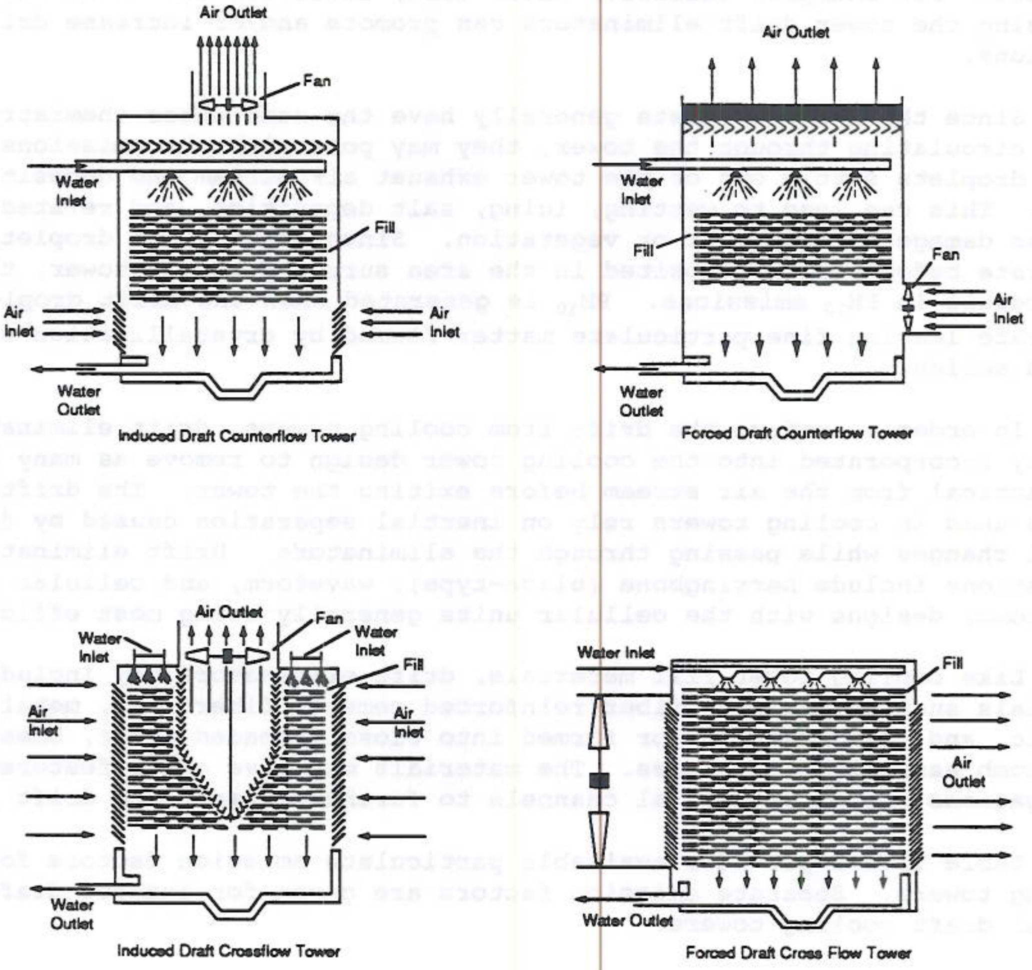
Fan Assist Counterflow Induced Draft

Fan Assist Crossflow Induced Draft

Figure 11.4-1. Atmospheric and natural draft cooling towers.

90-13 SEV kinsey schemA 042590

C.9.a
p.115



Induced Draft Counterflow Tower

Forced Draft Counterflow Tower

Induced Draft Crossflow Tower

Forced Draft Cross Flow Tower

Figure 11.4-2. Mechanical draft cooling towers.

90-23 SEV kinsey schm-c 072090

C.9.a
p.116

The magnitude of drift loss is influenced by the number and size of droplets produced within the cooling tower which in turn is determined by the fill design, the air and water patterns, and other interrelated factors. Tower maintenance and operation can also influence the formation of drift droplets. For example, excessive water flow, excessive air flow, and water bypassing the tower drift eliminators can promote and/or increase drift emissions.

Since the drift droplets generally have the same water chemistry as the water circulating through the tower, they may pose airborne emissions. Large drift droplets settle out of the tower exhaust air stream and deposit near the tower. This can lead to wetting, icing, salt deposition, and related problems such as damage to equipment or vegetation. Since other drift droplets may evaporate before being deposited in the area surrounding the tower, they can also result in PM_{10} emissions. PM_{10} is generated when the drift droplets evaporate leaving fine particulate matter formed by crystallization of dissolved solids.

In order to reduce the drift from cooling towers, drift eliminators are usually incorporated into the cooling tower design to remove as many droplets as practical from the air stream before exiting the tower. The drift eliminators used in cooling towers rely on inertial separation caused by directional changes while passing through the eliminators. Drift eliminator configurations include herringbone (blade-type), waveform, and cellular (or honeycomb) designs with the cellular units generally being most efficient.

Like cooling tower fill materials, drift eliminators may include various materials such as ceramic, fiber reinforced cement, fiberglass, metal, plastic, and wood installed or formed into closely spaced slats, sheets, honeycomb assemblies, or tiles. The materials may have other features such as corrugations and water removal channels to further enhance the drift removal.

Table 11.4-1 provides available particulate emission factors for wet cooling towers. Separate emission factors are given for induced draft and natural draft cooling towers.

References for Section 11.4

1. J. S. Kinsey, et al., Development of Particulate Emission Factors for Wet Cooling Towers, EPA Contract No. 68-02-4395, Assignment No. 35, Midwest Research Institute, Kansas City, MO, July 1990.

C.9.a
p.117

TABLE 11.4-1. PARTICULATE EMISSION FACTORS FOR WET COOLING TOWERS[a]

Type of cooling tower[b]	Heat transfer configuration	Total liquid drift emission factor[c]				Apparent PM_{10} emission factor[d]		
		Percent of circulating water flow	lb/10^3 gal	g/dkL	Emission factor rating	lb/10^3 gal[e]	g/dkL[e]	Emission factor rating
Induced draft	Counter-flow	0.016	1.3	1.5	D	0.024	0.028	E
	Cross-flow	0.033	2.7	3.3	D	0.012	0.015	E
Natural draft	NA	0.00088	0.073	0.088	E	NA	NA	-

[a] From Reference 1. Two significant figures. NA = not available.

[b] See Figures 11.4-1 and 11.4-2.

[c] Total liquid drift refers to water droplets entrained in the air stream exiting a cooling tower. Factors are expressed as: % of circulating water flow (10^{-2} gal drift/gal water flow or 10^{-2} L drift/L water flow); lb drift/10^3 gal circulating water flow; and g drift/dkL circulating water flow. 0.1 lb/10^3 gal = 0.12 g/dkL; 1 dkL = 10^1 L.

[d] Available data not sufficient to develop a true emission factor for wet cooling towers. Apparent emission factor calculated for each source using total drift emission factor and total dissolved solids (TDS) in circulating water assuming: TDS in circulating water = TDS in drift; and 100% conversion of TDS to PM_{10} size particles based on available test data. Does not account for near-source deposition of large droplets. Includes only solid PM_{10} particles.

[e] Emission factors expressed in terms of lb PM_{10}/10^3 gal circulating water flow and g PM_{10}/dkL circulating water flow.

C.9.a
p.118

11.5 INDUSTRIAL FLARES

11.5.1 Process Description

Flaring is a high temperature oxidation process used to burn combustible components of waste gases from industrial operations. Hydrocarbons are the major combustibles in most waste gases flared. In some waste gases, carbon monoxide (CO) is the major combustible component. Waste gases composed of natural gas, propane, ethylene, propylene, butadiene and butane constitute over 95 percent of the material flared. In combustion, gaseous hydrocarbons react with atmospheric oxygen to form carbon dioxide (CO_2) and water. Presented below as an example is the combustion reaction of propane.

$$C_3H_8 + 5\ O_2 \text{ ---> } 3\ CO_2 + 4\ H_2O$$

During a combustion reaction, several intermediate products are formed and eventually, most of them are converted to CO_2 and water. Some quantities of stable intermediate products such as carbon monoxide, hydrogen and hydrocarbons escape as emissions.

Flares are used extensively to burn purged and waste products from refineries, unrecoverable gases emerging with oil from oil wells, vented gases from blast furnaces, unused gases from coke ovens, and gaseous wastes from chemical industries. Gases flared from refineries, petroleum production, chemical industries and, to some extent, those flared from coke ovens are composed largely of low molecular weight hydrocarbons with high heating value. The gases flared from blast furnaces are composed largely of inert species and CO and have low heating value. Flares are also used for burning waste gases generated by sewage digesters, coal gasification, rocket engine testing, nuclear power plants with sodium/water heat exchangers, heavy water plants and ammonia fertilizer plants.

There are two types of flares: elevated and ground flares. Elevated flares, the most common type, have larger capacities than ground flares. In elevated flares a waste gas stream is fed through a stack 10 to over 100 meters tall and combusted at the tip of the stack. The flame is exposed to atmospheric disturbances such as wind and precipitation. In ground flares combustion takes place at ground level. Ground flares vary in complexity and may consist either of conventional flare burners discharging horizontally with no enclosures or multiple burners in refractory-lined steel enclosures.

The flare system typically consists of 1) a gas collection header and piping for collecting gases from processing units, 2) a knockout drum (disentrainment drum) to remove and store condensables and entrained liquids, 3) proprietary seal, water seal, or purge gas supply to prevent flash back, 4) a single or multiple burner unit and a flare stack, 5) gas pilots and an ignitor to ignite the mixture of waste gas and air, and, if required, 6) a provision for external momentum force (steam injection or forced air) for smokeless flaring. Natural gas, fuel gas, inert gas or nitrogen can be used as purge gas. Figure 11.5-1 is a diagram of steam-assisted elevated smokeless flare systems with typical components.

Sufficient combustion air and proper mixing of air and waste gas are required for complete combustion. Smoking may result from combustion depending upon the waste gas components and the quantity and distribution of combustion air. Waste gases containing methane, hydrogen, CO and ammonia usually burn without smoke. Waste gases containing heavy hydrocarbons such as paraffins above methane, olefins and aromatics cause smoke. External momentum force such as steam injection, the most common method, or blowing air is used for efficient air/waste gas mixing and turbulence for smokeless flaring of heavy hydrocarbon waste gas. Other external forces used for this purpose include water spray, high velocity vortex action or natural gas. External momentum force is rarely required in ground flares.

Steam injection is accomplished either by nozzles on an external ring around the top of the flare tip or by a single nozzle located concentrically within the tip. At some flare installations, these two methods are combined for use with varied waste gas flow conditions. The internal nozzle provides steam at low waste gas flow rates while the external jets are used for large waste gas flow rates. There are several other

C, 9.a
p. 119

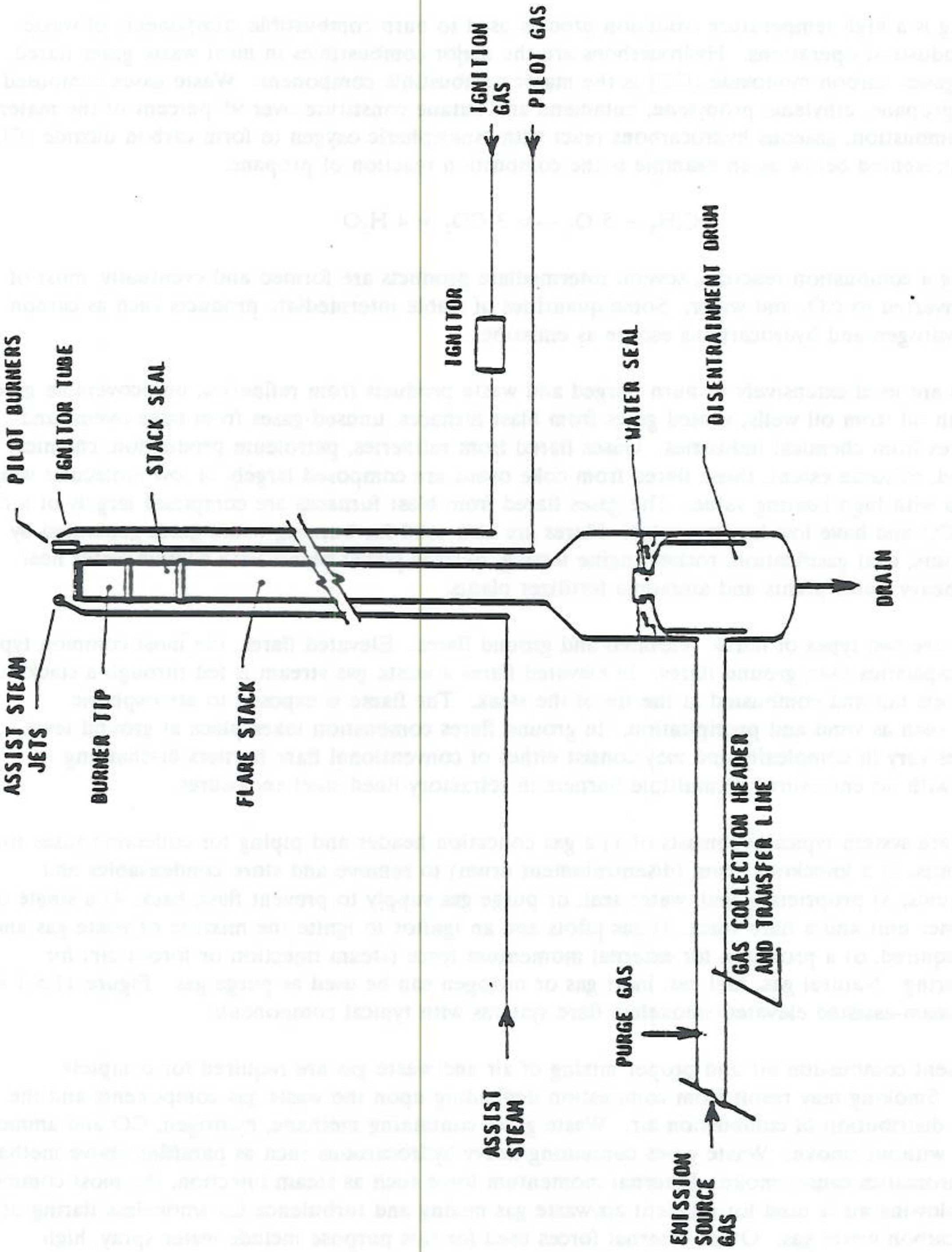


Figure 11.5-1. Diagram of steam-assisted smokeless elevated-flare system.

C.9.a
1.120

special purpose flare tips commercially available. One of these is for injecting both steam and air. Typical steam usage ratio varies from 7:1 to 2:1 on a weight basis.

Waste gases to be burned in flares must have a fuel value of at least 7,500 to 9,300 kJ/m^3 (200 to 250 Btu/ft^3) for complete combustion. If lacking such fuel value they must be supplemented with additional fuel. Flares providing supplemental fuel to waste gas are known as fired or endothermic flares. Some cases of waste gases having higher than minimum heat contents also require supplemental heat. One such case is ammonia flaring with a heating value of 13,600 kJ/m^3 (365 Btu/ft^3) and the presence of fuel-bound nitrogen which has a quenching effect on the flare. A higher heat content is required to minimize nitrogen oxide (NO_x) formation.

At many locations, flares are intended and designed to handle large quantities of intermittent waste gases generated during plant emergencies. These flares usually dispose of low volume continuous emissions during normal operations. Typical flare gas volumes vary from a few cubic meters per hour during regular flaring to several thousand cubic meters per hour during major upsets. For example, flow rates at a typical refinery could range from 45-90 kg/hr (100-200 lb/hr) for relief valve leakage to full plant emergency rate of 700 Mg/hr (750 tons/hr). Normal process blowdowns may release 450-900 kg/hr (1,000-2,000 lb/hr) and unit maintenance or minor failures may release 25-35 Mg/hr (27-39 tons/hr). At these typical flow rates, a waste gas of 40 molecular weight represents a minimum of 0.012 Nm^3/sec (25 scfm) to as high as 115 Nm^3/sec (241,000 scfm). The required flare turndown ratio for this typical case is over 15,000 to 1.

Many flare systems have two flares connected in parallel or in series. Parallel flares have the advantage that one flare can be shut down for maintenance while the other serves the system. In systems of flares in series, one flare, usually a low-level ground flare, is intended to handle regular low gas volumes and the other, an elevated flare, handle excess gas flows resulting from emergencies.

11.5.2 Emissions

Noise and heat are the most apparent undesirable effects of flare operation. Usually flares are located away from populated areas or sufficiently isolated, thus minimizing noise and heat effects on populations.

Emissions from flaring include carbon particles (soot), unburned hydrocarbons, and CO and other partially burned and altered hydrocarbons. Also released from the flares are emissions of nitrogen oxides (NO_x) and, if sulfur-containing material such as hydrogen sulfide or mercaptans is flared, sulfur dioxide (SO_2). The quantities of hydrocarbon emissions generated are related to the degree of combustion. The degree of combustion depends largely on the rate and extent of fuel-air mixing and the flame temperatures achieved and maintained. Properly operated flares achieve at least 98 percent combustion efficiency in the flare plume, meaning that the emissions of hydrocarbons and CO amount to less than 2 percent of input hydrocarbons.

The tendency of a fuel to smoke or soot is influenced by fuel characteristics as well as the amount and distribution of oxygen in the combustion zone. For complete combustion, at least the stoichiometric amount of oxygen must be provided in the combustion zone. The theoretical amount of oxygen required increases with the molecular weight of the gas burned. The oxygen supplied as air ranges from 9.6 units of air per unit of methane to 38.3 units of air per unit of pentane on a volume basis. Air is supplied to the flame as primary air and secondary air. Primary air is premixed with the gas prior to combustion, whereas secondary air is that drawn into the flame. For smokeless combustion, sufficient amount of air must be supplied as primary air. The amount of primary air required varies from about 20 percent of stoichiometric air for a paraffin to about 30 percent for an olefin. If the amount of primary air is insufficient, the gases entering the base of the flame are preheated by the heat from the combustion zone. As a result, larger hydrocarbon molecules crack to form hydrogen, unsaturated hydrocarbons and carbon. The carbon particles may escape further combustion and cool down to form soot or smoke. Olefins and

C.9.a
p.121

other unsaturated hydrocarbons may polymerize to form larger molecules which crack, in turn forming more carbon.

The fuel characteristics that influence soot formation include the carbon-to-hydrogen ratio and the molecular structure of the gases to be burned. All hydrocarbons above methane, i.e., those with a C-to-H ratio of greater than 0.33 tend to soot. Branched chain paraffins smoke more readily than corresponding normal isomers. The more highly branched the paraffin, the greater the tendency to smoke. Unsaturated hydrocarbons tend more toward soot formation than saturated ones. The addition of steam or air eliminates soot; for this reason most industrial flares are steam-assisted and some are air-assisted. The flare gas composition is a critical factor in determining the amount of steam necessary.

Since flares do not lend themselves to conventional emission testing techniques, only a few attempts have been made to characterize flare emissions. Recent EPA tests using propylene as flare gas indicated that efficiencies of 98 percent can be achieved when burning an offgas with at least 11,200 kJ/m^3 (300 Btu/ft^3). The tests conducted on steam-assisted flares at velocities as low as 0.66 m/sec (130 ft/min) to 19 m/sec (3,750 ft/min), and on air-assisted flares at velocities of 3 m/sec (617 ft/min) to 66 m/sec (13,087 ft/min) indicated that variations in incoming gas flow rates have no effect on the combustion efficiency. Flare gases with less than 16,770 kJ/m^3 (450 Btu/ft^3) do not smoke.

Table 11.5-1 presents flare emission factors and Table 11.5-2 presents emission composition data obtained from the EPA tests.[1] Crude propylene was used as flare gas during the tests. Methane was a major fraction of hydrocarbons present in the flare emissions, and acetylene was a predominant intermediate hydrocarbon species. Many other reports on flares indicate that acetylene is always formed as a stable intermediate product. The acetylene formed in the combustion reactions may further react with hydrocarbon radicals to form polyacetylenes followed by polycyclic hydrocarbons.[2]

In the case of flaring waste gases containing no nitrogen compounds, NO is formed by either the fixation of atmospheric nitrogen with oxygen or by the reaction between the hydrocarbon radicals present in the combustion products and atmospheric nitrogen, by way of the intermediate stages, HCN, CN, and OCN.[2] Sulfur compounds contained in a flare gas stream are converted to SO_2 upon burning. The amount of SO_2 emitted depends directly on the quantity of sulfur in the flared gases.

Table 11.5-1. EMISSION FACTORS FOR FLARE OPERATIONS[a]

Component	Emission Factor, lb/10^6 Btu
Total Hydrocarbons (THC)[b]	0.14
Carbon Monoxide (CO)	0.37
Nitrogen Oxides (NO_x)	0.068
Soot[c]	0 to 274

[a] Reference 1. Based on tests using crude propylene containing 80 percent propylene and 20 percent propane.

[b] Measured as methane equivalent.

[c] Soot is reported in concentration values, µg/liter: zero for nonsmoking flares, 40 µg/l for lightly smoking flares, 177 µg/l for average smoking flares, and 274 µg/l for heavily smoking flares.

C.9.a
p122

Table 11.5-2. FLARE EMISSION, HYDROCARBON COMPOSITION[a]

Composition	Average (range), Volume %	
Methane	55	(14-83)
Ethane/Ethylene	8	(1-14)
Acetylene	5	(0.3-23)
Propane	7	(0-16)
Propylene	25	(1-65)

[a] Reference 1. The composition presented is an average of a number of test results obtained under the following sets of test conditions: steam-assisted flare using high Btu content feed, steam-assisted using low Btu content feed, air-assisted flare using high Btu content feed, and air-assisted flare using low Btu content feed. In all tests "waste" gas was a synthetic gas consisting of a mixture of propylene and propane.

References for Section 11.5.

1. Engineering Science, Inc. Flare Efficiency Study, Industrial Environmental Research Laboratory, Report No. EPA-600/2-83-052, July 1983.

2. K. D. Siegel, Degree of Conversion of Flare Gas in Refinery High Flares, Ph. D. Dissertation, University of Karlsruhe, (Germany), February 1980.

3. <u>Manual On Disposal Of Refinery Wastes, Volume On Atmospheric Emissions, Chapter 15-Flares,</u> API Publication 931, American Petroleum Institute Refining Department, Washington, D.C., June 1977.

C, 9, a
11, 123

From:	Garwood, Gerri
Sent:	Monday, September 15, 2014 9:33 AM
To:	Cathe Kalisz
Subject:	FW: Coker Emissions
Attachments:	DCU_vent_summary_v4_Dahl.xlsx

Hi Kathe,

Attached is the spreadsheet that RTI used in developing Table 5-5 in the protocol, and a short explanation Jeff provided. If you still have questions, please let me know, and I will set up a call with Jeff and Brenda.

Thanks,

Gerri G. Garwood, P.E.

U.S. Environmental Protection Agency
OAR/OAQPS/SPPD
Measurement Policy Group
Ph: 919-541-2406 Fax: 919-541-3207

Gerri,
The coker studies are not very uniform in how they were done and what they tested for. The attached spreadsheet is a compilation of the data we have with summary emission factors calculated.

The sheet “pollutant_tables” has most of the summary data. The table “Summary” has more data for some of the other POM compounds. These data were used to develop the emission factors in the 1st and 3rd emission factor columns.

The emission factors (concentrations) in the 2nd column are calculated from the lb/1,000 lb steam emission factors, but it is assumed that the dry gas concentration is 2x higher after active steam generation stops. The moisture content of most of the venting process is 97 to 99% (assume 98% as a typical value). For use in Equation 11-1, it is assumed that the dry gas composition is the same, but the moisture content is half that during active steaming generation (i.e., moisture content is about 96% so I have twice as much pollutant emissions per amount of steam or total gas released). The calculation is essentially

VolFraction = 2 *EmF (lb/1,000 lb steam) / (MWt_poll * 1000/18)

From:	Cathe Kalisz <kaliszc@api.org>
Sent:	Wednesday, October 01, 2014 1:16 PM
To:	Garwood, Gerri; Gary Mueller
Cc:	Scott Evans (sevans@cleanair.com)
Subject:	Flare Emission Factors - Question

All:

Below is a question from Scott for discussion during our call at 3PM.

> 1) It seems with the equation in Column BA (on the AU tab), you are attempting to estimate the volumetric flow rate of the products of combustion. If my understanding is correct, how do you explain the result that you get up to 14,000 scfs of product for every scf of reactant gas? If my understanding is not correct can you explain what you are attempting here?

Cathe

Cathe Kalisz, P.E.
Policy Advisor
American Petroleum Institute
1220 L Street NW
Washington, DC 20005
PH: (202) 682-8318
FAX: (202) 682-8270
kaliszc@api.org

Garwood, Gerri

From:	Garwood, Gerri on behalf of RefineryFactor
Sent:	Thursday, October 02, 2014 10:25 AM
To:	Gurinder (Gary) Saini
Subject:	RE: [chief] Revised email with updated link - disregard previous email

Gurinder,

The spreadsheet you attached does contain all of the sources that are used as well as the sources that are not used in the factor development. The file has been filtered to show only the sources not used. If you turn off the filter on column DD, you will be able to see all of the sources.

We hope that this helps.

Sincerely,
The Emissions Factor Team

From: Gurinder (Gary) Saini [mailto:saini@rtpenv-nc.com]
Sent: Thursday, October 02, 2014 9:11 AM
To: RefineryFactor
Subject: FW: [chief] Revised email with updated link - disregard previous email

I am reviewing the background data for NOx emissions from SRUs AP-42 Chapter 8.13. The attached NOx spreadsheet from the website does not contain all the sources. Specifically it only lists source tests that were not included and does not provide tests that were included. The CO spreadsheet on the other hand includes all tests. Can this be corrected and if possible send me the complete file for NOx from SRUs.

Regards

GS
919-845-1422 Ext. 42

From: CHIEF Info [mailto:info.chief@epa.gov]
Sent: Tuesday, August 19, 2014 15:51
To: Gurinder Saini
Subject: [chief] Revised email with updated link - disregard previous email

August 19, 2014 ? EPA is proposing new and revised emissions factors for flares and new emissions factors for certain refinery process units. We are also proposing revisions to the refinery protocol document and proposing no changes to VOC emissions factors for tanks and wastewater treatment systems. We seek your comments on all aspects of these proposed actions regarding new and revised emissions factors for flares, proposed revisions to the refinery protocol document, as well as on the newly proposed emission factors for certain process units at refineries. We also seek your comments on our proposed determination that revisions to the VOC emission factors for tanks and wastewater treatment systems are not necessary. The proposed revisions and supporting documentation can be accessed at the following link: http://www.epa.gov/ttn/chief/consentdecree/index_consent_decree.html.

Please submit your written comments on the above referenced documents and the proposed actions to AP-42 by October 19, 2014.

Comments should be e-mailed to refineryfactor@epa.gov.

From: Cathe Kalisz <kaliszc@api.org>
Sent: Monday, October 06, 2014 3:54 PM
To: Garwood, Gerri
Subject: Questions - Proposed Revisions to Refinery Emissions Estimation Protocol

Gerri,

Below are some additional questions that we have regarding the Refinery Protocol estimation methods for Cokers and FCCUs. Some proposed times for a call to get clarification on these items are this Wednesday 10/8 at 3PM EDT or later or Thursday 10/9 anytime between 9AM – 2PM EDT.

Thanks,

Cathe

Questions for Coker Method Rank 4:

1. The Emissions Estimation Protocol states that emissions from draining coker quench water should be estimated using the weir model in RWET and that emissions from cutting water storage should be estimated using the equalization tanks model in RWET. Verify that emissions from cascading cutting water are not expected (weir model).

2. How did you determine that draining emissions were required if draining is initiated sooner than 1 hour after the start of venting (i.e., how did you choose this timeframe?)

3. Can you confirm that emissions from the coker water storage are NOT required if draining is initiated later than 1 hour after the start of venting?

4. The equalization tanks model in RWET has a required input of number of aerators/power to aerators. There is also a quiescent unit model in RWET but it requires a BOD concentration. Neither of these models seem transferable to coker water storage.

5. Please provide an explanation of the calculation methodology for the weir model including a definition of variables and reference.

6. Is the weir height the distance the water falls from the bottom of the coker vessel to the coker pit? AP42 specifies that weir height is the distance from wastewater overflow to the receiving body of water. RWET doesn't specify.

7. Should the wastewater flow rate include only the flow of quench water or the total of quench water flow plus cutting water flow (related to Question 1)?

8. Does EPA have guidance for what measurement should be used for the length of the weir (e.g. should we use the diameter of the opening in the bottom of the coker?)

9. Does EPA have an expectation regarding how drain water concentration is to be estimated?

Question re FCCU Factors

1. Is there supporting documentation for the FCCU HCN factor expressed as lb/klbs coke burnoff?

Cathe Kalisz, P.E.
Policy Advisor
American Petroleum Institute
1220 L Street NW
Washington, DC 20005
PH: (202) 682-8318
FAX: (202) 682-8270
kaliszc@api.org

Garwood, Gerri

From:	Garwood, Gerri
Sent:	Wednesday, October 08, 2014 2:23 PM
To:	Sparsh Khandeshi
Subject:	RE: Oct. 19 Emission Factor Deadline for Public Comments

Sparsh,

As the deadline is a Sunday, we will accept comments until Monday, Oct. 20.

Thanks,
Gerri
919-541-2406

From: Sparsh Khandeshi [mailto:skhandeshi@environmentalintegrity.org]
Sent: Wednesday, October 08, 2014 10:34 AM
To: Garwood, Gerri
Subject: Oct. 19 Emission Factor Deadline for Public Comments

Gerri,

The emission factor deadline for public comments is Oct. 19 which is a Sunday. Will EPA be accepting comments until Oct. 19, the Friday before, or the Monday after the deadline?

Thanks.

Best,
Sparsh Khandeshi
Attorney
Environmental Integrity Project
1000 Vermont Ave., NW
Eleventh Floor
Washington DC, 20005
Phone: 202-263-4446
Fax: 202-296-8822

From:	Lisa Beal <lbeal@ingaa.org>
Sent:	Thursday, October 09, 2014 2:56 PM
To:	Garwood, Gerri
Cc:	Brianne Kurdock; Carol Butero; Tom Bach
Subject:	RE: AP-42 Flare Comments - What is the Due Date?

Thank you!

From: Garwood, Gerri [mailto:Garwood.Gerri@epa.gov]
Sent: Thursday, October 9, 2014 2:15 PM
To: Lisa Beal
Cc: Brianne Kurdock; Carol Butero; Tom Bach
Subject: RE: AP-42 Flare Comments - What is the Due Date?

Hi Lisa,

We are going to accept comments until Oct. 20th. We apologize for the confusion.

Sincerely,
Gerri G. Garwood, P.E.

U.S. Environmental Protection Agency
OAR/OAQPS/SPPD
Measurement Policy Group
Ph: 919-541-2406 Fax: 919-541-3207

From: Lisa Beal [mailto:lbeal@ingaa.org]
Sent: Thursday, October 09, 2014 2:06 PM
To: Garwood, Gerri
Cc: Brianne Kurdock; Carol Butero; Tom Bach
Subject: AP-42 Flare Comments - What is the Due Date?

Hello –

INGAA is drafting comments to the proposed AP-42 revisions for flares. Based on the notice the comments are due by October 19, 2014 which is a Sunday. Can you please verify whether the comments should be filed on Friday October 17th or Monday October 20th.

Thank you,

Lisa S. Beal
VP, Environment & Construction Policy
INGAA
20 F Street NW
Suite 450
Washington, DC 20001
(O) 202-216-5935
(M) 202-256-9134

The linked image cannot be displayed. The file may have been moved, renamed, or deleted. Verify that the link points to the correct file and location.

From: Chetkowski, David <David.Chetkowski@monroe-energy.com>
Sent: Friday, October 10, 2014 6:06 PM
To: RefineryFactor
Subject: Flare NOX EF Comments - Draft AP-42 Chapter 13.5
Attachments: 20141009 Monroe Energy Flare NOX EF Comments.pdf

Attached please find Monroe Energy's comments regarding the proposed revisions to the NOX emission factor for industrial flares (Draft AP-42 Chapter 13.5).

Thank you,
David

David M. Chetkowski, P.E.
Air Program Lead
Monroe Energy, LLC
4101 Post Rd, Trainer PA 19061
Office: (610) 364-8528 | Cell: (610) 717-2495

Monroe Energy®

Monroe Energy, LLC
4101 Post Road
Trainer, PA 19061
(610) 364-8000

October 10, 2014

BY ELECTRONIC MAIL: refineryfactor@epa.gov

U.S. Environmental Protection Agency

Re: Proposed Revisions to AP-42 Chapter 13: Miscellaneous Sources
Section 13.5 Industrial Flares

Dear Sir or Madam:

Monroe Energy, LLC (Monroe Energy or Monroe) is pleased to submit the attached comments regarding the U.S. Environmental Protection Agency's ("U.S. EPA's") proposed revision of AP-42 Compilation of Air Pollutant Emission Factors, Chapter 13: Miscellaneous Sources, Section 13.5 Industrial Flares. Monroe's comments submitted herein are specific to U.S. EPA's proposed revision of the AP-42 industrial flare nitrogen oxides (NO_X) emission factor. Monroe owns and operates a petroleum refinery located on the Delaware River in Trainer, Pennsylvania (Trainer Refinery, or Refinery). The AP-42 industrial flare NO_X emission factor is used to estimate emissions from refinery flares for purposes of rulemaking, air quality permitting, emission inventory reporting, and compliance monitoring. As an owner and operator of the Trainer Refinery that will be affected by a change in the AP-42 industrial flare NO_X emission factor, Monroe has a significant interest in this proposed action.

Should you have any questions regarding our comments, please feel free to call me at (610) 364-8528.

Sincerely,
MONROE ENERGY, LLC

David M. Chetkowski, P.E.
Air Program Lead

Attachment

Monroe Energy, LLC (Monroe) Comments
Proposed Revisions to AP-42 Section 13.5 Industrial Flares
NO_X Emission Factor for Industrial Flares
October 10, 2014

1. U.S. EPA used inappropriate and limited data to develop the proposed revised AP-42 industrial flare nitrogen oxides (NO_X) emission factor.

U.S. EPA developed the proposed industrial flare NO_X emission factor (EF) by averaging the results of five (5) different emission tests and the existing AP-42 emission factor. The values U.S. EPA included in this average are summarized in Table 1.

Table 1
Summary of NO_X Test Results[(a)]

Facility Name	Flare Type	Average Test Results (lb NO_X/MMBtu)
FHRAU Flint Hills Resources Port Arthur, LLC in Port Arthur, TX	Steam-Assisted	16
MPCDET Marathon Petroleum Company, LLC, Detroit, MI	Steam-Assisted	0.011
INEOS ABS Corporation in Addyston, OH	Steam-Assisted	0.47
TCEQ Tests Conducted in John Zink Facility	Steam-Assisted	0.13
TCEQ Tests Conducted in John Zink Facility	Air-Assisted	0.58
Existing AP-42 NO_X Emissions Factor for Flares (OLD)[(b)]	Flare	0.068
Proposed Updated AP-42 Emission Factor	**All Industrial Flares**	**2.9**

[(a)] Table developed based on data in Table 21 – Analysis of Emissions Test Reports for NO_X From Flares of the U.S. EPA developed document titled *"DRAFT Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations"*.
[(b)] AP-42 5th Edition, Chapter 13.1, dated 9/1991.

All five (5) of the tests used to develop the proposed emission factor were not conducted in order to determine NO_X emissions. The five (5) tests were all conducted to determine the effect of varying operating conditions on the flare combustion efficiency. The data from all of the locations and varying operating conditions were paired down to include only the data which occurred during what U.S. EPA considered "normal" operating conditions. U.S. EPA deemed "normal" operating conditions as those periods which resulted in a combustion efficiency of greater than or equal to 96.5%. Under this criterion "normal" operating conditions made up only approximately 31% of all available data from the five (5) tests. After this, NO_X emissions were calculated by manipulating the data collected during just these "normal" periods of testing. This approach resulted in only including a limited amount of already questionable data. U.S. EPA itself alluded to the questionable nature of this data on page 31 of the document titled *"DRAFT EPA Review of Available Documents for Developing Proposed Emissions Factors for Flares, Tanks and Wastewater Treatment Systems"* where it states, "It ***may be possible*** to use these data to revise emissions factors for CO and NOx …" (emphasis added).

The test data used by U.S. EPA to develop the proposed industrial flare NO_X EF are inappropriate on the surface, as the testing that produced the data was not intended to produce NO_X emissions results, and more than two-thirds of the data collected during the test programs was discarded by U.S. EPA because it was collected during periods that were not "normal". U.S. EPA's manipulation of the available data raises further question on the validity of the data for use in developing an EF for wide use to be representative of normal operating conditions of a flare. U.S. EPA must use a robust set of specific NO_X emissions data that is representative of normal flare operation to develop any revision to the industrial flare NO_X EF.

2. U.S. EPA has improperly included a statistical outlier in the data used to develop the proposed new AP-42 industrial flare nitrogen oxide (NO_X) emission factor.

U.S. EPA's averaging of all the results of five (5) different emission tests and the existing AP-42 emission factor presented in Table 1 results in U.S. EPA's proposed updated industrial flare NO_X EF of 2.9 lb NO_X/MMBtu. This proposed new emission factor is 4,165% larger than the existing AP-42 emission factor of 0.068 lb NO_X/MMBtu. Such a drastic increase seems implausible, and for good reason. Even just a cursory review of the values shown in Table 1 reveals that the 16 lb NO_X/MMBtu emission result test from the FHRAU Flint Hills Resources Port Arthur, LLC (Flint Hills) Facility, located in Port Arthur, Texas is orders of magnitude greater than any of the other results obtained from the other tests, providing a clear indication that there is an outlier in the data set which should not have been included. However, U.S. EPA concluded on page 40 of the document titled *"DRAFT Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations"*, that no statistical outliers were used in the calculation of the proposed new NO_X emission factor. U.S. EPA concluded that the Flint Hills test result is not an outlier based on a statistical outlier test known as the Dixon Q test. The Dixon Q test is performed using the following equation:

$$Dixon\ Q = \frac{Gap}{Range}$$

Where: Gap = the difference between the value being tested for an outlier determination, and the closest value in the dataset to this value.
Range = the difference between the highest value in the data set and the lowest value in the data set.

Table 2 shows U.S. EPA's approach in determining the statistical outlier. U.S. EPA applied the Dixon Q formula to the natural log of each test result presented in Table 1 (not the actual test result values). This produced results indicating there were no statistical outliers. Using the

Table 2

Monroe Energy, LLC - Trainer Refinery, PA

U.S. EPA Dixon Q Outlier Test

Facility Name	Average Test Result	Natural Log of Average Test Results	Dixon Q - Gap	Dixon Q - Range	Dixon Q Test Results	Outlier?[(a),(b)]
	lb/MMBtu					
FHRAU Flint Hills Resources Port Arthur, LLC in Port Arthur, TX	16	2.77	3.32	7.28	0.46	No
MPCDET Marathon Petroleum Company, LLC, Detroit, MI	0.011	-4.51	1.82	7.28	0.25	No
INEOS ABS Corporation in Addyston, OH	0.47	-0.76	0.21	7.28	0.03	---
TCEQ Tests Conducted in John Zink Facility	0.13	-2.04	0.65	7.28	0.09	---
TCEQ Tests Conducted in John Zink Facility	0.58	-0.54	0.21	7.28	0.03	---
Existing AP-42 NO_X Emissions Factor for Flares (OLD)	0.068	-2.69	0.65	7.28	0.09	---

(a) A statistical outlier was determined based upon the 90% confidence level shown below:

Number of Test Values:	6
90% Confindence Level:	0.56

(b) The Dixon Q statistical test can only be applied to the two (2) end points (lowest and highest values) of a data set, therefore only the FHRAU Flint Hills Resources Port Arthur, LLC and MPCDET Marathon Petroleum Company, LLC test results were evaluated.

natural log of data points is a statistical method used to make data appear more linear or "normal." However, using the natural log of each value instead of the actual test values masked the Flint Hills test from being identified as an outlier. In addition, taking the natural log of each value did not make the data set have a "normal" distribution. Monroe believes that applying the Dixon Q method to the natural log of each value was improper. Table 3 represents the correct approach to determining if data points are statistical outliers, using the Dixon Q test without first calculating the natural log to the data points. As can be seen in Table 3, when the Dixon Q test formula is applied to the actual test result values presented in Table 1, the Flint Hills test result is clearly identified as a statistical outlier with over 99% confidence.

If U.S. EPA proceeds to use these questionable test results presented in Table 1 to develop a final revised industrial flare NO_X EF, U.S. EPA must eliminate the Flint Hills test result from the data set because it is unmistakably a statistical outlier.

Table 3

Monroe Energy, LLC - Trainer Refinery, PA

Monroe Energy Dixon Q Outlier Test

Facility Name	Average Test Result lb/MMBtu	Dixon Q - Gap	Dixon Q - Range	Dixon Q Test Results	Outlier?[(a),(b)]
FHRAU Flint Hills Resources Port Arthur, LLC in Port Arthur, TX	16	15.42	15.99	0.96	YES
MPCDET Marathon Petroleum Company, LLC, Detroit, MI	0.011	0.06	15.99	3.56E-03	No
INEOS ABS Corporation in Addyston, OH	0.47	0.11	15.99	6.88E-03	---
TCEQ Tests Conducted in John Zink Facility	0.13	0.06	15.99	3.88E-03	---
TCEQ Tests Conducted in John Zink Facility	0.58	0.11	15.99	6.88E-03	---
Existing AP-42 NO_X Emissions Factor for Flares (OLD)[(b)]	0.068	0.06	15.99	3.56E-03	---

(a) A statistical outlier was determined based upon the 99% confidence level shown below:

Number of Test Values:	6
99% Confindence Level:	0.74

(b) The Dixon Q statistical test can only be applied to the two (2) end points (lowest and highest values) of a data set, therefore only the FHRAU Flint Hills Resources Port Arthur, LLC and MPCDET Marathon Petroleum Company, LLC test results were evaluated.

From:	Wozniak, Russell (RA) <wozniara@dow.com>
Sent:	Wednesday, October 15, 2014 1:35 PM
To:	RefineryFactor
Cc:	Garwood, Gerri
Subject:	Comments on Proposed Changes to Section 13.5 of AP-42 for Flares
Attachments:	Dow Comments Changes to Emission Factors 10 15 14.pdf

Dear Sir/Madam:

The Dow Chemical Company (Dow) is providing the attached comments on the proposed changes to Section 13.5 of AP-42 for flares.

Thanks for considering these comments, and please let me know if you have any questions.

Regards,

Russell A. Wozniak
Air Advocacy Leader - Operations Regulatory Services
The Dow Chemical Company
Office 361-553-2920
Mobile 361-571-5420

October 15, 2014

Comments Submitted Electronically
Email: refineryfactor@epa.gov

Re: Comments on Proposed Changes to Section 13.5 of AP-42 for Flares

Dear Sir/Madam:

The Dow Chemical Company (Dow) appreciates the opportunity to comment on EPA's proposed changes to emission factors.

Dow is supportive of ongoing efforts to improve air quality and air emissions inventories in the United States. We have reviewed EPA's proposal to change the emission factors in Section 13.5 of AP-42 for flares, and have prepared the attached comments for your consideration.

If you have questions concerning the attached comments, please contact me at (361) 553-2920 or email: wozniara@dow.com.

Sincerely,

Russell A. Wozniak

Russell A. Wozniak
EH&S Regulatory Services
The Dow Chemical Company

Attachment

Dow Comments on Proposed Changes to Emission Factors and Section 13.5 of AP-42 for Flares

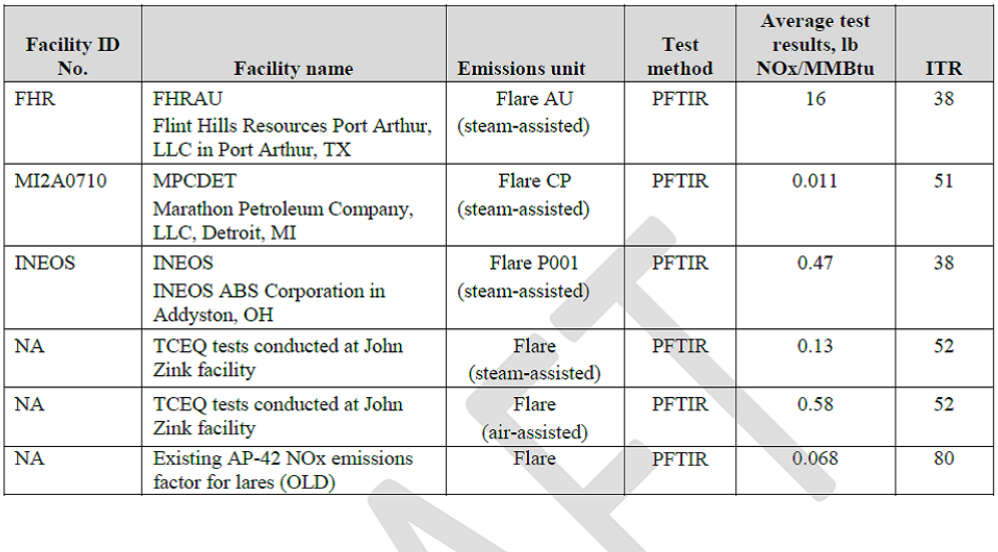
<u>EPA should not revise the emission factor for Nitrogen Oxide emissions from flares to 2.9 lbs/MMBtu in Table 13.5-2 without further reviewing existing test data and incorporating new test data.</u>

The proposed emission factor for Nitrogen Oxides (NOx) from flares of 2.9 lbs/MM Btu in Table 13.5-2 should not be revised at this time. The proposed factor has significant implications for regulated entities who are seeking air permits for new construction projects or revisions to their existing facilities as the proposal is to increase the value by a factor of > 42 (2.9/0.068).

In order to calculate the emission factor for NOx for flares, EPA takes the average of the following test results in Table 21 of the document: **DRAFT Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations.**

(16+0.11+0.47+0.13+0.58+0.068)/6 = 2.9

Table 21. Analysis of Emissions Test Reports for NOx from Flares



Facility ID No.	Facility name	Emissions unit	Test method	Average test results, lb NOx/MMBtu	ITR
FHR	FHRAU Flint Hills Resources Port Arthur, LLC in Port Arthur, TX	Flare AU (steam-assisted)	PFTIR	16	38
MI2A0710	MPCDET Marathon Petroleum Company, LLC, Detroit, MI	Flare CP (steam-assisted)	PFTIR	0.011	51
INEOS	INEOS INEOS ABS Corporation in Addyston, OH	Flare P001 (steam-assisted)	PFTIR	0.47	38
NA	TCEQ tests conducted at John Zink facility	Flare (steam-assisted)	PFTIR	0.13	52
NA	TCEQ tests conducted at John Zink facility	Flare (air-assisted)	PFTIR	0.58	52
NA	Existing AP-42 NOx emissions factor for lares (OLD)	Flare	PFTIR	0.068	80

EPA should take into account the fact that the existing AP-42 factor for flares of 0.068 lbs/MMBtu is actually calculated from greater than one test, thus the results of each test should be considered when calculating an average value.

.

EPA should also carefully evaluate whether or not the test results from the Flint Hills Resources test are valid, and whether or not these results should be averaged in with the other test results since the results are significantly higher than others tests. If the Flint Hills Resources test is excluded, the average emission factor becomes 0.25 lbs/MM Btu which is an order of magnitude lower than the proposed value of 2.9.

In addition to the aforementioned emission tests, Dow has also sponsored testing of a steam-assisted flare tip and a pressure-assisted flare tip. The testing was conducted at the John Zink Company test facility in Tulsa, Oklahoma in November, 2013. The results of the testing were provided to EPA's Office of Air Quality Planning and Standards in February, 2014. NOx emissions from the flare gas plumes were measured during each of the tests using a sample collection device and a continuous NOx emission analyzer. Three runs of 20 minutes were conducted for each operating condition. The test results are summarized in the tables below.

From Table 2 below, the NOx emissions per MMBTU are:

S1	S2	S3	S4	S5	S6	Average all 6 Runs
0.24	0.23	0.08	0.15	0.09	0.11	0.15

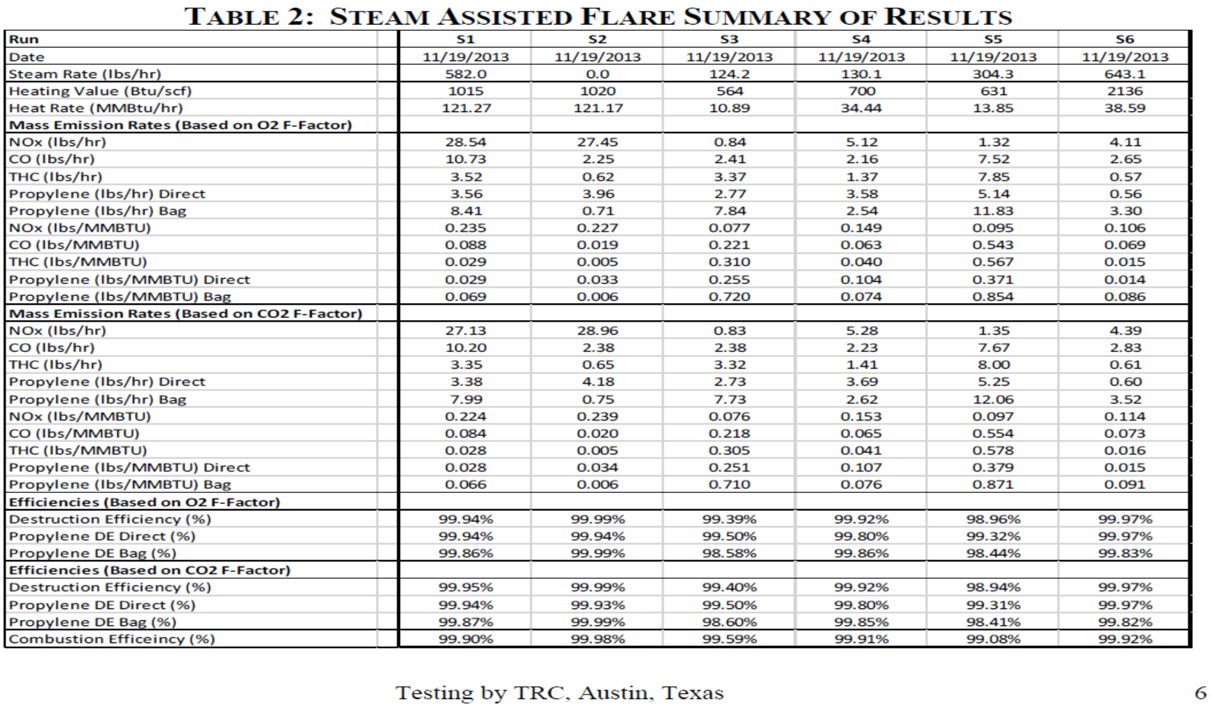


TABLE 2: STEAM ASSISTED FLARE SUMMARY OF RESULTS

Run	S1	S2	S3	S4	S5	S6
Date	11/19/2013	11/19/2013	11/19/2013	11/19/2013	11/19/2013	11/19/2013
Steam Rate (lbs/hr)	582.0	0.0	124.2	130.1	304.3	643.1
Heating Value (Btu/scf)	1015	1020	564	700	631	2136
Heat Rate (MMBtu/hr)	121.27	121.17	10.89	34.44	13.85	38.59
Mass Emission Rates (Based on O2 F-Factor)						
NOx (lbs/hr)	28.54	27.45	0.84	5.12	1.32	4.11
CO (lbs/hr)	10.73	2.25	2.41	2.16	7.52	2.65
THC (lbs/hr)	3.52	0.62	3.37	1.37	7.85	0.57
Propylene (lbs/hr) Direct	3.56	3.96	2.77	3.58	5.14	0.56
Propylene (lbs/hr) Bag	8.41	0.71	7.84	2.54	11.83	3.30
NOx (lbs/MMBTU)	0.235	0.227	0.077	0.149	0.095	0.106
CO (lbs/MMBTU)	0.088	0.019	0.221	0.063	0.543	0.069
THC (lbs/MMBTU)	0.029	0.005	0.310	0.040	0.567	0.015
Propylene (lbs/MMBTU) Direct	0.029	0.033	0.255	0.104	0.371	0.014
Propylene (lbs/MMBTU) Bag	0.069	0.006	0.720	0.074	0.854	0.086
Mass Emission Rates (Based on CO2 F-Factor)						
NOx (lbs/hr)	27.13	28.96	0.83	5.28	1.35	4.39
CO (lbs/hr)	10.20	2.38	2.38	2.23	7.67	2.83
THC (lbs/hr)	3.35	0.65	3.32	1.41	8.00	0.61
Propylene (lbs/hr) Direct	3.38	4.18	2.73	3.69	5.25	0.60
Propylene (lbs/hr) Bag	7.99	0.75	7.73	2.62	12.06	3.52
NOx (lbs/MMBTU)	0.224	0.239	0.076	0.153	0.097	0.114
CO (lbs/MMBTU)	0.084	0.020	0.218	0.065	0.554	0.073
THC (lbs/MMBTU)	0.028	0.005	0.305	0.041	0.578	0.016
Propylene (lbs/MMBTU) Direct	0.028	0.034	0.251	0.107	0.379	0.015
Propylene (lbs/MMBTU) Bag	0.066	0.006	0.710	0.076	0.871	0.091
Efficiencies (Based on O2 F-Factor)						
Destruction Efficiency (%)	99.94%	99.99%	99.39%	99.92%	98.96%	99.97%
Propylene DE Direct (%)	99.94%	99.94%	99.50%	99.80%	99.32%	99.97%
Propylene DE Bag (%)	99.86%	99.99%	98.58%	99.86%	98.44%	99.83%
Efficiencies (Based on CO2 F-Factor)						
Destruction Efficiency (%)	99.95%	99.99%	99.40%	99.92%	98.94%	99.97%
Propylene DE Direct (%)	99.94%	99.93%	99.50%	99.80%	99.31%	99.97%
Propylene DE Bag (%)	99.87%	99.99%	98.60%	99.85%	98.41%	99.82%
Combustion Efficeincy (%)	99.90%	99.98%	99.59%	99.91%	99.08%	99.92%

Testing by TRC, Austin, Texas 6

From Table 3 below, the NOx emissions per MMBTU are:

P1H Avg	P1L Avg	P2H Avg	P2L Avg	P3H Avg	P3L Avg	Average all 6 Runs
0.13	0.11	0.21	0.19	0.16	0.15	0.16

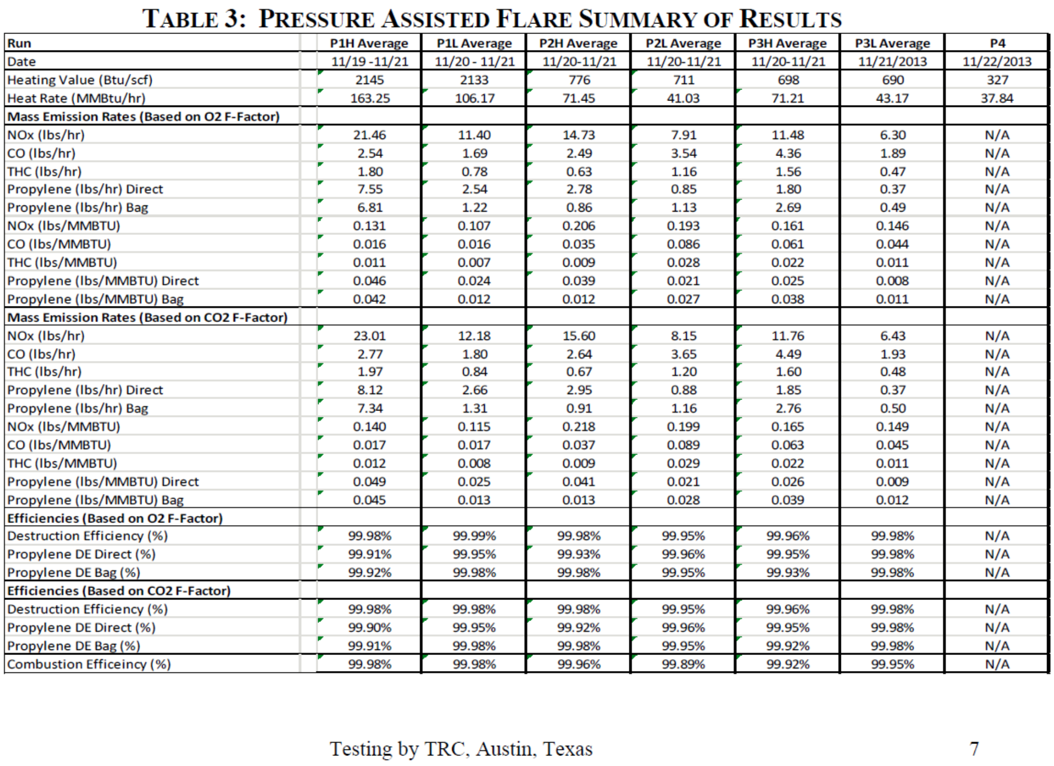


TABLE 3: PRESSURE ASSISTED FLARE SUMMARY OF RESULTS

Run	P1H Average	P1L Average	P2H Average	P2L Average	P3H Average	P3L Average	P4
Date	11/19 -11/21	11/20 - 11/21	11/20-11/21	11/20-11/21	11/20-11/21	11/21/2013	11/22/2013
Heating Value (Btu/scf)	2145	2133	776	711	698	690	327
Heat Rate (MMBtu/hr)	163.25	106.17	71.45	41.03	71.21	43.17	37.84
Mass Emission Rates (Based on O2 F-Factor)							
NOx (lbs/hr)	21.46	11.40	14.73	7.91	11.48	6.30	N/A
CO (lbs/hr)	2.54	1.69	2.49	3.54	4.36	1.89	N/A
THC (lbs/hr)	1.80	0.78	0.63	1.16	1.56	0.47	N/A
Propylene (lbs/hr) Direct	7.55	2.54	2.78	0.85	1.80	0.37	N/A
Propylene (lbs/hr) Bag	6.81	1.22	0.86	1.13	2.69	0.49	N/A
NOx (lbs/MMBTU)	0.131	0.107	0.206	0.193	0.161	0.146	N/A
CO (lbs/MMBTU)	0.016	0.016	0.035	0.086	0.061	0.044	N/A
THC (lbs/MMBTU)	0.011	0.007	0.009	0.028	0.022	0.011	N/A
Propylene (lbs/MMBTU) Direct	0.046	0.024	0.039	0.021	0.025	0.008	N/A
Propylene (lbs/MMBTU) Bag	0.042	0.012	0.012	0.027	0.038	0.011	N/A
Mass Emission Rates (Based on CO2 F-Factor)							
NOx (lbs/hr)	23.01	12.18	15.60	8.15	11.76	6.43	N/A
CO (lbs/hr)	2.77	1.80	2.64	3.65	4.49	1.93	N/A
THC (lbs/hr)	1.97	0.84	0.67	1.20	1.60	0.48	N/A
Propylene (lbs/hr) Direct	8.12	2.66	2.95	0.88	1.85	0.37	N/A
Propylene (lbs/hr) Bag	7.34	1.31	0.91	1.16	2.76	0.50	N/A
NOx (lbs/MMBTU)	0.140	0.115	0.218	0.199	0.165	0.149	N/A
CO (lbs/MMBTU)	0.017	0.017	0.037	0.089	0.063	0.045	N/A
THC (lbs/MMBTU)	0.012	0.008	0.009	0.029	0.022	0.011	N/A
Propylene (lbs/MMBTU) Direct	0.049	0.025	0.041	0.021	0.026	0.009	N/A
Propylene (lbs/MMBTU) Bag	0.045	0.013	0.013	0.028	0.039	0.012	N/A
Efficiencies (Based on O2 F-Factor)							
Destruction Efficiency (%)	99.98%	99.99%	99.98%	99.95%	99.96%	99.98%	N/A
Propylene DE Direct (%)	99.91%	99.95%	99.93%	99.96%	99.95%	99.98%	N/A
Propylene DE Bag (%)	99.92%	99.98%	99.98%	99.95%	99.93%	99.98%	N/A
Efficiencies (Based on CO2 F-Factor)							
Destruction Efficiency (%)	99.98%	99.98%	99.98%	99.95%	99.96%	99.98%	N/A
Propylene DE Direct (%)	99.90%	99.95%	99.92%	99.96%	99.95%	99.98%	N/A
Propylene DE Bag (%)	99.91%	99.98%	99.98%	99.95%	99.92%	99.98%	N/A
Combustion Efficeincy (%)	99.98%	99.98%	99.96%	99.89%	99.92%	99.95%	N/A

Testing by TRC, Austin, Texas 7

The test results in Tables 2 and 3 indicate that the average NOx emission factor should be in the 0.15 to 0.16 lbs/MMBtu range and that the proposed factor of 2.9 lbs/MMBtu would result in a gross over-estimate of NOx emissions from flares.

EPA should also consider waiting to revise the emission factors for flares until after the refining sector and other industrial sectors make physical or operational changes to flares as a result of future and anticipated rulemaking.

On June 30, 2014, EPA proposed a set of significant rule changes to the Refinery MACT rule that may drive changes to the way flares are operated by requiring a combination of steam-assist flow reduction and an increase in natural gas or fuel gas to flares. There is a three year period to implement these new requirements with the expected compliance date being sometime in 2018. Therefore, it is reasonable to expect that the refinery sector will be making both physical and operational changes to refinery flares between the 2015 and 2018 timeframe. EPA may or may not expand the requirement into other industrial sectors that also use flares, thus causing additional physical and operational changes to flares in the ~ 2020 timeframe. Therefore, we strongly recommend that EPA not revise the emission factors for flares at this time, but instead EPA should wait until these aforementioned changes are made so that the factors truly represent the majority of flares that are in service. This delay will also allow EPA more time to obtain additional NOx measurements and to establish a higher quality NOx emission factor for flares.

Garwood, Gerri

From:	Danielle Nesvacil <danielle.nesvacil@tceq.texas.gov>
Sent:	Wednesday, October 15, 2014 7:08 PM
To:	RefineryFactor
Cc:	Daphne McMurrer; Michael Wilhoit; Donaldson, Guy; David Brymer; Jayme Sadlier
Subject:	Proposed action: new or revised emissions factors for flares and certain refinery process units
Attachments:	TCEQ_comments__proposed_refinery_emissions_factors.pdf

Please accept the attached comments from the Texas Commission on Environmental Quality regarding EPA's proposed new and revised emission factors for flares and proposed new emission factors for certain refinery process units.

Danielle Nesvacil | **Emissions Assessment Section** | **TCEQ**
12100 Park 35 Circle, Bldg. E | Austin, Texas 78753 | Mail: MC-164, P.O. Box 13087, Austin TX 78711-3087
☎ (512) 239-2102 Fax: (512) 239-1515 | ✉: danielle.nesvacil@tceq.texas.gov

Bryan W. Shaw, Ph.D., P.E., *Chairman*
Toby Baker, *Commissioner*
Zak Covar, *Commissioner*
Richard A. Hyde, P.E., *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

October 19, 2014

United States Environmental Protection Agency

Transmitted via email to: refineryfactor@epa.gov

Dear Sir or Madam,

The Texas Commission on Environmental Quality (TCEQ) appreciates the opportunity to respond to the United States Environmental Protection Agency's (EPA) proposed action regarding refinery emissions factors. This proposed action would revise existing or publish new emissions factors for flares, sulfur recovery units, catalytic reforming units, hydrogen plants, and fluid catalytic cracking units and incorporate these emissions factors into the existing EPA refinery emissions estimation protocol.

The following comments are included in this response to this notice.

- The EPA should withdraw the proposed emissions factors. If this does not occur, the EPA should not require the use of the proposed emissions factors for any air quality activities, including air permitting or emissions inventory due to serious data quality concerns. In particular, the proposed flare emissions factors are based upon scientifically unsound data.
- The EPA should not use the emissions factors for its own air quality-related activities, due to the potential for creating unnecessary regulatory burdens based upon over-estimated emissions.

Detailed comments on the proposed action are enclosed. If there are any questions concerning the TCEQ's comments, please contact Mr. David Brymer, Director, Air Quality Division, at 512-239-1725 or david.brymer@tceq.texas.gov.

Sincerely,

Steve Hagle, P.E.
Deputy Director
Office of Air

Enclosure

cc: Guy Donaldson, EPA R6

P.O. Box 13087 • Austin, Texas 78711-3087 • 512-239-1000 • tceq.texas.gov

How is our customer service? tceq.texas.gov/customersurvey
printed on recycled paper

COMMENTS BY THE TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ) REGARDING PROPOSED NEW AND REVISED EMISSION FACTORS FOR FLARES AND PROPOSED NEW EMISSION FACTORS FOR CERTAIN REFINERY PROCESS UNITS; PROPOSED ACTION

I. Background

The United States Environmental Protection Agency (EPA) is proposing to update certain stationary source emissions factors to fulfill terms of a consent decree with Air Alliance Houston and others. Specifically, on August 19, 2014, the EPA posted on its Technology Transfer Network Web page notice of proposed revisions to certain refinery process unit emissions factors, including flare emissions factors. However, the EPA is specifically excluding emissions determination methods for storage tanks and wastewater units from the proposed updates. The consent decree terms require the EPA to issue a final determination on the necessity of revising emissions factors and determination methods for these sources by December 19, 2014.

II. Comments

The EPA's proposed revisions to flare emissions factors are not supported by available data and are based upon remote sensing technology measurements from an instrument not calibrated to measure nitrogen oxides. The TCEQ recommends that EPA withdraw the proposed updates to AP-42 emissions factors for flares based upon serious data quality concerns.

The PFTIR measurements used to develop the flare emissions were intended to assess a flare's overall combustion efficiency and were therefore focused on quantifying hydrocarbons as well as other carbon compounds (such as carbon monoxide and carbon dioxide). These measurements are not appropriate for developing a nitrogen oxides emissions factor. To the best of our understanding, the PFTIR instrument was never calibrated to measure nitrogen oxides emissions during the EPA testing, and has not undergone validation testing to ascertain whether its software processing algorithms can accurately measure nitrogen oxides in a flare plume. Reanalyzing and recalculating uncalibrated and unvalidated instrument data to develop a nitrogen oxides emissions factor is not sound science. For this reason alone, the EPA should withdraw the proposed nitrogen oxides flare factor.

Additionally, the calculation procedures for the nitrogen oxides factor appear to contain errors. First, nitrogen oxides formation is generally driven by either high temperatures (generally well above 2,400 degrees Fahrenheit), known as thermal nitrogen oxides formation, or fuel-bound nitrogen content. Flares typically do not reach temperatures high enough to produce significant quantities of thermal nitrogen oxides.

Second, the calculation for the nitrogen oxides emissions factor included a value from one particular flare test that was more than one order of magnitude greater than the other measurement values in the complete set of values used to develop the emissions factor. This value also received the lowest individual test rating of all the values used to develop the nitrogen oxides emissions factor. The report that details the emissions factor development, *Draft Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations*, erroneously states that this value is not an outlier. This value is clearly an outlier and should not be included in the nitrogen oxides emissions average or used for any other purposes. Several of the other individual test values appear high as well, and are higher than the current EPA AP-42 emissions factors for uncontrolled large natural gas-fired boilers.

As a result, the proposed flare nitrogen oxides emissions factor of 2.9 pounds per million British thermal units of heat input is larger than the corresponding factor for uncontrolled gasoline-fueled internal combustion engines or uncontrolled four-cycle rich-burn natural-gas fired internal combustion engines. The combustion temperatures in the cylinders of these engines can approach as high as 4,500 degrees Fahrenheit and thus thermal nitrogen oxides emissions are generated. This indicates the proposed nitrogen oxides emissions factor for flares is faulty, since flare temperatures are thousands of degrees lower than engine temperatures, and therefore cannot generate the same quantity of thermal nitrogen oxides emissions. Additionally, if nitrogen oxides generation from fuel-bound nitrogen at flares is a concern, then the EPA needs to develop and present a nitrogen oxides emissions factor in terms of nitrogen content of flared gas.

Finally, the proposed volatile organic compounds emissions factors for flares is higher than the current total organic compound emissions factor in AP-42. Flare volatile organic compounds emissions are directly dependent upon the composition of the combusted waste gas stream. Due to the varying processes flare abate across a broad range of industries, VOC emissions cannot be adequately represented by a single emissions factor.

If a flare that combusts VOC waste gas streams is equipped with steam or air assist, the potential for over-steaming or over-aeration exists, which can greatly increase the amount of VOC emissions. A single emissions factor cannot account for the complexities and variations of assist provided to a flare and therefore cannot be representative of actual VOC emissions. The inclusion of this factor greatly over simplifies and misrepresents potential actual VOC emissions from flares and should not be used for emissions inventory development purposes.

In conclusion, the EPA should withdraw the proposed flare factors due to the serious concerns about data quality and representativeness outlined above.

When developing the proposed flare emissions factors, the EPA neglected more robust test data in favor of measurements made predominantly by one remote sensing technology. The resulting factors are not necessarily representative of a wide range of industrial flares that were measured using standard, accepted source sampling techniques.

To develop the proposed emissions factor revisions for flares, the EPA relied primarily on passive Fourier transform infrared (PFTIR) spectroscopy measurements of five to nine flares at refineries across the country as well as the existing factors in AP-42 and one set of differential absorption lidar measurements. The EPA neglected to analyze more robust sources of data for inclusion in developing revised flare emissions factors, such as extractive sampling measurements from the TCEQ's 2010 Flare Study[1]. The nitrogen oxides emissions factors derived from the propane test runs during the TCEQ 2010 Flare Study across all combustion efficiencies ranged between 10 and 120 percent of the current AP-42 NO_X emissions factor[2]. These factors are much lower than the proposed nitrogen oxides emissions factor, which is approximately 43 times higher than (or 4,300 percent of) the current AP-42 NO_X emissions factor.

The EPA also neglected to publish the quality assurance project plan used to obtain pollutant concentrations from the PFTIR measurements used in the development of the proposed factors. Without knowing how well the instrument met data quality objectives for each of the pollutant

---

[1] Specifically, the study data should be analyzed for potential emissions factor development. Note: only the results of the propane test runs should be analyzed for nitrogen oxides emissions factor development, due to interference observed during the propylene test runs that impacted the nitrogen oxides monitors.

[2] Vincent M. Torres, Scott Herndon, Ezra Wood, Fahad M. Al-Fadhli, and David T. Allen, "Emissions of Nitrogen Oxides from Flares Operating at Low Flow Conditions," *Industrial and Engineering Chemistry Research* 51 (39), (2012): 12600–12605, doi: 10.1021/ie300179x.

concentration measurements, the accuracy of the data used to develop the flare emissions factors is questionable.

The EPA's flare factors are not necessarily representative of all industrial flares. The PFTIR measurements are predominantly of flares that use steam to prevent smoke (referred to as steam-assisted flares). Only one flare that uses air to prevent smoke (air-assisted flares) was included in the data set used for developing the proposed flare factors, and no unassisted flares were included. The lack of representative sampling of a wide range of flares makes the proposed factors statistically weak at best.

The EPA should perform more research, such as analyzing existing TCEQ 2010 Flare Study data, and perform additional testing to support any proposed factor revisions. The EPA should also determine whether different emissions factors for different flare assist types are warranted.

Certain proposed flare emissions factors are based upon scientifically unsound data, and the EPA should therefore withdraw the proposed emissions factors. The EPA should withdraw all of the proposed emissions factors due to lack of data availability and questions about representativeness. The EPA should not use the proposed emissions factors for any air quality activities, including air permitting or emissions inventory activities or requirements, due to the potential for creating unnecessary regulatory burdens derived from over-estimated emissions not based upon all scientifically valid data.

Using the proposed EPA flare emissions factor to determine nitrogen oxides emissions for air quality activities such as permitting would increase nitrogen oxides emissions by a factor of approximately 20 to 60, depending on the heating value of the waste gas stream. This increase would potentially affect modeling compliance with the short-term nitrogen dioxide standard and may trigger prevention of significant deterioration or nonattainment review for permits, as well as potential Title V permitting obligations. Industries that use flares as safety and control devices, such as oil and gas production, refining, or petrochemical industries, would be disproportionately affected by these factors. Therefore, the EPA should not require the proposed factors to be used in air quality-related activities.

If EPA were to use the proposed flare factors in its air quality modeling activities (e.g., interstate transport of pollutants) or emissions inventory development, pollution contributions from states or regions with large concentrations of industries that use flares (e.g., oil and gas, chemical industries) could be substantially over-estimated. This over-estimation may lead to unnecessary regulatory burdens including: restrictions on growth, lowered standards, or emissions controls or related rules developed for these areas or industries. The EPA should not use any of the proposed factors for any of its modeling activities, rule development, permitting, emissions inventory development, or other air-quality related activities due to the potential for misguided policy or rule development.

The other proposed emissions factors appear to be based on relatively few tests at a wide range of refineries across the country. Due to the limited data available, and the site-specific nature (i.e., uniqueness) of each individual process unit at a refinery, the TCEQ has concerns about how well these factors represent average process unit emissions. Therefore, the EPA should withdraw all of the proposed emissions factors. The EPA should perform further research and testing as well as improved differentiation among refinery units and processes to develop more robust and representative emissions factors.

Garwood, Gerri

From:	Gossett, Stephen R <srgosset@eastman.com>
Sent:	Thursday, October 16, 2014 11:44 AM
To:	RefineryFactor
Subject:	Eastman Chemical Company Comments on Proposed AP-42 Flare Factor
Attachments:	Eastman Flare Factor Comments.pdf

Steve Gossett
Eastman Chemical Company
423-229-2327

Eastman Chemical Company
P.O. Box 511
Kingsport, Tennessee 37662

EASTMAN

October 16, 2014

ELECTRONIC DELIVERY

U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, DC 20460
E-mail: refineryfactor@epa.gov

Subject: DRAFT EPA Review of Available Documents for Developing Proposed Emissions Factors for Flares, Tanks, and Wastewater Treatment Systems

Dear Sir/Madam:

Eastman Chemical Company (Eastman) appreciates the opportunity to comment on the DRAFT EPA Review of Available Documents for Developing Proposed Emissions Factors for Flares, Tanks, and Wastewater Treatment Systems.

Eastman has a vital interest in this proposed rule being a major chemical manufacturer of chemicals, plastics, and fibers with facilities located in the United States operated industrial flares.

NOx Factor for Flares: EPA is proposing a new emission factor for use on all types of flares that is 43 times higher than the current factor. Use of this factor will cause many problems with air permits for NOx emissions. Our review of the background documents and spreadsheets used by the EPA has revealed that this proposed factor has no technical basis and is flawed for at least the following reasons:

1. EPA has used data from five tests that are not representative of NOx concentrations. The spreadsheets used to determine hourly NO and NO2 lb/mmBtu emission rates use a column (Column BF) in the spreadsheet titled “NO2 ppm-m” which we believe to be concentration per meter of flare width. Flare width was not determined during the tests so the calculations based on mismatched units of measure provide meaningless results yet they are the determining factor for the emission factor being raised. EPA has apparently mis-used this data as concentration data. The data from these test should not be included in the revision of the emission factor.

2. Even if the underlying data were valid NOx emission data for flares, EPA has not done a proper statistical study of the data before determing an emission factor. EPA

simplistically has taken the overall test average from each test site (each site had multiple test conditions) and then taken the average of the averages. Properly conducted, EPA should have evaluated the causes for having such outliers. Were these a product of miss-calculations, errors in methodology or a difference in the production processes that would have established a separate category for flare factors. EPA did conduct an outlier analyses of the 6 test averages and determined that the one obvious potential outlier (16) is not an outlier using acceptable statistical tests. This is because of the small data set. See Figure 1 below:

Figure 1*

	Method	Avg Test Result (lb/MMBtu)			
Flare	PFTIR	NOx	CO	VOC	ITR
FHR_AU	PFTIR	16	0.23	0.5	38
FHR_LOU	PFTIR	-	0.15	0.95	38
MPC_Detroit	PFTIR	0.011	0.271	0.423	51
MPC_TX	PFTIR	-	88.444	0.016	51
INEOS	PFTIR	0.471	0.278	0.700	38
Shell	PFTIR	-	0.584	0.534	41
TCEQ, steam	PFTIR	0.129	0.313	0.587	52
TCEQ, air	PFTIR	0.577	0.367	0.469	52
BP	DIAL	-	-	0.247	40
old AP-42	extractive sampling	0.068	0.37	-	80

*From EPA as found in the “Draft Background Document” on http://www.epa.gov/ttn/chief/ap42/ch13/index.html#13.5 . See “EF Creation_NOx_flare_2014Aug.xlsm” – Excel Spreadsheet Flare Calculations

What EPA failed to do was evaluate the underlying large test data sets to see if there are outliers within each set. For example, in the file named “Flare Calculation.xlsx”, EPA reports the underlying instantaneous data from the performance test for flare FHR_AU. In the 639 minutes of reported data, there are two extremely high data points (approximately 3500 and 4500 lb/mmBTU). Within the dataset, there were instances where the flow reading lept from a relatively stable value to a 100 to 300 fold increase over the period of a single minute and the instantaneous value was in a range that we question whether it could have been possible. For instance, the *lower of the two* went from 34,000 SCFM to over 1,500,000 SCFM. Was this a real value? Each exceptionally high NOx emission rate data point was associated with one of the instantaneous flow transients. The graphical representation shown in Figure 2 of the actual data from the test illustrates how these two points skewed the results significantly. Application of any accepted outlier test would have flagged these two points as outliers. Removal of just these two obvious outliers would have yielded a much different result, changing the value of 16 to 3.

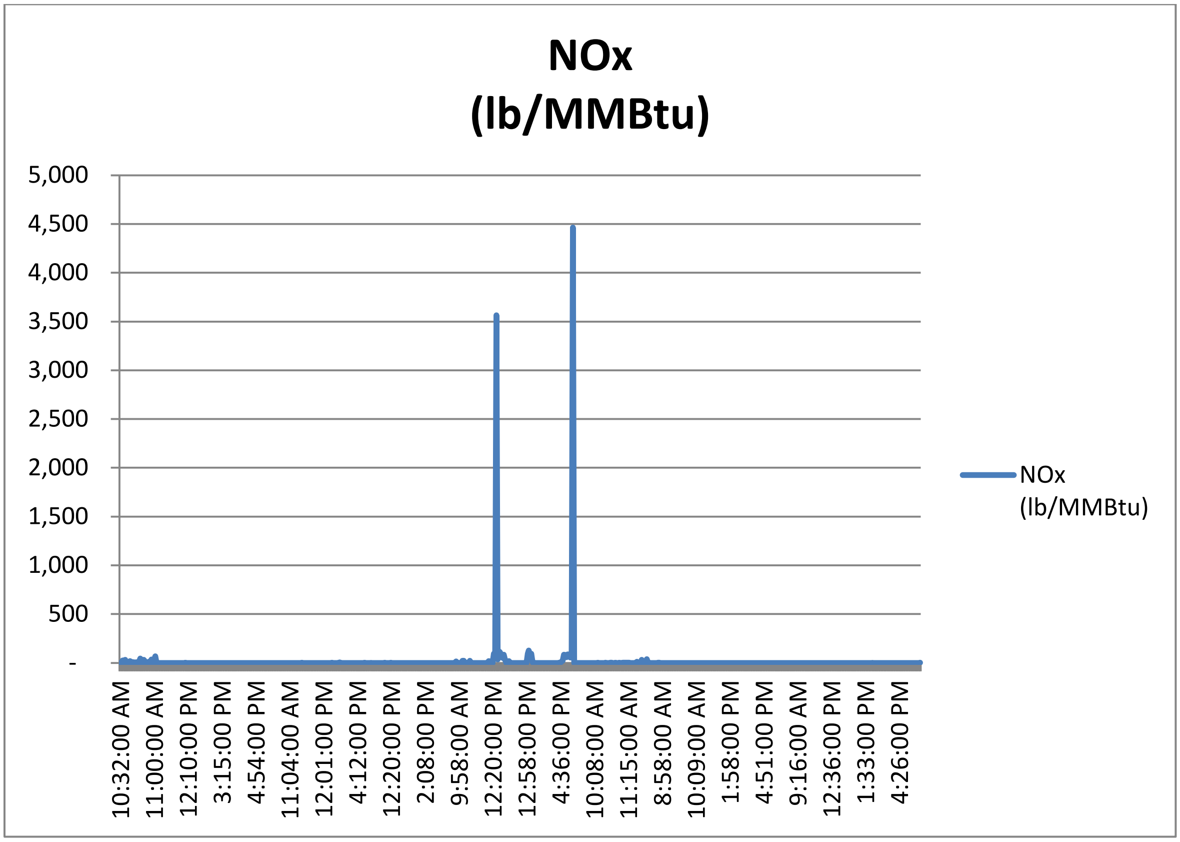


Figure 2: Calculated NOx Rate for Instantaneous Readings as Graphed from Column BF for Flare Test Associated with Flare FHR_AU

If you have any questions regarding these comments or would like further assistance, feel free to contact me.

Sincerely,

Stephen R Gossett

Stephen R Gossett
Environmental Fellow
E-mail: srgosset@eastman.com
Phone: (423) 229-2327

Garwood, Gerri

From: Garwood, Gerri
Sent: Monday, October 20, 2014 1:01 PM
To: dfriedman@afpm.org
Subject: FW: Quick Question on Emission Factor Comments

Hi Mr. Friedman,

I apologize for the late response; I was out of the office last week. We have extended the comment period to October 31. We have posted the extension on our website (http://www.epa.gov/ttn/chief/consentdecree/index_consent_decree.html) and sent out a listserv notice last week. I hope that you received the news in time. I apologize for any inconvenience the lateness of this message may have caused.

Sincerely,
Gerri G. Garwood, P.E.

U.S. Environmental Protection Agency
OAR/OAQPS/SPPD
Measurement Policy Group
Ph: 919-541-2406 Fax: 919-541-3207

From: David Friedman [mailto:DFriedman@afpm.org]
Sent: Thursday, October 16, 2014 1:21 PM
To: Shine, Brenda
Subject: Quick Question on Emission Factor Comments

Brenda,

The comments for the Emission Factors rule are due to EPA on October 19 which is a Sunday. Will EPA accept the comments if they are filed by Monday, October 20 ?

David N. Friedman
Vice President
Regulatory Affairs

American
Fuel & Petrochemical
Manufacturers
1667 K Street NW
Suite 700
Washington, DC 20006
202.457.0480 office
202.552.8461 direct
202.457.0486 fax

dfriedman@afpm.org

From:	Fischman, Gary <GFischman@achd.net>
Sent:	Thursday, October 16, 2014 2:09 PM
To:	RefineryFactor
Cc:	Deluca, Dean; Kelly, Marie; jmaranche@achd.net; Stern, Darrell; Etzel, Sandra; Ajenifuja, Hafeez; Kelly, Jim
Subject:	Allegheny County Comments to Proposed AP-42 Section 13.5 NOx Flare Emission Factor
Attachments:	Comments to Proposed AP-42 Sec. 13.5.docx; ref_06bc13s05_2014-calc NOx EF.xlsx; EF Creation_NOx_flare_2014Aug edited 10-14-2014 PA test.xlsx

Our comments on the proposed AP-42 Section are attached. They are submitted in response to the request for comments on “Proposed New and Revised Emission Factors for Flares and Proposed New Emission Factors for Certain Refinery Process Units and Proposed Determination for No Changes to VOC Emission Factors for Tanks and Wastewater Treatment Systems.” We have no comment at this time on the proposed new refinery process units or on Tanks and Wastewater Treatment Systems.

Supplementary spreadsheets showing recalculation of the NOx factor are attached. The larger spreadsheet contains data from the Port Arthur, TX stack tests which show that this test result was skewed by two outlier minutes out of 992 total minutes used in the calculation. We are proposing an emission factor of 0.76 lb/mmbtu instead of 2.9 lb/mmbtu. This is irrespective of any issues with any of the other test data used in developing the proposed factor.

Gary Fischman
Allegheny County Health Department
Air Quality Program
phone: (412) 578-8141
fax: (412) 578-8144
gfischman@achd.net

Allegheny County Health Department
Air Quality Program

Comments regarding proposed AP-42 Section 13.5, NO_X Flare emission factor
September 15, 2014

EPA proposes increasing the emission factor for NO_X from industrial flares by a factor of greater than 40 over the current emission factor, from 0.068 to 2.9 lb/mmbtu. This increase is mostly based on a single data set resulting from tests conducted at the Flint Hills Resources Port Arthur, LLC plant in Port Arthur, Texas, October 21-29, 2010. A separate data point was taken representing each minute of testing. From these test data, EPA calculated an emission factor of 16 lb NO_X/mmbtu.

From the Draft EF Development Report, EPA used all minute data with measurable steam flow, measurable nonzero CO_2, and combustion efficiency of at least 96.5% (considered equivalent to a destruction efficiency of 98%) to calculate an average NO_X emissions value. CO_2 concentrations were determined by PFTIR at 765 nm and 2,000 nm wavelengths, and these CO_2 concentrations were averaged for use in the emission factor calculation. For minutes where a CO_2 concentration exceeding the instrument error was determined at one wavelength but not the other, only the concentration exceeding the instrument error was used. The NO_x emission factor was calculated for each minute where sufficient data were available, and these emission factors were averaged to determine an overall emission factor for the test.

The two highest minute values of the NO_X emission factor should be considered as outliers. A Dixon's Q test on the 992 minutes for which an emission factor can be calculated (CO_2 >0) shows that the second highest minute, or data point, 3,376 lb/mmbtu, is an outlier. By extension, the highest data point is also an outlier. This test was run using a Qcritical for N=100, the highest tabulated value readily available, from http://www.chem.uoa.gr/applets/AppletQtest/Text_Qtest2.htm. The critical Q value decreases with increasing number of data points; thus, using a Qcritical for fewer than the actual number of data points provides a stiffer significance test than if Qcritical for the actual N were known and used. Data points with Q > Qcritical are considered outliers. For this case, Q critical = 0.1846, Q exp for the 3rd highest data point is 0.0013, and Qexp for the 2nd highest data point is 0.75. Qcritical for N=992 will be less than for N=100, so the 2nd highest data point is clearly an outlier; however, the 3rd highest data point is probably not an outlier.

The same cut-off is also apparent when the Dixon's Q test is performed on the logarithms of the nonzero NO_X emission factors. For this test, N = 222, so Qcritical again is 0.1846. Qexp is 0.004 for the 3rd highest test and 0.27 for the second highest.

The reason for these minutes being outliers is apparent in the CO_2 concentrations. The CO_2 concentration appears in the denominator of the NO_X emission rate calculation. The CO_2 concentration is 101 ppm-mole (ppm-m) for the highest NO_X minute and 311 ppm-m for the 2nd highest NO_X minute. When calculated using the procedure stated in the Draft EF Development Report, the average nonzero CO_2 concentration is 9953 ppm-m. The average nonzero CO_2 concentration for nonzero NO_X is 9392 ppm. The inlet carbon mass flows for the highest and second highest minutes, 929 and 925 lb/hr, respectively, are easily within one standard deviation of the average carbon inlet over all test runs, 981 lb/hr (std = 381 lb/hr). Thus, the extremely low CO_2 outlet concentrations for these minutes are illogical. These are not the only minutes with extremely low CO_2; however, the remaining such minutes also had very low or zero NO_X concentrations. This resulted in NO_X emission factors for these minutes that were not outliers, including some zeroes (zero values were figured into the average NO_X emission factor).

Excluding the two highest minutes, the average NO_X emission factor from the Port Arthur test is 3.3 lb/mmbtu. The overall average for all five tests plus the current AP-42 factor is 0.76 lb/mmbtu. ACHD recommends that the proposed factor be adjusted from 2.9 lb/mmbtu to 0.76 lb/mmbtu due to skewing of the emission factor from the two extremely high outlier minutes from the Port Arthur test .

GHF/ghf

Garwood, Gerri

From:	Morris,Paul J. <MORRISPJ@airproducts.com>
Sent:	Friday, October 17, 2014 10:43 AM
To:	RefineryFactor
Subject:	Air Products and Chemicals, Inc. Comments on Proposed AP-42 Factor Changes
Attachments:	APCI_20141017_EPA_AP42_Proposal_Comments_Final.PDF

Please find attached Air Products' comments on the proposed changes to AP-42 emission factors.

- Paul

Paul J. Morris | Senior Principal Environmental Engineer | Air Products and Chemicals, Inc. | Office: (713) 920-7296 | Fax: (713) 920-7445

Air Products and Chemicals, Inc.
7201 Hamilton Boulevard
Allentown, PA 18195-1501
Telephone (610) 481-4911
www.airproducts.com

October 17, 2014

U.S. EPA
Sent via e-mail to: refineryfactor@epa.gov

RE: Proposed Revision to AP-42 Flare NO_X Emission Factors

Dear Sir or Madam:

Air Products and Chemicals, Inc (Air Products) manufactures industrial gases and specialty chemicals, serving customers in industrial, energy, technology and healthcare markets worldwide. Founded in 1940, Air Products supplies industrial gases, performance materials, equipment and technology. Air Products is the world's largest supplier of hydrogen and helium and has built leading global supply positions in growth markets such as semiconductor materials, refinery hydrogen, coal gasification, natural gas liquefaction, and advanced coatings and adhesives.

Air Products appreciates the opportunity to comment on the proposed changes to the AP-42, Table 13.5-1 emission factors for flare operations, specifically the change to the nitrogen oxides (NO_X) emission factor. Air Products has concerns about the proposed revision to the emission factor. Air Products believes the revision will continue the misapplication of both the AP-42 emission factor and existing New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) to non-volatile organic compounds (VOC) vents. Air Products concurs with other commenters who have raised questions about the methodology used to derive the proposed factor and the implications of the huge increase in the factor. These concerns are as follows:

- The Assumption of Flares for Volatile Organic Compound (VOC) Control – EPA developed New Source Performance Standards (NSPS) 40 CFR §60.18 and Maximum Achievable Control Technology (MACT) 40 CFR §63.11 to control volatile organic compounds (VOC) emissions. Similarly, EPA established the AP-42 factors based on the assumption that flares are used primarily to control VOC emissions. The standards and AP-42 factors do not adequately address flares in non-VOC, primarily inorganic compound service. These flares are commonly found at hydrogen gas production facilities utilizing the steam-methane reformation (SMR) process as well as other industrial gas manufacturing facilities.

- Secondary Impact of EPA Revisions to Flare Regulations – States often incorporate-by-reference or adopt these EPA-developed regulations and emission calculation methodologies rather than develop their own to regulate flares not already regulated by the NSPS and MACT Standards. Air Products installs flares to safely and rapidly evacuate and combust hydrogen (H_2) and carbon monoxide (CO) from our processes. These currently fall outside EPA's NSPS and MACT flare regulations. However, states in which Air Products' facilities operate often attempt to incorporate these regulations through state air quality permits and rely on AP-42 factors to establish flare emission limits. This often results in the misapplication of these standards with questionable environmental improvement. These include attempts to restrict flare tip velocity to the NSPS (40 CFR §60.18) standards, when hydrogen flame stability at far higher tip velocities is well established.

- AP-42 Emission Factor Revision Relative to H_2 Rich Flares – A presentation titled "A Critique of the Flare Provisions of EPA's Proposed Refinery Sector Rule" at the American Flame Research Committee (AFRC) 2014 Industrial Combustion Symposium, noted: *"EPA assumes that NOx is solely a function of CO_2 produced during combustion. Hydrogen, of course, also produces NOx when combusted. Therefore by EPA's method, NOx emissions approach infinity as H2 concentrations in the vent gas approach 100%."* Air Products concurs with the commenters who argue the absurdity of the mathematical outcome for H_2-rich flares. EPA made attempts in the 1990s to address H_2-rich flares. However, the maximum H_2 concentration was still limited by this approach to approximately 15.5%. Air Products' hydrogen facilities' vent streams typically contain predominantly hydrogen, and often contain more than 90% hydrogen.

- Attempt to Fit Multiple Flares into Select Study – Air Products believes the flares studied to propose a new AP-42 emission factor were focused on the petroleum refining industry and do not reflect broad-based flare applications. EPA has based development of the proposed NO_X emission factor on data from four steam-assisted flares and one air-assisted flare. The EPA study included no non-assisted flares and no non-VOC flares. Air Products utilizes non-assisted flares on non-VOC process streams

Air Products requests EPA re-evaluate the study as pertains to unassisted, non-VOC, hydrogen rich flares, or clearly exclude them from applicability of the proposed AP-42 factor.

Sincerely,

Paul J Morris

On behalf of Air Products and Chemicals, Inc.,
Paul J. Morris
Senior Principal Environmental Engineer
Telephone: 713-920-7296
e-mail: morrispj@airproducts.com

Garwood, Gerri

From:	Anne Germain <agermain@wasterecycling.org>
Sent:	Friday, October 17, 2014 10:57 AM
To:	RefineryFactor
Cc:	Garwood, Gerri
Subject:	Comments to AP-42 Section 13.5
Attachments:	NWRA and SWANA letter on AP-42.pdf; Anne Germain.vcf

Attached please find comments from the National Waste & Recycling Association and from the Solid Waste Association of North America regarding AP-42 Section 13.5.

Best regards,
Anne Germain

Anne Germain, P.E., BCEE, Director of Waste & Recycling Technology
4301 Connecticut Avenue NW #300 | Washington, DC 20008
Office **202-364-3724** | *Fax* **202-966-4824** | *Mobile* **302-270-5483**
agermain@wasterecycling.org

National Waste & Recycling Association℠
Collect. Recycle. Innovate.

SWANA®
SOLID WASTE ASSOCIATION
of North America

October 17, 2014

Via Electronic Transmission: refineryfactor@epa.gov

Ms. Gerri Garwood
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC 20460

Dear Ms. Garwood:

Re: Revised Emissions Factors for Flares in Draft AP-42, Section 13.5 (Supplement D)

The National Waste & Recycling Association (NW&RA) and the Solid Waste Association of North America (SWANA) are pleased to offer comments on the proposed revisions to the Emissions Factors for Flares. The NW&RA and SWANA represent companies, municipalities and professionals in the solid waste industry. The NW&RA, formerly the National Solid Waste Management Association, is a not-for-profit trade association representing private solid waste and recycling collection, processing and management companies that operate in all fifty states. SWANA is a professional education association in the solid waste management field with members from both the private and public sectors across North America.

EPA has proposed new and revised emissions factors for industrial flares in the draft AP-42 Section 13.5, which substantially increases the emission factor for nitrogen oxides (NOx). While the new proposed factors might be appropriate for air assisted or steam assisted flares used at refineries, we do not believe they are appropriate for use with the candlestick (also called “open” or “utility”) flares that are in predominant use at municipal solid waste (MSW) landfills. The landfill sector’s candlestick flares are neither air nor steam assisted. Although the AP-42 has a chapter for MSW Landfills, the factors for NOx and CO in Section 13.5 are generally accepted as being more accurate, and are widely used within the landfill sector. Thus, the accuracy, validity and quality of the proposed emissions factors for use with non-assisted flares are very important to the landfill sector.

We reviewed the test results upon which EPA relied to establish the revised emission factors. It appears that none of the tests involved open, non-assisted flares, and none of the tests appeared to involve combustion of landfill gas. According to flare manufacturer, John Zink, Inc., (see attached letter) the test reports underpinning EPA’s revised emission factors involved high pressure, air or steam assisted, flares. Further, the tests were conducted with various flare tips not used within the

landfill sector, and the tests involved combustion of heavier, hydrocarbon-laden gases. Thus, the resulting emission factors are not applicable to non-assisted open flares burning landfill gas.

Nonetheless, EPA guidance in the draft section recommends that non-assisted flares use these new or revised emission factors. We are very concerned that EPA intends that these new emission factors be used in permitting MSW landfill candlestick flares. The proposed NOx emission factor is substantially higher than the existing factor. EPA appears to have used the result of one measurement from a single study to rationalize revising the NOx factor. In addition, the TCEQ studies referenced in the proposed revisions do not have NOx results, and thus cannot be used to support the revised factor. The Agency's recommendation that non-assisted flares use these new emission factors is inappropriate and not supported by the data. The test data supporting the revised factors are not relevant to non-assisted, open flares used in the landfill sector. Further, for the NOx emission factor, the dataset used to support the revision appears to be wholly inadequate, as it is based on one measurement from one study.

Although Section 13.5 of AP-42 is generally used by the petroleum industry, it is not limited to that industry. Section 13.5 itself notes, "flares are also used for burning waste gases generated by sewage digesters, coal gasification, rocket engine testing, nuclear power plants with sodium/water heat exchangers, heavy water plants and ammonia fertilizer plants." Given that the Section 13.5 factors are used by many industries, it is important that they accurately reflect emissions from all types of flares used in other industrial sectors.

As noted above, Section 13.5 has been widely used within the landfill sector as a source of emission factors. In fact, the majority of the air permitting conducted for landfill candlestick flares has relied upon AP-42 Section 13.5 factors for NOx and CO and many existing landfill permits have limits tied to the Section 13.5 factors. As such, there is a strong regulatory precedent for their use in federal, state, and local air permits for landfills. Further, the major manufacturers of landfill gas candlestick flares have recommended the use of the 1991 Section 13.5 factors as being the most appropriate and well-supported. See attached letter from the John Zink Company.

Because Section 13.5 is widely used in permitting by the landfill sector, it is essential that Section 13.5 retain factors that are appropriate for the non-assisted candlestick flares used at landfills and reflect their actual emissions as shown in high-quality emission tests. This can best be accomplished by maintaining the current factors for landfill gas and other biogas flares. We also propose that the Agency delete its recommendation that the revised factors be used for non-assisted flares. The proposed EFs should be limited to relevant industries that utilize steam and air assisted flares.

The NW&RA and SWANA appreciate your consideration of these comments and our requested revisions to the EPA's proposal. Should you have any questions about these comments, please call Anne Germain, Director of Waste & Recycling Technology for NW&RA, at 202-364-3724 or e-mail her at agermain@wasterecycling.org. You may also call Jesse Maxwell, Advocacy & eLearning Program Manager for SWANA, at 240-494-2237 or e-mail him at jmaxwell@swana.org.

Very truly yours,

Sharon H Kneiss

Sharon H. Kneiss
President & CEO
National Waste & Recycling Association

John H Skinner

John Skinner
Executive Director & CEO
Solid Waste Association of North America

From:	Banister, Amy <ABaniste@wm.com>
Sent:	Friday, October 17, 2014 1:01 PM
To:	RefineryFactor
Cc:	Schell, Bob; Garwood, Gerri
Subject:	Revised Emission Factors for Flares in Draft AP-42, Section 13.5 (Supplement D)
Attachments:	WM Comment Letter_AP-42Chapter13.5-10-17-14.pdf; NWRA and SWANA letter on AP-42.pdf

Dear Ms. Garwood.

Please find attached comments prepared by Waste Management, which include as an attachment comments submitted by SWANA and NW&RA.

If you have any questions, please let me know. Thank you.

Amy Van Kolken Banister
Senior Director of Air Programs, Environmental Management Group
abaniste@wm.com

Waste Management
1001 Fannin St., Suite 4000
Houston, TX 77002
Tel: 713-328-7340
Cell: 713-248-1369

Waste Management's renewable energy projects create enough energy to power more than one million homes. Learn more at www.wm.com.

WASTE MANAGEMENT

October 17, 2014

Via Electronic Transmission: refineryfactor@epa.gov

Ms. Gerri Garwood
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC 20460

Dear Ms. Garwood:

Re: Revised Emissions Factors for Flares in Draft AP-42, Section 13.5 (Supplement D)

Waste Management (WM) is pleased to provide comments to the U.S. Environmental Protection Agency's (EPA or Agency) on the proposed revisions to the Emissions Factors for Industrial Flares. WM supports the comments submitted by SWANA and NW&RA; a copy of the comment letter is attached.

WM is North America's leading provider of integrated waste management and environmental solutions. We operate 262 active, solid waste landfills, and at 137 of them, operate beneficial landfill-gas-to energy (LFGTE) projects. These projects produce renewable electricity, renewable fuel for stationary facilities, and renewable transportation fuel for vehicles, including 300 of our own refuse collection trucks. The proposed revisions will have a very significant impact on our landfill facilities and our renewable energy projects.

Waste Management operates 227 landfill gas collection and control systems (GCCS) across the U.S. Landfill gas (LFG) is controlled using open flares, enclosed flares, and beneficial use projects employing reciprocating engines, turbines, boilers, fuel conversion (gas to diesel, gas to CNG) and high-BTU fuel generating plants. Each GCCS consists of at least one flare and WM currently operates approximately 200 open flares (aka utility flare, candlestick flare, non-enclosed flare). Many of our open flares are permitted to serve as backup control devices for when the LFGTE plant is unable to utilize all of the collected gas, is offline due to utility demand, or is running at partial capacity for maintenance or other activities. The flare must be able to handle the entire gas flow to the energy plant and also be able to accommodate low flow conditions; open flares consistently have superior turndown when compared to enclosed flares. We also use open flares at our small and/or older landfills that exhibit reduced flow conditions and low methane quality.

EPA recognized the importance of flare operations in its June 2014 "Municipal Solid Waste Landfills Economic Impact Analysis for the Proposed New Subpart to the New Source Performance Standards" (Docket ID Number EPA-HQ-OAR-2003-0215-0045):

> *Flares are the most common control device used at landfills. Flares are also a component of each energy recovery option because they may be needed to control LFG emissions during energy recovery system startup and downtime and to control any gas that exceeds the capacity of the energy conversion equipment. In addition, a flare is a cost-effective way to gradually increase the size of the energy recovery system at an active landfill. As more waste is placed in the landfill and the gas collection system is expanded, the flare is used to control excess gas between energy conversion system upgrades (e.g., before addition of another engine).*

Even though the flare manufacturers guarantee the current Industrial Flare CO and NOx factors for LFG fired open flares, many air permit agencies instead rely on AP-42 emission factors for Industrial Flares to permit LFG fired open flares. In some cases the permit agencies require sites use these factors and the air permits directly reference AP-42, not the flare manufacturer guarantees.

EPA did not consider LFG-fired open flares or non-assisted flares in its review and proposed update of AP-42 factors. EPA appears to justify a 98% increase in the NOx emission factor based on just 4 test reports for 5 flares (4 steam-assisted, 1 air-assisted). Of concern is that EPA did not remove the outlier from this data set. EPA did remove the outlier from the CO emission factor analysis; but relies on only 6 test reports for 7 flares (6 steam-assisted, 1 air-assisted) to update the CO factor.

With such limited data, EPA has not justified the change in NOx or CO emission factors for industrial flares, especially non-assisted LFG or biogas fired flares as no test data from these types of flares was included in the analysis. WM therefore recommends EPA maintain the current CO and NOx emission factors (0.37 lb CO/MMBtu and 0.068 lb NOx/MMBtu) for non-assisted flares and specifically for LFG and biogas-fired non-assisted flares. EPA does not have any new data to support changes to the emission factors for these types of flares.

WM appreciates your consideration of our comments on the proposed emission factor revisions. If you have any questions, please contact Amy Banister at 713-328-7340 (abaniste@wm.com).

Sincerely,

Kerry Kelly

Kerry Kelly, Senior Director

Federal Affairs

Amy Van Kolken Banister, Senior Director

Corporate Air Programs

Cc: Bob Schell, OAQPS

Attachment: SWANA and NW&RA Letter dated October 17. 2014

National Waste & Recycling Association℠
Collect. Recycle. Innovate.

SWANA®
SOLID WASTE ASSOCIATION
of North America

October 17, 2014

Via Electronic Transmission: refineryfactor@epa.gov

Ms. Gerri Garwood
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC 20460

Dear Ms. Garwood:

Re: Revised Emissions Factors for Flares in Draft AP-42, Section 13.5 (Supplement D)

The National Waste & Recycling Association (NW&RA) and the Solid Waste Association of North America (SWANA) are pleased to offer comments on the proposed revisions to the Emissions Factors for Flares. The NW&RA and SWANA represent companies, municipalities and professionals in the solid waste industry. The NW&RA, formerly the National Solid Waste Management Association, is a not-for-profit trade association representing private solid waste and recycling collection, processing and management companies that operate in all fifty states. SWANA is a professional education association in the solid waste management field with members from both the private and public sectors across North America.

EPA has proposed new and revised emissions factors for industrial flares in the draft AP-42 Section 13.5, which substantially increases the emission factor for nitrogen oxides (NOx). While the new proposed factors might be appropriate for air assisted or steam assisted flares used at refineries, we do not believe they are appropriate for use with the candlestick (also called “open” or “utility”) flares that are in predominant use at municipal solid waste (MSW) landfills. The landfill sector’s candlestick flares are neither air nor steam assisted. Although the AP-42 has a chapter for MSW Landfills, the factors for NOx and CO in Section 13.5 are generally accepted as being more accurate, and are widely used within the landfill sector. Thus, the accuracy, validity and quality of the proposed emissions factors for use with non-assisted flares are very important to the landfill sector.

We reviewed the test results upon which EPA relied to establish the revised emission factors. It appears that none of the tests involved open, non-assisted flares, and none of the tests appeared to involve combustion of landfill gas. According to flare manufacturer, John Zink, Inc., (see attached letter) the test reports underpinning EPA’s revised emission factors involved high pressure, air or steam assisted, flares. Further, the tests were conducted with various flare tips not used within the

landfill sector, and the tests involved combustion of heavier, hydrocarbon-laden gases. Thus, the resulting emission factors are not applicable to non-assisted open flares burning landfill gas.

Nonetheless, EPA guidance in the draft section recommends that non-assisted flares use these new or revised emission factors. We are very concerned that EPA intends that these new emission factors be used in permitting MSW landfill candlestick flares. The proposed NOx emission factor is substantially higher than the existing factor. EPA appears to have used the result of one measurement from a single study to rationalize revising the NOx factor. In addition, the TCEQ studies referenced in the proposed revisions do not have NOx results, and thus cannot be used to support the revised factor. The Agency's recommendation that non-assisted flares use these new emission factors is inappropriate and not supported by the data. The test data supporting the revised factors are not relevant to non-assisted, open flares used in the landfill sector. Further, for the NOx emission factor, the dataset used to support the revision appears to be wholly inadequate, as it is based on one measurement from one study.

Although Section 13.5 of AP-42 is generally used by the petroleum industry, it is not limited to that industry. Section 13.5 itself notes, "flares are also used for burning waste gases generated by sewage digesters, coal gasification, rocket engine testing, nuclear power plants with sodium/water heat exchangers, heavy water plants and ammonia fertilizer plants." Given that the Section 13.5 factors are used by many industries, it is important that they accurately reflect emissions from all types of flares used in other industrial sectors.

As noted above, Section 13.5 has been widely used within the landfill sector as a source of emission factors. In fact, the majority of the air permitting conducted for landfill candlestick flares has relied upon AP-42 Section 13.5 factors for NOx and CO and many existing landfill permits have limits tied to the Section 13.5 factors. As such, there is a strong regulatory precedent for their use in federal, state, and local air permits for landfills. Further, the major manufacturers of landfill gas candlestick flares have recommended the use of the 1991 Section 13.5 factors as being the most appropriate and well-supported. See attached letter from the John Zink Company.

Because Section 13.5 is widely used in permitting by the landfill sector, it is essential that Section 13.5 retain factors that are appropriate for the non-assisted candlestick flares used at landfills and reflect their actual emissions as shown in high-quality emission tests. This can best be accomplished by maintaining the current factors for landfill gas and other biogas flares. We also propose that the Agency delete its recommendation that the revised factors be used for non-assisted flares. The proposed EFs should be limited to relevant industries that utilize steam and air assisted flares.

The NW&RA and SWANA appreciate your consideration of these comments and our requested revisions to the EPA's proposal. Should you have any questions about these comments, please call Anne Germain, Director of Waste & Recycling Technology for NW&RA, at 202-364-3724 or e-mail her at agermain@wasterecycling.org. You may also call Jesse Maxwell, Advocacy & eLearning Program Manager for SWANA, at 240-494-2237 or e-mail him at jmaxwell@swana.org.

Very truly yours,

Sharon H Kneiss

Sharon H. Kneiss
President & CEO
National Waste & Recycling Association

John H Skinner

John Skinner
Executive Director & CEO
Solid Waste Association of North America

Garwood, Gerri

From:	Georgette Reeves <GReeves@trinityconsultants.com>
Sent:	Friday, October 17, 2014 4:05 PM
To:	RefineryFactor
Cc:	Sue Sung; Richard Trzupek
Subject:	Trinity Consultants: Comments on Proposed AP42 Factor Changes
Attachments:	Trinity Consultants_AP-42 Flare NOx 1017-2014_0259.pdf

Good afternoon:

Our comments regarding the proposed changes to AP-42 are attached.

Respectfully submitted,

……………………………………………………………………………………………

Georgette Reeves
Gulf Region Business Development Manager
Managing Consultant
Trinity Consultants
9111 Jollyville Road | Suite 255 | Austin, Texas 78759

Office: **512-349-5800 Ext. 1004** | Mobile: 505-440-0477
Email: greeves@trinityconsultants.com | Website: www.TrinityConsultants.com

---

12770 Merit Drive | Suite 900 | Dallas, TX 75251 | P (972) 661-8100 | F (972) 385-9203
trinityconsultants.com

Trinity Consultants

VIA EMAIL: refineryfactor@epa.gov

October 17, 2014

To: United States (US) Environmental Protection Agency (EPA)
Re: Proposed updates to NOx emission factors for flares in AP-42

To Whom it may Concern:

Trinity Consultants is a nationwide air quality consulting firm with offices throughout the United States serving more than 1,200 industrial clients in all 50 states across a wide range of industry. As a leader among consulting firms in the air quality field for nearly 40 years, Trinity understands the nuances of quantifying emissions and other air-related regulatory requirements. As such, Trinity Consultants is deeply concerned regarding the quality of data used to justify the proposed changes, as well as the statistical mis-management of the data presented in EPA's justification for the proposed emission factor updates. While the subject of this analysis focuses on the proposed NOx emission factors, Trinity Consultants urges US EPA to carefully evaluate its overall data validation and Quality Assurance (QA) procedures relating to all of the proposed AP-42 emission factor updates.

It is our concern that these proposed updates do not appear to be based in sound science or statistical practices. Use of these factors as proposed would result in significant over-reporting of emissions from flares, creating an apparent massive increase in emissions in the petrochemical and natural gas sectors that would at least partially undermine the significant strides that both industry groups have made in reducing emissions of all kinds, in part due to effective partnerships with USEPA and local regulatory agencies. Furthermore, use of these factors would have a decidedly negative effect on regulatory policy decisions at both the national and state levels. Falsely reporting that flare emissions are much greater than they actually are will inevitably lead to over-emphasizing their importance when considering new control strategies and thus increasing the possibility that scarce EPA resources will be devoted to solve a problem that doesn't actually exist.

Trinity Consultants respectfully submits the following analysis and areas of concern relating to the proposed changes to AP-42 NOx emission factors for flares.

EXECUTIVE SUMMARY

It is understood that USEPA is considering a new default NOx emissions factor for flares of 2.9 lb/MMBtu ("the new factor"). The new factor has been calculated as an arithmetic average based on Passive Fourier Transform Infrared (PFTIR) Spectroscopy instrument measurements of five flares and the existing AP-42 emissions factor. This memorandum discusses the scientific and statistical validity of calculating the new factor using these data sets.

A review of the PFTIR data sets used in calculation of the new factor lead to the following conclusions:

- The high NOx concentration measurements of the Flint Hills Resources Port Arthur, TX refinery (FHR-AU) test results (if proven to be correct) are not reasonable from thermal formation of any external combustion sources, including flares. If the NOx concentration measurements were recorded due to instrument reading error, this data should not be used. If it is determined that these high NOx concentrations are the result of fuel-bound nitrogen present in the waste gas stream, the FHR-AU NOx emissions data should not be included in emission factor development since fuel-bound nitrogen concentrations can vary significantly from venting event to event, as well as from site to site.

- If it is determined that the waste gas stream in the FHR-AU test did not contain significant amount of fuel bound nitrogen, then the FHR-AU data should not be used for NOx emissions factor development at all, since the NOx concentrations measured could not be attributable to thermal NOx formation.

- The exhaust gas flow rate from the flare tested at the Flint Hills Resources Port Arthur, TX refinery (FHR–AU) was vastly over-estimated in several instances due to questionable low CO_2 concentration readings at those incidents.

- Two such instances with grossly over-estimated exhaust gas flow rate resulted in NOx emission rates and emission factors that were more than two orders of magnitude greater than any other NOx emission factors calculated during the FHR – AU test series. It appears that these two NOx emission rate data points are obviously erroneous and should not be used for any purpose. Simple removal of the two egregiously erroneous data points described above results in a NOx emissions factor of 0.79 lb/MMBtu (as compared to the proposed factor of 2.98 lb/MMBtu).

- Other anomalies and apparent errors in the FHR-AU data suggest that it should not be used for calculation of revised AP-42 emissions factors.

- Chief among the additional anomalies and apparent found in the FHR-AU data set are: the lack of correlation between CO emissions and NOx emissions; the absence of measured NO emissions in the FHR-AU flare plume (with the exception of two discrete instances); and several instances where measured NO_2 concentrations move from a high value one minute, to zero the next minute and back to a high value the minute after that.

- If it is determined to use the FHR-AU dataset at all, it is scientifically and statistically indefensible to weight it the same as the other four PFTIR datasets included in calculation of the new factor.

- USEPA should re-examine its methods of vetting datasets, both in the case of the proposed flare emissions factors and in general.

A more detailed discussion of the issues described above follows.

DATA REVIEW AND ANALYSIS

Table 1 summarizes the five PFTIR studies and existing AP-42 factor used to calculate the new factor:

Table 1

Flare	NOx Emission Rate (lb/MMBtu)
FHR-AU	16
MPC_Detroit	0.011
INEOS	0.471
TCEQ, steam	0.129
TCEQ, air	0.577
old AP-42	0.068
Average:	2.88

The standard deviation for this data set is 5.9 lb/MMBtu, greater than the calculated mean value. Removing the FHR-AU data point results in a mean value of 0.83 lb/MMBtu and a far more reasonable standard deviation of 0.23 lb/MMBtu. The vast difference between the FHR-AU data and the rest of the dataset should have triggered questions and additional investigation of the FHR-AU data set.

For the flare NOx emission factor, USEPA reviewed five data sets from various testing events. Trinity reviewed the data sets used by USEPA to develop the proposed NOx emission factor and found that the NOx concentration measurements in the FHR-AU test are highly questionable and should not be relied upon to calculate an emission factor. There are three chemical mechanisms for NOx formation from combustion:

(1) ***Thermal NOx*** is defined as that NOx produced from the combustion air which contains atmospheric nitrogen and oxygen. Thermal NOx is the largest contributor to NOx Formation in the combustion process.
$O_2 + N_2 \leftrightarrow 2NO$ (Reaction 1)
$NO + \frac{1}{2} O_2 \leftrightarrow NO_2$ (Reaction 2)

(2) ***Prompt NOx*** is defined as that NOx formed in the initial portion of the flame zone when fuel and air react. Prompt NOx generally is an important mechanism in lower temperature processes but not in flares.

(3) ***Fuel NOx*** is defined as that NOx produced from nitrogen that is chemical or organically bound in the fuel, such as (NH_3). Such fuel-bound nitrogen compounds are not typical in high concentrations in the gaseous fuel.

For flare operations, the majority of NOx is generated through **thermal formation**. The NOx concentration generated from this mechanism is typically well below 1000 ppmm, while FHR-AU test data shown most NOx concentration measurements exceed 1000 ppmm. One can determine the reasonably expected NOx concentration based on the chemical equilibrium using the following equations:

Equation 1: $$K_1 = \frac{(y_{NO})^2}{y_{N_2} y_{O_2}}$$

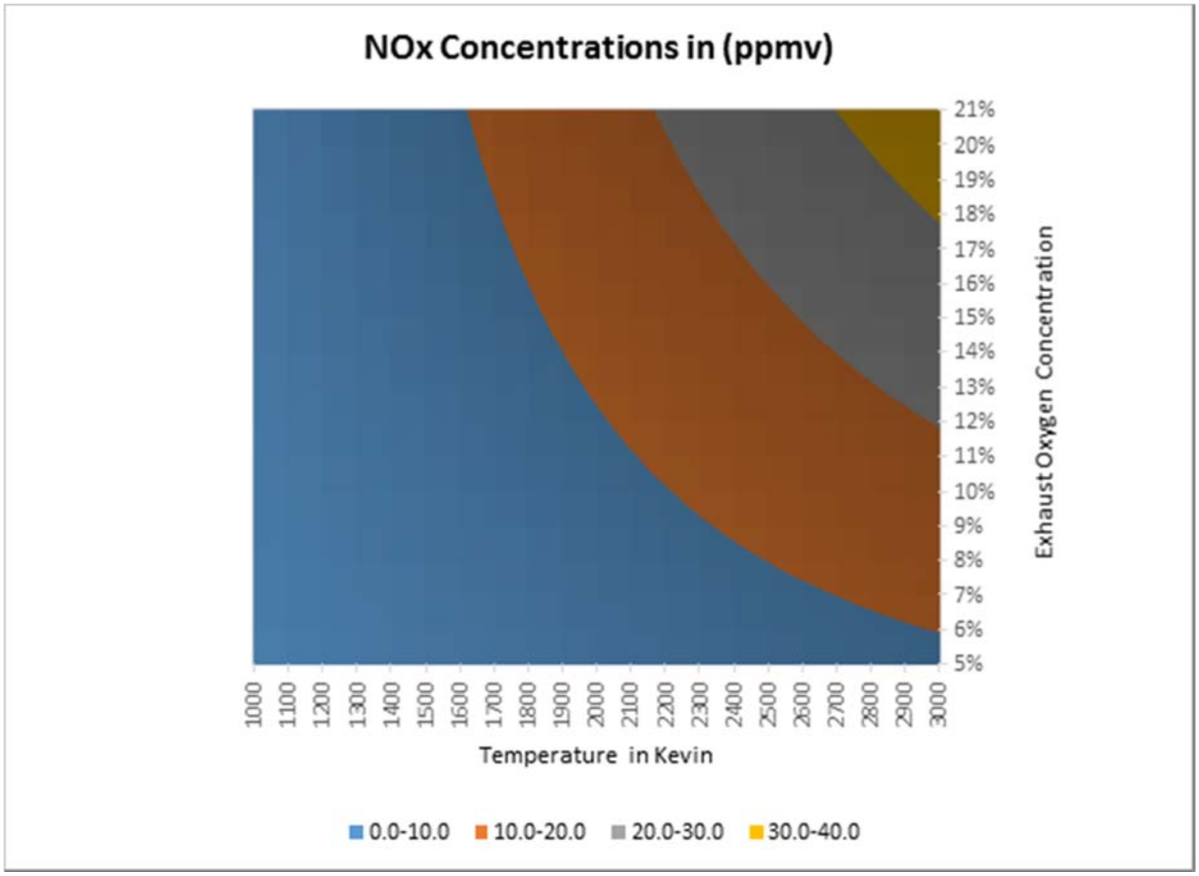
Equation 2: $$K_2 = (P_T)^{-1/2} \frac{y_{NO_2}}{y_{NO}\left(y_{O_2}\right)^{1/2}}$$

Combining Equation 1 with Equation 2, the NOx concentration can be calculated as follows:

$$y_{NO_2} = K_2 \cdot y_{O_2} \left(K_1 \cdot P_T \cdot y_{N_2}\right)^{1/2}$$

Based on published equilibrium constants[1] and van't Hoff Equation ($\ln K \propto 1/T$), one can determine the equilibrium constants between 1000 K and 3000 K. As shown in the figures below, the NOx concentration from thermal formation are mostly below 10 ppm in the flare tip temperature range. The results are supported by data reported in Marathon's testing data.

The high NOx concentration measurements of the FHR test results, if proven to be correct, might be attributable to the other mechanism, i.e., fuel-bound nitrogen NOx formation. Should these high NOx concentration measurements be contributed by fuel-bound nitrogen NOx, this data should not be included in emission factor development since fuel-bound nitrogen concentrations can vary significantly from venting event to event, as well as from site to site.



While Trinity Consultants is already concerned about the validity of the FHR data, we have gone on to analyze the data in more detail. A visual comparison of plots comparing emission rates in lb/MMBtu vs. time for each flare brings another problem with the FHR-AU dataset clearly to light. Each of the charts below compares NOx emission rate in lb/MMBtu (y axis) vs. minutes of sampling (x axis):

---

[1] Table 15.3, *Air Pollution Control*, A Design Approach by C. David Cooper and F.C. Alley, Second Edition 1*994*

Chart 1 – MPC-Detroit

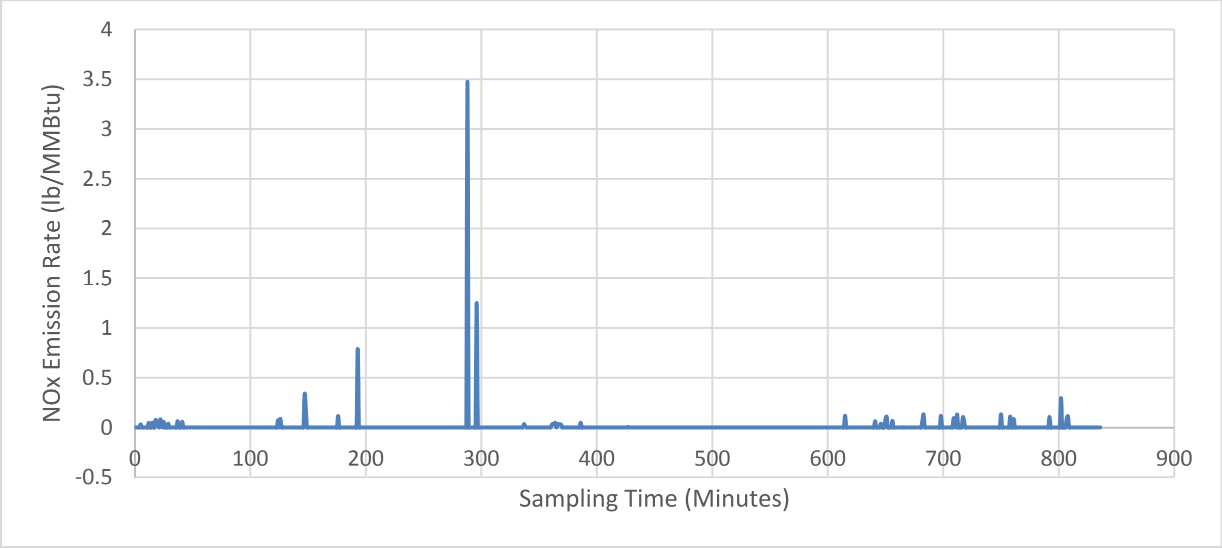


Chart 2 – INEOS

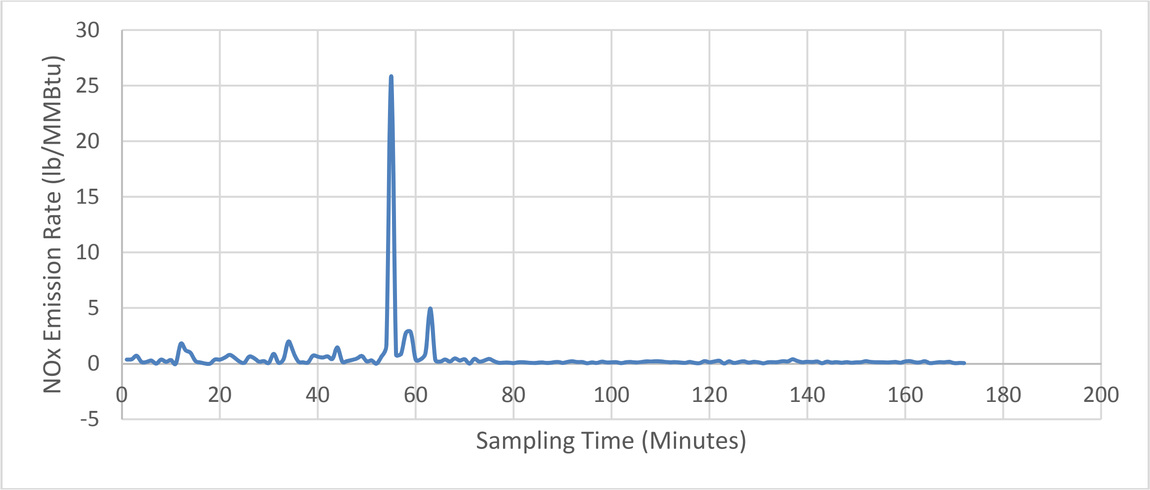


Chart 3 – TCEQ Steam

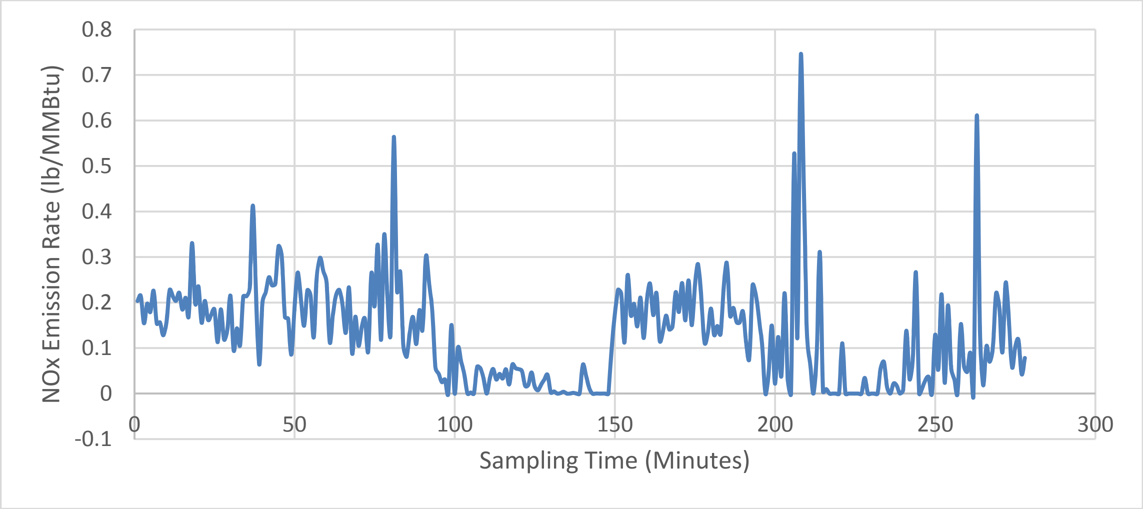
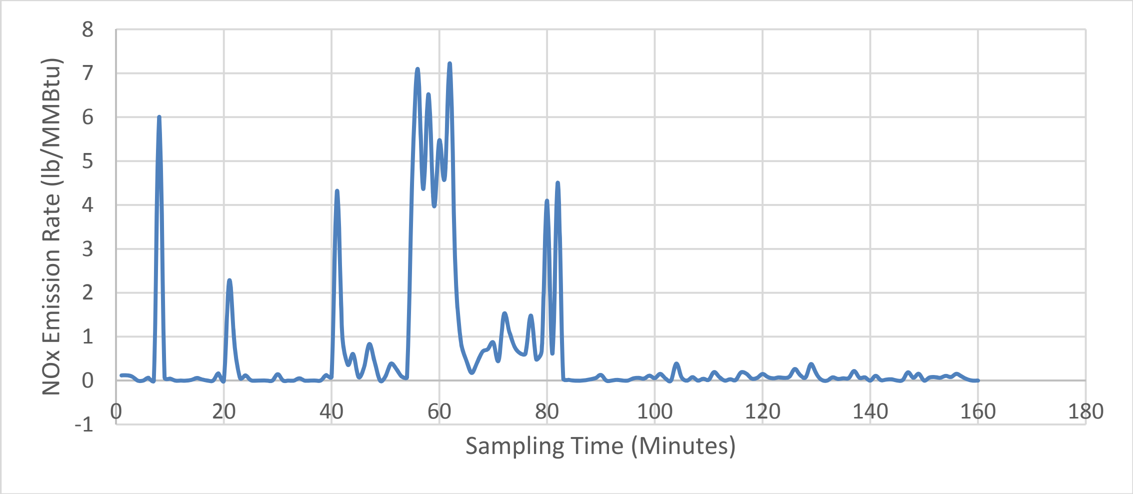


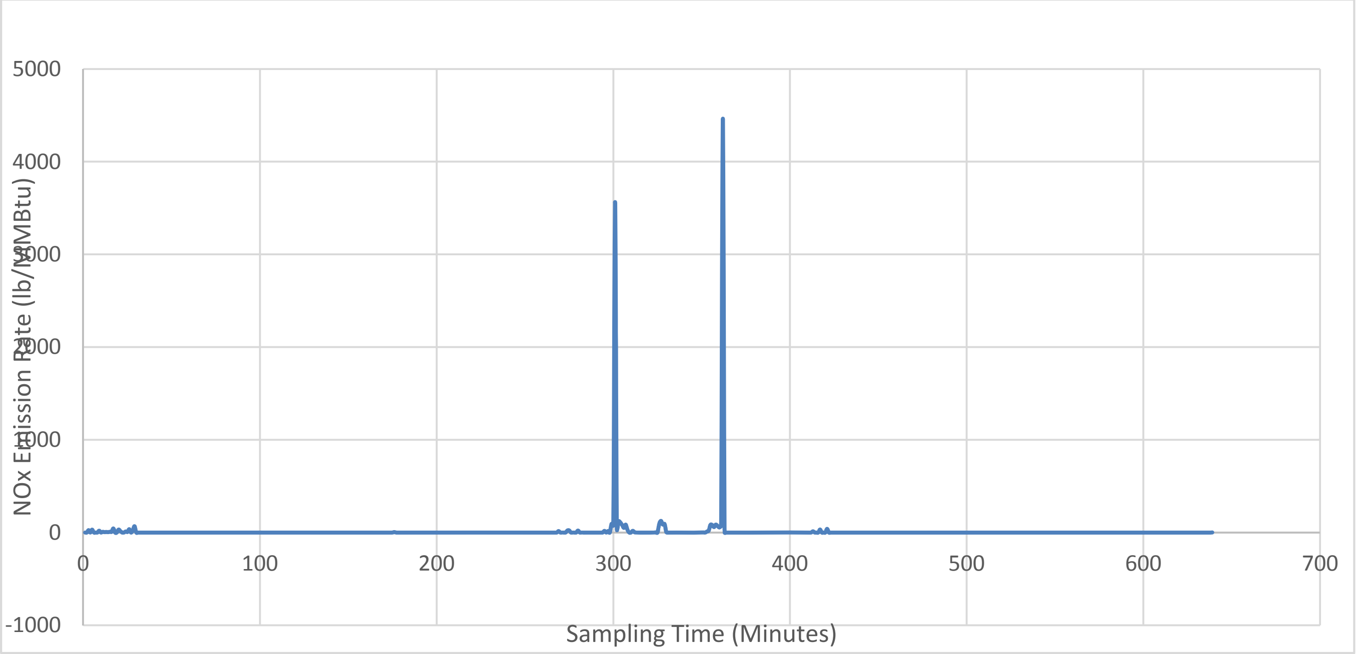
Chart 4 – TCEQ Air



Note that there in only one case (INEOS) does a calculated emission rate greater than 10 lb/MMBtu occur and the vast majority of calculated emission rates are less than 1 lb/MMBtu.

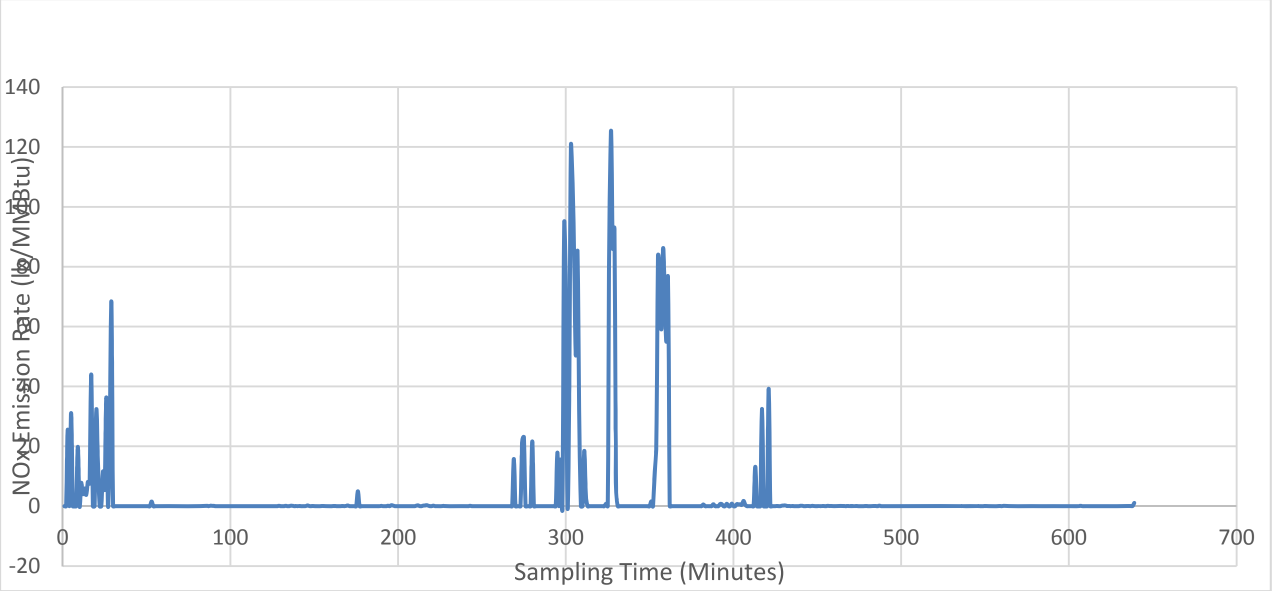
The plot of FHR-AU data is markedly different:

Chart 5 – FHR-AU (Uncorrected) NOx lb/MMBtu



Two features chart 5 stand out: 1) the scale of the y-axis (0 – 5,000 lb/MMBtu) is far larger than any of the previous charts, and 2) that scale is made necessary by two large peaks that exceed other calculated by values by at least two, and in most cases three, orders of magnitude. But, even removal of these two anomalous data points yields a much different-looking chart:

Chart 6 – FHR-AU (2 Anomalous Data Points Removed) NOx lb/MMBtu

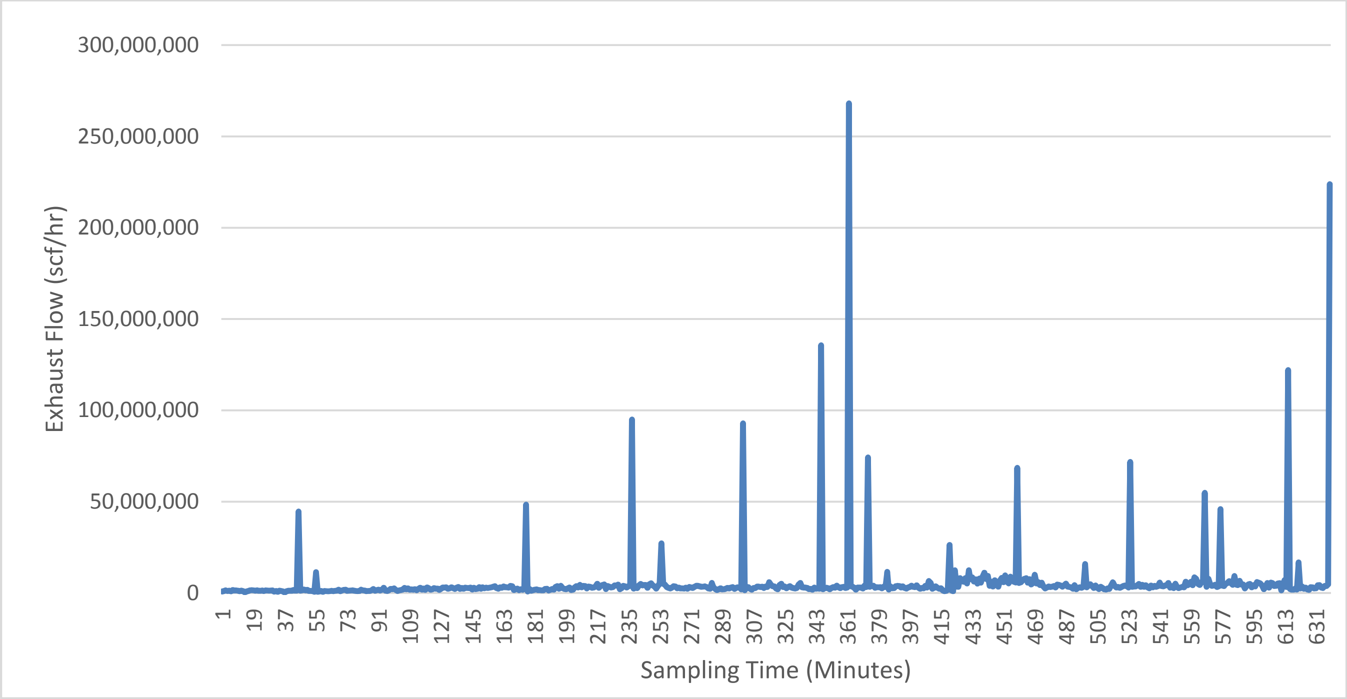


Many data points not only exceed the 1 lb/MMBtu "normal" upper limit described earlier, many also exceed the "extreme" upper limit of 25 lb/MMBtu established in the first four studies. A review of the data makes it clear that the large peaks observed in both Chart 5 and Chart 6 are attributable to erroneous calculation of exhaust gas flow rates. While, in most cases, the range of calculated exhaust gas flow rates for the FHR-AU flare are in the typical range of 1 to 10 MMscfh exhibited by similar-sized flares included in the study, the calculated exhaust gas flow rates for the FHR-AU flare exceed 10 MMscfh in 22 instances and exceed 100 MMscfh in 4 instances. These instances of over-estimated exhaust gas flow rates lead to vast over-estimation of NOx emissions rates. This is especially apparent in two instances: time stamp 10/26/10 at 12:23 and time stamp 10/26/10 at 17:28.

In the first case, a calculated exhaust gas flow rate of over 92 MM scfh leads to a calculated NOx emission rate of over 3,500 lb/MMBtu, even though the NOx concentration measured at that time (~8,900 ppm) and the vent gas flow rate (~36,000 scfh) are not markedly different from many other similar data points. The same is true in the latter case, where a calculated exhaust gas flow rate of over 268 MM scfh leads to a ludicrous calculated NOx emission rate of over 4,400 lb/MMBtu, even though measured NOx concentrations and vent gas flow rates are again in the normal range.

Chart 7 (below) provides a visual representation of the extreme variability in exhaust gas flow rate calculations in the FHR-AU case. Many of these erroneous calculations are problematic, because each erroneous flow rate calculation does not always correspond to a flaring event where NOx emissions are produced. But, when erroneous flow rate calculations do correspond to such a flaring event, an over-estimation of NOx emission rates inevitably occurs.

Chart 7 – FHR- AU (2 Anomalous Data Points Removed) Calculated SCFH



The root cause of the faulty exhaust gas flow rate calculations appears to be the methodology used to calculate those exhaust gas flow rates. The formula used to calculate exhaust gas flow rate is:

Eq. 1: $Q_s = \frac{C_i}{C_m} \times \frac{385.5}{12}$

Where,

Qs = calculated exhaust gas flow rate, in scfh
Ci = calculated total carbon in the vent gas based on bagged sample and DCS measured vent gas flow rate, in lbs/hr
Cm = PFTIR measured total carbon in the flare plume, fractional
385.5 = molar volume of ideal gas (scf/lb-mole)
12 = molecular weight of carbon (lb/lb-mole)

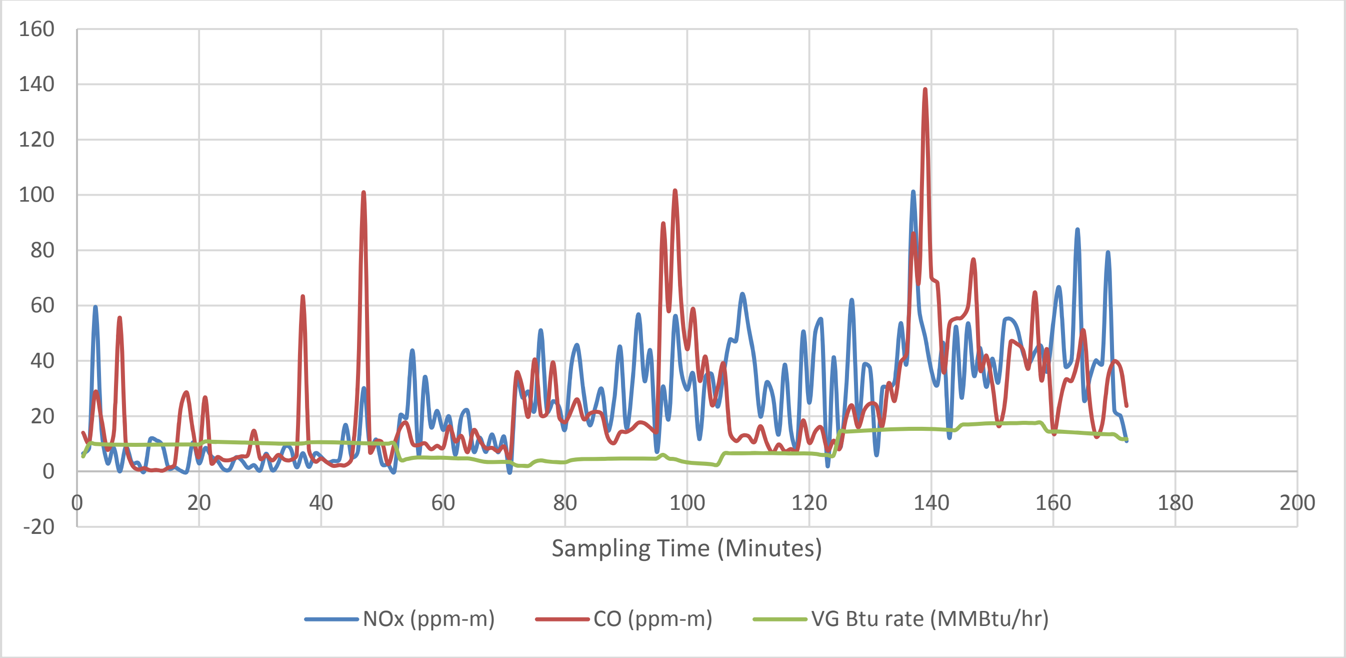
Equation 1 is thus sensitive to measured carbon concentrations in the exhaust gas plume. If apparent carbon concentrations in the plume drop significantly, the reduction in the denominator in the fraction Ci/Cm will cause the calculated exhaust gas flow rate to rise proportionally. This is clearly the cause of the majority of mis-calculations of exhaust gas flow rate. For example, the previously-mentioned anomalous data gathered at time stamp 10/26/10, 12:23 included a measured carbon concentration of 311 ppm-m, following a reading of 15,000 ppm-m the minute before and preceding a reading of 20,000 ppm-m the minute after. This sudden, unexplainable and dramatic “drop” in carbon concentration defies both common sense and basic principles of thermodynamics, and poisons subsequent calculations as well.

The faulty data may be attributable to measurement error, interference (a chronic problem with any form of FTIR) or possibly because the equation the Agency uses to calculate exhaust gas flow rate is too carbon sensitive to use when a flare gas stream is hydrogen-rich. While it is not known if the flare gas stream at FHR-AU was hydrogen rich, *if* it was, then the carbon sensitivity of the flow gas exhaust rate equation would be a concern.

In addition to the flow rate measurement issues, it’s clear that measurement of NOx concentrations in the FHR-AU exhaust plume are fraught with errors. In order to illustrate the problems with NOx concentration measurements in the FHR-AU data set, it is helpful to consider measured NOx concentrations in the plumes of the two other steam assisted flares of similar size that have been proposed to be used to calculate a new AP-42 NOx emissions factor for flares: INEOS and TCEQ-Steam.

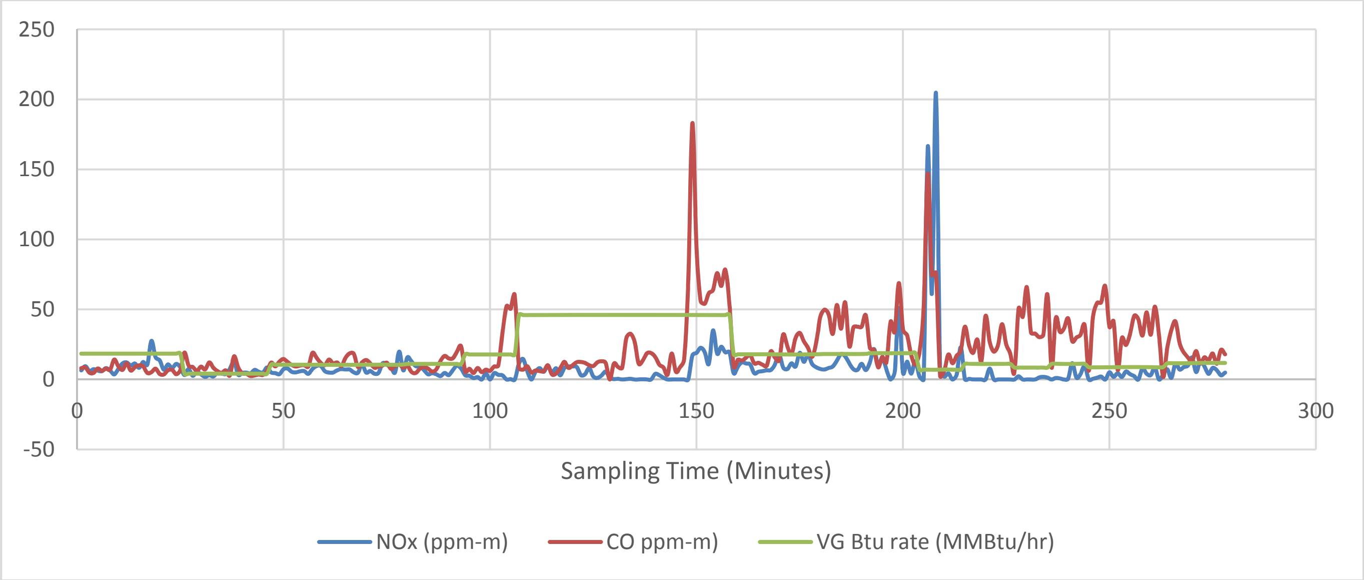
The INEOS chart compares measured NOx concentrations, CO concentrations and vent gas heating value versus time:

Chart 8 – INEOS NOx, CO and Heating Value vs. time



In this chart, NOx and CO concentrations seem to fluctuate as would be expected. There is no correlation between NOx and CO concentrations, nor would one be expected since combustion conditions that generate higher concentrations of one generally generate lower concentrations of the other. The important point is that flare combustion of any sort should reasonably be expected to generate detectable concentrations of each, and this chart is consistent with that expectation. The TCEQ-Steam chart reveals the same general pattern:

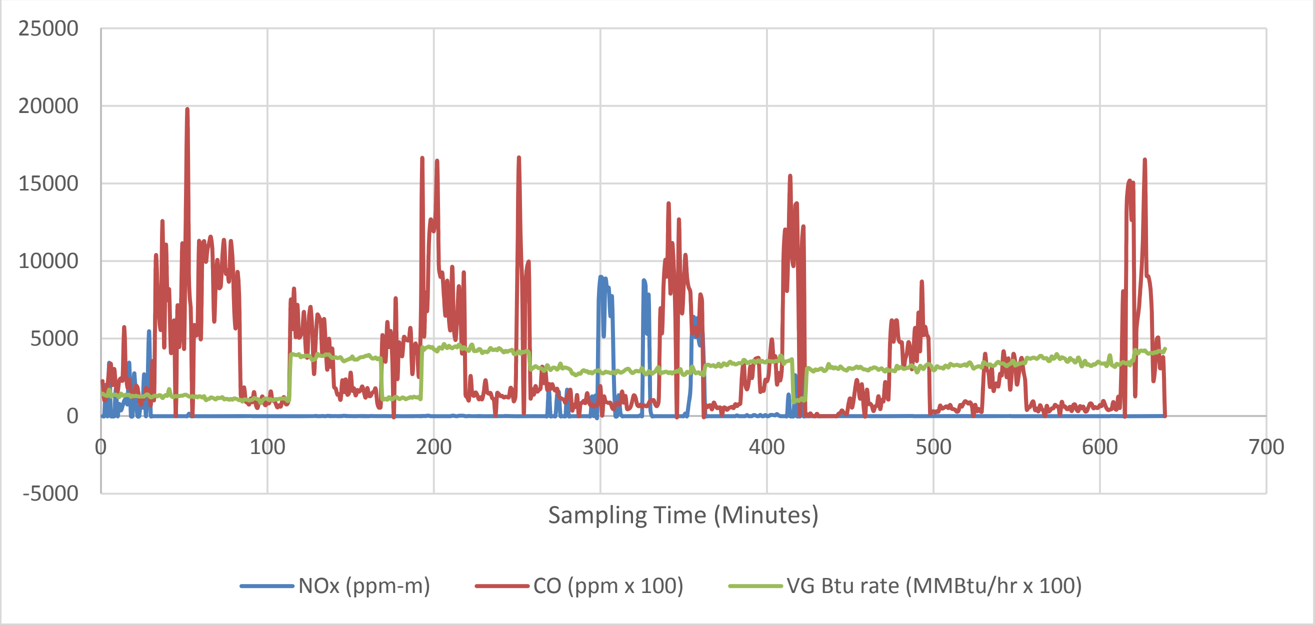
Chart 9 – TCEQ Steam NOx, CO and Heating Value vs. Time



Again, there is variance in CO and NOx concentrations and there isn't a consistent correlation pattern between the two, but non-zero measurement in both cases is the norm, not the exception. (Note that the Vent Gas Btu rate is apparently "flat" for long periods of time because measurement of that parameter involved periodic, rather than continuous, sampling in this case).

When the same data points are plotted for FHR-AU, a much different pattern emerges:

Chart 10 - FHR-AU NOx, CO and Heating Value vs. Time



CO concentrations and Vent Gas Btu rate have been normalized by multiplying each by a factor of 100 in order to allow for a visual comparison similar to Charts 8 and 9. Raw (non-normalized) CO and Btu data is in the same range as the INEOS and TCEQ-Steam data. Normalization is necessary to visualize this data against the inflated NOx concentrations that appear in the FHR-AU dataset.

While CO concentrations show the kind of variance observed in the other two cases, reported NOx concentrations are zero 72% of the time, suggesting that combustion conditions that produce CO are capable of producing no NOx whatsoever. This behavior is inconsistent with any of the other datasets examined and defies common sense. Equally troubling is that, with the exception of two data points, no NO_2 concentrations are reported in the FHR-AU dataset and that, in many occasions, the reported NO concentrations go from thousands of ppm to zero and back to thousands of ppm. (See, for example, time stamps 10/21/10 10:42 through 11:01, and time stamps 10/26/10, 12:17 through 12:42).

RECOMMENDATIONS

The following recommendations are offered for the Agency's consideration:

1. Evaluate whether high NOx test data is resulting from instrument reading error or unusually high fuel-bound nitrogen NOx formation, rather than thermal NOx formation. If this test data is resulting from

fuel-bound nitrogen NOx formation or is due to instrument reading error, this data set should not be used.

2. At a bare minimum (barring the point made above), the two most extreme anomalous data points in the FHR-AU dataset should be removed and the proposed emission factor recalculated.

3. Since erroneous flow rate measurements in the FHR-AU dataset will affect proposed emissions factors for other pollutants, the effect of erroneous flow rate measurements on those emission factors should be examined.

4. Because of the other serious problems with FHR dataset, the Agency should consider either not using the FHR-AU dataset at all, or – if it is to be used – reweighting and adjusting the data to account for the many discrepancies in it.

5. The Agency should review its data validation procedures. It is disturbing that two so-obviously erroneous data points could have such a dramatic effect on a proposed emissions-factor to be used on a nationwide basis, not to mention all of the other questions the FHR-AU dataset should have raised. Even if the FHR-AU dataset was deemed to be accurate in some form, it is difficult to justify use of this data as part of a simple arithmetic averaging exercise when: a) the data varies so much from the other data collected, and b) the 1:1 weighting inherent to the flare study assumes that the FHR-AU data is representative of 20% of all the flares in all industry sectors throughout the Untied States.

Trinity Consultants appreciates this opportunity to provide comment on this proposed change to AP-42.

Respectfully submitted,

Sue Sung, Ph.D., P.E.
Director, EHS Technology
Trinity Consultants (Dallas, TX)

Richard Trzupek
Principal Consultant
Trinity Consultants (Chicago, IL)

From:	sholcomb@nisource.com
Sent:	Friday, October 17, 2014 5:00 PM
To:	RefineryFactor
Subject:	Columbia Pipeline Group AP-42 flare comments
Attachments:	20141017_CPG_flare comments.pdf

Hello! Thank you for the opportunity to review the document, *DRAFT Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations.*
The attachment provides the Columbia Pipeline Group comments. We appreciate your consideration. If you have any questions, please let us know.

Regards,

Stephen Holcomb
Environmental Coordinator | NiSource
801 E. 86th Ave.
Merrillville, IN 46410
Office: (219) 647-5269
Cell: (219) 741-6742
sholcomb@nisource.com

Columbia Pipeline Group℠

October 17, 2014

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Sector Policies and Programs Division
Research Triangle Park, North Carolina 27711
Document emailed to refineryfactor@epa.gov as requested

Re: Columbia Pipeline Group Comments on *DRAFT Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations*

Columbia Pipeline Group (CPG) companies own and operate more than 15,700 miles of natural gas pipelines, integrated with one of the largest underground storage systems in North America. From the Gulf Coast to the Midwest, Mid-Atlantic, and Northeast, CPG systems connect natural gas supplies with some of the nation's strongest energy markets, serving customers in more than sixteen states. Approximately 1.3 trillion cubic feet of natural gas flows through CPG pipeline and storage systems each year, providing competitively priced, clean energy for millions of homes, businesses, and industries.

CPG appreciates the opportunity to comment on the document, *DRAFT Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations* ("Review"). Although not involved in refinery operations, CPG operates several industrial flares, and it uses the emission factors in AP-42 Table 13.5-1 in permitting and emission inventory activities. The proposed NOx emission factor increase of approximately 4,200% is concerning and appears to lack sufficient statistical basis. CPG encourages the Environmental Protection Agency (EPA) to reevaluate the proposed increase by analyzing more data, by creating more subcategories of emission factors, and by considering the impacts of the proposed increase to the regulated community.

The Review proposes an industrial flare NOx emission factor of 2.9 lb/mmbtu, which is more than 42 times greater than the current emission factor of 0.068 lb/mmbtu. The proposed factor is based on test results at five chemical and refining facilities. The Review states, "The statistical analysis for determining outliers in the data set determined that no outliers existed." However, application of Grubbs' test shows that the Flint Hills Resources data point of 16 lb/mmbtu is a significant outlier from the rest. This data point has the lowest Individual Test Rating in Table 21 of the Review; it should not be given equal weight considering the low confidence in its representativeness. Indeed, if this data point were removed from the group, the average value in Table 21 would decrease from 2.9 lb/mmbtu to 0.25 lb/mmbtu. CPG would like the EPA to remove the Flint Hills Resources data point from consideration because it is an outlier.

If removal of the data point is not acceptable, then CPG encourages the EPA to gather more emissions test data from industrial flares. Several industries not associated with chemicals and refining use the AP-42 factors in Table 13.5-1. For example, some natural gas facilities operate gas dehydration equipment that has been retrofit with a flare for VOC control. These types of flares should be considered in the Review as well. When publishing a numerical value without an associated standard deviation, the Agency should strive to gather as much data as possible. A simple average of emissions data from five facilities that represent limited industry breadth cannot accurately reflect the entire population.

CPG would like the EPA to subcategorize industrial flare emission factors into groups based on heat input and flare type; however, the Review states on multiple occasions that statistical analysis for subcategorization could not be performed because of the lack of data. The EPA seems to recognize the value of subcategorization by mentioning this shortcoming. Emission factors are more reflective of a specific source when the statistical analysis used to develop the emission factors is based on similar equipment. For example in AP-42 Table 1.4-1, the EPA has subcategorized large wall-fired boilers (greater than 100 mmbtu/hr), small boilers (less than 100 mmbtu/hr), and tangential-fired boilers in several uncontrolled and controlled scenarios. CPG would like the EPA to develop subcategories of industrial flare emission factors as well.

Lastly, the impacts of the proposed change should be evaluated by the EPA and disseminated to the regulated community. Assuming that the existing AP-42 factor will increase by a factor of 42, the regulated community could be presented with significant impacts to permit applicability. Does a company need to revisit permits where a synthetic minor was established based on the existing AP-42 flare emission factors? Formal guidance from the EPA would be helpful.

Thank you for considering these comments.

Sincerely,

Maureen Turman

Maureen Turman
NiSource, Manager of Environmental Policy
801 E. 86th Avenue
Merrillville, Indiana 46410
(219) 647-4887
mturman@nisource.com

From: Anne Germain <agermain@wasterecycling.org>
Sent: Monday, October 20, 2014 5:12 PM
To: RefineryFactor
Cc: Garwood, Gerri
Subject: FW: Comments to AP-42 Section 13.5
Attachments: NWRA and SWANA letter on AP-42.pdf; OPENFLARE.PDF; NW Emissions ZEF.PDF; Anne Germain.vcf

Dear Sir/Madam –

I forgot to attach the letters referenced in the NWRA/SWANA letter. So, please find the attachments along with the original letter.

Best,
Anne.

Anne Germain, P.E., BCEE, Director of Waste & Recycling Technology
4301 Connecticut Avenue NW #300 I Washington, DC 20008
Office **202-364-3724** | *Fax* **202-966-4824** | *Mobile* **302-270-5483**
agermain@wasterecycling.org

From: Anne Germain
Sent: Friday, October 17, 2014 10:57 AM
To: 'refineryfactor@epa.gov'
Cc: 'garwood.gerri@epa.gov'
Subject: Comments to AP-42 Section 13.5

Attached please find comments from the National Waste & Recycling Association and from the Solid Waste Association of North America regarding AP-42 Section 13.5.

Best regards,
Anne Germain

National Waste & Recycling Association℠
Collect. Recycle. Innovate.

SWANA®
SOLID WASTE ASSOCIATION
of North America

October 17, 2014

Via Electronic Transmission: refineryfactor@epa.gov

Ms. Gerri Garwood
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC 20460

Dear Ms. Garwood:

Re: Revised Emissions Factors for Flares in Draft AP-42, Section 13.5 (Supplement D)

The National Waste & Recycling Association (NW&RA) and the Solid Waste Association of North America (SWANA) are pleased to offer comments on the proposed revisions to the Emissions Factors for Flares. The NW&RA and SWANA represent companies, municipalities and professionals in the solid waste industry. The NW&RA, formerly the National Solid Waste Management Association, is a not-for-profit trade association representing private solid waste and recycling collection, processing and management companies that operate in all fifty states. SWANA is a professional education association in the solid waste management field with members from both the private and public sectors across North America.

EPA has proposed new and revised emissions factors for industrial flares in the draft AP-42 Section 13.5, which substantially increases the emission factor for nitrogen oxides (NOx). While the new proposed factors might be appropriate for air assisted or steam assisted flares used at refineries, we do not believe they are appropriate for use with the candlestick (also called “open” or “utility”) flares that are in predominant use at municipal solid waste (MSW) landfills. The landfill sector’s candlestick flares are neither air nor steam assisted. Although the AP-42 has a chapter for MSW Landfills, the factors for NOx and CO in Section 13.5 are generally accepted as being more accurate, and are widely used within the landfill sector. Thus, the accuracy, validity and quality of the proposed emissions factors for use with non-assisted flares are very important to the landfill sector.

We reviewed the test results upon which EPA relied to establish the revised emission factors. It appears that none of the tests involved open, non-assisted flares, and none of the tests appeared to involve combustion of landfill gas. According to flare manufacturer, John Zink, Inc., (see attached letter) the test reports underpinning EPA’s revised emission factors involved high pressure, air or steam assisted, flares. Further, the tests were conducted with various flare tips not used within the

landfill sector, and the tests involved combustion of heavier, hydrocarbon-laden gases. Thus, the resulting emission factors are not applicable to non-assisted open flares burning landfill gas.

Nonetheless, EPA guidance in the draft section recommends that non-assisted flares use these new or revised emission factors. We are very concerned that EPA intends that these new emission factors be used in permitting MSW landfill candlestick flares. The proposed NOx emission factor is substantially higher than the existing factor. EPA appears to have used the result of one measurement from a single study to rationalize revising the NOx factor. In addition, the TCEQ studies referenced in the proposed revisions do not have NOx results, and thus cannot be used to support the revised factor. The Agency's recommendation that non-assisted flares use these new emission factors is inappropriate and not supported by the data. The test data supporting the revised factors are not relevant to non-assisted, open flares used in the landfill sector. Further, for the NOx emission factor, the dataset used to support the revision appears to be wholly inadequate, as it is based on one measurement from one study.

Although Section 13.5 of AP-42 is generally used by the petroleum industry, it is not limited to that industry. Section 13.5 itself notes, "flares are also used for burning waste gases generated by sewage digesters, coal gasification, rocket engine testing, nuclear power plants with sodium/water heat exchangers, heavy water plants and ammonia fertilizer plants." Given that the Section 13.5 factors are used by many industries, it is important that they accurately reflect emissions from all types of flares used in other industrial sectors.

As noted above, Section 13.5 has been widely used within the landfill sector as a source of emission factors. In fact, the majority of the air permitting conducted for landfill candlestick flares has relied upon AP-42 Section 13.5 factors for NOx and CO and many existing landfill permits have limits tied to the Section 13.5 factors. As such, there is a strong regulatory precedent for their use in federal, state, and local air permits for landfills. Further, the major manufacturers of landfill gas candlestick flares have recommended the use of the 1991 Section 13.5 factors as being the most appropriate and well-supported. See attached letter from the John Zink Company.

Because Section 13.5 is widely used in permitting by the landfill sector, it is essential that Section 13.5 retain factors that are appropriate for the non-assisted candlestick flares used at landfills and reflect their actual emissions as shown in high-quality emission tests. This can best be accomplished by maintaining the current factors for landfill gas and other biogas flares. We also propose that the Agency delete its recommendation that the revised factors be used for non-assisted flares. The proposed EFs should be limited to relevant industries that utilize steam and air assisted flares.

The NW&RA and SWANA appreciate your consideration of these comments and our requested revisions to the EPA's proposal. Should you have any questions about these comments, please call Anne Germain, Director of Waste & Recycling Technology for NW&RA, at 202-364-3724 or e-mail her at agermain@wasterecycling.org. You may also call Jesse Maxwell, Advocacy & eLearning Program Manager for SWANA, at 240-494-2237 or e-mail him at jmaxwell@swana.org.

Very truly yours,

Sharon H Kneiss

Sharon H. Kneiss
President & CEO
National Waste & Recycling Association

John H Skinner

John Skinner
Executive Director & CEO
Solid Waste Association of North America

JOHN ZINK
JOHN ZINK COMPANY LLC

International Headquarters
P.O. Box 21220
Tulsa, Oklahoma 74121-1220
918/234-1800

June 13, 2007

Email: lkenelly@scsengineers.com; dpenoyer@scsengineers.com

SCS Engineers
4041 Park Oaks Blvd.
Suite 100
Tampa, FL 33610

Attention: Lindsey Kennelly, P.E.

Reference: Landfill Gas Flare Emissions

Dear Lindsey,

As we discussed previously, the emission factors most commonly used for open or candlestick flares in landfill gas service are those stated in the AP-42, Supplement D document for Industrial Flares. These factors are 0.37 lb/mmbtu for Carbon Monoxide and 0.068 for Nitrogen Oxides. These factors are the results of actual emissions tests by the EPA for open flares for the purposes of quantifying these limits.

While the Supplement D numbers seem to conflict the factors of 0.74 lb/mmbtu for Carbon Monoxide and 0.04 lb/mmbtu for Nitrogen Oxides as indicated in the AP-42 document MSW Landfills, they are generally accepted as being more accurate. The main reason for this is source of the MSW numbers. As indicated in the "References", this data was developed from actual source tests on enclosed flares, however these tests were mostly taken in the 1980's. In this timeframe, the emission criteria were such that efficient, controlled, combustion was not required. This is reflective in the results of the testing where we see high Carbon Monoxide numbers that were a direct result of low operating temperatures due to uncontrolled burning.

In the AP-42 MSW document it states "Where information on equipment was given in the reference, test data were taken from enclosed flares. Control efficiencies are assumed to be equally representative of open flares". Today, the industry standard emissions for enclosed flares are 0.20 lb/mmbtu for Carbon Monoxide and 0.06 lb/mmbtu for Nitrogen Oxides, which is much more representative of actual enclosed flares in operation. Therefore, if control efficiencies are assumed to be equally representative of open flares, then the AP-42 Supplement D factors of 0.37 lb/mmbtu for Carbon Monoxide and 0.068 lb/mmbtu for Nitrogen Oxides are more accurate emissions than the MSW document.

To summarize, based on our experience as being the industry leader in combustion technologies, our recommendation for emission factors to be used on open flares in landfill gas service, is to use the AP-42 Supplement D factors. Not only are these a more accurate reflection of the actual emissions, but the sources utilized for the MSW document are skewed at best.

If you should have any questions or comments regarding this information, please feel free to contact me at 918-234-2783.

Sincerely,

JOHN ZINK COMPANY, LLC

Tim Locke
Product Director

JOHN ZINK®
A JOHN ZINK COMPANY LLC

International Headquarters
P.O. Box 21220
Tulsa, Oklahoma 74121-1220
918/234-2961

Brandy S. Johnson, P.E.
Product Director

DATE: September 8, 2014

TO: Niki Wuestenberg

COMPANY: Republic Services

REFERENCE: Standard Emissions for Elevated Flares

Niki,

For all elevated flares supplied by John Zink, the guaranteed emissions are as listed below. These numbers are considered the industry standard and are based on EPA 40 CFR 60.18 for industrial flares.

Emissions for Elevated ZEF Landfill Flare(1)

Overall Destruction Efficiency(2)	98%
NOx, lb / MMBTU(3)	0.068
CO, lb / MMBTU(4)	0.37

(1).Emissions and destruction efficiency stated are based on EPA 40 CFR 60.18 and AP-42 Supplement D
(2) Typical sulphur containing compounds are expected to have greater than 98% oxidation efficiency.
(3) Excludes NOx from fixed nitrogen.
(4) Excludes CO contribution present in landfill gas.

NOTE: *Destruction efficiency, NOx, and CO emissions shown are valid for combustion of landfill gas only.*

John Zink is not aware of any testing preformed on open flares for the landfill industry to merit values different from what is listed above and used by Zink for many years. Although we are aware of recent testing on open flares, these tests are not applicable to landfill gas or non-assisted open flares. Many of these tests were for high pressure, air assisted, steam assisted, heavier hydrocarbons, or various types of flare tips that are not used in the landfill industry.

From: Angela D. Marconi <adm@dswa.com>
Sent: Tuesday, October 21, 2014 11:43 AM
To: RefineryFactor
Subject: AP-42 section 13.5 proposed revision
Attachments: DSWA AP42 Letter.pdf

Please see attached comments.
Thank you,

Angela D. Marconi, P.E., BCEE
Manager of Landfill Gas Systems
Delaware Solid Waste Authority

1706 East 12th Street
Wilmington, DE 19809
PHONE (302) 764-5385
FAX (302) 764-5386

DSWA

DELAWARE SOLID WASTE AUTHORITY

Pasquale S. Canzano, P.E., BCEE
Chief Executive Officer

Richard P. Watson, P.E., BCEE
Chief Operating Officer

October 21, 2014

Via Electronic Transmission: refineryfactor@epa.gov

Ms. Gerri Garwood
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC 20460

Dear Ms. Garwood:

Re: Revised Emissions Factors for Flares

The Delaware Solid Waste Authority (DSWA) is submitting the following comments on the United States Environmental Protection Agency's (EPA) proposed revision to section 13.5 of AP-42 Emission Factors for Industrial Flares.

DSWA was created in 1975 by the General Assembly of the State of Delaware. It is DSWA's mission to define, develop and implement cost-effective plans and programs for solid waste management, which best serve Delaware and protect our public health and the environment. Since its inception, DSWA has been an active participant in the Solid Waste Association of North America (SWANA) and leader in developing innovative technology in the field of solid waste management.

DSWA contributed to the letter submitted jointly by SWANA and the National Waste and Recycling Association (NW&RA) and we agree with the comments they have submitted. Therefore, we affirm the recommendation for continuing the use of the 1991 emission factors for landfill and other biogas flares where the heating value of the fuel can support non-assisted combustion. The new proposed emission factors should be limited to relevant industries that utilize steam and air assisted flares.

DSWA looks forward to continued participation in the comment and revision process. For further discussion please do not hesitate to contact me (adm@dswa.com, 302.764.5385).

Yours Truly,

ADMarconi

Angela D. Marconi, P.E., BCEE
Manager of Landfill Gas Systems

ADM:ur

c: R. P. Watson, P.E., BCEE
R. M. Roddy, P.E., BCEE
L. V. Miller, P.E., BCEE
F. M. Parkowski, Esq. (PG&S)

1128 S. Bradford Street, P.O. Box 455, Dover, Delaware 19903-0455
Phone: (302) 739-5361 Fax: (302) 739-4287
CITIZENS' RESPONSE LINE: 1-800-404-7080 www.dswa.com

National
Waste & Recycling
Association℠
Collect. Recycle. Innovate.

SWANA®
SOLID WASTE ASSOCIATION
of North America

October 17, 2014

Via Electronic Transmission: refineryfactor@epa.gov

Ms. Gerri Garwood
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC 20460

Dear Ms. Garwood:

Re: Revised Emissions Factors for Flares in Draft AP-42, Section 13.5 (Supplement D)

The National Waste & Recycling Association (NW&RA) and the Solid Waste Association of North America (SWANA) are pleased to offer comments on the proposed revisions to the Emissions Factors for Flares. The NW&RA and SWANA represent companies, municipalities and professionals in the solid waste industry. The NW&RA, formerly the National Solid Waste Management Association, is a not-for-profit trade association representing private solid waste and recycling collection, processing and management companies that operate in all fifty states. SWANA is a professional education association in the solid waste management field with members from both the private and public sectors across North America.

EPA has proposed new and revised emissions factors for industrial flares in the draft AP-42 Section 13.5, which substantially increases the emission factor for nitrogen oxides (NOx). While the new proposed factors might be appropriate for air assisted or steam assisted flares used at refineries, we do not believe they are appropriate for use with the candlestick (also called "open" or "utility") flares that are in predominant use at municipal solid waste (MSW) landfills. The landfill sector's candlestick flares are neither air nor steam assisted. Although the AP-42 has a chapter for MSW Landfills, the factors for NOx and CO in Section 13.5 are generally accepted as being more accurate, and are widely used within the landfill sector. Thus, the accuracy, validity and quality of the proposed emissions factors for use with non-assisted flares are very important to the landfill sector.

We reviewed the test results upon which EPA relied to establish the revised emission factors. It appears that none of the tests involved open, non-assisted flares, and none of the tests appeared to involve combustion of landfill gas. According to flare manufacturer, John Zink, Inc., (see attached letter) the test reports underpinning EPA's revised emission factors involved high pressure, air or steam assisted, flares. Further, the tests were conducted with various flare tips not used within the

landfill sector, and the tests involved combustion of heavier, hydrocarbon-laden gases. Thus, the resulting emission factors are not applicable to non-assisted open flares burning landfill gas.

Nonetheless, EPA guidance in the draft section recommends that non-assisted flares use these new or revised emission factors. We are very concerned that EPA intends that these new emission factors be used in permitting MSW landfill candlestick flares. The proposed NOx emission factor is substantially higher than the existing factor. EPA appears to have used the result of one measurement from a single study to rationalize revising the NOx factor. In addition, the TCEQ studies referenced in the proposed revisions do not have NOx results, and thus cannot be used to support the revised factor. The Agency's recommendation that non-assisted flares use these new emission factors is inappropriate and not supported by the data. The test data supporting the revised factors are not relevant to non-assisted, open flares used in the landfill sector. Further, for the NOx emission factor, the dataset used to support the revision appears to be wholly inadequate, as it is based on one measurement from one study.

Although Section 13.5 of AP-42 is generally used by the petroleum industry, it is not limited to that industry. Section 13.5 itself notes, "flares are also used for burning waste gases generated by sewage digesters, coal gasification, rocket engine testing, nuclear power plants with sodium/water heat exchangers, heavy water plants and ammonia fertilizer plants." Given that the Section 13.5 factors are used by many industries, it is important that they accurately reflect emissions from all types of flares used in other industrial sectors.

As noted above, Section 13.5 has been widely used within the landfill sector as a source of emission factors. In fact, the majority of the air permitting conducted for landfill candlestick flares has relied upon AP-42 Section 13.5 factors for NOx and CO and many existing landfill permits have limits tied to the Section 13.5 factors. As such, there is a strong regulatory precedent for their use in federal, state, and local air permits for landfills. Further, the major manufacturers of landfill gas candlestick flares have recommended the use of the 1991 Section 13.5 factors as being the most appropriate and well-supported. See attached letter from the John Zink Company.

Because Section 13.5 is widely used in permitting by the landfill sector, it is essential that Section 13.5 retain factors that are appropriate for the non-assisted candlestick flares used at landfills and reflect their actual emissions as shown in high-quality emission tests. This can best be accomplished by maintaining the current factors for landfill gas and other biogas flares. We also propose that the Agency delete its recommendation that the revised factors be used for non-assisted flares. The proposed EFs should be limited to relevant industries that utilize steam and air assisted flares.

The NW&RA and SWANA appreciate your consideration of these comments and our requested revisions to the EPA's proposal. Should you have any questions about these comments, please call Anne Germain, Director of Waste & Recycling Technology for NW&RA, at 202-364-3724 or e-mail her at agermain@wasterecycling.org. You may also call Jesse Maxwell, Advocacy & eLearning Program Manager for SWANA, at 240-494-2237 or e-mail him at jmaxwell@swana.org.

Very truly yours,

Sharon H Kneiss	John H Skinner
Sharon H. Kneiss President & CEO National Waste & Recycling Association	John Skinner Executive Director & CEO Solid Waste Association of North America

JOHN ZINK.
A JOHN ZINK COMPANY LLC

International Headquarters
P.O. Box 21220
Tulsa, Oklahoma 74121-1220
918/234-2961

Brandy S. Johnson, P.E.
Product Director

DATE: September 8, 2014

TO: Niki Wuestenberg

COMPANY: Republic Services

REFERENCE: Standard Emissions for Elevated Flares

Niki,

For all elevated flares supplied by John Zink, the guaranteed emissions are as listed below. These numbers are considered the industry standard and are based on EPA 40 CFR 60.18 for industrial flares.

Emissions for Elevated ZEF Landfill Flare(1)

Overall Destruction Efficiency(2)	98%
NOx, lb / MMBTU(3)	0.068
CO, lb / MMBTU(4)	0.37

(1) Emissions and destruction efficiency stated are based on EPA 40 CFR 60.18 and AP-42 Supplement D
(2) Typical sulphur containing compounds are expected to have greater than 98% oxidation efficiency.
(3) Excludes NOx from fixed nitrogen.
(4) Excludes CO contribution present in landfill gas.

NOTE: *Destruction efficiency, NOx, and CO emissions shown are valid for combustion of landfill gas only.*

John Zink is not aware of any testing preformed on open flares for the landfill industry to merit values different from what is listed above and used by Zink for many years. Although we are aware of recent testing on open flares, these tests are not applicable to landfill gas or non-assisted open flares. Many of these tests were for high pressure, air assisted, steam assisted, heavier hydrocarbons, or various types of flare tips that are not used in the landfill industry.

JOHN ZINK
JOHN ZINK COMPANY LLC

International Headquarters
P.O. Box 21220
Tulsa, Oklahoma 74121-1220
918/234-1800

June 13, 2007

Email: lkenelly@scsengineers.com; dpenoyer@scsengineers.com

SCS Engineers
4041 Park Oaks Blvd.
Suite 100
Tampa, FL 33610

Attention: Lindsey Kennelly, P.E.

Reference: Landfill Gas Flare Emissions

Dear Lindsey,

As we discussed previously, the emission factors most commonly used for open or candlestick flares in landfill gas service are those stated in the AP-42, Supplement D document for Industrial Flares. These factors are 0.37 lb/mmbtu for Carbon Monoxide and 0.068 for Nitrogen Oxides. These factors are the results of actual emissions tests by the EPA for open flares for the purposes of quantifying these limits.

While the Supplement D numbers seem to conflict the factors of 0.74 lb/mmbtu for Carbon Monoxide and 0.04 lb/mmbtu for Nitrogen Oxides as indicated in the AP-42 document MSW Landfills, they are generally accepted as being more accurate. The main reason for this is source of the MSW numbers. As indicated in the "References", this data was developed from actual source tests on enclosed flares, however these tests were mostly taken in the 1980's. In this timeframe, the emission criteria were such that efficient, controlled, combustion was not required. This is reflective in the results of the testing where we see high Carbon Monoxide numbers that were a direct result of low operating temperatures due to uncontrolled burning.

In the AP-42 MSW document it states "Where information on equipment was given in the reference, test data were taken from enclosed flares. Control efficiencies are assumed to be equally representative of open flares". Today, the industry standard emissions for enclosed flares are 0.20 lb/mmbtu for Carbon Monoxide and 0.06 lb/mmbtu for Nitrogen Oxides, which is much more representative of actual enclosed flares in operation. Therefore, if control efficiencies are assumed to be equally representative of open flares, then the AP-42 Supplement D factors of 0.37 lb/mmbtu for Carbon Monoxide and 0.068 lb/mmbtu for Nitrogen Oxides are more accurate emissions than the MSW document.

To summarize, based on our experience as being the industry leader in combustion technologies, our recommendation for emission factors to be used on open flares in landfill gas service, is to use the AP-42 Supplement D factors. Not only are these a more accurate reflection of the actual emissions, but the sources utilized for the MSW document are skewed at best.

If you should have any questions or comments regarding this information, please feel free to contact me at 918-234-2783.

Sincerely,

JOHN ZINK COMPANY, LLC

Tim Locke
Product Director

Garwood, Gerri

From:	Angela D. Marconi <adm@dswa.com>
Sent:	Tuesday, October 21, 2014 2:17 PM
To:	RefineryFactor
Subject:	RE: AP-42 section 13.5 proposed revision
Attachments:	DSWA AP42 Letter.pdf

Please replace the original letter with the one attached.

Thank you,
Angela

From: Angela D. Marconi [mailto:adm@dswa.com]
Sent: Tuesday, October 21, 2014 11:43 AM
To: 'refineryfactor@epa.gov'
Subject: AP-42 section 13.5 proposed revision

Please see attached comments.
Thank you,

Angela D. Marconi, P.E., BCEE
Manager of Landfill Gas Systems
Delaware Solid Waste Authority

1706 East 12th Street
Wilmington, DE 19809
PHONE (302) 764-5385
FAX (302) 764-5386

DSWA
DELAWARE SOLID WASTE AUTHORITY

Richard P. Watson, P.E., BCEE
Chief Executive Officer

Robin M. Roddy, P.E., BCEE
Chief Operating Officer

October 21, 2014

Via Electronic Transmission: refineryfactor@epa.gov

Ms. Gerri Garwood
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC 20460

Dear Ms. Garwood:

Re: Revised Emissions Factors for Flares

The Delaware Solid Waste Authority (DSWA) is submitting the following comments on the United States Environmental Protection Agency's (EPA) proposed revision to section 13.5 of AP-42 Emission Factors for Industrial Flares.

DSWA was created in 1975 by the General Assembly of the State of Delaware. It is DSWA's mission to define, develop and implement cost-effective plans and programs for solid waste management, which best serve Delaware and protect our public health and the environment. Since its inception, DSWA has been an active participant in the Solid Waste Association of North America (SWANA) and leader in developing innovative technology in the field of solid waste management.

DSWA contributed to the letter submitted jointly by SWANA and the National Waste and Recycling Association (NW&RA) and we agree with the comments they have submitted. Therefore, we affirm the recommendation for continuing the use of the 1991 emission factors for landfill and other biogas flares where the heating value of the fuel can support non-assisted combustion. The new proposed emission factors should be limited to relevant industries that utilize steam and air assisted flares.

DSWA looks forward to continued participation in the comment and revision process. For further discussion please do not hesitate to contact me (adm@dswa.com, 302.764.5385).

Yours Truly,

ADMarconi

Angela D. Marconi, P.E., BCEE
Manager of Landfill Gas Systems

ADM:ur

c: R. P. Watson, P.E., BCEE
R. M. Roddy, P.E., BCEE
L. V. Miller, P.E., BCEE
F. M. Parkowski, Esq. (PG&S)

National Waste & Recycling Association℠
Collect. Recycle. Innovate.

SWANA®
SOLID WASTE ASSOCIATION
of North America

October 17, 2014

Via Electronic Transmission: refineryfactor@epa.gov

Ms. Gerri Garwood
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC 20460

Dear Ms. Garwood:

Re: Revised Emissions Factors for Flares in Draft AP-42, Section 13.5 (Supplement D)

The National Waste & Recycling Association (NW&RA) and the Solid Waste Association of North America (SWANA) are pleased to offer comments on the proposed revisions to the Emissions Factors for Flares. The NW&RA and SWANA represent companies, municipalities and professionals in the solid waste industry. The NW&RA, formerly the National Solid Waste Management Association, is a not-for-profit trade association representing private solid waste and recycling collection, processing and management companies that operate in all fifty states. SWANA is a professional education association in the solid waste management field with members from both the private and public sectors across North America.

EPA has proposed new and revised emissions factors for industrial flares in the draft AP-42 Section 13.5, which substantially increases the emission factor for nitrogen oxides (NOx). While the new proposed factors might be appropriate for air assisted or steam assisted flares used at refineries, we do not believe they are appropriate for use with the candlestick (also called "open" or "utility") flares that are in predominant use at municipal solid waste (MSW) landfills. The landfill sector's candlestick flares are neither air nor steam assisted. Although the AP-42 has a chapter for MSW Landfills, the factors for NOx and CO in Section 13.5 are generally accepted as being more accurate, and are widely used within the landfill sector. Thus, the accuracy, validity and quality of the proposed emissions factors for use with non-assisted flares are very important to the landfill sector.

We reviewed the test results upon which EPA relied to establish the revised emission factors. It appears that none of the tests involved open, non-assisted flares, and none of the tests appeared to involve combustion of landfill gas. According to flare manufacturer, John Zink, Inc., (see attached letter) the test reports underpinning EPA's revised emission factors involved high pressure, air or steam assisted, flares. Further, the tests were conducted with various flare tips not used within the

landfill sector, and the tests involved combustion of heavier, hydrocarbon-laden gases. Thus, the resulting emission factors are not applicable to non-assisted open flares burning landfill gas.

Nonetheless, EPA guidance in the draft section recommends that non-assisted flares use these new or revised emission factors. We are very concerned that EPA intends that these new emission factors be used in permitting MSW landfill candlestick flares. The proposed NOx emission factor is substantially higher than the existing factor. EPA appears to have used the result of one measurement from a single study to rationalize revising the NOx factor. In addition, the TCEQ studies referenced in the proposed revisions do not have NOx results, and thus cannot be used to support the revised factor. The Agency's recommendation that non-assisted flares use these new emission factors is inappropriate and not supported by the data. The test data supporting the revised factors are not relevant to non-assisted, open flares used in the landfill sector. Further, for the NOx emission factor, the dataset used to support the revision appears to be wholly inadequate, as it is based on one measurement from one study.

Although Section 13.5 of AP-42 is generally used by the petroleum industry, it is not limited to that industry. Section 13.5 itself notes, "flares are also used for burning waste gases generated by sewage digesters, coal gasification, rocket engine testing, nuclear power plants with sodium/water heat exchangers, heavy water plants and ammonia fertilizer plants." Given that the Section 13.5 factors are used by many industries, it is important that they accurately reflect emissions from all types of flares used in other industrial sectors.

As noted above, Section 13.5 has been widely used within the landfill sector as a source of emission factors. In fact, the majority of the air permitting conducted for landfill candlestick flares has relied upon AP-42 Section 13.5 factors for NOx and CO and many existing landfill permits have limits tied to the Section 13.5 factors. As such, there is a strong regulatory precedent for their use in federal, state, and local air permits for landfills. Further, the major manufacturers of landfill gas candlestick flares have recommended the use of the 1991 Section 13.5 factors as being the most appropriate and well-supported. See attached letter from the John Zink Company.

Because Section 13.5 is widely used in permitting by the landfill sector, it is essential that Section 13.5 retain factors that are appropriate for the non-assisted candlestick flares used at landfills and reflect their actual emissions as shown in high-quality emission tests. This can best be accomplished by maintaining the current factors for landfill gas and other biogas flares. We also propose that the Agency delete its recommendation that the revised factors be used for non-assisted flares. The proposed EFs should be limited to relevant industries that utilize steam and air assisted flares.

The NW&RA and SWANA appreciate your consideration of these comments and our requested revisions to the EPA's proposal. Should you have any questions about these comments, please call Anne Germain, Director of Waste & Recycling Technology for NW&RA, at 202-364-3724 or e-mail her at agermain@wasterecycling.org. You may also call Jesse Maxwell, Advocacy & eLearning Program Manager for SWANA, at 240-494-2237 or e-mail him at jmaxwell@swana.org.

Very truly yours,

Sharon H Kneiss

Sharon H. Kneiss
President & CEO
National Waste & Recycling Association

John H Skinner

John Skinner
Executive Director & CEO
Solid Waste Association of North America

JOHN ZINK.
A JOHN ZINK COMPANY LLC

International Headquarters
P.O. Box 21220
Tulsa, Oklahoma 74121-1220
918/234-2961

Brandy S. Johnson, P.E.
Product Director

DATE: September 8, 2014

TO: Niki Wuestenberg

COMPANY: Republic Services

REFERENCE: Standard Emissions for Elevated Flares

Niki,

For all elevated flares supplied by John Zink, the guaranteed emissions are as listed below. These numbers are considered the industry standard and are based on EPA 40 CFR 60.18 for industrial flares.

Emissions for Elevated ZEF Landfill Flare(1)

Overall Destruction Efficiency(2)	98%
NOx, lb / MMBTU(3)	0.068
CO, lb / MMBTU(4)	0.37

(1).Emissions and destruction efficiency stated are based on EPA 40 CFR 60.18 and AP-42 Supplement D

(2) Typical sulphur containing compounds are expected to have greater than 98% oxidation efficiency.

(3) Excludes NOx from fixed nitrogen.

(4) Excludes CO contribution present in landfill gas.

NOTE: *Destruction efficiency, NOx, and CO emissions shown are valid for combustion of landfill gas only.*

John Zink is not aware of any testing preformed on open flares for the landfill industry to merit values different from what is listed above and used by Zink for many years. Although we are aware of recent testing on open flares, these tests are not applicable to landfill gas or non-assisted open flares. Many of these tests were for high pressure, air assisted, steam assisted, heavier hydrocarbons, or various types of flare tips that are not used in the landfill industry.

11920 East Apache | Tulsa, Oklahoma 74116 | FAX 918/234-1968 | TLX 497414

JOHN ZINK
JOHN ZINK COMPANY LLC

International Headquarters
P.O. Box 21220
Tulsa, Oklahoma 74121-1220
918/234-1800

June 13, 2007

Email: lkenelly@scsengineers.com; dpenoyer@scsengineers.com

SCS Engineers
4041 Park Oaks Blvd.
Suite 100
Tampa, FL 33610

Attention: Lindsey Kennelly, P.E.

Reference: Landfill Gas Flare Emissions

Dear Lindsey,

As we discussed previously, the emission factors most commonly used for open or candlestick flares in landfill gas service are those stated in the AP-42, Supplement D document for Industrial Flares. These factors are 0.37 lb/mmbtu for Carbon Monoxide and 0.068 for Nitrogen Oxides. These factors are the results of actual emissions tests by the EPA for open flares for the purposes of quantifying these limits.

While the Supplement D numbers seem to conflict the factors of 0.74 lb/mmbtu for Carbon Monoxide and 0.04 lb/mmbtu for Nitrogen Oxides as indicated in the AP-42 document MSW Landfills, they are generally accepted as being more accurate. The main reason for this is source of the MSW numbers. As indicated in the "References", this data was developed from actual source tests on enclosed flares, however these tests were mostly taken in the 1980's. In this timeframe, the emission criteria were such that efficient, controlled, combustion was not required. This is reflective in the results of the testing where we see high Carbon Monoxide numbers that were a direct result of low operating temperatures due to uncontrolled burning.

In the AP-42 MSW document it states "Where information on equipment was given in the reference, test data were taken from enclosed flares. Control efficiencies are assumed to be equally representative of open flares". Today, the industry standard emissions for enclosed flares are 0.20 lb/mmbtu for Carbon Monoxide and 0.06 lb/mmbtu for Nitrogen Oxides, which is much more representative of actual enclosed flares in operation. Therefore, if control efficiencies are assumed to be equally representative of open flares, then the AP-42 Supplement D factors of 0.37 lb/mmbtu for Carbon Monoxide and 0.068 lb/mmbtu for Nitrogen Oxides are more accurate emissions than the MSW document.

To summarize, based on our experience as being the industry leader in combustion technologies, our recommendation for emission factors to be used on open flares in landfill gas service, is to use the AP-42 Supplement D factors. Not only are these a more accurate reflection of the actual emissions, but the sources utilized for the MSW document are skewed at best.

If you should have any questions or comments regarding this information, please feel free to contact me at 918-234-2783.

Sincerely,

JOHN ZINK COMPANY, LLC

Tim Locke
Product Director

Garwood, Gerri

From: Lee Vail <lee.vail@keanmiller.com>
Sent: Friday, October 31, 2014 3:58 PM
To: RefineryFactor
Subject: Comments of Louisiana Chemical Association
Attachments: LCA Comment Letter to EPA (AP-42 Factor Flare).PDF; Lee Vail.vcf

Please find attached, comments of the Louisiana Chemical Association.

Lee Vail, P.E., Ph.D.
Special Counsel / Registered Patent Attorney
Kean Miller LLP

909 Poydras Street, Suite 3600
New Orleans, Louisiana 70112
504.620.3356 (direct)
504.585.3051 (facsimile)
lee.vail@keanmiller.com

KEAN | MILLER LLP
ATTORNEYS AT LAW

WEBSITE | BLOG | BIO

CONFIDENTIALITY STATEMENT

KEAN | MILLER LLP
ATTORNEYS AT LAW

R. LEE VAIL, SPECIAL COUNSEL
PH 504.620.3356 DIRECT FAX 504.620.3384
LEE.VAIL@KEANMILLER.COM

October 31, 2014

Via Email
U.S. Environmental Protection Agency
refineryfactor@epa.gov

Attention: Gerri Garwood

Re: Comments of the Louisiana Chemical Association Regarding Proposed Revisions to Section 13.5 of API-42

The Louisiana Chemical Association (LCA) appreciates the opportunity to comment on the above-referenced draft revision to API-42. LCA is a nonprofit Louisiana corporation, composed of 63 members with over 100 chemical manufacturing plant sites in Louisiana. Most, if not all plant sites have flares potentially affected by this proposed revision. These facilities have been issued Part 70 Operating Permits pursuant to LAC 33:III.507. Further, these facilities have a general duty to operate within the terms and conditions of the permit. See LAC 33:III.501.C. LCA has great concerns that, if adopted, that agencies may consider facilities in non-compliance with their permits through this proposed action. LCA requests that these comments be placed into the administrative record for the draft revisions to AP-42. Kean Miller, on behalf of LCA, presents the following comments.

LCA COMMENTS ON PROPOSED REVISIONS TO SECTION 13.5 of API-42

1. General--Incorporation of Other Comments.

LCA hereby adopts and incorporates by reference those comments on the proposed revisions to Section 13.5 of AP-42 made by members of LCA, members of the Louisiana Mid-Continent Oil and Gas Association ("LMOGA") and the American Petroleum Institute, to the extent such comments are not inconsistent with the comments made herein by LCA.

2. Flare NOx Estimates Were Not the Result of Carefully Planned NOx Studies.

A number of passive Fourier transform infrared ("FTIR") studies were conducted between 2009 and 2011 to investigate flare performance as the EPA had concerns that performance was affected by the ration of assist steam (or air) to flare gas. These studies were designed to measure destruction efficiency of hydrocarbon compounds. Data relied on by the EPA was incidentally generated during studies intended to evaluate hydrocarbon destruction in flare. EPA's Review of Available Documents Report[1] specifically mentioned three flare efficiency studies: 2010 TCEQ, Marathon Petroleum, and Flint Hills. In reference to these studies the EPA concluded:

> The review of passive FTIR studies summarized above previously focused on combustion efficiencies of flares. In further reviewing this data, it appears that passive FTIR studies provide data that can be used to propose revisions to the existing AP-42 CO and NOx emissions factors and propose a VOC emissions factors for flares.[2]

As such, the data generated therein was incidental to the plan to study VOC destruction. To the best of LCA's knowledge, the VOC destruction studies were not calibrated for NOx emissions nor were the results confirmed through blind validation. Concerns with validity of hydrocarbon analysis with the plume are expressed in the cited Marathon Texas City report.[3] LCA has greater concerns as EPA uses raw NOx data that was not the stated objective of the test.[4] LCA believes that the EPA should rely on data generated from studies designed to develop reliable NOx emission data and not use data incidentally generated from other studies.

3. <u>Raw Data from Cited Flare Studies Are Not Easily Available to the Public</u>

In developing proposed factors, the EPA used "raw data" that, if not unavailable, is difficult to locate. As mentioned above, this raw data was excluded from the final reports for the 2010 TCEQ, Marathon, and Flint Hills Studies. The Flint Hills Report (available at EPA-HQ-OAR-0682-0167) does not mention nitrogen oxide, let alone present any raw data or conclusions. A single reference is made to nitrogen oxide in the Flint Hill Appendices; nitrogen oxide was considered an interference to the FTIR spectra. See Sec. A.4.8. LCA had minimal notice of the specific reports used by the EPA and no reasonable notice of the specific "raw data" from which EPA draws their conclusions as this data is buried in a link from a footnote within EPA's report. Whereas EPA has had several years to consider the "raw data," the public has not. EPA should clearly identify the location of the data and afford the public more time to evaluate this information. Additionally, the EPA should draft a written analysis explaining and justifying their calculations and analysis.

---

[1] EPA (U.S. Environmental Protection Agency). 2014. Review of Available Documents for Developing Proposed Emissions Factors for Flares, Tanks, and Wastewater Treatment Systems. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. August 2014. Available at: http://www.epa.gov/ttn/chief/consentdecree/draft_report_review.pdf

[2] *Id.* At 24.

[3] See Section 3.4, p. 3-45, Performance Test of a Steam-Assisted Elevated Flare with Passive FTIR, http://www.tceq.texas.gov/assets/public/implementation/air/rules/Flare/2010flarestudy/mpc-txc.pdf (these same concerns are expressed on page 98 of the Marathon Detroit Report) (last visited Oct. 8, 2014).

[4] *Id.* at p. 1-1.

4. Underlying Reports Specifically Warn Against Using NOx Data Gathered in the VOC Destruction Test

Notwithstanding the general unavailability of raw data used in EPA's evaluation, at least one report specifically warns against use of the data. According to the 2010 TCEQ report:

> NOx was also measured during the flare tests, but it is not included because NOx was measured using a commercial chemiluminescence analyzer. This instrument did not meet the data quality objectives over all the ranges of DRE observed.[5]

The data was likely excluded from the report for a valid reason. According to the TCEQ report, the data was not included because it was not reliable. No information is available to LCA to evaluate the reliability of the data from the other test. Given its absence, one can only assume that those involved did not find the information reliable enough to include. Prior to using such data to generate new factors, factors that increase the emission by over 40 times, EPA should present sufficient information to document that the data is accurate and reliable.

5. EPA Provides No Explanation Why Proposed Factor is Radically Different Than General Combustion Experience.

The first AP-42 was published in 1968. The first AP-42 factor for the combustion of gas in boilers and heaters was 0.23 # per 1000 ft^3 gas burned (or approximately 0.23 # per MMBTU).[6] Since 1968, burner manufacturers have conducted extensive research and developed expertise with the aim of reducing NOx emissions. As NOx was not a concern in 1968, burner technology was relatively primitive. However, even given the primitive technology, emissions from burners back in 1968 were on 0.23 #/MMBTU. The proposed factor for combustion in flares is 2.9 #/MMBTU. Given historical knowledge, the proposed emission factor is beyond understanding. Prior to accepting a potentially meaningless factor, EPA should provide an explanation as to physical phenomenon that would cause such an unprecedented result.

6. EPA's Proposed NOx Factor Includes Obvious Outlier Data

In calculating the proposed flare NOx factor of 2.9, EPA apparently averaged six values ranging from 0.011 to 16. In doing so, EPA is assuming that the arithmetic mean of the six values is a reasonable and meaningful representation of the collective data. This hardly seems reasonable when the largest number in the set is 1,455 times or 145,500 percent greater than the smallest number in the set. LCA is of the understanding that EPA "determined" that it was

---

[5] TCEQ 2010 Flare Study Final Report, p. 124, found at http://www.tceq.texas.gov/assets/public/implementation/air/rules/Flare/2010flarestudy/2010-flare-study-final-report.pdfId.

[6] Compilation of Air Pollutant Emission Factors (1968), R. L. Dupry, Table 28, page 42, found at http://www.epa.gov/ttn/chief/ap42/oldeditions/1st_edition/ap42_phs_1968.pdf (last visited Oct. 8, 2014).

reasonable and meaningful to average these divergent values. LCA understands that EPA performed a statistical analysis of the data to determine if the Flint Hills data was an outlier from the mean. In doing so, EPA apparently evaluated the data by first converting the factor to the natural log of the factor. Implicit in this method is the determination that the data is not normally distributed, but instead is lognormally distributed.

Lognormal distributions are not uncommon in evaluating contamination in environmental media. This however is a very different situation, NOx , in effect, is being produced by a machine (i.e., a burner tip combusting a flammable gas. One would expect that the results of this operation would be more consistent. For example, when conducting a stack test, multiple "runs" are made and the data is averaged. In all likelihood the stack test data is normally distributed. A reviewing agency would be very suspicious of a stack test where the high value exceed the low value by 1,455 time. Further the evaluation necessary to determine that a data set is reliably lognormal requires a minimum amount of data. Further, the data set could be bi-modal. The EPA has failed to present this analysis and appears merely to jump to the conclusion that the data is lognormal. Through this manipulation of the data, EPA was able to camouflage the obvious; that 16 is an outlier when compared to 5 values ranging from 0.011 – 0.58. LCA is not aware of any EPA justification for this statistical maneuver.

EPA believed that it was reasonable to include data from the Flint Hill study; this result is nearly 30 times greater than the next highest result. LCA performed a simple statistical analysis comparing these six values and believes that the FHR test data fails a simple confidence interval test at 99.9%. Assuming a normal distribution, the Flint Hills data is an outlier.

	All 6 Flares		99.9%	Largest Outlier Omitted		99.9%	Highest and Lowest Flare Omitted	
	Values	% Diff of Avg.	Value within Conf. Interval	Values	% Diff of Avg.	Value within Conf. Interval	Values	% Diff of Avg.
	16	456%	Fail	Omitted	N/A	N/A	Omitted	N/A
	0.011	-100%	OK	0.011	-96%	OK	Omitted	N/A
	0.47	-84%	OK	0.47	87%	OK	0.47	51%
	0.13	-95%	OK	0.13	-48%	OK	0.13	-58%
	0.58	-80%	OK	0.58	130%	OK	0.58	86%
	0.068	-98%	OK	0.068	-73%	OK	0.068	-78%
Average	2.8765			0.2518			0.312	
Std. Dev.	5.872726			0.228879			0.217628	
Skewness	2.442543			0.590865			0.110814	
Confidence Interval	7.889137	0.001		0.336812	0.001			

The skewness of the data is quite high with the FHR data. If the FHR test data is removed, then the data becomes much less skewed, and the average NOx EF is 0.25 lb/mmbtu, which is still an increase of 270% from the original 0.068 lb/mmbtu NOx EF. Such a result is comparable to 1968 emission factors for NOx from unsophisticated primitive burner technology. At a minimum, EPA must present a proper analysis to demonstrate that their assumption, that emissions from a combustion device are lognormally distributed. Without such, EPA should drop the FHR test data from the dataset due to it being so obviously skewed.

The Consent Decree does not compel the EPA to revise the flare NOx emission factor at this time. Considering these comments it is clear that more study is warranted. LCA requests that EPA delay any revision of the AP-42 factor for NOx from flares at this time until these significant issues can be addressed. LCA welcomes further review and dialogue with EPA personnel in light of the significant impact the draft revisions to Section 13.5 of AP-42 may have on industry. Should you have any questions regarding the written comments of LCA, please do not hesitate to contact Henry Graham at (225) 376-7642, henry@lca.org. or me at (504) 620-3356, lee.vail@keanmiller.com.

Thank you for your assistance and cooperation.

Very truly yours,

R L Vail

R. Lee Vail, Counsel on behalf of
the Louisiana Chemical Association

From:	Binali, Khalid A (EPD) <khalid.binali.1@aramco.com>
Sent:	Monday, November 10, 2014 2:46 AM
To:	RefineryFactor
Subject:	Emission Factor Proposal
Importance:	High

Please find below my comments on the proposed revised emission factors for flares

1- With regard to the proposed new NOx emission factor for flares, I totally disagree with the methodology used to develop the new NOx emission factor for flares (2.9 Ib/MMBTU) which is the PFTIR instrument. This instrument is intended to measure the Combustion Efficiency (CE) of hydrocarbons not NOx emissions from the flares. As matter of fact, this new emerging technology is still under testing for the CE due to many challenges it faces such as the location of the instrument toward the flare, wind speed, etc. These challenges were mentioned in multiple reports i.e Shell Deer report and TCEQ. Furthermore , there is no third party consultant that can act as a versifier for the spectral data generated from the PFTIR instrument.

2- Withe regard the proposed new VOC emission factor for flares, refineries have different stream compositions going to flares and hence, the speciation of these streams differ from one refinery to another. EPA should conduct a comprehensive refinery speciation study for the streams going to flares and then build on it.

Regards,

Khalid Al-Binali, QEP
Air Quality & Meteorology Unit
EED/EPD

Garwood, Gerri

From: Anthony Stratton <astratton@montrose-env.com>
Sent: Tuesday, November 25, 2014 1:31 PM
To: RefineryFactor
Subject: Comments regarding oil storage tank VOC sampling programs for suggested revisions to AP-42 factors
Attachments: 2014 Letter to EPA Regarding Tank VOC Sampling.pdf

To Whom It May Concern:

Please accept the attached document in response to US Environmental Protection Agency's (EPA) request for comments on suggested revisions to AP-42. In particular, this attachment contains comments regarding the proposed determination that revisions to the VOC emission factors for liquid storage tanks are not necessary. Eastmount Environmental conducted the extended VOC sampling programs on residual oil and asphalt storage tanks in 2012 and 2013 in EPA Region 1, and felt obliged to provide commentary on observations made during the sampling programs.

Thank you for the opportunity to provide these comments.

Best Regards,

MONTROSE
ENVIRONMENTAL

Anthony Stratton
Senior Project Manager
Eastmount Environmental Services, LLC
an affiliate of Montrose Environmental Group, Inc.
2 New Pasture Road, Unit 5, Newburyport, MA 01950
T: 978.499.9300 | M: 508.989.8996 | F: 978.499.9303
astratton@montrose-env.com
www.montrose-env.com

EASTMOUNT ENVIRONMENTAL SERVICES
Air Quality Specialists

To: refineryfactor@epa.gov

Date: November 24, 2014

Re: Request for Comments on Proposed Determination for No Changes to VOC Emission Factors for Tanks and Wastewater Treatment Systems

On behalf of Eastmount Environmental Services, LLC (Eastmount) and its clients, we submit the following comments in response to the US Environmental Protection Agency's (EPA) request for comments on the suggested revisions to AP-42.

These comments are intended to provide clarification on the limitations of test results that are summarized in the *"DRAFT EPA Review of Available Documents for Developing Proposed Emissions Factors for Flares, Tanks, and Wastewater Treatment Systems, Section 5 – Tank Emissions Tests"*.

Overview

As referenced and summarized in Section 5 of the DRAFT EPA Review of Available Documents for Developing Proposed Emissions Factors for Flares, Tanks, and Wastewater Treatment Systems, Eastmount conducted a series of 30-day and 15-day Volatile Organic Compounds (VOC) sampling programs on residual oil and asphalt storage tanks located at Sprague Operating Resources in Searsport, Maine, and at Global Companies, LLC in South Portland, Maine. The programs were carried out in two phases:

> Phase 1 - Consisted of 30 days of continuous VOC measurement on a residual oil storage tank at Sprague's Searsport facility on June 13 through July 13, 2012, and on an asphalt storage tank at Global's South Portland facility on July 18 through August 16, 2012.
>
> Phase 2 - Consisted of 15 days of continuous VOC measurement on a residual oil storage tank at Global's South Portland facility on April 11 through 26, 2013, and on an asphalt storage tank at Sprague's Searsport facility on May 7 through 22, 2013.

Each sampling program consisted of attempting to quantify mass emissions of VOCs continuously over an extended period. Sampling consisted of measuring both total VOC concentration (in ppm) and volumetric flow rate (in wscfm) from all vents associated with the subject tanks under a variety of tank conditions that included normal breathing, vessel off-loading into the tank, and daily withdrawal of oil from the tank into tanker trucks. Samples were collected from tank vents located on the roof of the tank. These vents are not normally equipped with any fans or dampers, and therefore they are opened to allow unrestricted tank ventilation to maintain equilibrium with atmospheric pressure during normal tank breathing and transfer of oil into and out of the tank.

The primary challenge Eastmount faced during the test program was to detect a volumetric flow rate of air leaving or entering the tank vent using EPA Method 2. Volumetric flow rate is necessary to calculate the mass emission rate of VOC in pounds per hour or tons per year. The specific challenge was that the tank vent flow rate was so low that it was essentially undetectable using a pitot tube/manometer, the flow measuring equipment specified by EPA Method 2. Other technologies were considered, such as a hot wire anemometer, an impeller, or a displacement meter, but they were deemed unacceptable either because they were not intrinsically safe, they were not accurate for this application, or they could potentially cause excessive pressure in the tank.

The EPA representatives from Region 1 directed Sprague and Global to use a promulgated methodology, namely EPA Method 2 and EPA Method 204, to “encapsulate” each tank vent with a Temporary Total Enclosure (TTE), and capture fumes exiting the vents under minimal negative pressure induced by an ID fan with variable speeds in order to create an artificial and detectable volumetric flow rate. Both flow rate and VOC concentration were quantified just prior to the ID fan. The TTEs installed around the vents were maintained at a very slight negative pressure (approximately -0.015 inches water column). The entire premise of the capture system was to ensure that: 1) all fumes exiting the vents were delivered to the sample collection point without creating excessively negative vacuum in the TTEs, and 2) the gas/air velocity through the system was made detectable by a pitot tube/manometer assembly, following EPA Method 1 and 2.

Observations

There were three observations made during this program that could challenge the representativeness of the data collected by this capture/sampling system. They are summarized below:

1) Eastmount noted that, when the Method 204 fan speed was increased, the VOC concentration in the system duct remained constant while the flow rate increased. This resulted in an increase in the estimated VOC mass emission rate. It was expected that, as the fan speed increased, the duct gas concentration would be diluted with ambient air as it entered the natural draft openings of the TTE. But this did not happen. Regardless of fan speed, the system VOC concentration remained fairly constant while the flow rate was increased or decreased. One could essentially adjust the VOC mass emission rate by increasing or decreasing the system flow rate. It should also be noted that it was very difficult to maintain a continuous minimum TTE vacuum of just above -0.007” w.c. without potentially creating excessive vacuum in the TTEs due to the wide range ambient conditions outside the storage tank.

2) At the completion of the 30-day sampling period on the Sprague residual oil tank, Eastmount conducted a brief experiment in which one of the two tank vents (located further away from the highest point on the tank roof) was completely sealed. Then an S-type pitot tube was securely fixed inside the other opened tank vent (located near the highest point on the tank roof) at the center of the vent cross-section. (Please note that this vent did not meet EPA Method 1 criteria.) The pitot tube was connected to a manometer (or digital pressure transducer) with a resolution of 0.001” w.c. which was used to measure duct gas velocity. Eastmount also collected a VOC sample from the center of the vent into a Tedlar bag. The duct gas velocity was not detectable using this equipment. However, based on the Tedlar bag VOC concentration of approximately 1800 ppm (in term of propane) and a methane concentration of approximately 150 ppm, Eastmount calculated a mass emission rate of non-methane VOC using the resultant ppm value, and the lower detection limit of the digital manometer which was 0.001” w.c. The resultant calculation was approximately 4.4 tons per year. This is 41.5% of the 30-day average VOC mass emission rate and 66.7% of the lowest VOC emission rate observed using the TTE collection system. These results may indicate that the use of the variable speed fan during the TTE testing artificially increased flow from the tanks above normal tank configuration levels. However, other factors must be considered in evaluating this experiment, including the brevity of the experiment, non-conformance of the vent sampling location to EPA Method 1 criteria, and a high wind condition during the experiment.

3) During Phase 1 of the sampling program, Eastmount observed very sluggish VOC sampling system response to zero calibration gas. Although a heated, quartz fiber filter was placed in line between the probe and heated sample line to remove oil mists, Eastmount observed that a fairly long period of time was needed to achieve an acceptable zero gas value. Furthermore, oil was observed seeping out of the VOC analyzer on the asphalt sampling system.

Prior to Phase 2, Eastmount installed an unheated coalescing filter between the probe and heated filter to remove any oil mists/droplets prior to reaching the heated filter and sample line. Eastmount theorized that, throughout Phase 1, oil mists/droplets entrained in the TTE sampling systems were being volatized at 275°F in the heated filter/sample line, and ultimately included in the analysis of VOCs. This most likely resulted in a positive bias of the data collected during Phase 1 of the program. Once the coalescing filter was employed, calibration response to both zero and span gas was much faster. Additionally, VOC ppm concentration was reduced as compared to the Phase 1 data.

Summary Statements

The following summary statements are offered for consideration:

1) When using the TTE sampling system, it appeared that the VOC mass emission rate could be varied simply by increasing or reducing the fan speed, while maintaining negative pressure in the TTE(s). This makes it difficult to establish an accurate VOC mass emission rate.

2) The use of the TTE sampling system did not represent direct measurement of the tank vents under their normal configuration. It is expected that, at times, these tanks breathe both inward and outward depending on the ambient atmospheric conditions (temperature, wind speed, etc.). The inward flow condition was not considered during this sampling program for calculating annual VOC emissions. Furthermore, Eastmount conducted a brief, direct measurement on a single vent without the TTE system installed, and the test result was 41.5% of the 30-day VOC average mass emission rate.

3) The data collected during the Phase 2 sampling period, with the coalescing filter installed to remove oil mists/droplets, resulted in a 30% reduction in VOC emission from a residual oil tank, and 21% reduction in VOC emission from an asphalt tank as compared to Phase 1 sampling data. Therefore, one should consider that a learning curve following Phase 1 sampling may have led to generating closer to representative data during the Phase 2 sampling period.

Conclusion

The observations and summary statements submitted herein may warrant additional evaluation of the data collected during the 2012 and 2013 sampling programs. They may also warrant collection of additional data using other sampling techniques. The challenge remains to quantify VOC mass emissions from these vents without changing the vent configuration, or without imposing an artificial pressure drop around the vents, while considering that, at times, vent air flow may be inward, outward, or static depending on atmospheric conditions.

Should there be any questions regarding this submittal, please do not hesitate to contact me at (978) 499-9300 x12 (office) or (508) 989-8996 (mobile), or at astratton@montrose-env.com.

Sincerely,

Anthony M. Stratton
Senior Project Manager

Garwood, Gerri

From: Leduc, Jay <JLEDUC@spragueenergy.com>
Sent: Tuesday, November 25, 2014 5:00 PM
To: RefineryFactor
Cc: Garwood, Gerri
Subject: Submitted Comments regarding AP 42
Attachments: SKMBT_50114112517320.pdf

Importance: High

As requested, please find attached a copy of Sprague Operating Resources' comments on the *"Proposed New and Revised Emission Factors for Flares and Proposed New Emission Factors for Certain Refinery Process Units and Proposed Determination for No Changes to VOC Emission Factors for Tanks and Wastewater Treatment Systems."* In particular, the comments refer to the proposed determination that revisions to the VOC emission factors for tanks and wastewater treatment systems are not necessary.

If you require any additional information or have any questions please contact the undersigned at your convenience.

Best regards,

Jay Leduc
Director of Health, Safety, and Environment (HSE)
Sprague Resources GP LLC | O: 603.430.7298| M: 603.312.6880
185 International Drive
Portsmouth, NH 03801
jleduc@spragueenergy.com

Sprague

185International Drive
Portsmouth, New Hampshire 03801
(800) 225.1560

November 25, 2014

Gerri Garwood
US EPA
Office of Air Quality Planning and Standards
Mail Code D243-05
Research Triangle Park, NC 27711

Copy: refineryfactor@epa.gov

Re: Request for Comments on Proposed Determination for No Changes to VOC Emission Factors for Tanks and Wastewater Treatment Systems

Dear Gerri,

On behalf of Sprague Operating Resources (Sprague), please consider the following letter as comments for the record in response to US Environmental Protection Agency's (EPA) request for comments on suggested revisions to AP-42. In particular, these comments address the proposed determination that revisions to the VOC emission factors for liquid storage tanks are not necessary. Sprague is one of the largest independent suppliers of energy and material handling services in the Northeast with products including home heating oil, diesel fuels, residual fuels, gasoline and natural gas. Sprague operates a network of 17 refined product terminals with a combined storage capacity of ten million barrels and markets product through an additional 60 terminal locations throughout the northeast.

EPA states that it is proposing no changes to the VOC emission factors for tanks, primarily because the available emissions data for tanks is not adequate to allow for revisions to existing emissions estimation methods as provided in AP-42 Chapter 7. Among other things, a document entitled, "DRAFT EPA Review of Available Documents for Developing Proposed Emissions Factors for Flares, Tanks, and Wastewater Treatment Systems," (Draft Report) is referenced as providing details in support of this conclusion. In particular, the Draft Report outlines the conclusion that available emissions data for tanks is not adequate to allow for revisions to existing emissions estimation methods provided in AP-42 because additional target testing, accounting for site specific data, needs to be performed. As such, it is currently not possible to definitively determine whether there is a need to modify the existing equations in AP-42 for tank emissions.

The Draft Report also provides some details on the actual emissions testing for VOC's from residual oil and asphalt storage tanks conducted by Sprague at their Searsport, ME marine terminal. Based on EPA's discussion of this testing, one would likely conclude that EPA endorses the testing approach used by Sprague in Maine as an approach that should be used elsewhere to measure VOC's from storage tanks. However, Sprague believes the testing approach utilized in Maine provided emissions results that were significantly biased high. Sprague's original recommended test protocol was not approved by EPA who instead required Sprague to implement an experimental testing protocol, involving the construction of temporary total enclosures around the tank vents and use of a fan to induce air flow, which was untested and unprecedented for this type of application. Many concerns were raised, both by Sprague and the professional consulting firm that conducted the air emissions testing (Eastmount Environmental Services), regarding the likelihood that this experimental testing method artificially induces emissions causing an overstatement of actual emission levels. The results of this test are summarized in Section 5.2 of the Draft Report which clearly shows the direct correlation of the forced ventilation on emissions.

While Sprague agrees that insufficient data currently exists to enable an accurate revision of the existing AP-42 emissions estimate methods and that a significant amount of testing and analysis is still required before changes to VOC Emission factors for tanks can be recommended, we also strongly recommend that the method for measuring VOCs from tanks should be consistent throughout the country to ensure, to the extent additional testing is undertaken elsewhere, the test results are derived from consistent and proven emission estimation methods. Toward that end, we believe that the EPA must provide clear national guidance on the appropriate method for measuring tank emissions, particularly as it relates to heated (e.g. No. 6 oil and asphalt) storage tanks.

Independent testing which Sprague and other terminal operators have conducted on heated product tanks, and made available to the EPA Region 1, indicates results that in fact approximate within an order of magnitude of existing Table AP-42 factors. Sprague therefore believes that in the absence of sufficient data to enable updated emissions calculations, the currently published EPA recommended AP 42 Tables should remain as the national standard. Further, it is clear that if insufficient data is available on a national level to accurately develop a new standard, then it would be unrealistic to expect locally developed case by case experimental testing protocol would produce improved results. The net result of case by case testing by local authorities would only be to further exacerbate and confound compliance efforts by terminal operators such as Sprague. Businesses, and the public, require transparent and consistent compliance standards to best enable protection of the environment.

Sprague respectfully recommends that the EPA consider the following as part of their actions to meet compliance with the consent decree:

1. Conclude changes to VOC emissions factors for tanks are not possible at this time due to lack of necessary testing data and continue to rely on EPA published AP-42 emissions estimation methods until such time that more accurate methods exist.

2. Initiate a coordinated national effort to develop a consistent tank emissions testing protocol and to conduct additional testing in order to determine if modifications to equations in AP-42 Chapter 7 are in fact necessary, particularly for No. 6 oil and asphalt storage tanks.

3. Develop and implement changes to AP-42 only if necessary and as required within an appropriate timeframe.

4. Communicate to all EPA regions, details on the review and collection of necessary data to determine if changes to AP-42 are necessary and instruct that all VOC emission reporting requirements for No. 6 oil and asphalt tanks are to be delayed until such time that a clear and consistent national emission estimation method is developed.

In summary, Sprague has worked cooperatively with the EPA to investigate the applicability of existing AP-42 emission estimation methods for No. 6 oil and asphalt storage tanks. The experimental emission estimation method implemented at Sprague's Searsport, ME marine terminal, as referenced in Section 5.2 of the Draft Report, produced artificially elevated emissions and should not be relied upon or referenced until further testing is conducted. Sprague supports the conclusion that revisions to VOC emission factors for tanks are not necessary at this time, but also strongly recommends that the above noted actions be implemented as part of meeting the consent decree so that clear and consistent emission estimation methods for No. 6 oil and asphalt tanks may be applied and reviewed within an acceptable period of time.

We appreciate the opportunity to provide comments on this important matter and please feel free to contact the undersigned if you would like to discuss this issue in greater detail.

Sincerely,

Jay Leduc

Jay Leduc
Director of Health, Safety and Environment (HSE)

Garwood, Gerri

From: DeArment, Daniel <Daniel.DeArment@cbi.com>
Sent: Tuesday, December 02, 2014 8:20 AM
To: RefineryFactor
Cc: Keckler, Russell; Kalani, Louis
Subject: Comments on Revised Emission Factors for Flares in Draft AP-42, Section 13.5 (Supplement D)
Attachments: removed.txt; CBI_US EPA Revised Emission Factors in Draft Final AP-42 103114-comments....pdf

Ms. Garwood,

Attached are our comments on the revised emission factors in Draft AP-42. Thank you for your consideration.

Please call with any questions.

Best regards,

Daniel DeArment
Senior Operations Manager
LFG Specialties, LLC
Environmental and Infrastructure
Tel: +1 419 424 4925
Cell: +1419 306 2613
daniel.dearment@CBI.com

CB&I
16406 US Route 224E
Findlay, OH 45840
www.CBI.com/lfgspecialties

LFG Specialties, LLC
16406 US Route 224 East
Findlay, Ohio 45840
Tel: +1 419 424 4925

October 24, 2014

Via Electronic Transmission: refineryfactor@epa.gov

Ms. Gerri Garwood
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC 20460

Dear Ms. Garwood:

Re: Revised Emission Factors for Flares in Draft AP-42, Section 13.5 (Supplement D)

LFG Specialties, LLC, a wholly owned subsidiary of CBI, is a leading supplier of flares to the landfill gas industry. We have been in business for 27 years and have designed and manufactured over 800 open and enclosed flares. These flares are currently in operation in practically every state in the union.

We are formally commenting on the revised emission factors the EPA has proposed for industrial flares in the draft AP-42 Section 13.5. The proposed factor for nitrogen oxides (NOx) was increased substantially from 0.068 lbs/MMBTU to 2.9 lbs/MMBTU—42 times higher. We do not believe the revised emission factor is appropriate for candlestick (also called “open” or “utility”) flares that are widely used at municipal solid waste (MSW) landfills. These flares are not air or steam assisted.

The emission factors for NOx and carbon monoxide (CO) in Section 13.5 are used to permit a vast number of the candlestick flares in the solid waste industry in lieu of Section 2.4 (MSW Landfills). This is due to the fact that the current emission rates in Section 13.5 more closely resemble what we expect to see from an enclosed flare operating on landfill gas than do those in Section 2.4. The following table compares the values of Section 2.4, 13.5 and our standard guarantee for emissions from an enclosed flare:

Emission Factor Comparison Table

Pollutant	AP-42, Section 2.4 MSW Landfills	AP-42, Section 13.5(1) Industrial Flares	LFG Specialties Guarantee Enclosed Flares
NOx	0.07 lbs. / MMBtu(2)	0.068 lbs. / MMBtu	0.06 lbs. / MMBtu
CO	1.35 lbs. / MMBtu(2)	0.37 lbs. / MMBtu	0.20 lbs. / MMBtu

(1) LFG Specialties references these limits on all candlestick flares in its proposals, O&M manuals and product literature.

(2) These values were converted from lbs. / 10^6 dscf to lbs. / MMBtu for comparison.

Testing of a candlestick flare cannot be accomplished, due to the mechanical arrangement of the equipment (i.e. open flame, no test ports, and uncontrolled temperature). However, there is a significant amount of data available to support the emission guarantee for an enclosed LFG-fired flare stated in the table above. These enclosed flares generally operate around 1600° F, whereas the flame temperature in candlestick flares is lower, generally in the 1,500° F range. With this lower temperature, nitrogen oxide formation is expected to be lower than the levels found in enclosed flares. It is counter intuitive to believe that the NOx levels would rise when these levels should be falling with lower temperatures – see Attachment A (CO / NOx relationship vs. temperature).

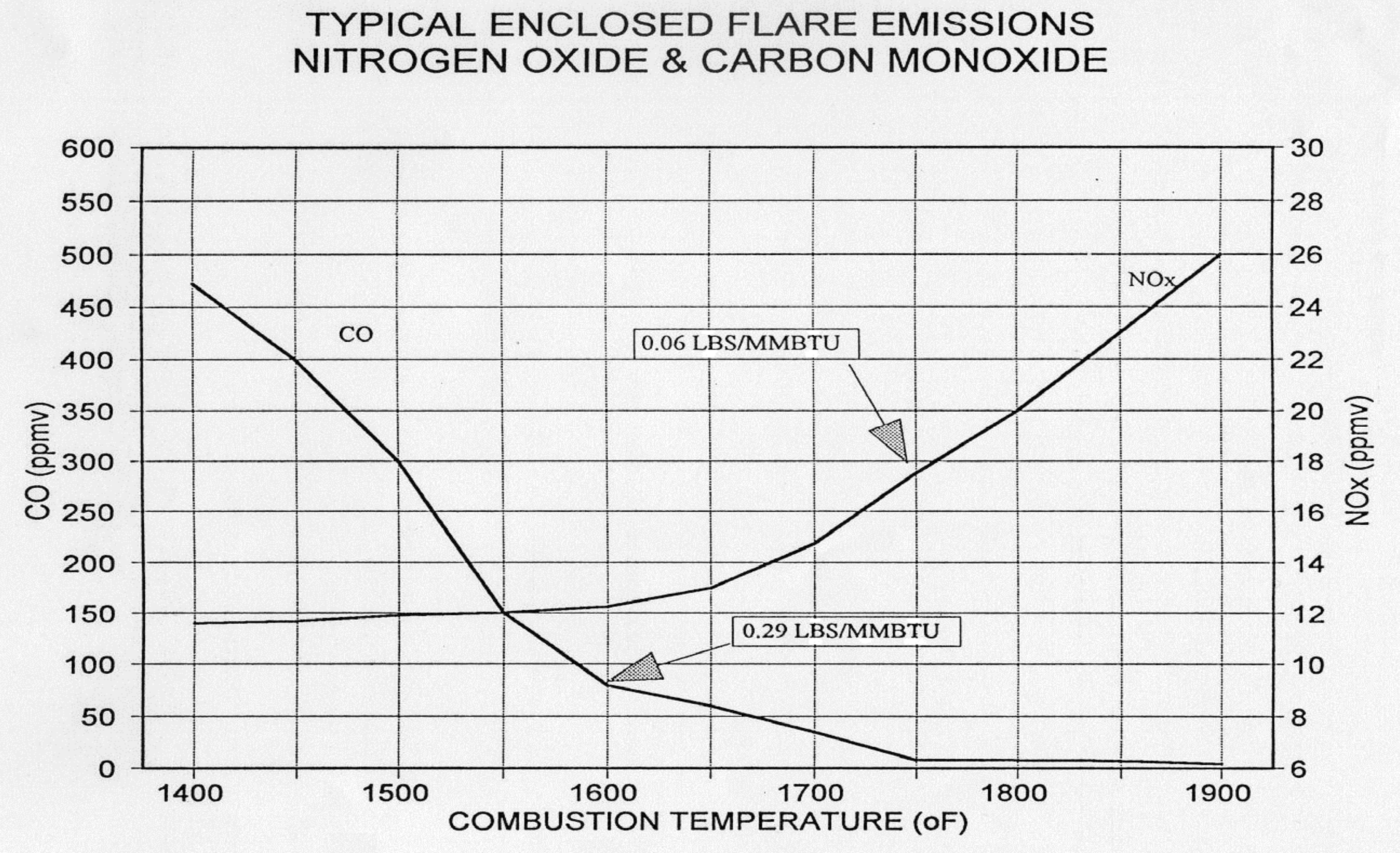
Furthermore, the emission data collected in the draft is not supportive of a candlestick flare operating on landfill gas. These tests were conducted on air and/or steam assisted flare combusting high calorific fuels, and should not be used as the status quo.

For these reasons, we believe that the current emission rates listed in AP-42 Section 13.5 should be left as is, or until such time that the emission values in Section 2.4 can be quantified by additional testing.

Sincerely,

Daniel DeArment
Vice President
LFG Specialties, LLC

Attachment A - Temperature Correlation between NOx & CO



Garwood, Gerri

From:	Garwood, Gerri
Sent:	Tuesday, December 02, 2014 2:57 PM
To:	Tonnesen, Gail
Cc:	Zubrow, Alexis
Subject:	RE: proposed new flare NOx emissions factor increased 46x

Hello Gail,

The public comments that we have received are provided on the bottom of the webpage provided in your email. We will be updating this list this week. There are many comments on the flare NOx factor.

I cannot say what our path forward will be once the comment period closes. We will have to digest all of the comments received before we decide whether we will finalize the factor as proposed or not.

Sincerely,
Gerri G. Garwood, P.E.

U.S. Environmental Protection Agency
OAR – Office of Air Quality Planning and Standards Sector Policies and Programs Division
Ph: 919-541-2406 Fax: 919-541-3207

-----Original Message-----
From: Tonnesen, Gail
Sent: Tuesday, December 02, 2014 2:34 PM
To: Garwood, Gerri
Cc: Zubrow, Alexis
Subject: RE: proposed new flare NOx emissions factor increased 46x

Hi Gerri,

I have a question on the revised flare NOx emissions factors that are discussed in AP 42 Chapter 13 available here:

http://www.epa.gov/ttn/chief/consentdecree/index_consent_decree.html

They report test results for 5 flares that range from 0.011 to 16 lb/hour and they propose an average of 2.9 lb/hr. This is an increase of 46 times the old NOx flare emissions factor. They also calculate the emissions factor using a combined NO and NO2 MW basis. This should be reported on an NO2 MW basis.

Have you already received public comments on this, and are you planning on revising this?

Thanks,
Gail

====================
Gail Tonnesen, Ph.D.
EPA Region 8 - Air Program
1595 Wynkoop St.
Denver, CO 80202
303-312-6113

-----Original Message-----
From: Ryan, Ron
Sent: Tuesday, November 25, 2014 8:22 AM
To: Mason, Rich; Zubrow, Alexis; Tonnesen, Gail
Cc: Snyder, Jennifer
Subject: RE: proposed new flare NOx emissions factor increased 43x

From AP-42 page:
Please submit your written comments on the above referenced documents and the proposed actions to AP-42 by December 19, 2014. Questions should be e-mailed to Gerri Garwood at garwood.gerri@epa.gov and comments should be e-mailed to refineryfactor@epa.gov.

-----Original Message-----
From: Mason, Rich
Sent: Monday, November 24, 2014 5:27 PM
To: Zubrow, Alexis; Tonnesen, Gail
Cc: Snyder, Jennifer; Ryan, Ron
Subject: RE: proposed new flare NOx emissions factor increased 43x

I'd say Ron or Jennifer would be most familiar with flare EFs in the NEI.

-----Original Message-----
From: Zubrow, Alexis
Sent: Monday, November 24, 2014 4:33 PM
To: Tonnesen, Gail
Cc: Mason, Rich; Snyder, Jennifer
Subject: RE: proposed new flare NOx emissions factor increased 43x

Gail,

I don't know who the right person is for the NOx EF from flares. Rich or Jennifer do you guys (see below for details)?

cheers,
az

Alexis Zubrow
Emission Inventory and Analysis Group
Office of Air Quality Planning and Standards US EPA Currently on detail to Region 1 Air Quality Unit
(617)918-1458

-----Original Message-----
From: Tonnesen, Gail
Sent: Monday, November 24, 2014 11:03 AM
To: Zubrow, Alexis
Subject: FW: proposed new flare NOx emissions factor increased 43x

Alexis,

Also, I had a question for Marc (email below) about proposed changes in the flare NOx emissions that seem questionable. The revised flare NOx emissions are discussed in AP 42 Chapter 13 available here:

http://www.epa.gov/ttn/chief/consentdecree/index_consent_decree.html

Thanks,
Gail

-----Original Message-----
From: Tonnesen, Gail
Sent: Thursday, August 28, 2014 10:14 AM
To: Houyoux, Marc
Subject: proposed new flare NOx emissions factor increased 43x

Hi Marc,

Do you know who is the contact person for the proposed new flare NOx emissions factor? They report test results for 5 flares that range from 0.011 to 16 lb/hour and they propose an average of 2.9 lb/hr. This is an increase of 46 times the old NOx flare emissions factor. They also calculate the emissions factor using a combined NO and NO2 MW basis. This should be reported on an NO2 MW basis.

Thanks,
Gail
303-312-6113

Garwood, Gerri

From: Giuliani, Anthony J. <AJGiuliani@vorys.com>
Sent: Wednesday, December 10, 2014 2:34 PM
To: RefineryFactor
Subject: FW: Momentum Energy Group (USEPA's Proposed Revisions to AP-42)
Attachments: removed.txt; (20743862)_(1)_2014-12-10 Letter to Gerri Garwood_USEPA re proposed revs. to AP-42 emission factors for industrial flares.PDF

Dear Ms Garwood,

Enclosed for the record are comments from Momentum Energy Group on the proposed revisions to the AP-42 emission factors for flares.

Sincerely,

Anthony Giuliani

The linked image cannot be displayed. The file may have been moved, renamed, or deleted. Verify that the link points to the correct file and location.

Anthony J. Giuliani
Partner

Vorys, Sater, Seymour and Pease LLP
52 East Gay Street | Columbus, Ohio 43215

Direct: 614.464.6279
Fax: 614.719.4734
Email: ajgiuliani@vorys.com
www.vorys.com

From the law offices of Vorys, Sater, Seymour and Pease LLP.

VORYS

Vorys, Sater, Seymour and Pease LLP
Legal Counsel

52 East Gay Street
P.O. Box 1008
Columbus, Ohio 43216-1008

614.464.6400 | www.vorys.com

Founded 1909

Anthony J. Giuliani
Direct Dial (614) 464-6279
Direct Fax (614) 719-4734
Email ajgiuliani@vorys.com

December 10, 2014

VIA E-MAIL

Gerri G. Garwood, P.F.
U.S. EPA
Measurement Policy Group
refineryfactor@epa.gov

Re: Momentum Energy Group: U.S. EPA's Proposed Revisions to AP-42 Emission Factors for Industrial Flares

Dear Ms. Garwood:

Momentum Energy Group submits the following comments on U.S. EPA's proposed revisions to its AP-42 emission factors for industrial flares. Momentum is an independent midstream company that processes natural gas and natural gas liquids and connects oil and gas producers with the marketplace. While Momentum believes that the U.S. EPA's pursuit of the most accurate and up-to-date emission factors is laudable, the proposed changes for flare emissions factors, however, would add inaccuracies in emissions estimates as the tests cited in the review are very limited in amount, source selection, and methodologies. Thus, Momentum is opposed to U.S. EPA revising the flare emission factors as proposed and submits the following comments.

The limited number of tests cited is concerning. The EPA has a wealth of flare tests to draw upon, yet limited itself to an analysis of less than 10 test results for each pollutant. The very small sample of tests proved to be especially problematic in the case of NOx, where one outlier changed the average by an order of magnitude. The current AP-42 factors for NOx and CO do not appear to be correctly weighted as it is the result of multiple tests and has a much higher Individual Test Rating (ITR). Any change in these factors, especially one as large as this, deserves to incorporate as much useable data as practical in order to allow some statistical credibility and significance to the changes.

The review had eight steam-assisted flares, one air-assisted, and no unassisted flares. Not only is this unrepresentative of the types, but it's also unrepresentative of the different industries using flares as a whole. While these types of flares may or may not deserve different factors, having these flares included with little or no data is dubious.

Furthermore, the data set was exclusively comprised of Passive (FT)IR instrument data. This may have made the testing easier, but is not nearly as accurate as testing the gas stream. The EPA should have, and in the past has, tested the gas stream directly. In addition, the low ITR scores suggest that the cited tests would not be acceptable for compliance testing, let alone a policy change.

In addition, Momentum notes the following:

- The DIAL study cautioned about the limited viability of its remote sensing capabilities. While the PFTIR certainly has enhanced resolution and speciation capabilities, there is nothing to suggest that it improved on its remote sensing limitations.
- No studies of enclosed flares were included. This would allow easy sampling of the gas stream directly and would provide much more accurate emission rates. Further, it seems appropriate as some enclosed flares may fall under the new emission factors.
- Several, if not all, of the studies relied on default assumptive process conditions instead of more accurate measured conditions.
- The emission factor change does not review a variety of industries that use similar flares.
- The flare air/steam assistance was varied to see the response in different conditions. While only the efficient combustion band was included in the emission rate calculation, this likely included times NOx/CO stoichiometry were less than ideal and likely not as engineered by the flare manufacturer. Changes to emission factors should be based on properly operated flares.

Based upon the foregoing, Momentum respectfully requests that the U.S. EPA keep the current AP-42 emission factors for flares in place. The proposed revisions are based upon faulty and scanty data that were created using tests and procedures that are neither accurate nor representative in nature.

Very truly yours,

Anthony J. Giuliani

Anthony J. Giuliani

AJG/lm

Garwood, Gerri

From:	Alice G Prior (Services - 6) <alice.g.prior@dom.com>
Sent:	Tuesday, December 16, 2014 4:34 PM
To:	RefineryFactor
Cc:	Alice G Prior (Services - 6); Garwood, Gerri
Subject:	Dominion Comments on AP-42 Industrial Flare emission factor proposed changes
Attachments:	Dominion comments on AP-42 Flare EFs Dec 16 2014.pdf

Please see attached comments.

Alice Prior
Environmental Projects Advisor
Dominion Environmental Services
5000 Dominion Blvd., 2NW
Glen Allen, VA 23060
Tie Line 8-730-4127
(804) 273-4127 (o)
(804) 229-4186 (c)

Pamela F. Faggert
Chief Environmental Officer and
Vice President-Corporate Compliance

Dominion Resources Services, Inc.
5000 Dominion Boulevard, Glen Allen, VA 23060
Phone: 804-273-3467

dom.com

BY ELECTRONIC DELIVERY
Email: *Submitted via email to refineryfactor@epa.gov*

December 16, 2014

Environmental Protection Agency
Clearinghouse for Inventories and Emission Factors
Washington, D.C. 20004

RE: Proposed Changes to AP-42 Chapter 13: Industrial Flares

Dear Sir or Madam:

Dominion Transmission, Inc. is pleased to provide comments regarding the Proposed Changes to AP-42 Chapter 13: Miscellaneous Sources Section 13.5 Industrial Flares. The proposed changes to the flare emission factors revise the current carbon monoxide (CO) and nitrous oxides (NOx) factors and create a new emission factor for volatile organic compounds (VOCs). Dominion Transmission, Inc., headquartered in Richmond, Virginia, is the interstate gas transmission subsidiary of Dominion. The company is primarily a provider of gas transportation and storage services. We operate one of the largest underground natural gas storage systems in the United States with links to other major pipelines and to markets in the Midwest, Mid-Atlantic and Northeast regions of the United States. We maintain 7,800 miles of pipeline in six states — Ohio, West Virginia, Pennsylvania, New York, Maryland and Virginia. We store and transport large quantities of natural gas for large customers, such as major utilities and power plants. Dominion Transmission also is a producer of natural gas liquids at facilities in West Virginia.

Dominion is concerned about the methodology used to establish the proposed revisions and requests that EPA withdraw, resample, and re-propose emission factors for industrial flares in AP-42 Chapter 13. Of most concern is the NOx emission factor, which would increase from 0.068 to 2.9 pounds per million British thermal units (lb/MMBtu). Overestimating NOx from flares will have potential compliance and permitting implications for existing, new and modified flares. To the extent that EPA does not withdraw the proposal, the following comments are provided:

Data and Methodology Issues

We have concerns with the data and methodology used to develop the new emission factors, especially for NOx, which render the accuracy of the proposed factors as not scientifically derived.

First, the new NOx factor has been calculated as an arithmetic average based on Passive Fourier Transform Infrared (PFTIR) Spectroscopy instrument measurements of five flares and the existing AP-42 emissions factor. However, the PFTIR instrument used to measure the NOx data sets was not calibrated for NO or NO2. The PFTIR is commonly used to measure combustion efficiency, not for gathering NO or NO2 concentration data. In addition, the PFTIR technology assumes a consistent path measurement which is problematic when evaluating a dynamic and variable flare plume. The PFTIR also has a limited dynamic range due to a one-sensor configuration and must operate at lower temperatures where atmospheric interferences can be significant.

Second, only five flares were sampled. A five-flare sample set does not represent a statistically significant data set, nor do the waste gases of the flares sampled (from refinery operations) represent waste gas typically found at a natural gas transmission or storage station. The proposed emission factor is assumed to account for each type of NOx formed from flare operations, which does not represent the various waste gas streams found in all industrial operations. The NOx emission factor should be based on a number of different types and designs of flares in addition to testing a statistically significant number of flares.

Third, data obtained at the Flint Hills Resources Port Arthur, Texas, refinery contains anomalies and apparent errors. The exhaust gas flow rate from the flare was over-estimated in several instances due to questionably low CO2 concentration readings, which also resulted in NOx emission rates that were more than two orders of magnitude greater than any other NOx emission factors calculated during the test series. There was a lack of correlation between CO emission and NOx emissions in the test series. Other than two instances, there were no NO emissions measurements from the flare plume. NO2 concentrations swung inconsistently from a high value one minute to a zero and back the next, indicating measurement problems. At a minimum, the Flint Hills Resources flare results should be rejected.

The data and methodology used to establish the proposed NOx emission factor for industrial flares should be re-examined by EPA to ensure that proper procedures are followed to provide valid, representative emissions data. Therefore, we request the current proposed AP-42 emission factor for NOx be withdrawn and that a much broader number and range of flares be sampled and presented in a subsequent proposal after adequate quality assurance and review.

Permitting and Compliance Implications from Over-Estimating NOx from Flares

To the extent that EPA does not withdraw and re-propose the NOx emission factor, such a dramatic change in NOx emissions estimates could affect historic air permitting assumptions and potentially impact facility compliance.

Future air permitting decisions could be impacted if threshold emission limits are triggered due to over-estimated potential NOx emissions. Higher potential NOx emissions estimates using the proposed AP-42 factor could cause a minor permit application to trigger major source thresholds. This is of particular concern in nonattainment areas for which the difference between a minor and a major permit could impact the viability (cost and schedule) of a project. Although the above issues for new flares are of concern to Dominion, flare manufacturers typically provide guaranteed emission rates much lower than the proposed AP-42 emission factors, thus superseding the need to rely on AP-42.

Existing flare emissions estimations, however, were established using a much lower NOx emission factor. Historical data from flare manufacturers may not be available to supersede use of the higher proposed AP-42 emission factor, even though operational evidence suggests much lower emissions. If state regulatory agencies require use of the new, higher AP-42 NOx emission factor in annual emission inventory calculations and or compliance demonstrations, permit limits could appear to be exceeded. If new factors that are significantly higher are finalized, we request that EPA develop guidance for permitting and compliance authorities to address the regulatory status of existing facilities.

Again, we appreciate the opportunity to comment on the proposed changes to AP-42 Chapter 13: Miscellaneous Sources Section 13.5 Industrial Flares. If you have any questions, please call me at 804-273-3467 or Alice Prior at 804-273-4127 (alice.g.prior@dom.com).

Sincerely,

Pamela F. Faggert

Pamela F. Faggert

Garwood, Gerri

From:	Erin K. Bartlett <ekb@vnf.com>
Sent:	Wednesday, December 17, 2014 1:47 PM
To:	RefineryFactor
Subject:	GPA's Comments on Proposed Emission Factor Revisions AP-42 Chapter 13
Attachments:	2014-12-17 GPA_Comments_EPA_EmissionFactors.pdf

To Whom It May Concern:

On behalf of the Gas Processors Association (GPA), please find attached to this email, a PDF of GPA's comments on the EPA's proposed revisions to AP-42 Section 13.5 emission factors. GPA appreciates the opportunity to comment on this matter. At your earliest convenience, please provide an email confirmation that GPA's comments have been received.

Thank you very much,

Erin K. Bartlett
Counsel for the Gas Processors Association

Erin K. Bartlett | Associate

**VanNess
Feldman** LLP

1050 Thomas Jefferson Street, NW
Washington, DC 20007

(202) 298-1812 (o) | (202) 338-2416 (f) | ekb@vnf.com | vnf.com

GAS PROCESSORS ASSOCIATION
MIDSTREAM'S GREATEST RESOURCE

December 17, 2014

By electronic transmission

Via email: refineryfactor@epa.gov

Emission Factor and Emission Estimation Tools
U.S. Environmental Protection Agency

Re: GPA's Comments on Proposed RevisionsAP-42 Chapter 13: Miscellaneous Sources Section 13.5 Industrial Flares

To Whom It May Concern:

The Gas Processors Association (GPA) respectfully recommends that the U.S. Environmental Protection Agency (EPA) withdraw the proposed AP-42 Section 13.5 emission factors for industrial flares. GPA asserts that the emission factors were developed using a limited data set and questionable methodology. The proposed emission factors for industrial flares would increase the oxides of nitrogen (NO_x) factor forty two (42) times above the current value and introduce a volatile organic compound (VOC) factor that is approximately four (4) times above the existing factor for total hydrocarbons (THC). Finalizing the proposed emission factors will cause uncertainty to both regulators and the regulated community alike due to the permit concerns outlined below. In addition, the midstream sector of the natural gas industry across the United States will be substantially harmed if other compliance methodology, such as performance testing, must be employed as an alternative to the current published emission factor for industrial flares.

In addition to GPA's comments below, we support the comments on this issue submitted by the American Petroleum Institute.

GPA has served the U.S. energy industry since 1921 as an incorporated non-profit trade association. GPA is composed of 130 corporate members that are engaged in the gathering and processing of natural gas into merchantable pipeline gas, commonly referred to in the industry as "midstream activities." Such processing includes the removal of impurities from the raw gas stream produced at the wellhead, as well as the extraction for sale of natural gas liquid products (NGLs) such as ethane, propane, butane, and natural gasoline. GPA members account for more than 90 percent of the NGLs produced in the United States from natural gas processing. GPA members own facilities that currently utilize the AP-42 emission factors for traditional and enclosed flares. GPA companies would be subject to increased regulatory burdens under the proposed revisions and submits the following comments.

General Comments on the Studies Used in the Emission Factor Development

GPA is concerned with the sample size used to develop the new emission factors. Specifically, the new NO_x emission factor was based on only five new data points with one value from the Flint Hills facility (16) that was orders of magnitude higher than the average of the other four data points (0.297). EPA's review document states that the higher emission number from Flint Hills was not a statistical outlier; however, due to the small data set further analysis is needed to estimate the uncertainty of its value.

Of the six (6) new studies evaluated to develop the revised emission factors, three (3) were requested as part of a Section 114 request and one (1) was required by a consent decree. These tests were performed to satisfy specific test requirements of those requests, and not in a manner appropriate for the data to be broadly applicable for the calculation of emission factors. Also, as requested by the Section 114 letters and consent orders, the operating conditions of the flares were modified during testing, including various levels of steam or air assistance, and did not represent typical flare operation. These modifications to flare operating conditions may have resulted in higher emissions as combustion efficiency was lowered.

GPA is also concerned the flare data on which the new factors were based was from one type of flare (steam-assisted) and only one type of facility in one industry sector (petroleum refineries) plus a test facility. The emission factors apply to many different facility types within oil and gas operations as well as other industry sectors; therefore, the studies used to develop the factor should be from diverse flare types and facilities.

Finally, the emissions data used by EPA appears to be unreliable for use in determining emission factors due to the analytical methods employed to collect and process the data. Specifically, the purpose of the study was to determine combustion efficiency, not quantify emissions. Additionally, the Passive Fourier Transform Infrared Spectroscopy (PFTIR) instrument was not calibrated for nitrogen oxide (NO) or nitrogen dioxide (NO_2), interference tests were not run, response times were not included, and there were no drift tests conducted. For these reasons, this data should not be used in an empirical analysis for the new emission factors.

Impact to Existing Minor Source Permits Nationwide

Performance testing for flares is not a simple or inexpensive task; therefore, most of the regulated community and flare manufacturers rely on the existing AP-42 emission factor to permit and demonstrate compliance with emission limits. As discussed above, the new emission factors were derived using results from questionable methods at petroleum refineries that were part of a revision to other refinery factors. Refineries are large sources of air emissions and typically fall into major source categories for Title V and PSD programs. The change in the flare emission factors may have little effect on their permitting activities. However, the majority of midstream facilities with flares are minor sources and utilize flares as control devices to stay below major source thresholds. Increasing the NO_x emission factor by a factor of forty two (42) could result in hundreds of facilities becoming major sources. The increase in permit applications alone could result in a significant regulatory burden on both the regulatory authorities and the regulated community. If facilities chose to conduct performance tests to show lower NO_x or VOC emission rates for flares at their facilities rather than use the emission factors, the expertise and number of companies available to conduct these tests does not exist and the costs associated with these tests may be prohibitive. Additionally, performance testing is not an option for a new or modified flare that must be permitted prior to construction.

Summary and Suggested Path Forward

Due to the uncertainty in the data used to derive the new emission factors and the potential impact to the natural gas midstream sector described above, GPA respectfully recommends EPA to withdraw all proposed changes to AP-42 Section 13.5 for industrial flares, keep the existing factors and take the following actions:

- Determine new industrial flare emission factors using performance test data developed from properly designed studies in multiple industry segments.
- Consider determining separate factors for different flare types (steam assisted, air assisted, pressure assisted and non-assisted; enclosed and unenclosed), feed composition, and industrial applications.

Thank you for the opportunity to comment on the proposed emission factors. GPA is willing to further engage on this issue with EPA. Please contact me at (918) 493-3872 or msutton@GPAglobal.org if GPA can be of assistance.

Respectfully Submitted,

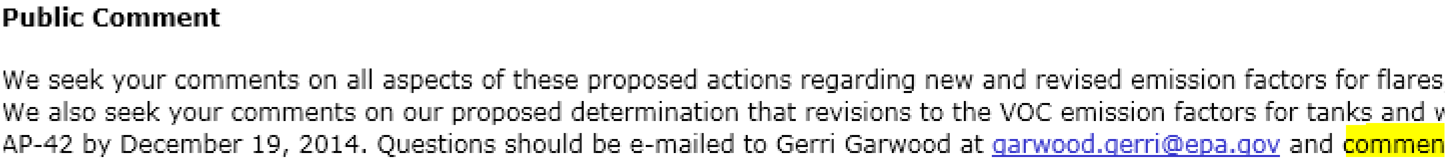
Mark F. Sutton
President and CEO
Gas Processors Association

From: Vicente Martinez <VMartinez@bepc.com>
Sent: Wednesday, December 17, 2014 3:43 PM
To: refineryfactor@epa.gov.; Garwood, Gerri
Cc: Daniel Whitley; Terrence Kizer; Peggy O'Neil; A. T. Funkhouser
Subject: AP-42 Comments
Attachments: 1105_001.pdf

Please see attached AP-42 comments.

Thanks

Vicente Martinez
Dakota Gasification Co.



Public Comment

We seek your comments on all aspects of these proposed actions regarding new and revised emission factors for flares
We also seek your comments on our proposed determination that revisions to the VOC emission factors for tanks and w
AP-42 by December 19, 2014. Questions should be e-mailed to Gerri Garwood at garwood.gerri@epa.gov and commen

DAKOTA GASIFICATION COMPANY
A BASIN ELECTRIC SUBSIDIARY

GREAT PLAINS SYNFUELS PLANT
420 COUNTY ROAD 26
BEULAH, NORTH DAKOTA 58523-9400
PHONE: 701/873-2100
FAX: 701/873-6404

Great Plains
SYNFUELS

December 17, 2014

Ms. Gerri Garwood
U.S. Environmental Protection Agency
refineryfactor@epa.gov

Dear Ms. Garwood:

Dakota Gasification Company (DGC) Great Plains Synfuels Plant (GPSP) would like to thank the U.S. EPA for extending the comment period on the proposed revisions to the AP-42 Compilation of Air Pollutant Emission Factors. DGC is pleased to submit the following comments on the proposed AP-42 changes; specifically, the proposed revision to the industrial flare nitrogen oxides (NO_x) emission factor as identified in Chapter 13: Miscellaneous Sources, Section 13.5 Industrial Flares.

The GPSP, a for-profit subsidiary of Basin Electric Power Cooperative, is the only commercial-scale coal gasification plant in the United States that manufactures synthetic natural gas (SNG). The GPSP gasifies more than six million tons of coal annually, and the average daily production is approximately 145 million standard cubic feet of SNG. DGC has one for-profit subsidiary, Souris Valley Pipeline LTD, which has the capacity to deliver about 165 mmscf of carbon dioxide daily to Canadian oil fields for enhanced oil recovery. Since the year 2000, the plant has captured and transported more than 31 million metric tons of CO_2.

The GPSP, like most other industrial facilities, has historically relied on certain AP-42 emission factors to estimate emissions in permitting activities and emissions reporting when reliable, site-specific emissions data is difficult or impossible to obtain. One such category where emissions data has historically been difficult to gather has been in industrial flare emissions, as the agencies own writings have attested to the difficulty in safely gathering emissions data from operating industrial flares.[1] As such, GPSP has historically relied on AP-42 emission factors for representing facility flare emissions in permitting and emissions reporting.

DGC is therefore concerned about the recently proposed change to the NO_x emission factor. The proposed emission factor of 2.9 pounds NO_x per million British thermal units (lb NO_x/MMBtu) is over 40 times greater than the existing AP-42 emission factor of 0.068 lb NO_x/MMBtu. Such a drastic change in an emission factor commonly relied upon should be carefully evaluated and the science supporting such change should be unquestionably of the highest quality. Furthermore, should such a change be in fact deemed justified and representative of the best available science, the U.S. EPA should provide guidance to both

---

[1] See U.S. EPA "Parameters for Properly Designed and Operated Flares," U.S. EPA Office of Air Quality Planning and Standards, April 2012.

regulated facilities and regulators on how such a change should be implemented into existing facility permits and emissions reporting.

DGC therefore has the following major concerns regarding the proposed AP-42 industrial flare NO_x emission factor changes:

1. DGC does not think the range of measurements and measurement techniques are adequate to support revision to the proposed AP-42 NO_x emission factor. EPA relies solely upon studies that used Passive Fourier Transform Infrared (PFTIR) technology for the new test results averaged with the old industrial flare NO_x emission factor to generate the new, proposed NO_x emission factor. While there are many advantages to the use of PFTIR technology, including safer test conditions and the ability to collect real-time data, there are also many technical shortcomings as well. As noted in the EPA's own technical guidance document on the subject, the data gathered by the use of PFTIR technology can give widely varying results depending on where the instrument is pointed in the flame.[2] EPA should therefore conduct more testing using a wider variety of testing technologies before relying on any one such testing methodology to change emission factors. Additionally, it is unclear from the test results how the NO and NO_2 emission factors were calculated using the PFTIR technology and whether or not the instrumentation was properly calibrated to measure these pollutants. DGC therefore recommends that more representative flare samples with a wider range of measurement techniques be evaluated before changes are made.
2. Even if the PFTIR technology provides reliable results, one of the test results used to develop the proposed AP-42 NO_x emission factor should be discarded as a statistical outlier. The FHRAU Flint Hills Resources Port Arthur, LLC facility in Port Arthur, Texas, at 16 lb NO_x/MMBtu is greater than one order of magnitude higher than any of the other results obtained from the other tests. The next highest test result is from the TCEQ tests conducted at a John Zink test facility using an air-assisted flare and provided a result of 0.58 lb NO_x/MMBtu, 26 times lower than the highest test result. The EPA has relied upon the "Q test" to determine that the point is not, in fact, an outlier. However, the EPA used the natural log of each test point before applying the "Q test." EPA assumes the aggregated test data is log-normally distributed; an assumption that should not presumptively be made without further statistical analysis of the individual test data points or the use of a more robust, distribution-free statistical method that does not rely on data parametrization (such as the Kolmogorov-Smirnov Test).
3. Additionally, the aggregated flare test data used to develop the proposed NO_x emission factor are poorly representative of the variety of test conditions that exist at many facilities. EPA should consider repeating the methodology used to develop the original NO_x emission factor and collect more sample data with a greater range of controlled variables, steam and gas ratios, and gas composition. The vent composition of the flare and the flare type can have a significant impact on the emission control efficiency and emission factors. EPA should evaluating more test

---

[2] See "Final Report: Development of Real-Time Flare Combustion Efficiency Monitor." U.S. EPA Contract Number EPD13024.

data and potentially developing multiple emission factor categories to account for the wide diversity of actual flare types used at industrial facilities, such as for sources that predominantly flare lighter compounds (C1-C3) with greater than 98% flare destruction removal efficiency.

4. If EPA does decide to finalize the proposed industrial flare NO_x emission factor of 2.9 lb/MMBtu, then EPA should publish policy on how facilities are supposed to update existing permits and the reporting of emissions. EPA should also update agencies responsible with developing and enforcing permit conditions on how the agencies are supposed to enforce compliance with the new emission factor. Since actual emissions from existing facilities are not literally changing due to a change in emission calculation methodology, facilities that have historically relied on the use of AP-42 emission factors as the best source for representing emissions should not be penalized for this change. In the case of the GPSP, the facility has an ambient monitoring network for NO_x emissions in place, and the proposed changes to emission factors would have no impact to the actual existing NO_x emissions observed around the facility. EPA should therefore make provisions for existing facilities to continue using the older emission factors that were relied upon in the original facility permitting and modeling activities.

While EPA has historically asserted that facilities rely on AP-42 emission factors at their own risk, EPA and agencies delegated permitting authority have traditionally placed greater emphasis on the use of these factors, particularly during the pre-construction permitting phase, than on other possible data sources. Even after sources are constructed, however, AP-42 emission factors are often relied on when source testing presents serious safety or data collection and validation concerns, as is the case with industrial flare testing. Therefore, even if EPA moves forward with drastic changes to emission factors, EPA should provide reasonable guidance on how to go about actually implementing these changes in facility permitting and compliance.

If you have any questions or concerns, please contact Dan Whitley at (701) 873-6619 or me at (701) 873-6620.

Sincerely,

Vicente Martinez
Environmental Engineering Supervisor

vjm/dew/plo

bc: R. Braun
A. T. Funkhouser
L. Dronen
D. Johnson
M. Just
T. Kizer
D. Whitley
9850-DEW-14-016

From:	Legel, Lucinda <Lucinda.Legel@fhr.com>
Sent:	Wednesday, December 17, 2014 5:42 PM
To:	RefineryFactor
Subject:	Flint Hills Resources, LLC Comments on USEPA Draft Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations - Due December 19, 2014
Attachments:	FHR AP-42 Comments.pdf

To Whom it May Concern,

Please find comments on EPA's Draft Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations in the attached document. Flint Hills Resources appreciates the opportunity to provide these comments.

Sincerely,

Lucinda F. Legel
FHR Director Environmental Compliance
WP 316-828-7995
CP 316-200-5459
Lucinda.legel@fhr.com

FLINT HILLS
resources®

December 17, 2014

Sector Policies and Programs Division
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711
E-mail: refineryfactor@epa.gov

Re: **U.S. Environmental Protection Agency's *Draft Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations* (August 2014)**

Flint Hills Resources, LLC (FHR) submits the following comments on the U.S. Environmental Protection Agency's (EPA's) *Draft Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations* (August 2014), specifically the flare emission factors that EPA is proposing as an update to the *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources*, AP-42 (EPA, 1995), and that are based, in part, on flare testing performed by Flint Hills Resources Port Arthur, LLC at the Port Arthur Chemicals facility.

FHR, through its subsidiaries, is a leading refining, chemicals, and grain processing company. Its subsidiaries produce and market gasoline, diesel, jet fuel, asphalt, ethanol, biodiesel, liquid natural gas, olefins, polymers, intermediate chemicals, as well as base oils, corn oil and distillers grain. The refining business operates refineries in Minnesota (Pine Bend Refinery) and Texas (Corpus Christi East and West Refineries), with a combined crude oil processing capacity of more than 600,000 barrels per day. The petrochemical business includes production facilities in Illinois (Peru and Joliet), Michigan (Marysville) and Texas (Houston, Port Arthur, and Longview). FHR's refining and petrochemical businesses rely upon flares for the safe and reliable operation of their refining and petrochemical facilities in accordance with applicable regulations.

The flare testing performed by Flint Hills Resources Port Arthur, LLC upon which EPA has relied to develop its proposed flare emission factors was conducted pursuant to a November 5, 2010, Clean Air Act Section 114 information request and as part of EPA's investigation into flare combustion efficiency.[1] As explained in the flare test report submitted to EPA:

> The main objective of the tests was to better understand the impacts of steam on the overall performance of each flare in terms of combustion efficiency (CE). Two additional

---

[1] *See* Letter from Philip A Brooks, Director, Air Enforcement Division, EPA, to Justin East, Environmental Manager, FHR, *Re: Section 114 Letter Requiring Emissions Testing, FHR Port Arthur Chemical Complex in Port Arthur, Texas* (Nov. 5, 2010), attached.

> operating parameters were also examined during this test program. The effect of hydrogen on combustion efficiency was studied on the AU flare. The effect of vent gas flow rate on combustion efficiency was studied on the LOU flare.[2]

Additionally, for each of condition under which the flares were tested, "steam flow was increased from the point of incipient smoke to a point just before snuffing the flare (incipient snuff)."[3]

According to EPA's *Recommended Procedures for Development of Emissions Factors and Use of the WebFIRE Database*, "[a]n emission factor is used to establish air pollutant emissions from a *normally-operating* process or activity...."[4] Although EPA recognizes that the conditions under which the flares were operated to investigate combustion efficiency were not representative of normal flare performance, it has attempted to overcome this critical flaw by excluding data from any one-minute periods during a test run where the flare combustion efficiency was less than 96.5 percent (considered to be equivalent to a destruction efficiency of 98 percent) or where there was no steam flow to the flare. Although properly operating flares do achieve at least 98 percent destruction efficiency, EPA's logic that a flare achieving at least 96.5 percent combustion efficiency (and, therefore, at least 98 percent destruction efficiency) for a one-minute period is being operated under conditions upon which an emission factor should be based does not hold. Contrary to EPA's assertion, the exclusion of data associated with periods of low flare combustion efficiency is not sufficient to ensure that the data that was relied upon is representative of normal flare performance. Instead, data from test runs where a flare was intentionally operated outside of its normal operating mode is not reflective of a "normally-operating" flare and, therefore, should not be relied upon to establish an emission factor, regardless of the combustion efficiency measured during any given minute within the test run.

For example, during AU flare test run 24, which consisted of 31 one-minute data points, the steam flow was elevated throughout the run and increased to a point just before snuffing the flare. This mode of operation resulted in a weighted average combustion efficiency of just 88 percent for the entire run, which, as recognized by EPA, is 8.5 percent lower than a properly operating flare. EPA's methodology of excluding data associated with low combustion efficiencies resulted in just 3 one-minute data points from this test run being used (17:25, 17:26, and 17:28). However, because the steam flow was elevated throughout the run, even these three data points correspond to periods where the flare steam to vent gas ratio was elevated (greater than 3.5). The mere exclusion of data associated with low combustion efficiencies does not change the fact that the flare was operated at elevated steam rates throughout the run and achieved an average combustion efficiency of just 88 percent and, therefore, is not sufficient to ensure that the remaining data is representative of normal flare performance.

---

[2] Clean Air Engineering, Inc., *PFTIR Test of Steam Assisted Elevated Flares – Port Arthur*, Final Report (June 17, 2011) at 4 of 21, attached.

[3] *Id.* at 15 of 21.

[4] EPA, *Recommended Procedures for Development of Emissions Factors and Use of the WebFIRE Database*, EPA-453/D-13-001 (August 2013) at 2-1 (emphasis added).

Not only was the Port Arthur Chemicals facility flare testing intentionally conducted under operating conditions that were not representative of normal flare performance, the purpose of the testing was not to determine flare emissions. Instead, as stated in the test report, the primary objective of the testing was to better understand the impacts of steam on the overall performance of the flares in terms of combustion efficiency. As a result, no flare emissions data was included in the flare test report submitted to EPA. In fact, although raw NO_X data was collected during the Port Arthur Chemicals flare testing, because it was neither relevant to the purpose of the testing nor reported, the Passive Fourier Transform Infrared Spectroscopy (PFTIR) instrument used to perform the testing was not calibrated for NO_X prior to the testing. For this additional reason, the NO_X test data resulting from the Port Arthur Chemicals facility flare testing should not be used to establish a NO_X emission factor for flares.

Finally, the PFTIR testing utilized for the Port Arthur Chemicals facility flare testing measured compounds in units of concentration x pathlength (parts per million x meter). As a result, to accurately determine the concentration of the measured compounds, the pathlength (meters) of the flare plume must be known. Here again, the purpose of the flare testing was to determine flare combustion efficiency and not emissions, and the flare pathlength, which varies, was not measured. Therefore, the Port Arthur Chemicals facility flare testing cannot be used to accurately determine emissions rates and should not be used to establish flare emission factors.

FHR appreciates the opportunity to provide these comments. If there are questions, please contact me at (316) 828-7995 or lucinda.legel@fhr.com.

Sincerely,

Lucinda Legel

Lucinda Legel
Director of Environmental Compliance

Attachments

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

NOV 05 2010

OFFICE OF
ENFORCEMENT AND
COMPLIANCE ASSURANCE

<u>CERTIFIED MAIL - RETURN RECEIPT REQUESTED AND ELECTRONIC MAIL</u>

Justin East
Environmental Manager
Flint Hills Resources, LP
4241 Savannah Ave.
Port Arthur, Texas 77640

Re: Section 114 Letter Requiring Emissions Testing
<u>Flint Hill Resources (FHR) Port Arthur chemical complex in Port Arthur, Texas</u>

Dear Mr. East:

The U.S. Environmental Protection Agency (EPA) is currently investigating flare efficiency at petroleum refineries. EPA has determined that testing using passive Fourier transform infrared (PFTIR) technology to measure combustion efficiency of the AU and LOU Flares at the FHR Port Arthur chemical complex in Port Arthur, Texas, is warranted. As such, please provide the information requested and conduct the tests in accordance with the procedures and deadlines identified in the Enclosures. As you know, the testing sought has been the subject of discussions between FHR and EPA during the last few months. EPA is aware that FHR has already commenced the PFTIR testing, and is in frequent contact with FHR to assure that the ongoing testing is consistent with the testing described herein.

Under 40 C.F.R. Part 2, Subpart B, you may assert a claim of business confidentiality for any portion of the submitted information. You must specify the page, paragraph, and sentence when identifying the information subject to your claim. Enclosure III specifies the assertion and substantiation requirements for business confidentiality claims. FHR must submit all requested information under an authorized signature with the following certification:

> I certify under penalty of law that I have examined and am familiar with the information in the enclosed documents, including all attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are, to the best of my knowledge and belief, true and complete. I am aware that there are significant penalties for knowingly submitting false statements and information, including the possibility of fines or imprisonment pursuant to section 113(c)(2) of the Act, and 18 U.S.C. §§ 1001 and 1341.

IN2010.133

We may use any information submitted in response to this request in an administrative, civil, or criminal action. This request is not subject to the Paperwork Reduction Act, 44 U.S.C. §§ 3501 et seq., because it seeks collection of information from specific individuals or entities as part of an administrative action or investigation. Failure to comply fully with this request for information may subject FHR to an enforcement action under section 113 of the Act, 42 U.S.C. § 7413.

You should submit your written response to each request contained herein to:

Patrick W. Foley
USEPA - Air Enforcement Division
MC 2242-A, Room 2119C
1200 Pennsylvania Ave., NW
Washington, DC 20002

Please contact either Patrick W. Foley at (202) 564-7978, or Robert Parrish at (202) 564-6946, if you have any questions about this request for information. We thank you in advance for your cooperation.

Sincerely,

Phillip A. Brooks, Director
Air Enforcement Division

Enclosures

Enclosure I
EPA Clean Air Act Section 114 Request to Flint Hills Resources

CONTENTS OF SOURCE TEST REPORTS

The Source Test Report shall be organized in the following manner:

Introduction

Background test report information pertinent to the test should be presented in this section. This information shall include, but shall not be limited to, the following:

a: Name and address of the manufacturer of the unit tested;

b: Name and address of the testing organization;

c: Test dates, names of persons present during test, and location of test;

d: Schematic drawings of the unit test, noting emission points, sampling sites, and stack cross sections, with sampling points labeled and dimensions indicated; and

e: A brief discussion of the operating principles of the type of unit tested, including maximum production rate of the unit and operating parameters of any air pollution control device on the unit.

Summary

A summary of test findings pertinent to the evaluation of the unit with respect to the applicable emission standard should be presented in this section. This information shall include, but not be limited to, the following:

a: A summary of emission rates found;

b: Isokinetic sampling rates achieved; and

c: The operating level of the unit and any other relevant process, fuel, or control device parameters monitored during the test.

Procedures

A description of the procedures used in the operation of the sampling train or measurement equipment and unit during the tests should be presented in this section. The information shall include, but shall not be limited to, the following:

a: A schematic drawing of the sampling devices and measurement equipment used, with each component designated and explained in a legend; and

b: A description of the principle of operation of and the method used to operate the sampling train and measurement equipment and the procedure used to recover any samples collected.

Analytical Technique

A description of all analytical techniques used to determine the emissions from the source should be presented in this section.

Data and Calculations

All actual data collected and the actual calculations should be presented in this section. This information shall include, but not be limited to the following:

a: All field data collected, including legible copies of field data sheets (raw data) and any transcribed or computer data sheets that might be relevant;

b: Laboratory data, including blanks, tare weights, calibration data, quality assurance samples, and results of the analyses;

c: All calculations used in the determinations of emission rates, process rates, or other factors relevant to the test results, compliance, etc.; and

d: Explanations and calculations substantiating the determination of the number and the location of traverse points used during the test.

Chain of Custody

A listing of the chain of custody of the emission test samples should be presented in this section.

Appendix

This section shall include, as a minimum, calibration work sheets for sampling equipment.

Verification of Production Parameters

Reports, log sheets, strip chart recordings of all relevant operating parameters must be included.

All data sheets, strip charts, and print-outs must be sufficiently annotated or explained to make their intention and information clear and understandable.

Enclosure II
EPA Clean Air Act Section 114 Request to Flint Hills Resources

The following request for information applies to the use of passive Fourier transform infrared (Passive FTIR) spectroscopy measurement technology to measure emissions of particular compounds and the combustion efficiency (CE) at the AU and LOU flares at the Flint Hill Resources (FHR) Port Arthur chemical complex in Port Arthur, Texas.

1. FHR shall undertake 2 runs of each condition described below, except that, in the event that, for any condition within each of these Test Series where (i) the combustion efficiency is 85 percent or greater, and (ii) the absolute difference in the combustion efficiency as between the first and second runs is greater than 5 percent, then FHR shall undertake a third test run for that condition. The first run for each condition shall be of a thirty minute duration. The second run for each condition also shall be of a thirty minute duration except as follows. If FHR so chooses, FHR may average the combustion efficiency data in ten minute intervals for each test condition in the first run. If all three averages are within 0.5 absolute percent of the thirty-minute average, then FHR may undertake the second run for that condition for only twenty minutes.

2. Because some PFTIR one-minute readings are deemed not valid based on review of the spectra, each thirty-minute or twenty-minute test run must include a minimum 15 valid one-minute data points to be considered a valid test run pursuant to this Section 114 Order.

3. FHR shall continue a particular test run even if the test condition results in low efficiency potentially indicating a permit or regulatory exceedance. FHR may discontinue a run after the collection of at least ten minutes of data that shows a CE of seventy-five percent or less, provided that the tester, at the time of the measurement, believes the data is valid. FHR also may discontinue a run at the point FHR believes the flare flame has been snuffed. Finally, FHR may discontinue a run after three minutes of observed opacity using Method 22. Pursuant to Method 22 "[s]moke emissions means a pollutant generated by combustion in a flare and occurring immediately downstream of the flame. Smoke occurring within the flame, but not downstream of the flame, is not considered a smoke emission." FHR is not required to perform test runs at S/VG ratios higher than the S/VG ratio that caused sub-seventy five percent CE or a snuffed flare flame. FHR is not required to perform test runs at S/VG ratios lower than the S/VG ratio that caused three minutes of visible emissions.

4. As to the discontinued test runs described in Paragraph 4, FHR, in both the preliminary data submittal and final report, shall report the results of such runs as valid runs and base the numeric results on the data collected before the run was terminated. Runs in which the flame is snuffed shall be considered valid runs and shall be reported as zero CE in both the preliminary data submittal and final report. The purpose of Paragraphs 3-4 is to allow FHR to limit environmental harm caused by operation at conditions that cause high emissions without sacrificing EPA's goal of obtaining important flare CE data.

5. FHR may also discontinue testing based on operational safety concerns. However, if FHR discontinues testing based on operational safety concerns, FHR shall immediately notify Robert Parrish by telephone at 202-564-6946, and by e-mail at parrish.robert@epa.gov, respectively, of any testing discontinuance. Within twenty-four hours of the end of the event that caused the operational safety concern, FHR shall provide EPA in writing a detailed explanation of the conditions that warranted the discontinuance. In the event of a testing discontinuance, FHR shall make its best efforts to resume testing as soon as is practicable.

6. "API 521 Recommended" as used below shall mean a calculated value using API 521 olefin/aromatic linear relationship of S/VG = 0.0067 (molecular weight) + 0.275.

7. "Minimum Steam Rates" as used below shall mean the minimum cooling steam recommended by the tip manufacturer/projected vent gas flow rate.

8. This 114 Order requires Passive FTIR testing at various steam to vent gas (S/VG) ratios. Test runs where the S/VG ratios are within plus or minus 0.25 of the required S/VGs set forth in this 114 Order shall be deemed compliant with this 114 Order.

9. FHR is not required to conduct greater than 30 days of testing provided that FHR is making best efforts to comply with the terms of this 114 Order

10. <u>AU: AU-A Test Series (Base Case)</u>.

    a. <u>S/VG Ratios for the AU-A Test Series</u>. The AU-A Test Series is composed of the test runs specified below, during which CE and the other parameters as specified in Paragraphs 17-18 will be measured. (FHR shall use the run identifier in brackets to identify each run in all deliverables to EPA. FHR shall state the run number in parenthesis after the run identifier.):

        i. S/VG ratio at API 521 Recommended [AU-A-521]
        ii. S/VG ratio at Minimum Steam Rates [AU-A-Min.]
        iii. S/VG of 1.0 [AU-A-1.0]
        iv. S/VG of 2.0 [AU-A-2.0]
        v. S/VG of 3.0 [AU-A-3.0]
        vi. S/VG of 4.0 [AU-A-4.0]
        vii. S/VG of 5.0 [AU-A-5.0]
        viii. S/VG of 6.0 [AU-A-6.0]
        ix. S/VG resulting in less than 75% CE, if not achieved during any of the preceding test runs. [AU-A-Low CE]
        x. S/VG resulting 98% or greater CE, if not achieved during any of the preceding test runs [AU-A-98% CE].

    b. <u>Acceptable Range of Vent Gas Flow During AU-A Runs</u>. AU-A test runs shall only be undertaken when the vent gas flow rate is between 600 and 1,100 lb/hr. FHR shall make best efforts to hold vent gas flow steady during each test run to between 700 and 1,000 lb/hr.

11. <u>AU: AU-B Test Series (Base Plus Methane, with the lowest achievable Hydrogen concentration, not to exceed 15 mol%).</u>

a. <u>S/VG Ratios for the AU-B Test Series</u>. The AU-B Test Series is composed of the test runs specified below, during which CE and the other parameters as specified in Paragraphs 17-18 will be measured. (FHR shall use the run identifier in brackets to identify each run in all deliverables to EPA. FHR shall state the run number in parenthesis after the run identifier.):

i. S/VG ratio at API 521 Recommended [AU-B-521]
ii. S/VG ratio at Minimum Steam Rates [AU-B-Min.]
iii. S/VG of 1.0 [AU-B-1.0]
iv. S/VG of 2.0 [AU-B-2.0]
v. S/VG of 3.0 [AU-B-3.0]
vi. S/VG of 4.0 [AU-B-4.0]
vii. S/VG of 5.0 [AU-B-5.0]
viii. S/VG of 6.0 [AU-B-6.0]
ix. S/VG resulting in less than 75% CE, if not achieved during any of the preceding test runs. [AU-B-Low CE]
x. S/VG resulting 98% or greater CE, if not achieved during any of the preceding test runs [AU-B-98% CE].

b. <u>Acceptable Range of Vent Gas Flow and Hydrogen Concentration During AU-B Runs</u>. During the AU-B test runs, FHR shall add methane to the vent gas to achieve a total vent gas flow of between 1,750 to 2,250 lb/hr (with a target of 2,000 lb/hr) and with the goal of achieving the lowest hydrogen composition in the vent gas; provided however, that AU-B test runs shall only be undertaken when the hydrogen composition of the vent gas is 15 mol% or less. FHR shall use best efforts to hold the vent gas flow steady during each test run.

12. <u>AU Flare: AU-C Test Series (AU-B Volumetric Flow with a Hydrogen Concentration of 25-35 mol%).</u>

a. <u>S/VG Ratios for the AU-C Test Series</u>. The AU-C Test Series is composed of the test runs specified below, during which CE and the other parameters as specified in Paragraphs 17-18 will be measured. (FHR shall use the run identifier in brackets to identify each run in all deliverables to EPA. FHR shall state the run number in parenthesis after the run identifier.):

i. S/VG ratio at API 521 Recommended [AU-C-521]
ii. S/VG ratio at Minimum Steam Rates [AU-C-Min.]
iii. S/VG of 1.0 [AU-C-1.0]
iv. S/VG of 2.0 [AU-C-2.0]
v. S/VG of 3.0 [AU-C-3.0]
vi. S/VG of 4.0 [AU-C-4.0]
vii. S/VG of 5.0 [AU-C-5.0]
viii. S/VG of 6.0 [AU-C-6.0]

ix. S/VG resulting in less than 75% CE, if not achieved during any of the preceding test runs. [AU-C-Low CE]
x. S/VG resulting 98% or greater CE, if not achieved during any of the preceding test runs [AU-C-98% CE].

b. Acceptable Volumetric Flow and Hydrogen Concentration During AU-C Runs. AU-C test runs shall only be undertaken when the volumetric flow to the flare is as close as possible to the average volumetric flow recorded during the AU-B runs. This volumetric flow shall be achieved by adding a combination of natural gas and hydrogen to the vent gas with goal of achieving a hydrogen concentration of 25-35 mol%. FHR shall make best efforts to hold vent gas flow steady during each test run.

13. AU Flare: AU-D Test Series (AU-B Volumetric Flow with a Hydrogen Concentration of 40-50 mol%).

a. S/VG Ratios for the AU-D Test Series. The AU-D Test Series is composed of the test runs specified below, during which CE and the other parameters as specified in Paragraphs 17-18 will be measured. (FHR shall use the run identifier in brackets to identify each run in all deliverables to EPA. FHR shall state the run number in parenthesis after the run identifier.):

i. S/VG ratio at API 521 Recommended [AU-D-521]
ii. S/VG ratio at Minimum Steam Rates [AU-D-Min.]
iii. S/VG of 1.0 [AU-D-1.0]
iv. S/VG of 2.0 [AU-D-2.0]
v. S/VG of 3.0 [AU-D-3.0]
vi. S/VG of 4.0 [AU-D-4.0]
vii. S/VG of 5.0 [AU-D-5.0]
viii. S/VG of 6.0 [AU-D-6.0]
ix. S/VG resulting in less than 75% CE, if not achieved during any of the preceding test runs. [AU-D-Low CE]
x. S/VG resulting 98% or greater CE, if not achieved during any of the preceding test runs [AU-D-98% CE].

b. Acceptable Volumetric Vent Gas Flow and Hydrogen Concentration During the AU-D Runs. AU-D test runs shall only be undertaken when the volumetric flow to the flare is as close as possible to the average volumetric flow recorded during the AU-B runs. This volumetric flow shall be achieved by adding a combination of natural gas and hydrogen to the vent gas with goal of achieving a hydrogen concentration of 40-50 mol%.

14. LOU Flare: LOU-A Test Series (Base Case).

a. S/VG Ratios for the LOU-A Test Series. The LOU-A Test Series is composed of the test runs specified below. FHR shall test CE and the other parameters set forth in Paragraphs 17-18 synchronized to the LOU Flare's Gas Chromatograph (GC) analysis cycle at each of the following S/VG ratios.

(FHR shall use the run identifier in brackets to identify each run in all deliverables to EPA. FHR shall state the run number in parenthesis after the run identifier.):

i. S/VG ratio at API 521 Recommended [LOU-A-521S]
ii. S/VG ratio at Minimum Steam Rates [LOU-A-Min.]
iii. S/VG of 1.0 [LOU-A-1.0]
iv. S/VG of 2.0 [LOU-A-2.0]
v. S/VG of 3.0 [LOU-A-3.0]
vi. S/VG of 4.0 [LOU-A-4.0]
vii. S/VG of 5.0 [LOU-A-5.0]
viii. S/VG of 6.0 [LOU-A-6.0]
ix. S/VG resulting in less than 75% CE, if not achieved during any of the preceding test runs. [LOU-A-75% CE]
x. S/VG resulting in 98% CE or greater, if not achieved during any of the preceding test runs. [LOU-A-98% CE].

b. Acceptable Range of Vent Gas Flow and Hydrogen Concentration During LOU-A Runs. LOU-A test runs shall only be undertaken when the vent gas flow rate is between 2,500 and 3,500 lb/hr. FHR shall make best efforts to hold vent gas flow steady during each test run. Based on gas chromatograph data recorded in the 24 hours immediately prior to the commencement of the first LOU-A run, FHR shall calculate the average concentration of the hydrogen in the vent gas representative of normal operating conditions. Thereafter, LOU-A test runs shall only be undertaken when the vent gas hydrogen concentration is within 5 mol% (plus or minus) of the average value.

15. LOU: LOU-B Test Series (Base Plus 5,000 lbs/hr Fuel Gas).

a. S/VG Ratios for the LOU-B Test Series. The LOU-B Test Series is composed of the test runs specified below, during which CE and the other parameters as specified in Paragraphs 17-18 will be measured synchronized to the LOU Flare's Gas Chromatograph (GC) analysis cycle at each of the following S/VG ratios. (FHR shall use the run identifier in brackets to identify each run in all deliverables to EPA. FHR shall state the run number in parenthesis after the run identifier.):

i. S/VG ratio at API 521 Recommended [LOU-B-521]
ii. S/VG ratio at Minimum Steam Rates [LOU-B-Min.]
iii. S/VG of 1.0 [LOU-B-1.0]
iv. S/VG of 2.0 [LOU-B-2.0]
v. S/VG of 3.0 [LOU-B-3.0]
vi. S/VG of 4.0 [LOU-B-4.0]
vii. S/VG of 5.0 [LOU-B-5.0]
viii. S/VG of 6.0 [LOU-B-6.0]
ix. S/VG resulting in less than 75% CE, if not achieved during any of the preceding test runs. [AU-B-Low CE]

x. S/VG resulting 98% or greater CE, if not achieved during any of the preceding test runs [AU-B-98% CE].

b. Acceptable Range of Vent Gas Flow and Hydrogen Concentration During LOU-B Runs. LOU-B test runs shall only be undertaken when the vent gas flow rate is between 7,000 and 9,000 lb/hr and the hydrogen concentration is within 5 mol% of the concentration measured prior to the commencement of the LOU-A test series, as set forth in Paragraph 14 above. The vent gas flow rate required during this series shall be achieved by the addition of approximately 5,000 lbs/hr of fuel gas to the base flow of the LOU flare. FHR shall make best efforts to hold vent gas flow steady during each test run.

16. LOU: AOU-C Test Series (Base Plus 10,000 lbs/hr Fuel Gas).

a. S/VG Ratios for the LOU-B Test Series. The LOU-C Test Series is composed of the test runs specified below, during which CE and the other parameters as specified in Paragraphs 17-18 will be measured synchronized to the LOU Flare's Gas Chromatograph (GC) analysis cycle at each of the following S/VG ratios. (FHR shall use the run identifier in brackets to identify each run in all deliverables to EPA. FHR shall state the run number in parenthesis after the run identifier.):

i. S/VG ratio at API 521 Recommended [LOU-C-521]
ii. S/VG ratio at Minimum Steam Rates [LOU-C-Min.]
iii. S/VG of 1.0 [LOU-C-1.0]
iv. S/VG of 2.0 [LOU-C-2.0]
v. S/VG of 3.0 [LOU-C-3.0]
vi. S/VG of 4.0 [LOU-C-4.0]
vii. S/VG of 5.0 [LOU-C-5.0]
viii. S/VG of 6.0 [LOU-C-6.0]
ix. S/VG resulting in less than 75% CE, if not achieved during any of the preceding test runs. [LOU-C-Low CE]
x. S/VG resulting 98% or greater CE, if not achieved during any of the preceding test runs [LOU-C-98% CE].

b. Acceptable Range of Vent Gas Flow and Hydrogen Concentration During LOU-C Runs. LOU-C test runs shall only be undertaken when the vent gas flow rate is between 12,000 and 14,000 lb/hr and the hydrogen concentration is within 5 mol% of the concentration measured prior to the commencement of the LOU-A test series, as set forth in Paragraph 14 above. The vent gas flow rate required during this series shall be achieved by the addition of approximately 10,000 lbs/hr of fuel gas to the base flow of the LOU flare. FHR shall make best efforts to hold vent gas flow steady during each test run.

17. The following sampling and analytical procedures shall be used during all test runs described above:

Test Methods Table	
Component	**Test Methods**
Vent gas (flow and molecular weight), pilot gas, steam	FHR process flow meters and estimates
Carbon dioxide, benzene, toluene, ethyl benzene, xylenes, hydrogen, carbon monoxide, ethane, oxygen, nitrogen, methane, propane, n-butane, i-butane, pentane and higher hydrocarbons, ethylene, propylene, cis- and trans-butenes, 1,3-butadiene, isobutylene in flare vent gas	EPA Method 18 (Direct Interface GC analysis) for the LOU Flare
Benzene, hydrogen, carbon monoxide, ethane, oxygen, nitrogen, methane, propane, n-butane, i-butane, pentane and higher hydrocarbons, ethylene, propylene, cis- and trans-butenes, 1,3-butadiene, acetylene in flare vent gas	EPA Method 18 from bag samples at the AU Flare. Samples shall be taken at the beginning of each test run and at the fifteen minute mark of each test run.
Carbon dioxide, carbon monoxide, total hydrocarbons, individual hydrocarbons (ethane, propane, n-butane, i-butane, pentane and higher hydrocarbons, ethylene, propylene, cis- and trans-butenes, 1,3-butadiene, acetylene) – flare tip hot gas plume	Passive FTIR measurement for AU and LOU Flare

During the test program, in addition to the parameters required by the table above, the following flare operational parameters will be measured or calculated and reported:

Parameter	Unit	Frequency
Vent Gas Volumetric Flow Rate	Scfm	Continuous (once per minute update to data historian)
Vent Gas Mass Flow Rate	lb/hr	Continuous (once per minute update to data historian)
Vent Gas Molecular Weight	lb/lb-mole	Continuous (once per minute update to data historian)
LOU Vent Gas Composition	vol. %	Every 15 min.

Steam Mass Flow Rate	lb/ hr	Continuous (once per minute update to data historian)
Steam Temperature at flow meas. Point	°F	Once per run
Combustion Zone Gas Net Heating Value	Btu/scf	Every 15 min.
Vent Gas Net Heating Value	Btu/scf	Every 15 min.
Actual Total Steam to Vent Gas Ratio	--	Continuous (once per minute update to data historian)
API 521 Steam to Vent Gas Ratio	--	Continuous (once per minute update to data historian)
Actual Total Steam to API 521 Steam Ratio	--	Continuous (once per minute update to data historian)
Hydrocarbon Mass Flow Rate	lb/hr	Every 15 min.
Steam to Hydrocarbon Ratio	--	Every 15 min.
Vent Gas Exit Velocity	Fps	Continuous (once per minute update to data historian)
Combustion Zone Exit Velocity	Fps	Calculated post-run for report, to include center and upper steam
FLIR Camera	--	Continuous

18. Weather conditions will be recorded for all tests. Wind speed and direction will be measured at one (1) minute intervals using the existing facility ambient air monitors. Ambient temperature, barometric pressure, and humidity (dewpoint) will be obtained at one (1) hour intervals from the nearby BPT airport. Precipitation events (i.e. rain, snow, hail, fog, etc); and sky conditions (sunny/cloudy) will be manually logged for each test.

19. FHR shall mobilize two PFTIR instruments. Both instruments shall be available for use at the same flare if necessary due to changes in wind direction. The two

instruments shall be located in positions that maximize the collection of valid data from at least one instrument. During all test runs, FHR shall record images of the flare flame with a FLIR camera and a digital visible spectrum video camera. Both of these cameras shall be co-located with the PFTIR instruments. FHR also shall record the location of the PFTIR measurement spectroscopic field of view within the flare plume, if feasible with the equipment being used. During each run, FHR shall review the video from all cameras to assess whether or not the run is valid.

20. FHR shall synchronize time clocks in DCS, testing equipment, testers watches used to record notes of time, the FLIR Camera, and video camera to the second. FHR shall document such synchronization.

21. FHR shall use best efforts to submit preliminary results in electronic format (editable native Excel format spreadsheet for test and process data and electronic video format for the FLIR and visual camera recordings) in eight (8) day segments, within five (5) days of the close of each eight (8) day segment. FHR shall provide all data required to be recorded during the test on a minute-by-minute basis (where available) as well as an average for each run. Such preliminary results shall include but not be limited to: CE, concentration (measured as ppm-meter) of the measured compounds, and the parameters required to be measured or calculated pursuant to Paragraph 17 (except for the data collected by the FLIR and the digital visible spectrum video camera).

22. Because this test program is being conducted on working chemical plant flares, it is understood that it might not always be possible to maintain stable conditions throughout the duration of a test condition. The flow rates and vent gas composition may change throughout the duration of each test condition run. In order to generate reliable data, FHR shall identify conditions under which the variability of vent gas flow or composition occurring during a test run is large enough to warrant concern over data quality. Therefore, at the end of each test run, FHR shall calculate whether the variability in vent gas flow rate or composition during the test run would have resulted in an S/VG ratio that would be more than 25% different than the S/VG ratio at which the test was conducted. If this is found to be the case, the test condition run shall be repeated once a stable flow rate and composition can be maintained.

23. Steam flow will be controlled differently depending on whether the test condition calls for an API 521 steam rate or a S/VG ratio. When an API 521 steam rate is called for, the instantaneous molecular weight value will be used to calculate the appropriate API 521 ratio.

24. FHR shall use best efforts to submit a Source Test Report consistent with the requirements set forth in Enclosure I in a timely fashion after completion of the field testing. FHR shall describe all assumptions, calculations, and measured data for each calculated value. FHR shall provide all data recorded during the test on shortest averaging period of Passive FTIR measurements in electronic format. FHR shall include in the test report at least the following for each run: CE, concentration (measured as ppm-meter) of the measured compounds, and the parameters required to be measured or calculated pursuant to Paragraph 17 (except for the data collected by the FLIR).

25. EPA is directing testing under specific test conditions requiring varying steam rates and varying amounts of hydrogen to the vent gas that may result in smoking of the flare, reduced efficiency of the flares/control devices and other combustion sources at the site, and releases to the atmosphere. Any federal, state, or local reporting that may be required as a result of the activities and test conditions associated with this use of Passive FTIR spectroscopy measurement technology to measure emissions from the AU Flare and LOU Flare may reference that the associated emissions are due to the specific testing and activities directed by the EPA.

Enclosure III
EPA Section 114 Request to Flint Hills Resources

Confidential Business Information

You may assert a business confidentiality claim covering all or part of the information you provide in response to this information request for any business information entitled to confidential treatment under Section 114(c) of the Clean Air Act (the Act), 42 U.S.C. § 7414, and 40 C.F.R. Part 2, subpart B. Under Section 114(c) of the Act, you are entitled to confidential treatment of information that would divulge methods or processes entitled to protection as trade secrets. Under 40 C.F.R. Part 2, subpart B, business confidentiality means "the concept of trade secrecy and other related legal concepts which give (or may give) a business the right to preserve the confidentiality of business information and to limit its use or disclosure by others in order that the business may obtain or retain business advantages it derives from its rights in the information." See 40 C.F.R. § 2.201(e).

The criteria EPA will use in determining whether material you claim as business confidential is entitled to confidential treatment are set forth at 40 C.F.R. §§ 2.208 and 2.301. These regulations provide, among other things, that you must satisfactorily show that: (1) the information is within the scope of business confidentiality as defined at 40 C.F.R. § 2.201(e), (2) that you have taken reasonable measures to protect the confidentiality of the information and that you intend to continue to do so, (3) the information is not and has not been reasonably obtainable by legitimate means without your consent, and (4) the disclosure of the information is likely to cause substantial harm to your business's competitive edge. See 40 C.F.R. § 2.208 (a)-(d). Emission data, as defined at 40 C.F.R. § 2.301(a)(2), is expressly not entitled to confidential treatment under 40 C.F.R. Part 2, subpart B. See 42 U.S.C. § 7414(c); 40 C.F.R. § 2.301(e).

Information covered by a claim of business confidentiality will be disclosed by EPA only to the extent, and by means of the procedures, set forth in Section 114(c) of the Act and 40 C.F.R. Part 2, subpart B. EPA will construe your failure to furnish a business confidentiality claim with your response to this information request as a waiver of that claim, and the information may be made available to the public without further notice to you.

To assert a business confidentiality claim, you must place on (or attach to) all information you desire to assert as business confidential either a cover sheet, stamped or typed legend, or other suitable form of notice employing language such as "trade secret," "proprietary," or "company confidential" at the time you submit your response to this information request. Allegedly confidential portions of otherwise non-confidential documents should be clearly identified, and may be submitted separately to facilitate identification and handling by EPA. You should indicate if you desire confidential treatment only until a certain date or until the occurrence of a certain event.

In addition, EPA is providing you notice that if you assert a claim of business confidentiality for information you provide in response to this information request, EPA will determine whether such information is entitled to confidential treatment, pursuant to 40 C.F.R. Part 2, subpart B. Accordingly, after EPA's receipt of your business confidentiality claim, you will receive a letter inviting your comments on the following questions:

1. What specific portions of the information are alleged to be entitled to confidential treatment? Specify by page, paragraph, and sentence when identifying the information subject to your claim.

2. For what period of time do you request that the information be maintained as confidential, e.g., until a certain date, until the occurrence of a specified event, or permanently? If the occurrence of a specific event will eliminate the need for confidentiality, specify that event. Additionally, explain why the information should be protected for the time period you've specified.

3. What measures have you taken to protect the information claimed as confidential from undesired disclosure? Have you disclosed the information to anyone other than a governmental body or someone who is bound by an agreement not to disclose the information further? If so, why should the information still be considered confidential?

4. Is the information contained in any publicly available material such as the Internet, publicly available databases, promotional publications, annual reports, or articles? Is there any means by which a member of the public could obtain access to the information? Is the information of a kind that you would customarily not release to the public?

5. Has any governmental body made a determination as to the confidentiality of the information? If so, please attach a copy of the determination.

6. For each category of information claimed as confidential, explain with specificity whether disclosure of the information is likely to result in substantial harm to your competitive position. Explain the specific nature of those harmful effects, why they should be viewed as substantial, and the causal relationship between disclosure and such harmful effects. How could your competitors make use of this information to your detriment?

7. Is there any other explanation you deem relevant to EPA's determination of your business confidentiality claim that is not covered in the preceding questions? If so, you may provide such additional explanation.

See, 40 C.F.R. § 2.204(e)(4). When you receive such a letter, you must provide EPA with a written response within the number of days set forth in the letter. EPA will construe your failure to furnish timely comments as a waiver of your confidentiality claim, consistent with 40 C.F.R. § 2.204(e)(1).

PFTIR Test of Steam-Assisted Elevated Flares – Port Arthur

Final Report
June 17, 2011

Flint Hills Resources Port Arthur, LLC
Port Arthur Chemicals
4241 Savannah Avenue
Port Arthur, Texas 77640

Testing Conducted
October 21 – November 8, 2010

Prepared by
Clean Air Engineering, Inc.
Project No: 11085

Table of Contents

Appendix List

Appendix A.1 – EPA 114 Request
Appendix A.2 – Flare Specifications and Equipment
Appendix A.3 – Calculations
Appendix A.4 – PFTIR Description
Appendix A.5 – PFTIR Theory and Operation
Appendix A.6 – Video Camera Descriptions
Appendix A.7 – Individual Test Series Results and Charts
Appendix A.8 – Individual Test Series Process Conditions
Appendix A.9 – Individual Run Results Data Tables
Appendix A.10 – Individual Run Vent Gas Composition Charts
Appendix A.11 – Wind Data Tables
Appendix A.12 – PFTIR QA/QC
Appendix A.13 – Electronic Minute Data
Appendix A.14 – Electronic PFTIR Raw Spectral Data
Appendix A.15 – Video of Runs
Appendix A.16 – Flare Visual Rating Data Sheets
Appendix A.17 – Independent Source Test Calibration Data
Appendix A.18 – Independent Source Test Gas Certifications
Appendix A.19 – Laboratory Records for AU Sample Bags
Appendix A.20 – Clock Synchronization Forms
Appendix A.21 – Hydrogen Net Heating Value Adjustment

1.0 Overview

1.1 Introduction

As required by a Clean Air Act Section 114 request in Appendix A.1, Flint Hills Resources Port Arthur, LLC (FHR) conducted PFTIR testing of the Aromatics Unit (AU) and Light Olefins Unit (LOU) flares at their facility in Port Arthur, TX, in October and November of 2010. The main objective of the tests was to better understand the impacts of steam on the overall performance of each flare in terms of combustion efficiency (CE). Two additional operating parameters were also examined during this test program. The effect of hydrogen on combustion efficiency was studied on the AU flare. The effect of vent gas flow rate on combustion efficiency was studied on the LOU flare. The PFTIR tests were conducted using a Passive Fourier Transform Infrared Spectroscopy (PFTIR) instrument developed and operated by Industrial Monitor and Control Corporation (IMACC). This report contains the AU and LOU flare test results.

Figure 1.1-1: AU Flare (left) and LOU Flare (right)

The test was conducted with the assistance of both Clean Air Engineering, Inc. (CAE) and Industrial Monitoring and Controls Corporation (IMACC).

Clean Air Engineering, Inc. 500 W Wood St. Palatine, IL 60067	IMACC 800 Paloma, Suite 100 Round Rock, TX 78645

1.2 Test Program Overview

1.2.1 Objectives

The overall objectives of the test program were as follows:

1. Evaluate the impacts of combustion efficiency over a range of operating scenarios by changing both flare vent gas composition and steam rates.
2. Evaluate key operating parameters such as steam to vent gas ratio (S/VG) and Net Heating Value of the Combustion Zone (NHV_{cz}) as indicators that may assist in maintaining flare operation at high efficiency conditions during day-to-day operation.

1.2.2 Flare Components

FHR Port Arthur has two flares: the Aromatics Unit (AU) flare and Light Olefins Unit (LOU) flare. Each flare has automatic steam control logic and equipment that is used during normal operation. This control system was used to set each flare at the required test conditions described in Section 1.2.3. Details of control and measurement equipment used for each flare are contained in Appendix A.2.

1.2.2.1 AU Flare Description

The AU flare is an elevated (120 ft.) steam-assisted flare. The current tip has a diameter of 20 inches and was installed in 1996. This tip was manufactured by Callidus and has two points of steam addition: center steam and ring steam. The center steam is injected in the vent gas stack prior to reaching the flare tip, and the ring steam is injected with nozzles around the flare tip rim. Appendix A.2 contains design specifications for the AU flare.

The AU flare serves as relief for the Aromatics Unit. The typical AU flare vent gas flow rate during normal operation is approximately 800 lb/hr, or less than 0.4% of the hydraulic capacity (approximately a 250:1 turndown factor). Base load includes flare header gas from the Aromatics Unit, seal purges from rotating equipment, sample station vents, and various process vents from process equipment. The flare was operated with a constant center steam of approximately 500 lb/hr and variable ring steam for the AU flare PFTIR test.

1.2.2.2 LOU Flare Description

The LOU flare is an elevated (370 ft.) steam-assisted flare. The current tip has a diameter of 78 inches (equivalent diameter of 54 inches – see Appendix A.2 for calculation) and was installed in June 2010. This tip was manufactured by Callidus and has two points of steam addition: center steam and lower steam. The center steam is injected in the vent gas stack prior to reaching the flare tip, and the lower steam is injected through internal tubes interspersed throughout the flare tip. Appendix A.2 contains design specifications for the LOU flare.

The LOU flare serves as relief for the Light Olefins Unit. The typical LOU flare vent gas flow rate during normal operation is approximately 3,000 lb/hr, or less than 0.3% of the hydraulic capacity (approximately a 333:1 turndown factor). Base load includes flare header gas from the Light Olefins Unit, seal purges from rotating equipment, sample station vents, and various process vents from process equipment. The flare was operated with a constant center steam of approximately 2,890 lb/hr and variable lower steam for the LOU flare PFTIR test.

1.2.3 *Test Conditions*

PFTIR test series were performed on both AU and LOU flares at their base loads. For the AU flare, additional test series were performed to study the effects of hydrogen on steam operating envelopes. For the LOU flare, additional test series were performed to study the effects of increased vent gas flow on steam operating envelopes. Each test series is described in the below sections.

1.2.3.1 AU Test Conditions

Four test series (A, B, C, and D) were conducted by setting a vent gas composition and vent gas flow rate. Within the test series, the steam flow was varied to achieve a range of steam to vent gas ratios on a mass basis (S/VG). The rationale for each test series is as follows:

AU-A	To simulate normal base load with typical flow conditions for the flare. This test represented day-to-day operation. Vent gas flow was between 600 lb/hr and 1,100 lb/hr, with a best effort to maintain the flow between 700 lb/hr and 1,000 lb/hr.
AU-B	To simulate a vent gas composition with low hydrogen content. This test added additional natural gas to the base load to bring the total flow up to between 1,750 lb/hr and 2,250 lb/hr. Hydrogen content in the vent gas was below 15% by volume.
AU-C	To simulate a vent gas composition with medium hydrogen content. This test added additional natural gas and hydrogen to the base load to bring the total flow up to match the volumetric flow rate of AU-B. Hydrogen content in the vent gas was between 25% and 35% by volume.
AU-D	To simulate a vent gas composition with high hydrogen content. This test added additional natural gas and hydrogen to the base load to bring the total flow up to match the volumetric flow rate of AU-B. Hydrogen content in the vent gas was between 40% and 50% by volume.

Because the AU flare vent gas header did not have a gas chromatograph installed, vent gas sample bags were collected twice for each run and analyzed by the on-site FHR laboratory for vent gas composition. The sample bag analysis was corrected to 0% oxygen for the final vent gas composition results.

1.2.3.2 LOU Test Conditions

Three test series (A, B, and C) were conducted by setting a vent gas flow rate. Within the test series, the steam flow was varied to achieve a range of steam to vent gas ratios (S/VG). The rationale for each test series is as follows:

LOU-A	To simulate normal base load with typical flow conditions for the flare. This test represented day-to-day operation. Vent gas flow was between 2,500 lb/hr and 3,500 lb/hr.
LOU-B	To simulate an increase in vent gas flow. This test added an additional 5,000 lb/hr of fuel gas to the base load. A best effort was made to maintain the hydrogen content of the vent gas so that it did not vary by more than 5% by volume (absolute) from LOU-A.
LOU-C	To simulate a further increase in vent gas flow. This test added an additional 10,000 lb/hr of fuel gas to the base load. A best effort was made to maintain the hydrogen content of the vent gas so that it did not vary by more than 5% by volume (absolute) from LOU-A.

1.2.3.3 Run Lengths and Replicates

Each test series had several runs that were performed at set steam to vent gas ratios on a mass basis (S/VG). Each run was repeated at least once. If the absolute difference in on-site preliminary combustion efficiency results for the two replicates was more than 5% and the average combustion efficiency was greater than 85%, a third replicate run would be performed. Additionally, at least 15 valid data points (as determined by CleanAir and IMACC site personnel from on-site preliminary data) were required to constitute a valid run.

The length for all initial replicate runs at a given condition was 30 minutes. At the conclusion of the initial run, the data was divided into 10-minute segments and analyzed. If none of the segment average combustion efficiencies varied from the 30 minute average by more than 0.5% absolute, the run length for the second replicate could be shortened to 20 minutes.

The S/VG set point for each set of replicate runs was incremented from the minimum or API 521 recommended steam rate using whole number S/VG steps to the incipient snuff point. If the S/VG set point resulted in visible emissions, the run would be discontinued after three minutes of Method 22 visible emissions.

1.3 PFTIR Testing Description

The IMACC instrument used to determine gas composition of the flare plume for each test condition listed in Section 1.2.3 is the Passive Fourier Transform Infrared (PFTIR) analyzer. PFTIR analysis operates on the principle of spectral analysis of thermal radiation emitted by hot gases. Passive means that no "active" infrared light source is used. Instead, the hot gases of the flare are the infrared source. The spectrometer is a receiver only. This approach is possible because the infrared emission spectra of hot gases have the same patterns or "fingerprints" as their absorption spectra do. Consequently, observing a flare with an infrared instrument allows for identification and quantification of species through emission spectroscopy just as with absorption spectroscopy. A detailed description of the instrument and testing procedure are found in Appendix A.4.

1.3.1 PFTIR Locations

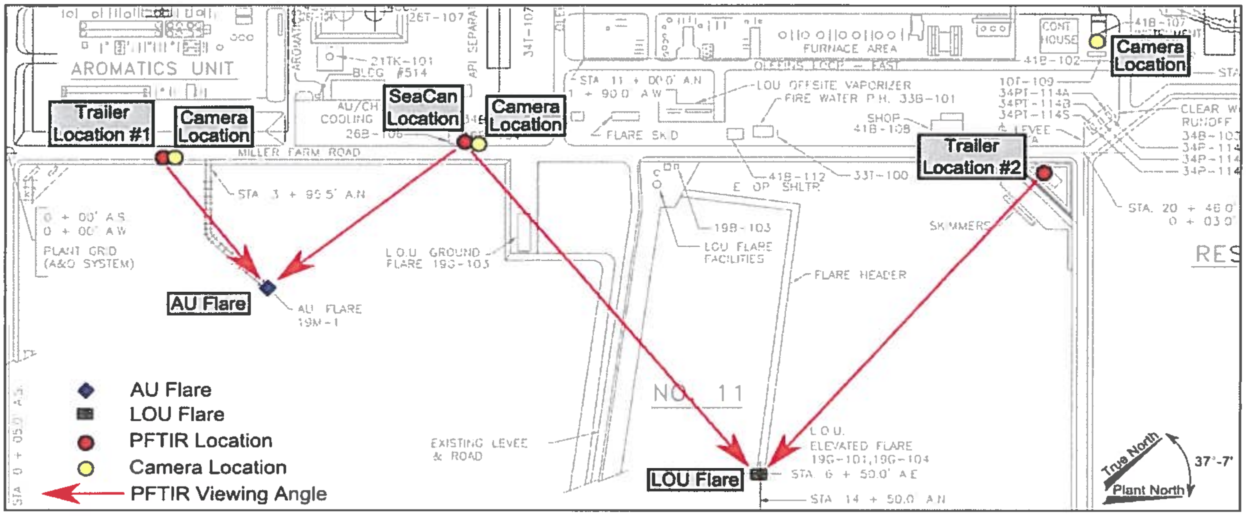
Two PFTIR instruments were used for this test program. They were placed at approximately 90° from one another in order to ensure a good view of the flare plume regardless of wind direction.

For the AU flare tests, one PFTIR location was inside a portable SeaCan container by the fenceline monitoring building ("SeaCan location"), and the second location was in a trailer on Miller Farm road ("Trailer location 1"). The Trailer location equipment was controlled from the SeaCan location via fiber optic and Ethernet cables. This allowed both PFTIRs to collect data during a run for simultaneous readings. However, only some runs had simultaneous readings due to wind and calibration restrictions.

For the LOU flare tests, the PFTIR at the SeaCan location was used, and the Trailer location was moved to the opposite end of Miller Farm road ("Trailer location 2"). The two locations were not connected by cable, so only one location could be controlled at a time. Thus, simultaneous readings were not performed for the LOU flare test.

Figure 1.3-1 shows a map of the PFTIR locations in relation to the flare. The PFTIR at the trailer locations (serial number "H") was mounted inside the rear of the trailer. The PFTIR at the SeaCan location (serial number "A") was mounted on a tripod and placed at the road location. Appendix A.4 contains more detailed information about each location.

Figure 1.3-1: Map of PFTIR Locations in Relation to AU and LOU Flares



1.3.2 Video Recordings

During the test program, video cameras recorded flare activity from the SeaCan and Trailer locations. At each location, one stationary visible light camera and one stationary infrared light camera were recording the flare tip. Additionally, one infrared camera was mounted on each PFTIR and recorded the aiming position of each PFTIR. For the Trailer location during the LOU test ("Trailer location 2"), the stationary visible and infrared cameras were located on the roof of the LOU control room. The types of cameras used during the test program are listed in Appendix A.6.

1.3.3 Preliminary Results and QA/QC

On-site preliminary combustion efficiency results were computed. On-site replicate and run length decisions were made with the preliminary combustion efficiency results. By design, these preliminary results did not take into account the sky backgrounds, compound lists, and interferents that are incorporated after the test program is complete (see Appendix A.4). Thus, the final combustion efficiency results may change when all fraction are included in the analysis.

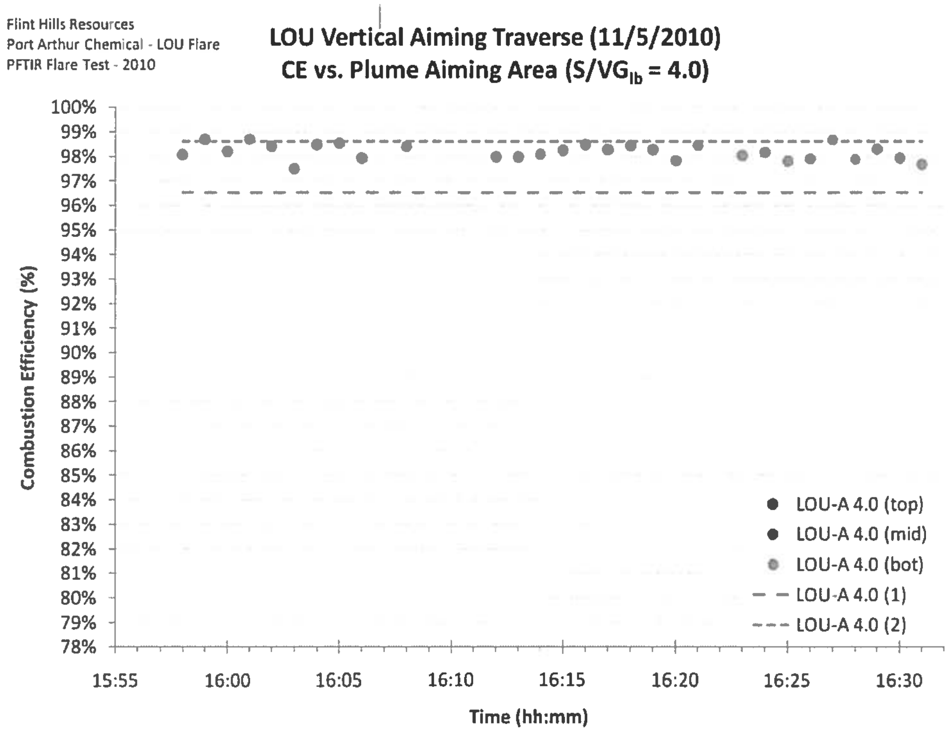
To ensure useable combustion efficiency results from the PFTIR, several QA/QC tests were performed during the test program. These tests included an independent source test, simultaneous measurements, and vertical traverses. Appendix A.12 contains data from these QA/QC tests.

1.3.4 Vertical Traverse

In selecting an aiming point for the PFTIR near the center of the flare plume, an assumption is made that the combustion efficiency at this location is representative of the overall combustion efficiency of the flare. In order to test this assumption, a separate vertical traverse of the plume was conducted along with the LOU A 4.0 test series. Measurements were made at the top, the middle, and the bottom of the plume. This traverse was conducted under high wind conditions that would maximize the possibility of combustion efficiency stratification in the plume (i.e., higher combustion efficiency at the edges of the plume and lower combustion efficiency in the center.)

Details of the traverse are found in Appendix Section A.12.3. Figure 1.3-2 shows the results of the traverse. Note that regardless of whether the PFTIR measures at the top, the middle, or the bottom of the plume, the combustion efficiency is essentially constant.

Figure 1.3-2: Vertical Traverse Results



2.0 Results

For results presented in this section, relationships between combustion efficiency and three operating parameters were analyzed:

- **Visual Rating** – Flare flame visual emission readings (1-10 scale)
- **S/VG** – Actual steam to vent gas ratio (lb steam/lb vent gas)
- **NHV_{cz}** – Net heating value of the combustion zone (BTU/scf)

These parameters were selected because they can potentially be used during normal flare operation to maintain high combustion efficiency. Analysis of the combustion efficiency results from the PFTIR during this test established a relationship between combustion efficiency and these parameters. Descriptions of calculations for these parameters are contained in Appendix A.3. Appendix A.7 contains tables and charts of completed runs based on the requirements of the 114 Request. Appendices A.7 through A.11 also contain detailed condition and run information for each test.

2.1 Visual Rating

Visual ratings can be performed quickly and easily by flare operators without specialized equipment or instruments. Visual observations are an effective tool to be used in conjunction with the other operating parameters S/VG and NHV_{cz}. A relationship between combustion efficiency and visual rating may help an operator identify desirable flare operating conditions. However, this parameter is limited in that flare combustion efficiency is not easily determined when the flare flame is transparent.

Flare visual readings were collected during the test program using the scale established for the PFTIR test. Table 2.1-1 describes the flare visual rating scale.

The incipient smoke point is designated as the number 5 (the center of the scale), and represents the point at which the flare displays a "marbled" texture, indicative of small carbon soot particles forming in the combustion zone but quickly dissipating. No visible soot particles are present outside of the flame boundary at the incipient smoke point.

Flame ratings above 5 indicate increasing visible emissions extending beyond the flame boundary observed by an increasingly distinct trailing smoke plume. Flame ratings less than 5 indicate a visible flame decreasing in intensity until it becomes transparent. Ratings of 2 to 4 indicate a visible flame and a rating of 1 indicates a transparent flame. A flame rating of 0 indicates that the flare may be extinguished with steam visually present.

Table 2.1-1: Flare Visual Rating Scale

Flame Rating	Flame Characteristic
0	Steam plume
1	Transparent
2	Mostly transparent, with occasional yellow flame.
3	Mostly yellow flame, with occasional transparency.
4	Yellow to orange flame.
5	Orange flame with some dark areas in the flame. (Incipient smoke point)
6	Orange flame with light smoke trail.
7	Clear steam at the flare tip, with an orange flame and a light smoke trail.
8	Orange flame with dark smoke trail leaving the flame.
9	Orange flame with heavy dark smoke trail leaving the flame.
10	Billowing black smoke

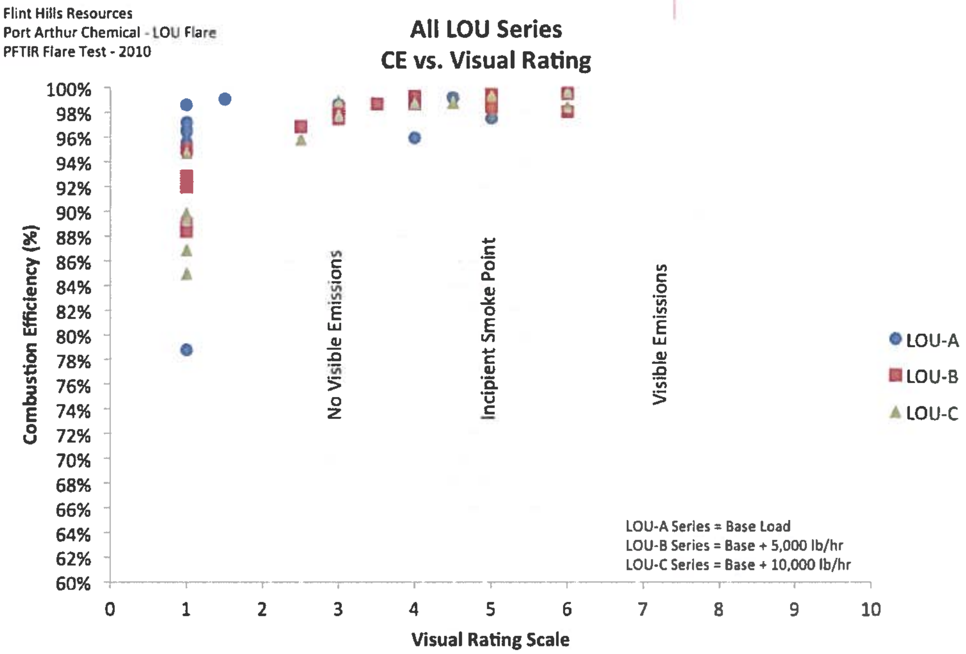
For the AU and LOU test programs, a FHR Port Arthur contractor recorded visual readings during each run using the flame rating scale. When the flare flame began consistently smoking (a rating of 6.0), the visual reader would alert the flare test control room and the run would be halted after 3 minutes of continuous visual emissions.

Figure 2.1-1 shows the relationship between combustion efficiency and visual rating for all runs in the AU flare tests. Most of the runs performed in the AU flare tests had transparent flames and low visual ratings.

Figure 2.1-2 shows the relationship between combustion efficiency and visual rating for all runs in the LOU flare tests. Like the AU flare tests, most of the runs performed in the LOU flare tests had transparent flames and low visual ratings.

Figure 2.1-1: CE vs. Visual Rating for AU Flare Tests

Figure 2.1-2: CE vs. Visual Rating for LOU Flare Tests



2.2 Steam to Vent Gas Ratio

S/VG can be used in control logic for maintaining smokeless combustion. Establishing a relationship between S/VG and combustion efficiency enables flare operators to better program steam control logic to improve combustion efficiency. However, S/VG alone may have limitations in its relationship to combustion efficiency. For example, a vent gas stream with high concentrations of inerts in the vent gas will not follow the same S/VG vs. combustion efficiency relationship as a vent gas stream with low concentrations of inerts.

PFTIR test runs for the AU and LOU flares were conducted at set steam to vent gas ratios (S/VG) on a mass basis (lb/lb). The S/VG set points for each run were established prior to the test by the 114 Request found in Appendix A.1. Figures showing S/VG ratios on a volumetric basis (scf/scf) are also included for comparison

For the AU flare base load (AU-A), low hydrogen (AU-B), mid hydrogen (AU-C), and high hydrogen (AU-D) test series, steam flow was increased from the point of incipient smoke to a point just before snuffing the flare (incipient snuff). For these test series, combustion efficiency remained relatively constant at a high level until the S/VG reached a point after which, combustion efficiency declined with increasing steam.

A mixture of hydrogen balanced with natural gas was added to the base load to achieve the desired hydrogen content (by volume) for the variable hydrogen tests. All of the variable hydrogen tests were performed at approximately the same volumetric flow rate. The vent gas for AU-B was less than 15% hydrogen content. The vent gas for AU-C had a hydrogen content between 25% and 35%. The vent gas for AU-D had hydrogen content between 40% and 50%. The increased hydrogen content appears to reduce the rate of combustion efficiency decline. Figure 2.2-1 shows this trend on a mass basis. Figure 2.2-3 shows this trend on a volumetric basis (scf/scf) for comparison.

For the LOU flare base load (LOU-A), mid flow (LOU-B), and high flow (LOU-C) series, steam flow was increased from the point of incipient smoke to a point just before snuffing the flare (incipient snuff). Like the AU flare results, combustion efficiency for the LOU flare remained relatively constant at a high level until the S/VG reached a point after which, combustion efficiency declined with increasing steam.

The LOU-B test series added an additional 5,000 lb/hr of fuel gas to the base load rate (3,000 lb/hr). Fuel gas was used because its hydrogen and methane content are similar to the LOU vent gas. The LOU-C test series added an additional 10,000 lb/hr of fuel gas to the base load rate. The rate of combustion efficiency decline seemed to increase slightly with increased vent gas flow. Figure 2.2-2 shows this trend on a mass basis. Figure 2.2-4 shows this trend on a volumetric basis (scf/scf) for comparison.

Figure 2.2-1: Combustion Efficiency vs. S/VG (lb/lb): AU-A,B,C,D

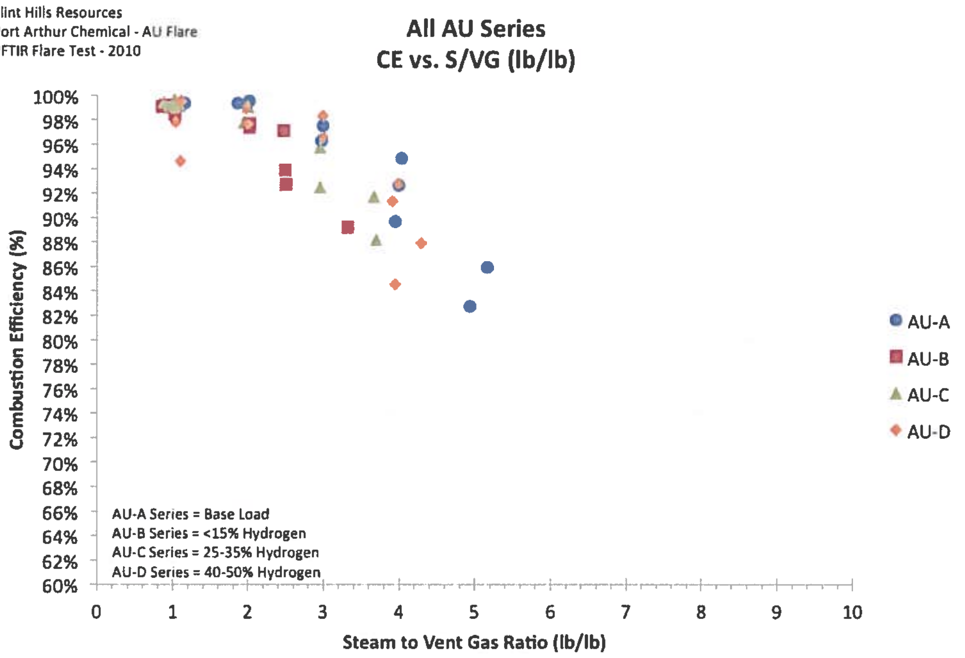


Figure 2.2-2: Combustion Efficiency vs. S/VG (lb/lb): LOU-A,B,C

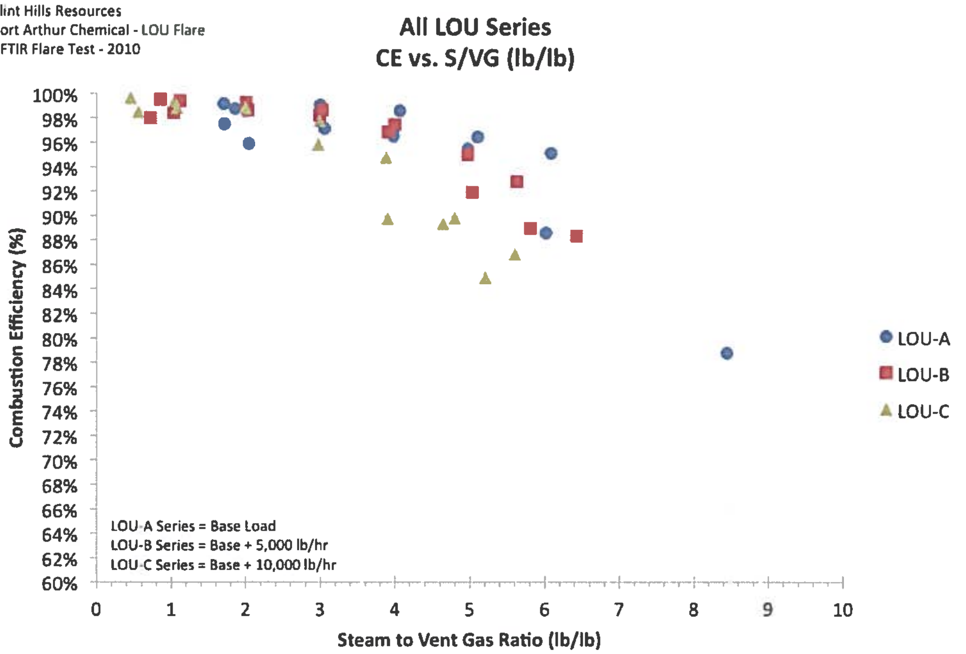


Figure 2.2-3: Combustion Efficiency vs. S/VG (scf/scf): AU-A,B,C,D

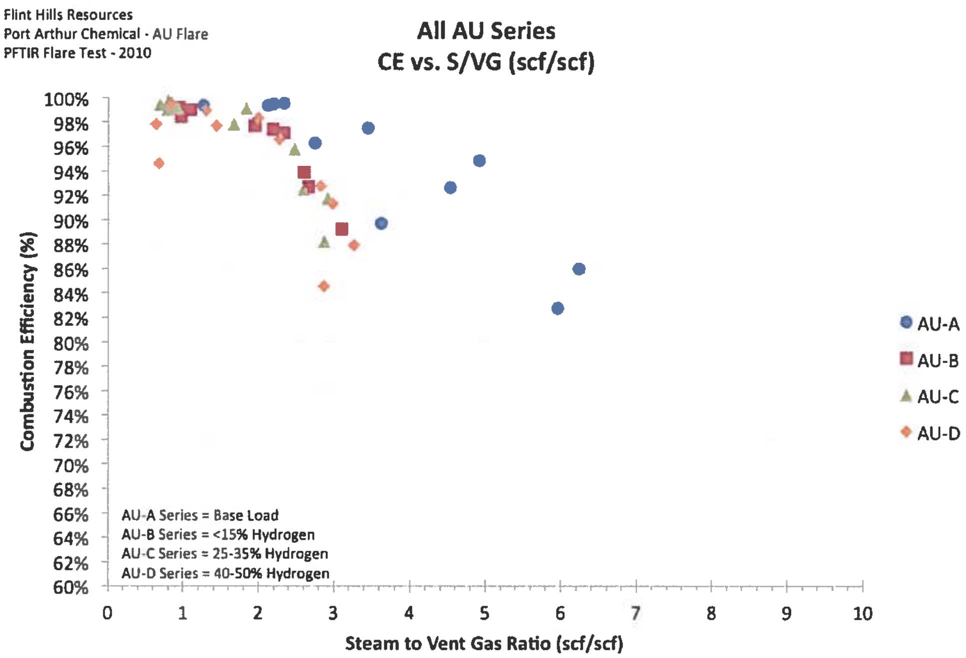
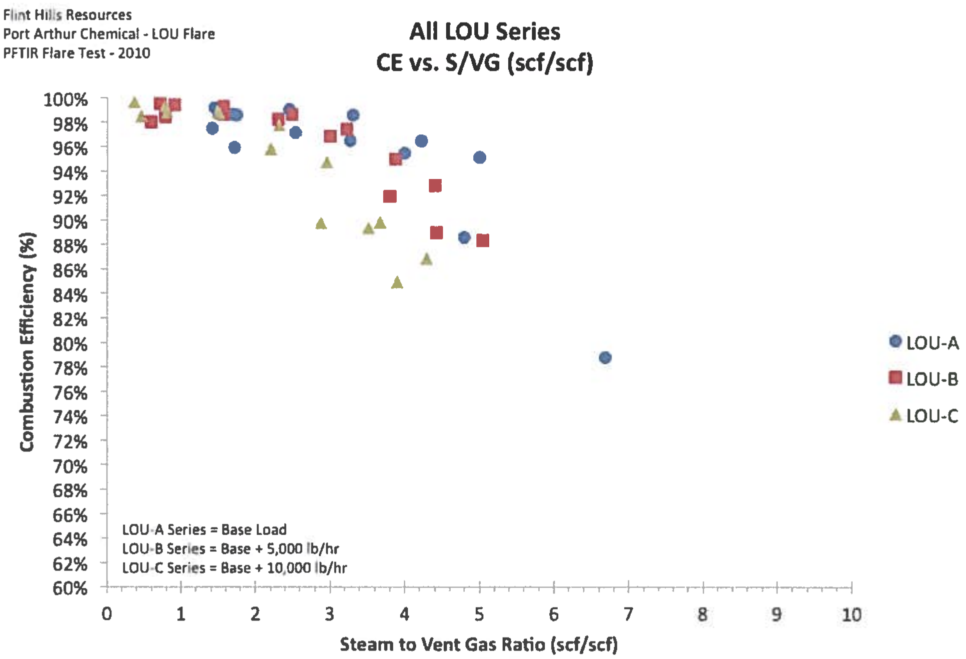


Figure 2.2-4: Combustion Efficiency vs. S/VG (scf/scf): LOU-A,B,C



2.3 Net Heating Value of the Combustion Zone

NHV_{cz} is another parameter that could be used to assist control of normal flare operation. The relationship between NHV_{cz} and combustion efficiency has a wider scope and can take into account more process variables. For example, inerts in the vent gas are taken into account for the NHV_{cz} calculation so the relationship to combustion efficiency remains valid when inerts are variable in the vent gas. However, NHV_{cz} requires the flare operator to measure vent gas composition, which may require new equipment be installed on the vent header. Because the vent gas composition may only be measured in 10+ minute increments it also may be difficult to use NHV_{cz} alone for control.

The Net Heating Value of the Combustion Zone (NHV_{cz}) , which includes total steam to the flare tip, is a calculated term representing the net heating value of all components in the combustion zone. The combustion zone is directly above the flare tip and is the point at which all materials combine for combustion. The NHV_{cz} is therefore the resultant heat content from the mixture of the vent gas from the flare header, the pilot gas, and the total steam. To compensate for the observed effects of hydrogen, an adjusted NHV_{cz} was calculated assuming hydrogen to have a net heating value of 1,212 BTU/scf instead of the unadjusted net heating value of 275 BTU/scf. For a more detailed discussion regarding the hydrogen adjusted $NHV_{cz,}$ calculation and value, see Appendix A.21.

Figure 2.3-1 shows the relationship between combustion efficiency and adjusted NHV_{cz} for the AU flare tests.

Figure 2.3-2 shows the relationship between combustion efficiency and NHV_{cz} for the LOU flare tests.

The adjusted NHV_{cz} appears to compensate well for the effects of hydrogen on combustion efficiency decline. When a hydrogen net heating value of 1,212 BTU/scf is used, the adjusted NHV_{cz} trends for the AU hydrogen test series (AU-B,C,D) shift into closer alignment. Figure 2.3-3 shows this shift from unadjusted NHV_{cz} to adjusted NHV_{cz} for the AU hydrogen tests.

The adjusted NHV_{cz} does not compensate for the effects of vent gas flow rate on combustion efficiency decline. Figure 2.3-4 shows this shift from unadjusted NHV_{cz} to adjusted NHV_{cz} for the LOU tests.

Figure 2.3-1: Combustion Efficiency vs. Adjusted NHV$_{cz}$: AU-A,B,C,D

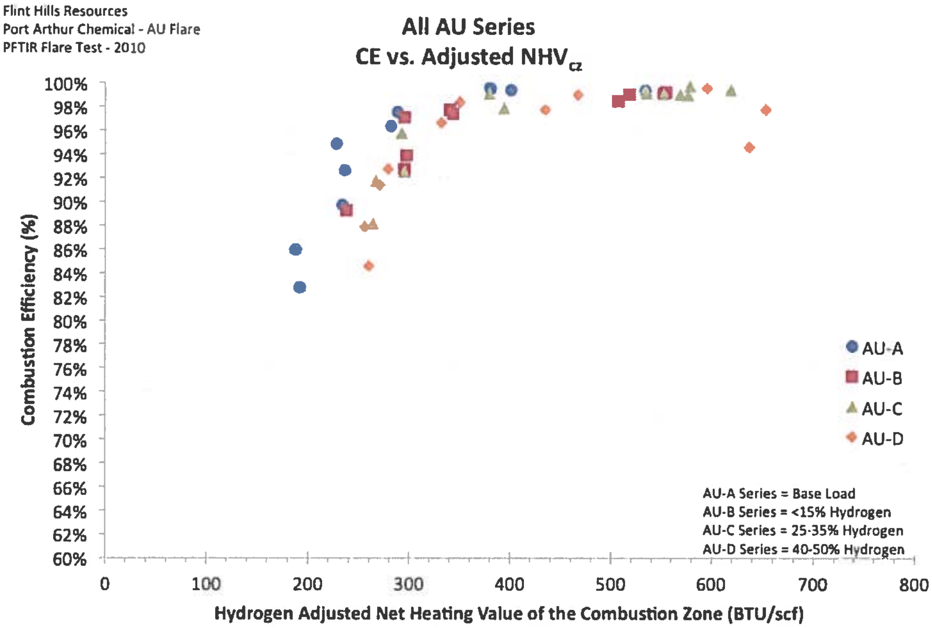


Figure 2.3-2: Combustion Efficiency vs. Adjusted NHV$_{cz}$: LOU-A,B,C

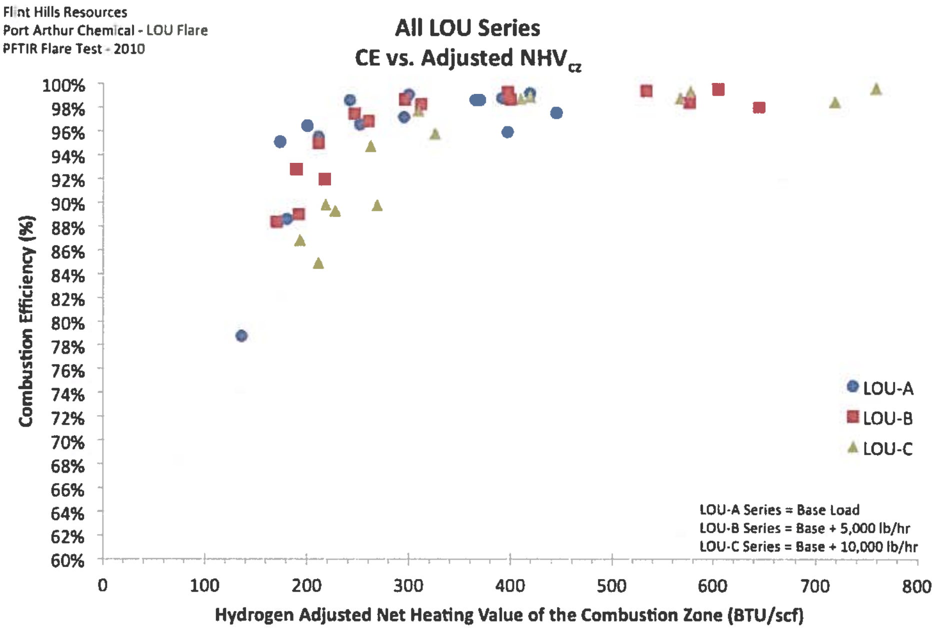


Figure 2.3-3: Adjusted/Unadjusted NHV_{cz} Comparison: AU-B,C,D

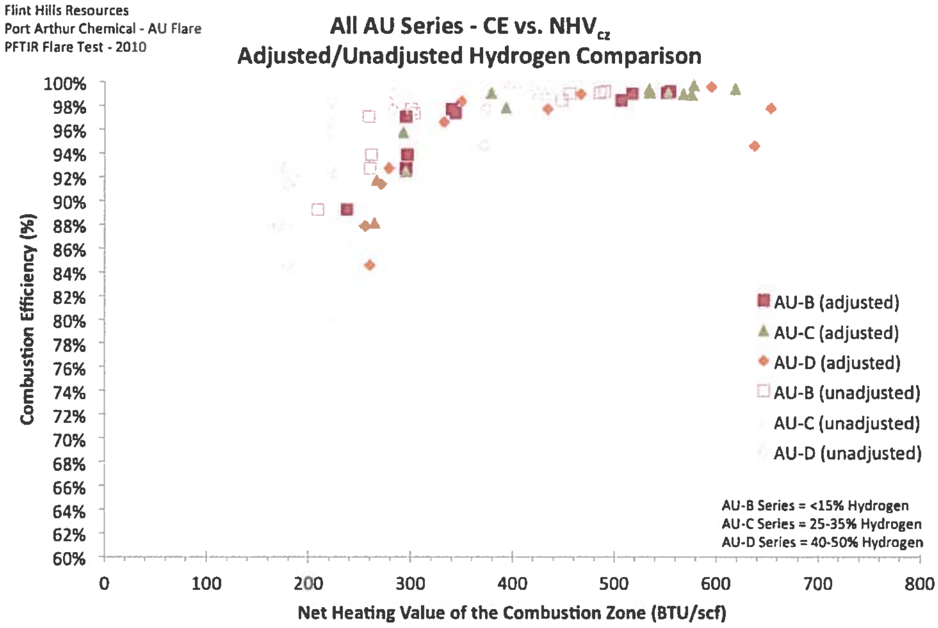
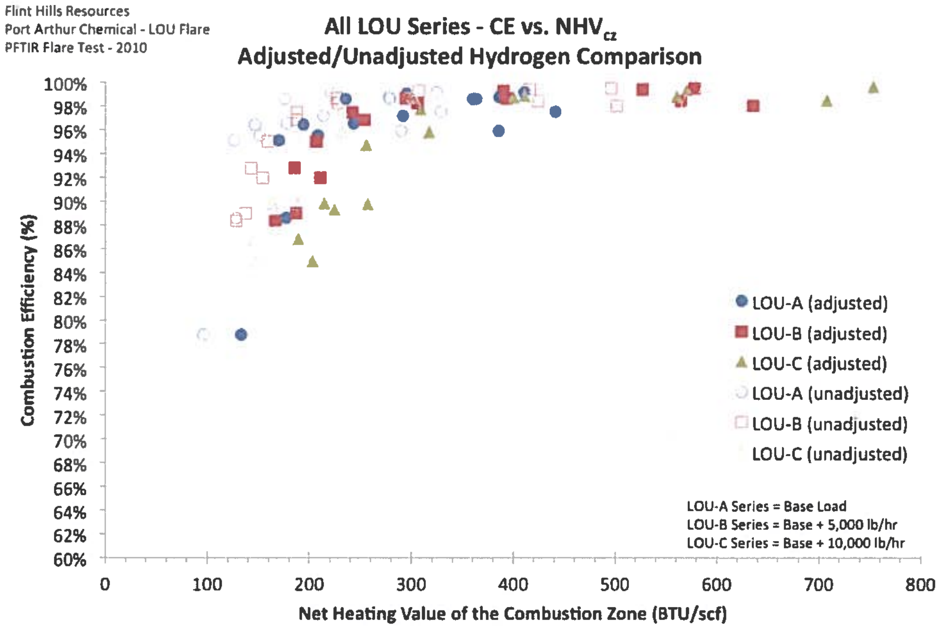


Figure 2.3-4: Adjusted/Unadjusted NHV_{cz} Comparison: LOU-A,B,C



3.0 Conclusions

The PFTIR test of the AU and LOU flares at the FHR Port Arthur chemical plant provided data to support the following conclusions.

Overall Observations

General

- The data shows that both the AU and LOU flares exhibit a fairly broad high efficiency operating range that is consistent with current and past flare operating practices.
- Each of the three approaches to manage combustion efficiency (visibility, S/VG, and NHVcz) have advantages and disadvantages. Using a combination of these approaches will likely result in the most effective overall flare control strategy.

Visiblity

- Combustion efficiency generally begins to decline once the flame transitions from a smokeless, visible flame to one that is transparent. However, depending on the vent gas composition, not all transparent flames have poor combustion efficiency. This is most evident on the LOU flare results which contain a high hydrogen, high methane composition vent gas.
- A visible orange flame generally indicates good combustion efficiency.

S/VG

- Once adequate steam is supplied to prevent smoking, combustion efficiency generally declines with increased S/VG during normal and higher flow operations.
- Combustion efficiency will decline more rapidly with increased steam to vent gas ratios on a mass basis when the vent gas flow rate increases.

NHVcz

- The characteristics of hydrogen combustion are different than those of hydrocarbon combustion.
- Adjusting the net heating value of hydrogen from 275 BTU/scf to 1,212 BTU/scf more closely reflects the true combustion characteristics of hydrogen.
- Adjusting the net heating value of hydrogen brings the combustion efficiency trend lines into closer alignment when calculating the net heating value of the combustion zone.

Garwood, Gerri

From:	Josh Nall <josh.nall@wyo.gov>
Sent:	Thursday, December 18, 2014 11:47 AM
To:	RefineryFactor
Cc:	Garwood, Gerri
Subject:	Comment letter from Wyoming DEQ
Attachments:	RefineryFlareNOx_WDEQcomments.pdf; RefineryFlareNOx_WDEQcomments.pdf

I have attached a letter with our comments on the Proposed New and Revised Emission Factors for Flares. Please let me know if you need any more information from me. Thank you, Josh

James (Josh) Nall
NSR Permitting Supervisor
Wyoming Dept. of Environmental Quality – Air Quality Division
122 W. 25th Street
Cheyenne, WY 82002
(307) 777-7816

Garwood, Gerri

From: Josh Nall <josh.nall@wyo.gov>
Sent: Thursday, December 18, 2014 11:49 AM
To: RefineryFactor
Cc: Garwood, Gerri
Subject: Re: Comment letter from Wyoming DEQ

For clarification, I inadvertently attached our comment letter twice. The two attachments to our e-mail are identical. Thanks, Josh.

James (Josh) Nall
NSR Permitting Supervisor
Wyoming Dept. of Environmental Quality – Air Quality Division
122 W. 25th Street
Cheyenne, WY 82002
(307) 777-7816

On Thu, Dec 18, 2014 at 9:46 AM, Josh Nall <josh.nall@wyo.gov> wrote:

> I have attached a letter with our comments on the Proposed New and Revised Emission Factors for Flares. Please let me know if you need any more information from me. Thank you, Josh
>
> James (Josh) Nall
> NSR Permitting Supervisor
> Wyoming Dept. of Environmental Quality – Air Quality Division
> 122 W. 25th Street
> Cheyenne, WY 82002
> (307) 777-7816

Department of Environmental Quality

To protect, conserve and enhance the quality of Wyoming's

environment for the benefit of current and future generations.

Matthew H. Mead, Governor

Todd Parfitt, Director

December 19, 2014

Via e-mail
U.S. Environmental Protection Agency
refineryfactor@epa.gov

Attention: Gerri Garwood

Re: Proposed New and Revised Emission Factors for Flares

The Wyoming Department of Environmental Quality (WDEQ) appreciates the opportunity to comment on the Environmental Protection Agency's (EPA's) proposed new and revised emission factors for flares for Section 13.5 of AP-42.

WDEQ has reviewed the data utilized in the analysis for revising the emission factors for flares and has concerns about the revised NO_x emission factor given the limited data pool. EPA should conduct a more thorough analysis that includes a larger data set than the six (6) sources used in the analysis. This small sample size does not adequately categorize emissions from the various types of flares being represented by the emission factor. Differences in flare design and Btu content of fuels used in the flares is not considered. Specifically, the data from the Port Arthur refinery appears to represent an outlier that skews the results significantly. However, EPA determined that the data was not an outlier and, as a result of including this data point, increased the proposed NO_x emission factor by more than 40 times over the existing emission factor.

WDEQ has concerns about the far-reaching implications that could arise due to such an extreme and unsubstantiated change in the NO_x emission factor. These implications include, but are not limited to, significant changes in emissions inventories, permitting for Prevention of Significant Deterioration and Non-Attainment New Source Review, as well as determining compliance with the 1-hour NO_2 National Ambient Air Quality Standard using dispersion models.

In summary, the EPA should reevaluate the proposed emission factor for NO_x by conducting or considering more extensive emissions testing on various types of flares. The EPA should consider various types of flare designs and the Btu contents of fuels that are burned by the flares to arrive at more appropriate NO_x emission factors for this important source category.

Thank you again for the opportunity to provide comment on this proposal. Please feel free to contact this office at (307) 777-7391 should you have any questions regarding these comments.

Sincerely,

Steven A. Dietrich

Steven A. Dietrich, P.E.
Air Quality Division Administrator

Herschler Building · 122 West 25th Street · Cheyenne, WY 82002 · http://deq.state.wy.us

ADMIN/OUTREACH	ABANDONED MINES	AIR QUALITY	INDUSTRIAL SITING	LAND QUALITY	SOLID & HAZ. WASTE	WATER QUALITY
(307) 777-7758	(307) 777-6145	(307) 777-7391	(307) 777-7369	(307) 777-7756	(307) 777-7752	(307) 777-7781
FAX 777-7682	FAX 777-6462	FAX 777-5616	FAX 777-5973	FAX 777-5864	FAX 777-5973	FAX 777-5973

Garwood, Gerri

From: Ulrich, Elizabeth <EUlrich2@mt.gov>
Sent: Thursday, December 18, 2014 5:49 PM
To: RefineryFactor
Cc: hrash@mt.gov; Merchant, Eric
Subject: Proposed AP-42 Emission Factor Comments
Attachments: AP-42_NOx_Comments 12-19-14.pdf

To Whom It May Concern,

The Montana Department of Environmental Quality is submitting the attached comments regarding the United States of Environmental Protection Agency's proposed revision of AP-42 Compilation of Air Pollutant Emission Factors.

Thank you in advance for considering our comments,

Liz Ulrich
Air Quality Planner & County Coordinator
Air Resources Management Bureau
Montana Department of Environmental Quality
(406) 444-9741

Montana Department of
ENVIRONMENTAL QUALITY

Steve Bullock, Governor
Tom Livers. Director

P. O. Box 200901 Helena, MT 59620-0901 (406) 444-2544 Website: www.deq.mt.gov

December 19, 2014

Comments Submitted Via Email: refineryfactor@epa.gov
U.S. Environmental Protection Agency

Re: EPA's Proposed New and Revised Emission Factors for AP-42 Section 13.5 Industrial Flares

To Whom It May Concern:

The Montana Department of Environmental Quality (DEQ) has reviewed and evaluated the U.S. Environmental Protection Agency's (EPA) proposed revision of AP-42 Compilation of Air Pollutant Emission Factors, Chapter 13: Miscellaneous Sources, Section 13.5 Industrial Flares. The DEQ appreciates the public comment period extension and is submitting the attached comments on EPA's proposed emission factors for flare operations.

The subject AP-42 emission factors are used to estimate emissions from flares for purposes of rulemaking, air quality permitting, emission inventory reporting, and compliance monitoring, and as such changes to the emission factors may result in significant regulatory impacts. Therefore, DEQ requests that EPA reevaluate the proposed emission factors to ensure they are supported with data that is scientifically sound and appropriate for the intended end use.

If you have any questions regarding these comments, please contact me as listed below.

Sincerely,

Hoby Rash

Hoby Rash
Air Permitting Compliance & Registration Program Manager
Air Resources Management Bureau
(406) 444-0055
(406) 444-1499 – fax
hrash@mt.gov

Comments on
EPA's Proposed New and Revised Emission Factors for
AP-42 Section 13.5 Industrial Flares

Submitted by the Montana Department of Environmental Quality
Air Resources Management Bureau

I. Background

The United States Environmental Protection Agency (EPA) is required to review, and if necessary, revise emission factors used to estimate the quantity of emissions of carbon monoxide (CO), volatile organic compounds (VOC), and oxides of nitrogen (NOx) from sources of such air pollutants at least every 3 years, according to 42 U.S. Code §7430. Due to EPA's failure to review the emission factors for VOC, CO, and NOx for flares, liquid storage tanks, and wastewater collection treatment and storage systems, EPA entered into a consent decree stipulating that they would review emission factors, and either revise them or determine that revision of the emission factors is not necessary. Following EPA's review of the data referenced in litigation, they determined that the data was not adequate to allow for revisions to existing emissions estimation methods for tanks and wastewater treatment systems. EPA has proposed revisions to the VOC, CO and NOx emission factors for flares.

The Montana Department of Environmental Quality (DEQ) is concerned that the data used to develop the proposed NOx emission factor is very limited, scientifically unsound, and may have a significant impact on the industry sectors that utilize AP-42 Section 13.5 emission factors, but were not represented in the data utilized to develop the proposed emission factor.

II. Comments

A. Concern with data quality

The studies used to develop the proposed emission factors were conducted to assess a flare's combustion efficiency and were not intended for use in developing emission factors. The facility operating conditions do not represent normal flare performance, but rather are used to determine conditions that result in poor flare combustion efficiencies.

The second concern DEQ has with data quality is specific to the proposed emission factor for NOx. It is based on data from five flares, with a wide range of resulting emission factors. We are concerned whether or not these studies provide representative data for their intended use. For example, the average test result for NOx from the Flint Hills Resources Port Arthur facility (16 lb/MMBtu) is substantially larger (27 times) than any other emission factor evaluated and more than 235 times greater than the current NOx emission factor of 0.068 lb/MMBtu. This appears to be an outlier and significantly skews the resulting proposed emission factor. EPA's proposed emission factor gives equal weight to each of the five studies and the current emission factor which results in the proposed factor of 2.9 lb/MMBTU, an increase of more than 43 times the current AP-42 NOx emission factor.

Interestingly, if the emission factor from the Flint Hills Resources Port Arthur refinery was discarded, the resulting emission factor would be 0.252 lb/MMBtu, approximately four times greater than the current NOx emission factor. An increase of almost four times seems much more reasonable than an increase of 43 times. It is very concerning that one data point used to develop an emission factor for several types of industrial flares could have such a significant impact.

B. Lack of flare subcategories

There are two types of flares represented in the emissions test reports for NOx, steam-assisted and air-assisted. There are other subcategories that should have been considered, such as type of flare and type of heat input. Not only are there steam- and air-assisted flares there are also unassisted and combined air- and steam-assisted. The reported emission tests represent flares with low BTU content (less than 1,000 BTU/SCF), flares with high BTU content were not considered. The subcategories represented in the proposed NOx emission factor do not represent the many types of sources that use AP-42 section 13.5 as a guide. The proposed NOx emission factor should be used only for relevant industries and not as a general "all inclusive" factor.

C. Implications for regulated entities

The AP-42 industrial flare NOx emission factor is used to estimate emissions for purposes of rulemaking, air quality permitting, emission inventory reporting, and compliance monitoring. Revising the NOx emission factor from 0.068 lb/MMBtu to 2.9 lb/MMBtu would result in significant implications for regulated entities that utilize AP-42 emission factors for flare combustion. The proposed NOx emission factor was developed from data specific to refinery flares, but there are many non-refinery industry groups that use the AP-42 factor. For example, flares are used as safety and control devices in the oil and natural gas production sector and the transmission and distribution sector. Many sources from these sectors are minor sources, which utilize the AP-42 emission factors for industrial flares to determine the facilities potential to emit. The proposed value would lead to over-estimating emissions and result in a significant increase in the number of Title V and/or synthetic minor permit applications as well as the potential for many sources being out of compliance.

III. Conclusion

DEQ agrees with the need to evaluate and revise emission factors as new technology and better data becomes available. However, we have significant concerns with the proposed NOx emission factor. We understand the emission factor review and revision is in response to a consent decree, but we believe it is crucial that EPA reevaluate the data and ensure that it is appropriate and adequate to develop new emission factors. The proposed NOx emission factor will have inappropriate impacts on both the regulated community and the governing agencies. Montana requests that EPA reevaluate the proposed emission factor, and expand the data set used to revise the existing AP-42 emission factor to ensure the final emission factor is supported with data that is scientifically sound and representative of the intended end use.

Garwood, Gerri

From:	Loren Anderson <loc.anderson30@gmail.com>
Sent:	Friday, December 19, 2014 11:26 AM
To:	RefineryFactor
Subject:	Docket ID No. EPA–HQ–OAR-2009-0174 AP-42 Chapter 13 - MSC Comments
Attachments:	12 19 2014_AP-42_Emissions_Comments_MSC.pdf

Good morning,

On behalf of the Marcellus Shale Coalition, attached are our comments on the USEPA's proposed rulemaking on:
Emissions Factors Program Improvements, AP-42 Chapter 13: Miscellaneous Sources Section 13.5 Industrial Flares [Docket ID No. EPA–HQ–OAR-2009-0174]
Thank you,

Loren

Loren A. Anderson, CPESC
Senior Manager, Technical Affairs & Special Projects
24 Summit Park Drive, 2nd Fl.
Pittsburgh, PA 15275
Office: 412.706.5160, Ext. 105
Mobile: 412.335.1912

landerson@marcelluscoalition.org

--

MARCELLUS
SHALE COALITION™

December 19, 2014

ANPRM Docket
United States Environmental Protection Agency
West, Room 3334,
1301 Constitution Ave. NW.
Washington, DC 20460
refineryfactor@epa.gov

Re: Proposed Rulemaking: Emissions Factors Program Improvements, AP-42 Chapter 13: Miscellaneous Sources Section 13.5 Industrial Flares [Docket ID No. EPA–HQ–OAR-2009-0174]

These comments are submitted on behalf of the Marcellus Shale Coalition (MSC), a regional trade association with a national membership. The MSC was formed in 2008 and is currently comprised of approximately 300 producing and supply chain members who are fully committed to working with local, county, state and federal government officials and regulators to facilitate the development of the natural gas resources in the Marcellus, Utica and related geological formations. Our members represent many of the largest and most active companies in natural gas production, midstream gathering and transmission in the country, as well as the suppliers and contractors who service the industry.

The MSC welcomes the opportunity to comment on the United States Environmental Protection Agency (USEPA) Proposed Rulemaking on Emissions Factors Program Improvements, specifically AP-42 Chapter 13: Miscellaneous Sources Section 13.5 Industrial Flares (Rulemaking). The MSC supports sound and accurate science as well as protecting natural resources and human health via emissions and promoting air quality. Capital investment in the oil and gas industry relies on a predictable and timely regulatory process.

The MSC is concerned about the USEPA study which was completed and led to the proposed Rulemaking. First, the equipment utilized during the study was not appropriately calibrated when taking samples. Second, the sample size used to develop the new emission standards was limited to a small dataset. Lastly, the study proposed new emissions standards which ignore the fact that emission factors apply to many different facility types and industry sectors beyond just petroleum refineries.

Natural gas midstream facilities are currently permitted as minor sources and utilize flares as control devices to stay below major source thresholds. Based on the results of the USEPA's study, the NOx emission factor would be increased by a factor of forty two, which could result in the majority of natural gas midstream facilities being required to be permitted as major sources. Due to the limited study size to develop these new emission standards, as well as limiting it to only petroleum refineries, the MSC recommends the USEPA withdraw the proposed Rulemaking until a more comprehensive study is completed.

In addition to the comments above, the MSC supports the comments submitted by the American Petroleum Institute and the Gas Processors Association.

Yours very truly,

David Spigelmyer
President

From: Texas Pipeline Association <texaspipelineassociation@yahoo.com>
Sent: Friday, December 19, 2014 11:35 AM
To: RefineryFactor
Subject: Proposed revisions to AP-42 emission factors
Attachments: AP42 Emission Factors_0199.pdf

Please see the attached comments of the Texas Pipeline Association.

We appreciate this opportunity to submit our comments. Please contact us if you have any questions or need anything further.

Thank you.

Angie Adams
Assistant to the President
Texas Pipeline Association
512/478-2871

Texas Pipeline Association

Thure Cannon
President

December 19, 2014

Transmitted via email to: refineryfactor@epa.gov
United States Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Re: Proposed revisions to AP-42 emission factors

Dear Sir or Madam:

The Texas Pipeline Association ("TPA") appreciates the opportunity to submit the following comments on EPA's proposed revisions to the AP-42 emission factors for flares. TPA is an organization composed of 48 members who gather, process, treat, and transport natural gas and hazardous liquids materials through intrastate pipelines in Texas. TPA's members will be affected by this proposal because the use of AP-42 factors is one of the methods with which TPA members estimate emissions and permit flares that they own and operate.

TPA believes that EPA's proposal to raise the flare nitrogen oxides ("NOx") emissions factor by over 40 times – from 0.068 lb/MMBtu to 2.9 lb/MMBtu – is the product of a flawed analysis. The comments filed by the Texas Commission on Environmental Quality ("TCEQ") and the American Petroleum Institute ("API") discuss the flaws inherent in EPA's analysis, and TPA endorses and adopts those comments in their entirety.

We also note that EPA has based its proposed new emission factor for flares on data that is not necessarily representative of conditions in all types of industries. Data regarding flares at petroleum refineries does not necessarily represent the conditions present in the midstream industry, where different kinds of flares may be used and where the composition of the combusted waste stream may be significantly different. Development of any new AP-42 factor should be based on data that accurately represents conditions in all industry segments to which the emission factor applies.

For the foregoing reasons, we urge EPA not to finalize the proposed emission factors for flares. We appreciate the opportunity to submit these comments.

Yours truly,

Thure Cannon
President

From: Giuliani, Anthony J. <AJGiuliani@vorys.com>
Sent: Friday, December 19, 2014 12:07 PM
To: RefineryFactor
Subject: FW: Comments on Draft AP-42 Revisions for Flares
Attachments: removed.txt; (20827256)_(1)_2014-12-19 Letter to Gerri Garwood_USEPA re Comments on Draft AP-42 Revisions for Flares.PDF

Ms. Garwood,

Enclosed for filing are the Ohio Oil and Gas Association's comments on USEPA's proposed revisions to the AP-42 emission factors.

Anthony Giuliani

Anthony J. Giuliani
Partner

Vorys, Sater, Seymour and Pease LLP
52 East Gay Street | Columbus, Ohio 43215

Direct: 614.464.6279
Fax: 614.719.4734
Email: ajgiuliani@vorys.com
www.vorys.com

VORYS

Vorys, Sater, Seymour and Pease LLP
Legal Counsel

52 East Gay Street
P.O. Box 1008
Columbus, Ohio 43216-1008

614.464.6400 | www.vorys.com

Founded 1909

Anthony J. Giuliani
Direct Dial (614) 464-6279
Direct Fax (614) 719-4734
Email ajgiuliani@vorys.com

December 19, 2014

VIA E-MAIL

Gerri G. Garwood, P.F.
U.S. EPA
Measurement Policy Group
refineryfactor@epa.gov

Re: Ohio Oil and Gas Association Comments on Draft AP-42 Revisions for Flares

Dear Ms. Garwood:

The Ohio Oil and Gas Association is a trade association with over 3,100 members, including numerous companies that could be impacted by the proposed revisions to U.S. EPA's AP-42 emission factors for flares. Accordingly, the Association is submitting this letter in support of the comments filed by the Gas Processors Association ("GPA") on December 17, 2014.

The Association agrees with GPA's concerns that the proposed revisions are based upon a very small sample size and utilized analytical methods to collect and process emissions data that were insufficient at best. Additionally, the tests employed failed to include the various types of flares that are commonly in use in various industries. With a very small sample and questionable analytical methods, the proposed revisions are not supported by sound scientific data and should not be adopted.

Based upon the foregoing, the Ohio Oil and Gas Association supports GPA's comments and requests that U.S. EPA withdraw its proposed revisions.

Very truly yours,

Anthony J. Giuliani

Anthony J. Giuliani
On behalf of the Ohio Oil and Gas Association

AJG/lm

Garwood, Gerri

From:	Garwood, Gerri on behalf of RefineryFactor
Sent:	Monday, December 22, 2014 1:39 PM
To:	David Callahan
Subject:	RE: MSC - USEPA AP:42 Flare Comment letter

Your comments have been received.

Sincerely,
The Emissions Factor Team

From: David Callahan [mailto:DECallahan@markwest.com]
Sent: Friday, December 19, 2014 12:29 PM
To: RefineryFactor
Cc: David Callahan
Subject: MSC - USEPA AP:42 Flare Comment letter

To Whom It May Concern:

Please find attached a PDF of the Marcellus Shale Coalition's comments on the EPA's proposed revisions to AP-42 Section 13.5 emission factors. At your earliest convenience, please provide an email confirmation that the comments have been received.

Thank you very much

David E. Callahan
VP, Government Affairs
MarkWest Energy Partners, LP

MARCELLUS
SHALE COALITION™

December 19, 2014

ANPRM Docket
United States Environmental Protection Agency
West, Room 3334,
1301 Constitution Ave. NW.
Washington, DC 20460
refineryfactor@epa.gov

Re: Proposed Rulemaking: Emissions Factors Program Improvements, AP-42 Chapter 13: Miscellaneous Sources Section 13.5 Industrial Flares [Docket ID No. EPA–HQ–OAR-2009-0174]

These comments are submitted on behalf of the Marcellus Shale Coalition (MSC), a regional trade association with a national membership. The MSC was formed in 2008 and is currently comprised of approximately 300 producing and supply chain members who are fully committed to working with local, county, state and federal government officials and regulators to facilitate the development of the natural gas resources in the Marcellus, Utica and related geological formations. Our members represent many of the largest and most active companies in natural gas production, midstream gathering and transmission in the country, as well as the suppliers and contractors who service the industry.

The MSC welcomes the opportunity to comment on the United States Environmental Protection Agency (USEPA) Proposed Rulemaking on Emissions Factors Program Improvements, specifically AP-42 Chapter 13: Miscellaneous Sources Section 13.5 Industrial Flares (Rulemaking). The MSC supports sound and accurate science as well as protecting natural resources and human health via emissions and promoting air quality. Capital investment in the oil and gas industry relies on a predictable and timely regulatory process.

The MSC is concerned about the USEPA study which was completed and led to the proposed Rulemaking. First, the equipment utilized during the study was not appropriately calibrated when taking samples. Second, the sample size used to develop the new emission standards was limited to a small dataset. Lastly, the study proposed new emissions standards which ignore the fact that emission factors apply to many different facility types and industry sectors beyond just petroleum refineries.

Natural gas midstream facilities are currently permitted as minor sources and utilize flares as control devices to stay below major source thresholds. Based on the results of the USEPA's study, the NOx emission factor would be increased by a factor of forty two, which could result in the majority of natural gas midstream facilities being required to be permitted as major sources. Due to the limited study size to develop these new emission standards, as well as limiting it to only petroleum refineries, the MSC recommends the USEPA withdraw the proposed Rulemaking until a more comprehensive study is completed.

In addition to the comments above, the MSC supports the comments submitted by the American Petroleum Institute and the Gas Processors Association.

Yours very truly,

David Spigelmyer
President

Garwood, Gerri

From: Schaefermeier, Martin <Martin.Schaefermeier@dlapiper.com>
Sent: Friday, December 19, 2014 12:39 PM
To: RefineryFactor
Cc: Grant, Andrea
Subject: Comments of the Independent Fuel Terminal Operators Association -- EPA NOPR "Proposed New and Revised Emission Factors for Flares and Proposed New Emission Factors for Certain Refinery Process Units"
Attachments: IFTOA VOC Testing Comments.pdf; ATT00001.txt

Dear Sir or Madam,

On behalf of the Independent Fuel Terminal Operators Association, we are submitting the attached comments on the EPA notice of proposed rulemaking regarding "Proposed New and Revised Emission Factors for Flares and Proposed New Emission Factors for Certain Refinery Process Units and Proposed Determination for No Changes to VOC Emission Factors for Tanks and Wastewater Treatment Systems."

Best regards.

Andrea Grant

Andrea Grant
Partner

T +1 202.799.4306
F +1 202.799.5306
M +1 202.538.0760
E andrea.grant@dlapiper.com

DLA PIPER

DLA Piper LLP (US)
500 Eighth Street, NW
Washington, DC 20004
United States
www.dlapiper.com

COMMENTS
OF THE
INDEPENDENT FUEL TERMINAL OPERATORS ASSOCIATION

SUBMITTED TO THE

ENVIRONMENTAL PROTECTION AGENCY

ON ITS

NOTICE OF PROPOSED RULEMAKING

REGARDING

“PROPOSED NEW AND REVISED EMISSION FACTORS FOR FLARES AND PROPOSED

NEW EMISSION FACTORS FOR CERTAIN REFINERY PROCESS UNITS AND PROPOSED DETERMINATION FOR NO CHANGES TO VOC EMISSION FACTORS FOR

TANKS AND WASTEWATER TREATMENT SYSTEMS”

December 19, 2014

The Independent Fuel Terminal Operators Association ("IFTOA") hereby submits these comments to the Environmental Protection Agency ("EPA") in response to the Notice of Proposed Rulemaking on the "Proposed New and Revised Emission Factors for Flares and Proposed New Emission Factors for Certain Refinery Process Units and Proposed Determination for No Changes to VOC Emission Factors for Tanks and Wastewater Treatment Systems." IFTOA is an association of deepwater terminal operators with petroleum facilities located primarily along the East Coast. They receive, store and distribute refined petroleum products. Tanks at many of the Member facilities would be impacted by a change in VOC Emission Factors. IFTOA supports EPA's determination that revisions to the volatile organic compounds (VOC) emission factors for liquid storage tanks are not currently necessary. In addition, these comments provide several recommendations applicable to future testing and standards.

I. Background

On August 19, 2014, the EPA proposed to revise certain AP-42 emission factors in compliance with a consent decree entered into with Air Alliance Houston et al.[1] Pursuant to section 130 of the Clean Air Act, the EPA is required to review, and if necessary, revise the VOC emission factors for various sources at least once every three years. However, in its analysis, the EPA reviewed available emissions data for tanks and found that the data were not adequate to justify revisions to existing emissions estimation methods in AP-42 Chapter 7. Therefore, the EPA proposed a determination that revisions of the VOC emission factors for tanks was not necessary.

II. Need for Additional Testing

The EPA cited the "DRAFT EPA Review of Available Documents for Developing Proposed Emissions Factors for Flares, Tanks, and Wastewater Treatment Systems" (Draft Report) to support its determination that no changes were necessary to the VOC emission factors for tanks at this time. The Draft Report documented an absence of testing data and concluded that further testing would need to include variations of tank size, locations in the country, times of year, materials stored and a number of other elements. These statements imply that EPA plans to defer to the results from many different testing protocols established for different geographic regions of the country when measuring compliance with the VOC standards.

IFTOA Members agree that different conditions can affect emission factors, but not to the degree implied by EPA, and compliance with multiple protocols becomes far more difficult and costly. Each region does not require its own finely-tuned testing protocol. Members knowledgeable about emissions testing believe that EPA will be able to develop a protocol with generally uniform national emission factors, making adjustments, where necessary, to reflect different types of materials stored and the time of year when such tests are conducted.

---

[1] Air Alliance Houston, et al. v. McCarthy, No. 1:13-cv-00621-KBJ (D.D.C).

III. National Emission Testing Protocol

The Draft Report details the testing conducted at two terminals in New England that handle refined petroleum products, including residual fuel oil. EPA directed both facilities to employ an experimental testing protocol to measure VOC emissions. The protocol required the construction of temporary total enclosures (TTE) around the tank exhaust vents and use of a fan to induce air flow. Members believe that this testing method may have resulted in VOC emissions at artificially high levels. Indeed, the terminal operators and outside environmental consultants with which they work have raised concerns about the correlation between forced ventilation and the recorded emissions.

VOC emissions are an important issue, and the EPA is to be commended for taking significant steps in this proposed rulemaking to address the problem and further comply with the Clean Air Act. However, there is a need for a proven estimation method to ensure the integrity of VOC estimation results. EPA should, therefore, provide clear national guidance on the appropriate methods for measuring tank emissions. Only uniform testing methods will ensure clear and consistent results. Only clear and consistent results will support an Agency determination regarding changes to the AP-42 VOC emission factors for tanks.

V. Conclusions and Recommendations

The Independent Fuel Terminal Operators Association supports EPA’s conclusion that revisions to VOC emission factors for tanks are not necessary at this time. In addition, the Association recommends that EPA:

1. Initiate, on a national basis, a coordinated effort to develop a more accurate testing protocol;

2. Continue to rely on AP-42 estimation methods until the new protocol can be adopted;

3. Refrain from pursuing enforcement actions regarding VOC emissions based on tests conducted using the experimental protocol; and

4. Revise AP-42 emission factors for tanks if the data dictate it is necessary.

* * *

IFTOA appreciates the opportunity to provide comments on this important rulemaking and would be pleased to work with EPA on this matter.

Thank you.

From: Nathan Wheldon <Nathan.Wheldon@markwest.com>
Sent: Friday, December 19, 2014 12:50 PM
To: RefineryFactor
Subject: AP-42 Emission Factor Comments
Attachments: 12 19 2014_AP-42_Emissions_Comments_MSC.pdf

Please see attached comments from the Marcellus Shale Coalition regarding the proposed AP-42 emission factors for industrial flares, Section 13.5. Thank you for your attention in this regard.

MARCELLUS
SHALE COALITION™

December 19, 2014

ANPRM Docket
United States Environmental Protection Agency
West, Room 3334,
1301 Constitution Ave. NW.
Washington, DC 20460
refineryfactor@epa.gov

Re: Proposed Rulemaking: Emissions Factors Program Improvements, AP-42 Chapter 13: Miscellaneous Sources Section 13.5 Industrial Flares [Docket ID No. EPA–HQ–OAR-2009-0174]

These comments are submitted on behalf of the Marcellus Shale Coalition (MSC), a regional trade association with a national membership. The MSC was formed in 2008 and is currently comprised of approximately 300 producing and supply chain members who are fully committed to working with local, county, state and federal government officials and regulators to facilitate the development of the natural gas resources in the Marcellus, Utica and related geological formations. Our members represent many of the largest and most active companies in natural gas production, midstream gathering and transmission in the country, as well as the suppliers and contractors who service the industry.

The MSC welcomes the opportunity to comment on the United States Environmental Protection Agency (USEPA) Proposed Rulemaking on Emissions Factors Program Improvements, specifically AP-42 Chapter 13: Miscellaneous Sources Section 13.5 Industrial Flares (Rulemaking). The MSC supports sound and accurate science as well as protecting natural resources and human health via emissions and promoting air quality. Capital investment in the oil and gas industry relies on a predictable and timely regulatory process.

The MSC is concerned about the USEPA study which was completed and led to the proposed Rulemaking. First, the equipment utilized during the study was not appropriately calibrated when taking samples. Second, the sample size used to develop the new emission standards was limited to a small dataset. Lastly, the study proposed new emissions standards which ignore the fact that emission factors apply to many different facility types and industry sectors beyond just petroleum refineries.

Natural gas midstream facilities are currently permitted as minor sources and utilize flares as control devices to stay below major source thresholds. Based on the results of the USEPA's study, the NOx emission factor would be increased by a factor of forty two, which could result in the majority of natural gas midstream facilities being required to be permitted as major sources. Due to the limited study size to develop these new emission standards, as well as limiting it to only petroleum refineries, the MSC recommends the USEPA withdraw the proposed Rulemaking until a more comprehensive study is completed.

In addition to the comments above, the MSC supports the comments submitted by the American Petroleum Institute and the Gas Processors Association.

Yours very truly,

David Spigelmyer
President

Garwood, Gerri

From: Lisa Beal <lbeal@ingaa.org>
Sent: Friday, December 19, 2014 1:36 PM
To: RefineryFactor
Subject: Proposed Changes to AP-42 Chapter 13: Miscellaneous Sources Section 13.5 Industrial Flares - INGAA Comments
Attachments: removed.txt; INGAA Flare EF Comments Final.pdf

The Interstate Natural Gas Association of America (INGAA), a trade association of the interstate natural gas pipeline industry, respectfully submits these comments regarding the Proposed Changes to AP-42 Chapter 13: Miscellaneous Sources Section 13.5 Industrial Flares.

Lisa S. Beal
VP, Environment & Construction Policy
INGAA
20 F Street NW
Suite 450
Washington, DC 20001
(O) 202-216-5935
(M) 202-256-9134

December 19, 2014

Environmental Protection Agency
Clearinghouse for Inventories and Emission Factors
Washington, D.C. 20004
Submitted via email to refineryfactor@epa.gov

Re: Proposed Changes to AP-42 Chapter 13: Industrial Flares

Dear Sir or Madam:

The Interstate Natural Gas Association of America (INGAA), a trade association of the interstate natural gas pipeline industry, respectfully submits these comments regarding the Proposed Changes to AP-42 Chapter 13: Miscellaneous Sources Section 13.5 Industrial Flares. INGAA represents a majority of the interstate natural gas transmission pipeline companies operating in the United States as well as comparable companies in Canada. INGAA's members operate a network of approximately 200,000 miles of pipelines. The proposed changes to the flare emission factors revise the current carbon monoxide (CO) and nitrous oxides (NOx) factors and create a new emission factor for volatile organic compounds (VOCs).

INGAA is primarily concerned with the emission factor that the U.S. Environmental Protection Agency (EPA) is proposing for NOx because it would significantly and adversely impact permitted emissions from numerous facilities that INGAA member companies operate. Furthermore, these proposed updates do not appear to be based on sound science or statistical practices. Use of these factors would result in significant regulatory uncertainty for both regulated industries and regulatory agencies. These factors suggest an increase of approximately 42 times the current NOx emission factors, potentially undermining the basis for existing permitting and compliance scenarios for hundreds, if not thousands, of facilities. The use of these new factors would likely result in many facilities that are currently minor sources becoming major sources. Individual companies would then be left with the option to conduct their own costly performance testing to demonstrate more appropriate emission levels. Finally, use of these factors would have a decidedly negative effect on regulatory policy decisions at both the national and state levels. Falsely reporting that flare emissions are much greater than they are will inevitably lead to over-emphasizing their importance when considering new control strategies and thus increasing the possibility that scarce EPA and industry resources will be devoted to solve a problem that does not actually exist.

INGAA respectfully submits the following analysis and areas of concern relating to the proposed changes to AP-42 NOx emission factors for flares. INGAA also supports GPA and API's comments regarding the proposed emission factor changes. Trinity Consultants assisted in the development of the data review and analysis section of the comments herein. Accordingly, the comments and supporting data are similar to the information in the comments submitted by Trinity Consultants to EPA on October 17, 2014.

Executive Summary

It is understood that EPA is considering a new default NOx emissions factor for flares of 2.9 lb/MMBtu (“the new factor”). The new factor has been calculated as an arithmetic average based on Passive Fourier Transform Infrared (PFTIR) Spectroscopy instrument measurements of five flares and the existing AP-42 emissions factor. This response discusses deficiencies with the scientific and statistical validity of the new NOx emission factor derived from these PFTIR data sets.

A review of the development of the new factor leads to the following conclusions:

1.0 Data Integrity

- The PFTIR instrument used to measure the NOx data sets, that are the basis of the proposed new emission factor, was not calibrated for NO or NO2; therefore, the results are not reliable.

2.0 Data Review and Analysis

- The exhaust gas flow rate from the flare tested at the Flint Hills Resources Port Arthur, TX refinery (FHR–AU) was vastly over-estimated in several instances due to questionable low CO2 concentration readings.

- Two such instances with grossly over-estimated exhaust gas flow rates resulted in NOx emission rates and emission factors that were more than two orders of magnitude greater than any other NOx emission factors calculated during the FHR – AU test series. It appears that these two NOx emission rate data points are erroneous and should not be used for any purpose. Simple removal of these two data points described above results in a NOx emissions factor of 0.79 lb/MMBtu (as compared to the proposed factor of 2.9 lb/MMBtu).

- Other anomalies and apparent errors in the FHR-AU data suggest that it should not be used for the calculation of revised AP-42 emissions factors. Chief among the additional anomalies found in the FHR-AU data set are: (1) the lack of correlation between CO emissions and NOx emissions; (2) the absence of measured NO emissions in the FHR-AU flare plume, with the exception of two discrete instances; and (3) several instances where measured NO_2 concentrations move from a high value one minute, to zero the next minute and back to a high value the minute after that.

- If EPA is determined to include the FHR-AU dataset, it is scientifically and statistically indefensible to weight it the same as the other four PFTIR datasets included in the calculation of the new factor.

- EPA should re-examine its quality assurance methods for reviewing datasets used for emission factor development, both in the case of the proposed flare emission factors and in general.

3.0 Flare Emissions Vary by Industry Type

- It is not accurate to assume the NOx emissions measured from a refinery flare accurately represent those of flares in other industries. Factors such as heating value, gas stream constituents and type of flare assist fuel need to be considered.

A more detailed discussion of the issues described above follows.

Detailed Comments:

1.0 Data Integrity

The underlining issue with the proposed NOx emission factor is the integrity of the data that was used in its development. The data used to develop the NOx emission factor was taken from a PFTIR instrument. This instrument is commonly used to measure or monitor combustion efficiency, but as described on EPA's webpage:

> The PFTIR technology is a path measurement method, and it has several technical shortcomings. The instrument must be aimed at a specific region of the flare plume and must assume that the optical path length during a data acquisition cycle remains constant. Flare plume dynamics and long data acquisition cycles (> 1 second per cycle) make both of these requirements unreliable. The PFTIR also has a limited dynamic range due to a one-sensor configuration and must operate at lower temperatures where atmospheric interferences can be significant. [1]

These technical shortcomings that make the data unreliable have been recognized by EPA and should be considered before using the collected data to develop published emission factors. As stated above, the PFTIR is commonly used to measure combustion efficiency, which was the purpose of using the instrument on the tested flares. There was no intent to gather NO or NO2 concentration data to be used for data analysis. The instrument automatically takes concentration readings as it runs. Since the NO or NO2 measurements were not intended for use, the instrument was not calibrated for these pollutants. Calibration is the process of adjusting an instrument, so that its readings can be related to the actual values measured. EPA recognizes the importance of calibration and has air monitoring regulations that require the use of Protocol Gas for instrument calibration. EPA states, "this protocol helps to ensure that air pollution measurements are accurate and can be trusted"[2]. In general, EPA does not accept emission testing data from industry that does not meet the calibration protocol, and considers it to be unreliable and unacceptable. The PFTIR used to gather the NOx data used in development of the proposed emission factor was not calibrated with Protocol Gas nor was it calibrated with any gas of known concentration. It is evident by EPA's statements on the importance of calibration that the data used to develop the proposed NOx emission factor are not reliable and the proposed factor should be revised.

---

[1] *EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards*. Retrieved 10 09, 2014, from EPA Air and Climate Change Research: http://www.epa.gov/nrmrl/appcd/mmd/db-traceability-protocol.html

[2] *Final Report: Development of Real-Time Flare Combustion Efficiency Monitor*. (n.d.). Retrieved 10 09, 2014, from EPA Extramural Research: http://cfpub.epa.gov/ncer_abstracts/index.cfm/fuseaction/display.abstractDetail/abstract/9999/report/F

2.0 Data Review and Analysis

Table 1 summarizes the five PFTIR studies and existing AP-42 factor used to calculate the new factor:

Table 1

Flare	NOx Emission Rate (lb/MMBtu)
FHR-AU	16
MPC_Detroit	0.011
INEOS	0.471
TCEQ, steam	0.129
TCEQ, air	0.577
Existing AP-42	0.068
Average:	2.88

The standard deviation for this data set is 5.9 lb/MMBtu, greater than the calculated mean value. Removing the FHR-AU data point results in a mean value of 0.83 lb/MMBtu and a far more reasonable standard deviation of 0.23 lb/MMBtu. The vast difference between the FHR-AU data and the rest of the dataset should have triggered questions and additional investigation of the FHR-AU data set.

A visual comparison of plots comparing emission rates in lb/MMBtu vs. time for each flare brings the first problem with the FHR-AU dataset clearly to light. Each of the charts below compares NOx emission rate in lb/MMBtu (y axis) vs. minutes of sampling (x axis):

Chart 1 – MPC-Detroit

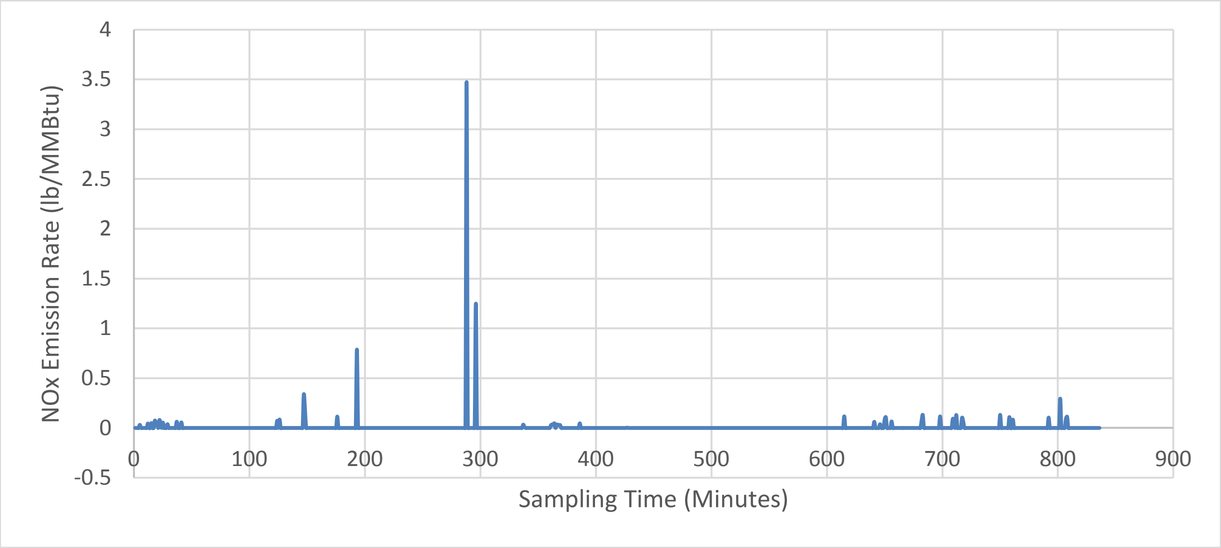


Chart 2 – INEOS

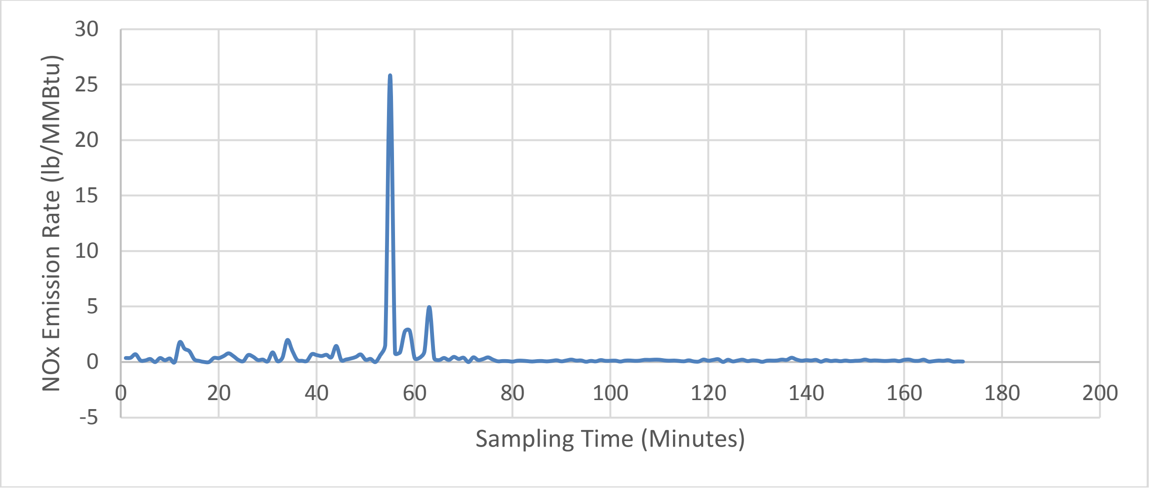


Chart 3 – TCEQ Steam

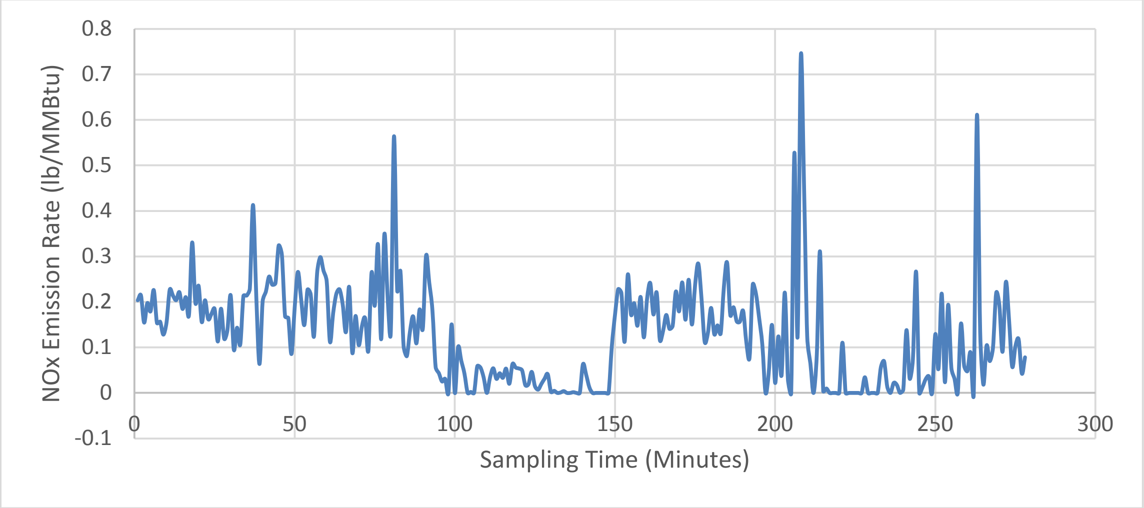
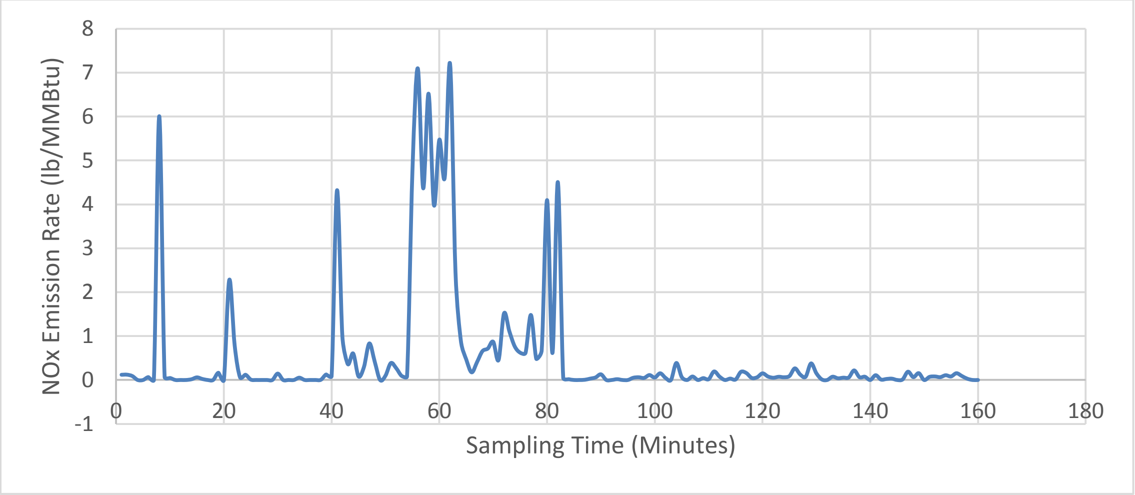
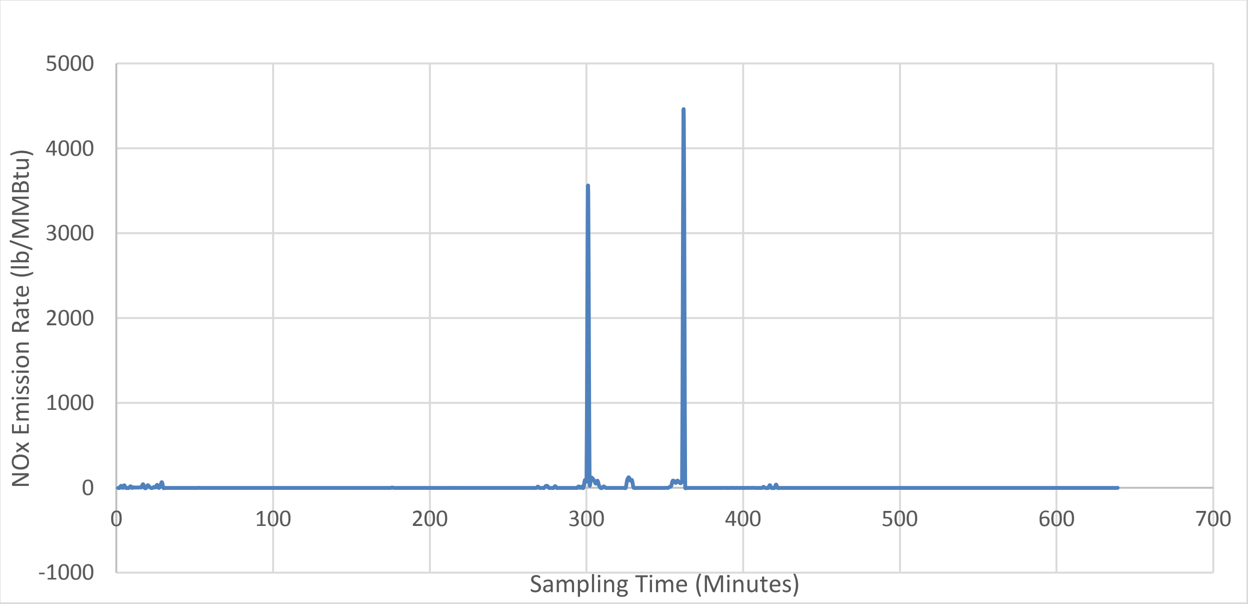


Chart 4 – TCEQ Air



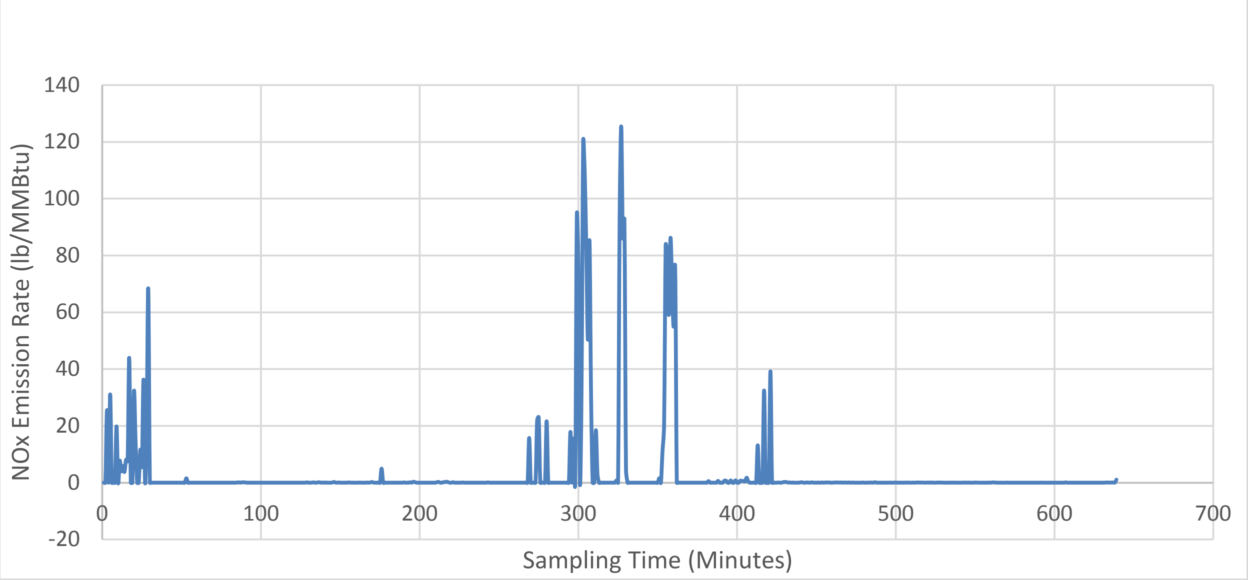
Note that there is only one case (Chart 2-INEOS) where a calculated emission rate greater than 10 lb/MMBtu occurs. The vast majority of calculated emission rates are less than 1 lb/MMBtu. The plot of FHR-AU data is markedly different:

Chart 5 – FHR-AU (Uncorrected) NOx lb/MMBtu



Two features of this chart stand out: (1) the scale of the y-axis (0 – 5,000 lb/MMBtu) is far larger than any of the previous charts, and (2) that scale is made necessary by two large peaks that exceed other calculated values by at least two, and in most cases three, orders of magnitude. Removal of these two anomalous data points yields a much different-looking chart:

Chart 6 – FHR-AU (2 Anomalous Data Points Removed) NOx lb/MMBtu

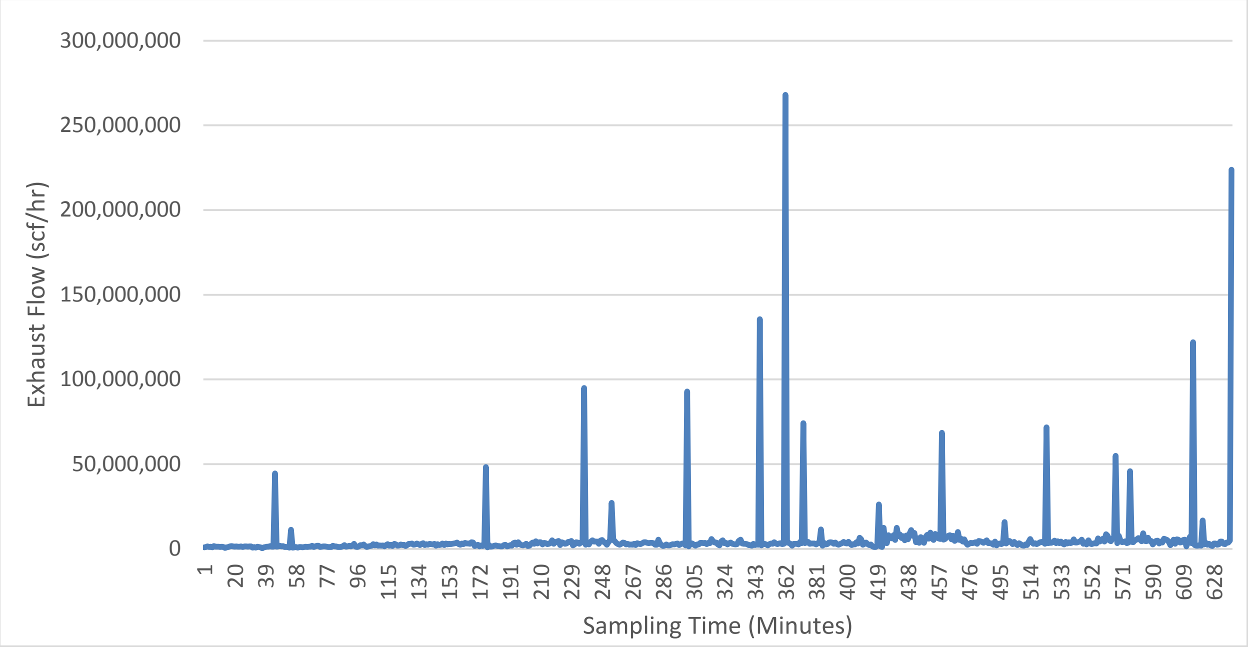


Many data points not only exceed the 1 lb/MMBtu "normal" upper limit described earlier, many also exceed the "extreme" upper limit of 25 lb/MMBtu established in the first four studies. While in most cases, the range of calculated exhaust gas flow rates for the FHR-AU flare are in the typical range of 1 to 10 MM scfh exhibited by similar-sized flares included in the study, the calculated exhaust gas flow rates for the FHR-AU flare exceed 10 MM scfh in 22 instances and exceed 100 MM scfh in 4 instances. These instances of over-estimated exhaust gas flow rates lead to vast over-estimation of NOx emissions rates. This is especially apparent in two instances: time stamp 10/26/10 at 12:23 and time stamp 10/26/10 at 17:28.

In the first case, a calculated exhaust gas flow rate of over 92 MM scfh leads to a calculated NOx emission rate of over 3,500 lb/MMBtu, even though the NOx concentration measured at that time (~8,900 ppm) and the vent gas flow rate (~36,000 scfh) are not markedly different from many other similar data points. The same is true in the latter case, where a calculated exhaust gas flow rate of over 268 MM scfh leads to a calculated NOx emission rate of over 4,400 lb/MMBtu, even though measured NOx concentrations and vent gas flow rates are again in the normal range.

Chart 7 (below) provides a visual representation of the extreme variability in exhaust gas flow rate calculations in the FHR-AU case. Many of the calculations are problematic, because each flow rate calculation does not always correspond to a flaring event where NOx emissions are produced. But, when an erroneous flow rate calculation does correspond to such a flaring event, an over-estimation of NOx emission rates inevitably occurs.

Chart 7 – FHR- AU (2 Anomalous Data Points Removed) Calculated SCFH



The root cause of the faulty exhaust gas flow rate calculations appears to be the methodology used to calculate those exhaust gas flow rates. The formula used to calculate exhaust gas flow rate is:

Eq. 1: $Q_s = \frac{C_i}{C_m} \times \frac{385.5}{12}$

Where,

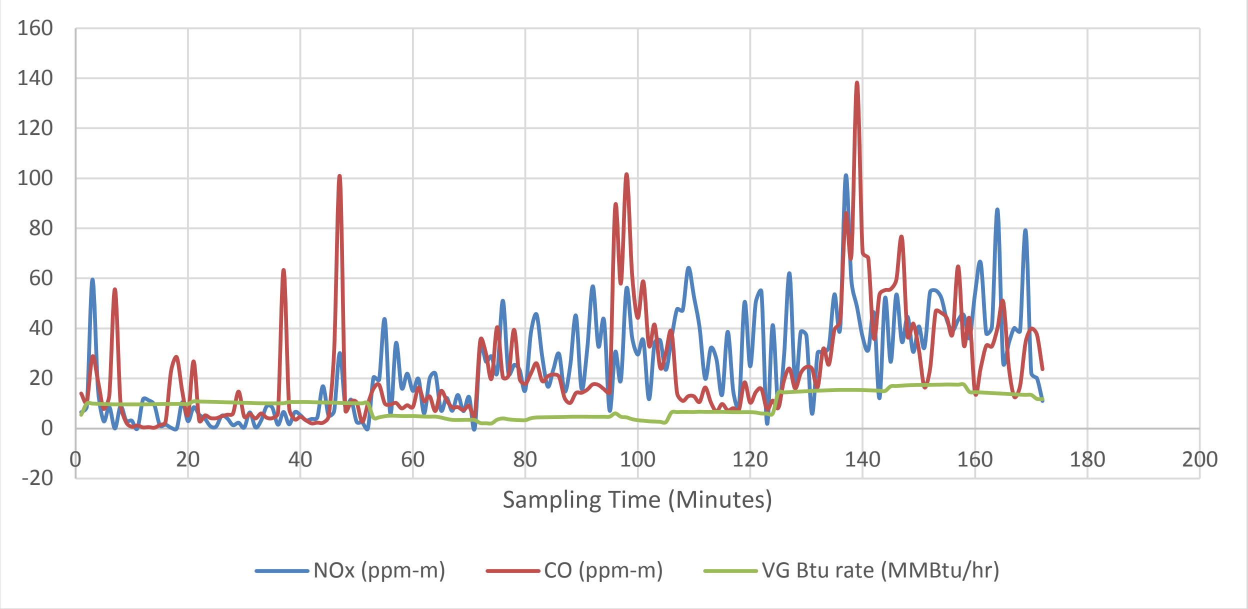
Qs = calculated exhaust gas flow rate, in scfh
Ci = calculated total carbon in the vent gas based on bagged sample and DCS measured vent gas flow rate, in lbs/hr
Cm = PFTIR measured total carbon in the flare plume, fractional
385.5 = molar volume of ideal gas (scf/lb-mole)
12 = molecular weight of carbon (lb/lb-mole)

Equation 1 is sensitive to measured carbon concentrations in the exhaust gas plume. If apparent carbon concentrations in the plume drop significantly, the reduction in the denominator in the fraction Ci/Cm will cause the calculated exhaust gas flow rate to rise proportionally. This is the cause of the majority of miscalculations of exhaust gas flow rate. For example, the previously-mentioned anomalous data gathered at time stamp 10/26/10, 12:23 included a measured carbon concentration of 311 ppm-m, following a reading of 15,000 ppm-m the minute before and preceding a reading of 20,000 ppm-m the minute after. This sudden, unexplainable and dramatic “drop” in carbon concentration defies both common sense and basic principles of thermodynamics, and these anomalies significantly impact subsequent calculations. The faulty data points may be attributable to measurement error, interference (a chronic problem with any form of FTIR), and/or because the equation EPA uses to calculate exhaust gas flow rate is too carbon sensitive to use when a flare gas stream is hydrogen-rich. While it is not known if the flare gas stream at FHR-AU was hydrogen rich, *if* it was, then the carbon sensitivity of the flow gas exhaust rate equation would be an additional concern.

In addition to the flow rate measurement issues, it is clear the measurement of NOx concentration in the FHR-AU exhaust plume is fraught with errors. In order to illustrate the problems with NOx concentration measurements in the FHR-AU data set, it is helpful to consider measured NOx concentrations in the plumes of the two other steam assisted flares of similar size that have been proposed to be used to calculate the new AP-42 NOx emissions factor for flares: INEOS and TCEQ-Steam.

The INEOS chart compares measured NOx concentrations, CO concentrations and vent gas heating value versus time:

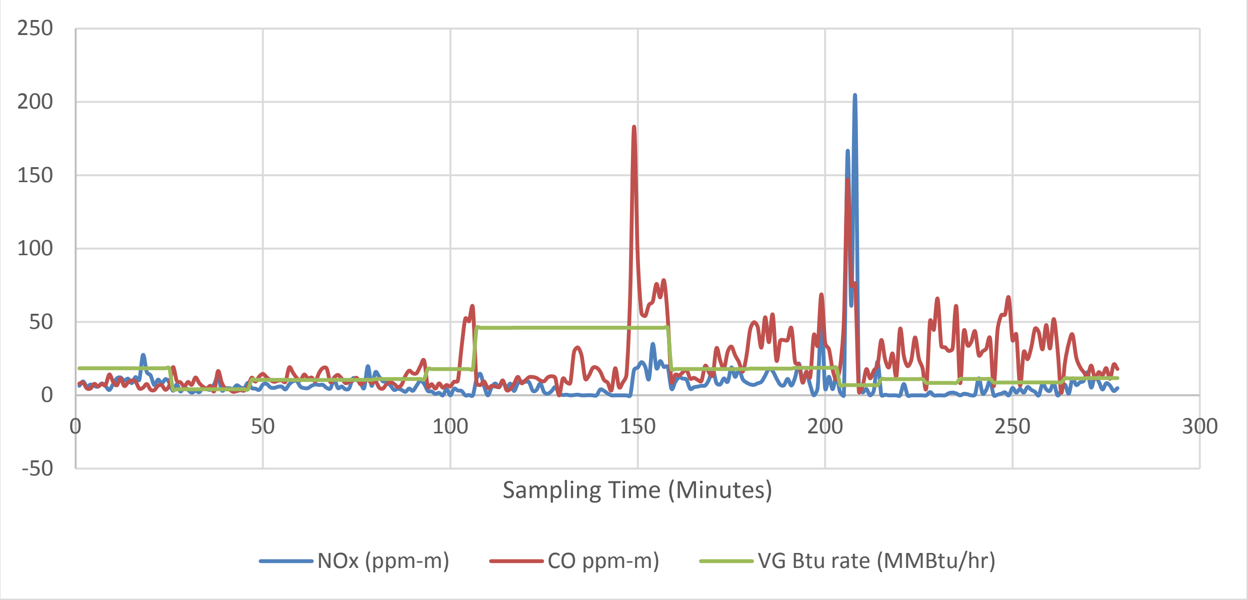
Chart 8 – INEOS NOx, CO and Heating Value vs. time



In this chart, NOx and CO concentrations seem to fluctuate as expected since combustion conditions that generate higher concentrations of one generally generate lower concentrations of the other. The important point is that flare combustion of any sort should reasonably be expected to generate detectable concentrations of each and this chart is consistent with that expectation.

The TCEQ-Steam chart reveals the same general pattern:

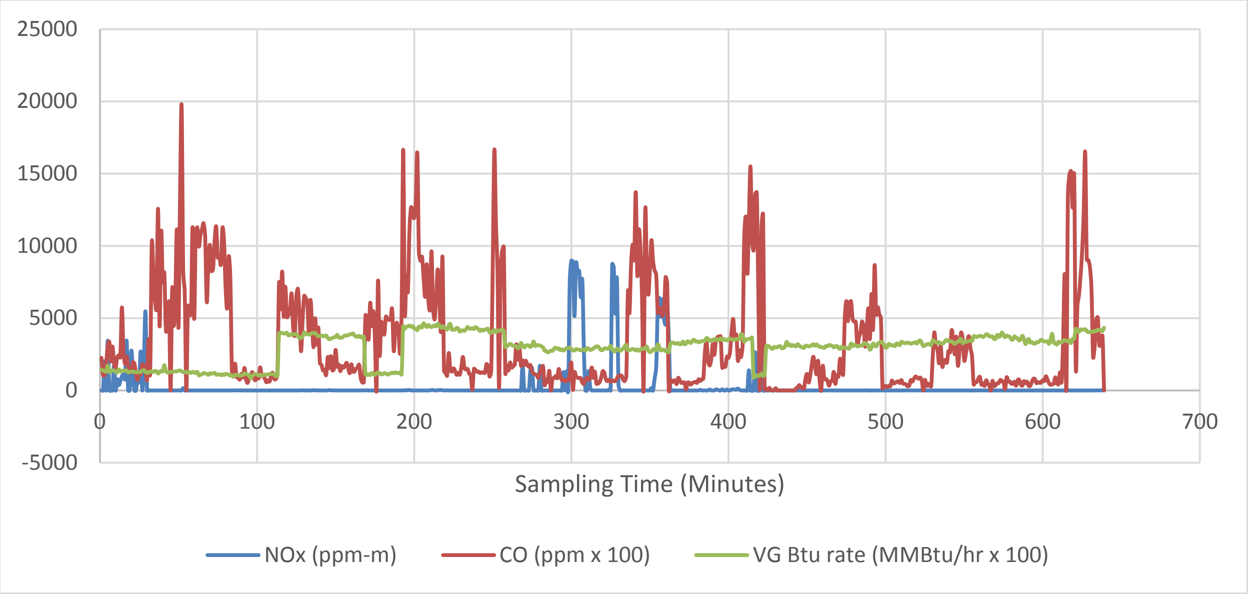
Chart 9 – TCEQ Steam NOx, CO and Heating Value vs. Time



Again, there is variance in CO and NOx concentrations and there isn't a consistent correlation pattern between the two, but non-zero measurement in both cases is the norm, not the exception. (Note that the Vent Gas Btu rate is apparently "flat" for long periods of time because measurement of that parameter involved periodic, rather than continuous, sampling in this case).

When the same data points are plotted for FHR-AU, a much different pattern emerges:

Chart 10 - FHR-AU NOx, CO and Heating Value vs. Time



CO concentrations and Vent Gas Btu rate have been normalized by multiplying each by a factor of 100 in order to allow for a visual comparison similar to Charts 8 and 9. Raw (non-normalized) CO and Btu data is in the same range as the INEOS and TCEQ-Steam data. Normalization is necessary to visualize this data against the inflated NOx concentrations that appear in the FHR-AU dataset.

While CO concentrations show the kind of variance observed in the other two cases, reported NOx concentrations are zero 72% of the time, suggesting that combustion conditions that produce CO are capable of producing no NOx whatsoever. This behavior is inconsistent with any of the other datasets examined and defies common sense. Equally troubling is that, with the exception of two data points, no NO_2 concentrations are reported in the FHR-AU dataset and that, in many occasions, the reported NO concentrations go from thousands to ppm to zero and back to thousands of ppm. (See, for example, time stamps 10/21/10 10:42 through 11:01, and time stamps 10/26/10, 12:17 through 12:42).

3.0 Flares Emissions vary by Industry Type

Emissions from flares are the products of combusting the waste stream being controlled. NOx formation is known to be caused by thermal NOx, which is formed from the oxygen and nitrogen molecules that are naturally occurring in the air coming together at high temperatures; fuel NOx, which comes from the oxidation of nitrogen in the fuel; and prompt NOx which is formed by molecular nitrogen in the air along with nitrogen in the stream. The emission factor proposed is assumed to account for each type of NOx formed and capture the emissions from various waste stream compositions being combusted. This is not realistic. Flares are used in many different industries each combusting a different type of waste stream.

Thermal NOx is dependent on the combustion temperature. Combustion temperature is based on the heat content and percent present of the individual components in a stream. This is often referred to as the heating value of the stream and is commonly measured in BTU/scf. The waste stream being combusted at a refinery, which is the data utilized during these emissions tests, does not have a similar profile to a flare that combusts waste streams found at natural gas sites (e.g. H2S control, tank vapors and dehydration unit emissions). The waste streams will have a different heating value, which leads to different combustion temperatures; therefore, it will produce different amounts of thermal NOx. The proposed NOx emission factors do not consider the heating value of the gas being combusted, which isn't accurate since the temperature of combustion is a factor in the amount of thermal NOx emissions.

Fuel NOx emissions depend on the amount of nitrogen in the stream being burned. Again, this varies along with the industry type and the composition of the waste stream. Reviewing only one industry segment, refineries, to develop an emission factor does not properly account for the operating conditions and emissions in other industries. In addition, most oil and natural gas sites do not use steam assisted flares, while four out of the five data sets used to develop the NOx emission factor where steam assisted.

In conclusion, one emission factor does not capture the emission from flares used in a wide range of industries combusting a wide range of waste gas streams with varying heat contents.

Recommendations

The following recommendations are offered for EPA's consideration:

1. The PFTIR data used to develop the NOx emission factor should be discarded and the proposed flare emission factors should be revised because the instrument was not calibrated. Proper measurement techniques need to be followed to obtain quality and reliable data for emission factor development.

2. At a minimum, the two most extreme anomalous data points in the FHR-AU dataset should be removed and the proposed emission factor recalculated.

3. Since erroneous flow rate measurements in the FHR-AU dataset will affect proposed emissions factors for other pollutants, the effect of erroneous flow rate measurements on those emission factors should be examined.

4. Because of the other serious problems with FHR dataset, EPA should consider either not using the FHR-AU dataset at all, or – if it is to be used – reweighting and adjusting the data to account for the many discrepancies in it.

5. EPA should review its data validation procedures. It is concerning that two obviously erroneous data points could have such a dramatic effect on a proposed emissions factor to be used on a nationwide basis, not to mention all of the other data quality assurance questions related to the FHR-AU dataset. Even if the FHR-AU dataset was deemed to be accurate in some form, it is

difficult to justify use of this data as part of a simple arithmetic averaging exercise when: a) the data varies so much from the other data collected, and b) the 1:1 weighting inherent to the flare study assumes that the FHR-AU data is representative of 20% of all the flares in all the refineries in the United States.

6. Consider reviewing and potentially conducting studies of the emissions from flares used in different industries. There are too many factors that contribute to emission rates to assume that all flares emit the same concentration of a pollutant.

INGAA appreciates your consideration of these comments. Please contact me at 202-216-5935 or lbeal@ingaa.org if you have any questions. Thank you.

Sincerely,

Lisa S Beal

Lisa Beal
Vice President, Environment and Construction Policy Interstate Natural Gas Association of America

Garwood, Gerri

From:	Gershman, Lorraine <Lorraine_Gershman@americanchemistry.com>
Sent:	Friday, December 19, 2014 2:32 PM
To:	RefineryFactor
Cc:	Garwood, Gerri
Subject:	ACC comments
Attachments:	ACC comments AP42 factors 12.19.14.pdf

Please find attached the comments of the American Chemistry Council on the draft AP-42 factors and emission estimation protocol for refineries.

Best,
Lorraine

Lorraine Krupa Gershman*, *P.E. | American Chemistry Council
Senior Director, Environment & Process Safety
lorraine_gershman@americanchemistry.com
700 2nd Street, NE | Washington, DC | 20002
O: 202-249-6411
www.americanchemistry.com

American Chemistry Council

Sent Electronically

December 19, 2014

U.S. Environmental Protection Agency
Attn: refineryfactor@epa.gov

Re: Proposed Revisions to Sections 5.1, 8.13, and 13.5 of AP-42 and Draft Emission Estimation Protocol for Petroleum Refineries - Version 3.0

The American Chemistry Council (ACC)[1] is pleased to submit these comments on EPA's proposed revisions to Sections 5.1, 8.13, and 13.5 of AP-42 and Draft Emission Estimation Protocol for Petroleum Refineries – Version 3.0, as posted on August 19, 2014[2]. ACC represents the leading companies engaged in the business of chemistry, and our members operate a number of flares that will be impacted by any final changes to AP-42 and emission estimation protocol.

ACC fully supports and endorses the detailed comments of the American Petroleum Institute (API) on these proposed changes submitted to EPA, dated December 19, 2014. We wish to take the opportunity to make three additional comments.

ACC is concerned about the timing of this review of AP-42 factors. EPA is proposing to revise AP-42 emission factors at the same time it is conducting its section 111 and section 112 Clean Air Act review of the refinery sector rulemaking. The refinery sector rulemaking touches all parts of a refinery, and is proposing emission limits for a number of pieces of process equipment. Emissions from some of these impacted units are calculated using the same AP-42 factors that are under review. It is difficult for covered facilities to truly understand the impacts of a proposal when both the emission limits and factors used to calculate the limits are under review and may be subject to change in the same time frame. ACC urges EPA to first finalize the refinery sector rulemaking, and then turn its attention to the AP-42 emission factors and protocol.

ACC also urges EPA to not finalize the proposed flare emission factors. Looking at the proposed NO_X factor, and the underlying data used to calculate this factor, it is apparent that

---

[1] *The American Chemistry Council (ACC) represents the leading companies engaged in the business of chemistry. ACC members apply the science of chemistry to make innovative products and services that make people's lives better, healthier and safer. ACC is committed to improved environmental, health and safety performance through Responsible Care®, common sense advocacy designed to address major public policy issues, and health and environmental research and product testing. The business of chemistry is an $812 billion enterprise and a key element of the nation's economy. It is one of the nation's largest exporters, accounting for twelve percent of all U.S. exports. Chemistry companies are among the largest investors in research and development. Safety and security have always been primary concerns of ACC members, and they have intensified their efforts, working closely with government agencies to improve security and to defend against any threat to the nation's critical infrastructure.*

[2] See: http://www.epa.gov/ttn/chief/consentdecree/index_consent_decree.html

there are some data issues that need to be addressed prior to moving forward. EPA's outlier analysis utilized an approach that did not detect true outliers. These undetected outliers are a major factor in why the NO_X factor for the Flint Hills AU flare is 64 times higher than the average of the other NO_X flare factors.

Beyond the outlier analysis, the quality of this factor is greatly affected by the fact that the PFTIR instruments used to collect the data at all of the recent flare tests were not calibrated for either NO or NO_2. Additionally, use of minute rather than run average data, averaging of the CO_2 spectral bands rather than choosing the appropriate spectral band, and the use of the unweighted, rather than weighted, combustion efficiency all combine to bias the resulting factor high. The model used to convert PFTIR data to mass emission data, based on a NO_X/CO_2 ratio, has some technical deficiencies. NO_X is also generated from hydrogen combustion, which is not accounted for in this model. By using this NO_X/CO_2 model on high hydrogen flares such as the Flint Hills AU flare, the calculated NO_X emissions are further biased high. ACC strongly encourages EPA to review the entire data set and conduct a more rigorous analysis of the available data. Given that EPA has recent NO_X testing data from the TCEQ and International Flaring Consortium (IFC) that show that the NO_X factor is even lower than the current AP-42 factor, it puzzles ACC why EPA has chosen to instead use flawed data to propose a much higher NO_X factor.

Finally, ACC is concerned that EPA has not indicated how revised emission factors will be treated going forward. When improved emissions data are obtained, there is the potential for a change to an emissions factor. A higher emission factor may result in emissions estimated from the new emissions factor to exceed the permitted level of emissions for a facility that was calculated using the previous, lower emissions factor. ACC asks that EPA guidance regarding updating of emission factors include the following language:

> "For purposes of determining permit compliance, the emissions factors that were current at the time of the permit application should continue to be used, or the permit limits should be adjusted in proportion to the change in the emissions factor."
>
> "A procedure is needed to ensure that a change to emissions factors does not, by itself, constitute a basis for being out of compliance with an existing permit or create a situation where a source that was previously determined to not require a permit is now considered to be out of compliance with State or federal permitting requirements. Similarly, sources should not be liable for retrospective emissions fee increases due to application of a new and improved emissions factor that would result in an increase in past emissions estimates. Changes in emission factors should not, by themselves, result in permit limit deviations or retroactive fee increases."

Thank you in advance for your consideration of ACC's comments. If you have any questions, or need clarification on any of our comments, please contact me at lorraine_gershman@americanchemistry.com or 202-249-6411.

Sincerely yours,

Lorraine Krupa Gershman, P.E.
Senior Director, Environment and Process Safety

From:	Larry @ PEI <lconner@perennialenergy.com>
Sent:	Friday, December 19, 2014 3:00 PM
To:	RefineryFactor
Cc:	Brad Alexander
Subject:	PEI comments to Draft AP-42 . . . attached
Attachments:	EPA Comments Letterhead.pdf

Ms. Garwood:

Attached please see the letter representing our response to the request for comments regarding the draft AP-42, Section 13.5 (supplement D) proposed modifications. Thank you for allowing us the opportunity to review and respond.

Larry H. Conner, Principal & Technical Consultant – Regulatory Liaison

PEI
PERENNIAL ENERGY

December 19th, 2014

Ms. Gerri Garwood
U.S. Environmental Protection Agency (EPA)
1200 Pennsylvania Ave., NW
Washington, DC 20460

Re: Comments to proposed emission factors in Draft AP-42, §13.5 (Supplement D)

Ms. Garwood:

Perennial Energy has provided flares of various types, including non-assisted open (candlestick) flares, principally, though not exclusively, for the waste gases generated from the waste water treatment plant and landfill environments. Our design guidance has long been based on compliance with EPA AP-42 and EPA 40 CFR §60.18, the emission factors of which we believe have been carefully derived from universally accepted combustion science, and are both accurate and appropriate for the markets that we service. We are not aware of any studies performed on open (candlestick) flares applicable to the waste water treatment or landfill industries that would suggest the above regulatory guidelines need to be modified or amended.

Our present and historical emission guarantees for Perennial Energy open (candlestick) flares are based on the above regulatory guidelines.

We have reviewed the data provided from the limited studies referenced in the Draft AP-42 §13.5, (supplement D) proposed modifications. While we have no comment relative to modifications that may be appropriate for the steam, air or high pressure assisted flares applied as control devices in industries generating the kinds of hydrocarbons delineated in the studies, we respectfully suggest that imposition of the proposed emission factor modifications are inappropriate for the non-assisted flares applied to anaerobically derived gases common to waste water treatment plant and landfill applications.

Respectfully,
PERENNIAL ENERGY

LHConner

Larry H. Conner, Principal
Technical Consultant - Regulatory Liaison

From:	Nathan Wheldon <Nathan.Wheldon@markwest.com>
Sent:	Friday, December 19, 2014 4:03 PM
To:	RefineryFactor
Subject:	Comments on AP-42 Emission Factors
Attachments:	MarkWest Comment on AP-42 Proposed Emission Factors.pdf

Please see attached comments from MarkWest on the proposed AP-42 Emission Factors for Industrial Flares Section 13.5. Thank you for your attention in this regard.

Nathan.

MARKWEST
Energy Partners, L.P.

December 19, 2014

Via Electronic Mail
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, D.C. 20460
refineryfactor@epa.gov

Re: AP-42 Chapter 13: Miscellaneous Sources - Section 13.5 Industrial Flares

To Whom It May Concern:

MarkWest Energy Partners, L.P. ("MarkWest") respectfully submits the following comments to the draft revisions to *AP-42 - Section 13.5 Industrial Flares* proposed by the U.S. Environmental Protection Agency ("EPA") on August 19, 2014. MarkWest is a publicly-traded master limited partnership engaged in the gathering, processing and transportation of natural gas; the gathering, transportation, fractionation, storage and marketing of natural gas liquids; and the gathering and transportation of crude oil. For the reasons set forth in the comments below, MarkWest respectfully requests that the EPA withdraw its draft revisions to *AP-42 - Section 13.5 Industrial Flares*.

General Comments to Draft Revisions to AP-42 - Section 13.5 Industrial Flares

1. By the EPA's own admission, none of the emissions data and test reports upon which the EPA's draft revisions to *AP-42 - Section 13.5 Industrial Flares* are based were collected for the purpose of developing new emission factors. In the introduction to the "*Draft Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations*" (the "Draft Report"), the EPA states that:

   > "As part of its efforts to comply with the [*Air Alliance Houston, et al*] consent decree, EPA reviewed emissions test data submitted by refineries for the 2011 Petroleum Refinery Information Collection Request … and test data collected during development of parameters for property designed and operating flares and developed new emissions factors …." (p. 7)

   Additionally, the EPA further states in numerous sections of the Draft Report that the operating conditions upon which the draft revisions to *AP-42 - Section 13.5 Industrial Flares* are based are not representative of normal flare performance. Given the widespread reliance on emission factors for permitting and other considerations, emission factors should be determined under normal operating conditions and not extreme operating conditions.

   Accordingly, the EPA should delay revising *AP-42 - Section 13.5 Industrial Flares* until such time as the EPA has collected data solely for this purpose, which data should be collected under normal operating conditions and from representative industries (*See* Comment 2).

2. The emissions data and test reports relied upon by the EPA in promulgating revisions to *AP-42 - Section 13.5 Industrial Flares* come solely from the petrochemical refining industry. While such data and reports are sufficient for revising *AP-42 - Section 5.1 Petroleum Refining* and may be adequate for revising *AP-42 - Section 8.13 Sulfur Recovery*, the data and reports are not representative of other industries and operations and, consequently, should not be relied upon as the sole basis for revising *AP-42 - Section 13.5 Industrial Flares*. Therefore, any revisions to AP-42 at this time should be limited to *AP-42 - Section 5.1 Petroleum Refining* and *AP-42 - Section 8.13 Sulfur Recovery*.

3. In determining statistical outliers to the data, the EPA assumes that all emissions data are log-normally distributed (*Recommended Procedures for Development of Emission Factors and Use of the WebFIRE Database*, EPA 2013). This is a faulty assumption that can lead to including data that does not belong to a dataset.

4. The EPA claims to use a Factor Quality Index (FQI) as an indicator of the emission factor's ability to estimate emissions for the entire national population. However, the EPA does not list the FQI or how it is determined in the Draft Report. The FQI relies solely on a statistical evaluation to determine if the *results* of each dataset seem to be similar. Relying solely upon numerical results does not indicate whether a population of datasets is representative of a national population, especially when the larger national population spans many industries, applications, service types, and capacities. The EPA should perform a qualitative analysis of the source population to determine if the entire body of datasets are representative of the national population prior to performing any numerical analysis. If the qualitative evaluation does not show that the data is representative of the national population then the numerical analyses should not be performed until sufficient additional data is collected to pass the qualitative test.

Specific Comments to Revised AP-42 - Section 13.5 Industrial Flares NOx Emission Factor

1. Only four (4) test reports from five (5) units were used to develop the emission factor for oxides of nitrogen (NOx) from flares. Five (5) units are inadequate to determine an average NOx emission factor for all industrial flares of varying size, service type, and method of operation. The Office of Inspector General ("OIG"), in an evaluation report titled "*EPA Can Improve Emissions Factors Development and Management*" (March 22, 2006) (the "OIG Evaluation Report"), states:

   > "EPA officials told us that the majority of emissions factors are developed using 10 points of data or less, which is substantially less than the 30-50 data points recommended for the development of a valid statistical analysis." (p. 17)

   Using the OIG Evaluation Report as a guide, the statistical analysis for the development of the revised NOx emission factor is not valid and, therefore, should not be used in developing a nationwide emission factor.

2. In determining statistical outliers, the EPA states that outliers cannot be determined with three (3) or fewer data points (*Recommended Procedures for Development of Emission Factors and*

Use of the WebFIRE Database, EPA 2013). Though there are more than three (3) data points in this case, the samples size is still very small. Accordingly, more test reports should be utilized to increase the confidence in determining which data points may be outliers. Moreover, all the data used to determine the existing NOx emission factor for industrial flares is lumped into one point for the EPA's analysis in the Draft Report. All the individual data points obtained for the existing NOx emission factor should be utilized to increase the relevance of the statistical analysis. The EPA should aim to include 30-50 data points as recommended in the OIG Evaluation Report.

3. None of the test reports relied upon by the EPA to develop the revised NOx emission factor include any data on NOx emissions. In fact, the EPA concedes in the "*Draft EPA Review of Available Documents for Developing Proposed Emissions Factors for Flares, Tanks, and Wastewater Treatment Systems* that although NOx data was not included in the test reports, the raw data on NOx emissions concentrations measured during the various tests and studies was available and was incorporated into the emission factor development process. Accordingly, the fact that such raw NOx emissions data was not the focus of the underlying reports questions both the validity of the data and the unfettered reliance by the EPA on the same in developing its revised NOx emission factor.

4. The EPA claims to use a Factor Quality Index (FQI) as an indicator of a single emission factor's ability to estimate emissions for the entire national population. However, the EPA does not list the FQI in the Draft Report. The dataset for NOx emissions from flares does not seem to represent the national population of industrial flares. The dataset only includes the petrochemical refining industry and consists of four (4) steam assisted flares, one (1) air assisted flare and zero (0) non-assisted flares. The FQI purports to be a statistical analysis to determine if data belongs to part of a population but does not include any quantifiable analysis to determine if a limited dataset for a single industry and limited service options are representative of a national population of flares.

5. The proposed emission factor is five (5) times higher than the test results for the lone air assisted flare. Given that three (3) or fewer datasets are needed to determine outliers it is not known if this data is representative and therefore should not be applied to air-assisted flares.

6. There are no emissions data points for non-assisted flares. Accordingly, the EPA should not apply the proposed emission factor to any flare that is non-assisted.

7. The NOx emissions data consisted of 1-minute concentration-pathlength data with 15-20 minutes runs. In the EPA test methods for compliance, one hour sample runs are required. The EPA should not use different sampling techniques to develop an emission factor than what is required to show compliance with an emission factor.

8. The formula for determining the mass flow of carbon in the flare vent gas (C_inlet) relies on a molar volume correction factor that is given as 385.5 scf/lb-mole. The EPA does not state how this factor is derived. This correction factor varies with the composition of the vent gas stream though the EPA seems to apply the same factor to each vent gas stream without regards to the composition. Thus, it appears that this factor has been overvalued for the representative vent flare streams. The use of the correction factor in the denominator therefore undervalues the mass flow of carbon in the flare vent gas. This has led to the NOx emissions per quantity

of vent gas flared being greatly exaggerated. This calculation should be redone using appropriate correction factors specific to the composition of the gas in each vent gas stream.

9. EPA has assigned an Individual Test Rating ("ITR") for each dataset included in the analysis. The data for the existing NOx emission factor has an ITR of 80. However, the data from the Draft Report has ITRs ranging from 38 to 52, which indicates far inferior data quality, even for the best sets. Based on this information, the EPA should disregard the proposed data and retain the currently published emission factor for NOx. This conclusion is supported by the OIG Evaluation Report, which stresses the importance of the quality of the data upon which emission factors are based and not just the quantity.

10. The dataset for the Flint Hills flare tests has an ITR of 38. In reviewing the calculation of the ITR it reveals that there has been no assessment of the validity or representativeness of the data, calibration gas certifications were not provided, interference tests were not run, response times were not included, calibration error tests were omitted, drift tests were not provided, bias tests were not conducted, and stratification tests were not included. If submitted to the EPA for compliance, these test results would not be accepted. The EPA should not be using data to create an emission factor that would not be accepted for showing compliance with such emission factor. Given the poor quality of the Flint Hills flare test data, the EPA should exclude this data. Further, the EPA should review all other ITR data and exclude any additional data that is not reliable for the calculation of emission factors.

11. The dataset for NOx appears to have data that greatly skews the emission factor from the Flint Hills facility. Because of the very limited sample size, this data may not be shown as an outlier using EPA recommended equations. However, an increased sample size, as recommended in the OIG Evaluation Report, including the use of all the individual data points obtained for the existing NOx emission factor, would allow for greater confidence on whether this data point belongs in the same population with the remaining data.

12. Review of the raw datasets reveals that not all data has been validated and corresponding outliers removed from the average for that unit. Specifically, the raw data for the Flint Hills data point has not been validated. Using EPA methods for determining outliers, many of the data points used to determine the average of the Flint Hills unit would be disregarded as outliers, thus lowering the average. The EPA should not be using non-validated data to determine nationwide emission factors. Further, the EPA should review and validate all the data from the dataset and disregard outliers in the raw data prior to creating an average emission factor for that unit.

Due to the questionable methodology and poor quality of the data upon which the draft revisions to *AP-42 - Section 13.5 Industrial Flares* are based, MarkWest respectfully requests that the EPA reject the proposed emission factors and withdraw the draft revisions to *AP-42 - Section 13.5 Industrial Flares*. MarkWest further respectfully requests that the currently published emission factors continue to be used until such time as the EPA obtains data of such quality and relevance to be representative of a national population.

Thank you for the opportunity to comment on the EPA's draft revisions to *AP-42 - Section 13.5 Industrial Flares.* Should you have any questions about this comment letter or be interested in engaging further on this matter, please contact me via telephone at (303) 542-0686 or email at nwheldon@markwest.com.

Sincerely,

Nathan M. Wheldon, PE
Environmental Manager

From:	Fournier, Jacob R. (MPC) <jrfournier@marathonpetroleum.com>
Sent:	Friday, December 19, 2014 4:12 PM
To:	RefineryFactor
Cc:	Lassiter, Penny; Shine, Brenda; Tsirigotis, Peter; Garwood, Gerri
Subject:	MPC Comments on Proposed changes to AP-42 sections 5.1, 8.13. and 13.5 posted August 19, 2014
Attachments:	MPC Comments EPA Proposed Revisions Petroleum Refineries.pdf

Attached are Marathon Petroleum Company's comments on the proposed revisions to Sections 5.1, 8.13, and 13.5 of AP-42 and the draft Emissions Estimation Protocol for Petroleum Refineries posted August 19, 2014.

Environmental Support

Marathon Petroleum Company LP

539 South Main Street
Findlay, OH 45840
Telephone 419/422-2121
FAX 419/425-7040

December 19, 2014

Honorable Janet McCabe
Acting Assistant Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, D.C. 20460

refineryfactor@epa.gov

Re: Proposed Revisions to Sections 5.1, 8.13, and 13.5 of AP-42 and the Draft Emission Estimation Protocol for Petroleum Refineries - Version 3.0 posted August 19, 2014

Dear Acting Assistant Administrator McCabe:

Marathon Petroleum Company LP (Marathon Petroleum) appreciates this opportunity to provide comments regarding revisions to sections 5.1, 8.13, and 13.5 of AP-42 and the Draft Emissions Estimation Protocol for Petroleum Refineries version 3.0. Marathon Petroleum is an independent refiner and is the nation's fourth largest refiner. Marathon Petroleum is proud to participate in Responsible Care®, a commitment to the continual improvement of environmental, health, safety and security performance. Responsible Care reflects Marathon Petroleum's commitment to doing the right things for the right reasons.

Marathon Petroleum worked with API on the development of the comments submitted for the proposed changes to AP-42. Marathon Petroleum fully supports the comments provided by API. Marathon Petroleum worked very closely with the people who developed the flare Passive Fourier Transform Inferred(PFTIR) testing used to develop the emission factors for flares in the early stages of the use of the testing.

Marathon Petroleum would like to take the opportunity to comment on the proposed emission factors that were developed based on the PFTIR testing. Marathon Petroleum would also like to take the opportunity to include data from Marathon Petroleum Hydrogen Cyanide (HCN) emissions testing from Fluid Catalytic Cracking Units (FCCUs) to include in potential reconsideration of the proposed emission factor (HCN). The data from the FCCU HCN testing can be found in Attachment 2 of this document. Please contact Charles Bennett (606-921-3636) or Jake Fournier (419-421-3514) with any questions regarding this submittal.

Sincerely,

Charles D. Bennett
Marathon Petroleum Company LP
Corporate Environmental Support
539 South Main Street
Findlay, OH 45840

Cc: Peter Tsirigotis
Penny Lassiter
Brenda Shine

ATTACHMENT 1
Detailed Comments and Supporting Data

Use of the flare PFTIR test results to develop the revised NOx emission factor does not properly represent NOx emissions from refining industry flares.

In April 2012, Marathon Petroleum signed an innovative agreement with the EPA to cap the volume of gas it sends to the flares and to install state-of-the art controls on its 22 flares to ensure combustion efficiency, which would result in reduced steam usage and increased product recovery. Marathon Petroleum, under the direction and oversight of EPA, spent more than $2.4 million to develop and pioneer the combustion efficiency testing of flares and to advance the understanding of the relationship between flare operating parameters and flare combustion efficiency. This testing was the PFTIR testing used by EPA to develop the NOx emission factor.

The PFTIR testing, however, was not developed nor used to determine the destruction efficiency of flares. The testing does not produce an actual concentration, but instead provides an average concentration per meter of the flare plume width. The flare plume width is not a constant width and, in fact, can have a fairly large variation on a minute-by-minute basis based on wind and other atmospheric conditions that would affect the measuring device's path through the plume.

When determining combustion efficiency, the formula for combustion efficiency provides carbon dioxide over the sum of the carbon-containing compounds. Using this equation, the ppm*meter units cancel, resulting in the desired unitless ratio. This allows for the data to be used to determine a combustion efficiency. Upon review of the data used to calculate the NOx emission factor, Marathon Petroleum believes this method must be used in order to develop the NOx emission factor. To do this, two critical assumptions must be made for the calculation to be valid. It must be assumed that the NOx to CO_2 ratio emitted remains constant for every stream regardless of composition. Similarly an assumption that there is a correlation between NOx formation and CO_2 formation must be made to make the equations used to calculate the new emission factor for NOx valid. The basic chemistry that dictates the formation of NOx does not support this assumption and make the calculations performed to derive the new emission factor problematic. These assumption becomes increasingly problematic when the vent gas stream is high in hydrogen when NOx would remain relatively constant compared to a similar stream of hydrocarbon but the CO_2 creation would be much smaller.

Marathon Petroleum does not believe that using one minute average data is appropriate when evaluating the data from the PFTIR testing. The PFTIR monitor is continually trying to produce a representative sample from the flare plume by manually directing the testing ray into the plume using a mechanical means. Because the plume is constantly changing direction with wind directional changes, data collected in a one minute period may not be representative of the entire flare plume. 20 minute averaging is used while evaluating the data from the PFTIR testing to account for the variability in the measurement position.

Marathon Petroleum believes there were also data quality issues associated with the use of the PFTIR data for the development of a NOx emission factor. Specifically, the test was not properly calibrated to collect NOx data. A requirement for performing the PFTIR testing is ensuring the spectral bands that are being analyzed during the test are optimized to minimize the potential for interference from other compounds. Water vapor can be a major source of interference which becomes problematic when readings are taken from a steam-assisted flare and the spectral bands are not optimized for a certain compound. During the PFTIR testing performed at the Marathon Petroleum facilities, NOx was not a compound selected to be studied and thus the spectra were not tuned to limit these types of interferences for the measurement of NOx. Another portion of the PFTIR testing involves the use of calibration gases to develop a calibration curve for the compounds being measured. A calibration curve was not developed for NOx during this testing, which also calls into question the quality of the NOx data that was used to develop the proposed emission factor.

Marathon Petroleum requests that EPA reconsider the use of the PFTIR data in the development of new NOx emission factors for flares. Other testing has been done with the intention of looking at NOx formation in flare systems. This includes data from TCEQ testing and tests performed by the International Flaring Consortium. The data from these tests more accurately represent refinery flare operations and could be used to develop AP-42 factors.

Marathon Petroleum reviewed data from the TCEQ where NOx emissions where a specific pollutant that the testing looked at and for which proper calibrations were made. An average of this data would show an emission factor of 0.017 lbs NOx/MMBTU. This factor is significantly lower than the proposed emission factor in the proposed changes to AP-42.

Attachment 2: FCCU HCN Stack Tests
Garyville
Detroit
Robinson

Table 2-3:
FCCU Regenerator Vent – VOC, Condition 1

Run No.		4	5	6	7	Average
Date (2014)		Mar 21	Mar 21	Mar 21	Mar 21	
Start Time (approx.)		08:34	10:30	12:51	14:08	
Stop Time (approx.)		09:54	11:40	13:52	15:11	
Process Conditions						
R_p	Production Rate (MW/gross)	70.0	70.3	71.0	71.2	70.7
P_1	L/G	18.0	18.0	18.0	18.0	18.
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	8,760	8,760
Gas Conditions						
O_2	Oxygen (dry volume %)	3.3	1.1	0.9	1.0	1.7
CO_2	Carbon Dioxide (dry volume %)	16.6	18.9	19.1	19.1	18.4
Gas Flow Rate						
Q_a	Volumetric flow rate, actual (acfm)	265,000	276,000	265,000	272,000	267,000
Q_s	Volumetric flow rate, standard (scfm)	224,000	234,000	230,000	231,000	229,000
Q_{std}	Volumetric flow rate, dry standard (dscfm)	175,000	183,000	180,000	181,000	178,000
Total Hydrocarbon Results						
C_s	THC Concentration (ppmwv)	2.49	2.44	2.10	0.99	1.86
$E_{lb/hr}$	THC Rate (lb/hr)	2.99	3.06	2.60	1.23	2.27
$E_{T/yr}$	THC Rate (Ton/yr)	13.11	13.40	11.37	5.41	9.96

Average includes 3 runs. Run 5 not included.

Table 2-4:
FCCU Regenerator Vent – HCN, Condition 1

Run No.		1	2	3	8	Average
Date (2014)		Mar 18	Mar 18	Mar 19	Mar 21	
Start Time (approx.)		10:45	17:56	09:14	08:23	
Stop Time (approx.)		12:01	19:09	10:23	09:32	
Process Conditions						
R_p	Coke Burn Rate (MPPH)	69.7	70.7	70.1	69.9	70.2
P_1	L/G	18.1	18.	18.7	18.	18.2
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	8,760	8,760
Gas Conditions						
O_2	Oxygen (dry volume %)	2.7	2.9	3.7	2.3	2.9
CO_{2out}	Carbon dioxide at the outlet of the sampling train (dry volume %)	13.5	13.8	11.7	13.4	13.1
CO_{2in}	Carbon dioxide in the stack (dry volume %)	17.5	17.4	17.5	17.5	17.5
T_s	Sample temperature (°F)	143	143	144	143	143
B_w	Actual water vapor in gas from concurrent USEPA Method 4 test (% by volume)	21.98	22.07	21.58	18.82	21.11
Gas Flow Rate						
Q_a	Volumetric flow rate, actual (acfm)	268,000	264,000	272,000	265,000	267,000
Q_s	Volumetric flow rate, standard (scfm)	232,000	229,000	237,000	224,000	231,000
Q_{std}	Volumetric flow rate, dry standard (dscfm)	181,000	178,000	185,000	175,000	180,000
Hydrogen Cyanide (HCN) Results						
C_{sd}	HCN Concentration (ppmdv)	26.99	31.35	25.03	31.93	28.82
C_{sd7}	HCN Concentration @7% O2 (ppmdv)	20.61	24.21	20.23	23.86	22.23
$E_{lb/hr}$	HCN Rate (lb/hr)	20.54	23.53	19.46	23.51	21.76
$E_{T/yr}$	HCN Rate (Ton/yr)	89.98	103.04	85.25	102.96	95.31

Average includes 3 runs. Run 1 was not included.

RESULTS

Table 2-7:
FCCU Regenerator Vent – VOC, Condition 2

Run No.		1	2	3	Average
Date (2014)		Mar 20	Mar 20	Mar 20	
Start Time (approx.)		09:07	13:07	14:20	
Stop Time (approx.)		10:17	14:09	15:22	
Process Conditions					
R_p	Production Rate (MW/gross)	70.2	70.2	70.6	**70.3**
P_1	L/G	21.8	21.8	21.8	**21.8**
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	**8,760**
Gas Conditions					
O_2	Oxygen (dry volume %)	1.3	1.2	1.1	**1.2**
CO_2	Carbon Dioxide (dry volume %)	18.8	18.8	18.9	**18.8**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	259,000	245,000	242,000	**249,000**
Q_s	Volumetric flow rate, standard (scfm)	224,000	215,000	211,000	**216,000**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	175,000	168,000	165,000	**169,000**
Total Hydrocarbon Results					
C_s	THC Concentration (ppmwv)	3.56	3.11	2.64	**3.10**
$E_{lb/hr}$	THC Rate (lb/hr)	4.27	3.58	2.99	**3.61**
$E_{T/yr}$	THC Rate (Ton/yr)	18.70	15.68	13.09	**15.82**

Table 2-8:
FCCU Regenerator Vent – HCN, Condition 2

Run No.		4	5	6	7	Average
Date (2014)		Mar 19	Mar 19	Mar 19	Mar 20	
Start Time (approx.)		11:23	13:27	15:31	09:31	
Stop Time (approx.)		12:32	14:38	16:41	11:11	
Process Conditions						
R_p	Production Rate (MW/gross)	70.5	70.4	70.7	70.3	**70.5**
P_1	L/G	20.8	20.8	20.8	21.8	**21.1**
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	8,760	**8,760**
Gas Conditions						
O_2	Oxygen (dry volume %)	10.0	2.3	1.8	3.6	**2.6**
CO_{2out}	Carbon dioxide at the outlet of the sampling train (dry volume %)	7.0	12.5	13.0	11.3	**12.3**
CO_{2in}	Carbon dioxide in the stack (dry volume %)	15.1	16.8	17.9	16.0	**16.6**
T_s	Sample temperature (°F)	144	143	143	143	**143**
B_w	Actual water vapor in gas from concurrent USEPA Method 4 test (% by volume)	20.19	19.86	21.42	20.37	**20.55**
Gas Flow Rate						
Q_a	Volumetric flow rate, actual (acfm)	277,000	287,000	274,000	259,000	**273,000**
Q_s	Volumetric flow rate, standard (scfm)	242,000	250,000	239,000	224,000	**237,000**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	188,000	195,000	186,000	175,000	**185,000**
Hydrogen Cyanide (HCN) Results						
C_{sd}	HCN Concentration (lb/dscf)	1.44E-06	1.61E-06	1.58E-06	1.56E-06	**1.58E-06**
$E_{lb/hr}$	HCN Rate (lb/hr)	16.22	18.84	17.71	16.32	**17.62**
$E_{T/yr}$	HCN Rate (Ton/yr)	71.04	82.50	77.56	71.49	**77.19**

Average includes 3 runs. Run 4 was not included.

End of Section 2 – Results

Time	CORRECTED REACTOR FEED MBPD 25F3012A	LIQUID TO GAS RATIO G/MSCF 30C3532L	REGEN COKE BURNING RATE MPPH 25CokeBN	Unit 30 Scrubber spray nozzle Pressure psig 30SCRspray01psig.or	Unit 30 Scrubber 02 spay nozzle Pressure psig 30SCRspray02psig.or	Unit 30 Scrubber 03 spay nozzle Pressure psig 30SCRspray03psig.or	Unit 30 Scrubber 04 spray nozzle Pressure psig 30SCRspray04psig.or	OXYGEN & BLOWER FEED CORR. MSCF 25AIrtot	THROAT VELOCITY feet/min 25C3147V	FLUE GAS STK TMP deg F 30TI6008	FLUE GAS SCRUBBR STK TMP deg F 30TI1807	Dry Flue Gas Rate MMOL/H 25F3147D	SCRUBBER STACK O2 % 30AI6014	SCRUBBER STACK SO2 ppm 30AI6013	SCRUBBER SELECTED NOX ppm 30AI6012
3/18/2014 10:45	127.29	18.11	69.47	7.10	6.90	7.30	5.70	203.01	252.24	142.71	143.03	29.65	1.53	2.28	33.77
3/18/2014 10:46	127.29	18.11	69.45	7.10	6.90	7.30	5.70	202.73	251.68	142.69	142.97	29.69	1.58	2.43	33.64
3/18/2014 10:47	127.30	18.09	69.49	7.10	6.90	7.30	5.70	203.23	251.57	142.60	142.78	29.71	1.50	2.34	33.59
3/18/2014 10:48	127.30	18.06	69.42	7.10	6.90	7.30	5.70	202.84	250.85	142.59	142.73	29.71	1.41	2.71	34.39
3/18/2014 10:49	127.29	17.97	69.31	7.10	6.90	7.30	5.70	201.91	249.97	142.56	142.54	29.73	1.44	2.54	34.35
3/18/2014 10:50	127.29	18.03	69.23	7.10	6.90	7.30	5.70	202.57	250.80	142.64	142.61	29.69	1.33	2.69	35.33
3/18/2014 10:51	127.29	18.20	68.96	7.10	6.90	7.30	5.70	202.37	251.06	142.86	142.82	29.62	1.28	2.56	33.96
3/18/2014 10:52	127.29	18.20	68.83	7.10	6.90	7.30	5.70	203.24	251.91	142.79	142.79	29.60	1.46	2.30	33.68
3/18/2014 10:53	127.29	18.29	68.66	7.10	6.90	7.30	5.70	203.52	252.05	142.58	142.71	29.57	1.44	2.24	32.84
3/18/2014 10:54	127.28	18.18	68.69	7.10	6.90	7.30	5.70	203.53	252.48	142.59	142.75	29.52	1.62	2.58	32.98
3/18/2014 10:55	127.28	18.16	68.84	7.10	6.90	7.30	5.70	203.61	252.12	142.63	142.86	29.56	1.50	2.51	33.11
3/18/2014 10:56	127.28	18.13	68.98	7.10	6.90	7.30	5.70	202.34	250.84	142.58	142.82	29.65	1.50	2.29	32.53
3/18/2014 10:57	127.28	18.05	69.06	7.10	6.90	7.30	5.70	201.84	250.06	142.45	142.70	29.71	1.50	2.18	33.22
3/18/2014 10:58	127.28	18.06	69.15	7.10	6.90	7.30	5.70	201.18	249.56	142.45	142.72	29.76	1.17	2.10	33.03
3/18/2014 10:59	127.28	18.07	69.17	7.10	6.90	7.30	5.70	201.83	249.58	142.45	142.75	29.78	1.07	2.00	32.29
3/18/2014 11:00	127.27	18.07	69.10	7.10	6.90	7.30	5.70	201.79	249.67	142.43	142.75	29.74	1.14	1.66	31.52
3/18/2014 11:01	127.27	18.06	69.21	7.10	6.90	7.30	5.70	201.60	249.49	142.38	142.75	29.77	1.44	1.59	31.21
3/18/2014 11:02	127.28	18.07	69.39	7.10	6.90	7.30	5.70	201.46	249.23	142.41	142.77	29.71	1.27	1.59	32.33
3/18/2014 11:03	127.28	18.30	69.43	7.10	6.90	7.30	5.70	201.83	250.04	142.50	142.83	29.66	1.24	1.42	31.77
3/18/2014 11:04	127.28	18.30	69.58	7.10	6.90	7.30	5.70	201.68	250.00	142.50	142.83	29.67	1.49	1.28	33.10
3/18/2014 11:05	127.29	18.20	69.65	7.10	6.90	7.30	5.70	201.47	249.70	142.48	142.82	29.71	1.46	1.31	32.66
3/18/2014 11:06	127.29	18.09	69.76	7.10	6.90	7.30	5.70	201.35	249.38	142.51	142.85	29.75	1.31	1.10	31.24
3/18/2014 11:07	127.29	18.07	69.70	7.10	6.90	7.30	5.70	201.89	250.28	142.62	142.92	29.73	1.12	1.07	31.31
3/18/2014 11:08	127.28	18.07	69.49	7.10	6.90	7.30	5.70	202.12	250.12	142.58	142.91	29.68	1.25	0.80	31.05
3/18/2014 11:09	127.28	18.07	69.36	7.10	6.90	7.30	5.70	202.19	249.63	142.63	142.87	29.63	1.43	0.76	30.04
3/18/2014 11:10	127.29	18.12	69.27	7.10	6.90	7.30	5.70	201.78	249.73	142.96	142.80	29.54	1.32	0.82	30.87
3/18/2014 11:11	127.29	18.28	69.21	7.10	6.90	7.30	5.70	201.44	249.42	142.60	142.53	29.51	1.23	0.51	29.58
3/18/2014 11:12	127.29	18.25	69.32	7.10	6.90	7.30	5.70	200.28	247.78	142.61	142.34	29.54	1.30	0.34	29.73
3/18/2014 11:13	127.29	18.16	69.36	7.10	6.90	7.30	5.70	200.22	248.42	142.64	142.41	29.59	1.04	0.36	28.77
3/18/2014 11:14	127.29	18.14	69.37	7.10	6.90	7.30	5.70	200.99	248.60	142.66	142.63	29.54	1.09	0.67	29.71
3/18/2014 11:15	127.29	18.08	69.42	7.10	6.90	7.30	5.70	200.23	247.41	142.72	142.72	29.54	1.11	0.47	29.23
3/18/2014 11:16	127.28	18.10	69.53	7.10	6.90	7.30	5.70	200.51	248.36	142.76	143.04	29.55	1.07	0.42	29.28
3/18/2014 11:17	127.28	18.17	69.55	7.10	6.90	7.30	5.70	201.35	249.08	142.88	143.03	29.46	1.09	0.28	27.76
3/18/2014 11:18	127.29	18.19	69.64	7.10	6.90	7.30	5.70	200.66	248.78	142.88	143.01	29.49	1.01	0.30	28.67
3/18/2014 11:19	127.30	18.25	69.76	7.10	6.90	7.30	5.70	201.43	249.34	142.87	143.03	29.49	0.97	0.25	28.90
3/18/2014 11:20	127.30	18.24	69.88	7.10	6.90	7.30	5.70	201.46	249.21	142.85	143.11	29.48	1.06	0.32	29.57
3/18/2014 11:21	127.30	18.21	70.07	7.10	6.90	7.30	5.70	200.67	248.57	142.80	143.17	29.57	1.26	0.18	29.73
3/18/2014 11:22	127.30	18.22	70.25	7.10	6.90	7.30	5.70	200.37	248.08	142.88	143.35	29.61	1.13	0.18	29.68
3/18/2014 11:23	127.29	18.23	70.30	7.10	6.90	7.30	5.70	201.30	248.82	143.12	143.37	29.59	1.08	0.18	28.10
3/18/2014 11:24	127.30	18.23	70.15	7.10	6.90	7.30	5.70	201.60	249.61	143.15	143.45	29.52	1.10	0.18	28.41
3/18/2014 11:25	127.30	18.22	70.05	7.10	6.90	7.30	5.70	201.61	249.41	143.24	143.48	29.56	1.16	0.19	29.25
3/18/2014 11:26	127.30	18.17	70.08	7.10	6.90	7.30	5.70	202.98	249.31	143.25	143.59	29.58	1.08	0.19	28.67
3/18/2014 11:27	127.29	18.00	70.21	7.10	6.90	7.30	5.70	203.20	250.77	143.31	143.58	29.66	1.15	0.18	28.75
3/18/2014 11:28	127.29	18.04	70.85	7.10	6.90	7.30	5.70	203.11	251.29	143.28	143.54	29.69	1.19	0.28	28.96
3/18/2014 11:29	127.30	18.14	70.20	7.10	6.90	7.30	5.70	204.13	252.69	143.21	143.51	29.64	1.25	0.18	28.96
3/18/2014 11:30	127.30	18.11	70.17	7.10	6.90	7.30	5.70	203.51	251.89	143.21	143.41	29.66	1.21	0.18	28.64
3/18/2014 11:31	127.30	18.01	70.27	7.10	6.90	7.30	5.70	203.17	251.36	143.21	143.40	29.72	1.15	0.19	27.68
3/18/2014 11:32	127.30	18.01	70.26	7.10	6.90	7.30	5.70	202.74	251.03	143.31	143.38	29.72	1.17	0.19	27.81
3/18/2014 11:33	127.30	18.00	70.16	7.10	6.90	7.30	5.70	202.44	250.39	143.58	143.42	29.72	1.05	0.18	28.19
3/18/2014 11:34	127.30	18.03	69.91	7.10	6.90	7.30	5.70	202.42	251.25	143.60	143.53	29.62	0.98	0.18	27.51
3/18/2014 11:35	127.30	18.11	69.76	7.10	6.90	7.30	5.70	202.30	250.42	143.67	143.63	29.55	0.90	0.19	25.72
3/18/2014 11:36	127.30	18.10	69.78	7.10	6.90	7.30	5.70	202.06	250.08	143.71	143.91	29.55	1.02	0.19	26.62
3/18/2014 11:37	127.31	18.06	69.88	7.10	6.90	7.30	5.70	202.28	250.54	143.84	143.97	29.59	0.95	0.19	27.14
3/18/2014 11:38	127.31	18.09	70.02	7.10	6.90	7.30	5.70	203.06	250.83	143.87	144.15	29.58	0.90	0.19	27.42
3/18/2014 11:39	127.30	18.17	70.11	7.10	6.90	7.30	5.70	203.51	251.70	143.98	144.18	29.58	1.15	0.19	27.94
3/18/2014 11:40	127.30	18.12	70.41	7.10	6.90	7.30	6.70	204.34	251.87	143.96	144.16	29.66	1.33	0.19	26.98
3/18/2014 11:41	127.30	17.96	70.53	7.10	6.90	7.30	5.70	203.88	252.24	143.90	144.29	29.69	1.36	0.18	27.17
3/18/2014 11:42	127.30	18.00	70.68	7.10	6.90	7.30	5.70	203.39	251.85	143.91	144.38	29.75	1.39	0.18	28.11
3/18/2014 11:43	127.31	18.13	70.60	7.10	6.90	7.30	5.70	203.30	251.59	143.93	144.35	29.70	1.41	0.18	29.19
3/18/2014 11:44	127.31	18.14	70.27	7.10	6.90	7.30	5.70	202.76	250.74	143.93	144.26	29.62	1.37	0.18	29.06
3/18/2014 11:45	127.30	18.15	69.94	7.10	6.90	7.30	5.70	203.04	250.93	143.92	144.29	29.59	1.20	0.18	28.47
3/18/2014 11:46	127.30	18.19	69.68	7.10	6.90	7.30	5.70	202.92	251.49	143.93	144.37	29.47	1.08	0.18	28.07
3/18/2014 11:47	127.29	18.30	69.32	7.10	6.90	7.30	5.70	203.27	251.33	143.96	144.34	29.45	1.13	0.19	28.64
3/18/2014 11:48	127.29	18.28	69.20	7.10	6.90	7.30	5.70	202.83	250.84	143.94	144.26	29.45	1.24	0.19	28.49
3/18/2014 11:49	127.30	18.24	69.29	7.10	6.90	7.30	5.70	203.06	251.42	143.85	144.22	29.46	1.26	0.18	28.31
3/18/2014 11:50	127.30	18.21	69.54	7.10	6.90	7.30	5.70	201.69	252.56	143.86	144.08	29.60	1.17	0.18	29.22
3/18/2014 11:51	127.28	18.12	69.89	7.10	6.90	7.30	5.70	202.84	250.93	143.89	144.01	29.67	1.36	0.18	28.67

Time	CORRECTED REACTOR FEED MBPD 25F3012A	LIQUID TO GAS RATIO G/MSCF 30C3532L	REGEN COKE BURNING RATE MPPH 25CokeBN	Unit 30 Scrubber spay nozzle Pressure psig 30SCRspray01psig.or	Unit 30 Scrubber 02 spay nozzle Pressure psig 30SCRspray02psig.or	Unit 30 Scrubber 03 spay nozzle Pressure psig 30SCRspray03psig.or	Unit 30 Scrubber 04 spay nozzle Pressure psig 30SCRspray04psig.or	OXYGEN & BLOWER FEED CORR. MSCF 25Airtot	THROAT VELOCITY feet/min 25C3147V	FLUE GAS STK TMP deg F 30TI6008	FLUE GAS SCRUBBR STK TMP deg F 30TI1807	Dry Flue Gas Rate MMOL/H 25F3147D	SCRUBBER STACK O2 % 30AI5014	SCRUBBER STACK SO2 ppm 30AI5013	SCRUBBER SELECTED NOX ppm 30AI5012
3/18/2014 11:52	127.28	18.31	69.93	7.10	6.90	7.30	5.70	202.74	251.24	143.88	143.78	29.65	1.32	0.18	27.59
3/18/2014 11:53	127.28	18.30	70.03	7.10	6.90	7.30	5.70	202.39	250.27	143.86	143.77	29.69	1.21	0.19	29.25
3/18/2014 11:54	127.28	18.09	70.00	7.10	6.90	7.30	5.70	202.18	249.79	143.84	143.71	29.68	1.26	0.19	29.28
3/18/2014 11:55	127.30	18.03	69.90	7.10	6.90	7.30	5.70	202.31	250.39	143.78	143.76	29.66	1.18	0.19	29.35
3/18/2014 11:56	127.30	18.04	69.89	7.10	6.90	7.30	5.70	202.61	250.66	143.80	143.90	29.69	1.16	0.19	29.32
3/18/2014 11:57	127.31	18.07	69.82	7.10	6.90	7.30	5.70	202.83	250.78	143.85	143.91	29.63	1.19	0.18	29.03
3/18/2014 11:58	127.30	18.09	69.68	7.10	6.90	7.30	5.70	204.09	252.83	143.77	143.95	29.60	1.36	0.18	28.35
3/18/2014 11:59	127.30	18.13	69.79	7.10	6.90	7.30	5.70	203.53	251.98	143.56	143.92	29.60	1.36	0.19	28.65
3/18/2014 12:00	127.30	18.16	69.76	7.10	6.90	7.30	5.70	203.67	251.98	143.53	143.86	29.58	1.44	0.19	29.87
3/18/2014 12:01	127.30	18.27	69.59	7.10	6.90	7.30	5.70	203.31	252.14	143.43	143.83	29.53	1.37	0.19	30.11
3/18/2014 12:02															
Average	127.29	18.12	69.68	7.10	6.90	7.30	5.70	202.37	250.50	143.16	143.35	29.62	1.25	0.79	29.97

Time	CORRECTED REACTOR FEED MBPD 25F3012A	LIQUID TO GAS RATIO G/MSCF 30C3532L	REGEN COKE BURNING RATE MPPH 25CokeBN	Unit 30 Scrubber spay nozzle Pressure psig 30SCRspray01psig.or	Unit 30 Scrubber 02 spay nozzle Pressure psig 30SCRspray02psig.or	Unit 30 Scrubber 03 spay nozzle Pressure psig 30SCRspray03psig.or	Unit 30 Scrubber 04 spay nozzle Pressure psig 30SCRspray04psig.or	OXYGEN & BLOWER FEED CORR. MSCF 25Airtot	THROAT VELOCITY feet/min 25C3147V	FLUE GAS STK TMP deg F 30TI6008	FLUE GAS SCRUBBR STK TMP deg F 30TI1807	Dry Flue Gas Rate MMOL/H 25F3147D	SCRUBBER STACK O2 % 30AI6014	SCRUBBER STACK SO2 ppm 30AI6013	SCRUBBER SELECTED NOX ppm 30AI6012
3/18/2014 17:56	127.24	17.90	70.55	7.10	6.90	7.30	5.70	198.13	245.28	143.16	143.58	29.73	1.05	0.20	36.21
3/18/2014 17:57	127.23	17.76	70.68	7.10	6.90	7.30	5.70	198.38	244.97	143.13	143.63	29.75	1.12	0.20	36.45
3/18/2014 17:58	127.23	17.81	70.68	7.10	6.90	7.30	5.70	198.70	246.02	143.15	143.57	29.68	1.20	0.20	35.84
3/18/2014 17:59	127.22	17.97	70.67	7.10	6.90	7.30	5.70	198.54	245.69	143.22	143.39	29.66	1.22	0.20	37.23
3/18/2014 18:00	127.21	17.96	70.68	7.10	6.90	7.30	5.70	198.52	245.05	143.21	143.36	29.65	1.11	0.20	36.74
3/18/2014 18:01	127.17	17.94	70.65	7.10	6.90	7.30	5.70	199.16	246.24	143.18	143.28	29.60	1.15	0.20	35.70
3/18/2014 18:02	127.17	17.95	70.52	7.10	6.90	7.30	5.70	199.57	246.68	143.16	143.22	29.57	1.24	0.20	36.81
3/18/2014 18:03	127.16	18.01	70.53	7.10	6.90	7.30	5.70	198.90	246.57	143.12	143.07	29.60	1.33	0.20	36.12
3/18/2014 18:04	127.16	17.97	70.63	7.10	6.90	7.30	5.70	198.76	246.06	143.13	143.13	29.69	1.19	0.20	36.27
3/18/2014 18:05	127.15	17.86	70.77	7.10	6.90	7.30	5.70	198.45	245.53	143.17	143.33	29.73	1.19	0.20	38.01
3/18/2014 18:06	127.15	17.86	70.74	7.10	6.90	7.30	5.70	198.84	245.68	143.18	143.39	29.71	1.15	0.20	36.01
3/18/2014 18:07	127.15	17.87	70.61	7.10	6.90	7.30	5.70	199.20	246.11	143.20	143.57	29.68	1.10	0.20	35.92
3/18/2014 18:08	127.15	17.87	70.53	7.10	6.90	7.30	5.70	198.79	246.07	143.21	143.59	29.66	1.16	0.20	36.12
3/18/2014 18:09	127.15	17.89	70.50	7.10	6.90	7.30	5.70	198.93	245.95	143.24	143.64	29.67	1.17	0.20	37.37
3/18/2014 18:10	127.15	17.92	70.63	7.10	6.90	7.30	5.70	199.25	245.76	143.26	143.67	29.71	1.30	0.20	35.19
3/18/2014 18:11	127.14	18.00	70.67	7.10	6.90	7.30	5.70	198.79	245.18	143.32	143.75	29.66	1.13	0.20	34.93
3/18/2014 18:12	127.13	18.00	70.65	7.10	6.90	7.30	5.70	198.17	244.98	143.31	143.69	29.64	1.19	0.20	36.97
3/18/2014 18:13	127.11	18.02	70.77	7.10	6.90	7.30	5.70	198.06	244.56	143.29	143.51	29.70	1.17	0.20	36.61
3/18/2014 18:14	127.10	18.03	70.80	7.10	6.90	7.30	5.70	197.93	245.41	143.38	143.47	29.72	1.13	0.20	35.79
3/18/2014 18:15	127.09	18.03	70.83	7.10	6.90	7.30	5.70	198.54	245.94	143.45	143.36	29.69	1.08	0.20	36.00
3/18/2014 18:16	127.09	18.03	70.69	7.10	6.90	7.30	5.70	198.45	245.92	143.39	143.32	29.66	1.23	0.20	34.69
3/18/2014 18:17	127.07	18.02	70.67	7.10	6.90	7.30	5.70	198.28	245.63	143.21	143.20	29.69	1.35	0.20	36.00
3/18/2014 18:18	127.07	17.99	70.78	7.10	6.90	7.30	5.70	198.00	245.09	143.27	143.32	29.72	1.37	0.20	36.33
3/18/2014 18:19	127.06	17.92	70.80	7.10	6.90	7.30	5.70	198.60	245.46	143.45	143.65	29.69	1.18	0.20	35.30
3/18/2014 18:20	127.06	17.94	70.67	7.10	6.90	7.30	5.70	198.52	245.27	143.45	143.65	29.67	1.28	0.20	36.63
3/18/2014 18:21	127.05	18.00	70.49	7.10	6.90	7.30	5.70	198.90	245.85	143.43	143.64	29.59	1.27	0.20	36.08
3/18/2014 18:22	127.05	17.96	70.38	7.10	6.90	7.30	5.70	198.78	245.74	143.42	143.68	29.62	1.37	0.20	35.83
3/18/2014 18:23	127.05	17.84	70.47	7.10	6.90	7.30	5.70	197.88	245.43	143.40	143.78	29.74	1.32	0.20	35.50
3/18/2014 18:24	127.05	17.84	70.74	7.10	6.90	7.30	5.70	197.62	245.05	143.42	143.84	29.78	1.15	0.20	35.24
3/18/2014 18:25	127.05	17.84	70.68	7.10	6.90	7.30	5.70	197.80	244.06	143.49	144.01	29.71	1.22	0.20	34.73
3/18/2014 18:26	127.04	17.88	70.47	7.10	6.90	7.30	5.70	197.01	244.49	143.50	143.97	29.67	1.02	0.20	34.97
3/18/2014 18:27	127.03	17.98	70.38	7.10	6.90	7.30	5.70	197.55	244.38	143.54	143.84	29.64	1.10	0.20	34.53
3/18/2014 18:28	127.03	17.97	70.46	7.10	6.90	7.30	5.70	197.52	244.23	143.55	143.76	29.65	1.17	0.20	37.29
3/18/2014 18:29	127.03	17.92	70.55	7.10	6.90	7.30	5.70	197.24	244.49	143.57	143.53	29.70	1.21	0.20	35.24
3/18/2014 18:30	127.03	17.91	70.79	7.10	6.90	7.30	5.70	196.92	243.89	143.54	143.51	29.71	1.19	0.20	35.07
3/18/2014 18:31	127.05	17.91	70.72	7.10	6.90	7.30	5.70	197.62	244.34	143.43	143.42	29.65	1.26	0.20	34.54
3/18/2014 18:32	127.04	17.90	70.72	7.10	6.90	7.30	5.70	197.70	244.01	143.44	143.46	29.64	1.31	0.20	35.14
3/18/2014 18:33	127.04	17.88	70.74	7.10	6.90	7.30	5.70	197.59	244.40	143.47	143.59	29.70	1.17	0.20	36.94
3/18/2014 18:34	127.04	17.90	70.77	7.10	6.90	7.30	5.70	197.36	243.71	143.49	143.64	29.69	1.14	0.23	37.04
3/18/2014 18:35	127.03	17.97	70.66	7.10	6.90	7.30	5.70	197.62	243.97	143.53	143.83	29.65	1.01	0.48	37.09
3/18/2014 18:36	127.04	17.98	70.52	7.10	6.90	7.30	5.70	197.45	244.74	143.55	143.87	29.58	1.00	1.07	36.40
3/18/2014 18:37	127.05	17.99	70.39	7.10	6.90	7.30	5.70	197.64	244.75	143.60	143.99	29.50	1.14	1.43	36.79
3/18/2014 18:38	127.05	17.97	70.40	7.10	6.90	7.30	5.70	197.92	244.78	143.57	143.98	29.53	1.14	1.51	37.81
3/18/2014 18:39	127.05	17.92	70.73	7.10	6.90	7.30	5.70	197.72	244.52	143.46	143.94	29.64	1.21	1.69	37.74
3/18/2014 18:40	127.05	17.93	70.97	7.10	6.90	7.30	5.70	197.59	243.74	143.51	143.94	29.69	1.15	1.65	38.72
3/18/2014 18:41	127.03	17.96	71.10	7.10	6.90	7.30	5.70	197.08	243.73	143.63	143.95	29.74	1.11	2.07	38.38
3/18/2014 18:42	127.04	17.93	71.14	7.10	6.90	7.30	5.70	196.83	243.39	143.64	143.89	29.73	1.22	1.98	39.83
3/18/2014 18:43	127.04	17.85	71.04	7.10	6.90	7.30	5.70	197.05	242.82	143.67	143.71	29.70	1.08	2.01	39.65
3/18/2014 18:44	127.05	17.88	71.00	7.10	6.90	7.30	5.70	196.93	244.08	143.68	143.70	29.67	0.98	2.43	38.79
3/18/2014 18:45	127.05	17.96	70.81	7.10	6.90	7.30	5.70	198.08	245.21	143.70	143.67	29.64	0.89	2.37	37.81
3/18/2014 18:46	127.05	17.99	70.58	7.10	6.90	7.30	5.70	198.47	246.43	143.64	143.62	29.52	1.07	2.86	38.25
3/18/2014 18:47	127.05	18.07	70.49	7.10	6.90	7.30	5.70	198.68	245.96	143.45	143.49	29.48	1.23	2.92	39.70
3/18/2014 18:48	127.04	18.03	70.52	7.10	6.90	7.30	5.70	198.50	246.08	143.45	143.54	29.48	1.30	3.03	39.52
3/18/2014 18:49	127.04	17.91	70.87	7.10	6.90	7.30	5.70	197.92	246.17	143.45	143.68	29.65	1.26	2.86	39.39
3/18/2014 18:50	127.04	17.94	71.10	7.10	6.90	7.30	5.70	197.90	245.33	143.48	143.74	29.76	1.12	2.89	40.59
3/18/2014 18:51	127.05	18.04	71.14	7.10	6.90	7.30	5.70	197.96	245.45	143.57	143.94	29.74	1.06	2.70	40.18
3/18/2014 18:52	127.05	18.01	70.98	7.10	6.90	7.30	5.70	198.29	245.81	143.53	143.93	29.72	0.95	2.37	38.93
3/18/2014 18:53	127.05	17.92	70.86	7.10	6.90	7.30	5.70	198.24	245.50	143.44	143.91	29.67	1.02	2.10	38.91
3/18/2014 18:54	127.05	17.94	70.87	7.10	6.90	7.30	5.70	198.44	244.53	143.44	143.91	29.68	1.19	2.05	38.86
3/18/2014 18:55	127.05	18.02	70.88	7.10	6.90	7.30	5.70	198.39	244.94	143.42	143.93	29.64	1.16	1.71	38.74
3/18/2014 18:56	127.05	17.99	70.90	7.10	6.90	7.30	5.70	198.58	246.14	143.41	143.81	29.61	1.20	1.73	38.55
3/18/2014 18:57	127.06	17.92	70.93	7.10	6.90	7.30	5.70	198.58	245.99	143.39	143.45	29.65	1.23	1.42	39.15
3/18/2014 18:58	127.06	17.94	70.90	7.10	6.90	7.30	5.70	198.45	245.56	143.40	143.41	29.64	1.29	1.24	38.22
3/18/2014 18:59	127.06	18.02	70.78	7.10	6.90	7.30	5.70	198.15	245.50	143.42	143.27	29.61	1.29	1.41	35.87
3/18/2014 19:00	127.06	18.02	70.74	7.10	6.90	7.30	5.70	198.54	245.49	143.41	143.32	29.64	1.22	1.49	37.82
3/18/2014 19:01	127.06	18.00	70.80	7.10	6.90	7.30	5.70	198.71	245.83	143.38	143.46	29.66	1.24	1.45	38.85
3/18/2014 19:02	127.06	18.00	70.79	7.10	6.90	7.30	5.70	198.44	245.10	143.39	143.52	29.71	1.20	1.72	37.81

Time	CORRECTED REACTOR FEED MBPD 25F3012A	LIQUID TO GAS RATIO G/MSCF 30C3532L	REGEN COKE BURNING RATE MPPH 25CokeBN	Unit 30 Scrubber spay nozzle Pressure psig 30SCRspray01psig.or	Unit 30 Scrubber 02 spay nozzle Pressure psig 30SCRspray02psig.or	Unit 30 Scrubber 03 spay nozzle Pressure psig 30SCRspray03psig.or	Unit 30 Scrubber 04 spay nozzle Pressure psig 30SCRspray04psig.or	OXYGEN & BLOWER FEED CORR. MSCF 25Airtot	THROAT VELOCITY feet/min 25C3147V	FLUE GAS STK TMP deg F 30TI6008	FLUE GAS SCRUBBR STK TMP deg F 30TI1807	Dry Flue Gas Rate MMOL/H 25F3147D	SCRUBBER STACK O2 % 30AI6014	SCRUBBER STACK SO2 ppm 30AI6013	SCRUBBER SELECTED NOX ppm 30AI6012
3/18/2014 19:03	127.05	18.01	70.72	7.10	6.90	7.30	5.70	198.83	245.08	143.45	143.70	29.69	1.13	1.39	37.05
3/18/2014 19:04	127.05	17.98	70.58	7.10	6.90	7.30	5.70	198.28	245.03	143.45	143.73	29.69	1.18	0.92	37.94
3/18/2014 19:05	127.04	17.90	70.57	7.10	6.90	7.30	5.70	197.74	244.98	143.45	143.81	29.70	1.15	0.96	38.22
3/18/2014 19:06	127.04	17.94	70.71	7.10	6.90	7.30	5.70	197.21	244.67	143.49	143.84	29.72	1.04	1.06	36.48
3/18/2014 19:07	127.05	18.09	70.88	7.10	6.90	7.30	5.70	197.70	244.34	143.60	143.92	29.76	1.17	1.13	35.61
3/18/2014 19:08	127.05	18.08	70.78	7.10	6.90	7.30	5.70	198.50	245.19	143.60	143.91	29.71	1.12	1.53	36.00
3/18/2014 19:09	127.05	18.08	70.72	7.10	6.90	7.30	5.70	198.57	246.03	143.59	143.84	29.67	1.14	1.21	38.49
3/18/2014 19:10															
Average	127.08	17.95	70.72	7.10	6.90	7.30	5.70	198.16	245.16	143.42	143.64	29.67	1.17	0.96	37.05

Time	CORRECTED REACTOR FEED MBPD 25F3012A	LIQUID TO GAS RATIO G/MSCF 30C3532L	REGEN COKE BURNING RATE MPPH 25CokeBN	Unit 30 Scrubber spray nozzle Pressure psig 30SCRspray01psig.or	Unit 30 Scrubber 02 spray nozzle Pressure psig 30SCRspray02psig.or	Unit 30 Scrubber 03 spray nozzle Pressure psig 30SCRspray03psig.or	Unit 30 Scrubber 04 spay nozzle Pressure psig 30SCRspray04psig.or	OXYGEN & BLOWER FEED CORR. MSCF 25Airtot	THROAT VELOCITY feet/min 25C3147V	FLUE GAS STK TMP deg F 30TI6008	FLUE GAS SCRUBBR STK TMP deg F 30TI1807	Dry Flue Gas Rate MMOL/H 25F3147D	SCRUBBER STACK O2 % 30AI6014	SCRUBBER STACK SO2 ppm 30AI6013	SCRUBBER SELECTED NOX ppm 30AI6012
3/19/2014 9:14	127.15	18.64	69.48	7.10	6.90	6.30	5.80	199.79	247.24	144.47	144.62	29.51	1.03	1.95	29.60
3/19/2014 9:15	127.16	18.77	69.48	7.10	6.90	6.30	5.80	200.56	248.20	144.42	144.51	29.47	1.14	1.75	30.21
3/19/2014 9:16	127.16	18.78	69.54	7.10	6.90	6.30	5.80	200.96	248.69	144.24	144.16	29.44	1.17	1.65	30.30
3/19/2014 9:17	127.15	18.81	69.68	7.10	6.90	6.30	5.80	200.52	248.11	144.20	144.12	29.44	1.22	1.50	30.40
3/19/2014 9:18	127.15	18.76	69.82	7.10	6.90	6.30	5.80	200.62	248.16	144.07	143.99	29.46	1.32	1.66	29.28
3/19/2014 9:19	127.16	18.62	69.84	7.10	6.90	6.30	5.80	200.64	248.30	144.04	144.01	29.49	1.22	1.58	29.03
3/19/2014 9:20	127.16	18.62	69.92	7.10	6.90	6.30	5.80	200.69	248.34	143.94	144.08	29.51	1.28	1.22	31.83
3/19/2014 9:21	127.15	18.62	69.98	7.10	6.90	6.30	5.80	200.69	248.45	144.01	144.14	29.58	1.13	1.78	29.86
3/19/2014 9:22	127.15	18.63	69.98	7.10	6.90	6.30	5.80	200.66	248.38	144.21	144.34	29.56	1.09	1.58	30.50
3/19/2014 9:23	127.15	18.69	69.95	7.10	6.90	6.30	5.80	200.53	248.15	144.21	144.36	29.57	1.06	1.42	30.42
3/19/2014 9:24	127.15	18.66	69.86	7.10	6.90	6.30	5.80	200.40	248.00	144.21	144.44	29.60	1.01	1.73	29.75
3/19/2014 9:25	127.15	18.59	69.86	7.10	6.90	6.30	5.80	200.14	247.64	144.20	144.45	29.59	1.04	1.58	28.43
3/19/2014 9:26	127.15	18.61	69.89	7.10	6.90	6.30	5.80	200.49	248.10	144.16	144.49	29.56	1.17	1.84	28.29
3/19/2014 9:27	127.16	18.68	70.02	7.10	6.90	6.30	5.80	200.05	247.45	144.12	144.47	29.54	1.26	1.58	29.25
3/19/2014 9:28	127.16	18.68	70.17	7.10	6.90	6.30	5.80	200.35	247.54	144.00	144.40	29.58	1.27	1.66	29.66
3/19/2014 9:29	127.15	18.68	70.22	7.10	6.90	6.30	5.80	200.27	247.85	144.06	144.45	29.62	1.11	1.31	30.93
3/19/2014 9:30	127.15	18.69	70.20	7.10	6.90	6.30	5.80	200.11	247.90	144.24	144.60	29.58	1.06	1.46	29.44
3/19/2014 9:31	127.14	18.72	70.09	7.10	6.90	6.30	5.80	200.40	248.08	144.24	144.57	29.45	1.05	1.84	27.57
3/19/2014 9:32	127.15	18.71	69.88	7.10	6.90	6.30	5.80	200.49	248.33	144.25	144.43	29.43	1.07	1.64	28.65
3/19/2014 9:33	127.16	18.69	69.79	7.10	6.90	6.30	5.80	201.30	249.11	144.24	144.21	29.46	1.25	1.75	27.71
3/19/2014 9:34	127.15	18.69	69.89	7.10	6.90	6.30	5.80	200.91	248.63	144.19	144.21	29.46	1.18	1.77	28.31
3/19/2014 9:35	127.14	18.69	70.05	7.10	6.90	6.30	5.80	199.82	247.18	144.19	144.21	29.52	1.09	1.42	29.85
3/19/2014 9:36	127.14	18.68	70.27	7.10	6.90	6.30	5.80	199.98	247.15	144.19	144.22	29.63	1.10	1.13	29.16
3/19/2014 9:37	127.14	18.65	70.50	7.10	6.90	6.30	5.80	199.92	247.40	144.20	144.26	29.65	1.31	1.30	29.10
3/19/2014 9:38	127.14	18.65	70.44	7.10	6.90	6.30	5.80	200.89	248.60	144.27	144.29	29.59	1.08	1.18	28.37
3/19/2014 9:39	127.13	18.63	70.41	7.10	6.90	6.30	5.80	201.18	249.01	144.21	144.41	29.49	1.07	1.26	27.40
3/19/2014 9:40	127.13	18.69	70.25	7.10	6.90	6.30	5.80	201.06	248.97	144.05	144.34	29.44	1.20	0.99	29.94
3/19/2014 9:41	127.14	18.86	69.99	7.10	6.90	6.30	5.80	201.15	248.82	144.00	144.14	29.40	1.44	0.74	29.28
3/19/2014 9:42	127.14	18.83	69.99	7.10	6.90	6.30	5.80	201.25	248.68	143.87	144.16	29.43	1.40	0.65	30.10
3/19/2014 9:43	127.15	18.72	70.16	7.10	6.90	6.30	5.80	200.56	248.20	143.88	144.23	29.53	1.22	1.32	28.03
3/19/2014 9:44	127.15	18.70	70.11	7.10	6.90	6.30	5.80	200.34	247.92	143.90	144.23	29.54	1.16	0.81	28.60
3/19/2014 9:45	127.13	18.61	70.12	7.10	6.90	6.30	5.80	199.45	246.82	143.88	144.24	29.62	1.12	0.73	30.47
3/19/2014 9:46	127.14	18.60	70.10	7.10	6.90	6.30	5.80	199.13	246.43	143.84	144.11	29.70	1.08	0.83	30.10
3/19/2014 9:47	127.14	18.57	70.02	7.10	6.90	6.30	5.80	199.86	247.28	143.86	144.12	29.62	1.23	1.18	28.90
3/19/2014 9:48	127.14	18.62	70.14	7.10	6.90	6.30	5.80	200.07	247.44	143.95	144.10	29.62	1.22	1.18	29.17
3/19/2014 9:49	127.14	18.77	70.03	7.10	6.90	6.30	5.80	200.42	247.95	143.95	144.02	29.50	1.26	1.03	30.02
3/19/2014 9:50	127.14	18.74	69.89	7.10	6.90	6.30	5.80	200.52	247.91	143.94	143.98	29.45	1.16	1.05	28.83
3/19/2014 9:51	127.14	18.64	69.93	7.10	6.90	6.30	5.80	200.33	247.78	143.92	143.86	29.52	1.29	0.60	29.47
3/19/2014 9:52	127.14	18.66	70.02	7.10	6.90	6.30	5.80	200.29	247.86	143.82	143.91	29.49	1.32	0.74	28.51
3/19/2014 9:53	127.13	18.75	69.94	7.10	6.90	6.30	5.80	200.43	248.09	143.89	144.08	29.48	1.21	0.60	28.72
3/19/2014 9:54	127.13	18.74	69.90	7.10	6.90	6.30	5.80	200.37	248.17	144.14	144.15	29.52	1.24	0.67	28.89
3/19/2014 9:55	127.13	18.73	69.78	7.10	6.90	6.30	5.80	200.71	248.43	144.11	144.38	29.50	1.23	0.95	27.42
3/19/2014 9:56	127.13	18.72	69.79	7.10	6.90	6.30	5.80	200.35	248.08	144.01	144.37	29.55	1.43	0.46	28.39
3/19/2014 9:57	127.13	18.67	69.87	7.10	6.90	6.30	5.80	199.51	246.94	144.03	144.34	29.58	1.36	0.17	30.07
3/19/2014 9:58	127.13	18.69	70.02	7.10	6.90	6.30	5.80	199.51	247.05	144.07	144.42	29.59	1.18	0.23	30.29
3/19/2014 9:59	127.14	18.73	69.98	7.10	6.90	6.30	5.80	199.93	247.41	144.11	144.66	29.55	0.99	0.37	28.77
3/19/2014 10:00	127.14	18.71	69.84	7.10	6.90	6.30	5.80	199.99	247.49	144.23	144.66	29.54	1.09	0.18	28.95
3/19/2014 10:01	127.13	18.63	69.75	7.10	6.90	6.30	5.80	200.21	247.76	144.23	144.65	29.50	1.03	0.21	29.15
3/19/2014 10:02	127.13	18.64	69.73	7.10	6.90	6.30	5.80	200.14	247.68	144.22	144.59	29.48	1.03	0.28	27.87
3/19/2014 10:03	127.15	18.68	69.87	7.10	6.90	6.30	5.80	199.71	247.14	144.18	144.40	29.52	1.25	0.27	28.01
3/19/2014 10:04	127.15	18.69	70.11	7.10	6.90	6.30	5.80	199.03	246.21	144.03	144.36	29.54	1.10	0.23	28.45
3/19/2014 10:05	127.15	18.72	70.22	7.10	6.90	6.30	5.80	199.41	246.50	144.08	144.22	29.52	0.98	0.18	28.29
3/19/2014 10:06	127.15	18.72	70.18	7.10	6.90	6.30	5.80	200.12	247.65	144.25	144.19	29.49	1.08	0.20	27.54
3/19/2014 10:07	127.15	18.76	70.04	7.10	6.90	6.30	5.80	200.73	248.36	144.18	144.08	29.42	1.04	0.27	26.32
3/19/2014 10:08	127.15	18.73	69.96	7.10	6.90	6.30	5.80	200.68	248.20	143.97	144.11	29.50	1.27	0.25	27.46
3/19/2014 10:09	127.13	18.65	70.08	7.10	6.90	6.30	5.80	199.93	247.42	143.98	144.19	29.55	1.27	0.16	27.36
3/19/2014 10:10	127.14	18.64	70.22	7.10	6.90	6.30	5.80	199.62	247.03	144.03	144.22	29.59	1.31	0.16	27.04
3/19/2014 10:11	127.14	18.64	70.21	7.10	6.90	6.30	5.80	200.73	248.41	144.02	144.33	29.52	1.16	0.17	27.27
3/19/2014 10:12	127.14	18.65	70.14	7.10	6.90	6.30	5.80	199.98	247.48	143.98	144.33	29.56	1.20	0.17	28.34
3/19/2014 10:13	127.14	18.68	70.00	7.10	6.90	6.30	5.80	199.74	247.18	144.03	144.32	29.57	1.16	0.17	28.50
3/19/2014 10:14	127.14	18.69	69.95	7.10	6.90	6.30	5.80	200.34	247.93	144.17	144.33	29.54	1.12	0.17	26.27
3/19/2014 10:15	127.14	18.72	70.11	7.10	6.90	6.30	5.80	199.30	246.39	144.17	144.36	29.61	1.49	0.17	28.07
3/19/2014 10:16	127.14	18.72	70.14	7.10	6.90	6.30	5.80	199.05	246.33	144.17	144.42	29.61	1.09	0.17	27.84
3/19/2014 10:17	127.14	18.72	70.20	7.10	6.90	6.30	5.80	199.07	246.35	144.19	144.61	29.53	1.08	0.17	26.63
3/19/2014 10:18	127.14	18.74	70.04	7.10	6.90	6.30	5.80	199.69	247.00	144.25	144.56	29.46	1.00	0.17	25.91
3/19/2014 10:19	127.15	18.80	69.93	7.10	6.90	6.30	5.80	199.90	247.00	144.27	144.41	29.49	1.16	0.17	28.04
3/19/2014 10:20	127.15	18.76	69.96	7.10	6.90	6.30	5.80	199.87	247.34	144.34	144.40	29.54	1.21	0.17	25.95

Time	CORRECTED REACTOR FEED MBPD 25F3012A	LIQUID TO GAS RATIO G/MSCF 30C3532L	REGEN COKE BURNING RATE MPPH 25CokeBR	Unit 30 Scrubber spay nozzle Pressure psig 30SCRspray01psig.er	Unit 30 Scrubber 02 spray nozzle Pressure psig 30SCRspray02psig.er	Unit 30 Scrubber 03 spray nozzle Pressure psig 30SCRspray03psig.er	Unit 30 Scrubber 04 spay nozzle Pressure psig 30SCRspray04psig.er	OXYGEN & BLOWER FEED CORR. MSCF 25Airtot	THROAT VELOCITY feet/min 25C3147V	FLUE GAS STK TMP deg F 30TI6008	FLUE GAS SCRUBBR STK TMP deg F 30TI1807	Dry Flue Gas Rate MMOL/H 25F3147D	SCRUBBER STACK O2 % 30AI6014	SCRUBBER STACK SO2 ppm 30AI6013	SCRUBBER SELECTED NOX ppm 30AI6012
3/19/2014 10:21	127.14	18.63	70.11	7.10	6.90	6.30	5.80	200.28	247.84	144.34	144.40	29.59	1.27	0.17	25.71
3/19/2014 10:22	127.14	18.62	70.33	7.10	6.90	6.30	5.80	198.99	246.25	144.36	144.43	29.53	1.09	0.17	27.36
3/19/2014 10:23	127.15	18.59	70.40	7.10	6.90	6.20	5.80	199.49	246.75	144.40	144.50	29.54	1.22	0.17	27.23
3/19/2014 10:24															
Average	127.14	18.69	70.01	7.10	6.90	6.30	5.80	200.19	247.71	144.12	144.31	29.53	1.17	0.86	28.68

Time	CORRECTED REACTOR FEED MBPD 15F3012A	LIQUID TO GAS RATIO G/MSCF 30C3532L	REGEN COKE BURNING RATE MPPH 25CokeBN	Unit 30 Scrubber spay nozzle Pressure psig 30SCRspray01psig.or	Unit 30 Scrubber 02 spay nozzle Pressure psig 30SCRspray02psig.or	Unit 30 Scrubber 03 spay nozzle Pressure psig 30SCRspray03psig.or	Unit 30 Scrubber 04 spay nozzle Pressure psig 30SCRspray04psig.or	OXYGEN & BLOWER FEED CORR. MSCF 25Airtot	THROAT VELOCITY feet/min 25C3147V	FLUE GAS STX TMP deg F 30TI6008	FLUE GAS SCRUBBR STK TMP deg F 30TI1807	Dry Flue Gas Rate MMOL/H 25F3147D	SCRUBBER STACK O2 % 30AI6014	SCRUBBER STACK SO2 ppm 30AI6013	SCRUBBER SELECTED NOX ppm 30AI6012
3/19/2014 11:23	127.11	20.69	70.81	7.10	6.90	6.30	5.80	198.23	245.31	143.95	143.97	29.63	1.04	0.22	27.33
3/19/2014 11:24	127.10	20.76	70.70	7.10	6.90	6.30	5.80	198.74	245.94	144.11	144.19	29.53	0.93	0.24	26.53
3/19/2014 11:25	127.06	20.72	70.67	7.10	6.90	6.30	5.80	198.27	245.47	144.12	144.22	29.56	1.07	0.19	28.05
3/19/2014 11:26	126.94	20.64	70.85	7.10	6.90	6.30	5.80	197.97	245.33	144.16	144.34	29.64	1.13	0.19	27.43
3/19/2014 11:27	126.85	20.84	70.93	7.10	6.90	6.30	5.80	197.87	244.89	144.19	144.39	29.57	1.07	0.20	28.18
3/19/2014 11:28	126.86	20.80	70.88	7.10	6.90	6.30	5.80	197.68	244.72	144.27	144.54	29.59	1.05	0.20	27.89
3/19/2014 11:29	126.87	20.68	70.95	7.10	6.90	6.30	5.80	197.10	243.91	144.27	144.59	29.65	1.18	0.18	28.77
3/19/2014 11:30	126.89	20.71	70.95	7.10	6.90	6.30	5.80	196.56	243.16	144.27	144.76	29.63	1.08	0.18	27.88
3/19/2014 11:31	126.99	20.80	70.86	7.10	6.90	6.30	5.80	196.80	243.29	144.30	144.74	29.56	1.09	0.19	28.06
3/19/2014 11:32	127.07	20.81	70.64	7.10	6.90	6.30	5.80	196.88	243.72	144.42	144.67	29.53	0.92	0.19	26.07
3/19/2014 11:33	127.14	20.85	70.73	7.10	6.90	6.30	5.80	196.48	243.40	144.46	144.65	29.55	0.67	0.18	25.98
3/19/2014 11:34	127.17	20.83	70.77	7.10	6.90	6.30	5.80	196.04	242.60	144.60	144.59	29.59	0.58	0.18	23.81
3/19/2014 11:35	127.23	20.76	70.66	7.10	6.90	6.30	5.80	196.96	243.73	144.50	144.46	29.45	0.85	0.19	26.46
3/19/2014 11:36	127.24	20.79	70.33	7.10	6.90	6.30	5.80	198.05	245.09	144.15	144.03	29.33	1.02	0.19	26.65
3/19/2014 11:37	127.27	20.86	70.45	7.10	6.90	6.30	5.80	198.54	245.70	144.05	144.00	29.38	1.16	0.19	27.26
3/19/2014 11:38	127.28	20.83	70.74	7.10	6.90	6.30	5.80	197.91	244.91	143.70	143.89	29.45	1.28	0.19	27.38
3/19/2014 11:39	127.32	20.75	71.04	7.10	6.90	6.30	5.80	197.57	244.49	143.71	143.91	29.54	1.21	0.19	27.41
3/19/2014 11:40	127.32	20.76	71.08	7.10	6.90	6.30	5.80	197.60	244.54	143.75	143.97	29.53	1.10	0.19	26.03
3/19/2014 11:41	127.34	20.79	70.92	7.10	6.90	6.30	5.80	197.60	244.53	143.74	143.98	29.50	0.86	0.19	25.12
3/19/2014 11:42	127.34	20.78	70.72	7.10	6.90	6.30	5.80	197.28	244.03	143.70	144.04	29.55	0.90	0.19	25.33
3/19/2014 11:43	127.34	20.74	70.53	7.10	6.90	6.30	5.80	197.74	244.37	143.69	144.06	29.51	1.00	0.19	25.72
3/19/2014 11:44	127.35	20.77	70.39	7.10	6.90	6.30	5.80	198.50	245.65	143.65	144.09	29.47	1.00	0.19	25.07
3/19/2014 11:45	127.36	20.86	70.42	7.10	6.90	6.30	5.80	199.54	246.93	143.60	143.99	29.44	1.10	0.19	26.24
3/19/2014 11:46	127.35	20.83	70.43	7.10	6.90	6.30	5.80	201.17	248.95	143.45	143.64	29.56	1.13	0.19	26.11
3/19/2014 11:47	127.32	20.73	70.86	7.10	6.90	6.30	5.80	200.54	248.10	143.46	143.60	29.63	1.45	0.18	28.10
3/19/2014 11:48	127.32	20.75	71.00	7.10	6.90	6.30	5.80	200.78	248.24	143.51	143.47	29.61	1.14	0.18	26.67
3/19/2014 11:49	127.30	20.79	70.86	7.10	6.90	6.30	5.80	200.98	248.71	143.48	143.44	29.56	1.03	0.19	25.62
3/19/2014 11:50	127.31	20.79	70.72	7.10	6.90	6.30	5.80	200.48	248.09	143.36	143.34	29.61	1.12	0.19	26.53
3/19/2014 11:51	127.31	20.80	70.66	7.10	6.90	6.30	5.80	199.00	246.26	143.38	143.40	29.60	1.13	0.20	26.11
3/19/2014 11:52	127.31	20.80	70.71	7.10	6.90	6.30	5.80	199.71	247.15	143.44	143.59	29.61	0.99	0.20	24.92
3/19/2014 11:53	127.31	20.81	70.74	7.10	6.90	6.30	5.80	200.09	247.73	143.43	143.61	29.65	1.12	0.19	26.10
3/19/2014 11:54	127.30	20.80	70.85	7.10	6.90	6.30	5.80	199.59	247.37	143.40	143.68	29.63	1.22	0.19	27.97
3/19/2014 11:55	127.29	20.77	70.94	7.10	6.90	6.30	5.80	198.80	246.01	143.40	143.71	29.65	1.20	0.19	27.99
3/19/2014 11:56	127.28	20.74	71.05	7.10	6.90	6.30	5.80	198.15	245.21	143.36	143.78	29.72	1.18	0.19	28.20
3/19/2014 11:57	127.28	20.62	71.04	7.10	6.90	6.30	5.80	197.61	244.55	143.43	143.84	29.74	1.06	0.20	28.64
3/19/2014 11:58	127.28	20.63	70.96	7.10	6.90	6.30	5.80	198.37	245.48	143.61	144.06	29.66	1.03	0.20	27.42
3/19/2014 11:59	127.28	20.64	70.72	7.10	6.90	6.30	5.80	198.84	245.98	143.58	143.98	29.61	0.99	0.20	24.41
3/19/2014 12:00	127.28	20.64	70.57	7.10	6.90	6.30	5.80	199.06	246.07	143.46	143.66	29.59	1.24	0.20	28.12
3/19/2014 12:01	127.28	20.65	70.65	7.10	6.90	6.30	5.80	198.75	245.96	143.45	143.45	29.69	1.42	0.20	29.67
3/19/2014 12:02	127.28	20.65	70.97	7.10	6.90	6.30	5.80	197.64	244.57	143.41	143.45	29.71	1.52	0.20	29.49
3/19/2014 12:03	127.28	20.63	71.07	7.10	6.90	6.30	5.80	197.37	244.17	143.48	143.44	29.65	1.31	0.20	28.90
3/19/2014 12:04	127.28	20.68	70.75	7.10	6.90	6.30	5.80	197.32	243.94	143.69	143.45	29.54	1.28	0.20	28.81
3/19/2014 12:05	127.28	20.83	70.39	7.10	6.90	6.30	5.80	196.62	243.32	143.64	143.48	29.56	1.36	0.20	28.70
3/19/2014 12:06	127.28	20.82	70.20	7.10	6.90	6.30	5.80	197.19	244.02	143.49	143.52	29.52	1.36	0.20	29.32
3/19/2014 12:07	127.27	20.79	69.95	7.10	6.90	6.30	5.80	197.28	244.14	143.51	143.67	29.51	1.33	0.20	29.47
3/19/2014 12:08	127.27	20.78	69.99	7.10	6.90	6.30	5.80	195.87	242.39	143.60	143.74	29.57	1.46	0.20	29.31
3/19/2014 12:09	127.27	20.75	70.11	7.10	6.90	6.30	5.80	196.31	242.93	143.63	143.97	29.63	1.42	0.20	27.35
3/19/2014 12:10	127.27	20.73	70.10	7.10	6.90	6.30	5.80	196.08	242.65	143.71	143.97	29.68	1.32	0.20	28.26
3/19/2014 12:11	127.26	20.67	70.07	7.10	6.90	6.30	5.80	195.13	241.47	143.70	143.99	29.72	1.48	0.20	28.47
3/19/2014 12:12	127.26	20.68	70.03	7.10	6.90	6.30	5.80	194.54	240.66	143.69	144.05	29.67	1.47	0.20	28.98
3/19/2014 12:13	127.26	20.70	69.86	7.10	6.90	6.30	5.80	194.60	240.57	143.74	144.24	29.60	1.30	0.20	28.55
3/19/2014 12:14	127.26	20.72	69.66	7.10	6.90	6.30	5.80	194.27	240.41	143.91	144.23	29.52	1.48	0.20	28.96
3/19/2014 12:15	127.25	20.77	69.59	7.10	6.90	6.30	5.80	194.62	240.91	143.95	144.17	29.54	1.46	0.20	28.30
3/19/2014 12:16	127.26	20.78	69.54	7.10	6.90	6.30	5.80	194.30	240.68	144.08	144.14	29.51	1.23	0.20	27.58
3/19/2014 12:17	127.27	20.81	69.63	7.10	6.90	6.30	5.80	193.48	239.43	144.06	144.04	29.58	1.23	0.19	28.13
3/19/2014 12:18	127.27	20.80	69.81	7.10	6.90	6.30	5.80	191.95	237.53	143.97	144.07	29.67	1.09	0.19	29.49
3/19/2014 12:19	127.26	20.76	69.75	7.10	6.90	6.30	5.80	191.37	236.83	144.05	144.25	29.45	0.82	0.20	26.45
3/19/2014 12:20	127.26	20.81	69.51	7.10	6.90	6.30	5.80	192.28	237.94	144.30	144.44	29.32	0.62	0.20	21.94
3/19/2014 12:21	127.27	20.96	69.42	7.10	6.90	6.30	5.80	192.41	238.11	144.26	144.23	29.30	0.75	0.20	25.04
3/19/2014 12:22	127.26	20.97	69.57	7.10	6.90	6.30	5.80	193.03	238.87	144.10	144.28	29.26	0.72	0.20	26.56
3/19/2014 12:23	127.25	21.00	69.93	7.10	6.90	6.30	5.80	193.39	239.32	144.08	144.48	29.36	0.88	0.20	26.37
3/19/2014 12:24	127.25	20.96	70.40	7.10	6.90	6.30	5.80	192.89	238.71	143.99	144.48	29.40	0.89	0.20	26.15
3/19/2014 12:25	127.26	20.81	70.81	7.10	6.90	6.30	5.80	193.57	239.62	143.98	144.50	29.47	0.93	0.20	27.30
3/19/2014 12:26	127.26	20.78	71.08	7.10	6.90	6.30	5.80	193.42	239.62	143.97	144.47	29.51	1.05	0.20	26.56
3/19/2014 12:27	127.27	20.68	71.14	7.10	6.90	6.30	5.80	193.59	239.62	143.94	144.36	29.57	0.87	0.20	26.62
3/19/2014 12:28	127.27	20.71	71.13	7.10	6.90	6.30	5.80	193.60	239.74	143.84	144.31	29.51	0.93	0.20	26.41
3/19/2014 12:29	127.27	20.82	71.04	7.10	6.90	6.30	5.80	194.04	240.12	143.84	144.13	29.44	0.82	0.20	25.09

Time	CORRECTED REACTOR FEED MBPD 25F3012A	LIQUID TO GAS RATIO G/MSCF 30C3532L	REGEN COKE BURNING RATE MPPH 25CokeBN	Unit 30 Scrubber spay nozzle Pressure psig 30SCRspray01psig.or	Unit 30 Scrubber 02 spay nozzle Pressure psig 30SCRspray02psig.or	Unit 30 Scrubber 03 spay nozzle Pressure psig 30SCRspray03psig.or	Unit 30 Scrubber 04 spay nozzle Pressure psig 30SCRspray04psig.or	OXYGEN & BLOWER FEED CORR. MSCF 25Airtot	THROAT VELOCITY feet/min 25C3147V	FLUE GAS STK TMP deg F 30TI6008	FLUE GAS SCRUBBR STK TMP deg F 30TI1807	Dry Flue Gas Rate MMOL/H 25F3147D	SCRUBBER STACK O2 % 30AI6014	SCRUBBER STACK SO2 ppm 30AI6013	SCRUBBER SELECTED NOX ppm 30AI6012
3/19/2014 12:30	127.27	20.82	70.93	7.10	6.90	6.30	5.80	294.20	240.32	143.84	144.07	29.49	0.80	0.20	25.38
3/19/2014 12:31	127.26	20.80	70.89	7.10	6.90	6.30	5.80	294.72	240.97	143.88	143.86	29.45	0.68	0.20	25.35
3/19/2014 12:32	127.26	20.78	70.75	7.10	6.90	6.30	5.80	295.01	241.32	143.98	143.87	29.43	0.63	0.20	21.78
3/19/2014 12:33															
Average	127.24	20.77	70.54	7.10	6.90	6.30	5.80	296.71	243.44	143.83	144.02	29.55	1.09	0.19	27.03

Time	CORRECTED REACTOR FEED MBPD 25F3012A	LIQUID TO GAS RATIO G/MSCF 30C3532L	REGEN COKE BURNING RATE MPPH 25CokeBN	Unit 30 Scrubber spay nozzle Pressure psig 30SCRspray01psig.or	Unit 30 Scrubber 02 spay nozzle Pressure psig 30SCRspray02psig.or	Unit 30 Scrubber 03 spay nozzle Pressure psig 30SCRspray03psig.or	Unit 30 Scrubber 04 spay nozzle Pressure psig 30SCRspray04psig.or	OXYGEN & BLOWER FEED CORR. MSCF 25Airtot	THROAT VELOCITY feet/min 25C3147V	FLUE GAS STK TMP deg F 30TI6008	FLUE GAS SCRUBBR STK TMP deg F 30TI1807	Dry Flue Gas Rate MMOL/H 25F3147D	SCRUBBER STACK O2 % 30AI6014	SCRUBBER STACK SO2 ppm 30AI6013	SCRUBBER SELECTED NOX ppm 30AI6012
3/19/2014 13:27	127.28	20.93	70.07	7.10	6.90	6.30	5.80	194.90	241.39	144.27	144.26	29.33	1.16	0.20	37.67
3/19/2014 13:28	127.28	20.92	70.06	7.10	6.90	6.30	5.80	195.73	242.21	144.28	144.43	29.42	1.20	0.20	38.38
3/19/2014 13:29	127.28	20.88	70.26	7.10	6.90	6.30	5.80	195.15	241.50	144.27	144.47	29.45	1.47	0.20	38.13
3/19/2014 13:30	127.28	20.91	70.30	7.10	6.90	6.30	5.80	195.63	242.05	144.26	144.59	29.45	1.29	0.20	37.66
3/19/2014 13:31	127.27	21.02	70.40	7.10	6.90	6.30	5.80	195.59	241.93	144.16	144.62	29.46	1.18	0.20	38.86
3/19/2014 13:32	127.27	20.99	70.28	7.10	6.90	6.30	5.80	195.45	241.87	144.27	144.77	29.49	1.18	0.20	38.70
3/19/2014 13:33	127.26	20.89	70.09	7.10	6.90	6.30	5.80	196.05	242.61	144.28	144.98	29.51	1.14	0.20	36.75
3/19/2014 13:34	127.27	20.87	70.13	7.10	6.90	6.30	5.80	195.06	241.32	144.34	144.90	29.52	1.18	0.20	38.86
3/19/2014 13:35	127.29	20.80	70.31	7.10	6.90	6.30	5.80	195.01	241.13	144.33	144.64	29.55	1.29	0.20	37.78
3/19/2014 13:36	127.28	20.81	70.53	7.10	6.90	6.30	5.80	194.37	240.49	144.30	144.59	29.58	1.22	0.20	37.51
3/19/2014 13:37	127.27	20.86	70.56	7.10	6.90	6.30	5.80	194.50	240.57	144.32	144.44	29.57	1.15	0.20	36.48
3/19/2014 13:38	127.27	20.86	70.44	7.10	6.90	6.30	5.80	194.62	240.84	144.38	144.40	29.54	0.94	0.20	36.37
3/19/2014 13:39	127.27	20.89	70.40	7.10	6.90	6.30	5.80	194.72	240.97	144.32	144.24	29.52	1.12	0.20	37.78
3/19/2014 13:40	127.27	20.88	70.38	7.10	6.90	6.30	5.80	195.17	241.52	144.12	144.24	29.46	1.26	0.20	37.80
3/19/2014 13:41	127.27	20.84	70.32	7.10	6.90	6.30	5.80	195.24	241.60	144.15	144.25	29.43	1.15	0.20	37.45
3/19/2014 13:42	127.27	20.82	70.32	7.10	6.90	6.30	5.80	194.24	240.52	144.25	144.34	29.44	1.18	0.20	36.26
3/19/2014 13:43	127.29	20.77	70.32	7.10	6.90	6.30	5.80	193.74	240.18	144.27	144.64	29.47	1.07	0.20	37.60
3/19/2014 13:44	127.29	20.78	70.31	7.10	6.90	6.30	5.80	193.59	239.47	144.35	144.71	29.50	1.05	0.10	38.29
3/19/2014 13:45	127.29	20.84	70.26	7.10	6.90	6.30	5.80	194.40	241.01	144.34	144.93	29.49	0.90	0.20	36.91
3/19/2014 13:46	127.29	20.88	70.09	7.10	6.90	6.30	5.80	194.92	241.54	144.31	144.89	29.39	1.04	0.10	36.90
3/19/2014 13:47	127.28	21.02	70.12	7.10	6.90	6.30	5.80	195.09	241.60	144.31	144.77	29.41	1.14	0.10	36.88
3/19/2014 13:48	127.28	20.95	70.28	7.10	6.90	6.30	5.80	195.52	241.79	144.33	144.66	29.49	1.14	0.10	36.98
3/19/2014 13:49	127.28	20.71	70.50	7.10	6.90	6.30	5.80	194.90	241.53	144.32	144.31	29.57	1.19	0.10	37.71
3/19/2014 13:50	127.28	20.73	70.71	7.10	6.90	6.30	5.80	194.24	240.41	144.28	144.30	29.59	1.16	0.10	38.60
3/19/2014 13:51	127.28	20.77	70.67	7.10	6.90	6.30	5.80	194.31	239.64	144.29	144.18	29.55	1.06	0.20	36.73
3/19/2014 13:52	127.29	20.79	70.53	7.10	6.90	6.30	5.80	195.07	240.74	144.33	144.25	29.48	1.07	0.20	34.98
3/19/2014 13:53	127.31	20.86	70.43	7.10	6.90	6.30	5.80	195.57	242.27	144.30	144.15	29.44	1.10	0.20	36.37
3/19/2014 13:54	127.31	20.86	70.29	7.10	6.90	6.30	5.80	195.48	242.25	144.19	144.20	29.46	1.15	0.20	35.85
3/19/2014 13:55	127.31	20.85	70.32	7.10	6.90	6.30	5.80	195.42	241.78	144.19	144.38	29.41	1.25	0.20	36.89
3/19/2014 13:56	127.30	20.82	70.45	7.10	6.90	6.30	5.80	195.05	240.95	144.19	144.44	29.42	1.15	0.20	35.65
3/19/2014 13:57	127.29	20.70	70.68	7.10	6.90	6.30	5.80	195.24	242.02	144.20	144.61	29.63	1.02	0.20	35.21
3/19/2014 13:58	127.29	20.72	70.90	7.10	6.90	6.30	5.80	194.59	240.99	144.26	144.65	29.60	1.12	0.20	35.20
3/19/2014 13:59	127.27	20.76	70.70	7.10	6.90	6.30	5.80	194.82	240.44	144.25	144.78	29.55	1.12	0.20	35.49
3/19/2014 14:00	127.27	20.77	70.61	7.10	6.90	6.30	5.80	194.56	240.41	144.25	144.75	29.54	1.11	0.20	36.53
3/19/2014 14:01	127.29	20.81	70.58	7.10	6.90	6.30	5.80	194.74	240.63	144.28	144.64	29.45	1.17	0.20	36.26
3/19/2014 14:02	127.29	20.77	70.47	7.10	6.90	6.30	5.80	196.03	241.78	144.37	144.53	29.53	1.15	0.20	35.59
3/19/2014 14:03	127.28	20.67	70.56	7.10	6.90	6.30	5.80	196.02	241.72	144.34	144.18	29.60	1.19	0.20	36.47
3/19/2014 14:04	127.28	20.68	70.82	7.10	6.90	6.30	5.80	195.39	241.52	144.24	144.17	29.65	1.14	0.20	36.68
3/19/2014 14:05	127.29	20.71	70.79	7.10	6.90	6.30	5.80	195.21	241.61	144.73	144.14	29.63	1.13	0.20	35.66
3/19/2014 14:06	127.29	20.71	70.65	7.10	6.90	6.30	5.80	195.35	241.89	144.20	144.18	29.56	1.24	0.20	36.17
3/19/2014 14:07	127.29	20.68	70.62	7.10	6.90	6.30	5.80	194.79	241.56	144.19	144.29	29.54	1.26	0.20	36.16
3/19/2014 14:08	127.29	20.69	70.64	7.10	6.90	6.30	5.80	194.38	240.63	144.14	144.33	29.52	1.38	0.20	36.29
3/19/2014 14:09	127.28	20.71	70.61	7.10	6.90	6.30	5.80	194.77	240.89	144.14	144.47	29.61	1.38	0.20	37.22
3/19/2014 14:10	127.28	20.74	70.62	7.10	6.90	6.30	5.80	194.10	240.35	144.16	144.52	29.57	1.29	0.20	37.75
3/19/2014 14:11	127.30	20.85	70.42	7.10	6.90	6.30	5.80	193.84	240.29	144.20	144.67	29.54	1.17	0.20	36.21
3/19/2014 14:12	127.30	20.85	70.23	7.10	6.90	6.30	5.80	193.59	238.62	144.32	144.69	29.52	1.15	0.20	36.90
3/19/2014 14:13	127.28	20.85	70.14	7.10	6.90	6.30	5.80	193.35	238.86	144.32	144.76	29.46	1.21	0.20	35.05
3/19/2014 14:14	127.28	20.82	70.01	7.10	6.90	6.30	5.80	193.63	239.67	144.31	144.71	29.47	1.10	0.20	36.14
3/19/2014 14:15	127.28	20.75	70.03	7.10	6.90	6.30	5.80	194.44	239.55	144.30	144.49	29.49	1.13	0.20	34.92
3/19/2014 14:16	127.28	20.72	70.16	7.10	6.90	6.30	5.80	193.89	239.16	144.24	144.28	29.57	1.40	0.20	36.49
3/19/2014 14:17	127.28	20.62	70.37	7.10	6.90	6.30	5.80	192.74	238.75	144.28	144.31	29.63	1.40	0.20	37.52
3/19/2014 14:18	127.29	20.68	70.29	7.10	6.90	6.30	5.80	192.14	237.51	144.44	144.41	29.42	1.14	0.20	37.33
3/19/2014 14:19	127.29	20.89	70.00	7.10	6.90	6.30	5.80	192.18	237.56	144.41	144.39	29.30	1.04	0.20	36.53
3/19/2014 14:20	127.29	20.90	69.84	7.10	6.90	6.30	5.80	191.10	236.43	144.32	144.42	29.32	1.20	0.20	36.36
3/19/2014 14:21	127.29	20.94	69.75	7.10	6.90	6.30	5.80	190.63	236.37	144.39	144.71	29.40	1.00	0.20	37.31
3/19/2014 14:22	127.29	20.92	69.89	7.10	6.90	6.30	5.80	190.99	236.40	144.64	144.77	29.37	0.80	0.20	34.74
3/19/2014 14:23	127.29	20.86	69.93	7.10	6.90	6.30	5.80	191.69	237.17	144.65	144.96	29.38	0.75	0.20	32.12
3/19/2014 14:24	127.29	20.86	70.01	7.10	6.90	6.30	5.80	191.47	237.33	144.66	144.96	29.41	1.05	0.20	34.29
3/19/2014 14:25	127.29	20.83	70.32	7.10	6.90	6.30	5.80	191.44	237.53	144.62	144.94	29.44	1.09	0.20	36.51
3/19/2014 14:26	127.29	20.84	70.57	7.10	6.90	6.30	5.80	191.24	236.85	144.50	144.93	29.37	0.97	0.20	36.72
3/19/2014 14:27	127.28	20.88	70.63	7.10	6.90	6.30	5.80	192.17	237.73	144.52	144.89	29.36	0.87	0.20	33.59
3/19/2014 14:28	127.28	20.89	70.61	7.10	6.90	6.30	5.80	192.30	237.17	144.59	144.81	29.35	1.01	0.20	34.75
3/19/2014 14:29	127.29	20.90	70.61	7.10	6.90	6.30	5.80	191.97	237.93	144.59	144.56	29.42	1.20	0.20	34.21
3/19/2014 14:30	127.29	20.89	70.83	7.10	6.90	6.30	5.80	191.65	237.97	144.59	144.56	29.47	1.05	0.20	35.54
3/19/2014 14:31	127.29	20.87	70.83	7.10	6.90	6.30	5.80	191.64	237.93	144.58	144.57	29.40	0.83	0.20	32.96
3/19/2014 14:32	127.29	20.87	70.58	7.10	6.90	6.30	5.80	191.65	237.68	144.55	144.59	29.38	0.85	0.20	33.90
3/19/2014 14:33	127.29	20.86	70.50	7.10	6.90	6.30	5.80	192.10	239.08	144.54	144.65	29.33	0.80	0.20	34.35

Time	CORRECTED REACTOR FEED MBPD 25F3012A	LIQUID TO GAS RATIO G/MSCF 30C3532L	REGEN COKE BURNING RATE MPPH 25CokeBN	Unit 30 Scrubber spray nozzle Pressure psig 30SCRspray01psig.or	Unit 30 Scrubber 02 spay nozzle Pressure psig 30SCRspray02psig.or	Unit 30 Scrubber 03 spay nozzle Pressure psig 30SCRspray03psig.or	Unit 30 Scrubber 04 spay nozzle Pressure psig 30SCRspray04psig.or	OXYGEN & BLOWER FEED CORR. MSCF 25Airtot	THROAT VELOCITY feet/min 25C3147V	FLUE GAS STK TMP deg F 30TI6008	FLUE GAS SCRUBBA STK TMP deg F 30TI1807	Dry flue Gas Rate MMOL/H 25F3147D	SCRUBBER STACK O2 % 30AI6014	SCRUBBER STACK SO2 ppm 30AI6013	SCRUBBER SELECTED NOX ppm 30AI6012
3/19/2014 14:34	127.29	20.85	70.50	7.10	6.90	6.30	5.80	193.38	240.19	144.50	144.64	29.39	0.80	0.26	34.38
3/19/2014 14:35	127.30	20.79	70.72	7.10	6.90	6.30	5.80	193.55	239.85	144.48	144.62	29.41	0.82	0.42	34.72
3/19/2014 14:36	127.30	20.81	70.84	7.10	6.90	6.30	5.80	193.15	238.73	144.40	144.68	29.39	0.82	0.59	35.70
3/19/2014 14:37	127.31	20.90	71.11	7.10	6.90	6.30	5.80	192.84	238.55	144.43	144.89	29.40	0.88	1.12	36.25
3/19/2014 14:38	127.30	20.87	71.28	7.10	6.90	6.30	5.80	192.46	237.82	144.50	144.89	29.44	0.99	1.20	35.83
3/19/2014 14:39															
Average	127.29	20.83	70.42	7.10	6.90	6.30	5.80	193.97	240.04	144.34	144.56	29.48	1.11	0.23	36.34

Time	CORRECTED REACTOR FEED MBPD 25F3012A	LIQUID TO GAS RATIO G/MSCF 30C3532L	REGEN COKE BURNING RATE MPPH 25CokeBN	Unit 30 Scrubber spay nozzle Pressure psig 30SCRspray01psig.or	Unit 30 Scrubber 02 spay nozzle Pressure psig 30SCRspray02psig.or	Unit 30 Scrubber 03 spay nozzle Pressure psig 30SCRspray03psig.or	Unit 30 Scrubber 04 spay nozzle Pressure psig 30SCRspray04psig.or	OXYGEN & BLOWER FEED CORR. MSCF 25Alrtot	THROAT VELOCITY feet/min 25C3147V	FLUE GAS STK TMP deg F 30TI6008	FLUE GAS SCRUBBR STK TMP deg F 30TI1807	Dry Flue Gas Rate MMOL/H 25F3147D	SCRUBBER STACK O2 % 30AI6014	SCRUBBER STACK SO2 ppm 30AI6013	SCRUBBER SELECTED NOX ppm 30AI6012
3/19/2014 15:31	127.27	20.70	71.24	7.10	6.90	6.30	5.80	195.08	241.25	144.37	144.74	29.63	0.97	0.21	35.53
3/19/2014 15:32	127.27	20.74	71.05	7.10	6.90	6.30	5.80	195.42	242.11	144.36	144.66	29.56	0.97	0.25	34.98
3/19/2014 15:33	127.27	20.84	70.77	7.10	6.90	6.30	5.80	195.83	241.83	144.33	144.58	29.49	1.18	0.20	34.72
3/19/2014 15:34	127.27	20.83	70.72	7.10	6.90	6.30	5.80	194.64	240.89	144.35	144.33	29.53	1.23	0.20	36.05
3/19/2014 15:35	127.27	20.79	70.83	7.10	6.90	6.30	5.80	194.69	241.02	144.39	144.34	29.57	1.15	0.20	35.02
3/19/2014 15:36	127.26	20.76	70.83	7.10	6.90	6.30	5.80	194.70	241.42	144.37	144.39	29.59	1.12	0.20	34.86
3/19/2014 15:37	127.26	20.67	70.85	7.10	6.90	6.30	5.80	194.10	241.34	144.29	144.38	29.60	1.20	0.20	35.34
3/19/2014 15:38	127.23	20.79	70.90	7.10	6.90	6.30	5.80	194.24	241.08	144.30	144.35	29.62	1.20	0.20	38.03
3/19/2014 15:39	127.22	20.80	70.88	7.10	6.90	6.30	5.80	194.58	241.09	144.31	144.41	29.62	1.33	0.20	37.45
3/19/2014 15:40	127.22	20.79	70.81	7.10	6.90	6.30	5.80	194.33	241.11	144.32	144.63	29.61	1.27	0.20	36.77
3/19/2014 15:41	127.22	20.75	70.71	7.10	6.90	6.30	5.80	194.39	241.15	144.38	144.67	29.57	1.13	0.20	34.98
3/19/2014 15:42	127.23	20.76	70.62	7.10	6.90	6.30	5.80	194.79	241.07	144.36	144.81	29.57	1.23	0.20	36.69
3/19/2014 15:43	127.24	20.77	70.66	7.10	6.90	6.30	5.80	194.24	240.25	144.39	144.82	29.58	1.24	0.20	36.14
3/19/2014 15:44	127.26	20.76	70.67	7.10	6.90	6.30	5.80	194.91	240.48	144.36	144.88	29.62	1.13	0.20	34.56
3/19/2014 15:45	127.26	20.73	70.67	7.10	6.90	6.30	5.80	195.14	241.23	144.26	144.76	29.62	1.20	0.20	34.98
3/19/2014 15:46	127.26	20.72	70.59	7.10	6.90	6.30	5.80	195.15	241.34	144.25	144.40	29.59	1.19	0.20	34.70
3/19/2014 15:47	127.26	20.70	70.56	7.10	6.90	6.30	5.80	195.54	241.72	144.20	144.36	29.57	1.15	0.20	36.75
3/19/2014 15:48	127.26	20.71	70.49	7.10	6.90	6.30	5.80	194.76	241.63	144.20	144.23	29.54	1.12	0.20	34.52
3/19/2014 15:49	127.27	20.74	70.64	7.10	6.90	6.30	5.80	194.17	240.93	144.23	144.27	29.64	1.18	0.20	36.94
3/19/2014 15:50	127.27	20.74	70.80	7.10	6.90	6.30	5.80	193.54	238.92	144.26	144.40	29.65	0.97	0.20	35.86
3/19/2014 15:51	127.27	20.71	70.78	7.10	6.90	6.30	5.80	194.73	241.32	144.36	144.42	29.63	1.10	0.20	34.30
3/19/2014 15:52	127.27	20.72	70.73	7.10	6.90	6.30	5.80	194.46	240.55	144.35	144.49	29.58	1.25	0.20	35.24
3/19/2014 15:53	127.27	20.72	70.76	7.10	6.90	6.30	5.80	194.68	240.49	144.32	144.56	29.68	1.19	0.20	36.39
3/19/2014 15:54	127.25	20.71	70.87	7.10	6.90	6.30	5.80	193.65	240.06	144.33	144.79	29.63	1.21	0.20	35.11
3/19/2014 15:55	127.25	20.69	70.92	7.10	6.90	6.30	5.80	193.18	239.09	144.38	144.83	29.65	1.03	0.20	34.18
3/19/2014 15:56	127.25	20.71	70.90	7.10	6.90	6.30	5.80	192.81	239.31	144.40	144.99	29.57	0.92	0.10	34.85
3/19/2014 15:57	127.25	20.79	70.81	7.10	6.90	6.30	5.80	194.12	240.22	144.49	144.93	29.53	0.85	0.20	35.00
3/19/2014 15:58	127.27	20.80	70.68	7.10	6.90	6.30	5.80	195.10	240.93	144.48	144.83	29.51	0.94	0.20	33.76
3/19/2014 15:59	127.27	20.85	70.51	7.10	6.90	6.30	5.80	194.92	241.13	144.45	144.41	29.43	0.96	0.20	35.02
3/19/2014 16:00	127.28	20.87	70.47	7.10	6.90	6.30	5.80	195.24	241.58	144.41	144.39	29.35	1.06	0.20	35.29
3/19/2014 16:01	127.28	20.92	70.55	7.10	6.90	6.30	5.80	194.48	240.57	144.24	144.32	29.43	1.15	0.20	35.78
3/19/2014 16:02	127.29	20.93	70.86	7.10	6.90	6.30	5.80	194.45	240.23	144.29	144.34	29.50	1.24	0.20	34.03
3/19/2014 16:03	127.28	20.88	70.92	7.10	6.90	6.30	5.80	195.10	241.35	144.46	144.42	29.45	1.10	0.20	34.23
3/19/2014 16:04	127.27	20.68	70.83	7.10	6.90	6.30	5.80	195.15	240.72	144.41	144.44	29.52	1.06	0.20	34.73
3/19/2014 16:05	127.27	20.70	70.83	7.10	6.90	6.30	5.80	194.51	240.82	144.24	144.52	29.53	1.24	0.20	34.30
3/19/2014 16:06	127.27	20.78	70.88	7.10	6.90	6.30	5.80	193.99	240.71	144.29	144.58	29.64	1.19	0.20	34.76
3/19/2014 16:07	127.27	20.78	71.02	7.10	6.90	6.30	5.80	193.40	239.38	144.45	144.76	29.63	0.99	0.20	34.34
3/19/2014 16:08	127.26	20.79	71.04	7.10	6.90	6.30	5.80	193.74	240.06	144.45	144.79	29.58	0.88	0.20	33.35
3/19/2014 16:09	127.26	20.78	70.89	7.10	6.90	6.30	5.80	193.48	239.76	144.48	144.88	29.56	1.01	0.20	34.83
3/19/2014 16:10	127.27	20.76	70.83	7.10	6.90	6.30	5.80	194.07	240.41	144.46	144.83	29.58	1.04	0.20	34.71
3/19/2014 16:11	127.27	20.79	70.79	7.10	6.90	6.30	5.80	194.20	240.59	144.40	144.65	29.49	0.99	0.20	33.15
3/19/2014 16:12	127.27	20.89	70.67	7.10	6.90	6.30	5.80	193.26	239.41	144.39	144.58	29.41	0.96	0.20	33.74
3/19/2014 16:13	127.27	20.86	70.80	7.10	6.90	6.30	5.80	192.69	239.43	144.34	144.32	29.43	1.08	0.20	33.73
3/19/2014 16:14	127.26	20.77	70.87	7.10	6.90	6.30	5.80	194.52	241.09	144.38	144.35	29.50	0.86	0.20	33.71
3/19/2014 16:15	127.26	20.75	70.78	7.10	6.90	6.30	5.80	194.92	241.04	144.49	144.47	29.47	0.94	0.20	34.07
3/19/2014 16:16	127.26	20.68	70.97	7.10	6.90	6.30	5.80	194.80	240.85	144.45	144.46	29.53	1.26	0.20	35.56
3/19/2014 16:17	127.26	20.70	71.10	7.10	6.90	6.30	5.80	195.07	241.02	144.30	144.42	29.53	1.05	0.20	35.85
3/19/2014 16:18	127.25	20.79	71.14	7.10	6.90	6.30	5.80	195.13	241.40	144.28	144.44	29.53	0.97	0.20	35.10
3/19/2014 16:19	127.25	20.82	71.12	7.10	6.90	6.30	5.80	194.56	240.97	144.22	144.51	29.54	1.10	0.19	35.79
3/19/2014 16:20	127.26	20.84	71.07	7.10	6.90	6.30	5.80	195.31	241.48	144.18	144.51	29.52	1.15	0.19	35.38
3/19/2014 16:21	127.26	20.58	71.07	7.10	6.90	6.30	5.80	195.44	241.59	144.04	144.50	29.57	1.21	0.20	34.36
3/19/2014 16:22	127.26	20.63	71.22	7.10	6.90	6.30	5.80	195.71	241.94	144.05	144.48	29.63	1.22	0.20	35.73
3/19/2014 16:23	127.26	20.81	71.26	7.10	6.90	6.30	5.80	195.00	241.41	144.10	144.43	29.68	1.11	0.20	35.21
3/19/2014 16:24	127.26	20.76	71.39	7.10	6.90	6.30	5.80	194.22	239.65	144.11	144.38	29.76	1.09	0.20	34.76
3/19/2014 16:25	127.26	20.61	71.35	7.10	6.90	6.30	5.80	193.65	239.64	144.17	144.20	29.74	0.94	0.20	33.38
3/19/2014 16:26	127.27	20.65	71.15	7.10	6.90	6.30	5.80	194.37	240.18	144.15	144.17	29.64	0.97	0.20	33.53
3/19/2014 16:27	127.26	20.78	70.84	7.10	6.90	6.30	5.80	194.75	241.93	144.08	144.07	29.55	0.84	0.20	32.65
3/19/2014 16:28	127.25	20.81	70.72	7.10	6.90	6.30	5.80	194.89	241.70	144.08	144.09	29.57	1.00	0.20	33.09
3/19/2014 16:29	127.26	20.90	70.75	7.10	6.90	6.30	5.80	194.92	242.38	144.06	144.14	29.52	1.04	0.20	34.67
3/19/2014 16:30	127.26	20.85	70.94	7.10	6.90	6.30	5.80	195.20	241.41	144.05	144.18	29.62	1.09	0.20	34.88
3/19/2014 16:31	127.26	20.71	71.27	7.10	6.90	6.30	5.80	194.68	240.42	144.02	144.31	29.67	1.25	0.20	35.85
3/19/2014 16:32	127.26	20.73	71.34	7.10	6.90	6.30	5.80	194.76	240.59	144.03	144.34	29.63	1.15	0.20	36.54
3/19/2014 16:33	127.26	20.80	71.30	7.10	6.90	6.30	5.80	194.69	241.14	144.06	144.45	29.62	1.17	0.20	36.04
3/19/2014 16:34	127.26	20.80	71.12	7.10	6.90	6.30	5.80	195.01	241.26	144.05	144.45	29.59	1.18	0.40	36.01
3/19/2014 16:35	127.26	20.79	70.93	7.10	6.90	6.30	5.80	195.34	241.89	144.05	144.48	29.56	1.20	1.21	35.71
3/19/2014 16:36	127.27	20.79	70.71	7.10	6.90	6.30	5.80	195.89	242.41	144.01	144.38	29.49	1.17	1.54	35.47
3/19/2014 16:37	127.27	20.79	70.63	7.10	6.90	6.30	5.80	195.20	241.24	143.87	144.01	29.52	1.20	1.16	34.95

Time	CORRECTED REACTOR FEED MBPD 25F3012A	LIQUID TO GAS RATIO G/MSCF 30C3532L	REGEN COKE BURNING RATE MPPH 25CokeBN	Unit 30 Scrubber spay nozzle Pressure psig 30SCRspray01psig.or	Unit 30 Scrubber 02 spay nozzle Pressure psig 30SCRspray02psig.or	Unit 30 Scrubber 03 spay nozzle Pressure psig 30SCRspray03psig.or	Unit 30 Scrubber 04 spay nozzle Pressure psig 30SCRspray04psig.or	OXYGEN & BLOWER FEED CORR. MSCF 25Airtot	THROAT VELOCITY feet/min 25C3147V	FLUE GAS STK TMP deg F 30TI6008	FLUE GAS SCRUBBR STK TMP deg F 30TI1807	Dry Flue Gas Rate MMOL/H 25F3147D	SCRUBBER STACK O2 % 30AI6014	SCRUBBER STACK SO2 ppm 30AI6013	SCRUBBER SELECTED NOX ppm 30AI6012
3/19/2014 16:38	127.26	20.81	70.71	7.10	6.90	6.30	5.80	195.02	241.43	143.90	143.99	29.54	1.43	1.21	37.94
3/19/2014 16:39	127.26	20.89	70.70	7.10	6.90	6.30	5.80	195.07	241.80	143.97	143.95	29.51	1.20	1.37	37.97
3/19/2014 16:40	127.26	20.85	70.66	7.10	6.90	6.30	5.80	195.09	240.89	143.98	143.93	29.53	1.10	1.44	37.81
3/19/2014 16:41	127.26	20.70	70.74	7.10	6.90	6.30	5.80	194.51	240.89	144.01	143.88	29.63	1.28	1.82	37.43
3/19/2014 16:42															
Average	127.26	20.77	70.87	7.10	6.90	6.30	5.80	194.62	240.91	144.26	144.45	29.57	1.10	0.32	35.23

Time	CORRECTED REACTOR FEED MBPD 25F3012A	LIQUID TO GAS RATIO G/MSCF 30C9532L	REGEN COKE BURNING RATE MPPH 25CokeBN	Unit 30 Scrubber spay nozzle Pressure psig 30SCRspray01psig.or	Unit 30 Scrubber 02 spay nozzle Pressure psig 30SCRspray02psig.or	Unit 30 Scrubber 03 spay nozzle Pressure psig 30SCRspray03psig.or	Unit 30 Scrubber 04 spay nozzle Pressure psig 30SCRspray04psig.or	OXYGEN & BLOWER FEED CORR. MSCF 25Airtot	THROAT VELOCITY feet/min 25C3147V	FLUE GAS STK TMP deg F 30TI6008	FLUE GAS SCRUBBR STK TMP deg F 30TI1807	Dry Flue Gas Rate MMOL/H 25F3147D	SCRUBBER STACK O2 % 30AI6014	SCRUBBER STACK SO2 ppm 30AI6013	SCRUBBER SELECTED NOX ppm 30AI6012
3/20/2014 9:31	127.07	21.81	70.16	6.00	5.80	4.90	5.50	198.89	246.16	143.14	143.49	29.50	1.01	0.20	27.71
3/20/2014 9:32	127.07	21.79	70.15	6.00	5.80	4.90	5.50	199.06	246.24	143.10	143.49	29.52	1.05	0.20	27.79
3/20/2014 9:33	127.07	21.78	70.32	6.00	5.80	4.90	5.50	199.00	246.20	143.12	143.51	29.55	1.04	0.20	27.20
3/20/2014 9:34	127.08	21.76	70.58	6.00	5.80	4.90	5.50	198.91	246.08	143.18	143.54	29.64	1.12	0.20	28.83
3/20/2014 9:35	127.08	21.79	70.80	6.00	5.80	4.90	5.50	199.13	246.25	143.19	143.62	29.67	1.12	0.20	28.66
3/20/2014 9:36	127.08	21.88	70.89	6.00	5.80	4.90	5.50	198.89	246.57	143.21	143.82	29.60	1.11	0.20	28.13
3/20/2014 9:37	127.08	21.90	70.83	6.00	5.80	4.90	5.50	198.82	246.19	143.22	143.84	29.53	0.98	0.20	27.85
3/20/2014 9:38	127.07	21.94	70.62	6.00	5.80	4.90	5.50	199.15	246.67	143.24	143.61	29.53	1.07	0.20	27.52
3/20/2014 9:39	127.07	21.90	70.56	6.00	5.80	4.90	5.50	199.95	247.18	143.20	143.51	29.57	1.21	0.20	28.71
3/20/2014 9:40	127.07	21.78	70.82	6.00	5.80	4.90	5.50	200.88	248.73	143.07	143.45	29.70	1.36	0.21	27.68
3/20/2014 9:41	127.08	21.74	70.92	6.00	5.80	4.90	5.50	200.00	248.28	142.98	143.18	29.76	1.47	0.21	27.78
3/20/2014 9:42	127.08	21.64	71.06	6.00	5.80	4.90	5.50	199.44	246.68	142.71	142.84	29.89	1.87	0.21	28.37
3/20/2014 9:43	127.08	21.63	71.24	6.00	5.80	4.90	5.50	198.87	245.82	142.81	142.90	29.93	1.64	0.20	29.07
3/20/2014 9:44	127.08	21.62	71.15	6.00	5.80	4.90	5.50	199.11	246.00	143.12	143.12	29.85	1.22	0.21	28.84
3/20/2014 9:45	127.08	21.64	70.75	6.00	5.80	4.90	5.50	199.44	246.54	143.11	143.33	29.81	1.05	0.21	27.57
3/20/2014 9:46	127.08	21.68	70.23	6.00	5.80	4.90	5.50	199.15	246.21	143.10	143.34	29.73	1.20	0.21	29.44
3/20/2014 9:47	127.07	21.71	69.94	6.00	5.80	4.90	5.50	198.61	245.68	143.14	143.37	29.63	1.22	0.21	29.12
3/20/2014 9:48	127.07	21.80	69.89	6.00	5.80	4.90	5.50	199.75	247.37	143.26	143.39	29.57	1.28	0.21	28.16
3/20/2014 9:49	127.08	21.80	69.94	6.00	5.80	4.90	5.50	199.71	247.17	143.25	143.47	29.57	1.40	0.20	27.86
3/20/2014 9:50	127.08	21.80	69.97	6.00	5.80	4.90	5.50	199.46	246.50	143.21	143.47	29.59	1.46	0.20	27.25
3/20/2014 9:51	127.07	21.78	70.10	6.00	5.80	4.90	5.50	199.05	246.39	143.20	143.49	29.68	1.52	0.20	28.58
3/20/2014 9:52	127.07	21.70	70.21	6.00	5.80	4.90	5.50	199.16	245.92	143.16	143.50	29.71	1.52	0.20	28.15
3/20/2014 9:53	127.08	21.73	70.16	6.00	5.80	4.90	5.50	199.03	245.71	143.19	143.53	29.69	1.38	0.20	27.14
3/20/2014 9:54	127.08	21.80	69.92	6.00	5.80	4.90	5.50	199.21	246.77	143.28	143.55	29.62	1.40	0.20	28.03
3/20/2014 9:55	127.07	21.78	69.68	6.00	5.80	4.90	5.50	199.61	247.40	143.24	143.62	29.60	1.22	0.20	28.08
3/20/2014 9:56	127.08	21.71	69.66	6.00	5.80	4.90	5.50	198.91	245.98	143.13	143.58	29.62	1.38	0.20	27.99
3/20/2014 9:57	127.08	21.71	69.79	6.00	5.80	4.90	5.50	198.29	245.83	143.13	143.47	29.69	1.33	0.20	26.96
3/20/2014 9:58	127.08	21.69	69.95	6.00	5.80	4.90	5.50	198.33	245.38	143.15	143.43	29.70	1.36	0.20	26.05
3/20/2014 9:59	127.09	21.71	70.06	6.00	5.80	4.90	5.50	198.36	245.08	143.24	143.30	29.71	1.39	0.20	26.39
3/20/2014 10:00	127.09	21.79	69.98	6.00	5.80	4.90	5.50	198.03	244.43	143.50	143.31	29.67	1.44	0.20	27.75
3/20/2014 10:01	127.09	21.79	69.94	6.00	5.80	4.90	5.50	197.86	245.18	143.55	143.43	29.66	1.32	0.20	28.27
3/20/2014 10:02	117.09	21.79	69.88	6.00	5.80	4.90	5.50	198.39	245.19	143.71	143.65	29.66	1.21	0.20	26.98
3/20/2014 10:03	127.08	21.82	69.99	6.00	5.80	4.90	5.50	197.87	244.62	143.67	143.70	29.73	1.33	0.20	26.98
3/20/2014 10:04	127.08	21.91	69.95	6.00	5.80	4.90	5.50	196.67	242.76	143.64	143.85	29.80	1.25	0.20	26.68
3/20/2014 10:05	127.09	21.90	69.82	6.00	5.80	4.90	5.50	196.88	242.97	143.85	143.90	29.51	1.02	0.20	26.55
3/20/2014 10:06	127.09	21.85	69.75	6.00	5.80	4.90	5.50	197.22	243.98	143.88	144.11	29.48	1.12	0.21	28.75
3/20/2014 10:07	127.09	21.85	69.70	6.00	5.80	4.90	5.50	197.69	245.15	143.98	144.32	29.40	1.19	0.21	27.62
3/20/2014 10:08	127.09	21.87	69.76	6.00	5.80	4.90	5.50	197.57	245.27	143.97	144.32	29.48	1.34	0.21	27.80
3/20/2014 10:09	127.09	21.88	69.98	6.00	5.80	4.90	5.50	197.99	245.52	143.94	144.30	29.55	1.25	0.20	28.74
3/20/2014 10:10	127.09	21.94	70.10	6.00	5.80	4.90	5.50	197.63	245.04	143.92	144.28	29.46	1.30	0.20	28.40
3/20/2014 10:11	127.08	21.91	70.14	6.00	5.80	4.90	5.50	197.78	245.18	143.85	144.22	29.39	1.45	0.20	27.22
3/20/2014 10:12	127.08	21.81	70.02	6.00	5.80	4.90	5.50	198.33	245.36	143.85	144.21	29.57	1.37	0.20	26.69
3/20/2014 10:13	127.10	21.81	70.13	6.00	5.80	4.90	5.50	197.77	244.54	143.84	144.19	29.63	1.19	0.20	27.09
3/20/2014 10:14	127.10	21.80	70.26	6.00	5.80	4.90	5.50	197.80	244.60	143.85	144.19	29.67	1.28	0.20	28.29
3/20/2014 10:15	127.10	21.82	70.28	6.00	5.80	4.90	5.50	197.98	244.93	143.89	144.20	29.70	1.13	0.20	27.95
3/20/2014 10:16	127.10	21.87	70.19	6.00	5.80	4.90	5.50	198.22	245.17	143.93	144.16	29.70	1.06	0.20	26.65
3/20/2014 10:17	127.10	21.89	70.20	6.00	5.80	4.90	5.50	198.14	244.76	144.07	144.02	29.67	0.99	0.20	25.96
3/20/2014 10:18	127.10	21.95	70.22	6.00	5.80	4.90	5.50	198.82	245.46	144.05	144.00	29.57	0.93	0.20	26.03
3/20/2014 10:19	127.10	21.90	70.22	6.00	5.80	4.90	5.50	198.54	245.43	144.01	143.92	29.62	0.98	0.20	25.17
3/20/2014 10:20	127.10	21.76	70.43	6.00	5.80	4.90	5.50	198.10	245.35	143.96	143.92	29.67	1.47	0.20	27.11
3/20/2014 10:21	127.10	21.76	70.67	6.00	5.80	4.90	5.50	198.04	245.20	143.83	143.91	29.66	1.35	0.20	29.06
3/20/2014 10:22	127.10	21.76	70.87	6.00	5.80	4.90	5.50	197.76	244.73	143.85	144.00	29.70	1.18	0.20	28.63
3/20/2014 10:23	127.10	21.74	70.89	6.00	5.80	4.90	5.50	197.69	244.93	143.94	144.26	29.64	1.23	0.20	27.33
3/20/2014 10:24	127.10	21.70	70.52	6.00	5.80	4.90	5.50	198.35	245.80	143.93	144.28	29.53	1.03	0.20	26.79
3/20/2014 10:25	127.11	21.70	70.16	6.00	5.80	4.90	5.50	198.54	246.42	143.93	144.33	29.51	1.06	0.20	25.87
3/20/2014 10:26	127.11	21.72	70.17	6.00	5.80	4.90	5.50	198.28	245.09	143.88	144.29	29.57	1.43	0.20	27.56
3/20/2014 10:27	127.09	21.73	70.37	6.00	5.80	4.90	5.50	198.40	246.00	143.73	144.14	29.63	1.55	0.20	26.77
3/20/2014 10:28	127.09	21.76	70.45	6.00	5.80	4.90	5.50	199.03	246.33	143.70	144.11	29.63	1.47	0.20	27.78
3/20/2014 10:29	127.10	21.74	70.47	6.00	5.80	4.90	5.50	199.51	246.89	143.60	144.03	29.66	1.40	0.20	27.75
3/20/2014 10:30	127.10	21.69	70.52	6.00	5.80	4.90	5.50	198.44	245.53	143.61	144.06	29.74	1.49	0.20	27.68
3/20/2014 10:31	127.10	21.71	70.45	6.00	5.80	4.90	5.50	197.67	244.88	143.65	144.26	29.75	1.57	0.20	27.42
3/20/2014 10:32	127.10	21.78	70.22	6.00	5.80	4.90	5.50	197.88	244.88	143.71	144.38	29.65	1.33	0.20	26.62
3/20/2014 10:33	127.11	21.79	70.03	6.00	5.80	4.90	5.50	198.24	245.06	143.92	144.26	29.60	1.13	0.21	26.60
3/20/2014 10:34	127.11	21.85	69.80	6.00	5.80	4.90	5.50	198.35	245.38	143.87	144.36	29.56	1.19	0.21	26.74
3/20/2014 10:35	127.10	21.82	69.62	6.00	5.80	4.90	5.50	197.95	245.07	143.74	143.87	29.55	1.37	0.20	27.46
3/20/2014 10:36	127.10	21.75	69.82	6.00	5.80	4.90	5.50	198.06	245.28	143.72	143.77	29.70	1.36	0.20	27.92
3/20/2014 10:37	127.11	21.73	70.26	6.00	5.80	4.90	5.50	197.58	243.66	143.67	143.46	29.77	1.36	0.20	29.44

Time	CORRECTED REACTOR FEED MBPD 25F3012A	LIQUID TO GAS RATIO G/MSCF 30C3532L	REGEN COKE BURNING RATE MPPH 25CokeBN	Unit 30 Scrubber spray nozzle Pressure psig 30SCRspray01psig.or	Unit 30 Scrubber 02 spray nozzle Pressure psig 30SCRspray02psig.or	Unit 30 Scrubber 03 spray nozzle Pressure psig 30SCRspray03psig.or	Unit 30 Scrubber 04 spray nozzle Pressure psig 30SCRspray04psig.or	OXYGEN & BLOWER FEED CORR. MSCF 25Airtot	THROAT VELOCITY feet/min 25C3147V	FLUE GAS STK TMP deg F 30TI6008	FLUE GAS SCRUBBR STK TMP deg F 30TI1807	Dry Flue Gas Rate MMOL/H 25F3147D	SCRUBBER STACK O2 % 30AI6014	SCRUBBER STACK SO2 ppm 30AI6013	SCRUBBER SELECTED NOX ppm 30AI6012
3/20/2014 10:38	127.11	21.66	70.55	6.00	5.80	4.90	5.50	196.98	243.58	143.71	143.54	29.76	1.21	0.40	29.49
3/20/2014 10:39	127.10	21.70	70.53	6.00	5.80	4.90	5.50	196.64	243.64	143.84	143.86	29.74	1.10	1.04	29.40
3/20/2014 10:40	127.10	21.83	70.37	6.00	5.80	4.90	5.50	197.20	244.49	143.90	144.13	29.69	0.86	1.21	27.91
3/20/2014 10:41	127.11	21.85	70.07	6.00	5.80	4.90	5.50	197.46	244.64	144.08	144.14	29.52	0.79	1.43	26.19
3/20/2014 10:42	127.11	21.92	69.91	6.00	5.80	4.90	5.50	197.57	245.08	144.00	144.17	29.45	1.02	1.62	28.27
3/20/2014 10:43	127.11	21.93	69.99	6.00	5.80	4.90	5.50	197.89	245.06	143.75	144.13	29.44	1.37	1.77	28.67
3/20/2014 10:44	127.11	21.90	70.40	6.00	5.80	4.90	5.50	197.89	245.00	143.75	144.02	29.51	1.60	1.56	28.28
3/20/2014 10:45	127.11	21.70	70.63	6.00	5.80	4.90	5.50	197.63	244.71	143.75	144.03	29.59	1.56	1.53	31.46
3/20/2014 10:46	127.11	21.68	70.80	6.00	5.80	4.90	5.50	196.82	243.83	143.75	144.07	29.71	1.53	2.10	30.40
3/20/2014 10:47	127.12	21.63	70.69	6.00	5.80	4.90	5.50	197.15	244.15	143.72	144.13	29.69	1.42	1.83	30.09
3/20/2014 10:48	127.11	21.68	70.30	6.00	5.80	4.90	5.50	198.35	244.93	143.72	144.32	29.63	1.18	1.91	29.59
3/20/2014 10:49	127.10	21.85	70.12	6.00	5.80	4.90	5.50	197.61	244.24	143.71	144.23	29.70	1.33	2.03	30.89
3/20/2014 10:50	127.10	21.82	70.18	6.00	5.80	4.90	5.50	196.88	243.67	143.68	143.96	29.79	1.42	1.72	31.02
3/20/2014 10:51	127.11	21.76	70.42	6.00	5.80	4.90	5.50	196.51	243.78	143.59	143.95	29.81	1.36	1.87	31.73
3/20/2014 10:52	127.11	21.76	70.57	6.00	5.80	4.90	5.50	196.69	243.87	143.67	143.91	29.73	1.17	1.78	31.81
3/20/2014 10:53	127.11	21.74	70.40	6.00	5.80	4.90	5.50	197.28	243.38	143.94	143.88	29.64	0.89	2.19	29.38
3/20/2014 10:54	127.11	21.79	70.05	6.00	5.80	4.90	5.50	197.54	244.37	143.86	143.79	29.50	0.90	2.33	29.59
3/20/2014 10:55	127.10	21.94	69.96	6.00	5.80	4.90	5.50	197.86	244.96	143.60	143.72	29.50	1.15	1.79	30.44
3/20/2014 10:56	127.10	21.94	70.16	6.00	5.80	4.90	5.50	198.09	244.71	143.54	143.50	29.52	1.47	1.32	30.72
3/20/2014 10:57	127.10	21.91	70.37	6.00	5.80	4.90	5.50	197.67	243.95	143.37	143.54	29.51	1.42	1.12	29.63
3/20/2014 10:58	127.10	21.89	70.63	6.00	5.80	4.90	5.50	197.13	243.83	143.39	143.66	29.66	1.47	1.23	30.24
3/20/2014 10:59	127.11	21.80	70.72	6.00	5.80	4.90	5.50	196.46	243.44	143.45	143.71	29.69	1.58	0.74	30.36
3/20/2014 11:00	127.11	21.77	70.59	6.00	5.80	4.90	5.50	196.17	243.30	143.47	143.85	29.70	1.36	0.50	30.36
3/20/2014 11:01	127.11	21.68	70.53	6.00	5.80	4.90	5.50	196.66	243.34	143.54	143.88	29.72	1.29	0.56	29.16
3/20/2014 11:02	127.11	21.68	70.31	6.00	5.80	4.90	5.50	197.36	244.45	143.54	143.98	29.72	1.09	0.52	28.98
3/20/2014 11:03	127.11	21.69	70.07	6.00	5.80	4.90	5.50	196.68	243.83	143.57	144.00	29.66	1.03	0.58	28.45
3/20/2014 11:04	127.11	21.72	69.98	6.00	5.80	4.90	5.50	197.22	244.42	143.58	144.06	29.71	1.03	0.54	28.44
3/20/2014 11:05	127.10	21.82	70.12	6.00	5.80	4.90	5.50	196.94	242.95	143.61	144.04	29.59	1.06	0.44	28.06
3/20/2014 11:06	127.11	21.83	70.11	6.00	5.80	4.90	5.50	197.55	243.91	143.63	143.98	29.55	0.96	0.42	27.38
3/20/2014 11:07	127.12	21.86	70.05	6.00	5.80	4.90	5.50	197.82	244.70	143.68	143.92	29.48	1.06	0.40	28.00
3/20/2014 11:08	127.12	21.85	70.00	6.00	5.80	4.90	5.50	197.98	244.77	143.63	143.71	29.44	1.26	0.44	28.86
3/20/2014 11:09	127.11	21.84	70.12	6.00	5.80	4.90	5.50	197.77	244.79	143.50	143.64	29.50	1.23	0.39	29.39
3/20/2014 11:10	127.11	21.83	70.16	6.00	5.80	4.90	5.50	197.27	244.39	143.50	143.41	29.49	1.20	0.48	28.83
3/20/2014 11:11	127.12	21.79	70.30	6.00	5.80	4.90	5.50	197.85	245.00	143.49	143.48	29.57	1.07	0.50	28.93
3/20/2014 11:12															
Average	127.09	21.79	70.26	6.00	5.80	4.90	5.50	198.12	245.18	143.57	143.81	29.63	1.26	0.53	28.23

Time	CORRECTED REACTOR FEED MBPD 25F3012A	LIQUID TO GAS RATIO G/MSCF 30C3532L	REGEN COKE BURNING RATE MPPH 25CokeBN	Unit 30 Scrubber spay nozzle Pressure psig 30SCRspray01psig.ai	Unit 30 Scrubber 02 spay nozzle Pressure psig 30SCRspray02psig.ar	Unit 30 Scrubber 03 spay nozzle Pressure psig 30SCRspray03psig.ar	Unit 30 Scrubber 04 spay nozzle Pressure psig 30SCRspray04psig.ar	OXYGEN & BLOWER FEED CORR. MSCF 25Airtot	THROAT VELOCITY feet/min 25C3147V	FLUE GAS STK TMP deg F 30TI6008	FLUE GAS SCRUBBR STK TMP deg F 30TI1807	Dry Flue Gas Rate MMOL/H 25F3147D	SCRUBBER STACK O2 % 30AI6014	SCRUBBER STACK SO2 ppm 30AI6013	SCRUBBER SELECTED NOX ppm 30AI6012
3/21/2014 8:23	127.20	18.04	69.88	6.00	3.10	3.40	5.40	202.66	250.48	144.07	143.97	29.53	1.24	0.20	25.50
3/21/2014 8:24	127.20	18.04	69.98	6.00	3.10	3.40	5.40	202.47	250.37	144.01	143.94	29.51	1.60	0.20	25.35
3/21/2014 8:25	127.20	18.04	70.14	6.00	3.10	3.40	5.40	201.68	249.77	143.83	143.84	29.61	1.74	0.19	24.97
3/21/2014 8:26	127.20	18.00	70.34	6.00	3.10	3.40	5.40	201.13	248.97	143.86	143.92	29.66	1.70	0.19	25.78
3/21/2014 8:27	127.20	17.89	70.40	6.00	3.10	3.40	5.40	201.37	248.93	143.96	144.18	29.71	1.32	0.20	26.69
3/21/2014 8:28	127.20	17.93	70.26	6.00	3.10	3.40	5.40	200.94	248.80	144.01	144.22	29.72	1.37	0.20	26.78
3/21/2014 8:29	127.19	18.08	69.99	6.00	3.10	3.40	5.40	201.19	248.90	144.19	144.35	29.65	1.31	0.20	26.74
3/21/2014 8:30	127.19	18.05	69.73	6.00	3.10	3.40	5.40	201.51	249.22	144.19	144.39	29.66	1.23	0.20	26.08
3/21/2014 8:31	127.19	17.98	69.57	6.00	3.10	3.40	5.40	201.71	249.23	144.22	144.51	29.58	1.11	0.20	26.80
3/21/2014 8:32	127.19	17.99	69.51	6.00	3.10	3.40	5.40	201.45	249.27	144.22	144.53	29.52	0.91	0.20	23.88
3/21/2014 8:33	127.19	18.04	69.52	6.00	3.10	3.40	5.40	201.84	249.43	144.24	144.60	29.49	0.86	0.19	23.29
3/21/2014 8:34	127.19	18.03	69.57	6.00	3.10	3.40	5.40	202.13	249.96	144.19	144.55	29.48	1.00	0.27	23.57
3/21/2014 8:35	127.20	18.00	69.65	6.00	3.10	3.40	5.40	202.04	249.86	144.03	144.38	29.47	1.43	0.51	25.13
3/21/2014 8:36	127.20	18.02	69.96	6.00	3.10	3.40	5.40	201.56	249.38	144.01	144.34	29.54	1.40	0.58	27.44
3/21/2014 8:37	127.20	18.10	70.20	6.00	3.10	3.40	5.40	201.15	248.96	143.95	144.21	29.55	1.45	0.83	27.91
3/21/2014 8:38	127.19	18.06	70.30	6.00	3.10	3.40	5.40	201.57	249.05	143.97	144.23	29.58	1.45	0.99	28.05
3/21/2014 8:39	127.18	17.95	70.38	6.00	3.10	3.40	5.40	201.27	249.16	144.07	144.30	29.61	1.50	1.24	28.84
3/21/2014 8:40	127.18	17.95	70.11	6.00	3.10	3.40	5.40	200.96	248.57	144.07	144.26	29.58	1.38	1.84	29.73
3/21/2014 8:41	127.19	17.94	69.89	6.00	3.10	3.40	5.40	200.93	248.57	144.05	144.15	29.56	1.25	1.71	29.35
3/21/2014 8:42	127.19	17.97	69.75	6.00	3.10	3.40	5.40	201.06	248.78	144.08	144.13	29.51	1.11	2.07	29.46
3/21/2014 8:43	127.19	18.08	69.53	6.00	3.10	3.40	5.40	201.87	249.52	144.19	144.05	29.55	1.09	2.21	28.54
3/21/2014 8:44	127.19	18.06	69.58	6.00	3.10	3.40	5.40	201.64	249.51	144.13	144.04	29.54	1.12	2.05	30.65
3/21/2014 8:45	127.19	18.01	69.79	6.00	3.10	3.40	5.40	201.42	249.47	143.93	144.03	29.63	1.30	2.25	30.54
3/21/2014 8:46	127.19	18.00	70.01	6.00	3.10	3.40	5.40	201.43	249.30	143.90	144.02	29.62	1.30	2.24	29.35
3/21/2014 8:47	127.18	18.00	70.19	6.00	3.10	3.40	5.40	200.77	248.62	143.79	143.99	29.56	1.39	2.19	31.58
3/21/2014 8:48	127.18	17.99	70.24	6.00	3.10	3.40	5.40	200.71	248.51	143.84	144.05	29.57	1.42	2.13	30.60
3/21/2014 8:49	127.19	17.97	70.13	6.00	3.10	3.40	5.40	201.22	249.41	144.00	144.24	29.59	1.24	2.28	30.84
3/21/2014 8:50	127.19	17.95	70.08	6.00	3.10	3.40	5.40	200.94	248.99	144.01	144.27	29.60	1.12	2.28	31.65
3/21/2014 8:51	127.20	17.93	70.10	6.00	3.10	3.40	5.40	201.52	248.93	144.05	144.36	29.62	1.14	2.30	31.55
3/21/2014 8:52	127.20	17.94	70.12	6.00	3.10	3.40	5.40	201.21	248.89	144.08	144.38	29.60	1.12	2.49	30.74
3/21/2014 8:53	127.20	17.97	69.99	6.00	3.10	3.40	5.40	201.00	249.41	144.18	144.48	29.54	1.07	2.74	29.76
3/21/2014 8:54	127.20	18.00	69.85	6.00	3.10	3.40	5.40	201.69	249.51	144.12	144.43	29.50	1.21	2.41	31.58
3/21/2014 8:55	127.19	18.08	69.98	6.00	3.10	3.40	5.40	201.66	249.82	143.92	144.25	29.46	1.40	2.09	32.49
3/21/2014 8:56	127.19	18.05	69.97	6.00	3.10	3.40	5.40	201.32	249.61	143.91	144.24	29.54	1.41	1.93	31.25
3/21/2014 8:57	127.19	17.96	70.25	6.00	3.10	3.40	5.40	200.71	249.08	143.88	144.21	29.63	1.49	1.48	30.95
3/21/2014 8:58	127.19	17.97	70.26	6.00	3.10	3.40	5.40	201.47	249.54	143.91	144.20	29.54	1.29	0.98	30.92
3/21/2014 8:59	127.19	17.99	70.06	6.00	3.10	3.40	5.40	201.88	249.57	144.02	144.17	29.49	1.31	1.65	27.55
3/21/2014 9:00	127.19	17.99	69.81	6.00	3.10	3.40	5.40	202.56	249.89	143.99	144.08	29.47	1.53	1.54	27.25
3/21/2014 9:01	127.20	18.00	69.62	6.00	3.10	3.40	5.40	201.77	250.06	143.89	143.79	29.49	1.81	0.81	28.35
3/21/2014 9:02	127.20	17.99	69.76	6.00	3.10	3.40	5.40	201.13	248.20	143.91	143.84	29.56	1.67	0.49	29.60
3/21/2014 9:03	127.20	17.93	69.91	6.00	3.10	3.40	5.40	200.73	248.41	143.99	144.02	29.65	1.43	0.43	30.78
3/21/2014 9:04	127.20	17.93	69.96	6.00	3.10	3.40	5.40	200.31	248.94	144.00	144.07	29.68	1.29	0.76	29.07
3/21/2014 9:05	127.20	17.93	69.73	6.00	3.10	3.40	5.40	200.23	248.36	144.04	144.24	29.60	1.28	0.96	28.06
3/21/2014 9:06	127.20	17.93	69.53	6.00	3.10	3.40	5.40	201.21	249.08	144.09	144.28	29.59	1.19	1.11	27.35
3/21/2014 9:07	127.20	17.95	69.52	6.00	3.10	3.40	5.40	201.18	249.09	144.24	144.41	29.55	1.09	1.05	28.64
3/21/2014 9:08	127.20	17.94	69.53	6.00	3.10	3.40	5.40	200.96	249.17	144.19	144.40	29.59	1.19	1.30	26.69
3/21/2014 9:09	127.20	17.91	69.77	6.00	3.10	3.40	5.40	200.61	249.14	144.00	144.16	29.64	1.42	0.89	28.91
3/21/2014 9:10	127.20	17.94	69.95	6.00	3.10	3.40	5.40	200.93	249.04	144.01	144.34	29.63	1.33	0.57	30.23
3/21/2014 9:11	127.21	18.05	69.97	6.00	3.10	3.40	5.40	200.88	248.53	144.04	144.29	29.53	1.47	0.48	29.41
3/21/2014 9:12	127.21	18.03	69.89	6.00	3.10	3.40	5.40	201.39	248.75	144.05	144.32	29.53	1.53	0.37	29.66
3/21/2014 9:13	127.20	17.95	70.04	6.00	3.10	3.40	5.40	201.43	249.46	144.09	144.43	29.55	1.55	0.46	27.40
3/21/2014 9:14	127.20	17.98	69.96	6.00	3.10	3.40	5.40	200.96	249.34	144.11	144.47	29.59	1.46	0.53	28.43
3/21/2014 9:15	127.19	18.08	69.83	6.00	3.10	3.40	5.40	200.17	248.56	144.16	144.59	29.53	1.41	0.88	28.16
3/21/2014 9:16	127.19	18.09	69.81	6.00	3.10	3.40	5.40	199.82	247.34	144.18	144.55	29.65	1.24	0.69	30.12
3/21/2014 9:17	127.19	18.10	69.89	6.00	3.10	3.40	5.40	199.77	247.73	144.22	144.42	29.64	1.22	0.57	29.69
3/21/2014 9:18	127.19	18.09	69.71	6.00	3.10	3.40	5.40	199.97	247.56	144.22	144.37	29.60	1.15	0.61	28.83
3/21/2014 9:19	127.20	18.05	69.71	6.00	3.10	3.40	5.40	200.06	247.16	144.20	144.18	29.56	1.12	0.56	29.73
3/21/2014 9:20	127.20	18.05	69.73	6.00	3.10	3.40	5.40	200.46	247.88	144.12	144.12	29.55	1.29	0.93	27.67
3/21/2014 9:21	127.20	18.05	69.88	6.00	3.10	3.40	5.40	200.54	248.50	143.88	143.94	29.57	1.29	0.46	29.68
3/21/2014 9:22	127.20	18.05	69.99	6.00	3.10	3.40	5.40	199.99	248.50	143.90	144.01	29.55	1.40	0.83	28.33
3/21/2014 9:23	127.20	18.03	70.04	6.00	3.10	3.40	5.40	200.38	248.28	143.96	144.25	29.49	1.19	0.96	29.62
3/21/2014 9:24	127.20	18.05	69.95	6.00	3.10	3.40	5.40	200.36	247.64	143.97	144.26	29.48	1.23	0.90	27.43
3/21/2014 9:25	127.19	18.11	69.88	6.00	3.10	3.40	5.40	201.06	247.98	144.00	144.30	29.52	1.19	0.71	28.12
3/21/2014 9:26	127.19	18.08	69.80	6.00	3.10	3.40	5.40	200.10	247.55	143.98	144.28	29.47	1.15	0.80	27.26
3/21/2014 9:27	127.19	17.96	69.88	6.00	3.10	3.40	5.40	199.90	247.51	143.93	144.24	29.47	1.37	1.06	29.02
3/21/2014 9:28	127.19	17.95	69.92	6.00	3.10	3.40	5.40	200.44	247.36	143.99	144.29	29.47	1.25	0.94	29.39
3/21/2014 9:29	127.19	17.93	69.90	6.00	3.10	3.40	5.40	200.17	247.62	144.18	144.45	29.46	1.19	0.95	28.41

Time	CORRECTED REACTOR FEED MBPD 25F3012A	LIQUID TO GAS RATIO G/MSCF 30C3532L	REGEN COKE BURNING RATE MPPH 25CokeBN	Unit 30 Scrubber spay nozzle Pressure psig 30SCRspray01psig.or	Unit 30 Scrubber 02 spay nozzle Pressure psig 30SCRspray02psig.or	Unit 30 Scrubber 03 spay nozzle Pressure psig 30SCRspray03psig.or	Unit 30 Scrubber 04 spay nozzle Pressure psig 30SCRspray04psig.or	OXYGEN & BLOWER FEED CORR. MSCF 25Airtot	THROAT VELOCITY feet/min 25C3147V	FLUE GAS STK TMP deg F 30TI6008	FLUE GAS SCRUBBR STK TMP deg F 30TI1807	Dry Flue Gas Rate MMOL/H 25F3147D	SCRUBBER STACK O2 % 30AI6014	SCRUBBER STACK SO2 ppm 30AI6013	SCRUBBER SELECTED NOX ppm 30AI6012
3/20/2014 14:33															
Average	127.12	21.85	70.23	6.00	5.80	4.90	5.50	195.79	242.29	144.02	144.21	29.55	1.18	0.20	26.10

Time	CORRECTED REACTOR FEED MBPD 25F3012A	LIQUID TO GAS RATIO G/MSCF 30C3532L	REGEN COKE BURNING RATE MPPH 25CokeBN	Unit 30 Scrubber spay nozzle Pressure psig 30SCRspray01psig.or	Unit 30 Scrubber 02 spay nozzle Pressure psig 30SCRspray02psig.or	Unit 30 Scrubber 03 spay nozzle Pressure psig 30SCRspray03psig.or	Unit 30 Scrubber 04 spay nozzle Pressure psig 30SCRspray04psig.or	OXYGEN & BLOWER FEED CORR. MSCF 25Airtot	THROAT VELOCITY feet/min 25C3147V	FLUE GAS STK TMP deg F 30TI6008	FLUE GAS SCRUBBR STK TMP deg F 30TI1807	Dry Flue Gas Rate MMOL/H 25F3147D	SCRUBBER STACK O2 % 30AI6014	SCRUBBER STACK SO2 ppm 30AI6013	SCRUBBER SELECTED NOX ppm 30AI6012
3/21/2014 9:30	127.19	17.96	69.81	6.00	3.10	3.40	5.40	200.16	248.26	144.13	144.41	29.43	1.25	2.26	27.15
3/21/2014 9:31	127.17	18.06	69.83	6.00	3.10	3.40	5.40	199.81	247.11	143.97	144.29	29.52	1.49	0.48	29.46
3/21/2014 9:32	127.28	18.05	70.06	6.00	3.10	3.40	5.40	199.67	247.09	144.00	144.32	29.55	1.44	0.66	28.18
3/21/2014 9:33															
Average	127.19	18.00	69.91	6.00	3.10	3.40	5.40	201.03	248.83	144.04	144.24	29.56	1.31	1.06	28.54

Time	CORRECTED REACTOR FEED MBPD 25F3012A	LIQUID TO GAS RATIO G/MSCF 30C3532L	REGEN COKE BURNING RATE MPPH 25CokeBN	Unit 30 Scrubber spay nozzle Pressure psig 30SCRspray01psig.or	Unit 30 Scrubber 02 spay nozzle Pressure psig 30SCRspray02psig.or	Unit 30 Scrubber 03 spay nozzle Pressure psig 30SCRspray03psig.or	Unit 30 Scrubber 04 spay nozzle Pressure psig 30SCRspray04psig.or	OXYGEN & BLOWER FEED CORR. MSCF 25Airtot	THROAT VELOCITY feet/min 25C3147V	FLUE GAS STK TMP deg F 30TI6008	FLUE GAS SCRUBBR STK TMP deg F 30TI1807	Dry Flue Gas Rate MMOL/H 25F3147D	SCRUBBER STACK O2 % 30AI6014	SCRUBBER STACK SO2 ppm 30AI6013	SCRUBBER SELECTED NOX ppm 30AI6012
3/21/14 8:34	127.19	18.03	69.57	6.00	3.10	3.40	5.40	202.13	249.96	144.19	144.55	29.48	1.00	0.27	23.57
3/21/14 8:35	127.20	18.00	69.65	6.00	3.10	3.40	5.40	202.04	249.86	144.03	144.38	29.47	1.43	0.51	25.13
3/21/14 8:36	127.20	18.02	69.96	6.00	3.10	3.40	5.40	201.56	249.38	144.01	144.34	29.54	1.40	0.58	27.44
3/21/14 8:37	127.20	18.10	70.20	6.00	3.10	3.40	5.40	201.15	248.96	143.95	144.21	29.55	1.45	0.83	27.91
3/21/14 8:38	127.19	18.06	70.30	6.00	3.10	3.40	5.40	201.57	249.05	143.97	144.23	29.58	1.45	0.99	28.05
3/21/14 8:39	127.18	17.95	70.18	6.00	3.10	3.40	5.40	201.27	249.16	144.07	144.30	29.61	1.50	1.24	28.84
3/21/14 8:40	127.18	17.95	70.11	6.00	3.10	3.40	5.40	200.96	248.57	144.07	144.26	29.58	1.38	1.84	29.73
3/21/14 8:41	127.19	17.94	69.89	6.00	3.10	3.40	5.40	200.93	248.57	144.05	144.15	29.56	1.25	1.71	29.35
3/21/14 8:42	127.19	17.97	69.75	6.00	3.10	3.40	5.40	201.06	248.78	144.08	144.13	29.51	1.11	2.07	29.46
3/21/14 8:43	127.19	18.08	69.53	6.00	3.10	3.40	5.40	201.87	249.52	144.19	144.05	29.55	1.09	2.11	28.54
3/21/14 8:44	127.19	18.06	69.58	6.00	3.10	3.40	5.40	201.64	249.51	144.13	144.04	29.54	1.12	2.05	30.65
3/21/14 8:45	127.19	18.01	69.79	6.00	3.10	3.40	5.40	201.42	249.47	143.93	144.03	29.63	1.30	2.25	30.54
3/21/14 8:46	127.19	18.00	70.01	6.00	3.10	3.40	5.40	201.43	249.30	143.90	144.02	29.62	1.30	2.24	29.35
3/21/14 8:47	127.18	18.00	70.19	6.00	3.10	3.40	5.40	200.77	248.62	143.79	143.99	29.56	1.39	2.19	31.58
3/21/14 8:48	127.18	17.99	70.24	6.00	3.10	3.40	5.40	200.71	248.51	143.84	144.05	29.57	1.42	2.13	30.60
3/21/14 8:49	127.19	17.97	70.13	6.00	3.10	3.40	5.40	201.22	249.41	144.00	144.24	29.59	1.24	2.28	30.84
3/21/14 8:50	127.19	17.96	70.08	6.00	3.10	3.40	5.40	200.94	248.99	144.01	144.27	29.60	1.12	2.28	31.65
3/21/14 8:51	127.20	17.93	70.10	6.00	3.10	3.40	5.40	201.52	248.93	144.05	144.36	29.62	1.14	2.30	31.55
3/21/14 8:52	127.20	17.94	70.12	6.00	3.10	3.40	5.40	201.21	248.89	144.08	144.38	29.60	1.12	2.49	30.74
3/21/14 8:53	127.20	17.97	69.99	6.00	3.10	3.40	5.40	201.00	249.41	144.18	144.48	29.54	1.07	2.74	29.76
3/21/14 8:54	127.20	18.00	69.95	6.00	3.10	3.40	5.40	201.69	249.51	144.12	144.43	29.50	1.21	2.43	31.58
3/21/14 8:55	127.19	18.08	69.98	6.00	3.10	3.40	5.40	201.68	249.82	143.92	144.25	29.46	1.40	2.09	32.49
3/21/14 8:56	127.19	18.05	69.97	6.00	3.10	3.40	5.40	201.32	249.61	143.91	144.24	29.54	1.41	1.93	31.25
3/21/14 8:57	127.19	17.96	70.25	6.00	3.10	3.40	5.40	200.71	249.08	143.88	144.21	29.63	1.49	1.48	30.95
3/21/14 8:58	127.19	17.97	70.26	6.00	3.10	3.40	5.40	201.47	249.54	143.91	144.20	29.54	1.29	0.98	30.92
3/21/14 8:59	127.19	17.99	70.06	6.00	3.10	3.40	5.40	201.88	249.57	144.02	144.17	29.49	1.31	1.65	27.55
3/21/14 9:00	127.19	17.99	69.81	6.00	3.10	3.40	5.40	202.56	249.89	143.99	144.08	29.47	1.53	1.54	27.25
3/21/14 9:01	127.20	18.00	69.61	6.00	3.10	3.40	5.40	201.77	250.06	143.89	143.79	29.49	1.81	0.81	28.15
3/21/14 9:02	127.20	17.99	69.76	6.00	3.10	3.40	5.40	201.13	248.20	143.91	143.84	29.56	1.67	0.49	29.60
3/21/14 9:03	127.20	17.93	69.91	6.00	3.10	3.40	5.40	200.73	248.41	143.99	144.02	29.65	1.43	0.43	30.78
3/21/14 9:04	127.20	17.93	69.96	6.00	3.10	3.40	5.40	200.31	248.94	144.00	144.07	29.68	1.29	0.76	29.07
3/21/14 9:05	127.20	17.93	69.73	6.00	3.10	3.40	5.40	200.23	248.16	144.04	144.24	29.60	1.18	0.96	28.06
3/21/14 9:06	127.20	17.93	69.53	6.00	3.10	3.40	5.40	201.21	249.08	144.09	144.28	29.59	1.19	1.11	27.35
3/21/14 9:07	127.20	17.95	69.52	6.00	3.10	3.40	5.40	201.18	249.09	144.24	144.42	29.55	1.09	1.05	28.64
3/21/14 9:08	127.20	17.94	69.53	6.00	3.10	3.40	5.40	200.96	249.13	144.29	144.40	29.59	1.19	1.30	26.69
3/21/14 9:09	127.20	17.91	69.77	6.00	3.10	3.40	5.40	200.61	249.14	144.00	144.36	29.64	1.42	0.89	28.91
3/21/14 9:10	127.20	17.94	69.95	6.00	3.10	3.40	5.40	200.93	249.04	144.01	144.34	29.63	1.33	0.57	30.23
3/21/14 9:11	127.21	18.05	69.97	6.00	3.10	3.40	5.40	200.88	248.53	144.04	144.29	29.53	1.47	0.48	29.41
3/21/14 9:12	127.21	18.03	69.89	6.00	3.10	3.40	5.40	201.39	248.75	144.05	144.32	29.53	1.53	0.37	29.66
3/21/14 9:13	127.20	17.95	70.04	6.00	3.10	3.40	5.40	201.43	249.46	144.09	144.43	29.55	1.55	0.46	27.40
3/21/14 9:14	127.20	17.98	69.96	6.00	3.10	3.40	5.40	200.96	249.34	144.11	144.47	29.59	1.46	0.53	28.43
3/21/14 9:15	127.19	18.08	69.83	6.00	3.10	3.40	5.40	200.17	248.56	144.36	144.59	29.53	1.41	0.88	28.16
3/21/14 9:16	127.19	18.09	69.81	6.00	3.10	3.40	5.40	199.82	247.34	144.18	144.55	29.65	1.24	0.69	30.12
3/21/14 9:17	127.19	18.10	69.89	6.00	3.10	3.40	5.40	199.77	247.73	144.22	144.42	29.64	1.22	0.57	29.69
3/21/14 9:18	127.19	18.09	69.71	6.00	3.10	3.40	5.40	199.97	247.56	144.22	144.37	29.60	1.15	0.61	28.83
3/21/14 9:19	127.20	18.05	69.71	6.00	3.10	3.40	5.40	200.06	247.16	144.20	144.18	29.56	1.12	0.56	29.73
3/21/14 9:20	127.20	18.05	69.73	6.00	3.10	3.40	5.40	200.46	247.88	144.12	144.12	29.55	1.29	0.93	27.67
3/21/14 9:21	127.20	18.05	69.88	6.00	3.10	3.40	5.40	200.54	248.50	143.88	143.94	29.57	1.29	0.46	29.68
3/21/14 9:22	127.20	18.05	69.99	6.00	3.10	3.40	5.40	199.99	248.50	143.90	144.01	29.55	1.40	0.83	28.33
3/21/14 9:23	127.20	18.03	70.04	6.00	3.10	3.40	5.40	200.38	248.28	143.96	144.25	29.49	1.19	0.96	29.62
3/21/14 9:24	127.20	18.05	69.95	6.00	3.10	3.40	5.40	200.36	247.64	143.97	144.26	29.48	1.23	0.90	27.43
3/21/14 9:25	127.19	18.11	69.88	6.00	3.10	3.40	5.40	201.06	247.98	144.00	144.30	29.52	1.19	0.71	28.12
3/21/14 9:26	127.19	18.08	69.80	6.00	3.10	3.40	5.40	200.10	247.55	143.98	144.28	29.47	1.35	0.80	27.26
3/21/14 9:27	127.19	17.96	69.88	6.00	3.10	3.40	5.40	199.90	247.51	143.93	144.24	29.47	1.37	1.06	29.01
3/21/14 9:28	127.19	17.95	69.92	6.00	3.10	3.40	5.40	200.44	247.36	143.99	144.29	29.47	1.25	0.94	29.39
3/21/14 9:29	127.19	17.93	69.90	6.00	3.10	3.40	5.40	200.17	247.62	144.18	144.45	29.46	1.29	0.95	28.41
3/21/14 9:30	127.19	17.96	69.81	6.00	3.10	3.40	5.40	200.16	248.26	144.13	144.41	29.43	1.25	1.26	27.15
3/21/14 9:31	127.17	18.06	69.83	6.00	3.10	3.40	5.40	199.81	247.11	143.97	144.29	29.52	1.49	0.48	29.46
3/21/14 9:32	127.18	18.05	70.06	6.00	3.10	3.40	5.40	199.67	247.09	144.00	144.32	29.55	1.44	0.66	28.18
3/21/14 9:33	127.19	18.04	70.09	6.00	3.10	3.40	5.40	199.39	247.12	144.07	144.43	29.56	1.32	0.25	27.53
3/21/14 9:34	127.20	18.06	70.20	6.00	3.10	3.40	5.40	199.79	247.30	144.08	144.39	29.58	1.29	0.20	29.03
3/21/14 9:35	127.21	18.11	70.14	6.00	3.10	3.40	5.40	199.29	246.74	144.09	144.30	29.54	1.19	0.21	27.97
3/21/14 9:36	127.21	18.11	69.96	6.00	3.10	3.40	5.40	199.87	247.16	144.15	144.28	29.57	1.04	0.29	27.70
3/21/14 9:37	127.20	18.10	69.93	6.00	3.10	3.40	5.40	200.37	247.37	144.31	144.20	29.52	0.96	0.42	26.82
3/21/14 9:38	127.20	18.12	69.80	6.00	3.10	3.40	5.40	200.55	248.04	144.27	144.16	29.48	0.96	0.23	26.30
3/21/14 9:39	127.20	18.18	69.73	6.00	3.10	3.40	5.40	200.69	248.21	144.17	144.06	29.38	1.06	0.29	24.82
3/21/14 9:40	127.20	18.11	69.89	6.00	3.10	3.40	5.40	200.40	248.45	144.13	144.08	29.48	1.23	0.20	26.46

RESULTS

Table 2-1:
NSFPM, CPM and Total Non-Sulfate PM (M-5F/202) – Condition 1

Run No.		1	2	3	Average
Date (2012)		Apr 24	Apr 24	Apr 24	
Start Time (approx.)		10:33	12:48	14:33	
Stop Time (approx.)		11:43	13:53	15:55	
Process Conditions					
R_P	Coke burn-off rate (Mlb coke/hr)	18.4	18.2	18.2	**18.3**
P_1	FCC charge rate (bpd)	33,000	33,000	33,000	**33,000**
P_2	ESP operation	West / MPR	West / MPR	West / MPR	
P_3	NH3 injection (lb/hr)	8	8	8	
Gas Conditions					
O_2	Oxygen (dry volume %)	2.0	2.0	2.2	**2.1**
CO_2	Carbon dioxide (dry volume %)	16.3	16.3	16.2	**16.3**
T_s	Sample temperature (°F)	569	568	566	**568**
B_w	Actual water vapor in gas (% by volume)	9.5	9.3	9.4	**9.4**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	129,000	129,000	127,000	**128,000**
Q_s	Volumetric flow rate, standard (scfm)	63,700	63,700	63,100	**63,500**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	57,600	57,800	57,100	**57,500**
Q_a	Volumetric flow rate, actual (acf/hr)	7,720,000	7,720,000	7,630,000	**7,690,000**
Q_s	Volumetric flow rate, standard (scf/hr)	3,820,000	3,820,000	3,780,000	**3,810,000**
Q_{std}	Volumetric flow rate, dry standard (dscf/hr)	3,460,000	3,470,000	3,430,000	**3,450,000**
Sampling Data					
V_{mstd}	Volume metered, standard (dscf)	36.01	33.86	36.26	**35.38**
%I	Isokinetic sampling (%)[1]	99.5	93.0	100.7	**97.7**
Laboratory Data					
m_n	Total NSFPM (g)	0.02630	0.02447	0.02664	
m_{CPM}	Total CPM (g)	0.05004	0.04841	0.05142	
m_{Part}	Total non-sulfate particulate matter (g)	0.07634	0.07289	0.07806	
n_{MDL}	Number of non-detectable fractions	N/A	N/A	N/A	
DLC	Detection level classification	ADL	ADL	ADL	
NSFPM Results					
C_{sd}	Particulate Concentration (lb/dscf)	1.61E-06	1.59E-06	1.62E-06	**1.61E-06**
$E_{lb/hr}$	Particulate Rate (lb/hr)	5.57	5.52	5.55	**5.55**
E_{Rp}	Particulate Rate - Production-based (lb/Mlb coke)	0.303	0.303	0.305	**0.304**
CPM Results					
C_{sd}	Particulate Concentration (lb/dscf)	3.06E-06	3.15E-06	3.13E-06	**3.11E-06**
$E_{lb/hr}$	Particulate Rate (lb/hr)	10.6	10.9	10.7	**10.7**
E_{Rp}	Particulate Rate - Production-based (lb/Mlb coke)	0.577	0.599	0.589	**0.588**
Total Non-Sulfate Particulate Matter Results					
C_{sd}	Particulate Concentration (lb/dscf)	4.67E-06	4.75E-06	4.75E-06	**4.72E-06**
$E_{lb/hr}$	Particulate Rate (lb/hr)	16.2	16.4	16.3	**16.3**
E_{Rp}	Particulate Rate - Production-based (lb/Mlb coke)	0.881	0.902	0.894	**0.892**

Average includes 3 runs.

[1] Sample flow rates as determined by EPA Method 2 were used to calculate isokinetic sampling conditions.

Detection level classifications are defined as follows:

ADL = Above Detection Level - all fractions are above detection limit

052912 135657

RESULTS

Table 2-2:
NSFPM, CPM and Total Non-Sulfate PM (M-5F/202) – Condition 2

Run No.		4	5	6	Average
Date (2012)		Apr 25	Apr 25	Apr 25	
Start Time (approx.)		09:08	12:07	14:06	
Stop Time (approx.)		10:12	13:14	15:23	
Process Conditions					
R_P	Coke burn-off rate (Mlb coke/hr)	18.1	18.1	18.1	**18.1**
P_1	FCC charge rate (bpd)	32,500	32,500	32,500	**32,500**
P_2	ESP operation	Both / MPR	Both / MPR	Both / MPR	
P_3	NH3 injection (lb/hr)	8	8	8	
Gas Conditions					
O_2	Oxygen (dry volume %)	2.4	2.5	2.3	**2.4**
CO_2	Carbon dioxide (dry volume %)	16.1	16.0	16.2	**16.1**
T_s	Sample temperature (°F)	557	557	557	**557**
B_w	Actual water vapor in gas (% by volume)	9.6	9.9	9.7	**9.7**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	129,000	129,000	128,000	**128,000**
Q_s	Volumetric flow rate, standard (scfm)	65,100	65,200	64,600	**65,000**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	58,800	58,700	58,400	**58,700**
Q_a	Volumetric flow rate, actual (acf/hr)	7,710,000	7,730,000	7,660,000	**7,700,000**
Q_s	Volumetric flow rate, standard (scf/hr)	3,910,000	3,910,000	3,880,000	**3,900,000**
Q_{std}	Volumetric flow rate, dry standard (dscf/hr)	3,530,000	3,520,000	3,500,000	**3,520,000**
Sampling Data					
V_{mstd}	Volume metered, standard (dscf)	35.40	35.60	35.65	**35.55**
%I	Isokinetic sampling (%)[1]	101.0	101.4	101.3	**101.2**
Laboratory Data					
m_n	Total NSFPM (g)	0.01293	0.01333	0.01576	
m_{CPM}	Total CPM (g)	0.04205	0.04405	0.04385	
m_{Part}	Total non-sulfate particulate matter (g)	0.05498	0.05738	0.05961	
n_{MDL}	Number of non-detectable fractions	N/A	N/A	N/A	
DLC	Detection level classification	ADL	ADL	ADL	
NSFPM Results					
C_{sd}	Particulate Concentration (lb/dscf)	8.05E-07	8.25E-07	9.75E-07	**8.69E-07**
$E_{lb/hr}$	Particulate Rate (lb/hr)	2.84	2.91	3.41	**3.06**
E_{Rp}	Particulate Rate - Production-based (lb/Mlb coke)	0.157	0.161	0.189	**0.169**
CPM Results					
C_{sd}	Particulate Concentration (lb/dscf)	2.62E-06	2.73E-06	2.71E-06	**2.69E-06**
$E_{lb/hr}$	Particulate Rate (lb/hr)	9.25	9.61	9.50	**9.45**
E_{Rp}	Particulate Rate - Production-based (lb/Mlb coke)	0.510	0.531	0.526	**0.522**
Total Non-Sulfate Particulate Matter Results					
C_{sd}	Particulate Concentration (lb/dscf)	3.42E-06	3.55E-06	3.69E-06	**3.55E-06**
$E_{lb/hr}$	Particulate Rate (lb/hr)	12.1	12.5	12.9	**12.5**
E_{Rp}	Particulate Rate - Production-based (lb/Mlb coke)	0.666	0.692	0.715	**0.691**

Average includes 3 runs.

[1] Sample flow rates as determined by EPA Method 2 were used to calculate isokinetic sampling conditions.

Detection level classifications are defined as follows:

ADL = Above Detection Level - all fractions are above detection limit

052912 135657

Table 2-3:
NSFPM, CPM and Total Non-Sulfate PM (M-5F/202) – Condition 3

Run No.		7	8	9	Average
Date (2012)		Apr 26	Apr 26	Apr 26	
Start Time (approx.)		08:24	10:10	11:58	
Stop Time (approx.)		09:31	11:17	13:17	
Process Conditions					
R_P	Coke burn-off rate (Mlb coke/hr)	18.1	18.1	18.1	**18.1**
P_1	FCC charge rate (bpd)	32,500	32,500	32,500	**32,500**
P_2	ESP operation	Both / LPR	Both / LPR	Both / LPR	
P_3	NH3 injection (lb/hr)	8	8	8	
Gas Conditions					
O_2	Oxygen (dry volume %)	2.3	2.3	2.4	**2.3**
CO_2	Carbon dioxide (dry volume %)	16.0	16.0	15.8	**15.9**
T_s	Sample temperature (°F)	560	558	556	**558**
B_w	Actual water vapor in gas (% by volume)	10.0	10.1	10.0	**10.0**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	130,000	127,000	126,000	**128,000**
Q_s	Volumetric flow rate, standard (scfm)	65,500	64,100	63,700	**64,500**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	58,900	57,700	57,400	**58,000**
Q_a	Volumetric flow rate, actual (acf/hr)	7,830,000	7,650,000	7,580,000	**7,690,000**
Q_s	Volumetric flow rate, standard (scf/hr)	3,930,000	3,850,000	3,820,000	**3,870,000**
Q_{std}	Volumetric flow rate, dry standard (dscf/hr)	3,540,000	3,460,000	3,440,000	**3,480,000**
Sampling Data					
V_{mstd}	Volume metered, standard (dscf)	36.79	36.53	35.97	**36.43**
%I	Isokinetic sampling (%)[1]	104.3	103.4	102.6	**103.5**
Laboratory Data					
m_n	Total NSFPM (g)	0.01655	0.01699	0.01364	
m_{CPM}	Total CPM (g)	0.04177	0.04585	0.04593	
m_{Part}	Total non-sulfate particulate matter (g)	0.05832	0.06284	0.05957	
n_{MDL}	Number of non-detectable fractions	N/A	N/A	N/A	
DLC	Detection level classification	ADL	ADL	ADL	
NSFPM Results					
C_{sd}	Particulate Concentration (lb/dscf)	9.92E-07	1.03E-06	8.36E-07	**9.51E-07**
$E_{lb/hr}$	Particulate Rate (lb/hr)	3.51	3.55	2.88	**3.31**
E_{Rp}	Particulate Rate - Production-based (lb/Mlb coke)	0.194	0.196	0.159	**0.183**
CPM Results					
C_{sd}	Particulate Concentration (lb/dscf)	2.50E-06	2.77E-06	2.82E-06	**2.70E-06**
$E_{lb/hr}$	Particulate Rate (lb/hr)	8.85	9.57	9.69	**9.37**
E_{Rp}	Particulate Rate - Production-based (lb/Mlb coke)	0.490	0.530	0.536	**0.519**
Total Non-Sulfate Particulate Matter Results					
C_{sd}	Particulate Concentration (lb/dscf)	3.50E-06	3.79E-06	3.65E-06	**3.65E-06**
$E_{lb/hr}$	Particulate Rate (lb/hr)	12.4	13.1	12.6	**12.7**
E_{Rp}	Particulate Rate - Production-based (lb/Mlb coke)	0.684	0.726	0.695	**0.702**

Average includes 3 runs.

[1] Sample flow rates as determined by EPA Method 2 were used to calculate isokinetic sampling conditions.

Detection level classifications are defined as follows:

ADL = Above Detection Level - all fractions are above detection limit

052912 135657

RESULTS

Table 2-4:
NH_3 (Mod. CTM-027) – Condition 1

Run No.		**1**	**2**	**3**	**Average**
Date (2012)		Apr 24	Apr 24	Apr 24	
Start Time (approx.)		10:33	12:48	14:33	
Stop Time (approx.)		11:33	13:48	15:33	
Process Conditions					
R_P	Coke burn-off rate (Mlb coke/hr)	18.4	18.2	18.2	**18.3**
P_1	FCC charge rate (bpd)	33,000	33,000	33,000	**33,000**
P_2	ESP operation	West / MPR	West / MPR	West / MPR	
P_3	NH3 injection (lb/hr)	8	8	8	
Gas Conditions					
O_2	Oxygen (dry volume %)	2.0	2.0	2.2	**2.1**
CO_2	Carbon dioxide (dry volume %)	16.4	16.4	16.2	**16.3**
T_s	Sample temperature (°F)	568	567	567	**567**
B_w	Actual water vapor in gas (% by volume)	9.9	10.1	9.7	**9.9**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	129,000	129,000	127,000	**128,000**
Q_s	Volumetric flow rate, standard (scfm)	63,700	63,800	63,000	**63,500**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	57,400	57,300	56,900	**57,200**
Q_a	Volumetric flow rate, actual (acf/hr)	7,720,000	7,720,000	7,630,000	**7,690,000**
Q_s	Volumetric flow rate, standard (scf/hr)	3,820,000	3,830,000	3,780,000	**3,810,000**
Q_{std}	Volumetric flow rate, dry standard (dscf/hr)	3,440,000	3,440,000	3,410,000	**3,430,000**
Sampling Data					
V_{mstd}	Volume metered, standard (dscf)	34.66	35.47	36.12	**35.41**
%I	Isokinetic sampling (%)[1]	98.9	101.2	100.6	**100.2**
Laboratory Data					
m_n	Total NH_3 collected (mg)	20.1313	20.6721	21.0722	
Ammonia (NH_3) Results					
C_{sd}	Ammonia Concentration (lb/dscf)	1.28E-06	1.29E-06	1.29E-06	**1.28E-06**
C_{sd}	Ammonia Concentration (ppmdv)	29.0	29.1	29.1	**29.1**
$E_{lb/hr}$	Ammonia Rate (lb/hr)	4.41	4.42	4.39	**4.41**
E_{Rp}	Ammonia Rate - Production-based (lb/Mlb coke)	0.240	0.242	0.241	**0.241**

Average includes 3 runs.

[1] Sample flow rates as determined by EPA Method 2 were used to calculate isokinetic sampling conditions.

060412 100420

RESULTS

Table 2-5:
NH_3 (Mod. CTM-027) – Condition 2

Run No.		**4**	**5**	**6**	**Average**
Date (2012)		Apr 25	Apr 25	Apr 25	
Start Time (approx.)		09:08	12:07	14:06	
Stop Time (approx.)		10:08	13:07	15:06	
Process Conditions					
R_P	Coke burn-off rate (Mlb coke/hr)	18.1	18.1	18.1	**18.1**
P_1	FCC charge rate (bpd)	32,500	32,500	32,500	**32,500**
P_2	ESP operation	Both / MPR	Both / MPR	Both / MPR	
P_3	NH3 injection (lb/hr)	8	8	8	
Gas Conditions					
O_2	Oxygen (dry volume %)	2.7	2.5	2.6	**2.6**
CO_2	Carbon dioxide (dry volume %)	15.9	16.0	15.9	**15.9**
T_s	Sample temperature (°F)	555	555	554	**555**
B_w	Actual water vapor in gas (% by volume)	9.7	9.6	9.7	**9.7**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	129,000	129,000	128,000	**128,000**
Q_s	Volumetric flow rate, standard (scfm)	65,200	65,300	64,800	**65,100**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	58,900	59,100	58,500	**58,800**
Q_a	Volumetric flow rate, actual (acf/hr)	7,710,000	7,730,000	7,660,000	**7,700,000**
Q_s	Volumetric flow rate, standard (scf/hr)	3,910,000	3,920,000	3,890,000	**3,910,000**
Q_{std}	Volumetric flow rate, dry standard (dscf/hr)	3,530,000	3,550,000	3,510,000	**3,530,000**
Sampling Data					
V_{mstd}	Volume metered, standard (dscf)	34.28	34.82	33.03	**34.04**
%I	Isokinetic sampling (%)[1]	99.9	101.6	99.6	**100.4**
Laboratory Data					
m_n	Total NH_3 collected (mg)	10.5610	10.5713	9.5688	
Ammonia (NH_3) Results					
C_{sd}	Ammonia Concentration (lb/dscf)	6.79E-07	6.69E-07	6.39E-07	**6.63E-07**
C_{sd}	Ammonia Concentration (ppmdv)	15.4	15.2	14.5	**15.0**
$E_{lb/hr}$	Ammonia Rate (lb/hr)	2.40	2.37	2.24	**2.34**
E_{Rp}	Ammonia Rate - Production-based (lb/Mlb coke)	0.132	0.131	0.124	**0.129**

Average includes 3 runs.

[1] Sample flow rates as determined by EPA Method 2 were used to calculate isokinetic sampling conditions.

060412 100420

RESULTS

Table 2-6:
NH_3 (Mod. CTM-027) – Condition 3

Run No.		**7**	**8**	**9**	**Average**
Date (2012)		Apr 26	Apr 26	Apr 26	
Start Time (approx.)		08:24	10:10	11:58	
Stop Time (approx.)		09:24	11:10	12:58	
Process Conditions					
R_P	Coke burn-off rate (Mlb coke/hr)	18.1	18.1	18.1	**18.1**
P_1	FCC charge rate (bpd)	32,500	32,500	32,500	**32,500**
P_2	ESP operation	Both / LPR	Both / LPR	Both / LPR	
P_3	NH3 injection (lb/hr)	8	8	8	
Gas Conditions					
O_2	Oxygen (dry volume %)	2.4	2.5	2.5	**2.5**
CO_2	Carbon dioxide (dry volume %)	15.9	15.8	15.9	**15.9**
T_s	Sample temperature (°F)	558	556	553	**555**
B_w	Actual water vapor in gas (% by volume)	10.7	9.9	10.3	**10.3**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	130,000	127,000	126,000	**128,000**
Q_s	Volumetric flow rate, standard (scfm)	65,700	64,200	63,900	**64,600**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	58,700	57,900	57,300	**58,000**
Q_a	Volumetric flow rate, actual (acf/hr)	7,830,000	7,650,000	7,580,000	**7,690,000**
Q_s	Volumetric flow rate, standard (scf/hr)	3,940,000	3,850,000	3,840,000	**3,880,000**
Q_{std}	Volumetric flow rate, dry standard (dscf/hr)	3,520,000	3,470,000	3,440,000	**3,480,000**
Sampling Data					
V_{mstd}	Volume metered, standard (dscf)	34.33	35.18	34.08	**34.53**
%I	Isokinetic sampling (%)[1]	100.5	101.1	102.3	**101.3**
Laboratory Data					
m_n	Total NH_3 collected (mg)	10.6365	9.7750	10.4514	
Ammonia (NH_3) Results					
C_{sd}	Ammonia Concentration (lb/dscf)	6.83E-07	6.13E-07	6.76E-07	**6.57E-07**
C_{sd}	Ammonia Concentration (ppmdv)	15.5	13.9	15.3	**14.9**
$E_{lb/hr}$	Ammonia Rate (lb/hr)	2.41	2.13	2.33	**2.29**
E_{Rp}	Ammonia Rate - Production-based (lb/Mlb coke)	0.133	0.118	0.129	**0.126**

Average includes 3 runs.

[1] Sample flow rates as determined by EPA Method 2 were used to calculate isokinetic sampling conditions.

060412 100420

Table 2-7:
NH_3 (Mod. CTM-027) – Condition 4

Run No.		**10**	**11**	**12**	**Average**
Date (2012)		Apr 27	Apr 27	Apr 27	
Start Time (approx.)		09:28	11:12	12:45	
Stop Time (approx.)		10:28	12:12	13:45	
Process Conditions					
R_P	Coke burn-off rate (Mlb coke/hr)	17.9	17.9	17.9	**17.9**
P_1	FCC charge rate (bpd)	32,500	32,500	32,500	**32,500**
P_2	ESP operation	Both	Both	Both	
P_3	NH3 injection (lb/hr)	8	8	8	
Gas Conditions					
O_2	Oxygen (dry volume %)	3.8	2.8	3.1	**3.2**
CO_2	Carbon dioxide (dry volume %)	14.7	15.6	15.4	**15.2**
T_s	Sample temperature (°F)	551	552	552	**552**
B_w	Actual water vapor in gas (% by volume)	9.8	9.7	9.3	**9.6**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	123,000	126,000	121,000	**123,000**
Q_s	Volumetric flow rate, standard (scfm)	63,200	64,800	62,500	**63,500**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	57,100	58,600	56,700	**57,400**
Q_a	Volumetric flow rate, actual (acf/hr)	7,360,000	7,550,000	7,280,000	**7,400,000**
Q_s	Volumetric flow rate, standard (scf/hr)	3,790,000	3,890,000	3,750,000	**3,810,000**
Q_{std}	Volumetric flow rate, dry standard (dscf/hr)	3,420,000	3,510,000	3,400,000	**3,450,000**
Sampling Data					
V_{mstd}	Volume metered, standard (dscf)	34.70	34.61	34.17	**34.49**
%I	Isokinetic sampling (%)[1]	100.7	100.5	99.5	**100.2**
Laboratory Data					
m_n	Total NH_3 collected (mg)	10.7336	11.1983	11.3417	
Ammonia (NH_3) Results					
C_{sd}	Ammonia Concentration (lb/dscf)	6.82E-07	7.14E-07	7.32E-07	**7.09E-07**
C_{sd}	Ammonia Concentration (ppmdv)	15.4	16.2	16.6	**16.1**
$E_{lb/hr}$	Ammonia Rate (lb/hr)	2.33	2.51	2.49	**2.44**
E_{Rp}	Ammonia Rate - Production-based (lb/Mlb coke)	0.130	0.140	0.139	**0.136**

Average includes 3 runs.

[1] Sample flow rates as determined by EPA Method 2 were used to calculate isokinetic sampling conditions.

060412 100420

Table 2-8:
HCN (OTM-29) – Condition 4

Run No.		**1**	**2**	**3**	**Average**
Date (2012)		Apr 27	Apr 27	Apr 27	
Start Time (approx.)		09:28	11:12	12:45	
Stop Time (approx.)		10:34	12:17	14:00	
Process Conditions					
R_P	Coke burn-off rate (Mlb coke/hr)	17.9	17.9	17.9	**17.9**
P_1	FCC charge rate (bpd)	32,500	32,500	32,500	**32,500**
P_2	ESP operation	Both	Both	Both	
P_3	NH3 injection (lb/hr)	8	8	8	
Gas Conditions					
O_2	Oxygen (dry volume %)	3.0	2.9	4.9	**3.6**
CO_2	Carbon dioxide (dry volume %)	11.6	11.7	12.2	**11.8**
T_s	Sample temperature (°F)	554	554	555	**554**
B_w	Actual water vapor in gas (% by volume)	9.8	9.7	9.3	**9.6**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	123,000	126,000	121,000	**123,000**
Q_s	Volumetric flow rate, standard (scfm)	63,100	64,700	62,300	**63,400**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	56,900	58,400	56,500	**57,300**
Q_a	Volumetric flow rate, actual (acf/hr)	7,360,000	7,550,000	7,280,000	**7,400,000**
Q_s	Volumetric flow rate, standard (scf/hr)	3,780,000	3,880,000	3,740,000	**3,800,000**
Q_{std}	Volumetric flow rate, dry standard (dscf/hr)	3,410,000	3,510,000	3,390,000	**3,440,000**
Sampling Data					
V_{mstd}	Volume metered, standard (dscf)	32.54	33.06	32.13	**32.58**
%I	Isokinetic sampling (%)[1]	104.2	105.7	103.1	**104.3**
Laboratory Data					
m_n	Total HCN collected (µg)	16,533	16,450	16,954	**16,646**
Hydrogen Cyanide (HCN) Results					
C_{sd}	HCN Concentration (lb/dscf)	1.12E-06	1.10E-06	1.16E-06	**1.13E-06**
C_{sd}	HCN Concentration (ppmdv)	16.0	15.7	16.6	**16.1**
$E_{lb/hr}$	HCN Rate (lb/hr)	3.82	3.85	3.95	**3.87**
E_{Rp}	HCN Rate - Production-based (lb/Mlb coke)	0.213	0.214	0.220	**0.216**

Average includes 3 runs.

[1] Sample flow rates as determined by EPA Method 2 were used to calculate isokinetic sampling conditions.

052912 135657

Table 2-9:
Uncertainty Analysis – NSFPM (M-5F)

		Condition 1 Coke Burn = 18.3 Mlb/hr Charge = 33,000 bpd ESP Operation = West / MPR NH_3 Injection = 8 lb/hr		Condition 2 Coke Burn = 18.1 Mlb/hr Charge = 32,500 bpd ESP Operation = Both / MPR NH_3 Injection = 8 lb/hr		Condition 3 Coke Burn = 18.1 Mlb/hr Charge = 32,500 bpd ESP Operation = Both / LPR NH_3 Injection = 8 lb/hr
		NSFPM Results (lb/Mlb coke)		**NSFPM Results (lb/Mlb coke)**		**NSFPM Results (lb/Mlb coke)**
Method		**5F/202**		**5F/202**		**5F/202**
Run No.	**1**	0.303	**4**	0.157	**7**	0.194
	2	0.303	**5**	0.161	**8**	0.196
	3	0.305	**6**	0.189	**9**	0.159
SD		0.001		0.018		0.021
AVG		**0.304**		**0.169**		**0.183**
RSD		0.4%		10.5%		11.3%
N		3		3		3
SE		0.001		0.010		0.012
RSE		0.2%		6.0%		6.6%
P		95.0%		95.0%		95.0%
TINV		4.303		4.303		4.303
CI +		0.307		0.213		0.235
AVG		**0.304**		**0.169**		**0.183**
CI -		0.301		0.125		0.132
TB +		0.313		0.304		0.342

AVG (average) is the mean value of the runs; N is the number of individual runs.

SD (standard deviation) and RSD (relative standard deviation) are measures of the variability of individual runs.

SE (standard error) and RSE (relative standard error) are measures of the variability of the average of the runs.

P (probability) is the confidence level associated with the two-tailed Student's t-distribution.

TINV (t-value) is the value of the Student's t-distrubution as a function of P (probability) and N-1 (degrees of freedom).

CI (confidence interval) indicates that if the test is conducted again under the same conditions, the average would be expected to fall within the interval (CI- to CI+) about 95% of the time.

TB+ (upper tolerance bound) is the value below which 95% of future runs are expected to fall (assuming testing at the same conditions).

Table 2-22:
HCN Results – OTM-29

Run No.		**1**	**2**	**3**	**Average**
Date (2011)		Jul 20	Jul 20	Jul 21	
Start Time (approx.)		09:36	12:29	07:56	
Stop Time (approx.)		10:57	14:01	09:15	
Process Conditions					
R_P	Production rate (bbl/hr)	2,002	2,002	2,088	**2,031**
P_1	Coke burn rate (1000 lb/hr)	34.020	32.295	33.646	**33.320**
Gas Conditions					
O_2	Oxygen (dry volume %)	3.8	3.8	3.8	**3.8**
CO_2	Carbon dioxide, flue gas (dry volume %)[1]	13.9	13.7	13.7	**13.8**
T_s	Sample temperature (°F)	150	151	151	**151**
B_w	Actual water vapor in gas (% by volume)	26.1	26.6	26.5	**26.4**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	197,012	193,501	207,016	**199,176**
Q_s	Volumetric flow rate, standard (scfm)	166,755	163,583	175,266	**168,535**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	123,177	120,034	128,855	**124,022**
Sampling Data					
V_{mstd}	Volume metered, standard (dscf)	33.39	31.22	34.30	**32.97**
%I	Isokinetic sampling (%)	108.2	103.8	106.3	**106.1**
Laboratory Data					
m_n	Total HCN collected (μg)	2,115.6384	4,473.1555	5,850.3097	
Hydrogen Cyanide (HCN) Results					
C_{sd}	HCN Concentration (lb/dscf)	1.40E-07	3.16E-07	3.76E-07	**2.77E-07**
C_{sd}	HCN Concentration (ppmdv)	1.99	4.51	5.36	**3.95**
C_{sd}	HCN Concentration (μg/dscm)	2,237	5,059	6,022	**4,440**
$E_{lb/hr}$	HCN Rate (lb/hr)	1.03	2.28	2.91	**2.07**

[1] Actual flue gas CO_2 obtained from concurrent M-26A run.

End of Section 2 – Results

Garwood, Gerri

From:	Andriy Shvab <AShvab@afpm.org>
Sent:	Friday, December 19, 2014 4:58 PM
To:	RefineryFactor
Cc:	Garwood, Gerri; Shine, Brenda; Lassiter, Penny
Subject:	AFPM Comments on the Proposed Revisions to Sections 5.1, 8.13, and 13.5 of AP-42 and the Draft Emission Estimation Protocol for Petroleum Refineries - Version 3.0 posted August 19, 2014
Attachments:	AFPMEFCOMMENTS12192014.pdf

Please find attached AFPM comments on the Proposed Revisions to Sections 5.1, 8.13, and 13.5 of AP-42 and the Draft Emission Estimation Protocol for Petroleum Refineries - Version 3.0 posted August 19, 2014.

Please let us know if you have any questions.

Andriy Shvab
Regulatory Affairs Coordinator
Regulatory Affairs

American
Fuel & Petrochemical
Manufacturers
1667 K Street NW
Suite 700
Washington, DC 20006
202.457.0480 office
202.552.4374 direct
202.457.0486 fax

ashvab@afpm.org
Learn more about AFPM at afpm.org

David Friedman
Vice President,
Regulatory Affairs

American
Fuel & Petrochemical
Manufacturers

1667 K Street, NW
Suite 700
Washington, DC
20006

202.457.0480 office
202.552.8461 direct
202.457.0486 fax
Dfriedman@afpm.org

December 19, 2014

Ms. Gerri Garwood
Environmental Protection Agency
109 T.W. Alexander Drive
Mail Code D243-02
Research Triangle Park, NC 27709

refineryfactor@epa.gov

RE: Proposed Revisions to Sections 5.1, 8.13, and 13.5 of AP-42 and the Draft Emission Estimation Protocol for Petroleum Refineries - Version 3.0 posted August 19, 2014

Dear Ms. Garwood:

The American Fuel & Petrochemical Manufacturers (AFPM) appreciates the opportunity to comment on the Proposed Revisions to Sections 5.1, 8.13, and 13.5 of AP-42 and the proposed incorporation of the Draft Emission Estimation Protocol for Petroleum Refineries ("the Protocol"). AFPM is a national trade association of more than 400 petroleum refiners and petrochemical manufacturers throughout the United States. AFPM members operate 120 U.S. refineries comprising more than 95 percent of U.S. refining capacity.

AFPM members operate facilities that will be directly affected by the agency's proposal on emissions factors through NSR Permitting, Emission Reporting, SIP/Attainment regulations, and Enforcement. As delineated in our comment on the proposed Consent Decree (March 27, 2014), our members have, and continue to have, significant concerns regarding EPA's proposal to both revise AP-42 emissions factors for selected emission sources and to reclassify the Refinery Information Collection Request ("ICR") Protocol to a broader industry and federal, state, and local agency guidance document. Given the concurrence this effort has with the Refinery Risk and Technology proposal ("RTR") and the potential overlap therein, it is critical that the agency reevaluate its schedule to avoid prejudicing either action. We recommend the agency take several important steps:

1. Decouple any action other than that mandated by the Consent Decree (CD) until a later date. The magnitude of the impact on end-users across multiple industries warrants sufficient time on the part of the Agency toward carefully consideration the quality of the data. The objectives to review all available data meeting the appropriate quality standards

and to use a sufficient quantity of data to ensure statistical validity should not be sacrificed in an effort to expedite the process.[1]

2. Do not finalize the proposed flare emissions factors. The analysis used to derive the factors is technically compromised due to inaccurate application of data processing techniques associated with the spectroscopic data considered. Furthermore, not all available, technically valid data were considered in the emissions factor derivation.
3. Delay the other emissions factors revisions and re-propose them after promulgation of the RTR regulations. Ensure that any revisions to the emissions factors consider changes in emissions that will result from implementing NSPS Subpart Ja and that may result from implementing the final promulgated RTR regulations, and allow at least a 180 day comment period. Delay applicability and implementation of any new emissions factors until at least a year after promulgation of the final RTR regulations.
4. Ensure that the future evaluations of these and any other emissions factors go through notice and comment through the *Federal Register*. Furthermore, use *Federal Register* notice and comment procedures to identify any and all uses of revised emissions factors for regulatory purposes including all TRI, permitting and permit-related, emissions reporting, and air quality/SIP planning and attainment efforts.
5. Issue guidance to the States on how to address the implications of the revisions such as the impacts of incorporating the revised emissions factors into air permitting, enforcement, emission inventory, emission fees, and National Ambient Air Quality Standards air quality planning efforts.

AFPM agrees that emissions factors for liquid storage tanks and wastewater treatment systems should not be developed at this time due to insufficient background data.

AFPM supports and adopts the comments and attachments filed by the American Petroleum Institute on this matter. AFPM would need additional time to fully evaluate all technical aspects of the emissions factor derivations in light of the significant overlap with the comment deadline for EPA's proposed RTR. Our detailed comments follow.

General Discussion

AFPM Appreciates that EPA has Extended the Comment Period

AFPM supports the extension of the comment period to December 19, 2014 as a necessary action to provide sufficient time to review the impacts of the proposed action. Emissions factors form

---

[1] Report No. 2006-P-00017, "EPA Can Improve Emissions Factors Development and Management", Office of Inspector General, states, "EPA officials told us that the majority of emissions factors are developed using 10 points of data or less, which is substantially less than the 30 to 50 data points recommended for the development of a valid statistical analysis." Page 17.

the basis for much of the emission reporting industry provides to federal, state, and local agencies. Given the implication of revising emissions factors as EPA has proposed, there will be tremendous impacts on numerous programs ranging from NSR permitting programs to SIP planning and requirements and annual emissions reporting. The breadth of impacts is significant, involving multiple regulatory programs and regulatory bodies. We support the agency in recognizing that it is in the agency's interest, as well as the refining industry's interest, to allow for sufficient time to review the myriad impacts these proposed changes will engender. It is important to provide thorough and complete comments, or risk moving forward with insufficient information on which to base a final action.

Industry Should Have Been More Involved in the Process

EPA entered in a Consent Decree with Air Alliance Houston, Community In-Power and Development Association, Inc., Louisiana Bucket Brigade and Texas Environmental Justice Advocacy Services ("Plaintiffs"). [Air Alliance Houston, et al. v. McCarthy, No. 1:13-cv-00621-KBJ (D.D.C.)]. The Consent Decree resolves litigation in which EPA failed to perform nondiscretionary duties pursuant to Clean Air Act (CAA) section 130 to review, and, if necessary, revise the emissions factors for volatile organic compounds (VOC) for flares, liquid storage tanks ("tanks"), and wastewater collection, treatment, and storage systems ("wastewater treatment systems") at least once every three years. Under the terms of the CD, EPA committed to review and revise as necessary certain emissions factors by August 19, 2014.

As discussed in AFPM's comments to the proposed Consent Decree (March 27, 2014), AFPM has a compelling interest in this settlement agreement, as it sets deadlines for EPA to establish emissions factors that will be used in promulgating standards for AFPM members' operations under several complex and costly regulations. Given that it is EPA's intent that AFPM members will ultimately use the emissions factors revised under this consent decree, EPA should have included AFPM in the discussions establishing the scope and schedule of the CD. This is another example of EPA negotiating a settlement agreement, but excluding direct stakeholders from the settlement discussions and failing to adequately consider all of the consequences of such action. The result of this "sue and settle" action represents a maneuver by non-governmental organizations to reallocate the Agency's resources and, in this case, truncate the regulatory process to the detriment of the regulated community.

EPA Should Delay the Schedule to Finalize the Emissions Factors to Allow for Sufficient Technical Review

Length of the comment period aside, EPA should delay the current schedule to finalize these revisions to emissions factors to match the schedule of the refinery RTR rule. The CD specifies a completion date of December 19, 2014. It is critical that industry have further opportunity to discuss not only with EPA but with the state agencies the implications of the agency's proposed revisions. Significantly more clarity is needed around the significance of these proposed factors in the context of permitting and related programs such as netting and offsets, emissions inventories, air quality planning and SIP development, compliance, and enforcement, each of which will take considerable thought and time to address. Given that this period to finalize this action falls across the holidays, key personnel from both the agencies and industry may be scarce, making progress difficult.

An expedited process is particularly problematic here. The AP-42 emissions factors for flares have not been revised since 1991.   The Agency must take the time it needs to fully review all of the available data – and allow the affected public to do the same. It is arbitrary to have ignored the emissions factors for such an extended period and then insist that an update is so urgent that it must be accomplished within a few months without opportunity for full public engagement in the process. In 2006, the Office of Inspector General stated, "Although EPA has made progress in emissions factors development since our 1996 review, the need for better quality emissions factors has outpaced the Agency's efforts to improve existing factors and develop new ones, "[2] and little has changed since then. We recommend that EPA confer with the litigants and extend the deadline on which to finalize this action to one year after promulgation of the Refinery RTR regulations.   Further, EPA should ensure that any effort to review flare emissions factors takes into account the requirements for flare efficiency and operation that EPA has promulgated at the time of completing the review.

In light of the significant technical issues identified below, the Agency should exercise this right and limit its current review to those pollutants required by the court order. In addition, the Agency should further coordinate this current review after the Refinery Sector Rule has been promulgated.

EPA's Efforts Should Focus on More Than the Refining Sector

Section 130 of the CAA is not specific to the refining sector, and instead applies broadly to any emission source:

> Within 6 months after enactment of the Clean Air Act Amendments of 1990, and at least every 3 years thereafter, the Administrator shall review and, if necessary, revise, the methods ('emissions factors') used for purposes of this Act to estimate the quantity of emissions of carbon monoxide, volatile organic compounds, an [sic] oxides of nitrogen *from sources of such air pollutants (including area sources and mobile sources).* (Emphasis added)

---

[2] Ibid, page 14.

It is unclear why during the course of litigation and requirement to consider a broad range of emission sources that the agency has chosen to focus almost entirely upon the refining sector, with the proposed emissions factors for flares covering a range of industries but all the other proposed factors covering only petroleum refining. This attention to refining comes simultaneously with the Refinery Risk and Technology proposal, on which the emission factor revisions may have significant impacts. It is clear from the language above that Section 130 applies to all sources regardless of industry, major source status or otherwise. Yet the agency has chosen to revise emissions factors for this sector simultaneously to other rulemakings on which the impact could be significant.

There is no published plan or schedule by which EPA intends to fulfill its non-discretionary duty to consider its responsibility in the broader sense of the statute, even though the 2006 report of the Office of Inspector General (OIG) recommended that EPA develop and implement a comprehensive strategic plan for the Emissions Factors program including "criteria for prioritizing emissions factors development"[3]. Further, although the Report states that "EPA officials said that they do not believe they can properly prioritize the competing needs of all the emissions factors stakeholders to arrive at a common priority list to improve emissions factors"[4] the OIG report responded, "We agree that while developing a priority list of emissions factors is a challenge, it is critical for effective managing the program."[5] The OIG Report then goes on to provide several paragraphs of discussion under the topic, "Comprehensive Plan Needed to Improve Data Collection and Set Priorities". What is EPA's comprehensive plan?

Section 130 of the CAA does not obligate EPA to consider refinery emissions factors on a three-year cycle; it requires EPA to consider all sources of specified pollutants. We contend that EPA's narrow implementation of the statute is inappropriate and arbitrary, and must be revised to consider the broader universe of emission sources.

EPA is Obligated to Formalize the Process (i.e. *Federal Register* Publication)

The agency's decision to forego *Federal Register* notice and comment raises significant legal questions regarding the administrative process and attendant legal obligations. Lacking the official process in the *Federal Register*, EPA has left significant questions unanswered that are critical to regulated community, such as:

- What is EPA's legal obligation to review and consider comments?
- What legal recourse exists in the process should the final action be untenable?
- What type of "action" does this qualify as? Rulemaking? Guidance? Other?

---

[3] Report No. 2006-P-00017, "EPA Can Improve Emissions Factors Development and Management", Office of Inspector General, page 26.

[4] Ibid, page 20.

[5] Ibid, page 21.

- What is industry's legal obligation to use these factors?
- Will EPA consider their final publication a "final action" by the agency?

Section 130 of the CAA requires sufficient public consideration of revisions to emissions factors. Other than this key difference, EPA seems to be treating this action as little more than guidance promulgation. We contend that the agency should have provided significantly more guidance to the regulated community regarding this public review process, as this knowledge impacts the scope and depth of our response, and consequently EPA should withdraw the current proposal until such information is made available. Providing a *Federal Register* notice and comment period for these emissions factors would be consistent with EPA's own guidance for release of large or very important emissions factors detailed in EPA's "Recommended Procedures for Development of Emissions Factors and Use of the WebFIRE Database".[6]

Revised Emissions Factors Should Not Result in Enforcement

The new emissions factors will have far-reaching consequences. AP-42 emissions factors are frequently relied upon as the default assumptions in a wide range of contexts, including permit terms, attainment demonstrations, emissions credits and offsets, SIP requirements, emissions inventories, and others. Of equal concern has been OECA's ("Office of Enforcement and Compliance Assistance") active pursuit over the past several years of enforcement against a variety of sources, alleging that emissions from flares are higher than previously believed and therefore violate a variety of permit terms, SIPS, and regulatory requirements. OECA may attempt to use the revised emissions factors retroactively in these ongoing and in future enforcement actions.

It is critical that EPA avoid the appearance that its "regulatory" arm is rushing the current review to provide additional support for the Agency's "enforcement" arm. The Agency's decision to forego *Federal Register* notice and comment, raises the inference that the decision here is driven by enforcement objectives rather than by sound science. The agency must take the time necessary to evaluate all relevant data and provide for a reasonable review period by *all* affected parties – not just those few who were involved in the initial lawsuit.

Technical Discussion

EPA should not incorporate the overly conservative and invalid assumptions of the ICR Protocol into emissions factors

AFPM strongly opposes EPA's attempt to legitimize the Refinery Emission Estimation Protocol, not only within AP-42 but as a stand-alone reference and guide for determining refinery

---

[6] Page 11-3.

emissions factors outside the context of the original Refinery Information Collection Request ("ICR"). The Protocol was initially designed to provide a consistent methodology for estimating refinery emissions to assist in EPA's residual risk evaluation for refineries. An initial version of the Protocol was submitted for public comments in 2010; it was then revised and issued as part of the instructions to EPA's 2011 ICR for the refining industry. EPA now proposes to incorporate data obtained from the ICR into revisions to the Protocol, and then cites the revised Protocol as one of the bases for the revised AP-42 emissions factors. This direct translation from the ICR to the revised AP-42 emissions factors skips a critical step: the evaluation of the underlying ICR data to ensure both that it accurately reflects average industry-wide operations and that it was collected in a sufficiently rigorous manner.

When the ICR was issued to the refining industry, EPA specifically instructed the respondents to use the Protocol for making certain assumptions in developing and reporting their emissions data for Component 2 of the ICR. For example, the Protocol provided an emission factor developed from limited test data for calculating HCN emissions from FCCUs regardless of the configuration (e.g. full burn or partial burn regenerator) and emission controls. However, after analyzing only eight additional FCCU HCN test results from Component 4 of the ICR, the agency decided to increase the Protocol's HCN emissions factor tenfold (770 to 8,000 lb/MM bbls FCCU feed) for residual risk modeling purposes. The agency now proposes to revise the HCN emission factor in the Protocol by this same tenfold increase (8,000 lb/MM bbls FCCU feed) and also specify it as an AP-42 emissions factor supported by only assessing the eight additional test results submitted in Component 4 of the ICR .

This circular reasoning falls far short of the kind of rigorous analysis necessary for the development of AP-42 emissions factors. AP-42 emissions factors should be designed to reflect the best available data, based on rigorous analysis - not just of the results of the available studies and testing, but of the methodologies used. The ICR data was not collected using the same rigorous methodologies EPA recommends for developing emissions factors. Yet EPA now proposes to incorporate this data into the revised Protocol, and incorporate the revised Protocol into the new AP-42 emissions factors, without even scrutinizing the accuracy, reliability, or repeatability of the test methods and their results.

Furthermore, many of the assumptions underlying the ICR were biased high. These assumptions may be justified for the limited purpose of establishing a one-time model for estimating the residual risks associated with refinery emissions. However, the upward bias built into these assumptions likely results in overestimates of the true emissions associated with refinery operations. Accordingly, before EPA may rely on the ICR data in establishing the revised AP-42 emissions factors, the Agency must review the assumptions used to develop those data and document that those assumptions reasonably reflect the long-term average emissions from typical refinery operations.

The inevitable result of the Agency's wholesale modification and incorporation of the Protocol will be the generation of inaccurate AP-42 factors based on unreliable data that falls well short of EPA data quality standards. Besides the issue presented on the FCCU HCN emissions factor, the following are additional examples where the Protocol falls short on its ability to substantiate the generation of AP-42 emission factors:

- The standard for emissions from boilers and process heaters is based on a single source test (Hansell and England, 1998). See Protocol, Table 4-3, note b
- Significant inconsistencies continue to exist between fuels used in a variety of combustion sources. Pages 64-76 highlight emissions factors for various combustion sources using various fuels. Emissions factors for natural gas include trace metals - these metals are not combusted or reacted in the process of using a fuel, and therefore, on a per-unit basis, using the same fuel will emit the same amount of metals regardless of the combustion device employed. The factors EPA provides, however, would indicate that metal emissions vary on a per-unit basis, by a factor of over 3 times in some instances, depending on the equipment used and not the fuel.
- Other emissions factors are based on no "emissions" at all, but rather merely on the detection limits of the test methodology – in other words, where all of the available test data showed "non-detect" for a pollutant, EPA simply assumed that the operation in question emitted at the detection limit. Id. note a. While these kinds of shortcuts might be sufficient to support a residual risk determination, they cannot establish the average actual long-term emissions from these operations across the entire refining industry. Furthermore, this methodology is inconsistent with EPA's more typical practice of using half the detection limit for non-detect analytical results, limited to cases where the pollutant would be expected to be present.

In addition, EPA should not incorporate any new methods into Section 5.3 of the Refinery Protocol for calculating emissions from delayed coking units. These methods should instead be directly incorporated into AP-42 after completing the appropriate quality assurance/quality control process outlined by EPA for AP-42 updates. EPA should also provide the option to use engineering calculations based on site-specific delayed coking unit emissions models, which will be more accurate than using an emission factor.

EPA Should Issue Guidance to Minimize Regulatory Implications Associated with Revising Emissions Factors

AFPM supports the development and maintenance of reliable emissions factors that are representative of industry operations. AFPM (then NPRA) along with API provided significant input in 2010 and 2011 in the support of emissions factors development by providing review and input on EPA's Emission Estimation Protocol for Petroleum Refineries.

AP-42 emissions factors are widely used by industry and the regulatory agencies to determine federal and state air quality permit applicability, regulation applicability, and stationary source classification under the CAA Title I, III, and V programs. Additionally, AP-42 emissions factors may serve as the basis for permit limits, for PSD netting calculations to determine PSD applicability, and for generating or determining the need to obtain offset credits.

AP-42 emissions factors are often used for permitting new sources since source-specific data cannot be obtained and for permitting modified existing sources when there is too much variability in source-specific data for determining applicability for the modified existing source. For example, when permitting a modified existing source, particulate emissions (PM) source test data may not be reliable for a process heater firing refinery fuel gas that has the potential for positive bias due the variability of sulfur compounds in the fuel gas.

EPA has acknowledged the use of AP-42 emissions factors for making permitting applicability determinations in the October 2009 ANPRM and in the "Introduction to AP-42", Fifth Edition, dated January 1995:

> Emission factor use may also be appropriate in some permitting applications, such as in applicability determinations and in establishing operating permit fees.[7]

Section 130 of the Clean Air Act (CAA) supports pre-1990 AP-42 emissions factors as EPA's only alternative to new factors established by the Administrator through an official review process. Congress, in enacting Section 130 of the CAA, considered the pre-1990 AP-42 emissions factors valid until and unless replaced by revised AP-42 emissions factors:

> ….Until the Administrator has completed the revision required by this section, nothing in this section shall be construed to affect the validity of emissions factors established by the Administrator before the date of the enactment of the Clean Air Act Amendments of 1990. [CAA Section 130]

In an analogous situation, EPA amended the GHG Mandatory Reporting Regulation (MRR) in Nov. 2013 by adding 40 CFR part 98.3(k). This citation provided that any revisions to global warming potential (GWP) emissions factors should not become retroactive to previous emission calculations and reporting, thus eliminating the concern of how GHGs (e.g. CO_2) should be addressed for NSR permitting applicability determinations for new and modified equipment when GWP emissions factors are revised.

---

[7] Compilation of Air Pollutant Emission Factors: Volume I: Stationary Point and Area Sources, Fifth Edition, January 1995, pg. 2.

AFPM recommends that EPA's Air Quality Policy Division in OAQPS develop guidance to address permitting implications when emissions factors are updated. Guidance should clarify that, for purposes of determining permit compliance, the emissions factors that were current at the time of the permit application should continue to be used, or the permit limits should be adjusted in proportion to the change in the emissions factor. Guidance should also address how updated AP-42 emissions factors are to be used when renewing NSR construction permits and/or Title V permits, when the best available information at that time is considered, and for emissions credits and offsets determinations and netting calculations.

EPA must establish policy to ensure that a change to emissions factors does not, by itself, constitute a basis for being out of compliance with an existing permit or create a situation where a source that was previously determined to not require a permit is now considered to be out of compliance with State or Federal permitting requirements. Similarly, sources should not be liable for retrospective emissions fee increases due to application of a new and improved emissions factor that would result in an increase in previous emissions estimates. Changes in emissions factors should not, by themselves, result in permit limit deviations or retroactive fee increases.

Finally, guidance should be provided as to how to address SIP requirements in light of revised emissions factors that make sources targets for more stringent regulations. Despite that fact that actual emissions are unaffected by this action, higher emissions factors target sources for deeper emission reductions when states enact regulations under the SIP for NAAQS purposes. Guidance to the states is necessary to prevent this eventuality. These potential implications to SIP planning are discussed in further detail below in the section about flares. Another concern about emissions factors that may significantly overestimate emissions is the resulting inappropriate impact to RACT and BACT cost-effectiveness decisions in rulemaking and air permitting.

AFPM believes such policy and guidance as outlined above would reflect Congressional intent for EPA under Section 130 of the CAA.

EPA Should Limit the Scope of Emissions Factors Revisions at This Time to That Required by the CD

The CD is limited with respect to the pollutants and the emissions units as follows:

- Flares – VOC
- Tanks – VOC
- Wastewater treatment systems – VOC

These revisions go beyond the scope of the CD and include other process units not identified in the Petition. AFPM recommends that EPA limit its publication of new and revised emissions factors to those covered in the CD.

An example of EPA's expansion beyond the requirements of the CD is in EPA's proposal for an emission factor for hydrogen cyanide emissions from FCC units, where neither hydrogen cyanide nor FCC units were included in the CD. Furthermore EPA does not have a data set large enough for statistical significance for this factor and was similarly unable to parse the data into complete burn and partial burn FCC units even though EPA acknowledges that these two types of units have different HCN emissions. EPA justified its proposal of creating a factor for HCN emissions from FCC units by stating, "HCN is a risk driver for the petroleum refinery source category;"[8] however, that is not germane to the technical evaluation regarding adequacy of data to derive a representative emission factor. Given the lack of data sufficient to demonstrate statistical significance, the inability to parse the data based on known chemical interactions, and the fact that the FCCU HCN emissions factor is not required by the CD, EPA should defer action on this particular emission factor to address data gaps and facilitate an informed technical decision.

EPA's inclusion of the flare NOx emissions factor in the proposed factors was similarly unnecessary at this time. EPA used only a handful of flare test results, far less than the number of tests that would be needed for statistically valid results. This is not acceptable for such an important emissions factor--for a pollution control and safety device that is ubiquitous throughout industry. EPA's lack of analysis to determine the reasons the Flint Hills Resources' (FHR) results is considerably different from all the other test results, leaving a significant gap in the justification for inclusion. While EPA's choice of statistical analysis tools indicated the data point should be included, that in itself provides insufficient justification to include it; a careful review and comparison of the testing situation and test results must be made to assess whether some other issue caused these results to fall out of line with all other flare test results. EPA's decision to include this data without a more careful and thorough evaluation and understanding, considering the huge impact the FHR data has on the proposed flare NOx emissions factor and the likely widespread use of the factor by industry across the country, will likely further perpetuate the use of poorly rated emissions factors and/or emissions factors that fail to represent actual emissions[9]. See below for additional comments about the flare NOx emission factor. Thus, EPA should not finalize this factor, which is beyond the scope of the CD requirements, at this time.

EPA Should Further Evaluate the HCN Emission Factors for FCCUs

AFPM believes that EPA does not have an adequate data set to justify the proposed FCCU HCN emission factor. Thus the proposed factor should not be finalized. In order to develop an appropriate HCN emissions factor, EPA needs to further evaluate the additional FCCU HCN test reports besides the 8 samples currently considered using the ITR (Individual Test Rating) criteria

---

[8] "DRAFT Review of Emissions Test Report for Emissions Factors Development for Flares and Certain Refinery Operations", Environmental Protection Agency, page 9.

[9] See page 11 for additional comments about the flare NOx emissions factor.

described in Appendix A of EPA RPDEF (Recommended Procedures for Development of Emission Factors and Use of the WebFIRE Database). When reviewing the data sets, EPA also needs to properly analyze this data against the process differences between FCCUs to understand HCN formation and its destruction or removal. Such process differences include the FCCU's configuration (e.g. full and partial burn regenerators) as well as whether the FCCU has a fired CO boiler or heater, and/or uses pollution control devices, such as regenerator additives, and NOx, SO_2 and PM air pollution control technologies (e.g., Selective Catalytic Reductions, Electrostatic Precipitators and scrubbers). Until this evaluation is completed, AFPM recommends that EPA should not finalize the HCN emission factor for FCCUs.

EPA Should Further Evaluate the THC Emission Factor for CRUs

AFPM believes EPA does not have an adequate data set to justify the proposed Catalytic Reforming Unit (CRU) total hydrocarbon (THC) emission factor and the proposed factor should not be finalized. In order to develop an appropriate THC emission factor, EPA needs to further evaluate additional CRU THC test reports besides the 4 samples currently considered using the ITR criteria described in Appendix A of EPA RPDEF. When reviewing the data sets, EPA also needs to properly analyze this data against the process differences between CRUs to understand THC formation and its destruction or removal during the coke burn step of the CRU reactors regeneration cycle. Such process differences include the CRU's configuration (e.g. semi-regenerative, cyclical and continuous) as well as pollution control devices (e.g. scrubbers, Chlorsorb^{TM}) used to control HCl (hydrogen chloride) emissions to comply with the emission standards in Refinery MACT UUU (e.g. 40 CFR Part 63, Subpart UUU). Until this evaluation is completed, AFPM recommends that EPA should not finalize the THC emission factor for CRUs.

EPA Should Further Evaluate the Emission Factors for Industrial Flares

AFPM contends that the proposed flare emissions factors should not be finalized. The technical analysis and methodology appear to be scientifically questionable, with a number of significant issues identified such as:

- Use of uncalibrated nitric oxide (NO) and nitrogen dioxide (NO_2) data
- Use of Passive Fourier Transform Infrared (PFTIR) minute data instead of run average data
- Apparent averaging of the carbon dioxide (CO_2) spectral bands rather than choosing the appropriate band based on spectral analysis
- Use of unweighted, rather than weighted, combustion efficiency
- Use of potentially invalid zero data values
- Use of a pollutant ratio model to predict NOx mass emission rates based on CO_2 data

- Failure to use the higher quality extractive sampling results from studies sponsored by TCEQ and by The Dow Chemical Company.

EPA has proposed an entirely new set of emissions factors in AP-42 for flares, based on new flare data from PFTIR testing. The Agency's reliance on this new data set raises several technical and regulatory concerns.

First, because many of these studies were performed as a part of the current OECA flaring enforcement initiative, the testing was designed to elucidate combustion efficiency under a variety of non-representative operating conditions. AP-42 emissions factors, however, are specifically designed to represent *average* flare operations – not abnormal or worst-case emissions. Thus, much of the data derived from these tests may be biased by averaging in a significant number of non-representative conditions. A data set based on flares that EPA itself claims are *not* operating normally cannot generate an emissions factor that represents average, normal operations.

Second, the new studies that form the basis of this second table all appear to be based on PFTIR or DIAL (Differential Absorption Lidar) testing. Neither PFTIR nor DIAL represents an EPA-approved test method for measuring flare emissions; neither has been objectively compared against approved testing methodologies to confirm that the readings are accurate, replicable, *and* sufficiently precise. EPA should take sufficient time to investigate this use of these methodologies to determine whether they are appropriately rigorous and reliable to serve as the sole basis for the proposed revised factors. Furthermore, EPA's use of minute data expressly contradicts the Agency's "Recommended Procedures for Development of Emissions Factors and Use of the WebFIRE Database", dated August 2013, which states,

> Short-term emissions from a particular process will vary significantly over time (i.e., within-process variability) because of fluctuations in normal process operating conditions, control device operating conditions, raw materials, ambient conditions and other factors. Because of the relatively short duration of emissions tests and the limited range of conditions they represent, the available emissions and process data used to develop an emissions factor are not sufficient to account for these short-term emissions fluctuations.[10]

Third, EPA has considered existing AP-42 factor for flares as a single test result in calculating average flare emissions and should have, instead, used the result of each individual test that went into developing the existing factor in the calculation of the average value.

Furthermore, EPA has ignored the much higher quality data obtained from the extractive sampler in the 2010 TCEQ flare emissions study conducted by the University of Texas and similar data obtained by The Dow Chemical Company on a steam-assisted flare tip and a pressure-assisted

---

[10] Page 4-1

flare tip, obtained during testing at the John Zink Company test facility in Tulsa, Oklahoma in November 2013 and provided to EPA's Office of Air Quality Planning and Standards in February 2014. The DOW study included six runs for the steam-assisted flare tip and six additional runs for the pressure-assisted flare tip, resulting in average NOx emissions per MMBTU of 0.15 and 0.16, respectively, more than an order of magnitude less than EPA's proposed factor.[11]

Technical testing details aside, the manner in which EPA established the revised NO_x emissions factor illustrates further concerns with the use of the resulting test data. The resultant flare NO_X emissions factor is more than forty times higher than the existing emissions factor (see Appendix A), yet that change is based on only five new tests. Not only has EPA failed to use all testing data available to them for this analysis and failed to use higher quality data from the TCEQ and DOW studies, EPA failed to recognize the sufficient amount of data needed to establish the validity of the new factor.

EPA's approach is problematic, as follows:

- As illustrated in the figure in Appendix A, the FHR test result is a statistical outlier and should be disregarded. EPA provides no basis or explanation for its assumption that this test is not an outlier. Indeed, the second-highest value after the FHR result is 0.58 lbs NO_x/MMBtu – less than ¼ of the new standard, and less than 1/30 of the FHR result.

- The previous AP-42 emissions factor is itself an average of several individual test results. By combining these results into only one average figure, EPA significantly under-valued the prior emissions tests and incorrectly weighted recent test data. If EPA wants to establish a new emissions factor based on a simple arithmetic average, it should include each of the older test results individually.

- Had EPA included all of the relevant data including the TCEQ and Dow extractive sampler data in its calculation of average flare emissions, even including the statistical outlier FHR data would have had a lesser impact on the resulting emissions factor.

We note that the current AP-42 language identifies "typical" steam-to-vent-gas ratios through the industry as ranging from approximately 2:1 to 7:1. The proposed revision strikes this language, without explanation, and replaces it with generic statements reflecting the same concerns with "oversteaming" that OECA's current flaring enforcement initiative are based on. This conjunction suggests that the current revisions are an effort to fundamentally change the nature of AP-42 emissions factors. As AFPM noted in its comments on the settlement that led to this proposal, AP-42 emissions factors are designed to represent long-term averages for all facilities in

---

[11] Comment letter from Russell A. Wozniak, The Dow Chemical Company, to EPA at refineryfactor@eap.gov, October 15, 2014, available in the comment letters that EPA posted on its website for the refinery emissions factors revision.

the source category – *not* whatever may qualify as EPA's current version of "best practices" or "enhancements." Accordingly, if the "average" steam-to-vent-gas ratio in use throughout the industry remains within the 2:1 to 7:1 range, the revised AP-42 should continue to so state.

Furthermore, the impact that these gross errors in the factor revisions may have on NAAQS modeling and SIP air quality planning has not been evaluated. In particular, the sensitivity to hourly NO_2 modeling or regional photochemical ozone modeling has not been evaluated and could be significant. Because of the potentially significant impact on the ability to demonstrate NAAQS compliance via modeling in addition to previously described regulatory concerns, extreme care should be taken to ensure that only the highest quality data and most rigorous analysis are used for factor revisions, especially in light of making such a major change in the factor. The concern about NOx modeling to demonstrate NAAQS compliance is two-fold: compliance with the NAAQS for attainment demonstrations in SIP planning and modeling to show that a project undergoing permitting does not cause or contribute to an exceedance of a NAAQS.

Furthermore, NAAQS modeling is calibrated against actual data with a specific emissions inventory and corresponding set of meteorological conditions. Incorrect changes in emissions inventories of significance to the modeling would be evidenced by degrading the agreement between the model and measured ambient air quality data. This evaluation of the representativeness of the new emissions factors based upon agreement with observations has not been conducted.

This issue in the proposed factors may be illustrated by considering the relatively high agreement of ozone modeling for the Houston-Galveston-Brazoria ozone nonattainment area in light of the relatively high number of flares at refineries and petrochemical plants located within that nonattainment area and the very significant, long-lasting, and real improvements in ozone made in the area over the past three decades, based on air quality planning efforts that utilized modeling of flare emissions based on existing flare AP-42 factors.

To the extent that EPA proceeds with finalizing a new flare NO_X factor, it should first confirm with air quality modeling that use of the new factor does not degrade the model vs. actual performance of AERMOD for NO_2 dispersion modeling and CMAQ or CMAX for ozone modeling.

Additional Data Issues

The Office of Inspector General in its 2006 report stated, "EPA officials told us that the majority of emissions factors are developed using 10 points of data or less, which is substantially less than the 30 to 50 data points recommended for the development of a valid statistical analysis." Much of the 2006 OIG report is dedicated to the need to improve the quality of emissions factors so that they may be reliable sources of emissions estimates that are appropriate to use in making air quality, permitting, and other decisions. Yet, EPA's proposed refinery emission factors rely on small data sets for the most part; only the SRU CO and NOx meet the breadth of data target discussed by the OIG. Several factors including the critical factors for flares rely on less than ten emissions test reports each. We believe that these small data sets results in conclusions that are arbitrary and capricious.

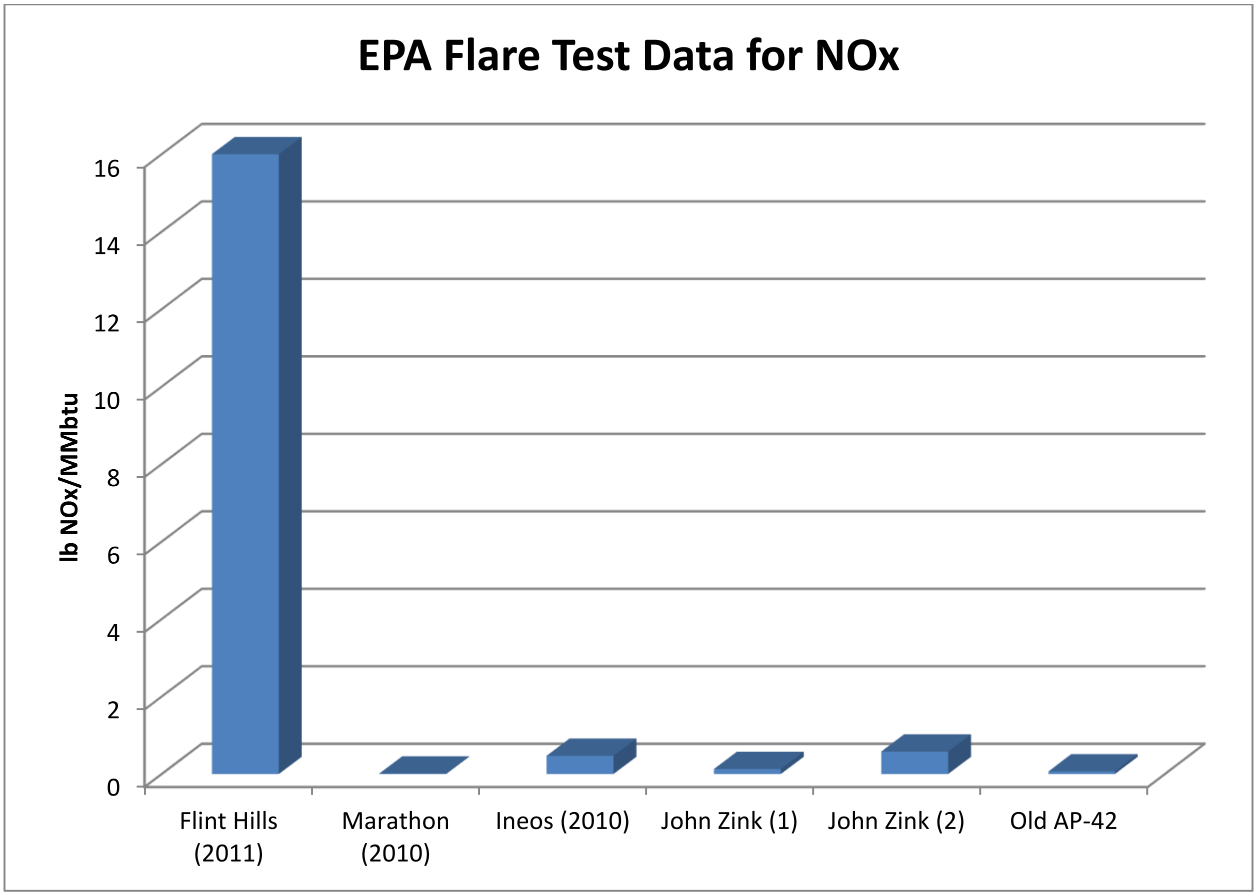
AFPM strongly urges EPA to delay this proposal due to concurrent and conflicting regulatory developments, and to limit this round of AP-42 revisions to only that required by the current court-ordered CD. This will allow EPA to conduct further analysis and obtain additional data as appropriate for developing factors beyond the scope of the CD. This will also allow industry adequate time to review the regulatory changes and underlying data, and craft meaningful responses. AFPM is committed to working with EPA to meet their statutory obligations under CAA 130 in ways that are reasonable, scientifically sound, technically feasible, and cost effective. We look forward to your response. Please contact me at (202) 552-8461 should you have any questions.

Sincerely,

David Fried

David Friedman,
Vice President, Regulatory Affairs
AFPM

Appendix A


EPA Flare Test Data for NOx
lb NOx/MMbtu
0
2
4
6
8
10
12
14
16
Flint Hills (2011)
Marathon (2010)
Ineos (2010)
John Zink (1)
John Zink (2)
Old AP-42

Garwood, Gerri

From:	Wuestenberg, Niki <NWuestenberg@republicservices.com>
Sent:	Friday, December 19, 2014 6:50 PM
To:	RefineryFactor
Cc:	Garwood, Gerri
Subject:	Draft AP-42, Section 13.5 - Revised Emission Factors (Supplement D)
Attachments:	Republic comments Industrial Flares final.pdf

Republic Services, Inc. is pleased to submit comments on the "Draft AP-42, Section 13.5 - Revised Emission Factors (Supplement D)."

Respectfully submitted,

Niki Wuestenberg
Republic Services, Inc.

REPUBLIC
SERVICES

December 19, 2014

Via Electronic Transmission: refineryfactor@epa.gov

Ms. Gerri Garwood
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC 20460

Subject: Draft AP-42, Section 13.5 - Revised Emission Factors for Flares (Supplement D)

Dear Ms. Garwood:

Republic Services (Republic) appreciates the opportunity to provide comments on the proposed revisions to the Emissions Factors for Industrial Flares. Republic has had the opportunity to review comments submitted by the National Waste & Recycling Association (NW&RA) and the Solid Waste Association of North America (SWANA) and we support the comments submitted on October 17, 2014 *(see Attachment)*.

Republic is the second largest owner/operator of municipal solid waste landfills in the United States. We own and/or operate nonhazardous landfills consisting of over 190 active and 130 closed landfills. Republic is committed to environmental stewardship by our efforts to identify and implement economically viable and long-term beneficial reuses for landfill gas to displace both natural gas and electricity generated by other sources. Currently Republic uses the landfill gas from 70 landfills to generate electricity, and we are continuously seeking additional landfill gas to energy opportunities.

The proposed revisions to industrial flares will significantly impact our landfill operations and beneficial energy projects. At present, Republic operates over 200 landfill gas collection and control systems (GCCS) that consist of approximately 160 open flares and 110 enclosed flares. Many of these open flares rely upon AP-42 Section 13.5 factors for permitting CO and NOx. The permitting ramifications are not justified since there is no test data to support any changes for open flares using non-assisted flares combusting landfill gas.

Republic urges the EPA to carefully consider the comments provided by NW&RA and SWANA and we appreciate your consideration of this request. If you have any questions, please do not hesitate to contact me at 563.285.1404 or nwuestenberg@republicservices.com at your earliest convenience.

Respectfully submitted,

Niki Wuestenberg

Niki Wuestenberg
Manager, Air Compliance

Attachment: NW&RA and SWANA letter dated October 17, 2014

18500 North Allied Way
Phoenix, AZ 85054
(480) 627-3100
Nwuestenberg@republicservices.com

ATTACHMENT

NW&RA AND SWANA LETTER

October 17, 2014

National Waste & Recycling Association℠
Collect. Recycle. Innovate.

SWANA®
SOLID WASTE ASSOCIATION
of North America

October 17, 2014

Via Electronic Transmission: refineryfactor@epa.gov

Ms. Gerri Garwood
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC 20460

Dear Ms. Garwood:

Re: Revised Emissions Factors for Flares in Draft AP-42, Section 13.5 (Supplement D)

The National Waste & Recycling Association (NW&RA) and the Solid Waste Association of North America (SWANA) are pleased to offer comments on the proposed revisions to the Emissions Factors for Flares. The NW&RA and SWANA represent companies, municipalities and professionals in the solid waste industry. The NW&RA, formerly the National Solid Waste Management Association, is a not-for-profit trade association representing private solid waste and recycling collection, processing and management companies that operate in all fifty states. SWANA is a professional education association in the solid waste management field with members from both the private and public sectors across North America.

EPA has proposed new and revised emissions factors for industrial flares in the draft AP-42 Section 13.5, which substantially increases the emission factor for nitrogen oxides (NOx). While the new proposed factors might be appropriate for air assisted or steam assisted flares used at refineries, we do not believe they are appropriate for use with the candlestick (also called "open" or "utility") flares that are in predominant use at municipal solid waste (MSW) landfills. The landfill sector's candlestick flares are neither air nor steam assisted. Although the AP-42 has a chapter for MSW Landfills, the factors for NOx and CO in Section 13.5 are generally accepted as being more accurate, and are widely used within the landfill sector. Thus, the accuracy, validity and quality of the proposed emissions factors for use with non-assisted flares are very important to the landfill sector.

We reviewed the test results upon which EPA relied to establish the revised emission factors. It appears that none of the tests involved open, non-assisted flares, and none of the tests appeared to involve combustion of landfill gas. According to flare manufacturer, John Zink, Inc., (see attached letter) the test reports underpinning EPA's revised emission factors involved high pressure, air or steam assisted, flares. Further, the tests were conducted with various flare tips not used within the

landfill sector, and the tests involved combustion of heavier, hydrocarbon-laden gases. Thus, the resulting emission factors are not applicable to non-assisted open flares burning landfill gas.

Nonetheless, EPA guidance in the draft section recommends that non-assisted flares use these new or revised emission factors. We are very concerned that EPA intends that these new emission factors be used in permitting MSW landfill candlestick flares. The proposed NOx emission factor is substantially higher than the existing factor. EPA appears to have used the result of one measurement from a single study to rationalize revising the NOx factor. In addition, the TCEQ studies referenced in the proposed revisions do not have NOx results, and thus cannot be used to support the revised factor. The Agency's recommendation that non-assisted flares use these new emission factors is inappropriate and not supported by the data. The test data supporting the revised factors are not relevant to non-assisted, open flares used in the landfill sector. Further, for the NOx emission factor, the dataset used to support the revision appears to be wholly inadequate, as it is based on one measurement from one study.

Although Section 13.5 of AP-42 is generally used by the petroleum industry, it is not limited to that industry. Section 13.5 itself notes, "flares are also used for burning waste gases generated by sewage digesters, coal gasification, rocket engine testing, nuclear power plants with sodium/water heat exchangers, heavy water plants and ammonia fertilizer plants." Given that the Section 13.5 factors are used by many industries, it is important that they accurately reflect emissions from all types of flares used in other industrial sectors.

As noted above, Section 13.5 has been widely used within the landfill sector as a source of emission factors. In fact, the majority of the air permitting conducted for landfill candlestick flares has relied upon AP-42 Section 13.5 factors for NOx and CO and many existing landfill permits have limits tied to the Section 13.5 factors. As such, there is a strong regulatory precedent for their use in federal, state, and local air permits for landfills. Further, the major manufacturers of landfill gas candlestick flares have recommended the use of the 1991 Section 13.5 factors as being the most appropriate and well-supported. See attached letter from the John Zink Company.

Because Section 13.5 is widely used in permitting by the landfill sector, it is essential that Section 13.5 retain factors that are appropriate for the non-assisted candlestick flares used at landfills and reflect their actual emissions as shown in high-quality emission tests. This can best be accomplished by maintaining the current factors for landfill gas and other biogas flares. We also propose that the Agency delete its recommendation that the revised factors be used for non-assisted flares. The proposed EFs should be limited to relevant industries that utilize steam and air assisted flares.

The NW&RA and SWANA appreciate your consideration of these comments and our requested revisions to the EPA's proposal. Should you have any questions about these comments, please call Anne Germain, Director of Waste & Recycling Technology for NW&RA, at 202-364-3724 or e-mail her at agermain@wasterecycling.org. You may also call Jesse Maxwell, Advocacy & eLearning Program Manager for SWANA, at 240-494-2237 or e-mail him at jmaxwell@swana.org.

Very truly yours,

Sharon H Kneiss

Sharon H. Kneiss
President & CEO
National Waste & Recycling Association

John H Skinner

John Skinner
Executive Director & CEO
Solid Waste Association of North America

JOHN ZINK
JOHN ZINK COMPANY LLC

International Headquarters
P.O. Box 21220
Tulsa, Oklahoma 74121-1220
918/234-1800

June 13, 2007

Email: lkenelly@scsengineers.com; dpenoyer@scsengineers.com

SCS Engineers
4041 Park Oaks Blvd.
Suite 100
Tampa, FL 33610

Attention: Lindsey Kennelly, P.E.

Reference: Landfill Gas Flare Emissions

Dear Lindsey,

As we discussed previously, the emission factors most commonly used for open or candlestick flares in landfill gas service are those stated in the AP-42, Supplement D document for Industrial Flares. These factors are 0.37 lb/mmbtu for Carbon Monoxide and 0.068 for Nitrogen Oxides. These factors are the results of actual emissions tests by the EPA for open flares for the purposes of quantifying these limits.

While the Supplement D numbers seem to conflict the factors of 0.74 lb/mmbtu for Carbon Monoxide and 0.04 lb/mmbtu for Nitrogen Oxides as indicated in the AP-42 document MSW Landfills, they are generally accepted as being more accurate. The main reason for this is source of the MSW numbers. As indicated in the "References", this data was developed from actual source tests on enclosed flares, however these tests were mostly taken in the 1980's. In this timeframe, the emission criteria were such that efficient, controlled, combustion was not required. This is reflective in the results of the testing where we see high Carbon Monoxide numbers that were a direct result of low operating temperatures due to uncontrolled burning.

In the AP-42 MSW document it states "Where information on equipment was given in the reference, test data were taken from enclosed flares. Control efficiencies are assumed to be equally representative of open flares". Today, the industry standard emissions for enclosed flares are 0.20 lb/mmbtu for Carbon Monoxide and 0.06 lb/mmbtu for Nitrogen Oxides, which is much more representative of actual enclosed flares in operation. Therefore, if control efficiencies are assumed to be equally representative of open flares, then the AP-42 Supplement D factors of 0.37 lb/mmbtu for Carbon Monoxide and 0.068 lb/mmbtu for Nitrogen Oxides are more accurate emissions than the MSW document.

To summarize, based on our experience as being the industry leader in combustion technologies, our recommendation for emission factors to be used on open flares in landfill gas service, is to use the AP-42 Supplement D factors. Not only are these a more accurate reflection of the actual emissions, but the sources utilized for the MSW document are skewed at best.

If you should have any questions or comments regarding this information, please feel free to contact me at 918-234-2783.

Sincerely,

JOHN ZINK COMPANY, LLC

Tim Locke
Product Director

JOHN ZINK®
A JOHN ZINK COMPANY LLC

International Headquarters
P.O. Box 21220
Tulsa, Oklahoma 74121-1220
918/234-2961

Brandy S. Johnson, P.E.
Product Director

DATE: September 8, 2014
TO: Niki Wuestenberg
COMPANY: Republic Services
REFERENCE: Standard Emissions for Elevated Flares

Niki,

For all elevated flares supplied by John Zink, the guaranteed emissions are as listed below. These numbers are considered the industry standard and are based on EPA 40 CFR 60.18 for industrial flares.

Emissions for Elevated ZEF Landfill Flare(1)

Overall Destruction Efficiency(2)	98%
NOx, lb / MMBTU(3)	0.068
CO, lb / MMBTU(4)	0.37

(1).Emissions and destruction efficiency stated are based on EPA 40 CFR 60.18 and AP-42 Supplement D
(2) Typical sulphur containing compounds are expected to have greater than 98% oxidation efficiency.
(3) Excludes NOx from fixed nitrogen.
(4) Excludes CO contribution present in landfill gas.

NOTE: *Destruction efficiency, NOx, and CO emissions shown are valid for combustion of landfill gas only.*

John Zink is not aware of any testing preformed on open flares for the landfill industry to merit values different from what is listed above and used by Zink for many years. Although we are aware of recent testing on open flares, these tests are not applicable to landfill gas or non-assisted open flares. Many of these tests were for high pressure, air assisted, steam assisted, heavier hydrocarbons, or various types of flare tips that are not used in the landfill industry.

From:	Cathe Kalisz <kaliszc@api.org>
Sent:	Friday, December 19, 2014 7:09 PM
To:	RefineryFactor
Cc:	Garwood, Gerri
Subject:	API Comments - Proposed Revisions to AP-42 and Refinery Estimation Protocol
Attachments:	API Comments Proposed EF Revisions 12.19.14.pdf

API submits the attached comments on EPA's proposed revisions to AP-42 emission factors and the Draft Emission Estimation Protocol for Petroleum Refineries – Version 3.

Cathe Kalisz, P.E.
Policy Advisor
American Petroleum Institute
1220 L Street NW
Washington, DC 20005
PH: (202) 682-8318
FAX: (202) 682-8270
kaliszc@api.org

Cathe Kalisz
Policy Advisor

Regulatory and Scientific Affairs
1220 L Street, NW
Washington, DC 20005-4070 USA
Telephone: 202-682-8318

Email: kaliszc@api.org
www.api.org

December 19, 2014

refineryfactor@epa.gov

RE: Proposed Revisions to Sections 5.1, 8.13, and 13.5 of AP-42 and the Draft Emission Estimation Protocol for Petroleum Refineries - Version 3.0 posted August 19, 2014

The American Petroleum Institute (API) submits the attached comments on the Environmental Protection Agency's (EPA) proposed revisions to Sections 5.1, 8.13 and 13.5 of AP-42 and to the Draft Emissions Estimation Protocol for Petroleum Refineries -Version 3.

On August 19, 2014, in response to its Consent Decree with Air Alliance Houston et al.[1] (Consent Decree), EPA posted a notice on its Technology Transfer Network (TTN) Chief website proposing to revise the AP-42 emission factors for volatile organic compounds (VOCs) from industrial flares and to make no changes to existing VOC factors for liquid storage tanks and wastewater treatment systems. In addition to the emission factors for these three specific emission types required to be reviewed per the Consent Decree, EPA also proposed to add or revise AP-42 emission factors for nitrogen oxides (NOx) and carbon monoxide (CO) from flares, and to add or update certain emission factors for petroleum refinery Fluid Catalytic Cracking Units, Hydrogen Plants, Sulfur Recovery Units, Catalytic Reforming Units, and Delayed Coker Units. Concurrently with the proposed AP-42 revisions, EPA posted an updated version (Draft Version 3) of the Emissions Estimation Protocol for Petroleum Refineries (Refinery Protocol), which incorporates the proposed AP-42 emission factor revisions and makes other revisions. EPA initially provided a 60-day comment period, which was later extended through December 19, 2014, to gather public input on all of the above proposed revisions.

The American Petroleum Institute represents over 600 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and, since 2000, has invested nearly $2 trillion in U.S. capital projects to advance all forms of energy, including alternatives. API members own and operate flares, tanks, wastewater treatment systems and refining process units that would be directly impacted by any new or revised emission factors, particularly since EPA is under a parallel consent decree timetable to propose and finalize amendments to refinery National Emission Standards for Hazardous Air Pollutants (NESHAP) rules and those amendments address emissions from these same sources, among others.

---

[1] Air Alliance Houston, et al. v. McCarthy, No. 1:13-cv-00621-KBJ (D.D.C.)

As described in our September 11, 2014 letter, API has significant concerns with EPA's proposed schedule for revising emission factors and with its proposed reclassification of the Information Collection Request (ICR) Emissions Estimation Protocol for Petroleum Refineries to a broader industry and Federal, State, and local agency guidance document. API requests that EPA do the following:

- Decouple its actions required by the Consent Decree from other potential revisions to AP-42 and the Refinery Protocol.
- Delay finalization of those other revisions to AP-42 and the Refinery Protocol until one year after the Refinery Sector Rule is promulgated, and incorporate NSPS Ja and Sector rule impacts into the new emission factors (i.e., any revisions of refinery related emission factors should reflect the impacts of the changes imposed by the Refinery Sector Rule and NSPS Ja and any learnings about emissions resulting from the Refinery Sector Rule effort).
- Keep the Refinery Protocol as an ICR tool and do not link AP-42 to the Refinery Protocol. If the Agency does intend to require use of the Refinery Protocol outside of the ICR activity, it must provide notice and comment rulemaking under the regulations that require the emission estimates where its use is desired (e.g., Toxics Release Inventory, State Implementation Plan [SIP] regulations for criteria emissions inventory reporting).

Acknowledging the above concerns, API has prepared the attached comments as initial input to EPA's review process for the proposed updates to AP-42 and the Refinery Protocol. Outlined below are some key issues identified during our review:

Proposed Revisions to Flare Emissions Factors

Recent flare testing and analyses do not suggest a need to revise the existing AP-42 emission factors at this time.

While recent flare testing and analyses have suggested some changes to the operating conditions that define a well operated steam-assist flare, the new flare test data are consistent with the existing emission factors. Existing data and new data both support very high combustion efficiency for steam and air-assisted flares. However, the new data indicate that the operating envelope for a high destruction efficiency flare requires additional parameters to assess the proper amount of assist gas. While this results in some minor changes to the operating envelope (for steam assisted flares only) and the parameters used to define it, it does not invalidate the existing emission factors.

The proposed flare emission factors should not be finalized. The proposed factors were developed using some technically inappropriate analyses and methodologies.

Specific technical issues identified in the development of the proposed factors include:

- Use of uncalibrated nitric oxide (NO) and nitrogen dioxide (NO_2) data in attempting to calculate NOx emissions rates from Infrared (IR) spectra, rendering the calculated NOx factor as not technically defensible.

- Use of passive Fourier Transform Infrared (PFTIR) minute data instead of run average data. Use of run average data is necessary for valid analyses.
- Inappropriate filtering of PFTIR minute data.
- Apparent averaging of the carbon dioxide (CO_2) spectral bands rather than choosing the appropriate band based on spectral analysis.
- Use of unweighted, rather than hydrocarbon weighted, combustion efficiency.
- Misinterpretation of PFTIR zero data values.
- Use of a pollutant ratio model to calculate NOx mass emission rates based on CO_2 data.
- Several computational errors and spreadsheet referencing errors.

These issues should be addressed in the development of any updated CO, VOC or NOx factors for flares.

<u>Emission Factors for Liquid Storage Tanks and Wastewater Treatment Systems</u>

API agrees with EPA's conclusion that existing data are not adequate to support revision of the emissions estimating methods for liquid storage tanks and wastewater treatment systems.

As EPA noted in its *DRAFT EPA Review of Available Documents for Developing Proposed Emissions Factors for Flares, Tanks, and Wastewater Treatment*[2], most new reports and study information "…cannot be used for emissions factor development due to (1) the lack of operational data by which to normalize the emissions rates, (2) the fact that many of the measurements do not isolate one particular emissions source and/or (3) the fact that the studies did not attempt to characterize the range of normal operating conditions." The fundamental limitations noted by EPA led to the appropriate conclusion to not revise the emission factors.

<u>Implementation of Emission Factor Revisions</u>

EPA must identify and address impacts from any changes to emission factors.

When the emission factors are updated, whether as part of this action or any other, EPA should provide specific guidance for the implementation of updated emission factors. Guidance should clarify that, for purposes of determining permit compliance, the emissions factors that were current at the time of the permit application should continue to be used, or the permit limits should be adjusted in proportion to the change in the emissions factor. Guidance should also address how updated AP-42 emission factors are to be used when renewing New Source Review (NSR) construction permits and/or Title V permits, when the best available information at that time is considered.

Changes in emission factors should not, by themselves, result in permit limit deviations or retroactive fee increases. Policy is needed to ensure that a change to emissions factors does not, by itself, 1) constitute a basis for a finding of non-compliance with an existing permit or 2) create a situation where a source with emissions previously calculated below a threshold requisite for a permit is now considered to be out of compliance with State or Federal permitting requirements.

---

[2] http://www.epa.gov/ttn/chief/consentdecree/draft_report_review.pdf

Similarly, sources should not be liable for retrospective emissions fee increases due to application of a new and improved emissions factor that would result in an increase in past emissions estimates.

API supports the development and maintenance of reliable emissions factors that are representative of petroleum industry operations. API has sponsored research and provided data in support of emissions factors development and improvement in the past, and is committed to continuing to do so in the future. We welcome the opportunity to work with EPA to improve emissions estimating methods for our industry.

Thank you for your consideration of these comments. If you have any questions, or would like to discuss further, please contact me at kaliszc@api.org or at (202) 682-8318.

Sincerely,

/s/

Cathe Kalisz

American Petroleum Institute (API)

Comments on

Proposed Revisions to Sections 5.1, 8.13, and 13.5 of AP-42

and

Draft Emission Estimation Protocol for Petroleum Refineries - Version 3.0 posted August 19, 2014

December 19, 2014

Review of Proposed Revisions to Sections 5.1, 8.13, and 13.5 of AP-42 and the Draft Emission Estimation Protocol for Petroleum Refineries - Version 3.0

Executive Summary

Overarching Comments on EPA's Approach to Proposed AP-42 and Refinery Protocol Revisions

API supports the development and maintenance of reliable emissions factors that are representative of petroleum industry operations.

API sponsored research and provided data in support of emissions factors development and improvement in the past, and is committed to continuing to do so in the future. For example, API previously worked extensively with the Environmental Protection Agency (EPA) to develop and improve estimating methods for fugitive equipment leaks and atmospheric storage tanks.

EPA's decision to expand the scope of updates beyond the actions required under EPA's Consent Decree with Air Alliance Houston et al.[1] (Consent Decree) complicates the public review of proposed emission factors, as does the overlap of the proposed changes with the ongoing Refinery Sector Rulemaking.

The Consent Decree only requires EPA to evaluate any needed revisions to the volatile organic compound (VOC) emission factors for flares, tanks and wastewater treatment systems. By including the non-VOC emission factors and sources not covered by the Consent Decree in the proposed updates, EPA is unnecessarily compressing the review period for those proposed changes. This approach limits EPA's ability to complete full and robust analyses.

Furthermore, EPA is under a parallel consent decree timetable to propose and finalize amendments to refinery National Emission Standards for Hazardous Air Pollutants (NESHAP) rules (i.e., Refinery Sector Rule) and those amendments also address emissions from flares, tanks, and wastewater systems, and many of the emission sources included in the Emission Estimation Protocol for Petroleum Refineries (Refinery Protocol). In setting a revised schedule for updating AP-42 emission factors and the Refinery Protocol, EPA should provide sufficient time for considering the comments received in the refinery NESHAPS rulemaking as they impact emission estimates, and allow for incorporation of the impacts of the NESHAPS rulemaking on emissions. EPA sanctioned emission factors should reflect emissions as they will be over the life of the emission factor (i.e., until the next update) and not historical emissions that EPA has taken action to reduce.

As outlined in API's letter dated September 11, 2014, EPA should delay finalization of any revisions to AP-42 and the Refinery Protocol until one year after the Refinery Sector Rule is promulgated, and

---

[1] Air Alliance Houston, Community In-Power and Development Association, Inc., Louisiana Bucket Brigade and Texas Environmental Justice Advocacy Services ("Plaintiffs"), Air Alliance Houston, et al. v. McCarthy, No. 1:13-cv-00621-KBJ (D.D.C.)

incorporate New Source Performance Standards Subpart Ja (NSPS Ja) and Sector rule impacts into the new emission factors. EPA should also decouple its actions required by the Consent Decree from other potential revisions to AP-42 and the Refinery Protocol.

The Refinery Protocol should remain as an Information Collection Request (ICR) tool and should not be linked to AP-42.

It is inappropriate to reference the Emission Estimation Protocol for Petroleum Refineries within AP-42. The Refinery Protocol was intended to provide for consistent estimation of refinery emissions as part of an ICR data collection effort, and many of the emissions factors and estimation methods contained therein were not developed using the rigorous methods set out by EPA's recommended procedures for developing emissions factors. Further, the EPA has not committed to funding Refinery Protocol updates, as they have committed to support an ongoing AP-42 effort. The Refinery Protocol should remain as an ICR tool and should not be linked to AP-42.

EPA must identify and address impacts from any changes to emission factors.

When the emission factors are updated, whether as part of this action or any other, EPA should provide specific guidance for the implementation of updated emission factors. Guidance should clarify that, for purposes of determining permit compliance, the emissions factors that were current at the time of the permit application should continue to be used, or the permit limits should be adjusted in proportion to the change in the emissions factor. Guidance should also address how updated AP-42 emission factors are to be used when renewing New Source Review (NSR) construction permits and/or Title V permits, when the best available information at that time is considered.

Changes in emission factors should not, by themselves, result in permit limit deviations or retroactive fee increases. Policy is needed to ensure that a change to emissions factors does not, by itself, 1) constitute a basis for a finding of non-compliance with an existing permit or 2) create a situation where a source with emissions previously calculated below a threshold requisite for a permit is now considered to be out of compliance with State or Federal permitting requirements. Similarly, sources should not be liable for retrospective emissions fee increases due to application of a new or improved emissions factor that would result in an increase in past emissions estimates.

Recommended Procedures for Development of Emission Factors and Use of WebFIRE, Draft, 8/2013

In developing the proposed new or updated emission factors in AP-42, EPA indicates it has utilized its draft August 2013 *Recommended Procedures for Development of Emission Factors and Use of WebFIRE* (RPDEF). EPA's draft emission factor development report provides an overdue update to the emission factor development procedures. The shift towards more objective processes and criteria is commendable. However, the desire to shift to objective (and ultimately automated) emission factor development processes should not override the need for interpretation and judgment in evaluating data and applying process understanding, especially with very limited data sets such as those used for the proposed petroleum refinery emission factor updates.

There are several significant issues that must be addressed before applying the procedures to development of new or revised emission factors. These include:

- The individual test rating (ITR) methodology described in Appendix A of the RPDEF fails to reflect serious data quality defects in ITR scores.
- The statistical approaches described in RPDEF Appendices C, D and E are inconsistent with generally accepted statistical analysis procedures for dealing with non-normal data distributions and comparing different data sets using Student's t-tests.
- The statistical approaches described in RPDEF Appendices C, D and E do not adequately address treatment of small data sets (<25 and <10 samples), leading to weak characterization of data distributions and consequently flawed analysis of emission factors and data set combinations.
- The handling of outliers (both as defined in the RPDEF and as applied in development of the proposed emission factors) requires further review and improvement.

Proposed Revisions to AP-42

Storage Tanks (AP-42 Chapter 7) and Wastewater Treatment Systems (AP-42 Section 4.3)

API agrees with EPA's conclusion that existing data do not support revision of the emissions estimating methods for tanks and wastewater treatment systems.

As EPA noted in its *DRAFT EPA Review of Available Documents for Developing Proposed Emissions Factors for Flares, Tanks, and Wastewater Treatment*[2], most new reports and study information "…cannot be used for emissions factor development due to (1) the lack of operational data by which to normalize the emissions rates, (2) the fact that many of the measurements do not isolate one particular emissions source and/or (3) the fact that the studies did not attempt to characterize the range of normal operating conditions." The fundamental limitations noted by EPA led to the appropriate conclusion to not revise the emission factors.

Fluid Catalytic Cracking Unit Hydrogen Cyanide Emission Factor – AP-42 Section 5.1

EPA has not adequately developed or justified the proposed Fluid Catalytic Cracking Unit (FCCU) hydrogen cyanide (HCN) emission factor and the proposed factor should not be finalized.

EPA did not include significant impacts of process configurations on HCN formation and emissions in its derivation of associated emission factors. Additionally, EPA failed to use the representative process activity rate for emission factor development, used a data set that is too small to provide representative emission factors, inappropriately applied statistics, and did not comply with its own procedures outlined in the RPDEF.

---

[2] http://www.epa.gov/ttn/chief/consentdecree/draft_report_review.pdf

Catalytic Reforming Unit Total Hydrocarbon Emission Factor – AP-42 Section 5.1

EPA has not adequately developed or justified the proposed Catalytic Reforming Unit (CRU) total hydrocarbon (THC) emission factor and the proposed factor should not be finalized.

EPA used a data set that is too small to provide representative emission factors and needs to evaluate test and production data for additional units besides the four CRUs currently considered. EPA should consider potential emission differences due to process configurations, and use robust statistical methods consistent with best practices already established by EPA.

Hydrogen Reformer Nitrogen Oxides Emission Factor – AP-42 Section 5.1

A nitrogen oxides (NOx) emission factor for uncontrolled hydrogen plant reformer furnaces is likely of limited value.

The majority of existing hydrogen plant reformer furnaces likely have NOx control technologies installed and the proposed emission factor would not be applicable to them. Therefore, there is limited value in establishing a NOx emission factor for uncontrolled furnaces. Further, EPA has not fully evaluated data quality when reviewing any of the reformer furnace test reports. EPA should complete all portions of the ITR criteria described in RPDEF Appendix A to assure that data quality has been evaluated, and address other API suggested improvements to the RPDEF procedures.

Delayed Coking Unit Emissions – AP-42 Section 5.1

EPA should not reference the Refinery Protocol in AP-42 for the estimation of emissions from delayed coking units.

API believes it would be more appropriate for EPA to incorporate any new emissions estimation method(s) directly into AP-42 after completion of the appropriate quality assurance/quality control process outlined by EPA for AP-42 updates.

Sulfur Recovery Unit NOx, Carbon Monoxide, and THC Emission Factors – AP-42 Section 8.13

EPA should conduct further analyses before adding new emission factors for Sulfur Recovery Units normalized by sulfur production.

EPA should not finalize the proposed AP-42 factors until an improved assessment of the impacts of variations in unit configuration is completed. EPA should determine if it would be more appropriate to correlate NOx, carbon monoxide (CO), and THC emissions to the firing of the incinerator or thermal oxidizer versus sulfur production. Further, EPA has not fully evaluated data quality when reviewing any of the test reports. EPA should complete all portions of the ITR criteria described in RPDEF Appendix A to assure that data quality has been evaluated, and address other API suggested improvements to the RPDEF procedures.

Industrial Flare NOx, CO, and VOC Emissions Factors – AP-42 Section 13.5

Recent flare testing and analyses do not suggest a need to revise the existing AP-42 emission factors at this time.

While recent flare testing and analyses have suggested some changes to the operating conditions that define a well operated steam-assist flare, the new flare test data are consistent with the existing emission factors. Existing data and new data both support very high combustion efficiency for steam and air-assisted flares. However, the new data indicate that the operating envelope for a high destruction efficiency flare requires additional parameters to assess the proper amount of assist gas. While this results in some minor changes to the operating envelope (for steam assisted flares only) and the parameters used to define it, it does not invalidate the existing emission factors.

It is inappropriate to revise the basis for combustion efficiency guidance because the conclusion from the proposed Refinery Sector Rulemaking (RSR) that properly operated flares only achieve 98% destruction efficiency is not representative of all flares in all industries.

A 98% flare destruction efficiency is simply the minimum destruction efficiency asserted for refinery flares in the recently proposed Refinery Sector Rulemaking. In fact, many flares operate with destruction efficiencies exceeding 99%, and all refinery flares will have to average above the 98% minimum to assure compliance with the short averaging time required by the RSR. The AP-42 guidance should not reflect a unilateral reduction of the assumed flare destruction efficiency across all industries.

The proposed flare emission factors should not be finalized. The proposed factors were developed using some technically inappropriate analyses and methodologies.

Specific technical issues identified in the development of the proposed factors include:

- Use of uncalibrated nitric oxide (NO) and nitrogen dioxide (NO_2) data in attempting to calculate NOx emissions rates from Infrared (IR) spectra, rendering the calculated NOx factor as not technically defensible.
- Use of passive Fourier Transform Infrared (PFTIR) minute data instead of run average data. Use of run average data is necessary for valid analyses.
- Inappropriate filtering of PFTIR minute data.
- Apparent averaging of the carbon dioxide (CO_2) spectral bands rather than choosing the appropriate band based on spectral analysis.
- Use of unweighted, rather than hydrocarbon weighted, combustion efficiency.
- Misinterpretation of PFTIR zero data values.
- Use of a pollutant ratio model to calculate NOx mass emission rates based on CO_2 data.
- Several computational errors and spreadsheet referencing errors.

These issues should be addressed in the development of any updated CO, VOC or NOx factors for flares.

Proposed Revisions to Emission Estimation Protocol for Petroleum Refineries – Draft Version 3.0

EPA should incorporate all of API's outstanding recommendations on the previous versions of the Emission Estimation Protocol for Petroleum Refineries.

Outstanding API recommendations on previous versions of the Protocol are included in Appendix 3 of these comments.

With respect to new or revised methodologies in Draft Version 3 of the Refinery Protocol, API suggests the following actions:

Delayed Coking Units – Section 5.3

An option for facility specific estimation should be included.

EPA must allow the use of internally developed delayed coking unit emissions models based on site-specific information and engineering calculations as a coker vent emission methodology. The use of site-specific information is generally more accurate than using an emission factor.

The following changes will improve the accuracy of Methodology Rank 3.

The proposed Methodology Rank 3 approach for emissions from the opening of coke drums and resulting venting to the atmosphere is too conservative and results in an overestimate of emissions. The following adjustments to Methodology Rank 3 are needed:

- Update the mass of steam calculations to represent the overhead temperature and coke bed temperature using the saturation temperature of steam at the indicated overhead pressure,

- Update the coke density to provide a more accurate representation of the void space and the coke mass, and

- Recommend the use of site-specific test data in lieu of values in Table 5-5 where available.

API/AFPM commented extensively on the modelling of coke drum emissions in their October 28, 2014 comments on the proposed RSR rule and those comments should be the basis for revising the Refinery Protocol factors for coke drum emissions.

Methodology Rank 4 should be deleted.

Proposed Methodology Rank 4 should be deleted because limited or no test data exists to validate the proposed methodologies used to handle the drum opening and coke cutting operations.

Methodology Rank 5 should be deleted.

With recent changes to NSPS Ja and the proposed changes in the Refinery Sector Rule, the operating characteristics for coke drums are subject to changes which will directionally lower emissions. The test data behind the factors for proposed Methodology Rank 5 do not reflect these changes and therefore will not accurately represent emissions. Furthermore, the raw data used to derive emission factors included in Methodology Rank 5 were not reviewed for statistical outliers as recommended by EPA’s procedures for developing emissions factors. For these reasons, Methodology Rank 5 should be deleted.

Table of Contents

List of Appendices

List of Acronyms

ANPRM	Advanced Notice of Proposed Rulemaking
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
Bbl	Barrel
BDL	Below detection limit
CAA	Clean Air Act
CBI	Confidential Business Information
CCU	Catalytic Cracking Unit
CE	Combustion Efficiency
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COB	Carbon Monoxide Boiler
CRU	Catalytic Reforming Unit
CTM	Conditional Test Method
DCU	Delayed Coker Unit
DEFR	Draft Emission Factor Report
DGM	Dry Gas Meter
DIAL	Differential Absorption Lidar
EF	Emission Factor
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitators
FCCU	Fluid Catalytic Cracking Unit
FGD	Flue Gas Desulfurization
FHR	Flint Hills Resource
FID	Flame Ionization Detector
FTIR	Fourier Transform Infrared
GHG	Greenhouse Gas
GWP	Global Warming Potential
H_2S	Hydrogen Sulfide
HAP	Hazardous Air Pollutant
HCl	Hydrogen Chloride
HCN	Hydrogen Cyanide
HHV	Higher Heating Value
hr	Hour
ICR	Information Collection Request
IFC	International Flaring Consortium
IR	Infrared
ITR	Individual Test Rating
klb	Thousand pounds
lb	Pound
LHV	Lower Heating Value
MACT	Maximum Achievable Control Technology

MMBbl	Million Barrels
MMBtu/hr	Million British Thermal Units per Hour
MPC	Marathon Petroleum Company, LP
MRR	Mandatory Reporting Regulation
$NaCO_3$	Sodium Carbonate
NaOH	Sodium Hydroxide
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	Ammonia
NIST	National Institute of Standards and Technology
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NOx	Nitrogen Oxides
N_2O	Nitrous Oxide
NSPS Ja	New Source Performance Standards Subpart Ja
NSR	New Source Review
OAQPS	Office of Air Quality Planning and Standards
OTM	Other Test Method
PFTIR	Passive Fourier Transform Infrared
PM	Particulate Matter
ppm	Parts Per Million
ppm-m	Parts Per Million Times Meters
PSD	Prevention of Significant Deterioration
QA/QC	Quality Assurance/Quality Control
Refinery Protocol	Emission Estimation Protocol for Petroleum Refineries
RPDEF	Recommended Procedures for Development of Emission Factors and Use of WebFIRE
RSD	Relative Standard Deviation
RSR	Refinery Sector Rulemaking
RWET	Refinery Wastewater Emissions Tool
SCC	Source Classification Code
scf	Standard Cubic Foot
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SRU	Sulfur Recovery Unit
TCEQ	Texas Commission on Environmental Quality
THC	Total Hydrocarbon
TTN	Technology Transfer Network
VOC	Volatile Organic Compounds
WebFIRE	Internet version of the Factor Information Retrieval (FIRE) data system
WGS	Wet Gas Scrubber

Review of Proposed Revisions to Sections 5.1, 8.13, and 13.5 of AP-42 and the Draft Emission Estimation Protocol for Petroleum Refineries - Version 3.0

1.0 General Comments

1.1 Scope of EPA's Proposed Revisions

EPA Consent Decree with Air Alliance Houston et al
As EPA describes in the website[1] proposing updates to AP-42, EPA is proposing certain actions in compliance with a Consent Decree entered into with Air Alliance Houston and others ("Plaintiffs"). [Air Alliance Houston, et al. v. McCarthy, No. 1:13-cv-00621-KBJ (D.D.C.)] The Consent Decree resolves litigation in which Plaintiffs alleged that EPA failed to perform nondiscretionary duties pursuant to Clean Air Act (CAA) section 130 to review, and, if necessary, revise the emission factors for volatile organic compounds (VOC) for flares, liquid storage tanks ("tanks"), and wastewater collection, treatment, and storage systems ("wastewater treatment systems") at least once every three years. Under the terms of the Consent Decree, by August 19, 2014, EPA will review and either propose revisions to the VOC emission factors for flares, tanks and wastewater treatment systems under CAA section 130, or propose a determination under CAA section 130 that revision of these emission factors is not necessary.

EPA indicated that the proposed new VOC emission factors for flares are a result of an evaluation of all data collected during the 2011 Refinery Information Collection Request (ICR) and other test data available to the Agency for flares, tanks and wastewater treatment systems. Further, EPA is also proposing a determination that revisions of the VOC emission factors for tanks and wastewater treatment systems are not necessary.

Other Revisions to AP-42
In addition to its obligations under the Consent Decree, EPA has chosen to expand the scope of the proposed revisions to include changes to Sections 5.1, 8.13, and 13.5 of AP-42 which incorporate the following new and revised emissions factors for nitrogen oxides (NOx), carbon monoxide (CO), total hydrocarbons (THC), and hydrogen cyanide (HCN):

- Flares – NOx (revised), CO (revised)
- Sulfur Recovery Units (SRU) – NOx (new), CO (new), THC (new)
- Catalytic Reforming Units (CRU) – THC (new)
- Hydrogen Plants – NOx (new)
- Fluid Catalytic Cracking Units (FCCU) – HCN (new)

---

[1] http://www.epa.gov/ttn/chief/consentdecree/index_consent_decree.html

- Delayed Coker Units (DCU) – See proposed Draft Emissions Estimation Protocol for Petroleum Refineries (Version 3)

Revisions to the Emissions Estimation Protocol for Petroleum Refineries

EPA is also proposing to revise its Emissions Estimation Protocol for Petroleum Refineries (Refinery Protocol or Protocol) to include the proposed emission factors from Sections 5.1, 8.13, and 13.5 of AP-42, and to make other updates, including revisions to the following sections:

- Section 3.3 Methodology Rank 3 for Storage Tanks
- Section 5.1 Methodology Rank 5B for Catalytic Cracking Units
- Section 5.3 Methodology Ranks 3, 4, and 5 for Delayed Coking Units
- Section 5.6.2 for Asphalt Plant Vents
- Section 7 and Appendix B for Wastewater Collection and Treatment Systems

The Refinery Protocol was intended to provide for consistent estimation of refinery emissions as part of an ICR data collection effort and many of the emissions factors and estimation methods contained therein were not developed using the rigorous methods set out by EPA's draft August 2013 *Recommended Procedures for Development of Emissions Factors and Use of the WebFIRE Database* (RPDEF) [2].

In Version 3 of the Refinery Protocol, EPA states:

> "This Refinery Emissions Protocol document is intended to provide guidance and instructions to petroleum refinery owners and operators and to federal, state, and local agencies for the purpose of improving emission inventories for the petroleum refining industry."
>
> "This "version" (Version 3) of the Refinery Emissions Protocol document provides updates to certain emissions factors and methodologies developed using the additional test data collected as part of the 2011 ICR. While efforts have been made to coordinate the revisions of this Refinery Emissions Protocol document with the updates to the emissions factors in AP-42 (U.S. EPA, 1995a) and WebFIRE (the internet version of the Factor Information Retrieval (FIRE) data system), this Refinery Emissions Protocol document may include additional methodologies and emissions factors that are not included in AP-42, particularly for hazardous air pollutants (HAP). The EPA website (http://www.epa.gov/ttn/chief/efpac/esttools.html) should be checked prior to preparing an emissions inventory to ensure that the most recent Refinery Emissions Protocol document is used."

These statements imply that EPA now intends for the Refinery Protocol to set ongoing requirements for refinery emission estimating, rather than to serve as instructions for responding to the one-time

---

[2] EPA, Recommended Procedures for Development of Emissions Factors and Use of the WebFIRE Database, EPA-453/D-13-001, August 2013. Available at http://www.epa.gov/ttnchie1/efpac/procedures/procedures81213.pdf. Accessed September 23, 2014.

refinery ICR. If the Agency does intend to require use of the Refinery Protocol outside of the ICR activity, it must provide notice and comment rulemaking under the regulations that require the emission estimates where its use is desired (e.g., Toxics Release Inventory, State Implementation Plan regulations for criteria emissions inventory reporting).

EPA should not repurpose the Refinery Protocol as a broader industry and government agency guidance document, and AP-42 should not reference the Refinery Protocol. For example, the proposed revisions to AP-42 Section 5.1.2.3.2 for Coking Units reference the Refinery Protocol for estimating emissions from Coker venting and subsequent decoking steps. Furthermore, the Refinery Protocol includes recommendations for emission factors for equipment leaks, storage vessels, wastewater, combustion devices and other general types of equipment that are separately addressed in AP-42. This assuredly will result in two different EPA recommendations of emission factors for refinery equipment, most likely an updated AP-42 factor and an out-of-date Refinery Protocol factor. Aside from the concern with referencing Refinery Protocol emission factors not subject to the same quality standards as AP-42, linking AP-42 and the Refinery Protocol document would forever require simultaneous updates to avoid inconsistent documents. If the final AP-42 revisions reference the Refinery Protocol, EPA should make clear that it will update the Protocol whenever it updates any AP-42 factor covered by the Protocol, and that the Protocol will be reviewed and updated on the same schedule as AP-42.

1.2 Timing of EPA's Proposed Revisions

While EPA has indicated that they are negotiating an extension, the Consent Decree currently requires EPA to issue final revisions to the VOC emission factors for flares, tanks and wastewater treatment systems, or issue a final determination that revision of these emission factors is not necessary, by December 19, 2014.

EPA is also under a parallel consent decree timetable to propose and finalize amendments to refinery National Emission Standards for Hazardous Air Pollutants (NESHAP) rules (i.e., Refinery Sector Rule) and those amendments also address emissions from flares, tanks, and wastewater systems, among other sources.

In setting a revised schedule for updating AP-42 emission factors and the Refinery Protocol, EPA should provide sufficient time for considering the comments received in the refinery NESHAPS rulemaking as they impact emission estimates, and allow for incorporation of the impacts of the NESHAPS rulemaking on emissions. As outlined in our letter dated September 11, 2014, EPA should:

- *Decouple its actions required by the Consent Decree from other potential revisions to AP-42 and the Refinery Protocol.*

  The Consent Decree only requires EPA to evaluate any needed revisions to the VOC emission factors for flares, tanks and wastewater treatment systems. By including the non-VOC emission factors and sources not covered by the Consent Decree in the proposed updates, EPA is unnecessarily compressing the review period for those proposed changes. This approach limits EPA's ability to complete full and robust analyses.

- *Delay finalization of those other revisions to AP-42 and the Refinery Protocol until one year after the Refinery Sector Rulemaking (RSR) is promulgated, and incorporate New Source Performance Standards Subpart Ja (NSPS Ja) and Sector rule impacts into the new emission factors (i.e., any revisions of refinery related emission factors should reflect the impacts of the changes imposed by the Refinery Sector Rule and NSPS Ja and any learnings about emissions resulting from the Refinery Sector Rule effort).*

1.3 Implementation of EPA's Proposed Revisions

API supports the development and maintenance of reliable emissions factors that are representative of industry operations. API has sponsored research and provided data in support of emissions factors development and improvement in the past, and is committed to continuing to do so in the future. As emission factors may be used for inputs to air models used to assess compliance with increasingly stringent NAAQS, use of accurate emissions data is critical. Revisions to emission factors should be based on use of the highest quality data and rigorous analysis.

API previously submitted comments related to EPA's proposals for the development of an alternative emissions factor system. These include comments on the Emissions Factors Improvement Program Advanced Notice of Proposed Rulemaking (ANPRM) published in the Federal Register on October 14, 2009 and comments on the "Recommended Procedures for Development of Emission Factors and Use of WebFIRE Emission Factor Database" (Draft EF Procedures) draft dated December 17, 2010. Many of the concerns and issues identified in API's earlier submittals also apply to EPA's current proposed revisions to AP-42. These issues, which are in addition to those outlined in Section 1.2 above, must be acknowledged and addressed prior to finalization of any AP-42 emission factors.

AP-42 emission factors are widely used by industry and the regulatory agencies to determine federal and state air quality permit applicability, regulation applicability, and in determining stationary source classification under the CAA Title I, III, and V programs. AP-42 emission factors are often used for permitting new sources since source-specific data cannot be obtained, and for permitting modified existing sources when modified source characteristics will be significantly different from existing source characteristics. Additionally, AP-42 emission factors may serve as the basis for permit limits that allow a stationary source to avoid additional requirements, e.g., Prevention of Significant Deterioration (PSD) avoidance limitations. This is particularly true in those cases where it may be impractical to collect source specific test data for equipment, such as VOC emissions from storage tanks or emissions from flares.

EPA has acknowledged the use of AP-42 emission factors for determining permitting applicability determinations in the October 2009 ANPRM and in the "Introduction to AP-42", Fifth Edition, dated January 1995:

> "Emission factor use may also be appropriate in some permitting applications, such as in applicability determinations and in establishing operating permit fees."[3]

---

[3] Compilation of Air Pollutant Emission Factors: Volume I: Stationary Point and Area Sources, Fifth Edition, January 1995, pg. 2.

For the same reason EPA is taking action to revise AP-42 emission factors to comply with Section 130 of the Clean Air Act (CAA), Section 130 also states that the only alternative to AP-42 emission factors EPA can use are those established by the Administrator through an official review process. Congress, in enacting Section 130 of the CAA, considered the pre-1990 AP-42 emission factors valid until and unless replaced by revised AP-42 emission factors:

> "….Until the Administrator has completed the revision required by this section, nothing in this section shall be construed to affect the validity of emission factors established by the Administrator before the date of the enactment of the Clean Air Act Amendments of 1990." [CAA Section 130]

Section 130 of the CAA requires periodic revision of EPA emission factors, but also creates a presumption that previous factors remain valid while EPA is conducting its review. This principle is equally true for the real life application of the standards in permitting and other compliance applications.

For a parallel circumstance, EPA amended the Greenhouse Gas (GHG) Mandatory Reporting Regulation (MRR) in Nov. 2013 by adding 40 Code of Federal Regulations (CFR) Part 98.3(k). This citation provided that any revisions to global warming potential (GWP) emission factors should not become retroactive to previous emission calculations and reporting, thereby eliminating the issue of how GHGs (e.g. carbon dioxide [CO_2]) should be addressed for NSR permitting applicability determinations for new and modified equipment when GWP emission factors are revised.

API recommends that EPA's Air Quality Policy Division in the Office of Air Quality Planning and Standards (OAQPS) develop guidance to address permitting implications when emission factors are updated. Guidance should clarify that, for purposes of determining permit compliance, the emissions factors that were current at the time of the permit application should continue to be used, or the permit limits should be adjusted in proportion to the change in the emissions factor. Guidance should also address how updated AP-42 emission factors are to be used when renewing NSR construction permits and/or Title V permits, when the best available information at that time is considered.

Changes in emission factors should not, by themselves, result in permit limit deviations or retroactive fee increases. Policy is needed to ensure that a change to emissions factors does not, by itself, 1) constitute a basis for a finding of non-compliance with an existing permit or 2) create a situation where a source with emissions previously calculated below a threshold requisite for a permit is now considered to be out of compliance with State or Federal permitting requirements. Similarly, sources should not be liable for retrospective emissions fee increases due to application of a new and improved emissions factor that would result in an increase in past emissions estimates.

API believes such policy and guidance as outlined above would reflect what Congress intended EPA to follow under Section 130 of the CAA as well as EPA's intent in the reporting of GHG emissions under the MRR.

2.0 Emission Estimating Methods for Wastewater Treatment Systems and Storage Tanks

Based on EPA's review of the available emissions data for tanks and wastewater treatment systems, they determined that the data were not adequate to allow for revisions to existing emissions estimation methods for those sources. Specifically, as described in the "*DRAFT EPA Review of Available Documents for Developing Proposed Emissions Factors for Flares, Tanks, and Wastewater Treatment Systems*"[4], EPA is proposing that, "while the cited reports provide valuable information regarding the potential emissions from petroleum refinery and other process units, the data from these studies (with the exception of the passive FTIR studies and one Differential Absorption Lidar [DIAL] study) cannot be used for emissions factor development due to (1) the lack of operational data by which to normalize the emissions rates, (2) the fact that many of the measurements do not isolate one particular emissions source and/or (3) the fact that the studies did not attempt to characterize the range of normal operating conditions."

API agrees with EPA's conclusion that existing data are not adequate to support revision of the emissions estimating methods for tanks and wastewater treatment systems. The fundamental limitations noted by EPA led to the appropriate conclusion to not revise the emission factors.

3.0 Comments on Proposed Revisions to AP-42

A full descriptive report on the proposed NOx, CO, and VOC emission factors for industrial flares can be found in Appendix 1. For clarity, we have separated our technical and grammatical suggestions on the proposed revisions to AP-42 that are not related to emissions factors into Appendix 2.

3.1 EPA's Emission Factor Development Methodology

In developing the proposed new or revised AP-42 emission factors, EPA utilized its August 2013 draft RPDEF. Our review of the proposed factors highlighted some deficiencies in the draft RPDEF, which are discussed below.

Overview of EPA's Emission Factor Methodology

In the RPDEF, EPA strives to: make use of electronic test data reporting tools; automate emission factor development; provide criteria for excluding outliers; provide a test report quality screening tool; provide a methodology for excluding lower quality test data as higher quality test data become available; and other changes. A comprehensive review of the methodologies in the RPDEF is beyond the scope of these comments. Comments on specific aspects of the RPDEF related to the proposed emission factors are provided below.

Appendix A – Test Report Quality Rating Tool

Appendix A of the RPDEF presents a Test Report Quality Rating Tool used for establishing Individual Test Rating (ITR) scores. The tool has two sections, one (completed by the report originator) that

---

[4] http://www.epa.gov/ttn/chief/consentdecree/draft_report_review.pdf

addresses the completeness of the test report and the other (completed by a regulatory agency reviewer) that addresses data quality. Numerical scores are assigned to each criterion, which are summed and normalized for the overall ITR score. While the tool is intended to provide a more consistent, less subjective method for reviewing test reports, the criteria and scoring method do not give sufficient detail or weight to evaluation of serious data quality deficiencies. For example:

- The tool does not address calibration of analytical instruments used in laboratories for sample analyses. Test results obtained from an analytical instrument that is not calibrated are typically considered invalid.

- Analytical spike recoveries determine the accuracy of a measurement in several source test and laboratory analysis methods. A deficiency in spike recoveries generally would cast serious doubt on the validity of the test results regardless of how well other aspects of the test were conducted. If spike recoveries are outside the control limits specified in the test methods, the accuracy of the results is questionable. If recoveries are outside the control limits by only a small amount, the impact on data quality can be considered small and possibly grounds for excluding the datum. If spike recoveries are far outside of control limits, the impact on data quality is undoubtedly large and clearly grounds for excluding the data point. While the relevant ITR criterion (in the regulatory reviewer section) is “Were required spike recoveries within method requirements?”, the required answer is simply “yes”, “no” or “n/a”. If the tester and regulatory review fields in EPA’s ITR spreadsheet are completed with positive results for all other criteria, entering a “no” for this criterion has zero impact on the score – whereas spike recoveries well outside the control limits would indicate a significant data quality problem and generally would be grounds for rejecting a test result.

Thus, ITRs as defined in the RPDEF do not provide a reliable indication of data quality. Moreover they can provide a false sense of acceptable data.

Appendix C – Data Set Distribution

Appendix C Section 1 of the RPDEF (implicitly) acknowledges that environmental data sets often are not normally distributed (e.g., they may be log-normal, bimodal, or otherwise distributed). Without going into an extended discussion of statistical methods and advanced techniques, the following basic techniques should be considered for any of the statistical methods discussed in the RPDEF:

- When data are not normally distributed, application of statistics that assume a normal distribution does not provide an accurate description of the data. It is appropriate to first apply a data transformation that normalizes the data, such as natural logarithm for data that are log-normally distributed as specified in Appendix B, before proceeding. However, data may be neither normally nor log-normally distributed such that other transforms or analysis may be appropriate before determining characteristic statistics. For example, EPA’s ProUCL software also addresses statistics for environmental data which fit a Gamma distribution and non-parametric methods for data that do not fit normal, log-normal or Gamma distributions.

- EPA only addresses normality of a data set in the context of outlier analysis in RPDEF Appendix C. However, normality is important for all of the analysis specified in RPDEF Appendices C, D and E. For example, if log transformed data are normally distributed, then all of the key statistics and tests should be applied to the transformed data. The appropriate central characteristic for a log-normally distributed data set, for example, is the mean of the log-transformed data (i.e., geometric mean of the untransformed data) rather than the mean of the untransformed data (in many cases the median of untransformed log-normal data also provides an appropriate central characteristic).

- EPA specifies that data sets must be log-transformed before applying Dixon's outlier test. It is not appropriate to log-transform a data set for application of any tests or statistics if the raw data distribution is normal. Further, if the log-transformed data set does not fit a normal distribution, Dixon's outlier test does not produce useful results.

- As noted in EPA's *Data Quality Assessment: Statistical Methods for Practitioners*[5], "Tests for normality with small samples have very little statistical power" and "for small sample sizes it is common for a nonparametric statistical test to be selected …in order to avoid incorrectly assuming the data are normally distributed when there is simply not enough information." Nonparametric tests can be very useful with small data sets. EPA should revise its RPDEF to specify more reliable procedures for small data sets and use of alternative analysis methods including graphical methods to evaluate data distributions (and other characteristics such as clusters suggesting the need for further subcategorization of emission factors).

- If using parametric statistics (mean, standard deviation, etc.), rather than assuming a priori that a data set is not normally distributed the data first should be examined to determine goodness of fit to a normal distribution before applying outlier tests or other analyses. Graphical methods (e.g., Q-Q or normal probability plots) and a robust statistical normality test (e.g., Shapiro-Wilk, Lillefor's, Anderson-Darling) should be used to evaluate normality at a specified confidence level (typically 95%). Skewness and kurtosis are not reliable indicators of normality for data sets with fewer than 50 data points[6], but they are easy to calculate in Microsoft Excel (Excel). Ease of implementation in an Excel spreadsheet should not override the need for a robust normality test and good judgment when evaluating data sets.

- If a data set is not normally distributed, tests for alternative distributions (e.g., log-normal, Gamma) should be applied. Analysis then can be performed on the transformed data set. If the data do not fit a distribution, non-parametric methods generally should be used. ProUCL provides robust tools for this analysis.

Data Detection Limits

It is not uncommon for the minimum detection limits of a test method to shift downward over time as sampling and analytical techniques improve. Full or half detection limits are typically substituted for undetected results in environmental data sets. Changes in detection limits with improvements in methods and practices can bias a data set to higher values as newer data are added. EPA specifies that an undetected result should be excluded only if it exceeds the highest detected value in a data set. This is not robust practice. The Kaplan-Meier method is very useful for identifying which non-detect data

---

[5] *Data Quality Assessment: Statistical Methods for Practitioners,* EPA QA/G-9S, EPA/240/B-06/003, Office of Environmental Information, U.S. Environmental Protection Agency, Washington, D.C. (February 2006).

[6] Table 4-2 in Data Quality Assessment: Statistical Methods for Practitioners, EPA QA/G-9S

should be excluded to minimize the impact of varying detection limits in a data set. Again, ProUCL provides tools for identifying which undetected values should be eliminated.

Appendix C – Identifying Outliers

Appendix C of EPA's Emission Factor Methodology describes procedures for identifying outliers in a data set. It also specifies that all outliers should be removed from the data set.

- As EPA notes in its publication *Data Quality Assessment: A Reviewer's Guide*[7], "Outliers are measurements that are extremely large or small relative to the rest of the data and, therefore, are suspected of misrepresenting the population from which they were collected. Outliers may result from transcription errors, data-coding errors, or measurement system problems such as instrument breakdown. **However, outliers may also represent true extreme values of a distribution (for instance, hot spots) and indicate more variability in the population than was expected. Not removing true outliers and removing false outliers both lead to a distortion of estimates of population parameters.** [emphasis added]."

- Generally, an outlier in a small data set should be excluded only if there is a valid, scientific reason – e.g., an invalid test method, process upset resulting in unrepresentative emissions, major flaws in sample collection or analysis, etc. Removing an outlier simply because it is one or to improve fit to a normal distribution is arbitrary and may introduce an unwarranted bias in the resulting emission factor. This is especially true for small data sets (<30) that often underlie emission factors where the presence of outliers may have a relatively large impact on the emission factor statistics such as means. That said, outliers also should be viewed in context with scientific and engineering fundamentals and other data for similar populations. As given in EPA's *Data Quality Assessment: Statistical Methods for Practitioners*, EPA QA/G-9S, "The statistical tests alone cannot determine whether a statistical outlier should be [retained,] discarded or corrected within a data set. This decision should be based on judgmental or scientific grounds."

- Exclusion of outliers is especially important for small data sets that represent only a small fraction of the entire population of source types, because the presence of outliers may suggest process differences that are not generally represented in the data set. This may indicate a need for additional data for the population of units and/or further emission factor subcategorization. Therefore, statistical outlier tests should be used only to identify potential problems rather than as a definitive criterion for excluding data, especially with small data sets such as those used for the proposed emission factor revisions. EPA should revise the outlier procedure described in Appendix C to specify outlier analysis only to *identify* data points requiring further investigation rather than as a definitive exclusion criterion.

---

[7] Data Quality Assessment: A Reviewer's Guide, EPA QA-G9R, EPA/240/B-06/002, Office of Environmental Information, U.S. Environmental Protection Agency, Washington, D.C. (February 2006) (http://www.epa.gov/quality/qa_docs.html, accessed October 7, 2014).

Appendix D – Mean Statistic

Appendix D of RPDEF describes the procedures to calculate the emission factor for a source type. This procedure specifies using the arithmetic mean of the candidate data set as the appropriate statistic for emission factors. Since emissions data often are not normally distributed (typically skewed right), the use of the median instead of the mean generally provides a more representative emission factor. The geometric mean (log mean) provides a more representative statistic for log-normally distributed data. Therefore, EPA should revise RPDEF to specify more appropriate statistics such as median or geometric mean when data sets are not normally distributed.

Appendix E – Identifying Data Combinations

Appendix E of EPA's RPDEF describes procedures for identifying valid data combinations (e.g., when evaluating how to subcategorize a data set according to pollution control equipment type, process configuration, fuel types, etc.). The procedure specifies use of the Student's t-test for determining whether the means of two data sets are the same at a given level of confidence. We note that:

- The Student's t-test is valid only when the variances of the two data sets are equal.

- Before applying the Student's t-test, the data sets must to be tested for equality of variances, e.g., using the F-test or Levene's test. If the variances are equal, the Student's t-test is appropriate. The F-test is available as an Excel statistical -function F.TEST and can be easily implemented in Excel. ProUCL also provides tools for comparing data sets.

- If the variances are not equal, a different t-test such as Welch-Satterthwaite (the latter is used in EPA's ProUCL software) should be used instead. Both of these t-tests are available in Excel's T.TEST statistical function and so could be easily implemented in EPA's emission factor creation spreadsheets.

Presentation of Descriptive Statistics

EPA's RPDEF does not specify descriptive statistics to reflect the uncertainty or other indicators of data dispersion associated with an emission factor. For example, the number of samples (units) along with mean, median, minimum, maximum, and standard deviation would provide the end user with insight into the robustness of an emission factor and data dispersion, and therefore enable good judgment in its application. EPA should revise its RPDEF to specify presentation of descriptive statistics along with a recommended emission factor.

3.2 AP-42 Section 5.1 Petroleum Refining

3.2.1 AP-42 Table 5.1-2 FCCU HCN Emission Factor

The issues with the revisions to the FCCU HCN emission factor fall in three general categories: Process Considerations, Data Limitations and Emission Factor Development and Presentation.

FCCU HCN Emission Factor - Process Considerations

HCN emissions are anticipated to vary among FCCUs of different designs, operating modes, and feed characteristics. FCCU regenerator operating mode (full burn versus partial burn) is a key factor influencing HCN formation and emissions potential. When coke is burned in the FCCU regenerator, the nitrogen in coke may form several species including molecular nitrogen (N_2), ammonia (NH_3), HCN, nitrous oxide (N_2O) and nitric oxide (NO).

Full and Partial Burn FCCU Operating Mode

The formation of HCN varies with the stoichiometric air-fuel ratio in the FCCU regenerator. Partial burn operating modes represent an oxygen deprived atmosphere which favors formation of reduced nitrogen species (primarily HCN and NH_3) rather than NOx. As the stoichiometric ratio approaches 1.0 (full burn operation) and higher, chemical equilibrium shifts to favor NOx formation and the formation of reduced nitrogen species decreases.

EPA has not adequately considered the effects of FCCU process configuration, regenerator operation and air pollution control devices in aggregating data from the eight units selected by EPA (which are all full burn units) for a single HCN emission factor.

HCN concentrations in the regenerator offgas from full burn units are known to be less than that from partial burn units because chemical equilibrium favors NOx production when excess oxygen is present as opposed to HCN formation under very fuel rich conditions. HCN and NOx concentrations also will depend on combustion temperature, local stoichimetries in the regenerator, to a lesser extent on the nitrogen content of the FCCU feed, and nitrogen partitioning to the catalyst coke layer, as well as many other factors. Wider variation in HCN values would be expected for full burn FCCU's given the number of factors that may influence the distribution of reduced and oxidized nitrogen-containing species (e.g., NOx). However, in a well-mixed full burn regenerator with low CO levels, low levels of HCN would be expected since CO and HCN are both byproducts of incomplete combustion. EPA implicitly recognizes this in the proposed refinery sector rule[8] through its decision to use CO as a surrogate for HCN and other organic compounds in establishing emission limits.

Use of CO Boilers

The offgas from partial burn FCCU regenerators typically has percent-level CO concentrations and therefore flows to a fired CO boiler or heater to recover reaction heat via CO combustion and latent heat prior to exhausting to the stack with the CO boiler combustion products. Some partial burn FCCU regenerators that have been converted to operate in full burn mode, and those that may operate in either mode, have retained fired CO boilers/heaters. HCN is very reactive at combustion temperatures and will be efficiently destroyed (reacted to form NOx and N_2) under overall fuel-lean (oxidizing) conditions in fired CO boilers/heaters. Rapid conversion of HCN at combustion temperatures to combustion intermediates leading to NO and N_2 is well established process chemistry and is a key aspect of staged combustion approaches for controlling NOx emissions[9,10]. Therefore, it is reasonable to expect lower HCN emissions and less variability in HCN values from units equipped with fired CO boilers/heaters compared with those without fired CO boilers.

---

[8] 79 FR 125 Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards; Proposed Rule (June 30, 2014).

[9] E.g., England, G.C., Heap, M.P., Pershing, D.W. and Nihart, R. Mechanisms of NOx Formation and Control: Alternative and Petroleum-Derived Liquid Fuels, Eighteenth Symposium (International) on Combustion, The Combustion Institute (1981).

[10] E.g., Bowman C.T. Kinetics of Pollutant Formation and Destruction on Combustion, *Prog. Energy Combust. Sci.* 1 33-45, (1975).

EPA's data set used for the proposed HCN emission factor does not contain any valid test results for units with fired CO boilers in operation. However, API has compiled HCN emission factor data for nine units from the ICR test reports and other sources on a coke burn basis that includes two partial burn units with fired CO boilers. Although the API dataset could be expanded if more time were available, the HCN data for the units with CO boilers are near the low end of the range for these units which is consistent with high HCN destruction in a CO boiler.

Considering the above process effects, API recommends that EPA develop HCN emission factors for at least the following FCCU configurations: partial burn with CO boiler; full burn with CO boiler; and full burn without CO boiler. In fact, some API member companies have compiled and evaluated HCN data for various FCCU configurations and concluded that HCN emissions do strongly associate with FCCU configuration and operations.

Use of Wet Gas Scrubbers and Electrostatic Precipitators

Wet gas scrubbers (WGS) for reducing SO_2 emissions from FCCUs typically use aqueous basic (i.e., sodium hydroxide, NaOH or sodium carbonate, $NaCO_3$) absorbing solutions. HCN is an acid gas and therefore also may be partially absorbed by the basic reagent used in a WGS. However, the amount of HCN absorption would be low at the lower absorbing solution concentrations typically used for WGS in FCCU applications. Electrostatic Precipitators (ESPs) on the other hand are not expected to significantly reduce HCN emissions since HCN is a gas and ESPs collect primarily solid and liquid particles.

Neither EPA's data set for FCCU pound HCN per barrel (lb HCN/bbl) feed nor API's for lb HCN/lb coke burned contain sufficient data to make any strong conclusion regarding differences in emissions for units with WGS and ESPs, and these will also be primarily affected by the previously discussed regenerator operations as well.

Other Process Considerations

Review of the data collected as part of Component 1 of EPA's 2011 ICR shows there are many other differences in process and air pollution control configurations among the FCCU HCN data set selected by EPA. Several of these technologies, especially NOx control technologies where cyanide species play a direct role, could reasonably be expected to influence HCN emissions, including low NOx burners, selective catalytic reduction (SCR) systems, selective non catalytic reduction (SNCR) systems, WGS, ESPs, CO boilers, low NOx combustion additives, etc. The wide range of emission factors among the eight units suggests the data set is too small to develop <u>any</u> reliable HCN emission factors. These FCCU operating factors and potential effects on HCN emission factors should be discussed in AP-42 Section 5.1 and the Refinery Protocol. Indeed, publishing the AP-42 emission factor as a "moderately" representative factor does not have a solid basis; no factor should be derived at this time. Any factor derived from the limited ICR data base would at best be described as "very poor" given the above discussions.

Normalization of Emission Factors Using FCCU Feed Rate

EPA established the proposed new AP-42 factors for HCN and mercury emissions in Section 3.3 of EPA's draft emission factor report[11] (including the cited Excel spreadsheets), herein referred to as "DEFR," using FCCU feed rate as the characteristic process activity rate, as opposed to coke burn rate which has been used historically.

The FCCU feed rate is not a representative process rate characteristic for HCN emission factor development. EPA already recognizes in the Refinery Protocol that coke burn rate is a superior activity rate for certain air pollutants. API supports the use of coke burn rate as the appropriate activity rate for HCN, considering that:

- HCN in the regenerator flue gas results from the combustion of coke during catalyst regeneration and the nitrogen content of the coke. Thus, the source of HCN in the regenerator offgas is far more closely related to coke combustion and catalyst regeneration mode than to FCCU feed rate. Based on process chemistry derived from coal combustion studies, fixed nitrogen in the feed becomes enriched in the residual solids (char or coke). Fixed nitrogen in the coke rapidly converts to HCN and ammonia during the combustion process. HCN and ammonia are the most favored fixed nitrogen species under fuel-rich conditions characteristic of partial burn units. Under near-stoichiometric conditions characteristic of full burn units, NO is the favored species.
- Feeds to some FCCUs may include recycled slurry or heavy cycle gas oil, which has different characteristics than fresh feed. These feeds typically result in higher coke yields (mass of coke produced per mass of feed). Since HCN production during catalyst regeneration is more closely related to coke burn rate and since coke yield varies with feed characteristics, coke burn rate provides a much more representative activity rate than does FCCU feed rate.
- Depending on FCCU feed temperature, feed characteristics and other operating parameters, the coke burn rate could be very similar for different feed rates, depending on coke yield. For example, eleven units in API's data set have coke yields ranging from 11.4 to 21.3 lb coke/bbl feed (Figure 3.2.1-1). Thus, FCCU feed rate alone is not a reliable indicator of coke burn rate.

---

[11] DRAFT Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations, Contract No. EP-D-11-084, Work Assignment No. 2-12, prepared for U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina (August 2014).

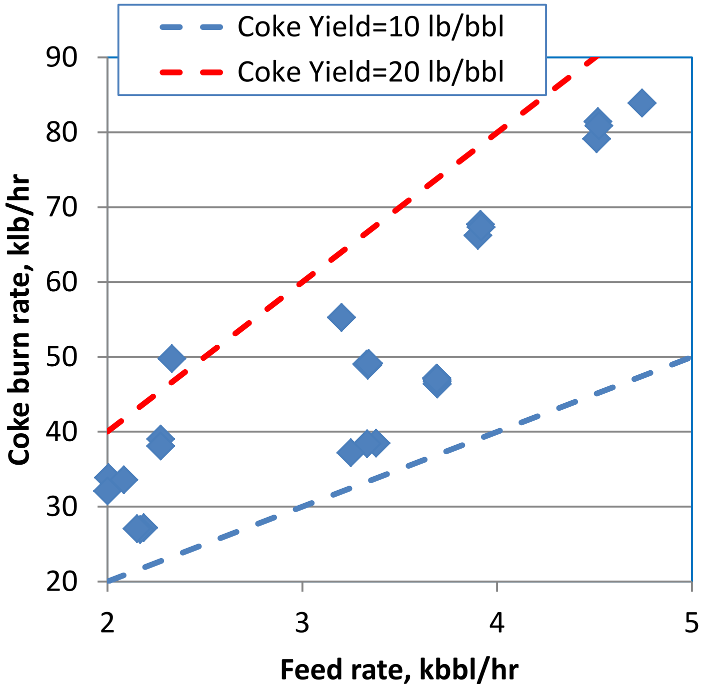


Figure 3.2.1-1. Coke yields for eleven units in API's FCCU HCN emission factor data set.

<u>Based on these considerations, API recommends that EPA should use **coke burn rate** as the HCN emission factor basis, and qualify HCN emission factors in lb/bbl as being unreliable (at best, "very poor") because feed rate is not a reliable process indicator of HCN emissions. In general, API does not support setting FCCU emissions factor values based on feed rate.</u>

Furthermore, while EPA appears to have used total reactor feed rate, EPA has not defined "feed rate" in the DEFR or Refinery Protocol. EPA should verify that total feed rate was used, and also add discussion to the DEFR indicating that total feed rate (as distinguished from fresh feed rate) was used for their derivation. This distinction could be important because recycled streams (e.g., gas oil, slurry) are sometimes included with fresh feed to the reactor.

FCCU HCN Emission Factor Comments – Data Limitations

Tests Excluded due to Unacceptable HCN Measurements

In the 2011 ICR, EPA specified use of either EPA Other Test Method 29 (OTM-29) or a direct extractive instrumental method, EPA Method 320, for HCN measurements. OTM-29 captures total gaseous cyanide ions soluble in 6 times normal (6N) sodium hydroxide solution, which is subsequently analyzed for total cyanide ion and reported as hydrogen cyanide. Method 320 employs a Fourier transform infrared (FTIR) gas analyzer with a direct extraction sampling system for direct measurements of HCN concentration.

OTM-29, which specifies using a 6N sodium hydroxide solution, was published in 2011 at about the same time as the ICR was issued. Prior to that, EPA had been specifying its predecessor, Conditional Test Method 33 (CTM-033) which is based on similar principles using 0.1N sodium hydroxide solution. It has been shown that SO_2 and CO_2 in the stack gas sample can deplete the sodium hydroxide absorbing reagent and that if pH is not maintained at 12 or higher, the HCN results may be biased low. Section 4.1 of OTM-29[12] states that a decrease in pH of the impinger solution decreases the ability to capture and retain HCN. OTM-29 differs from CTM-033 for this reason, specifying a stronger (6N) sodium hydroxide concentration for the absorbing reagent. OTM-29 specifies that a test is valid only if the pH in the final NaOH impinger is maintained at least as high as 12 throughout the test run (at OTM-29 Section 4.1), adding additional 6N sodium hydroxide solution periodically during the test run if necessary. OTM-29 also specifies (at OTM-29 Section 8.7.1.5) measuring and documenting the pH in all three NaOH impingers in the field at the end of the test run and, if necessary, adjusting the pH of each impinger by adding 6N sodium hydroxide solution until pH is 12 or higher. OTM-29 further specifies (at OTM-29 Section 4.1) that the pH of the absorbing solutions must remain at 12 or higher after the test until analysis.

An artifact of using 6N sodium hydroxide solution in OTM-29 is that CO_2 in the stack gas sample also is absorbed, reducing the volume of stack gas sample measured by the test equipment. This results in a positive (high) bias in the measured HCN concentration of several percent unless ancillary measurements (e.g., measuring CO_2 concentration in the stack gas sample before and after the impingers) are made so that the sample gas volume can be corrected.

Because OTM-29 was new at the time of the ICR and stack testers were not aware of issues related to reagent strength and pH as they were evolving, several tests conducted during and prior to the ICR were performed using CTM-033 or other similar methods with 0.1N sodium hydroxide solution (Table 3.2.1-1). Field notes provided in the appendices of the test reports show that several tests in the ICR data set, including two tests for one unit (MS3C0740) that EPA included in its data set used for HCN emission factor development, did not increase the sodium hydroxide reagent strength to maintain high pH, did not meet the minimum pH criterion and/or did not document pH check results. As noted elsewhere in these comments, these deficiencies are not reflected in ITR scores because the state regulatory reviewer sections were not completed. The quality of the results for those tests that did not use OTM-29 or methods with appropriate modifications and documentation therefore is not sufficient for emission factor development (indicated by “No” in the last column of Table 3.2.1-1 per API’s review).

---

[12] USEPA, Other Test Method 29 – Sampling and Analysis for Hydrogen Cyanide Emissions from Stationary Sources, Draft, Revised March, 2011. Available at http://www.epa.gov/ttn/emc/prelim/otm29.pdf, Accessed October, 2014.

Table 3.2.1-1: Summary of HCN Measurement Results Review

Facility ID	**Test Method**	**Test Date**	**Ok? (EPA)**	**Ok? (API)**
LA3C0630	EPA CTM-033	6/15/2011	No	No
IL2A0420	EPA OTM-029	7/20/2011	Yes	Yes
MS3C0740	CTM-033	5/7/2007	**Yes**	**No**
MS3C0740	CTM-033	4/22/2008	**Yes**	**No**
IN2A0440	EPA M301/M320	6/7/2011	Yes	Yes
MN2B0720	EPA OTM-029	7/28/2011	**Yes**	**No**
CA5A1090	EPA OTM-029	6/28/2011	Yes	Yes
NJ1A0860	CTM-033, modified	8/26/2007	Yes	Yes
NJ1A0820	CTM-033, modified	9/14/2010	Yes	Yes
TX3B1250	EPA OTM-029	6/6/2011	Yes	Yes
LA3C0560	EPA OTM-029	5/18-19/2011	Yes	Yes
VI6A1530	EPA OTM-029	6/15/2011	Yes	Yes
CA5A0120	CARB Method 426	12/16/1991	No	No
CA5A0120	CARB Method 426	12/16/1991	No	No
CA5A0130	CARB Method 426	8/30/2006	No	No
HI5A0380	EPA Method 320	6/23/2011	Yes	Yes
NJ1A0820	CARB Method 426	9/14/2010	No	No
NJ1A0850-A*	EPA CTM-033, modified	9/16/2010	**No**	**Yes**
NJ1A0850-B*	EPA CTM-033, modified	9/16/2010	**No**	**Yes**
OH2A0940	EPA CTM-033, modified	10/29/2009	Yes	Yes
PA1A1020	EPA CTM-033 modified	7/28/2009	No	No
PA1A1030	EPA OTM-029	6/21/2011	No	No
TX3B1160	FTIR	3/21/2007	No	No
TX3B1160	FTIR	3/24/2007	No	No
TX3B1160	FTIR	4/11/2007	No	No

EPA identified several tests that have unacceptable HCN results during test report reviews (indicated by “No” in the second to last column of Table 3.2.1-1). Based on our review of the twenty-five test reports compiled by EPA for potential use in HCN emission factor development, API agrees with most of EPA’s findings regarding questionable HCN measurements (Table 3.2.1-1). However, we also identified questionable measurements for two units (MS3C0740 and MN2B0720) that EPA included in its emission factor analysis. Further details on these two units, which should not be used for emission factor development, are included in the discussion below:

- MS3C0740: Test documentation clearly shows that 0.1N sodium hydroxide absorbing solution was used and critical quantitative pH checks are not documented in both the 2007 and 2008 tests. In fact, the HCN emission factor for this unit is the lowest in EPA’s data set, which is consistent with a negative (low) bias in the results due to reagent depletion. Thus, we conclude that the quality of the HCN measurement results in both tests is not adequate for use in emission factor development and should be deleted from EPA’s data set.

- MN2B0720: Review of the test report shows that: (a) Run 1 was stopped at 33 minutes because the sampling train was plugged due to coagulation in impinger #2, and the test was invalidated; and (b) Run 2 was stopped after 48 minutes because impingers #2 and #3 were gelled. A fourth test run was performed. Further, critical pH checks are not documented or otherwise mentioned in the report. These results suggest serious problems with the results and lack of pH documentation suggests procedural deficiencies. Thus, we conclude that the quality of the HCN measurement results for this unit is not adequate for use in emission factor development and should be deleted from EPA's data set.

- V16A1530: There are conflicting data in the test report regarding pH of the EPA OTM-29 sample solutions following the test. The tester's sample recovery data sheets indicate that pH checks of the final impinger and combined sample (all impingers) were performed in the field and showed that the pH of both the final impinger and the combined (total) impinger catch was greater than 12 following the test. This conforms to OTM-29 specifications. Dated and initialed marginal notes on the laboratory's sample custody log included with the laboratory report, presumably made by laboratory staff upon receiving the samples at the laboratory, indicate that the pH of the combined samples ranged from 10.62 to 10.85. OTM-29 also specifies that the pH of all the impingers must remain at 12 or higher after the test until analysis. There is no narrative in either the test or laboratory reports discussing the discrepancy or the potential impact on the results. Since the pH of the combined sample was less than 12 upon receipt at the laboratory, this suggests that HCN results may be biased low. However, the reported HCN concentrations for this test are the highest of EPA's data set. HCN was detected well above the analytical detection limit in each of the samples and all other aspects of the measurements appear satisfactory. Based on these considerations, our testing experts conclude that the results can be considered as a lower bound for actual HCN emissions from this unit, but that the true accuracy of the results is uncertain. As the highest among this very small statistical sample of the FCCU population, the results can be considered as a likely upper bound for HCN emissions that may prove to be an outlier inconsistent with other results as more data become available. Because the field pH check results conform to OTM-29 specifications, the test results are considered valid for use in emission factor development at this time. However, the uncertainty in test accuracy justifies a lower test report quality rating, which may justify excluding the data in the future as additional data of higher quality become available.

- NJ1A0850: The test report cites CTM-033 as the test method used, but clearly indicates that the method was modified to use much higher reagent strength, pH checks are documented and pH remained at 12 or above. EPA concluded incorrectly that the reagent modifications were not made and consequently rejected these data. However, we conclude that the quality of the HCN measurement results for this unit is acceptable for use in emission factor development.

After excluding three data sets for the two additional units discussed above, this leaves only six units remaining with feed rate data and acceptable HCN measurement results in EPA's data set. None of the six remaining units were operating with fired CO boilers during the tests (although CA5A1090 has a CO boiler which can be fired, it was not fired during the tests). Although, the HCN measurements for

NJA0850 are acceptable, feed rate data are not provided in the report for use in EPA's data set (although coke burn data are provided, as discussed below).

Tests Excluded due to Lack of Production Data

EPA included data only for facilities that provided FCCU reactor total feed rates corresponding to the test measurement periods. As noted above, an understanding of HCN formation and emission mechanisms supports the use of coke burn rate, rather than FCCU reactor feed rate, as a much more representative process activity rate for emission factor development. Some facilities submitted coke burn rate data as confidential business information (CBI) and therefore, EPA did not use these data. EPA has overlooked a number of reports for units with acceptable HCN measurement results that also provided coke burn rate data in the test reports: CA5A1090, LA3C0560, NJ1A0850, NJA0860, TX3B1250 and VI6A1530.

Note, EPA rejected results for NJ1A0850 because reactor feed rate data are not included in the report (CBI) and EPA concluded the HCN measurements are not acceptable. However, coke burn data are provided and, as discussed above, we conclude that the HCN measurements are acceptable. As noted, there are two separate test reports for the two separate stacks serving this unit – the sum of HCN emissions from the two stacks represent emissions from the single FCCU. EPA incorrectly rejected one of two sets of test results because production data were not provided in the report. However, the report for the other stack does include coke burn data. Thus, there are both coke burn data and acceptable HCN measurement results for this unit, bringing the total to six units with coke burn data and acceptable HCN results available among the ICR test reports.

API was able to obtain coke burn data for three additional FCCUs with acceptable HCN measurement results during preparation of these comments, increasing the total number of units available for emission factor development using coke burn rate to nine, three more than in EPA's valid data set using feed rate. While we believe this data set yet may be too small to be representative, it is more robust than EPA's data set of six units with feed data (after excluding the two units noted above) and includes both partial and full burn units. We have included these data in our discussion of analysis of emission factors provided below.

FCCU HCN Emission Factor Comments – Emission Factor Development and Presentation

Individual Test Ratings (ITRs):

- EPA has not fully evaluated data quality when reviewing any of the test reports. EPA has completed only the sections of the review normally completed by the source or tester, and left the sections for state regulatory agency review blank. The source tester evaluation section only addresses report completeness and does not address data quality. Report completeness is necessary to evaluate data quality, but alone is not sufficient and does not provide an indication nor assurance of data quality. The state regulatory agency review section, which is left blank, addresses data quality questions such as:
    - "Were all test method deviations acceptable?";
    - "Were all sampling issues handled such that data quality was not adversely affected?";

- "Was the DGM [dry gas meter] pre-test calibration within the criteria specified by the test method?";
- "Did isokinetic sampling rates meet method criteria?";
- "Were required laboratory duplicates within acceptable limits?"; and
- "Were required spike recoveries within method requirements?".

None of these aspects of data quality have been evaluated and this is a serious flaw in the review. It is especially surprising that EPA, as the developer of these emission factors, has not completed the sections of the evaluation pertaining to the regulatory agency reviewer as it certainly would seem appropriate and consistent with the RPDEF for EPA to assume this role. Prior to proposing new emission factors, EPA should ensure that the test report reviews are handled in accordance with its own draft procedures given in the RPDEF. EPA should complete the regulatory agency reviewer section of the ITR criteria to assure that data quality has been reviewed in addition to the completeness of the test report.

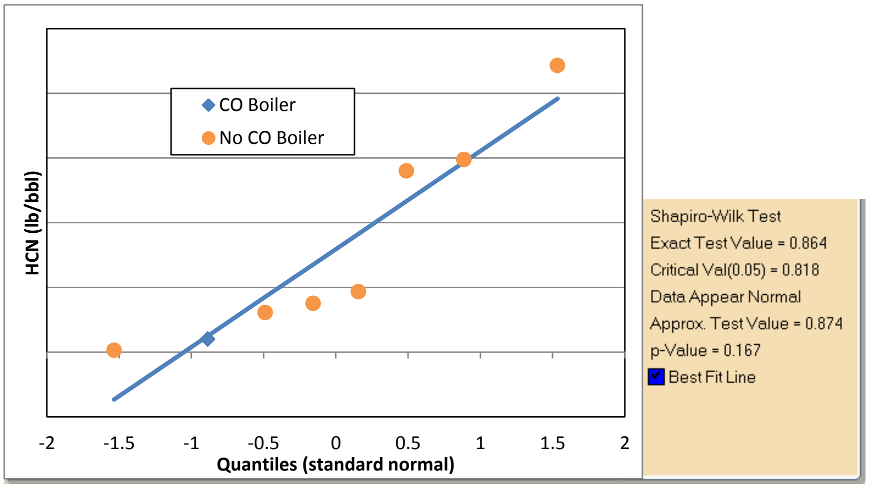
As described in our comments on EPA methodology in RPDEF, EPA's ITR criteria related to data quality do not give sufficient weight to serious data quality deficiencies. For example, the recovery of analytical spikes is a critical indicator of HCN measurement accuracy. However, a hypothetical negative answer to the question (in the state regulatory reviewer section of EPA's test report review checklist provided in Appendix A of RPDEF) "Were required spike recoveries within method requirements?" would reduce the ITR score insignificantly, from 65 to 63, for the highest scoring test report that EPA reviewed for the proposed HCN emission factor (CA5A0190). Spike recoveries outside of control limits specified in the test method would cast serious doubt on the acceptability of the test results. This is a systemic flaw in EPA's ITR methodology. We recommend that EPA revise the data quality criteria, weighting and scoring method for ITRs such that ITR scores accurately reflect the true quality of the test results.

Small Emission Factor Data Sets – an Illustration

The data set EPA used for the proposed revised FCCU HCN emission factor is small (8 samples for different FCCUs). This raises special challenges in applying statistical tests because normal methods are not robust. Putting aside API's recommendation that emission factors should be based on coke burn rate rather than reactor feed rate, and that three of the 8 samples used by EPA should be excluded based on EPA's own protocol for review, the analysis below on EPA's original data set illustrates some of the challenges with small data sets.

To identify outliers in this dataset, EPA applied the Dixon test (appropriate for datasets <25). This test is typically valid only for normally distributed data. Therefore the data set should first be tested for normality (Figure 3.2.1-2a). Although the Shapiro-Wilk Test indicates that the aggregated data are normally distributed (at the 95% confidence level) in Figure 3.2.1-2a, the data for units with wet gas scrubbers and electrostatic precipitators fall at opposite ends of the data set and have very different slopes when presented on a Q-Q plot (Figure 3.2.1-2b). Each data set appears to be normally distributed on inspection (i.e., a straight line on a Q-Q plot). This suggests that there are two distinct data subsets. A box plot of the two subsets generated using EPA's free statistical analysis software, ProUCL 5.0, (Figure 3.2.1-3) also shows two distinct data subsets.

To test this statistically, we first determined that the variances of the two data sets are equal, and since the data are normally distributed the Student's t-test was applied (as did EPA – but without first checking for normality or equality of variances). This shows that the means of the two data sets are not equal at the 95% confidence level. Regardless, the data sets are much too small (3 for ESP and 5 for WGS) to draw any strong conclusions. <u>Subgroups should not be established on statistical results alone without some degree of engineering judgment considering process effects, especially with small data sets.</u>



Shapiro-Wilk Test
Exact Test Value = 0.864
Critical Val(0.05) = 0.818
Data Appear Normal
Approx. Test Value = 0.874
p-Value = 0.167
☑ Best Fit Line

Figure 3.2.1-2a. Normal Q-Q Plot for full burn FCCU HCN emission factor data – Comparison as to CO boilers (EPA data set).

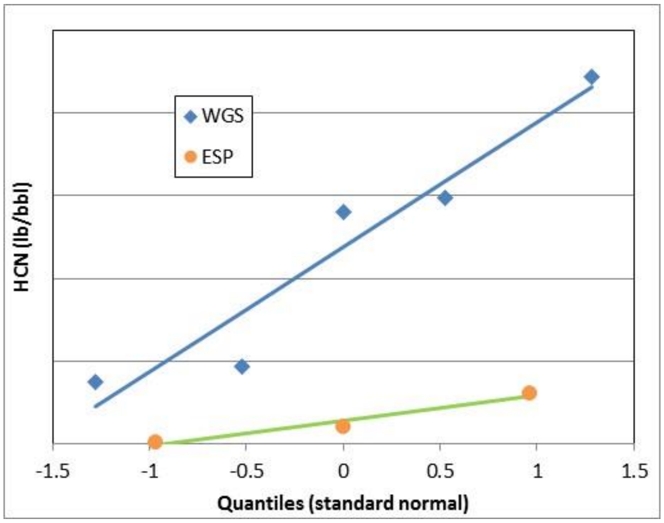


Figure 3.2.1-2b. Normal Q-Q plot for full burn FCCU HCN emission factor data (EPA data set).

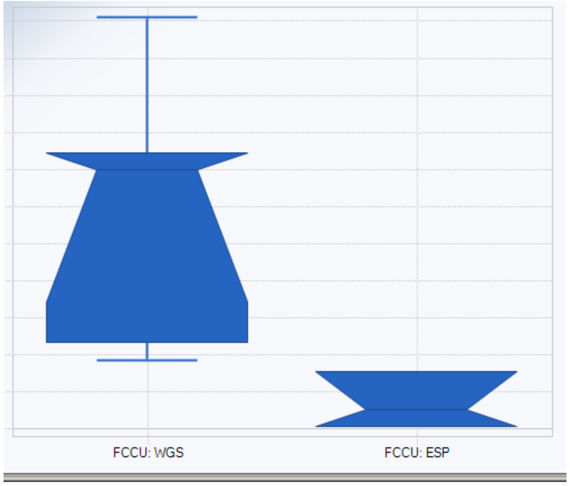


Figure 3.2.1-3. Box plot for FCCU HCN emission factor data in lb/bbl feed (EPA data set).

Regarding statistical methods, it is unclear why EPA has not made more use of the more rigorous and well-established statistical tools available in ProUCL (EPA's free statistical analysis software) for evaluating and analyzing emission factor data. ProUCL incorporates robust tests for analysis of environmental data such as tests for goodness of fit and graphical analysis tools (e.g., Q-Q plots) that are very useful. Further, EPA's *Data Quality Assessment: Statistical Methods for Practitioners, QA/G-9S* provides useful guidance for evaluating data and special considerations for small data sets. EPA should take advantage of its own available tools and guidance and apply well-established statistical methods for emission factor development.

Small Emission Factor Data Sets – the Corrected EPA Data Set

As noted above, HCN measurement results for three tests of two units in EPA's data set are not acceptable, leaving just six units with valid HCN measurements remaining (Figure 3.2.1-4). The remaining data are normally distributed based on the Shapiro-Wilk test at the 95% confidence level. The excluded data points eliminated the two lowest data points evident in Figure 3.2.1-2a and the remaining data fit a normal distribution much better (i.e., straight line in Figure 3.2.1-4). This illustrates how graphical analysis and judgment should be used along with statistical test results to guide data analysis for emission factor development. Regardless, we believe this data set is simply too small and potentially unrepresentative for FCCU emission factor development.

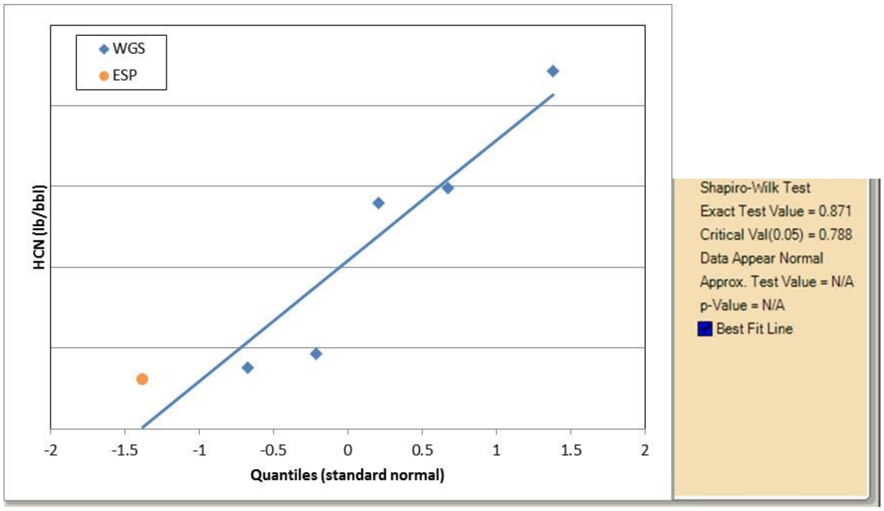


Figure 3.2.1-4. FCCU emission factor data for corrected EPA data set (acceptable HCN measurements only).

Emission Factors on Coke Burn Basis

As noted earlier, API recommends presenting FCCU HCN emission factors using coke burn rate as the characteristic process activity rate because FCCU reactor feed rate is a poor indicator of HCN formation in the FCCU catalyst regenerator.

Using the data from the API-reviewed valid ICR test reports and from the three additional FCCU units for which API was able to obtain coke burn data (Table 3.2.1-2), we calculated HCN emissions in pounds per thousand pounds of coke burned (lb/klb coke burned) for nine units (Figure 3.2.1-5).

Table 3.2.1-2: FCCUs with acceptable HCN measurements and coke burn data in API data set.

Facility ID	lb HCN/klb coke burned
IN2A0440	0.0095
IL2A0420	0.0627
NJ1A0850	0.0634
CA5A1090	0.179
NJ1A0860	0.224
HI5A0380	0.425
TX3B1250	0.775
LA3C0560	1.19
VI6A1530	1.25

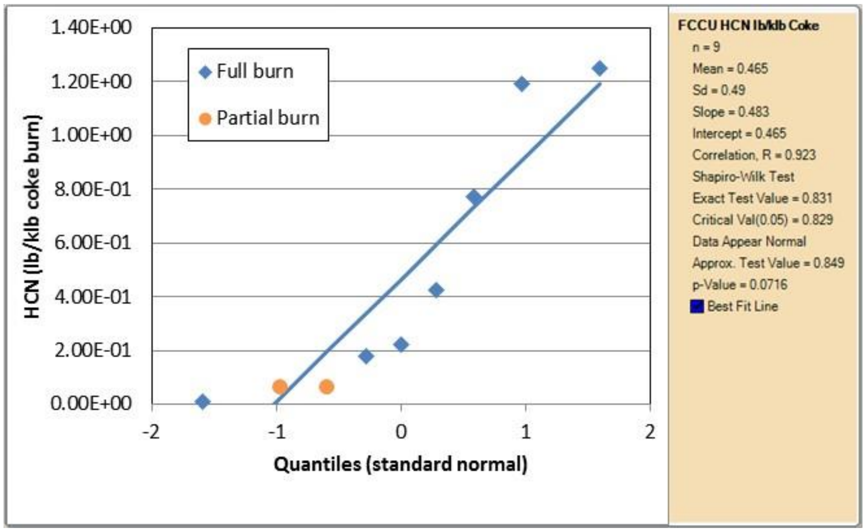
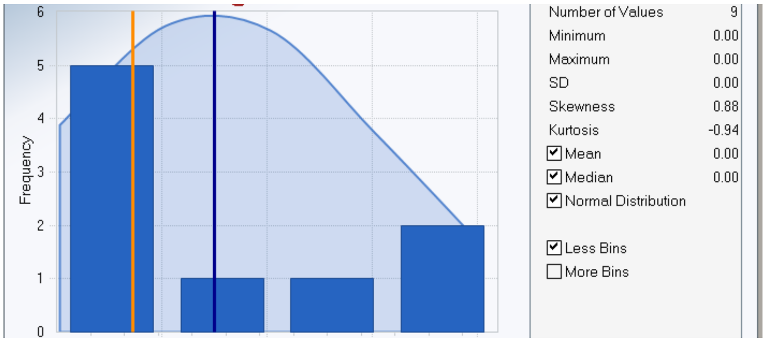


Figure 3.2.1-5. Normal Q-Q plot for FCCU HCN emission factor data in lb/klb coke burned.

An outlier test shows that although the high and low data points are potential outliers, they are not outliers at the 95% confidence level. Although the Shapiro-Wilk test indicates the data fit a normal distribution at the 95% confidence level, it is evident the data are left-skewed (Figure 3.2.1-6) and there is some s-shaped curvature in the normal Q-Q plot that suggests a lognormal distribution. A Q-Q plot of the log-transformed data (Figure 3.2.1-7) shows a very close fit to a normal distribution, also consistent with the Shapiro-Wilk test results for this set. Since the log-transformed data appear to provide the best fit, the mean of the log-transformed data set is the best central characteristic of the data set. This suggests an emission factor of 0.21 lb HCN/klb coke burned for the aggregated data set, compared with EPA's proposed factor in the Refinery Protocol of 0.50 lb HCN/klb coke burned. (Note that this EPA emission factor was not actually derived from the EPA dataset but was calculated from the feed rate based EF by assuming a constant coke-to-feed ratio, as discussed below.)



Number of Values 9
Minimum 0.00
Maximum 0.00
SD 0.00
Skewness 0.88
Kurtosis -0.94
☑ Mean 0.00
☑ Median 0.00
☑ Normal Distribution

☑ Less Bins
☐ More Bins

Figure 3.2.1-6. Histogram for FCCU HCN emission factor data in lb/klb coke burned.

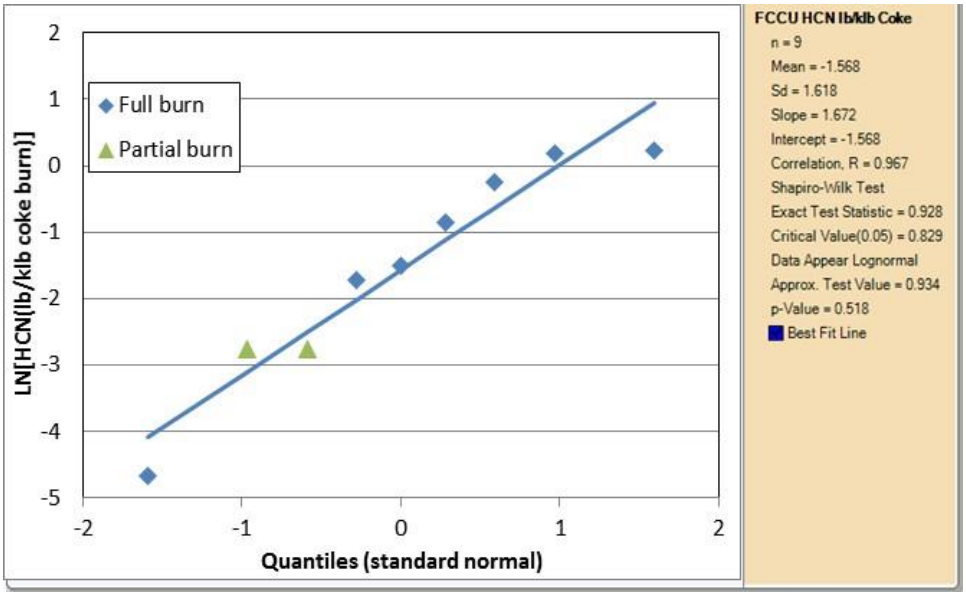


Figure 3.2.1-7. Q-Q plot for log-transformed FCCU HCN emission factor data.

This discussion illustrates the importance of graphical analysis and judgment to complement numerical statistics when developing meaningful emission factors. All of these analyses and charts can be generated using EPA’s free ProUCL Version 5.0 software (Q-Q plots were generated in Excel for clarity in this report).

Also apparent in Figures 3.2.1-5 to 3.2.1-7 is the difference in HCN levels for the two partial burn units with CO boilers in the data set, which, along with a single full burn unit, are near the low end of the range. None of the full burn units have CO boilers. Although partial burn units have the potential to generate more HCN, CO boilers are very effective in destroying it and these results would be consistent with that process. Examining the differences in emission factor data for those units with WGS and those with ESPs, there does not appear to be a significant difference between the two subsets with the current available data (Figure 3.2.1-8). As with EPA’s data set, the number of data points is too small to support robust statistical analysis to establish the significance of these differences. Therefore, any potential subgroupings would be based solely on process differences.

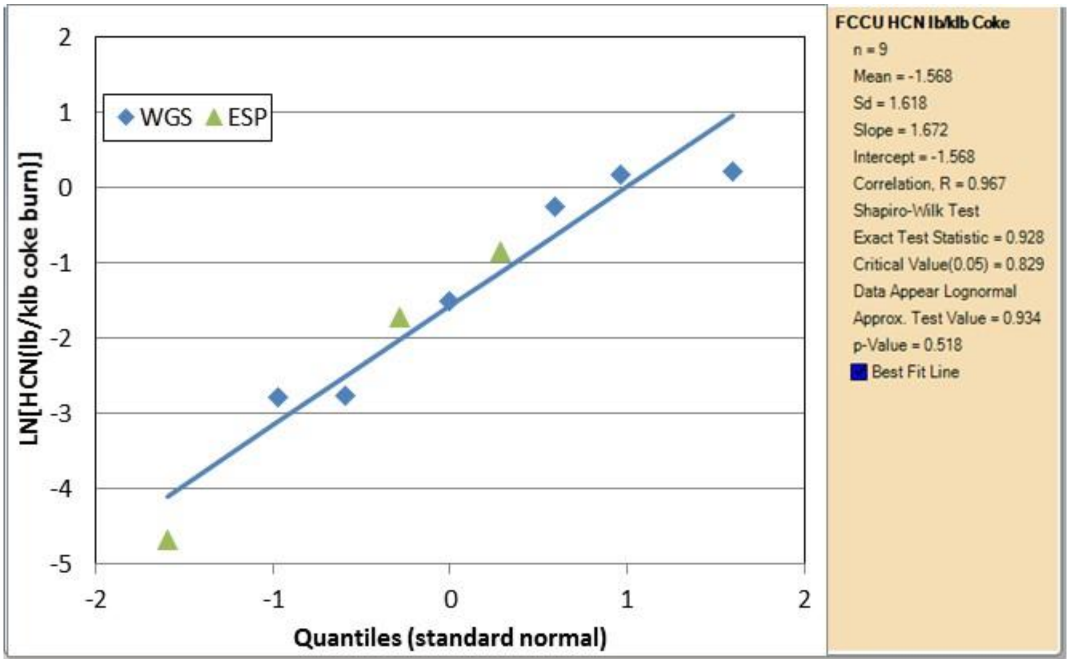


Figure 3.2.1-8. Q-Q plot for FCCU HCN emission factor data in lb/klb coke burned for WGS vs. ESP.

Refinery Protocol Emission Factor: EPA lb/klb coke

The FCCU HCN emission factor in units of lb/klb coke burned presented in Table 5-4 of the Refinery Protocol is unsupported by any explanation of its derivation in either the Protocol or the DEFR. The latter report does not provide any factors in lb/klb coke burned, so it is unclear how these values were developed. From the data in the table it appears that constant coke yield of 16 lb coke per barrel of feed was used for all of the units. As noted earlier, the relative amount of coke produced per unit of FCCU feed (coke yield or make) is a complex issue depending on many factors such as FCCU design characteristics, feed characteristics (API Gravity, recycled and slurry streams, etc.), reactor and regenerator temperatures and other operating conditions. API believes that using a constant coke yield to convert lb HCN/bbl feed to lb HCN/lb coke burned is misleading and will result in an inaccurate emission factor. EPA assumes coke yield is constant across all units when, in fact, the coke yield can vary significantly among different units. For example, data available in the test reports used by EPA indicate coke yields range from a lower end of 11.4 to 21.3 lb of coke per bbl of feed. Therefore, converting lb HCN/bbl feed to lb HCN/klb coke burned using a constant coke yield does not provides a representative emission factor and introduces even greater uncertainty.

API recommends deleting the emission factors in lb HCN/klb coke burned from Table 5-4 unless they can be derived from actual coke burned data during HCN emissions tests. We have identified data sets for six units in the ICR test reports that have acceptable HCN measurement results and coke burn data. Including these with data for three additional units for a total of nine suggests it is possible to develop an emission factor on a coke burned basis using actual test data. We recommend that EPA not publish the current lb HCN/bbl feed factor, but derive coke burn based emission factors, along with development of separate emission factors for full burn FCCUs with CO boilers, full burn FCCUs without CO boilers and partial burn FCCUs with CO boilers.

Emission Factor Robustness

Presentation of emission factors should be accompanied by additional information to assist the end user in applying them. EPA proposes to categorize emission factor quality as “Highly Representative,” “Moderately Representative” and “Poorly Representative.” These qualitative terms are only useful to the extent that quantitative information, such as the dispersion of the individual data points, has been used to inform this characterization.

The relative standard deviation of the eight data points underlying EPA’s proposed HCN emission factor is 100%. This indicates a very high degree of uncertainty in EPA’s mean emission factor – the emission factor could be zero or twice as high with 68% probability. EPA classifies the emission factor quality as “moderately” representative, which is highly inconsistent with the fact that the emission factor could be zero with high probability. Further, EPA makes no assessment of the number and configurations of units tested relative to the total population of FCCUs and therefore the representativeness of the eight units tested to the total population is unknown.

For this and other reasons discussed previously, we strongly disagree with characterization of the proposed HCN emission factor as “moderately representative.” <u>API strongly discourages publication of an HCN emission factor in lb/bbl feed; however, if EPA decides to do so then API recommends characterizing the emission factor as “potentially unrepresentative – high uncertainty”, with advice to use extreme caution in applying it.</u>

Quantitative indicators of data dispersion (e.g., mean, median, geometric mean, standard deviation, minimum and maximum values) provided along with emission factors and sample size would be much more meaningful to end users than a qualitative “moderate” representativeness rating. Another important aspect of the data is the contribution of undetected results (with substitution of half detection limits). An emission factor dominated by undetected results could hardly be deemed representative. While this is not the case with these data for FCCU HCN emission factors, it certainly can be important for others. We recommend that EPA add descriptive statistics indicating data distribution and dispersion, and sample size when reporting emission factors. We also recommend that EPA develop a quantitative indication of the contribution of detection limits to emission factors.

Summary and Conclusions

EPA has not adequately developed or justified the proposed FCCU HCN emission factor and the proposed factor should not be finalized. EPA did not include significant impacts of process configurations on HCN formation and emissions in its derivation of associated emission factors. Additionally, EPA failed to use the representative process activity rate for emission factor development, used a data set that is too small to provide representative emission factors, inappropriately applied statistics, and did not comply with its own procedures outlined in the RPDEF.

Process Considerations

- EPA has not adequately considered FCCU process configurations and expected effects on HCN emissions in evaluating valid data combinations. The Student’s t-test procedure described in RPDEF Appendix E and in the DEFR, does not provide a robust assessment of valid data combinations for HCN with such a small data set (see also comments on the RPDEF regarding procedures for small data sets).

- EPA should revise its analysis of valid HCN data combinations, considering HCN formation, destruction and removal mechanisms and how this would be expected to differ among process configurations (e.g., full and partial burn regenerators, fired CO boilers or heaters, regenerator additives, NOx and acid gas air pollution control technologies, etc.) that may affect HCN emissions.

Data Limitations

- EPA's FCCU HCN data set is very small (8 units, all of which are full burn units) and the range within the data set is very large relative to the arithmetic mean. Additionally, three tests for two of these units should be excluded based on EPA's own test method evaluation methodology which would further decrease the sample size. This leaves a data set that is too small to justify the proposed revised HCN emission factor, for example, because of different process configurations affecting HCN emissions. Also, small data sets require different statistical methods than are currently specified in the RPDEF. At a minimum, assuring a normal distribution exists or transforming the data (e.g., log) to normalize the distribution is necessary to assure accurate emission factor development.

Emission Factor Development & Presentation

- EPA has not completed FCCU HCN test report reviews necessary to determine that test data quality is acceptable for emission factor development. EPA should complete all portions of the ITR criteria described in Appendix A of its RPDEF to assure that test data quality has been evaluated and is adequately reflected in the ITR scores.
- EPA's characterization of the FCCU lb HCN/bbl feed emission factor quality as "moderately representative" is highly misleading. Feed rate is not a representative indicator of HCN emissions. The range of the underlying data is very large relative to the mean, indicating very low confidence in the reported emission factor. Further, EPA makes no assessment of the number and configurations of units tested relative to the total population of FCCUs and therefore the representativeness of the eight units tested to the total population is unknown. At best, we would characterize the emission factor as "potentially unrepresentative – high uncertainty", with advice to use extreme caution in applying it.
- API strongly discourages publication of an HCN emission factor in lb/bbl feed because feed rate is not a representative indicator of HCN emissions.

API supports development of an HCN emission factor on a pounds HCN per thousand pounds of coke burned (lb HCN/klb coke burned) basis, with the consideration of impact by process configuration, when data become available for a sufficiently large and representative number of units. API has and will continue to work with its member companies and others to expand the FCCU HCN data set for potential emission factor development.

3.2.2 AP-42 Table 5.1-2 CRU THC Emission Factor

API's comments regarding the proposed addition of a CRU THC emission factor fall into three general categories: technology considerations; data limitations; and emission factor development and presentation.

CRU THC Emission Factors – Technology Considerations

Type of CRU

Hydrocarbon emissions occur during catalyst regeneration in CRUs, not during the reforming process itself. There are three basic types of CRUs that differ significantly in their technology for regenerating their catalyst: continuous, cyclic and semi-regenerative (see Refinery Protocol, Section 5.4). All four of the CRUs in EPA's data set are identified as continuous regeneration units. Although the catalyst regeneration process by burning coke off the spent catalyst is similar among these different types of CRU technology, process conditions affecting THC emissions will vary depending upon the following conditions: duration and frequency of purge cycles; method of hydrogen chloride (HCl) emissions control (e.g., scrubber, Chlorosorb); temperatures, pressures and oxygen concentrations during coke burning; coke properties; and other factors. Therefore, it is reasonable to expect different levels of THC emissions to be emitted during the coke burn cycle for different CRU types. For example, a 1997 API data set derived from an earlier EPA ICR (2 semi-regenerative and 5 cyclic CRUs) suggests a significantly wider range of VOC emissions for semi-regenerative compared with cyclic CRUs (Figure 3.2.2-1). THC emissions for one semi-regenerative CRU lies well within the range of the data for cyclic units, while THC emissions for the other semi-regenerative CRU is far higher. The underlying test results for the 1997 data are not available for validation, and the representativeness of the results relative to current CRU configurations, operations and regeneration steps is unknown. Regardless, the data suggest there may be important differences in THC emissions for different CRU technology that should be considered before finalizing a THC emission factor for CRUs.

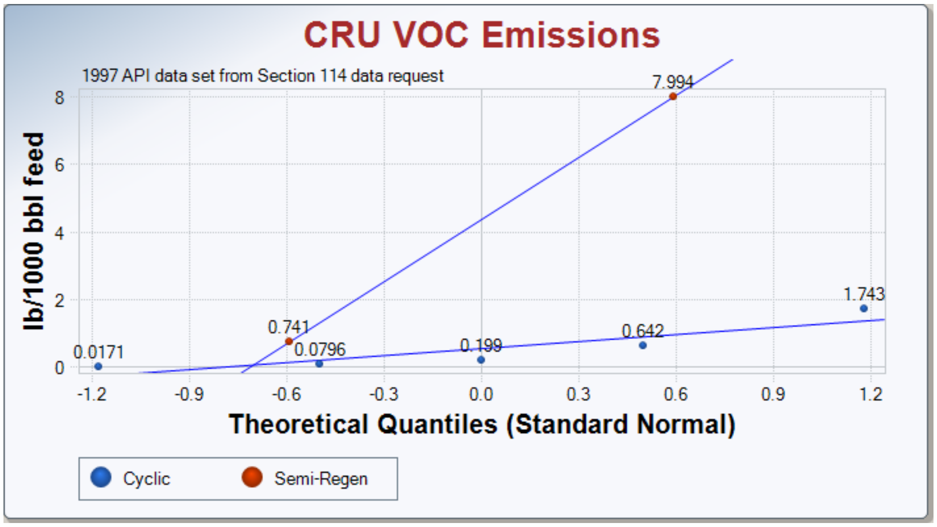


Figure 3.2.2-1: VOC emission factors for five cyclic and two semi-regenerative CRUs (1997 API data set).

Use of Coke Burn Rate as a Normalization Factor

For the similar reasons explained elsewhere in these comments regarding the proposed FCCU HCN emission factor (see Section 3.2.1), coke burn rate may be a better characteristic activity parameter rather than reactor feed rate for CRU THC emission factor development. The majority of hydrocarbon emissions from CRUs occurs primarily due to incomplete combustion during coke burn off and therefore depends on coke combustion conditions during regeneration. Coke yields per barrel of feed vary with CRU process design, configuration, operating conditions and feeds etc. In fact, for cyclic and semi-regenerative units, the coke burn step occurs while feed to the reactor being regenerated is zero. Thus, feed throughput has little direct influence on coke combustion conditions. Therefore, CRU reactor feed rate (or cumulative feed between regenerations) is not necessarily a reliable indicator of coke combustion rate or of combustion conditions in the regenerator that generate THC emissions. API recommends that EPA evaluate THC emission factors for CRU catalyst regeneration based on coke burn rate before publishing any THC emission factor based on feed rate.

CRU THC Emission Factors – Data Limitations

EPA’s dataset used for estimating the THC emission factor for CRUs is very small (only four CRUs). The range within the data set (366% of the mean) and standard deviation (180% relative to the mean) are very large, implying very large uncertainty (±286% at the 95% confidence level) in the emission factor. THC for one unit is more than an order of magnitude higher than for the other three units; it clearly appears to be an outlier, yet there is no valid technical reason to exclude it and the data set is too small to judge whether it is inconsistent with the rest of the population.

The data set could be improved by including data for additional units. Most of the data that EPA reviewed and that has acceptable THC test results could not be used because production data are not available. Based on our review, the data available to EPA from the 2011 ICR includes four additional units that API believes could be used if production data were available (Table 3.2.2-1). Note, EPA appears to have overlooked one 2011 test report that includes acceptable Method 25A results for THC concentration and mass emission rate (TX3B1220, a continuous CRU) albeit production data are not available for this unit.

Table 3.2.2-1: Summary of CRU THC test data review results (EPA and API).

Facility ID	CRU Type	Test Results Ok? (EPA)	Test Results OK? (API)	Use for EF Development? (EPA)	Use for EF Development? (API)
OK2C0990	Continuous	Yes	Yes	Yes	Yes
TX3B1310	Continuous	Yes	Yes	Yes	Yes
TX3B1250	Continuous	Yes	Yes	Yes	Yes
MS3C0740	Continuous	Yes	Yes	Yes	Yes
TX3B1220	Continuous	not evaluated	Yes	not evaluated	Need production data
IL2A0420	Continuous	Yes	Yes	No	Need production data
KS2C0470	Continuous	Yes	Yes	No	Need production data
KY2A0490	Continuous	Yes	Yes	No	Need production data
LA3C0610	Continuous	**Yes**	**No** (1)	No	No
LA3C0650	Continuous	No	No	No	No
TX3B1140	Continuous	**Yes**	**No** (2)	No	No
WA5A1420	?	Yes	Yes	No	No (3)

(1) Stack gas flow rate was not determined.
(2) While results met calibration error and bias check specifications, measurements were at very low end of calibrated range and calibration gas dilution was large. Results may be useable but consider results BDL.
(3) Measurements not made during coke burn cycle.

EPA has attempted to present the THC emission factor as a VOC emission factor in the Refinery Protocol assuming THC and VOC are equal. Note, the test method to measure THC emissions for all of EPA's data includes methane and ethane, which are not VOCs. Methane and ethane, if present in the samples, should not be included in a VOC emission factor. EPA has not considered results that could be used to better estimate the fraction of THC that is VOC (i.e., non-methane/ethane THC). For example, one test utilized a Method 25A analyzer with a methane precutter to determine methane, and another included both Method 25A and Method 18 measurements to determine methane and ethane (Table 3.2.2-2). The results show that only 85 to 92% of THC should be reported as VOC when measured as propane equivalent.

Table 3.2.2-2: Speciated THC results for IL2A0420 and LA3C0610

	Test Run	THC as C_3H_8, ppmvw	CH_4 as C_3H_8, ppmvd*	C_2H_4 as C_3H_8, ppmvd	NMETHC
IL2A0420 (M25A with CH_4 precutter)	1	8.06	1.21	not determined	0.850
	2	7.84	0.88	not determined	0.888
	3	8.05	1.10	not determined	0.863
	Average	7.98	1.06		0.867
LA3C0610 (M25A and M18)	1	23.65	0.66	1.31	0.917
	2	23.06	0.68	1.28	0.915
	3	23.18	0.65	1.31	0.915
	Average	23.3	0.66	1.30	0.916

*CH_4 as CH_4 results adjusted to propane basis by dividing by three.

Regardless of the above, API believes that EPA's current data set is inadequate for emission factor development at the present time because it is too small to be representative, the uncertainty in the average emission factor is very large and production data as coke burn rate are not available.

CRU THC Emission Factors – Emission Factor Development and Presentation

Individual Test Ratings (ITRs)

Similarly to our comments regarding the FCCU HCN emission factor, there is a lack of correspondence between data quality indicators and ITR scores developed for the proposed CRU THC emission factor. For example, a negative answer to the question "Did calibration error tests meet method requirements?" in the state regulatory reviewer section of the ITR spreadsheet for the highest scoring CRU THC report changes the score from 41 to 38, whereas failing this criterion generally should invalidate an instrumental method test. Therefore, EPA needs to revise the ITR criteria and scoring methodology to more accurately reflect serious defects in measurement quality.

EPA has not evaluated data quality when reviewing any of the test reports. EPA has completed only the sections of the review normally completed by the source tester and did not complete the sections for state regulatory agency review. The source tester evaluation section only addresses report completeness. The regulatory agency review section, which EPA did not complete, addresses data quality criteria. Thus, EPA provided no assessment of data quality, such as whether the test procedures and quality assurance/quality control results conformed to specifications in the reference test methods or good measurement practices. This is unacceptable for emission factor development and does not conform to EPA's own specifications in its RPDEF. EPA should complete the regulatory reviewer portion of the ITR criteria and otherwise assure that data quality has been evaluated and is acceptable for emission factor development.

Central Characteristic

The data EPA has used clearly are not normally distributed (Figure 3.2.2-2, left, a Q-Q plot in which normally distributed data form a straight line). The data are highly skewed by the data for MS3C0740 that is more than 16 times higher than the next highest unit. Although the Shapiro-Wilk test indicates the data fit a normal distribution at the 95% confidence level, the data set is too small for robust results and (following guidance in EPA's *Data Quality Assessment: Statistical Methods for Practitioners QA-G9S*) must be evaluated graphically and with judgment to determine the best distribution. The fit to a lognormal distribution is much better, both visually and as indicated by the Shapiro-Wilk test statistic (Figure 3.2.2-2, right).

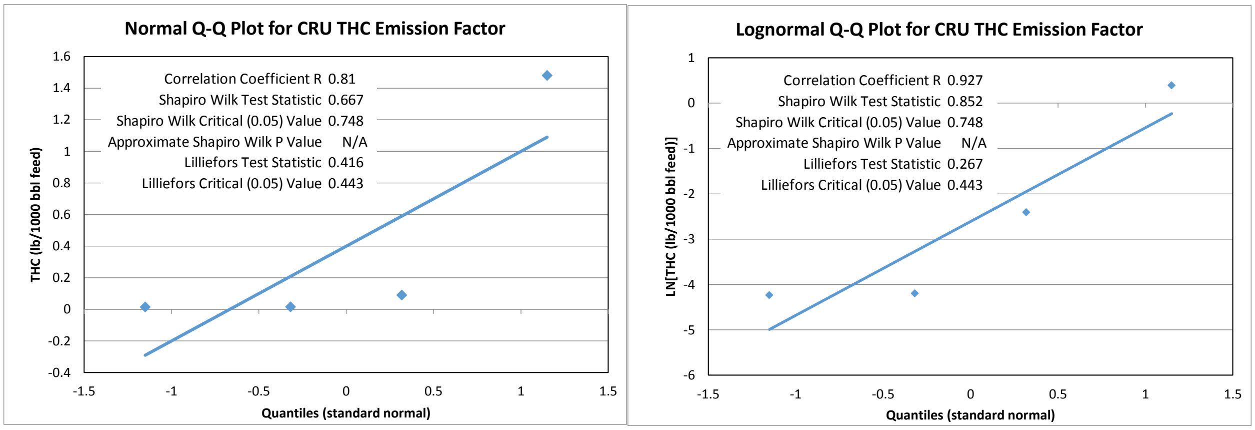


Figure 3.2.2-2: Normal (left) and lognormal (right) Q-Q plots for CRU THC data.

Therefore, the mean of the raw data does not provide the best central characteristic of this data set. As noted in RPDEF Appendix C, EPA presumes most environmental data are log-normally distributed and specifies conducting outlier tests on log transformed data sets. Dixon's outlier test, which applies only to data that are normally distributed, indicates there are no outliers at the 95% confidence level. EPA has correctly normalized the data before applying Dixon's outlier test to the data set. However, because the data best fit a log-normal distribution, the mean of the log-transformed data (geometric mean) also should be used for determining the most representative emission factor. This yields a THC emission factor of 0. 073 lb THC/1000 bbl feed, which is less than one-fifth of EPA's proposed emission factor of 0.40 lb THC/1000 bbl feed based on the mean of the untransformed data.

The mean of the untransformed data set is unduly weighted by a result for one CRU that is two orders of magnitude higher than the other three. This illustrates a key flaw in the analytical procedures specified in the RPDEF (see also comments on EPA's general methodology). As noted above, the mean of the log-transformed data provides the best representation of the data and should be used for the CRU THC emission factor. Alternatively, the median of the untransformed data (0.053 lb THC/1000 bbl feed) also provides a more representative central characteristic for this skewed data set.

VOC Emission Factor

In the Refinery Protocol Table 5-6, EPA reports an emission factor for VOC. Although definitions of VOC vary, VOC emission factors are generally used to represent reactive hydrocarbons involved in atmospheric photochemical reactions in air quality models. However, EPA has based the CRU VOC emission factor on measurements of THC for CRUs based on EPA Method 25A test results. Method 25A is an instrumental test method employing a flame ionization detector (FID) gas analyzer. An FID responds to hydrogen-carbon bonds (some less equally than others) and does not differentiate among individual hydrocarbon species. Non-VOC hydrocarbons, in particular methane and ethane, are often present at significant concentrations relative to total hydrocarbons from combustion processes like CRU catalyst regeneration. Therefore, THC can be a poor indicator of VOC unless methane and ethane are first removed from the sample before the FID.

An inspection of the four test reports used for the THC emission factor reveals no indication that methane or ethane were removed before Method 25A analysis, or that other samples were analyzed to determine hydrocarbon speciation. In fact, as noted in the draft emission factor report, EPA has deliberately avoided using available THC speciation data from other test results. To be consistent with the actual measurements, API recommends revising the proposed Refinery Protocol Table 5-6 and related discussion on page 5-19, specifically replacing “VOC” and “volatile organic compounds” with “THC” and “total hydrocarbons,” respectively.

Emission Factor Rating

EPA assigns a data quality rating of “poorly” representative to the CRU THC emission factor. This is overly generous because tests of just four different continuous CRUs resulting in an emission factor with extremely high uncertainty can hardly be considered representative of the entire population of CRUs. EPA should characterize the proposed emission factor as “Potentially highly unrepresentative with high uncertainty” and supplement with advice to use with extreme caution. EPA’s data set is much too limited (small number of units, only continuous CRUs) to evaluate the critical technology differences among CRU types that can affect THC and other air emissions. Further, EPA makes no assessment of the number and configurations of units tested relative to the total population of CRUs and therefore the representativeness of the four units tested to the total population is unknown.

Summary and Conclusions

The methodology and data that EPA has employed in developing the THC emission factor for CRUs requires further evaluation. API recommends that EPA not finalize the THC emission factor for CRUs at this time, for the following key reasons:

- EPA’s data set is inadequate to justify the proposed CRU THC emission factor, and therefore the proposed factor should not be finalized. To develop an appropriate THC emissions factor, EPA needs to further evaluate test and production data for additional units besides the four CRUs currently considered.
- Emission factor development must include reviewing the CRU THC test reports using the ITR criteria described in Appendix A of the RPDEF and other measures to assure that test data are acceptable for emission factor development.
- When reviewing the data sets, EPA also needs to properly analyze this data against the technology differences among CRUs to understand THC formation and its destruction or removal during the coke burn step of the CRU reactor regeneration cycle. Such technology differences include the CRU’s configuration (e.g., semi-regenerative, cyclical and continuous) as well as pollution control devices (e.g., scrubbers, Chlorosorb) used to control HCl emissions to comply with the emission standards in Refinery MACT UUU (i.e., 40 CFR Part 63, Subpart UUU). API recommends that EPA further evaluate the three major CRU technologies (cyclic, semi-regenerative and continuous) and their method for controlling HCl emissions before proposing a THC emission factor for each type of CRU technology.
- API recommends evaluating emission factors based on coke burn rate in addition to reactor feed rate because coke burn rate is a better indicator of combustion conditions leading to THC emissions and the catalyst coke yield varies independent of reactor feed rate among different CRUs due to many design and operating factors.
- EPA must use robust statistical methods consistent with best practices already established by EPA (e.g., in ProUCL and in EPA’s *Data Quality Assessment: Statistical Methods for Practitioners QA-G9S)* for evaluating test data and deriving emission factors.

3.2.3 AP-42 Table 5.1-2 Hydrogen Reformer Furnace NOx Emission Factor

Hydrogen reformer furnaces are generally some of the larger furnaces in a refinery, with many being in excess of 100 million British thermal units per hour (MMBtu/hr) design firing rate. As such, many of these furnaces, and certainly the new or recently modified units, are required to either operate continuous emissions monitoring systems (CEMS) or perform stack testing to determine and monitor NOx emission rates.

As part of developing these comments, API conducted a survey of existing hydrogen reformer furnaces and only four units were identified as not having ultra-low NOx burners or SCR technology installed. The majority of units in the survey had one or both of these technologies installed and therefore, the proposed emission factor would not be applicable to them. Additionally, existing units with or without controls generally have stack test data or CEMS data, which is used for emission inventory purposes. Therefore, API sees limited value in establishing a NOx emission factor for hydrogen reformer furnaces. If EPA moves forward with finalizing an updated emission factor, API offers the comments below about the process to do so.

Similar to our comments regarding the FCCU HCN emission factor, there is a lack of correspondence between data quality indicators and ITR scores developed for the proposed Hydrogen Reformer Furnaces NOx emission factor. EPA has not fully evaluated data quality when reviewing any of the test reports. EPA has completed only the sections of the review normally completed by the source tester and left the sections for regulatory agency review blank. The source tester evaluation only addresses report completeness. The regulatory agency review addresses data quality questions. EPA should complete all portions of the ITR criteria described in RPDEF Appendix A to assure that data quality has been evaluated, and address other API suggested improvements to the RPDEF procedures.

3.3 AP-42 Section 8.13 Sulfur Recovery

The issues with the proposed new SRU NOx, CO, and THC emission factors fall in two general categories: Process Considerations and Emission Factor Presentation and Development.

3.3.1 SRU Emission Factors – Process Considerations

There are many different Sulfur Recovery Unit processes/configurations, especially considering the various tail gas treatment technologies in the industry. Tail gas treatment technologies vary depending upon the type of amine used, desired chemical reactions, catalysts, and tail gas thermal oxidation/incineration design. Tail gas compositions and the amount of tail gas produced can be very different depending on the SRU configurations. For example, the tail gas from a Claus unit will contain about 10,000 parts per million (ppm) CO. If the tail gas unit includes a cobalt molybdenum catalyst (such as Shell Claus Offgas Treating or Beavon unit), the CO will be reduced down to a few hundred ppm. However, if the tail gas is from a SuperClaus unit followed by a caustic scrubber system, the CO will not be affected and the CO going to the thermal oxidizer/incinerator (“incinerator”) will be higher than for other configurations.

Emissions of NOx, CO and THC are closely related to the tail gas composition, firing rate in the incinerator, and installed control technologies (e.g., ultra-low NOx burners or oxidation catalyst for

CO). The fuel usage in the incinerator is not always directly related to the total sulfur production. Therefore, sulfur production would not be an appropriate basis for SRU emission factors. API recommends that EPA develop emission factors on the incinerator fuel firing basis for different types of SRU processes/configurations.

As part of developing these comments, API conducted a survey of existing SRUs. NOx, CO, and THC emissions data were plotted with sulfur production in Figures 3.3.1-1 through 3.3.1-3 below. It can be seen from the trend lines shown on each of the Figures, that there is no apparent relationship between NOx, CO, or THC and sulfur production for the surveyed SRUs.

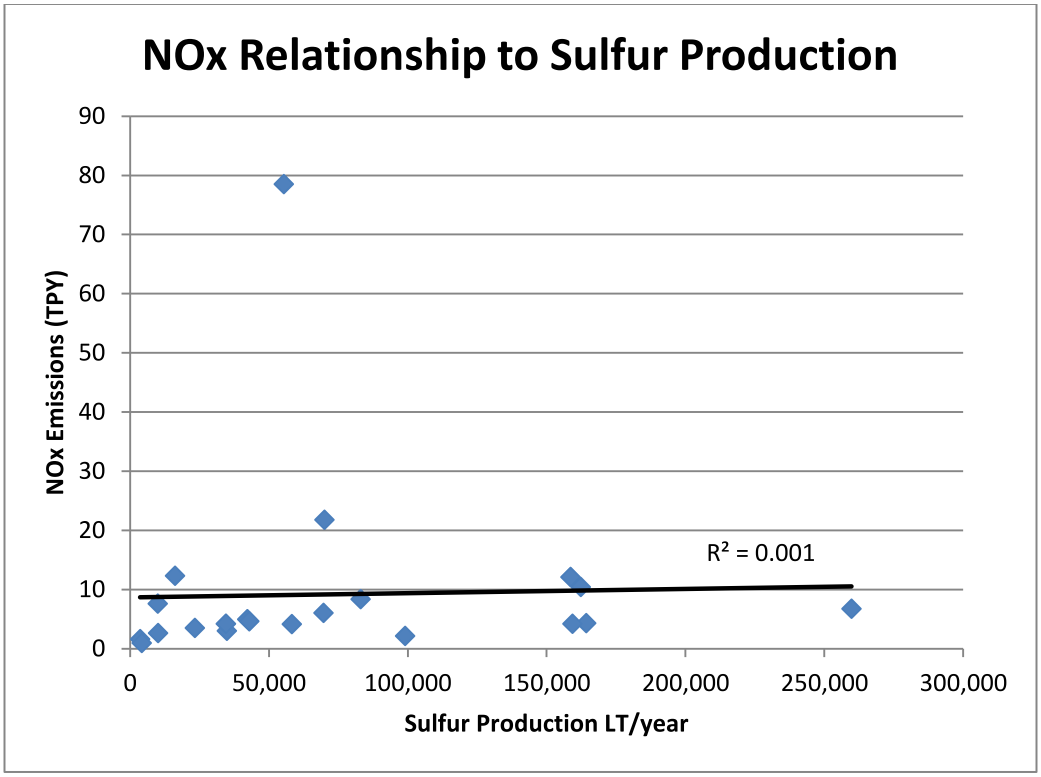


Figure 3.3.1-1: NOx Emissions Versus Sulfur Production

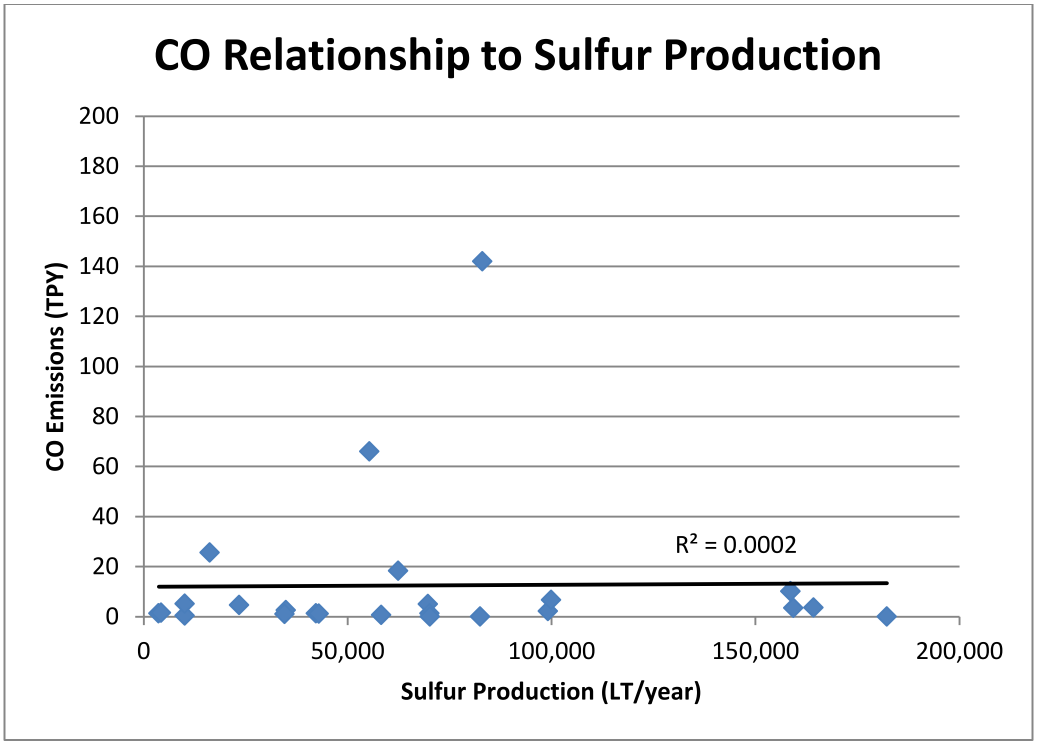


Figure 3.3.1-2: **CO Emissions Versus Sulfur Production**

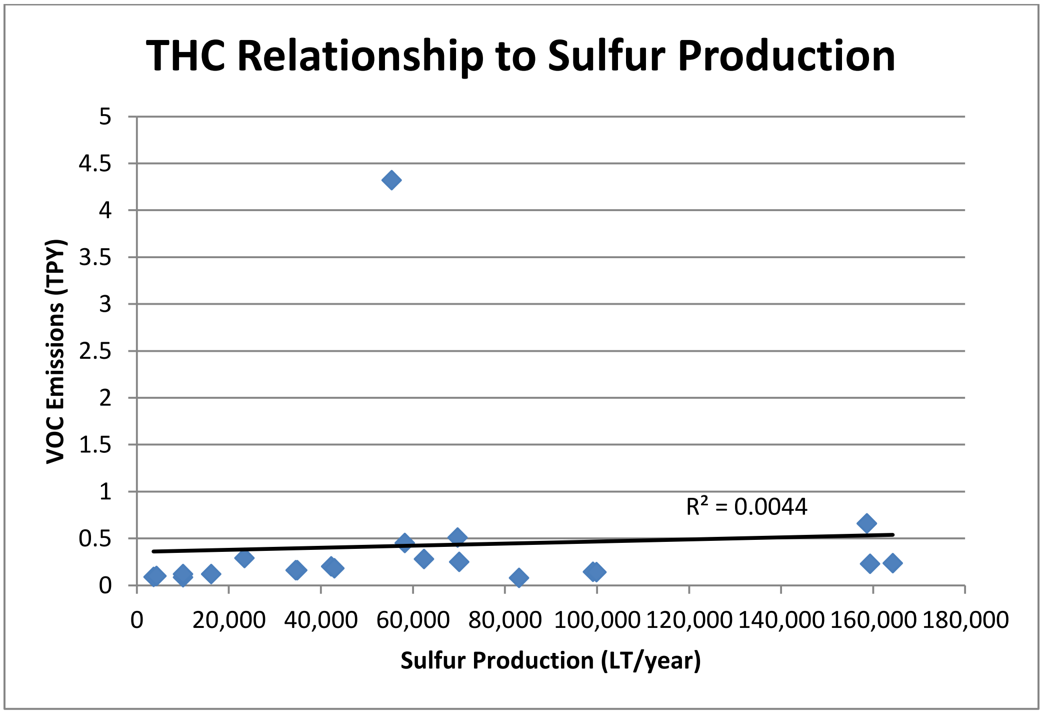


Figure 3.3.1-3: **THC Emissions Versus Sulfur Production**

EPA should not update the AP-42 factor until an improved assessment of the impacts of variations in unit configuration is completed and EPA determines if it would be more appropriate to correlate NOx, CO, and THC emissions to the firing of the thermal oxidizer/incinerator versus sulfur production. If EPA moves forward with finalizing an updated emission factor, API offers the comments below about the process to do so.

3.3.2 SRU Emission Factors – Emission Factor Presentation and Development

Similar to our comments regarding the FCCU HCN and Hydrogen Reformer Furnace NOx emission factors, there is a lack of correspondence between data quality indicators and ITR scores developed for the proposed SRU NOx, CO, and THC emission factors.

EPA has not fully evaluated data quality when reviewing any of the test reports. EPA has completed only the sections of the review normally completed by the source tester and left the sections for regulatory agency review blank. The source tester evaluation only addresses report completeness. The regulatory agency review addresses data quality questions. EPA should complete all portions of the ITR criteria described in RPDEF Appendix A to assure that test data quality has been evaluated, and address other API suggested improvements to the RPDEF procedures.

3.4 AP-42 Section 13.5 Industrial Flares

A full descriptive report on the proposed NOx, CO, and VOC emission factors for industrial flares can be found in Appendix 1.

3.4.1 Adequacy of Existing Emission Factors and Guidance

Recent flare testing and analyses do not suggest a need to revise the existing AP-42 emission factors at this time.

While recent flare testing and analyses have suggested some changes to the operating conditions that define a well operated steam-assist flare, the new flare test data are consistent with the existing emission factors. Existing data and new data both support very high combustion efficiency for steam and air-assisted flares. However, the new data indicate that the operating envelope for a high destruction efficiency flare requires additional parameters to assess the proper amount of assist gas. While this results in some minor changes to the operating envelope (for steam assisted flares only) and the parameters used to define it, it does not invalidate the existing emission factors.

It is inappropriate to revise the basis for combustion efficiency guidance because the conclusion from the proposed RSR that properly operated flares only achieve 98% destruction efficiency is not representative of all flares in all industries.

A 98% flare destruction efficiency is simply the minimum destruction efficiency asserted for refinery flares in the recently proposed Refinery Sector Rulemaking. In fact, many flares operate with destruction efficiencies exceeding 99%, and all refinery flares will have to average above the 98% minimum to assure compliance with the short averaging time required by the RSR. The AP-42 guidance should not reflect a unilateral reduction of the assumed flare destruction efficiency across all industries.

See also our comments in Appendix 2 of this document regarding the proposed text changes to AP-42 Section 13.5 with regard to flare combustion and destruction efficiencies.

A generic VOC factor has limited utility

In most circumstances, use of a generic VOC emissions factor for industrial flares is inappropriate and unnecessary. Facilities typically calculate VOC emissions from flares based on site-specific knowledge of the streams being routed to the flare and the destruction efficiency associated with the flare. This approach results in the most accurate emissions estimates possible. In practice, the VOC content of materials sent to a flare can vary from 0% (e.g., hydrogen flaring) to essentially 100% (e.g., flaring of fuel or chemical vapors from loading). Assigning one VOC emission factor to represent all flares and the ranges of materials that may be sent to them would result in a poor characterization of actual emissions.

If a VOC emission factor is ultimately added to AP-42, the development of the proposed VOC factor and its relationship to the existing THC factor need further review. However, similar to any generic VOC factor, the existing THC factor is seldom used because facilities typically use site-specific data to estimate hydrocarbon emissions.

3.4.2 Evaluation of Proposed Flare Emission Factors

The proposed flare emission factors should not be finalized. The proposed factors were developed using some technically inappropriate analyses and methodologies.

Specific technical issues identified in the development of the proposed factors include:

- Use of uncalibrated NO and NO_2 data in attempting to calculate NOx emissions rates from IR spectra, rendering the calculated NOx factor as not technically defensible.
- Use of PFTIR minute data instead of run average data. Use of run average data is necessary for valid analyses.
- Inappropriate filtering of PFTIR minute data.
- Apparent averaging of the CO_2 spectral bands rather than choosing the appropriate band based on spectral analysis.
- Use of unweighted, rather than hydrocarbon weighted combustion efficiency.
- Misinterpretation of PFTIR zero data values.
- Use of a pollutant ratio model to calculate NOx mass emission rates based on CO_2 data.
- Several computational errors and spreadsheet referencing errors.

These issues should be addressed in the development of any updated CO, VOC or NOx factors for flares.

Also, the calculations shown in the spreadsheets provided by EPA are not the same as those shown in the support documents. EPA does not provide explanation or validation that the calculations from these two sources are equivalent. See the discussion of the Emission Model - Calculations starting on page 15 of Appendix 1 of this document for further details.

NOx Factor Issues

The primary issue affecting the quality of this factor is that the PFTIR instruments used to collect the data at all of the recent flare tests were not calibrated for either NO or NO_2. Additionally, use of minute rather than run average data, averaging of the CO_2 spectral bands, and the use of the unweighted combustion efficiency all combine to bias the resulting factor high.

The model used to convert PFTIR data to mass emission data, based on a NOx/CO_2 ratio, has technical deficiencies. The model presumes NOx emissions can be predicted solely from CO_2 concentration in the flare plume. However, NOx is also produced from hydrogen combustion, which does not generate CO_2. Since hydrogen was present in the vent gas streams of most of the flares tested with the PFTIR and used for this emission factor analysis, the resulting factors are inaccurate to an unknown degree.

In principle, a Pollutant/CO_2 ratio model could be used to develop CO and VOC emission factors from PFTIR data if a correlation can be demonstrated between these pollutants and CO_2 in the flare plume. However, since NOx emissions are a function of BOTH plume CO_2 and vent gas hydrogen concentration, a NOx/CO_2 ratio model is not appropriate nor technically justifiable.

Finally, in conducting the outlier analysis on these data, an approach was used that has the potential to overlook certain outliers. These undetected outliers are a major factor in why the NOx factor for the Flint Hill Resources AU flare is 64 times higher than the average of the other NOx flare factors.

VOC Factor Issues

Development of Proposed New Factor

The proposed new VOC factor is potentially biased high due to a combination of technical issues including the use of PFTIR minute data instead of run average data, averaging of the CO_2 spectral bands, and the use of the unweighted combustion efficiency. The hydrogen content of the vent gas may also affect the VOC factor. Increased hydrogen will tend to increase flame temperature, which may improve VOC destruction efficiency. However, there is insufficient data from the recent flare tests to effectively evaluate this possibility.

Inconsistency with Existing THC Factor

The proposed VOC emission factor is inconsistent with the existing emission factor provided for THC. Generally, VOC is considered to be a fraction of THC emissions, but the proposed VOC emission factor is significantly higher than the existing THC factor.

Because the two factors are derived from different data sets using different technology, and there is a potentially high bias of the proposed VOC factor, it is not unexpected that the two factors are inconsistent. But publishing a VOC emission factor which is higher than the THC factor creates confusion, because this is not technically valid if factors were derived from a common data set.

CO Factor Issues

The proposed new CO factor is potentially biased high due to a combination of technical issues including the use of PFTIR minute data instead of run average data, averaging of the CO_2 spectral bands, and the use of the unweighted combustion efficiency.

4.0 Comments on Draft Emission Estimation Protocol for Petroleum Refineries – Version 3.0

Concurrent with the proposed AP-42 revisions, EPA posted an updated version (Draft Version 3) of the Emissions Estimation Protocol for Petroleum Refineries, which incorporates the proposed AP-42 emission factor revisions, and updates the methodologies for Storage Tanks, Catalytic Cracking Units, Delayed Coking Units, Asphalt Plant Vents, and Wastewater Collection and Treatment Systems. Draft Version 3 also changes the function of the Refinery Protocol document from the Refinery ICR tool for industry to now "provide guidance and instructions to petroleum refinery owners and operators *and to federal, state, and local agencies* [emphasis added] for the purpose of improving emission inventories."

API previously submitted comments on Version 1 and Version 2 of the Refinery Protocol on January 29, 2010 and January 21, 2011, respectively. We appreciate the many improvements made to the Refinery Protocol and thank the Agency for its serious consideration of our comments on the previous versions. We have limited our comments here to items that were added in Version 3. Our outstanding comments on Version 1 and 2 of the Refinery Protocol are included as Appendix 3.

API also requests that if the final AP-42 references the Refinery Protocol, EPA make clear that it will update the Protocol whenever it updates any AP-42 factor covered by the Protocol and that the Protocol will be reviewed and updated on the same schedule as AP-42.

4.1 Section 5.1.4 Methodology Rank 5B for Catalytic Cracking Units

See Section 3.2.1 of these comments for a detailed discussion of the FCCU HCN emission factor developed for AP-42.

As noted in Section 3.2.1, the FCCU HCN emission factor in units of lb/klb coke burned presented in Table 5-4 of the Refinery Protocol is unsupported by any explanation of its derivation in either the Protocol or the DEFR. The latter report does not provide any factors in lb/klb coke burned, so it is unclear how these values were developed. From the data in the table it appears that constant coke yield of 16 lb coke per barrel of feed was used for all of the units. As noted earlier, the relative amount of coke produced per unit of FCCU feed (coke yield or make) is a complex issue depending on many factors such as FCCU design characteristics, feed characteristics (API Gravity, recycled and slurry streams, etc.), reactor and regenerator temperatures, and other operating conditions. <u>API believes that using a constant coke yield to convert lb HCN/bbl feed to lb HCN/lb coke burned is misleading and will most likely result in an inaccurate emission factor.</u> EPA assumes coke yield is constant across all units when, in fact, the coke yield can vary significantly among different units. For example, data available in the test reports used by EPA indicate coke yields range from a lower end of 11.4 to 21.3 lb of coke per bbl of feed. Therefore, converting lb HCN/bbl feed to lb HCN/klb coke burned using a constant coke yield does not provides a representative emission factor and introduces even greater uncertainty. API recommends deleting the emission factors in lb HCN/klb coke burned from Table 5-4 unless they can be derived from actual coke burn data during HCN emissions tests.

Table 5-4 includes emission factors for organic HAPs including hydrogen chloride, hydrogen cyanide, and mercury. The RTI International Technical Memorandum for Review of HAP Emission Factors for Fluid Catalytic Cracking Units based on Component 4 Source Test Data (EPA-HQ-OAR-2010-0682-0205) suggests that "there is essentially an order of magnitude (*i.e.*, factor of 10) difference in the emission factors for hydrogen chloride [decrease], hydrogen cyanide [increase] and mercury [decrease] between the Protocol defaults and the Component 4 source test results". RTIs preliminary analysis of the ICR stack test data suggests that the factors for hydrogen chloride and mercury should be reduced. However, only the proposed emission factor for mercury has been lowered. EPA should consider revisions of all emission factors presented in Table 5-4, using all available data and subject to its RPDEF with suggested API improvements.

4.2 Section 5.3 Delayed Coking Units

AP-42 Reference to Refinery Protocol

The proposed updates to AP-42 Chapter 5.1 include a single reference to the Emission Estimation Protocol for Petroleum Refineries. This reference is made relative to the estimation of emissions from delayed coking units during end of cycle venting and subsequent decoking steps. This appears to be the only place that EPA has referenced the Refinery Protocol directly in its AP-42 revisions. As stated elsewhere in these comments, EPA's intent with regard to the use of the Refinery Protocol is unclear at best. The Refinery Protocol should not be referenced as part of AP-42 since it has not been subject to the same rigorous review process EPA outlines for AP-42 updates.

EPA should not incorporate the Refinery Protocol by reference for venting from delayed coking units. API believes it would be more appropriate for EPA to incorporate any new method(s) directly into AP-42 after completion of the appropriate quality assurance/quality control process outlined by EPA for updates.

Site-Specific Emissions Data

Absent from Section 5.3 of the Refinery Protocol for Delayed Coking Units is the option for each facility to use internally developed delayed coking unit emissions models based on site-specific information and engineering calculations. The use of site-specific information is generally more accurate than using an emission factor. *EPA must allow the use of site-specific delayed coking unit emissions models as a coker vent emission methodology in the Refinery Protocol.*

Impact of Operating Conditions for Delayed Coking Units

Delayed Coking Unit emissions are highly dependent on coker operating parameters. All the proposed methodologies fail to adequately account for these operating parameters. EPA links the coke bed temperatures and generation of steam to the magnitude of vent emissions. However, there are several important factors that influence the ability to cool the bed that are not accounted for in such a generalized approach to emissions estimates, including:

- Coking unit operational parameters, such as the furnace outlet temperature; and
- Coke drum quenching technique such as steam stripping at a sufficient rate and time to remove trapped hydrocarbons in the coke bed. Proper drum quenching techniques lower the hydrocarbon partial pressure and allow for the completion of coking reactions.

A significant portion of the discharged hydrocarbon is attributable to the drum vent. The mass of hydrocarbon per vent depends on multiple parameters and can be quite low depending on those operating parameters. Overhead temperature at the drum vent, cited in EPA's proposed Methodology Rank 3, for example, is not an adequate singular differential.

The drilling process should have negligible emissions unless there is ongoing chemical reaction, formation of coke, or tail gas and liquid hydrocarbons due to uncompleted reaction when feeding the coke drum.

EPA's Proposed Methods

API appreciates the difficulty associated with estimating emissions from delayed coking units due to the nature of process operations. With respect to the methods outlined in Draft Version 3 of the Refinery Protocol, API suggests the actions outlined in the sections below.

In summary, Methodology Rank 3 oversimplifies the emissions through a dependence only on drum overhead temperature at the time of the vent. The approaches in Methodology Rank 4 lack technical justification and Rank 4 is unnecessary; it could be replaced by a modified version of Methodology Rank 3. Methodology Rank 5 does not distinguish between units on any basis and is thus not representative of varying emissions profiles for delayed coking units.

4.2.1 Section 5.3.3 Methodology Rank 3 for Delayed Coking Units

EPA's proposed Methodology Rank 3 (Proposed Rank 3 Method) Equations 5-2 through 5-4 rely on a mass of steam approach developed by the South Coast Air Quality Management District (SCAQMD). Further, Equation 5-5 directs the user to rely upon emissions factors for delayed coking units for pollutant "i" in Table 5-5 that are provided in units of pounds per 1,000 pounds (lbs/1000 lb) steam. Several aspects of this method need improvement as described below.

The values in Table 5-5 were developed using test data obtained over the last several years. It should be noted that the raw data used to derive emission factors included in Table 5-5 was not reviewed for statistical outliers as recommended by EPA's procedures for developing emissions factors. EPA has not fully evaluated data quality when developing the emission factors in Table 5-5. Furthermore, facilities that have conducted coker vent testing will have more relevant compound concentration data, which could be used in conjunction with Equation 5-5. EPA should allow for use of site-specific test data in lieu of the values in Table 5-5.

Additionally, Proposed Rank 3 Method is believed to be overly conservative and would lead to an overestimate of emissions. Specifically, API believes the Proposed Rank 3 Method overestimates the amount vented from the coke drum during venting for the following reasons:

1) The Proposed Rank 3 Method significantly overstates the amount of steam that is generated upon opening the coke drum to the atmosphere, because it makes the following incorrect assumptions:

   a. There is a uniform temperature throughout the entire coke bed and the quench water at the time the vent is started,

   b. that the amount of heat evolved is derived from cooling the entire mass of coke and quench water from that initial uniform temperature to 212°F,

   c. 10% of the heat removed from the coke bed and quench water is dissipated through the coke drum and overhead metal and the balance of the heat removed from the coke bed (90%) goes into steam generation, and

   d. 100% of the water in the coke drum at the time of venting is at its bubble point (i.e., all the heat evolved goes toward affecting evaporation and none of it is used in heating the water to the boiling point).

These assumptions are not supported by the experience of API members. Coker process experts report significant temperature gradients through the coke mass and the quench water throughout the drum. The water and coke in the bottom of the drum is at approximately the temperature of the incoming quench water (much less than 212^{o}F). Therefore, the assumption that the entire mass must be cooled overstates the heat generated significantly.

Furthermore, our experts disagree that all of the water is at the bubble (boiling) point. On average, the majority of the water in a coke drum is below the bubble (boiling) point temperature. Thus, much less steam is evolved than is calculated by the model in cooling the portion of the bed that is above 212°F. This is because some of the heat removed from the coke after the drum is opened to the atmosphere goes into raising the temperature of the cooler water and coke in the drum rather than going into steam generation.

2) The Proposed Rank 3 Method underestimates the mass of coke in the drum and overestimates the porosity of that coke.

By assuming a coke bed density of 42.2 lb/ft^{3,13} versus a typical density of 52 – 60 lb/ft^3, the Proposed Rank 3 Method overstates the void fraction in the coke bed, resulting in overestimating the amount of quench water that could be in the bed and underestimating the mass of coke and thus the potential heat that will be generated by cooling the bed to 212°F. In addition, the model assumption that all the void space is filled with water is not supported by available information, such as discussed above. If the model void fraction is decreased from 0.5 to 0.35, while maintaining the EPA pure coke density of 84.3 lb/ft^3 (a value in line with

---

[13] In the Proposed Rank 3 Method Equation 5-3, the coke bed density is obtained by multiplying the density of coke (taken as 84.3 lb/ft^3) by the coke bed porosity factor (taken as 0.5 in the Proposed Rank 3 Method), which yields a coke bed density of 42.15 lb/ft^3.

available data for green coke) to represent a typical coke bed density of around 55 lb/ft^3[14], Equation 5-3 yields a more accurate representation of the void space and coke mass.

3) <u>EPA overestimates the emissions because it assumes the coke and quench water for the average coke drum is at a much higher temperature than indicated by correlation to the overhead pressure.</u>

The Proposed Rank 3 Method assumes that the entire coke bed and all of the quench water are at the overhead temperature of the coke drum in developing the heat balance. Overhead temperature is not an accurate reflection of drum overhead pressure and does not reflect the temperature of steam vapor saturation for a given drum pressure. This is because superheated steam is used for safety valve and instrument purges and because the hot metal of the walls have a significant impact on the gas near the metal walls. For the purposes of emission estimates, the overhead temperature and coke bed temperature should be taken at the saturation temperature of steam at the indicated overhead pressure.

Any finalization of updates to the emission estimation methodology should be in done in AP-42, following the full procedure for such updates. API recommends the following adjustments to Methodology Rank 3 to improve its accuracy: (1) update the mass of steam calculations to represent the overhead temperature and coke bed temperature using the saturation temperature of steam at the indicated overhead pressure, (2) update the coke density to provide a more accurate representation of the void space and the coke mass, and (3) allow the use of site-specific test data in lieu of values in Table 5-5.

4.2.2 Section 5.3.3 Methodology Rank 4 for Delayed Coking Units

For the reasons discussed below, Methodology Rank 4 should be removed entirely. Facilities that have coker steam vent data can use Methodology Rank 3 (at the time when it is appropriate to finalize) with the option to use their own site-specific test factors in lieu of the factors in Table 5-5.

Hydrocarbons have a very low solubility in water. The proposed Methodology Rank 4 could greatly overstate the concentrations that would be expected in the bulk water in relation to the overhead drum vent.

The drilling process should have negligible emissions unless there is ongoing chemical reaction, formation of coke, or tail gas and liquid hydrocarbons due to uncompleted reaction when feeding the coke drum. Drilling emissions cannot be directly measured but can be correlated to hot spots, coke drum blowbacks, coke dust incidents and odors. Because these conditions are so undesirable from a safety and community perspective, these occurrences have been minimized and thus it is reasonable to assume the coke cutting contribution to the overall emissions is quite small.

Methodology Rank 4 requires facilities that conduct steam vent testing and initiate draining within 1 hour or less following the start of venting to also assess emissions from drained water. EPA has

---

[14] In calculating the coke bed mass, the Proposed Rank 3 Method multiplies the density of coke by the coke bed porosity factor. Since the porosity factor represents the void volume, not the portion of the volume that is coke, the calculation should multiply by 1 minus the porosity factor.

provided no basis for the 1 hour time period, where the threshold was not supported with any technical rationale.

Furthermore, there are several deficiencies to using the Refinery Wastewater Emissions Tool (RWET) weir model to approximate water draining from a coke drum into a coke pit. Many assumptions must be made that do not reflect the design of most coking unit drain systems. Using the RWET equalization tank model with partial aeration to reflect the operation of the coke pit is not reflective of reality and it is very difficult to approximate an appropriate aerator size that is required by the model inputs. In addition, pollutant concentrations are required as model inputs and very few sites have data available. Either sites would have to sample the drain stream and use site-specific data or EPA would be expected to provide default pollutant concentrations.

4.2.3 Section 5.3.3 Methodology Rank 5 for Delayed Coking Units

For the reasons discussed below, Methodology Rank 5 should be removed entirely. The Refinery Protocol provides emissions factors on a pounds per vent cycle basis based on historical test data obtained over the last several years. In developing these factors in Table 5-5, no adjustments are made for differences in coker drum size, design, vent pressures or other operational data. Additionally, EPA has not assessed how delayed coking units will be impacted by the relatively recent changes to NSPS Ja and the proposed changes to the Maximum Achievable Control Technology (MACT) requirements under the Refinery Sector Rule. The lowering of the allowable drum pressure is expected to reduce emissions to the atmosphere. The test data behind the factors for proposed Methodology Rank 5 do not reflect these changes and therefore will not accurately represent emissions.

Lastly, it should be noted that the raw data used to derive emission factors included in Table 5-5 was not reviewed for statistical outliers as recommended by EPA’s procedures for developing emissions factors.

4.3 Section 5.4.1 Emissions Estimation Methodology for Catalytic Reforming Units

See Section 3.2.2 of these comments for a detailed discussion of the CRU THC Emission Factor developed for AP-42.

The emission factor for VOC in Table 5-6 of the Refinery Protocol is listed as 0.40 lb/1,000 bbl, which is identical to the THC factor listed in Table 5.1-2 in AP-42. These classes of compounds should not be used interchangeably. **The entry in Table 5-6 for the emission factor for VOC should be revised to THC, if appropriate**.

4.4 Section 5.5.3 Methodology Rank 5 for Sulfur Recovery Plants

See Section 3.3 of these comments for a detailed discussion of the SRU NOx, CO, and THC Emission Factors developed for AP-42.

The first paragraph of Section 5.5.3 of the Refinery Protocol says that SRU CO, NOx, and VOC EFs come from the ICR component 4 data, but Section 8.13 of AP-42 lists many test reports, not just the

ICR stack tests. **EPA must clarify the sources of the SRU CO, VOC, and NOx emission factors in the Refinery Protocol**.

Table 8.13-2 of AP-42 has an emission factor for THC from controlled sulfur recovery plants, but the Refinery Protocol lists the same emission factor for VOC in Table 5-7. These classes of compounds should not be used interchangeably. **The entry in Table 5-7 for the emission factor for VOC should be revised to THC, if appropriate**.

4.5 Section 6 Flares

See Section 3.4 of these comments for a detailed discussion of the Industrial Flare NOx, CO, and VOC Emission Factors developed for AP-42.

In Section 6, the third and fourth sentences of the second paragraph indicate that the DIAL technique provides a direct measurement of flare emissions, but only as a snapshot. While DIAL has some use as a research tool, it is very limited in the emissions it can identify, much less quantify, and is difficult to employ even for short term use. Thus, **we believe these sentences and the related following sentence overstate DIAL's value and they should be deleted.**

Review of Proposed Revisions to Sections 5.1, 8.13, and 13.5 of AP-42 and the Draft Emission Estimation Protocol for Petroleum Refineries - Version 3.0

Appendix 1

Comments on Industrial Flare NOx, CO, and VOC Emission Factors

CleanAir

CleanAir Engineering
500 W. Wood Street
Palatine, IL 60067-4975
800-627-0033
www.cleanair.com

A Review of EPA's Draft AP-42 Emission Factor Revisions for Flares

Prepared for American Petroleum Institute
December 19, 2014

By Scott Evans

Table of Contents

Introduction/Background

The United States Environmental Protection Agency (US EPA) recently released draft revisions to its emission factor document AP-42 affecting refinery sources. Included with this draft are proposed changes to flare factors. This review is an analysis of basis and validity of these changes.

The documents reviewed for this paper include the following:

Draft EF Development Report.pdf
Part of Draft Background Documents zip file
http://www.epa.gov/ttn/chief/ap42/ch13/bgdocs/db13s05_8-19-14.zip

draft_report_ef.pdf
http://www.epa.gov/ttn/chief/consentdecree/draft_report_ef.pdf

draft_report_review.pdf
http://www.epa.gov/ttn/chief/consentdecree/draft_report_review.pdf

dc13s05rlso_8-19-14.pdf
http://www.epa.gov/ttn/chief/ap42/ch13/final/dc13s05rlso_8-19-14.pdf

Comments and Questions as of 10/02/14
http://www.epa.gov/ttn/chief/consentdecree/Comments_as_of_Oct_2_2014.pdf

Attachments to Comments and Questions as of 10/02/14
http://www.epa.gov/ttn/chief/consentdecree/Comments_as_of_Oct_2_2014_Attachments.zip

Relevant background experience of the author and firm include planning and execution of the Marathon tests at Texas City and Detroit and the Flint Hills Resources tests on the two flares at Port Arthur. Additionally, the author and firm have collaborated with Robert Spellicy, PhD of IMACC over the preceding five years to refine and develop the Passive Fourier Transform Infrared (PFTIR) test methodology. In particular, Scott Evans co-chairs the ASTM committee tasked with method development on the standard instrument method.

Table 1 shows proposed revisions to flare factors.

Table 1: Comparison of Existing and Proposed AP-42 Flare Emission Factors

Pollutant	Existing Factor	EPA Draft Factor
Total Hydrocarbons (THC)	0.14 lb/MMBtu	0.14 lb/MMBtu
Soot	0-274 μg/m^3	0-274 μg/m^3
Speciated Organics	Various Limits	None
Volatile Organic Compounds (VOC)	None	0.55 lb/MMBtu
Carbon Monoxide (CO)	0.37 lb/MMBtu	0.34 lb/MMBtu
Nitrogen Oxides (NOx)	0.068 lb/MMBtu	2.9 lb/MMBtu

The factors for two pollutants (CO and NOx) were revised and a new pollutant (VOC) was added.

The proposed new factors for CO and NOx are based upon an average of the existing factors and factors derived from new test data. There is no existing VOC factor, so the proposed new factor was developed solely from new test data. Except for data collected from one test conducted with Differential Absorption Lidar (DIAL) technology[1], which were used for the VOC factor, all new data were taken from tests conducted with Passive FTIR (PFTIR) technology.

It is worth noting that the PFTIR technology was developed to measure flare combustion efficiency. It was not designed for and the methods were not developed to measure absolute concentration or mass emissions of flare combustion byproducts such as CO, NOx and VOC. PFTIR is an open path technology. As such, PFTIR data are reported on a ppm x pathlength basis, rather than as an absolute concentration (e.g., ppm). The pathlength of concern here is the cross-section of the flare plume at the point of measurement, which is unknown. Therefore, since no absolute pollutant concentrations are reported, it is not possible to convert PFTIR data to mass emission rates (as was done with these factors) without making technical assumptions and performing data manipulation that was not anticipated in the development of the PFTIR method.

Finally, and most importantly, the PFTIR test reports tracked the development of the technology and associated method. Thus the reports provided data that was uncalibrated and unqualified as well as calculations that were not used in final data analysis because the data set was used to support technology and method development.

This review focuses on the proposed flare factors and background documents and is presented in three sections:

1. <u>Data Quality</u>– Comments on the quality of data used from the PFTIR tests.

---

[1] DIAL test data was used only in the development of the VOC factor

2. Data Analysis –Comments on potential errors identified in the evaluation and processing of the PFTIR data.
3. Emission Model – Extrapolation of PFTIR data to lb/hr or lb/MMBtu emission rates.

Data Quality

An emission factor is only as good as the data used to create it. The use of reliable, high quality data is essential. Unfortunately, some of the data used to update the flare emission factors, particularly the NOx factor, do not meet minimum data quality criteria.

PFTIR Not Calibrated for NO or NO_2

Calibration of the measurement instruments used for data collection is fundamental to the generation of reliable data. Calibration would have been required for both the NO and NO_2 measurements made at each of the PFTIR flare tests in order for those tests to provide reliable, quantitative NOx data. However, none of the PFTIR flare tests included calibration for either NO or NO_2. NOx was not considered in those tests because it does not play a role in the determination of combustion efficiency. NOx values are included in the flare reports only because they are part of the standard PFTIR software reporting format. It was an unfortunate error that these uncalibrated data were not removed prior to the issuance of the flare reports.

Quantitation of a given species from spectral data with PFTIR requires two steps. First, the spectral region corresponding to the compound in the infrared spectrum must be identified. Only selected portions of that region free from interferences (such as water) are used in the analysis. Often, this requires fine-tuning of the selected spectral bands to avoid such interference. Water is a significant interferent in the infrared and particularly in the spectral region of NO and NO_2 detection. Although the PFTIR analytical method used during the tests had a general region for NO and NO_2 defined, it was never fine-tuned to avoid interferences since it was not used for the tests. Most of the data used for the NOx emission factor were generated from testing on steam-assisted flares. Thus, the water content of the flare plume is quite high, in addition to other sources of water and humidity present in all cases. It is likely that much of what is reported as NO or NO_2 is, in fact, water vapor.

The second step in accurate PFTIR measurement is calibration. A NIST traceable calibration is performed for each PFTIR test employing a “hot cell”. This procedure entails flowing NIST traceable calibration gas through a heated quartz/glass cell with transparent ends. The PFTIR is aimed at the transparent end of the cell, where measurements are performed on the known concentration of gas. The concentration of the gas is varied and the procedure is repeated at least twice more for each species of interest. A calibration curve for the PFTIR is then constructed. This critical procedure was never performed for either NO or NO_2.

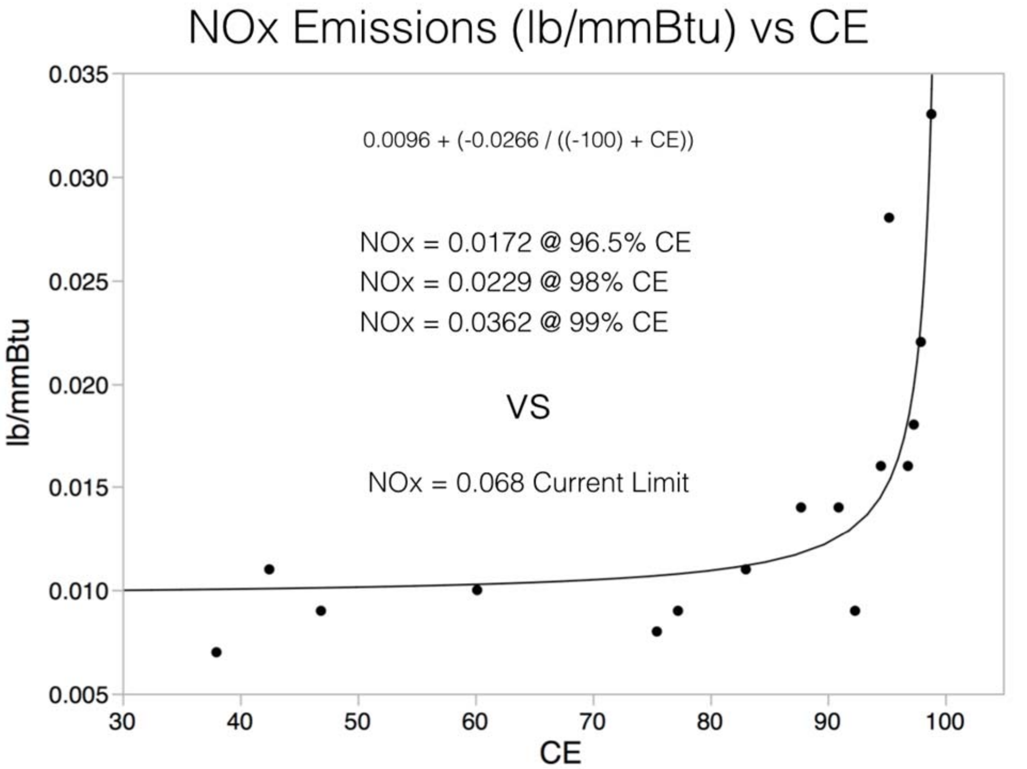
Since the PFTIR was never calibrated for either NO or NO_2, the data are not valid and cannot be used to determine a NOx emission factor. Proper calibrations were performed for CO and for the major constituents comprising "VOCs".

Other Available NOx Data

While data from the PFTIR tests may not be used for emission factor development, other flare NOx data of excellent quality are available for use in updating the NOx factor. These data are discussed below.

TCEQ Extractive Test

During the 2010TCEQ test extractive sampling was performed in addition to the PFTIR testing. While there were issues with extractive NOx calibration during the propylene test runs, good NOx data was collected during the propane runs. The extractive instruments were properly calibrated for NOx during the propane test runs. The NOx data are available from this test and described in the literature.[2] This data is shown in Figure 1 with a least squares curve fit.


NOx Emissions (lb/mmBtu) vs CE

0.0096 + (-0.0266 / ((-100) + CE))

NOx = 0.0172 @ 96.5% CE
NOx = 0.0229 @ 98% CE
NOx = 0.0362 @ 99% CE

VS

NOx = 0.068 Current Limit

Source: TCEQ 2010 Flare Test Extractive Data - propane steam flare tests (NOx/Total C basis)

Figure 1. Emission factors derived from TCEQ extractive flare test (propane test runs)

---

[2] Torres, V. M., et. al., "Emissions of Nitrogen Oxides from Flares Operating at Low Flow Conditions," Industrial Engineering and Chemistry Research, American Chemical Society, **2012**, *51* (39), pp 12600–12605

Note that at 98% combustion efficiency, the NOx factor determined using this data is about one-third of the current factor. The NOx factor corresponding to 96.5% combustion efficiency is lower still. This suggests that a revision downward of the current factor is supported by the higher quality data.

IFC Data

The International Flaring Consortium (IFC) also has available data.[3] These test results for NOx show factors ranging from 0.0093 lb/MMBtu to 0.093 lb/MMBtu.

Note that the valid data from recent flare tests indicates the NOx factor should likely be lower than the current value – not 40 times higher.

Data Analysis

Once good data are collected, proper analytical procedures must be used to convert the data from its raw format into an emission factor. Our analysis shows that the analytical procedures used in the development of these draft emission factors are problematic.

PFTIR Minute Data vs. Run Average Data

The proposed revisions to the AP-42 flare factors are based upon an analysis of PFTIR minute data instead of run average data. This approach might be amenable to data collected with a CEMS instrument on a stack but is not applicable to PFTIR data collected from a flare plume.[4]

The PFTIR generates a data point once each minute during the flare measurement process. Every minute, the concentration x pathlength values for each pollutant of interest are recorded. PFTIR measurements of flares require data acquisition periods (runs) of approximately 10-20 minutes. This is due to the spatial and temporal fluctuations of combustion efficiency and pollutant concentrations along the plume. All minute data points collected during a run are averaged for each pollutant. These run average values are used to calculate flare combustion efficiency.

The spatial and temporal fluctuations arise because a flare operates with a turbulent diffusion flame. The flame is dynamic and undergoes complex combustion reactions over a continually moving and changing reaction space. At all times, the flare flame and plume consist of fuel-rich regions, stoichiometric regions, and fuel-lean regions, giving rise to combustion efficiencies within the reaction space of the plume that range over all possible values from 0% to 100% at any given point in time.

Furthermore, the rich, lean, and stoichiometric regions are shifting relative to each other and passing through the PFTIR field of view. Often an eddy of fuel-rich,

---

[3] IFC Flare Test Facility – Results, October 2010, Section 6.3 Nitrogen Oxides, pp. 71-73

[4] Evans, S., and Spellicy, R., “EPA PFTIR Data Analysis Critique,” 2014. Submitted to Docket EPA-HQ-OAR-2010-0682

incompletely combusted gas will break away from the base flame due to turbulence and drift into the PFTIR field of view. While PFTIR operators attempt to avoid these eddies, it is often difficult in flare plumes with the high turbulence characteristic of low velocity flames. In any given minute, the wind may, for example, have twisted the plume causing the PFTIR to sample from an area of incomplete combustion.

PFTIR flare combustion efficiency measurements are made with the instrument aimed at the flare plume in an area far enough from the flame tip that all combustion reactions have ceased. However, due to varying ambient conditions, the plume is often moving rapidly. The PFTIR must be continually aimed to track the optimal measurement location. This area is constantly changing from very narrow to very wide depending on the angle relative to the PFTIR and the wind velocity. Because the plume is non-uniform, a representative measurement must spatially sample the plume in its entirety. This is accomplished through both aiming technique and averaging.

As a result of the factors discussed above, the products of combustion such as CO_2, NOx, and CO are detected in varying amounts depending on the location of the measurement taken within the plume. PFTIR measurements are taken across a small cross-section the plume and require both spatial and temporal averaging to be representative of flare combustion chemistry.

Thus, any individual one-minute data point is not representative of a given flare parameter, whether that parameter is combustion efficiency, NOx or any other measured value. Only an average of measurements over time can characterize the flare. During the PFTIR flare tests, every effort was made to operate the flares under stable conditions so that a representative average could be obtained. In addition, great care was taken to select an appropriate averaging interval. For recent flare testing, EPA has required facilities to use a 20-minute averaging period, which serves as a guideline for an appropriate averaging interval. Average intervals below approximately 10 minutes in duration, as used in the calculations for the draft emission factors, do not provide representative values for flare plume parameters.

Minute Data Censoring

The most significant impact on the draft emission factors result from EPA's selective censoring of the minute data. Not all minute data from each run was used in the factor analysis. An example of how this approach affects the final factors may be found in the Flint Hills AU NOx data. During the testing on the AU flare, 45 runs were conducted totaling 1,163 minutes of data. The emission factor analysis uses only 638 of these data points. The very high NOx factor calculated from this data is the result of just 5 one minute data points. The highest of these was 4,464 lb/MMBtu of NOx. This is obviously physically impossible and cannot be a real value. The effect of these high values is magnified because the lower values that tend to be a counterbalance to these high values were not included in the analysis. Upon further examination of these points, they are clearly the result of invalid CO_2 values and should have been discarded as outliers. This improper application of the outlier procedure is discussed further below.

Aggregate Analysis

In conducting the data analysis for these factors, selected data across all runs and conditions was aggregated together from each flare. Taking this approach masks important quality characteristics of the data.

A fundamental assumption of the approach used for the development of these emission factors is that the pollutant emission rate can be predicted as a function of CO_2. This is explained in more detail in the Emission Model section below. In order for this approach to make sense, a correlation between the pollutant and CO_2 must be present in the data[5]. If the data shows no correlation, this approach cannot be used.

Analysis of the PFTIR one-minute data was conducted on an aggregate of data, undifferentiated with respect to specific conditions and runs. This approach makes it impossible to evaluate whether any relationship between the pollutant and CO_2 exists. As an example of this, Figure 2 shows CO vs CO_2 plots for the Marathon Detroit test. The first graph shows all data from all runs. It is difficult to discern any underlying relationships in the data. The next two graphs show example data from two specific runs. A clear linear relationship is revealed by looking at the run average data. Note that the slope of the correlation line is not the same for these two conditions. This is highly relevant to the determination of accurate emission estimation from PFTIR data but is completely ignored in EPA's analysis. The importance of the correlation line slope is explored further below.

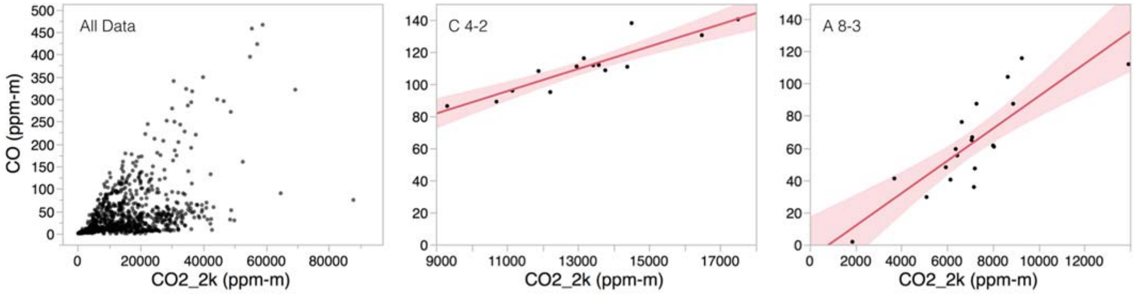


Figure 2. Aggregate Analysis vs Run Analysis

Averaging CO_2 Data

Because absolute concentrations of pollutants are not directly measured by the PFTIR, pollutant mass emissions are estimated from the pollutant to CO_2 ratio.

---

[5] Herndon, S; et. al, "Application of the Carbon Balance Method to Flare Emissions Characteristics," Industrial and Engineering Chemistry Research, American Chemical Society, 2012, 51 (39), pp 12577-12585

Therefore, accurate measurement of CO_2 is critical to converting the data from ppm x pathlength to an estimated lb/MMBtu.

The PFTIR collects spectra across a broad swath of the infrared region from around 4,000 to 400 wavenumbers (cm^{-1}) (equivalent to wavelengths between 2.5 and 25 μm). Certain compounds have unique spectral characteristics that allow identification. For example, CO_2 exhibits spectral characteristics in three distinct regions: around 2,000 cm^{-1} (2k); around 1,000 cm^{-1} (1k); and around 765 cm^{-1}. However, these three regions are not equally interpretable under all conditions. For example, the 1k region suffers from water interference as well as possible interference from organics. A CO_2 signal can be obtained in this region, but it has been found to be generally unreliable due to these interferences, particularly when dealing with a steam-assisted flare. The data are acquired in the PFTIR measurement, but are seldom used in data analysis for those reasons.

Typically either the 765 or 2K regions are used for CO_2 quantification. The 765 region offers strong signal strength and lack of interference. However, it is at the edge of the detector range and occasionally becomes too detection limited and is thus not usable. In the 2K region, signal strength is less intense than for 765 but it does not suffer from the significant interferences the 1k region does. Ultimately, the choice of which region represents the best measurement for CO_2 is made by a PFTIR operator trained in spectroscopic analysis. There is no statistical algorithm or other "automated" technique available at this time to select the best measurement region. The infra-red regions selected during the measurement program at each flare are ones used to report the CO_2 measurements in the flare reports and are the only correct regions to use.

The analysis conducted for the development of the proposed emission factors did not use the selected CO_2 regions. Instead, EPA averaged the data acquired in the 765 and 2K CO_2 regions. This procedure introduces error into calculated emission factors. The CO_2 spectral region used for each flare was selected because it results in the most reliable data. Averaging in the unused spectral region data only degrades the data quality and reliability of the resulting emission factor.

Figure 3 shows the errors introduced when averaging CO_2 values collected in different spectral regions. Results using the correct spectral regions were compared with results using EPA's averaging procedure. Positive errors result in the calculated emission from that data point being biased high. For negative errors, the calculated emission will be biased low.

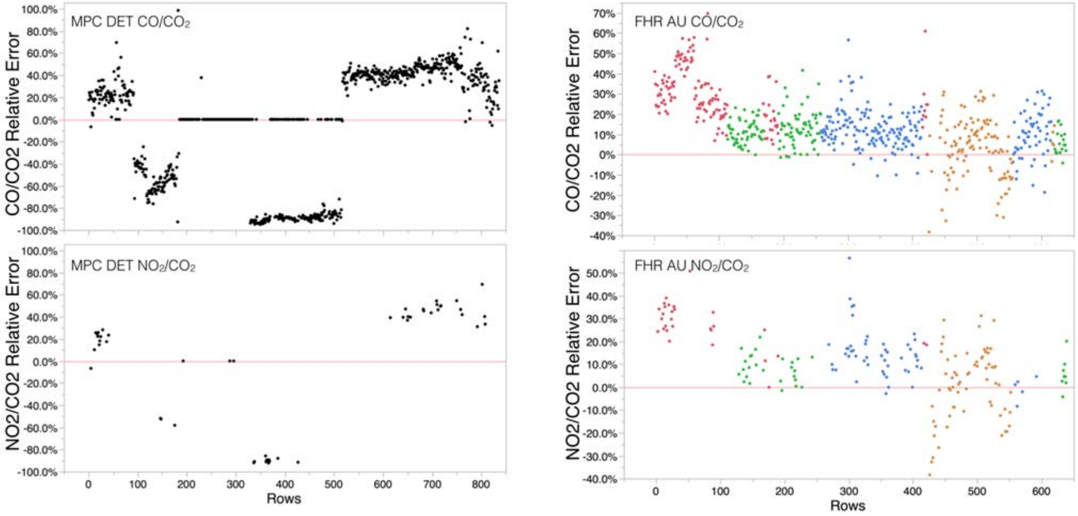


Figure 3. Errors introduced by CO_2 Averaging. AU data (what is AU?) colored by condition (A, B, C, and D). Data points above the zero line indicate a positive bias. Data points below the zero line represent a negative bias.

The PFTIR data analysis methodology was validated during a double blind test of extractive vs. passive flare combustion efficiency measurements during the 2010 TCEQ test. This validated methodology did not include CO_2 averaging. By employing this CO_2 averaging approach EPA has deviated from the validated PFTIR method used in the flare reports, which are the source of data used in this emission factor development

In summary, a determination of which spectral region is applicable for an individual test run is made on-site by a spectroscopist. The value from the chosen spectral region is used for the balance of the analysis of a given run. This analytical approach was disregarded in the development of the proposed flare emission factors, which instead averaged data from two of the available spectral regions for each data point.

Accurate CO_2 measurements are critical for the determination of reliable emission factors derived from PFTIR data. As stated above, the methodology employed to develop the proposed emission factor revisions relies on the pollutant to CO_2 ratio. Biases in the CO_2 measurement affect all three factors: VOC, NOx and CO.

Adjustment of CO_2 Data

An “Adjusted CO_2 value” column was found in the spreadsheets EPA provided as supporting documentation. This adjusted value appears to filter data exceeding an EPA-defined error threshold. The rationale for this adjustment is unclear and is not compatible with the data analysis algorithms developed for the validated PFTIR method. Any additional data filtering or adjustment beyond what is already included in the validated PFTIR method may result in unreliable emission factor estimates.

Elimination of CO_2 1K data from INEOS test

The INEOS test predated detector advancements that afforded the IR spectral data choices of the current configuration. Thus, it was one of the few instances where 1k CO_2 data was used for the analysis. Because of the unilateral application of an average of 765 and 2k data, the analysis completely dismisses the 1k data for this test set. The spreadsheets in the supporting documentation do not list 1K CO_2 data from INEOS. So in the case of the INEOS factor, the proper data was not used for the analysis, as part of an average or otherwise.

Use of Unweighted Combustion Efficiency (CE)

The combustion efficiency parameter is used in the calculation of all three revised flare factors. The data spreadsheets from the PFTIR testing provided in the supporting documentation have combustion efficiency tabulated in two ways referred to as “unweighted” and “weighted.” The weighted combustion efficiency accounts for the number of carbon atoms in each molecule of the compounds detected in the flare plume. This is necessary to determine how much of the incoming carbon is converted to CO_2. The unweighted combustion efficiency is does not take the number of carbon atoms into account and is always higher than the weighted combustion efficiency. For example, 10 ppm-meters of ethylene is 20 ppm-meters of carbon since ethylene has two carbon atoms. This carbon weighting is necessary in the calculation of combustion efficiency to maintain the carbon balance.

The PFTIR report data spreadsheets provided both weighted and unweighted CE simply as a comparison. The unweighted value does not have any analytical value is never used for any calculation in the PFTIR flare reports. It is not representative of the actual combustion efficiency of the flare.

The analysis EPA conducted in the development of the proposed revised emission factors employs the unweighted value. The use of the unweighted values results in emission factors that are biased high by an amount proportional to the difference between the unweighted and weighted efficiencies.

It may be unclear as to why a higher CE value results in emission factors biased high. Intuition would indicate that as CE rises, pollutant emissions are reduced. The answer lies in the method used to convert ppm x pathlength data into mass emissions. As explained in the Emission Model section below, because the PFTIR does not measure absolute concentration, pollutant emissions are estimated as a function of CO_2. As CE rises, the flare plume CO_2 concentration rises. Therefore, when the pollutant/CO_2 ratio is multiplied by a higher CO_2 value, the calculated pollutant emissions are also higher.

It is unclear why the unweighted CE value was used in the emission factor analysis; however, its use was affirmed in a response to a comment received on these draft emission factors[6]:

> *"We chose to use the unweighted CE where it was available." – Response to Gary Fischman, p8*

Data Filtering with Unweighted Combustion Efficiency (CE)

Of perhaps more significant consequence are the errors introduced from the unweighted combustion efficiency being used to filter data included in the emission factor analysis. All minute data points with an unweighted combustion efficiency >96.5% were included in the emission factor evaluation. However, since unweighted CE is higher than weighted CE, this practice results in many low CE data points (as properly determined with the weighted CE) being included in the analysis.

Also, as stated above, individual one-minute data points are not representative of actual flare combustion efficiency. Only the run averages provide a true indication of flare performance. Filtering the data by unweighted CE results in the inclusion of many data points from lower efficiency runs being in the analysis. This could lead to significantly different emission factors compared to use of weighted CE. Figure 4 shows a comparison of the unweighted one minute data points used for factor development (in the blue shaded area) and the run average efficiencies reported in the PFTIR testing.

Note that virtually all the high combustion efficiency run data are captured, but also captured are a large number of data points where the run average weighted combustion efficiency is less than 96.5%. In some cases, such as the AU A 3.0(2) run, almost every data point in the set was included in the analysis even though the run itself had a weighted combustion efficiency < 96.5%.

---

[6] Comments and Questions as of 10/02/14
http://www.epa.gov/ttn/chief/consentdecree/Comments_as_of_Oct_2_2014.pdf

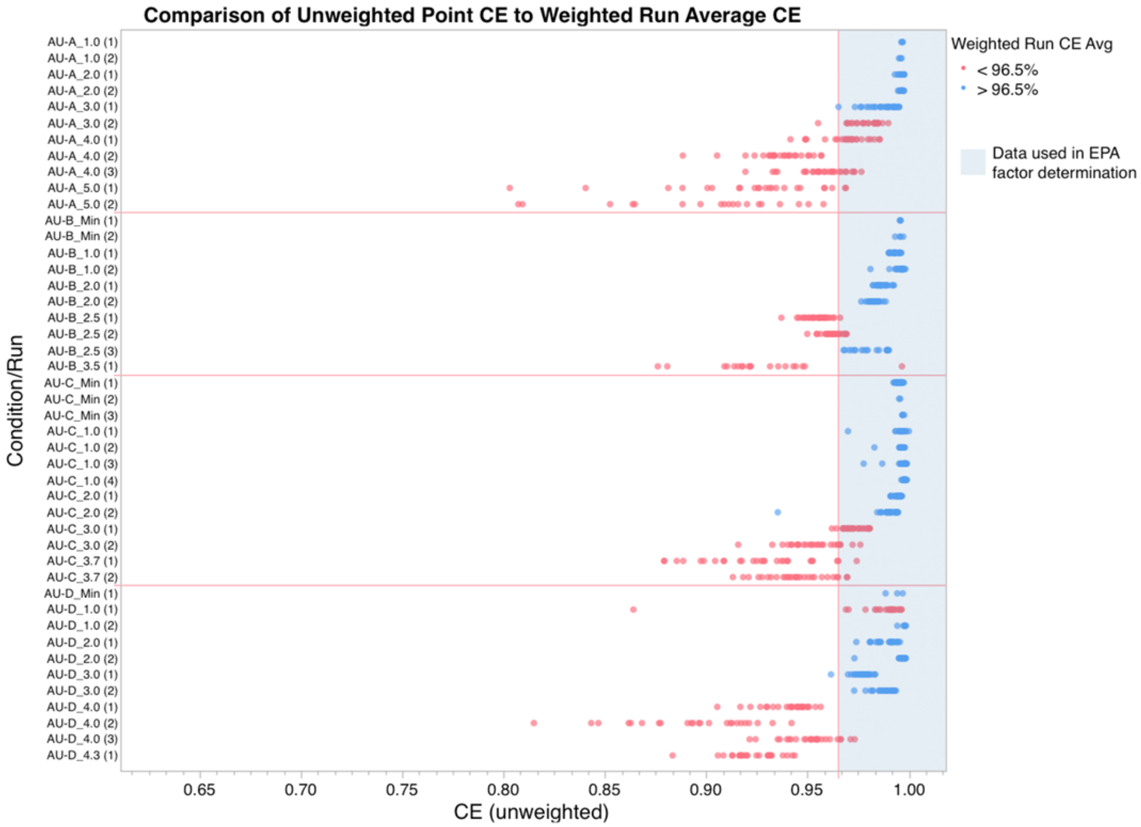


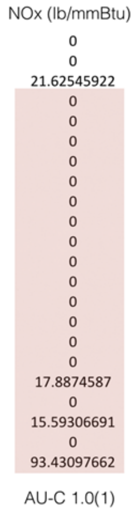
Figure 4. Unweighted point combustion efficiency values compared to weighted run averages

Another example of the problems with this approach can be found in the data from the FHR AU flare run AU C 3.7(1). The minute data point AU C 3.7(1) 10/26/10 5:28 PM has a calculated NOx emission rate of 4,464 lb/MMBtu by the analysis employed in the emission factor revision methodology. While this value is not physically possible, it is illustrative of how single data point inclusion from the unweighted combustion efficiency is problematic. Because the unweighted combustion efficiency associated with this point is > 96.5%, the point was used in the AU NOx emission factor determination. However, the weighted CE for this point is < 96.5% so the point would have been excluded if weighted efficiency were applied. Eliminate of this single point would have significantly lowered the resulting emission factor. Moreover, the run average weighted efficiency associated with this point is <96.5%.

The use of unweighted combustion efficiency values has a significant impact on the results of the emission factor analysis. Use of these values bias the emission factors high and is not technically supported.

Inclusion of Null Data

Inspection of the data shows that many of the values reported for certain pollutants are zero – particularly in the case of NO and NO_2. For the Detroit data, 94% of the data used to determine the NOx emission factor were zero. For FHR AU, 71% were zero.



NOx (lb/mmBtu)
0
0
21.62545922
0
0
0
0
0
0
0
0
0
0
0
0
0
0
17.8874587
0
15.59306691
0
93.43097662

AU-C 1.0(1)

Figure 5. Zero Example.

In a response posted on the emission factor website[7], EPA states:

> *"We included the zeros as we believe that they represent actual measurements, similar to how other instrumental methods will fall to zero or below zero (because of instrument drift) at times." – Response to Gary Fischman, p10.*

The zero data are unlikely to represent actual emissions values and should not be included. In fact, they are an indication of poor data quality for the run. Figure 5 shows a segment of NO_2 data from the Flint Hills AU flare run AU C 1.0(1). This snippet of data is typical of many others.

In this example, if this data is to be believed, the highly efficient (>99%) combustion process (i.e., hot) on this flare produces no NOx at all for 14 minutes. Then NOx emissions jump to almost 18 lb/MMBtu and back down to zero within one minute. Then, emissions jump to about 16 lb/MMBtu and down to zero within a minute. Finally, the NOx emissions from the flare jump from zero lb/MMBtu to 93 lb/MMBtu – a value that is likely physically impossible. Furthermore, these fluctuating NOx values occur while the flare is operating at a steady, consistent condition. This scenario is not technically sound and does not represent true flare emissions.

The above data segment illustrates that these zeros are not likely actual data. The PFTIR software reports a data point as zero for various reasons. If a QA/QC check is failed, the value may be reported as zero. Remember that the NO and NO_2 data were not calibrated for any of the PFTIR flare tests. Many of these zeros are likely a result of the lack of calibration.

There are other reasons data may be reported as zero in the PFTIR report. A poor fit between the sample spectrum and reference spectrum results in reported zeroes. Data below the detection limit may be reported as zero. If the PFTIR is aimed too close or too far from the flame the result may be reported as zero.

The decision regarding whether or not to consider a zero in the PFTIR report as actual data is determined by analysis of the data by a qualified spectroscopist. In the

---

[7] Comments and Questions as of 10/02/14
http://www.epa.gov/ttn/chief/consentdecree/Comments_as_of_Oct_2_2014.pdf

case of NO and NO_2, this evaluation was never performed since the data was never intended to be used. Decisions for other pollutants were made when analyzing the PFTIR data in the flare reports. Second-guessing these decisions by assuming all zeros represent actual data leads to less reliable results.

Other Data Analysis Issues

There are also other calculation errors in the spreadsheets. The 88 lb/MMBtu CO factor for the Marathon Texas City flare is the result of a spreadsheet reference error. The calculation references CO_2 values instead of CO values. The VOC factor for the Texas City flare is also miscalculated.

EPA did not use any of the measured PFTIR data for the Flint Hills LOU flare. Instead, they calculated CO_2 concentration in the plume by a series of equations that that are unexplained and unsupported in the documentation.

The supporting documentation supplied by EPA includes a series of equations to convert PFTIR data to units of mass emissions (lb/MMBtu). However, the spreadsheets provided by EPA use an entirely different set of equations. One example of the many differences is that the spreadsheets make use of a term labeled “Exhaust Gas Flow” to calculate the emission factor. This term is never mentioned in the supporting documentation nor does it appear in the equations included in the supporting documentation. EPA makes no attempt to explain the difference in these equations nor does it provide evidence that the two approaches are equivalent.

Emission Model

As mentioned above, the PFTIR does not measure absolute concentration. The PFTIR is an open - path measurement system. It senses and measures pollutants along the entire length of the path. PFTIR data is in units of ppm x pathlength also referred to as ppm-m where the m represents meters of pathlength. In order to use PFTIR data to calculate mass emissions such as lb/MMBtu, the units must be converted to ppm. In order to do this, the pathlength of the measurement must be known. The relevant path length for this application is the length of the measurement path through the flare plume. Unfortunately, this is not known. The plume dimensions are constantly changing during each measurement and the angle of the PFTIR measurement path to the plume is also changing as the plume moves in the wind.

However, it is possible to estimate mass emissions using a carbon balance technique. The details of the technique are found in Herndon[8] and Torres[9] and will not be described in detail here.

---

[8] Herndon, S; et. al, “Application of the Carbon Balance Method to Flare Emissions Characteristics,” Industrial and Engineering Chemistry Research, American Chemical Society, 2012, 51 (39), pp 12577-12585

As stated above, the PFTIR does not measure absolute pollutant concentrations. Absent any outside source of a given pollutant drifting into the path during the test, the only significant emissions originate from the flare plume. However, the measurement path through the flare plume is not constant. Wind conditions will affect the shape of the plume making it larger or smaller. This, in turn, affects the length of the measurement path through the plume. As the wind blows the plume away from and toward the PFTIR during the test, the measurement path will intersect the plume at more or less of an angle also resulting in measurement path fluctuations. Unless the dimensions of the plume are known for each minute of data (which is not the case for PFTIR analysis), an absolute concentration in ppm cannot be determined.

Calculations

In calculations of combustion efficiency (Equation 1), both the numerator and denominator of the ratio utilize the same units (ppm-m). The combustion efficiency is a ratio of plume measurements, where both measurements are simultaneously made on the same plume (and thus have the same path length) and so the lack of plume characterization is unimportant to this calculation.

$$CE = \frac{CO_2}{CO_2 + CO + HC} \qquad \text{Equation 1}$$

In their emission factor analysis, EPA adapted this ratio method with the objective of converting PFTIR data (ppm-m) to mass emission rates (lb/hr and lb/MMBtu). In order to do this, they propose that each pollutant can be expressed as a function of CO_2 produced in the flare plume. The analysis employs Equation 2 in expressing emissions as a ratio in terms of CO_2:

$$Pollutant\ ratio = \frac{Pollutant\ (ppm - m)}{CO_2\ (ppm - m)} \times \frac{MW_{pollutant}}{MW_{carbon}} \qquad \text{Equation 2}$$

The molecular weights convert from a volume ratio to a mass ratio specific to the pollutant of interest. Since the units cancel, the resulting ratio is unitless.

Using the measured carbon mass flow of the vent gas going to the flare (*Carbon In*) coupled with the measured combustion efficiency determined by the PFTIR, a mass emission rate is estimated as follows:

$$E_{lb/hr} = \ Carbon\ in_{lb/hr}\ \times\ CE\ \times\ Pollutant\ Ratio \qquad \text{Equation 3}$$

---

[9] Torres, V; et. al, “Emissions of Nitrogen Oxides from Flares Operating at Low Flow Conditions,” Industrial and Engineering Chemistry Research, American Chemical Society, 2012, 51 (39), pp 12600-12605

For example, 100 lb/hr of carbon flowing to a flare with a combustion efficiency of 98% results in 98 lb/hr of the carbon oxidized to CO_2, where 2 lb/hr is either uncombusted vent gas or some partially oxidized intermediate product. If the calculated pollutant ratio is, for example 0.001 parts pollutant to 1 part CO_2, then the pollutant mass emission rate is calculated as 0.098 lb/hr (100 x .98 x 0.001).

This is the process described by EPA in the Draft EF Development Report. For some reason, the calculations EPA provided in the spreadsheets do not match the equations in the Draft EF Development Report. EPA does not provide discussion or evidence that these two sets of calculations are equivalent.

Key Assumptions

There are two key assumptions that must be true in order for this proposed approach to be valid:

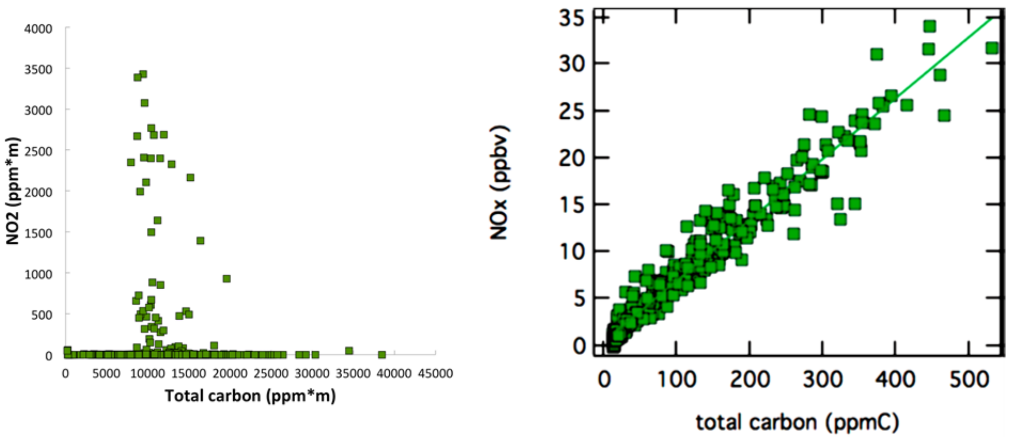
1. There must be a correlation between the pollutant measurement in ppm-m and the CO_2 measurement in ppm-m, at least under the same operating condition.

   The presumption inherent in this ratio approach is that there is an actual relationship between the concentration of the pollutant of interest in the flare plume and the concentration of CO_2. Such a relationship has been demonstrated in the case of combustion efficiency as demonstrated in the many combustion efficiency graphs found in the flare reports. However, EPA does not demonstrate the presence of a similar relationship between each pollutant and CO_2. This is critical since if the data do not show a correlation, the presumption that a pollutant can be predicted from the CO_2 concentration fails.

   Unfortunately, EPA's use of aggregated one-minute data and the censoring of that data in their analysis obscures such relationships if they do exist.

   As can be seen in Figure 2 above, data from individual runs (in this case for CO) can show this correlation. The ratio needed for this analysis is not the ratio of individual one-minute data points, but rather the slope of the regression line. If a regression line cannot be drawn, there is no correlation.

   Figure 6(a) shows the NO_2 ppm-m vs total carbon ppm-m from the Flint Hills AU flare test. This aggregated data shows no evidence of correlation between NO_2 and carbon in the flare plume. This is true whether the AU data is plotted in aggregate as shown here or on a run-by run-basis. Compare this to Figure 6(b), which shows results from a single run from the 2010 TCEQ flare test.


(a)

(b)

Figure 6. Comparison of (a) AU NO_2 data (all data) to (b) TCEQ NOx data S13.4 R3 (reprinted from Torres et al, 2012)

Note that the TCEQ data in 6(b) show a clear correlation between total carbon and NOx. The NOx/carbon ratio is determined from the slope of the regression line.

Figure 7 shows the same data on a CO_2 basis -- NO_2 vs CO_2 2k for the Flint Hills AU flare tests. The 2k CO_2 region was the actual CO_2 value used to calculate combustion efficiency in these tests.

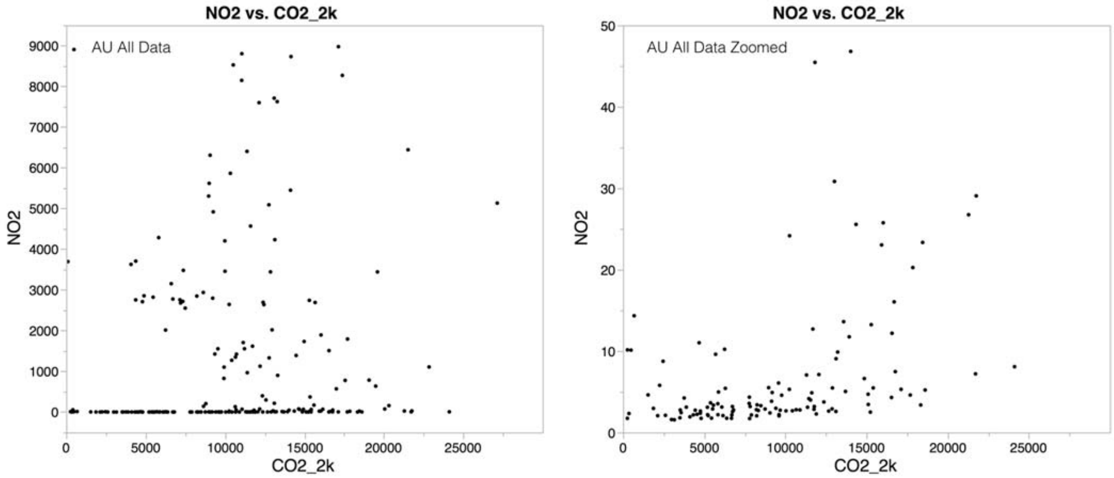


Figure 7. NO_2 vs CO_2 in ppm*m for the AU Flare

The graph on the left shows data from all runs. When run average data is plotted individually, there is also no evidence of any correlation between NO_2 and CO_2. If a correlation between the pollutant of interest and CO_2 is not demonstrated even under the same operating condition, then there is no basis to predict pollutant mass emissions from CO_2 concentration.

Also in Figure 7, the data points lying along the x-axis on the left graph are not zero NO_2 points. As the zoomed graph on the right shows, there is a range of variation of NO_2 at an entirely different scale than in the left graph.

To further illustrate this point, Figures 8 and 9 show relative standard deviation (RSD) of the NOx/CO_2 ratios calculated from the minute data of each run compared to the RSD of the CO/CO_2 ratios for both the FHR AU flare and the MPC DET flare.

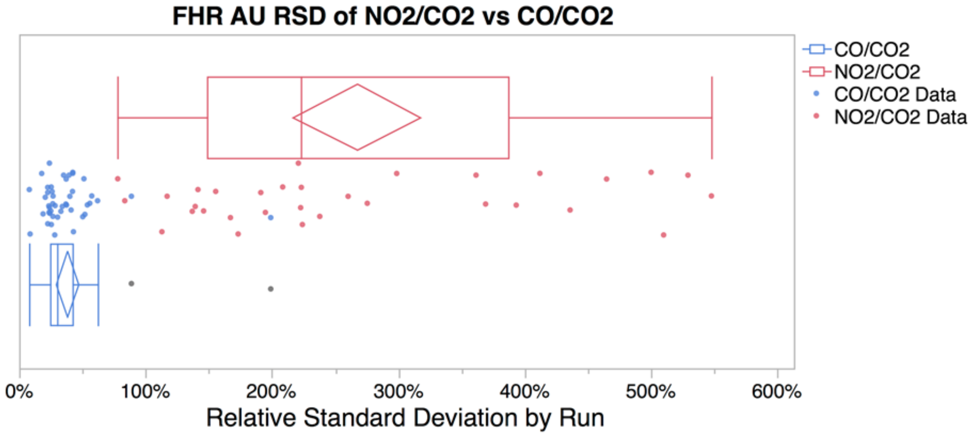


Figure 8. Comparison box plots of the NO_2 ratio spreads to the CO ratio spreads for the FHR AU flare

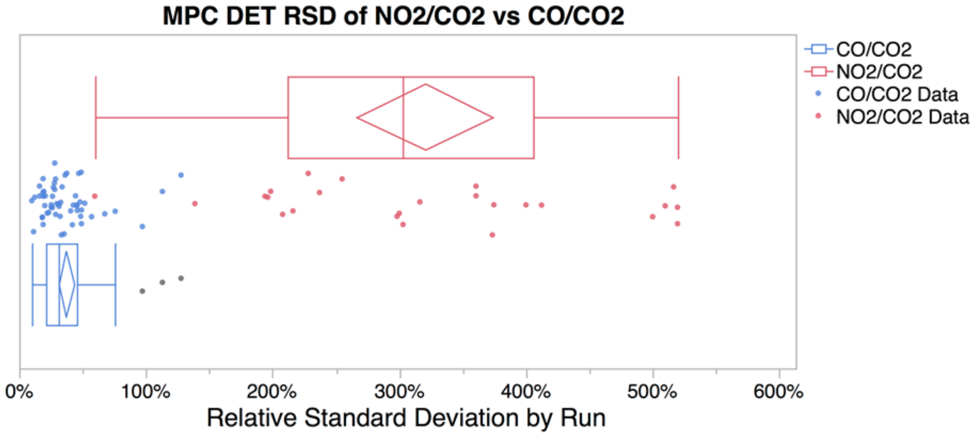


Figure 9. Comparison box plots of the NO_2 ratio spreads to the CO ratio spreads for the MPC DET flare

These graphs show variation in the NO_2/CO_2 ratio during a given run (i.e. constant condition) is very large, ranging from about 75% to over 500%. The CO/CO_2 ratio variation is shown for comparison. Under constant conditions, a relatively constant ratio is expected. This is further demonstration that the relationship presumed between NO_2 and CO_2 does not exist in the data.

Therefore, one of the two main conditions necessary to convert PFTIR data to mass emissions data (correlation between NO_2 and CO_2) is not met for the AU flare.

2. There must be a physical relationship between the pollutant generated and CO_2.

   In the pollutant ratio calculation it is assumed that NOx emissions are solely a function of CO_2 generation in the flare plume. This may be true of CO and VOC, but NOx is not a direct product of hydrocarbon combustion. Hydrocarbon combustion products are CO_2 and water (and partially oxidized carbon to a much lesser extent). NOx formation occurs through one of three mechanisms:

   a) Thermal NOx is formed by the high temperature reaction of nitrogen with oxygen. The nitrogen for this reaction will, in most cases, come primarily from the combustion air but may also come from molecular nitrogen in the vent gas. This is the primary mechanism by which NOx forms in a high combustion efficiency flare.

   b) Prompt NOx is formed by a reaction between nitrogen, oxygen and hydrocarbon radicals. This reaction becomes important at lower temperature combustion processes; but, when a flare is operated at high combustion efficiency, the combustion zone is very hot and prompt NOx formation is not expected to be significant.

   c) Fuel NOx is formed by the direct oxidation of organically bound nitrogen contained in fuel. Typical refinery vent gas (at least the vent gas from the flares EPA used in the emission factor development) contains little or no organically bound nitrogen. Therefore, fuel NOx from refinery flares is not expected to be significant.

   Only sufficient heat in the presence of nitrogen is required for the formation of thermal NOx. A carbon source is not required. Refinery flares burn hydrogen, which also results in the formation of thermal NOx. When hydrogen combusts, it generates heat and water, but no CO_2. This fact is critical in understanding why the model used for the development of the NOx emission factor is not valid for many refinery flares.

   Consider a flare flame with increasing amounts of hydrogen in the vent gas over time. Hydrogen is an excellent fuel and will combust quite well producing no CO_2 whatsoever. As the hydrogen concentration increases, the combustion temperature remains constant or increases slightly but the CO_2 generated decreases. Therefore NOx emissions remain relatively constant while CO_2 generated decreases since there are less carbon compounds in the vent gas.

   Using the NOx/CO_2 pollutant ratio method, as hydrogen increases in the vent gas, CO_2 declines. As the denominator of the ratio becomes smaller, overall magnitude (the NOx per unit of CO_2) increases. In fact, using this approach,

> the NOx/CO_2 ratio approaches infinity as hydrogen approaches 100% in the vent gas. At the same time, the carbon inlet mass flow rate decreases. Intuition may suggest that one offsets the other, however, when the extreme case of 100% hydrogen vent gas is considered, the carbon mass flow is zero and so the calculated NOx emissions are zero. This is obviously not a reflection of the actual NOx emissions for hydrogen combustion.
>
> Because hydrogen combustion generates NOx with no CO_2, the presumption that NOx emissions can be predicted from CO_2 generation is not valid for any flare with hydrogen in the vent gas at least not with the emissions model EPA proposes here.

The data do not show a reliable correlation between NOx emissions and CO_2 in the flare plume for these PFTIR tests. This is caused by the combined effects of the use of uncalibrated NO/NO_2 data, use of minute data rather than run average data, and an emission model that does not take hydrogen into account.

General Emission Factor Development Procedures

Log Distribution Assumption for Outlier Checking

To calculate the NOx emission factor, data from five recent flare tests were used together with the previous factor. These are shown in Figure 10A.

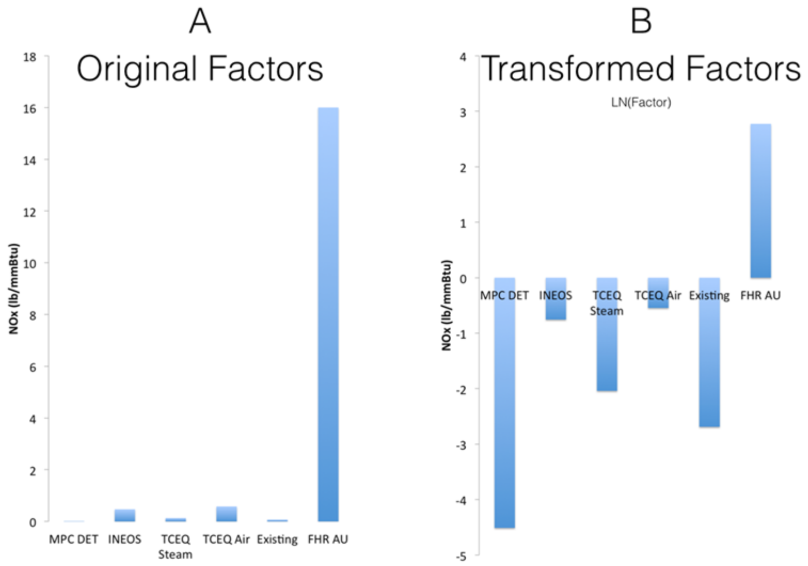


Figure 10. Comparison Proposed NOx Emission Factors

As part of the emission factor development process for the NOx factor, an outlier analysis was conducted by EPA. The conclusion, based on transforming the data as shown in Figure 8B was that the FHR AU test was NOT an outlier.

A Dixon Q test was performed on the natural logarithm of the factors. The factors were transformed in accordance with EPA's draft emission factors procedures, which note:

> *Emissions data are usually log-normally distributed; therefore, for the purposes of evaluating outliers for emissions factor development, we assume that all emissions test data values in the candidate data set follow log normal distributions. Thus, we log-transform every test value in the candidate data set prior to conducting outlier tests.*

The above guidance however, may not always be an appropriate statistical practice. This approach may be reasonable if there are historical data or process knowledge to indicate the data may actually be log-normally distributed. However, in this case, there is only a single data point that stands out. Furthermore, outlier detection with small data sets such as this is very difficult. With only 6 data points it is not possible to determine with a high degree of confidence whether the single large value is an outlier or whether it represents a true lognormal data distribution.

The outlier detection procedure is covered in much greater detail in Appendix A of this review.

Conclusions

Proposed Flare Emission Factors

The proposed flare emission factors should not be finalized. The proposed factors were developed using some technically inappropriate analyses and methodologies.

Specific technical issues identified in the development of the proposed factors include:

- Use of uncalibrated NO and NO_2 data in attempting to calculate NOx emissions rates from IR spectra, rendering the calculated NOx factor as not technically defensible
- Use of PFTIR minute data instead of run average data. Use of run-average data is necessary for valid analyses.
- Inappropriate filtering of PFTIR minute data
- Apparent averaging of the CO_2 spectral bands rather than choosing the appropriate band based on spectral analysis
- Use of unweighted, rather than hydrocarbon weighted, combustion efficiency
- Misinterpretation of PFTIR zero data values
- Use of a pollutant ratio model to calculate NOx mass emission rates based on CO_2 data
- Several computational errors and spreadsheet referencing errors

These issues should be addressed in the development of any updated CO, VOC or NOx factor.

Also, the calculations shown in the spreadsheets provided by EPA are not the same as those shown in the support documents. EPA does not provide explanation or validation that the calculations from these two sources are equivalent.

NOx Factor Issues

The primary issue affecting the quality of this factor is that the PFTIR instruments used to collect the data at all of the recent flare tests were not calibrated for either NO or NO_2. Additionally, use of minute rather than run average data, averaging of the CO_2 spectral bands, and the use of the unweighted combustion efficiency all combine to bias the resulting factor high.

The model used to convert PFTIR data to mass emission data, based on a NOx/CO_2 ratio, has technical deficiencies. The model presumes NOx emissions can be predicted solely from CO_2 concentration in the flare plume. However, NOx is also produced from hydrogen combustion, which does not generate CO_2. Since hydrogen was present in the vent gas streams of most of the flares tested with the PFTIR and used for this emission factor analysis, the resulting factors are inaccurate to an unknown degree.

In principle, a Pollutant/CO_2 ratio model could be used to develop CO and VOC emission factors from PFTIR data if a correlation can be demonstrated between these pollutants and CO_2 in the flare plume. However, since NOx emissions are a function of BOTH plume CO_2 and vent gas hydrogen concentration, a NOx/CO_2 ratio model is not appropriate nor technically justifiable.

Finally, in conducting the outlier analysis on these data, an approach was used that has the potential to not detect true outliers. These undetected outliers are a major factor in why the NOx factor for the AU flare is 64 times higher than the average of the other NOx flare factors.

VOC Factor Issues

The proposed new VOC factor is potentially biased high due to a combination of technical issues including the use of PFTIR minute data instead of run average data, averaging of the CO_2 spectral bands, and the use of the unweighted combustion efficiency. The hydrogen content of the vent gas may also affect the VOC factor. Increased hydrogen will tend to increase flame temperature, which may improve VOC destruction efficiency. However, there is insufficient data from the recent flare tests to effectively evaluate this possibility.

In addition, the proposed VOC factor is inconsistent with the existing emission factor provided for total hydrocarbons (THC). Generally, VOC is considered to be a fraction of THC emissions, but the proposed VOC emission factor is significantly higher than the existing THC factor. Because the two factors are derived from different data sets using different technology, and there is a potentially high bias of the proposed VOC factor, it is not unexpected that the two factors are inconsistent. But publishing a VOC emission factor which is higher than the THC factor creates confusion, because this is not technically valid if factors were derived from a common data set.

CO Factor Issues

The proposed new CO factor is potentially biased high due to a combination of technical issues including the use of PFTIR minute data instead of run average data, averaging of the CO_2 spectral bands, and the use of the unweighted combustion efficiency.

Emission Factor Procedures and Development Process

As a result of this review, it is evident that improvements can be made in EPA's emission factor process and procedures. Recommended improvements are discussed in Section 3.1 of the comment package.

Emission Factor Alternatives

The use of generic emission factors for flares is not the best technical approach to estimating emissions over a broad range of flares. Flare emissions are highly dependent on both vent gas composition and flare operation. Vent gas composition may vary tremendously over the installed base of flares. For example, flares with very high concentrations of methane, ethane, and/or hydrogen will have almost no VOC emissions. Any emission factor for VOCs derived from data collected from flares with high VOC vent gas would have limited applicability to these types of flares.

Also, combustion efficiency plays an important role here. If a flare operator has the information to estimate combustion efficiency that would be a more reliable indicator of emissions than a generic emission factor. These proposed factors have been calculated with combustion efficiencies as low as 96.5% (even lower with the data analysis issues discussed above). However, it is quite feasible that a flare operator could achieve 99.5% combustion efficiency or higher.

This page intentionally left blank

Appendix A - Performing Outlier Tests on PFTIR Data

This Appendix outlines the recommended approach to analyzing PFTIR data for outliers. It should be emphasized that the data being used in Appendix A are not valid because the PFTIR instrument was never calibrated for NO or NO_2. However, the recommended outlier analysis technique can be effectively demonstrated on incorrect data, and as such, the recommended technique will be demonstrated in this appendix for illustration purposes only. This demonstration, however, highlights one of the main reasons why EPA's proposed NOx emission factor for flares is technically flawed.

The data used in this analysis is the NOx data from the AU flare test. This data set was specifically chosen since EPA's calculated results from this test show a NOx emission factor for this flare 64 times higher (16 lb NOx/MMBtu)than the average of all the other NOx emission data collected).

EPA calculated the AU flare NOx factor using PFTIR minute data from the flare tests rather than the run average data. Also, the unweighted combustion efficiency value was used rather than the weighted value. Finally, results from two CO_2 spectral bands were averaged rather than choosing the appropriate band based on spectral analysis. The body of this report details the effects these errors have on emission factor determination. The data used in this Appendix corrects these errors. Specifically, run average data is used with weighted combustion efficiency and correct CO_2 values.

Finally, for each pollutant, EPA averages data from all of the various conditions tested at each flare together to produce one overall emission factor for that flare. This results in a total of six data points – one from each of the five flares tested along with the existing emission factor. EPA then performs an outlier test on these six values. This approach is problematic. Six data points is a very small data set to perform any meaningful statistical analysis. Furthermore, this approach "hides" potential outliers in the run average data. These hidden outliers are a major cause of the unrealistically high NOx emission factor proposed by EPA and also have a tendency to bias other factors either high or low depending on the outlier data.

EPA states in the Draft EF Development report that the results of their outlier test have 95% confidence. However, confidence intervals calculated on such a small data set are so large as to be effectively meaningless in any practical sense. The very large confidence intervals mean that the power of a statistical test to give meaningful answers is very small. In the case of the outlier test, almost any data will fall within the huge interval meaning the test will not be effective at screening true outliers.

Each run is an independent test that should be judged in comparison to all of the other runs. Outliers should be identified on a run-by-run basis rather than on a flare-by-flare basis. In some cases, runs were identified as outliers during the AU PFTIR test program. These outlier runs were repeated.

Identification of outliers on a run-by-run basis is more technically appropriate. In addition, it also improves the reliability of the statistical analysis by dramatically increasing the number of data points available.

The following is a suggested step-by-step procedure for conducting an outlier analysis on the PFTIR data. The AU flare NOx data is used as an example.

Step 1: Transform the Data

As discussed in the main body of the report, EPA assumes all emissions data is log-normally distributed. That is, they assume actual emissions data is skewed in such a way that the natural logarithm of the data exhibits the bell-shaped curve of a normal distribution. Therefore, when evaluating outliers, EPA transforms the data by taking the natural log of each data point before conducting an outlier test.

If the assumption about lognormality is correct, this transformation is necessary since the statistical outlier test used by EPA (the Dixon Q Test) requires the data to be normally distributed in order to work properly. The actual NOx emission data as well as the lognormal transformed data from the AU flare are shown in Figure A1.

Run	NOx lb/mmBtu	LN (NOx)
AU-A_2.0 (1)	9.173462538	2.216314809
AU-A_2.0 (2)	0.015372125	-4.175199465
AU-A_3.0 (1)	0.033870828	-3.385201169
AU-B_1.0 (1)	0.022294896	-3.803397507
AU-B_1.0 (2)	0.012396345	-4.39035358
AU-B_2.0 (1)	0.019283325	-3.948514549
AU-B_2.0 (2)	0.075686666	-2.581153282
AU-B_2.5 (3)	0.018954983	-3.965688435
AU-C_1.0 (1)	101.9540288	4.624522014
AU-C_1.0 (3)	0.013847072	-4.279681449
AU-C_1.0 (4)	0.007195513	-4.934297587
AU-C_2.0 (1)	2.972619644	1.089443599
AU-C_2.0 (2)	0.796847296	-0.227092216
AU-C_Min (1)	13.730172	2.619595747
AU-D_2.0 (1)	0.037368641	-3.286923412
AU-D_2.0 (2)	0.024907017	-3.692605724
AU-D_3.0 (1)	0.016912928	-4.079676958
AU-D_3.0 (2)	0.014604206	-4.226445709

Figure A1. Actual emissions data and lognormal transformed data from the AU flare test. This includes all runs with CE > 96.5% and with greater than 10 data points. Red shaded run indicate potential outlier points (discussed below).

Step 2: Check for Normality

If EPA's lognormality assumption is correct, the resulting distribution of the transformed data should be approximately normal with the exception of any outliers that distort the distribution.

EPA's statistical guidance document requires a check for normality prior to performing an outlier test.

> *This test [the Dixon Q Test] assumes that the data without the suspected outlier are normally distributed; therefore, it is necessary to perform a test for normality on the data without the suspected outlier before applying this test.*
>
> *From EPA QA/G-9S "Data Quality Assessment: Statistical Methods for Practitioners," February 2006, p117*

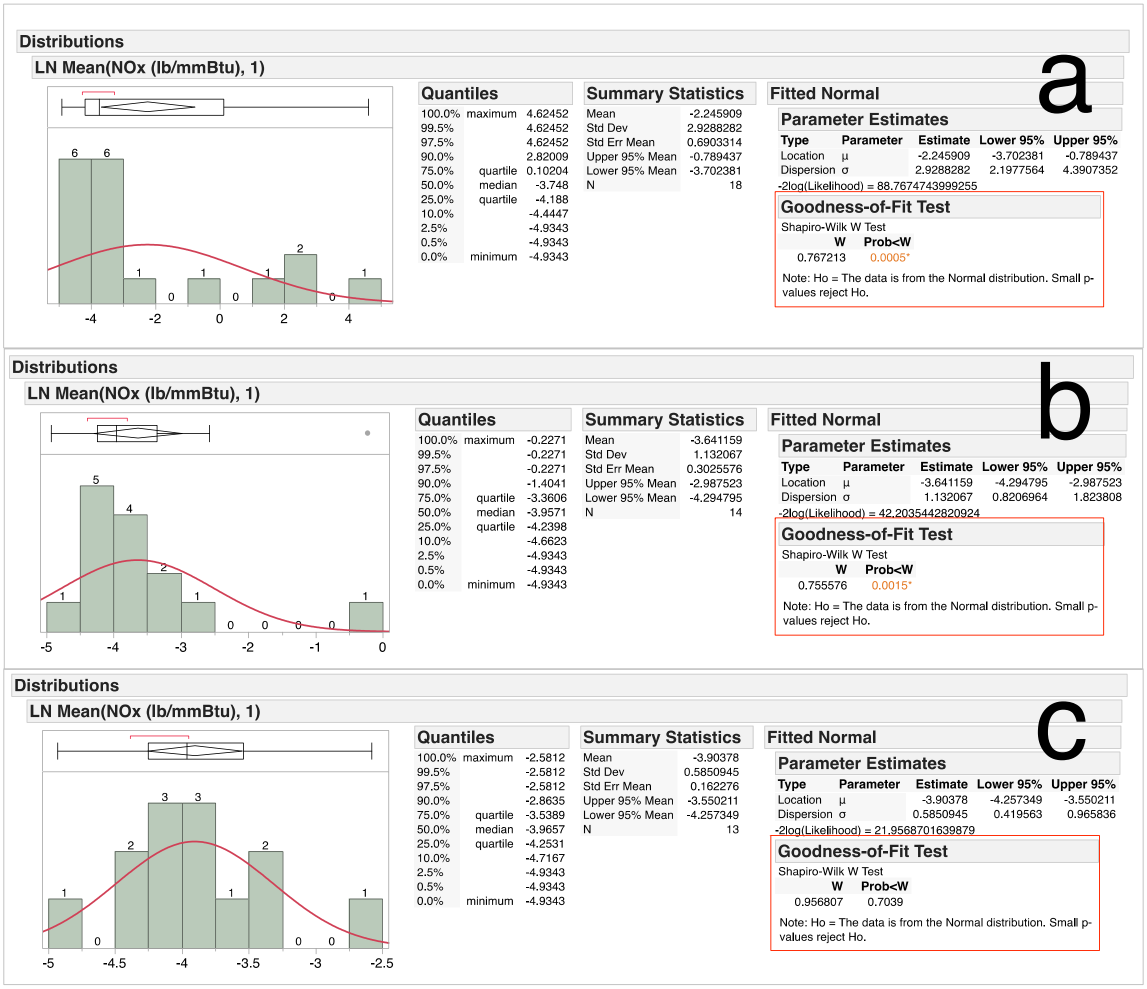
A histogram of the lognormal data distribution is shown in Figure A2(a). The histogram shows the transformed data with a normal curve superimposed. A visual observation indicates the data is not normally distributed as one would expect if the raw data were lognormal. The "Goodness-of-Fit Test" results confirm this. This indicates there may be outliers distorting the distribution. Again, a visual observation of the histogram shows several data points that have the potential to be outliers. Once these outliers are removed, the distribution should be normal.

In the case of the AU flare NOx data, there appear to be several outliers. First, let's remove the four most extreme data points to see whether this results in a normal distribution. The data points removed are runs AU A 2.0(1), AU C 1.0(1), AU C 2.0(1), and AU C Min (1). It should be noted that two of these runs, AU C 1.0(1) and AU C Min (1), were noted in the flare test report as not meeting proper test conditions and were repeated.

Figure A2(b) shows the same distribution with these four runs removed. A check of the Goodness-of-Fit results shows the distribution is not yet normal. The histogram shows another potential outlier that may be removed. This is run AU C 2.0(2).

Figure A2(c) shows the same distribution with the fifth run removed. Now the data shows a normal distribution.

Since the distribution of the transformed data becomes normal after removal of the five most extreme data points, these points are potential candidates for outliers.



Distributions

LN Mean(NOx (lb/mmBtu), 1)

Quantiles

100.0%	maximum	4.62452
99.5%		4.62452
97.5%		4.62452
90.0%		2.82009
75.0%	quartile	0.10204
50.0%	median	-3.748
25.0%	quartile	-4.188
10.0%		-4.4447
2.5%		-4.9343
0.5%		-4.9343
0.0%	minimum	-4.9343

Summary Statistics

Mean	-2.245909
Std Dev	2.9288282
Std Err Mean	0.6903314
Upper 95% Mean	-0.789437
Lower 95% Mean	-3.702381
N	18

Fitted Normal

Parameter Estimates

Type	Parameter	Estimate	Lower 95%	Upper 95%
Location	μ	-2.245909	-3.702381	-0.789437
Dispersion	σ	2.9288282	2.1977564	4.3907352

-2log(Likelihood) = 88.7674743999255

Goodness-of-Fit Test

Shapiro-Wilk W Test

W	Prob<W
0.767213	0.0005*

Note: Ho = The data is from the Normal distribution. Small p-values reject Ho.

Distributions

LN Mean(NOx (lb/mmBtu), 1)

Quantiles

100.0%	maximum	-0.2271
99.5%		-0.2271
97.5%		-0.2271
90.0%		-1.4041
75.0%	quartile	-3.3606
50.0%	median	-3.9571
25.0%	quartile	-4.2398
10.0%		-4.6623
2.5%		-4.9343
0.5%		-4.9343
0.0%	minimum	-4.9343

Summary Statistics

Mean	-3.641159
Std Dev	1.132067
Std Err Mean	0.3025576
Upper 95% Mean	-2.987523
Lower 95% Mean	-4.294795
N	14

Fitted Normal

Parameter Estimates

Type	Parameter	Estimate	Lower 95%	Upper 95%
Location	μ	-3.641159	-4.294795	-2.987523
Dispersion	σ	1.132067	0.8206964	1.823808

-2log(Likelihood) = 42.2035442820924

Goodness-of-Fit Test

Shapiro-Wilk W Test

W	Prob<W
0.755576	0.0015*

Note: Ho = The data is from the Normal distribution. Small p-values reject Ho.

Distributions

LN Mean(NOx (lb/mmBtu), 1)

Quantiles

100.0%	maximum	-2.5812
99.5%		-2.5812
97.5%		-2.5812
90.0%		-2.8635
75.0%	quartile	-3.5389
50.0%	median	-3.9657
25.0%	quartile	-4.2531
10.0%		-4.7167
2.5%		-4.9343
0.5%		-4.9343
0.0%	minimum	-4.9343

Summary Statistics

Mean	-3.90378
Std Dev	0.5850945
Std Err Mean	0.162276
Upper 95% Mean	-3.550211
Lower 95% Mean	-4.257349
N	13

Fitted Normal

Parameter Estimates

Type	Parameter	Estimate	Lower 95%	Upper 95%
Location	μ	-3.90378	-4.257349	-3.550211
Dispersion	σ	0.5850945	0.419563	0.965836

-2log(Likelihood) = 21.9568701639879

Goodness-of-Fit Test

Shapiro-Wilk W Test

W	Prob<W
0.956807	0.7039

Note: Ho = The data is from the Normal distribution. Small p-values reject Ho.

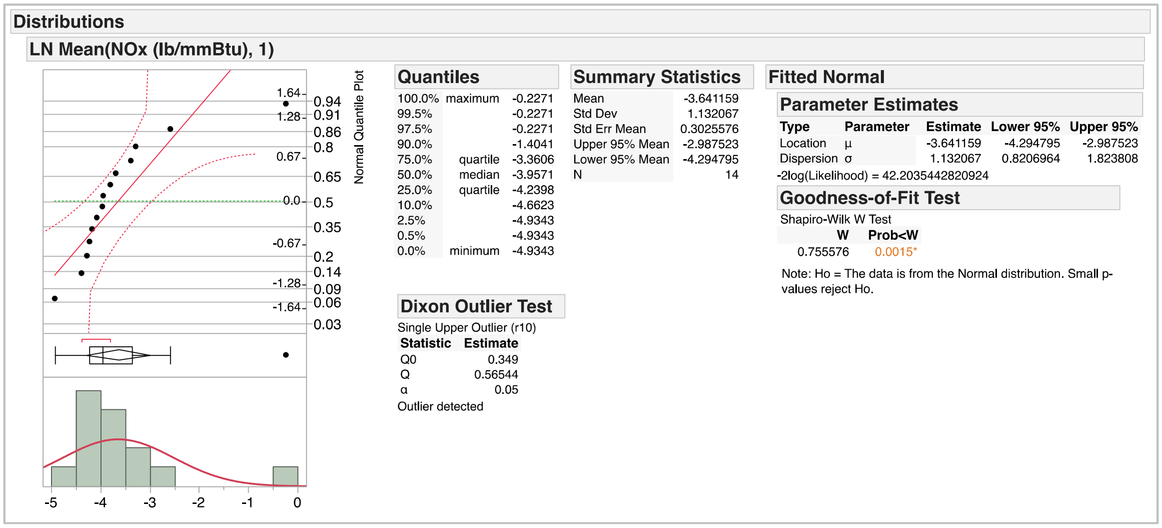
Figure A2. (a) The distribution of the lognormal NOx results from the AU runs. Numbers above the bars indicate the number of data points represented by each bar. (b) The same distribution with the four most extreme data points removed. (c) The same distribution with the five most extreme data points removed.

Step 3: Perform the Outlier Test

Once potential candidates are identified, the outlier test can be performed. However, there is a caution here. Where multiple outliers are possible, a condition known as “masking” may occur where the outliers will “hide” each other. This results in outliers not being detected, when in fact they are present. EPA recognizes this in their statistical guidance document and provides a technique to avoid potential masking.

> *This guidance recommends using this test when only one outlier is suspected in the data. If more than one outlier is suspected, the Extreme Value [Dixon] test may lead to masking where two or more outliers close in value "hide" one another. Therefore, if the analyst decides to use the Extreme Value test for multiple outliers, apply the test to the least extreme value first.*
>
> *From EPA QA/G-9S "Data Quality Assessment: Statistical Methods for Practitioners," February 2006, p117*

Following EPA's guidance, the Dixon outlier test may now be performed using the normally distributed data set with the closest outlier added. This is the data set shown in Figure A2(b) above. The results of the Dixon test on this data are shown in Figure A3.



Distributions

LN Mean(NOx (lb/mmBtu), 1)

Quantiles

100.0%	maximum	-0.2271
99.5%		-0.2271
97.5%		-0.2271
90.0%		-1.4041
75.0%	quartile	-3.3606
50.0%	median	-3.9571
25.0%	quartile	-4.2398
10.0%		-4.6623
2.5%		-4.9343
0.5%		-4.9343
0.0%	minimum	-4.9343

Summary Statistics

Mean	-3.641159
Std Dev	1.132067
Std Err Mean	0.3025576
Upper 95% Mean	-2.987523
Lower 95% Mean	-4.294795
N	14

Fitted Normal

Parameter Estimates

Type	Parameter	Estimate	Lower 95%	Upper 95%
Location	μ	-3.641159	-4.294795	-2.987523
Dispersion	σ	1.132067	0.8206964	1.823808

-2log(Likelihood) = 42.2035442820924

Goodness-of-Fit Test

Shapiro-Wilk W Test

W	Prob<W
0.755576	0.0015*

Note: Ho = The data is from the Normal distribution. Small p-values reject Ho.

Dixon Outlier Test

Single Upper Outlier (r10)

Statistic	Estimate
Q0	0.349
Q	0.56544
α	0.05

Outlier detected

Figure A3. The results of the Dixon outlier test.

Note that the test identified the AU C 2.0(2) run as an outlier. Since this was the closest potential outlier to the non-outlier data, all data points more extreme will also be outliers. Based on the results of this test, all five data points removed may be considered as outliers.

Step 4: Determine How to Handle the Outliers

Once outlier data has been identified, the key questions now become 1) Why is the data an outlier? and 2) How should it be handled? These questions are related since the Why will often determine the How.

Just because data has been identified as an outlier does not mean it should be automatically excluded from further analysis. If the data are real, they may provide valuable insight into the underlying process.

Outlier data may be treated in one of three ways:

1. Correct the data
2. Eliminate the data from any further analysis
3. Use the data for all further analysis

Statistics can only help identify potentially problematic data. Statistics, however, cannot help in deciding what to do with this data. Only application of technical and scientific knowledge can do this. EPA also addresses this point.

> *This decision [how to handle identified outliers] should be based on scientific reasoning <u>in addition to</u> the results of the statistical test. For instance, data points containing transcription errors should be corrected, whereas data points collected while an instrument was malfunctioning may be discarded. [Emphasis in original]*
>
> *From EPA QA/G-9S "Data Quality Assessment: Statistical Methods for Practitioners," February 2006, p116*

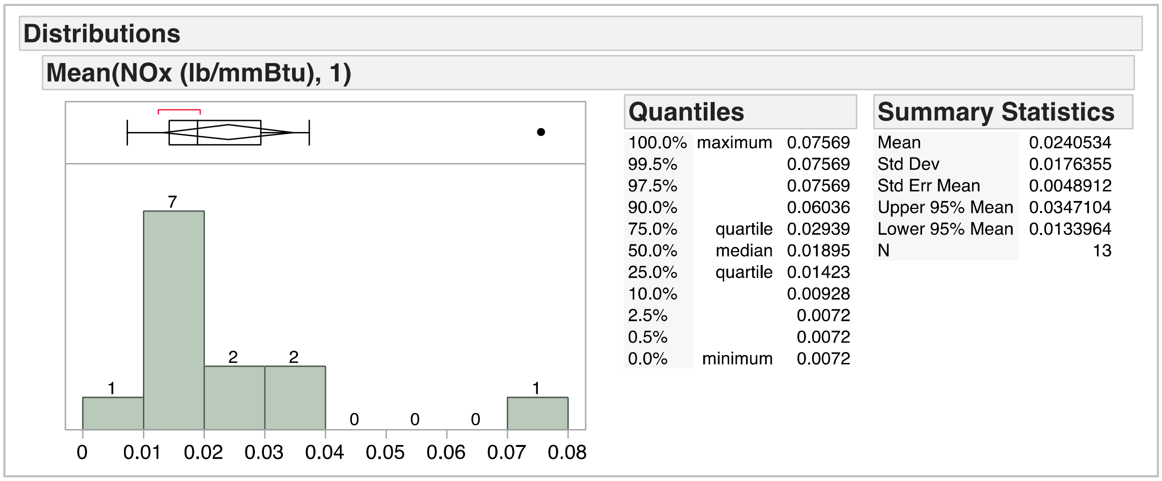
Regarding the outlier points identified in the AU flare NOx data, four of the most extreme values are most likely physically impossible. No values this high have ever been measured in past data. These extreme values are likely a result of the lack of instrument calibration noted in the body of the report. As mentioned above, two of these data points were flagged in the flare test report as being conducted under non-ideal test conditions.

The data point from Run AU C 2.0(2) is closer to the rest of the data. However, it is still very high and again is likely the result of the lack of instrument calibration.

For the final analysis, we assume that all five data points do not conform to expected NOx emissions from flares and they are eliminated in this example.

Step 5: Calculate the Emission Factor

Once the disposition of the outliers has been decided, the final data set may now be used to determine the emission factor. Figure A4 shows the final raw data (not the transformed data). The mean value shown under Summary Statistics is the emission factor for the AU flare calculated as the average of the final run data set, i.e., 0.0241 lb/MMBtu NOx.



Distributions

Mean(NOx (lb/mmBtu), 1)

Quantiles

100.0%	maximum	0.07569
99.5%		0.07569
97.5%		0.07569
90.0%		0.06036
75.0%	quartile	0.02939
50.0%	median	0.01895
25.0%	quartile	0.01423
10.0%		0.00928
2.5%		0.0072
0.5%		0.0072
0.0%	minimum	0.0072

Summary Statistics

Mean	0.0240534
Std Dev	0.0176355
Std Err Mean	0.0048912
Upper 95% Mean	0.0347104
Lower 95% Mean	0.0133964
N	13

Figure A4. Final data set (untransformed) after disposition of the outlier data.

It should be emphasized again that since the PFTIR was never calibrated for NOx, the NOx emissions values are not valid and the final result obtained here is also not valid. However, the statistical techniques shown here demonstrate that how the outlier analysis is performed can have a very large effect on the end result -- in this case an emission factor of 0.0241 lb/MMBtu as opposed to EPA’s draft emission factor of 16 lb/MMBtu calculated using the same underlying data.

Review of Proposed Revisions to Sections 5.1, 8.13, and 13.5 of AP-42 and the Draft Emission Estimation Protocol for Petroleum Refineries - Version 3.0

Appendix 2

API's Comments to Sections 5.1, 8.13, and 13.5 of AP-42 that are Not Related to the New and Revised Emissions Factors

AP-42 Section 5.1 Petroleum Refining

In Section 5.1 the following corrections are suggested.

Section 5.1.2.6, Fourth Paragraph, Second Sentence "The PSA ~~off-~~tailgas vent contains hydrocarbons and methanol." [change "off-gas" to "tailgas"]

Section 5.1.2.6, Fourth Paragraph, Fourth Sentence "The~~se~~ PSA ~~off-~~tailgas vent and deaerator vent may be directed to the steam methane reforming furnace, which is expected to reduce the hydrocarbon emissions." [change "These" to "The" and change "off-gas" to "tailgas"]

AP-42 Section 8.13 Sulfur Recovery

In Section 8.13 the following corrections are suggested.

Section 8.13.2, Fourth Paragraph, First Sentence "The furnace normally operates at combustion chamber temperatures ranging from 980 to 1540°C (1800 to 2800°F) with pressures rarely higher than 70 kilopascals (kPa) (10 pounds per square inch ~~absolute~~ gauge)." [change "absolute" to "gauge"]

Section 8.13.2, Fourth Paragraph, Fourth Sentence "Liquid sulfur from the condenser runs through a seal leg or sulfur trap (sulfur traps operate similar to an inverted bucket condensate trap) into a covered pit from which it is pumped to trucks or railcars for shipment to end users. [add "or sulfur trap (sulfur traps operate similar to an inverted bucket condensate trap)"]

Section 8.13.2, Sixth Paragraph, First Sentence "The catalytic reactors operate at lower temperatures, ranging from 200 to 315°C (400 to 600°F). Activated alumina or ~~bauxite~~ titanium dioxide is sometimes used as a catalyst." [add "Activated" and delete "bauxite"]

Section 8.13.3, First Paragraph, Third Sentence "Claus plants without tailgas ~~cleanup~~treatment, have sulfur recovery efficiencies ranging from 92 to 97 percent; Claus plants with tailgas ~~cleanup~~treatment, have sulfur recovery efficiencies ranging from 99 to 99.9 percent." [change "cleanup" to "treatment"]

Section 8.13.3, First Paragraph, Fourth Sentence “The efficiency depends upon several factors, including the number of catalytic stages, the concentrations of H_2S and contaminants in the feedstream, stoichiometric balance of gaseous components of the inlet, operating temperature, catalyst maintenance, and the type of tailgas ~~cleanup~~treatment process used.” [change “cleanup” to “treatment”]

Section 8.13.3, First Paragraph, Fifth Sentence “Regardless of whether or not a tailgas ~~cleanup~~treatment process is used to increase recovery efficiency, most sulfur recovery plants use a thermal oxidizer or incinerator to convert H_2S and other sulfur compounds SO_2 prior to atmospheric release.” [change “cleanup” to “treatment”]

Section 8.13.3, Table 8.13-1, for the Mod. Claus 3 Stage w/o Tailgas Cleanup Control (95-96% Removal), Average % Sulfur Recovery “~~95.5~~96.0% with the range being 95-97% Removal” [change “95.5” to “96.0% with the range being 95-97% Removal”]

Section 8.13.3, Table 8.13-1, for the Mod. Claus 3 Stage w/o Tailgas Cleanup Control (95-96% Removal), kg/Mg of Sulfur Produced “~~94~~83” [change “94” to “83”]

Section 8.13.3, Table 8.13-1, for the Mod. Claus 3 Stage w/o Tailgas Cleanup Control (95-96% Removal), lb/ton of Sulfur Produced “~~188~~166” [change “188” to “166”]

Section 8.13.3, Table 8.13-1, Footnote a “The emission factors were determined assuming all sulfur compounds are converted to SO_2 prior to atmospheric release. These emissions factors are applicable to all Claus sulfur recovery plants whether or not the sulfur recovery plant employs a tailgas ~~cleanup~~treatment system provided the emissions are controlled using a thermal incinerator or thermal oxidizer. These emissions factors are also applicable for Claus sulfur recovery plants with oxidative tailgas ~~cleanup~~treatment systems that do not use incineration.” [change “cleanup” to “treatment”]

Section 8.13.3, Second Paragraph, First Sentence “A 2-bed catalytic Claus plant typically achieves 92 to 95 percent sulfur recovery efficiency. Recoveries range from 95 to 9~~6~~7 percent for a 3-bed catalytic plant~~ and range from 9796 to 98.597 percent for a 4-bed catalytic plant~~.” [change “96” to “97” and delete “and range from ~~97~~96 to ~~98.5~~97 percent for a 4-bed catalytic plant”]. Note that sulfur recovery efficiency is a function of the hydrogen sulfide concentration in the acid gas. API recommends a range from 95 to 97% for a 3-bed Claus plant.

Section 8.13.3, Third Paragraph, First Sentence “Emissions from the Claus process may be reduced by: (1) extending the Claus reaction into a lower temperature liquid phase and thereby increase sulfur recovery efficiencies, (2) adding a scrubbing process to the Claus exhaust stream for the purposes of increasing sulfur recovery efficiencies, ~~or~~ (3) incinerating the sulfur compounds to SO_2 and using conventional flue gas desulfurization (FGD) scrubbing techniques to reduce the SO2 emissions, or (4) providing a SuperClaus unit that involves a special catalyst that converts H_2S to sulfur by direct oxidation.” [delete “ or” and add “or (4) providing a SuperClaus unit that involves a special catalyst that converts H_2S to sulfur by direct oxidation”]

Section 8.13.3, Fifth Paragraph, Fourth Sentence “There are at least ~~3~~4 oxidation scrubbing processes: the Wellman-Lord, Stauffer Aquaclaus, ~~and~~ IFP-2, and Cansolv.” [change “3” to “4”, delete “and”, and add “, and Cansolv”]

Section 8.13.3, Tenth Paragraph, Eighth Sentence “Scrubbing processes that recycle H_2S or SO_2 to~~n~~ the Claus feed become ineffective when there are operational issues with the upstream Claus process.” [change “ton” to “to”]

Section 8.13.4, First Paragraph, Seventh Sentence “All of the data available for NOx, CO, and THC are for units with tailgas ~~clean-up~~treatment units designed to increase the sulfur recovery efficiencies to 99.9 percent; however, the emissions of these pollutants is not expected to be as closely tied to sulfur recovery efficiencies as emissions of SO_2.” [change “clean-up” to “treatment”]

Section 8.13.4, Table 8.13-2, Footnote e “SCC = Source Classification Code. Emission factors were developed specifically for units with tail gas treatment ~~unis~~units (e.g., SCC 30103204).” [change “unis” to “units”]

AP-42 Section 13.5 Industrial Flares

In Section 13.5 the following corrections are suggested.

Section 13.5.1, Fourth Paragraph, Fifth Sentence “Ground flares vary in complexity, and they may consist either of conventional flare burners ~~discharging horizontally~~ with no enclosures or of multiple burners in refractory-lined steel enclosures.” [delete “discharge horizontally”]

Section 13.5.1, Sixth Paragraph, Eleventh Sentence “However, if flare waste gas concentrations are near the LFL prior to mixing with air, the air-waste gas mixture can ~~will~~ ~~quickly~~ fall below the flammability region, and ~~poor~~ reduced combustion efficiencies can ~~will~~ occur.” [change “will” to “can”, delete “quickly” and change “poor” to “reduced”]

Section 13.5.1, Sixth Paragraph, Thirteenth Sentence “Thus, even if there are adequate concentrations of combustibles in the waste gas, if too much steam is added to the waste gas so that the combustibles concentration becomes diluted to near the LFL as the steam-waste gas mixture enters the combustion zone, ~~poor~~ reduced combustion efficiencies will result.” [change “poor” to “reduced” API recommends that it be clarified that LFL and UFL are defined for well, uniformly mixed mixtures of air and fuel. While using LFL correlating variable for combustion efficiency appears to provide an improved correlation relative to steam-to-vent-gas ratio, it should be noted that when assessing the combustibility of hydrocarbon mixtures (with inerts as potential constituents), the LFL applies to uniformly mixed gases. Since the mixing intensity of many flares is not well characterized, using the LFL as a representation of potential vent gas combustibility may not be representative.]

Section 13.5.1, Eighth Paragraph, Third Sentence “Waste gases containing heavy hydrocarbons such as paraffins above methane, olefins, and aromatics, usually ~~burn with smoke~~have a higher tendency to smoke unless the introduction of air into the combustion zone is assisted.” [change “burn with smoke” to “have a higher tendency to smoke unless the introduction of air into the combustion zone is assisted”]

Section 13.5.1, Twelfth Paragraph “~~Many plants have 2 or more flares, in parallel or in series. In the former, 1 flare can be shut down for maintenance while the other serves the system. In systems of flares in series, 1 flare, usually a low-level ground flare, is intended to handle regular gas volumes, and the other, an elevated flare, to handle excess gas flows from emergencies.~~” [API recommends that the entire paragraph be removed as each plant’s flare system varies.]

Section 13.5.2, Second Paragraph, First Sentence “Emissions from flaring may include carbon particles (soot), unburned hydrocarbons, CO, and partially burned and altered hydrocarbons.” [add “may”]

Section 13.5.2, Third Paragraph, Fourth through Seventh Sentences “~~The oxygen supplied as air ranges from 9.6 units of air per unit of methane to 38.3 units of air per unit of pentane, by volume. Air is supplied to the flame as primary air and secondary air. Primary air is mixed with the gas before combustion, whereas secondary air is drawn into the flame. For smokeless combustion, sufficient primary air must be supplied, this varying from about 20 percent of stoichiometric air for a paraffin to about 30 percent for an olefin.~~” [API recommends deletion of these sentences as they only apply to air-assisted flares]

Section 13.5.2, Third Paragraph, Eighth Sentence “If the amount of ~~primary~~ air is insufficient, the gases entering the base of the flame are preheated by the combustion zone, and larger hydrocarbon molecules crack to form hydrogen, unsaturated hydrocarbons, and carbon.” [delete “primary”]

Section 13.5.2, Fourth Paragraph, Sixth Sentence “Soot is eliminated by ~~adding steam or air~~using an assisted medium (air, steam, or gas pressure) to induce additional air; hence, most industrial flares are steam-assisted and some are air-assisted.” [change “adding steam or air” to “using an assisted medium (air, steam, or gas pressure) to induce additional air”]

Section 13.5.2, Sixth Paragraph, Second Sentence “~~Crude p~~Propylene was used as flare gas during the early EPA tests.” [delete “Crude”]

Review of Proposed Revisions to Sections 5.1, 8.13, and 13.5 of AP-42 and the Draft Emission Estimation Protocol for Petroleum Refineries - Version 3.0

Appendix 3

Previous Comments on Version 1 and 2 of the Emissions Estimation Protocol for Petroleum Refineries

Section 5 Process Vents

Section 5.1 Catalytic Cracking Units (CCUs)

The title of this section and the titles of the subsections refer to Catalytic Cracking Units, but in fact, only deal with the CCU Regenerator vents. In some places in Section 5.1, a sentence refers to the CCU, when it clearly is referring to the CCU Regenerator Vent. Depending on what equipment a site includes in its designation of its CCU, there may be hydrocarbon vents associated with the CCU feed or products. Those vents are not addressed in Section 5.1, or for that matter, anywhere in Section 5. **The Section 5.1 titles, and in appropriate cases the content, should be revised to refer specifically to the CCU regenerator vents, since that is all that is addressed.**

Section 5.1.2 Methodology Ranks 3 and 4 for Catalytic Cracking Units

Section 5.1.2 states "If multiple tests have been conducted on the CCU and no significant modifications have been made on the CCU or its control system, then an arithmetic average of the emission factors should be used to estimate annual average emissions." While this recommendation is generally valid, there are cases where there are several tests and an obvious outlier measurement. In such cases the median is the most statistically valid value to use. Thus, **we suggest generalizing this recommendation** as follows "If multiple tests have been conducted on the CCU regenerator vent and no significant modifications have been made on the CCU or its control system, then an arithmetic average or the median of the emission factors should be used to estimate annual average emissions, depending on the data distribution."

Section 5.1.2 states "To estimate maximum hourly emissions, the highest emission factor developed from the individual runs should be used along with the maximum capacity (or coke burn-off rate) of the CCU." This approach is then used in Example 5-1. **This recommendation suffers from two serious faults and should be revised.**

Using individual runs from a performance test is unreasonable and unscientific. Performance tests call for three runs in order to have an emission estimate with reasonable accuracy and precision. Basing an emissions estimate on a single performance test run results in an estimate of little statistical validity. The basis for the maximum hourly emissions should be the highest average emission factor developed from any performance test still considered applicable (considering whether the CCU has been modified since that performance test).

Additionally, the maximum unit capacity or coke-burnoff rate is not the appropriate basis if being used to provide the maximum hourly emissions for a given year. As in Example 5-1, the basis should be the highest hourly coke burn-off rate or CCU feed rate for the year being estimated (i.e., 2009 for the ICR).

Section 5.1.2.2 PM Size Distribution Estimates for Catalytic Cracking Units

The first sentence of Section 5.1.2.2 states "AP-42 does not contain PM size distribution data for uncontrolled CCU PM emissions, but it does contain typical control device default control efficiencies for different types of PM emissions control devices." All AP-42 emission factor data and information concerning FCCUs are extremely out-of-date. There are seven references cited—all dated from 1958 until 1973. None of this information is relevant to modern units equipped with wet scrubbers and electrostatic precipitators and use of the AP-42 control device efficiencies would result in incorrect emission estimates. **The Estimation Protocol should not be recommending use of incorrect and out-of-date AP-42 control efficiency factors.**

Section 5.1.3 Methodology Rank 5A for CCU Metal HAP Emissions Estimates

This section does not provide technically sound references for its recommendations, for instance:

- Paragraph 4 states "if metal HAP concentrations for CCU fines are not available, then the metal HAP composition of the emitted PM can be estimated as 80% of the E-cat concentration." There is no basis provided for this assertion and it should be deleted. Sources can evaluate the appropriate percentage of old and new catalyst in their system and that would provide a much better estimate than using an unsupported 80%.

- Footnote "b" for Table 5-3 "recommend[s] that a default value of 10 percent of the total chromium emissions be used to estimate the hexavalent chromium emissions associated with the CCU," but gives no technical back-up information or documentation for this recommendation. It, too, should be deleted or a basis provided.

Section 5.1.4 Methodology Rank 5B for Catalytic Cracking Units

Table 5-4 includes emission factors for dioxins and furans that appear to be based on detection limits and may result in emission estimates for species that may or may not be present. **All of the emission factors based primarily on lack of detection or only a few detections should be removed from Table 5-4.**

Section 5.4 Catalytic Reforming Units

As for CCUs, this section confuses catalytic reformer units with catalytic reformer regeneration vents and the wording of the section needs to be corrected to be clear when the regenerator vent is being discussed and when the entire unit is being discussed.

Section 5.4.1 Emissions Estimation Methodology for Catalytic Reforming Units

Unlike in other sections of the draft, the rank of the proposed emission estimating methodology for CRUs is not clearly indicated. Thus, **the Title of this section should be revised to be consistent with the rest of the document and be changed to "Methodology Rank 5 for Catalytic Reforming Units."**

The default emission factors provided are based on data from a continuous regeneration process (CCR), but are proposed to be used for the cyclic and semi-regenerative processes, as well. Each of the CRU regeneration types has different operating severities and thus sound science would indicate that significantly different emissions will occur. **The use of the Table 5-6 factors should be limited to only the continuous regeneration process.** It is bad policy and bad science to use information from one process to estimate emissions from another process, when an engineering analysis indicates the processes are likely to have different emissions.

It is also unreasonable of EPA to expect that we characterize and report emissions of chemicals where we have no method or means of getting that data. As stated in the paragraph's last sentence above Table 5-6: "No data are available to characterize the small portion of venting that occurs directly into the atmosphere from these purge cycles, but these emissions should be characterized and reported in the inventory."

Note "a" to Table 5-6 states "Emissions factor in pounds pollutant emitted per 1,000 barrels of catalytic reforming unit process capacity." However, the proposed factors are a function of the amount of feed to the unit, not the unit capacity. In particular, for the ICR, the correct factor is the amount of feed for the year 2009. Thus, "**Note a" should be revised to "Emissions factor in pounds pollutant emitted per 1,000 barrels of catalytic reforming unit feed in 2009."**

The Title to Table 5-6 does not represent the information in the Table and should be changed. The factors in Table 5-6 are indicated in the discussion to represent the coke burn emissions from CRU regeneration. However, they only represent emissions from a portion of regeneration.

Section 5.5 Sulfur Recovery Plants

Section 5.5.3 Methodology Rank 5 for Sulfur Recovery Plants

In Table 5-7, the correct carbonyl sulfide CAS No. is 463-58-1.

Section 6 Flares

Section 6.3 Methodology Rank 3 for Flares

Example 6-1 should be revised and corrected. Section 6 is relatively good about clarifying that lower heating value (LHV) is typically used for characterizing flare gas heat content. Table 6-2 gives a CO emissions factor of 0.34 lb/MMBtu LHV. However, in Example 6-1, the flare gas heating value is given on a higher heating value (HHV) basis (1,200 Btu/SCF HHV). The example uses this HHV value and the CO emission factor from Table 6-2 without ever converting the flare gas heat content from HHV to LHV, thereby calculating an incorrect CO emission estimate.

Section 6.5 Methodology Ranks 5 and 6 for Flares

Equation 6-3 is provided for estimating flare emissions using default emission factors. However, the variable in the equation is identified as refinery capacity, rather than average bbl/cd of crude fed for the year being estimated (2009 for the ICR). **Equation 6-3 needs to be corrected.**

Typographical and Minor Editorial Items

In Section 5 the following corrections are suggested.

Section 5.3, First Paragraph, Fourth Sentence "The process heater heats the heavy feed oil to near cracking temperatures, and then the oil is fed to one of the coking drums" should be "The process heater heats ~~the~~ heavy ~~feed~~ oil to near cracking temperatures, and then the oil is fed to one of the coking drums." [delete "the" and "feed"]

Section 5.4.1, Second Paragraph, Fourth and Fifth Sentences "The wet scrubbers used for these vents were characterized into two classes: single-stage scrubbers and multiple-stage scrubbers" should be "The wet scrubbers used for these vents are characterized into two classes: single-stage scrubbers and multiple-stage scrubbers."
[Change "were" to "are"]

From:	Errol Villegas <errol.villegas@valleyair.org>
Sent:	Friday, December 19, 2014 7:44 PM
To:	RefineryFactor
Cc:	Garwood, Gerri; Sheraz Gill
Subject:	San Joaquin Valley APCD Comments on Proposed AP-42 Flare Emission Factor
Attachments:	SJVAPCD Comments - Flares AP-42.pdf
Importance:	High

Please find the attached comments from the SJVAPCD on EPA's proposed revision to the NOx emission factor for flares.

Thank you for your consideration and please let me know if you have any comments or questions.

Sincerely,
Errol Villegas
Program Manager - Strategies & Incentives Department
San Joaquin Valley Air Pollution Control District
(559) 230-5806
errol.villegas@valleyair.org

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

December 19, 2014

US EPA
Office of Air Quality Planning and Standards (OAQPS)
Info CHIEF Help Desk
Mail Code D243-05
Research Triangle Park, NC 27711

Via email: refineryfactor@epa.gov

RE: Comments on Draft Emission Estimation Protocol for Petroleum Refineries

Dear Sir or Madam:

The San Joaquin Valley Air Pollution Control District (District) appreciates the opportunity to comment on the United States Environmental Protection Agency's (EPA) efforts to review and revise emission estimation techniques identified in the "Draft Emission Estimation Protocol for Petroleum Refineries." Specifically, the proposed action would revise existing or publish new emission factors for flares and other refinery operations and incorporate these emission factors into EPA's Compilation of Air Pollutant Emission Factors (also known as AP-42). Comments submitted herein are specific to EPA's proposed revision of the AP-42 industrial flare emission factors, particularly with respect to the proposed nitrogen oxides (NOx) emission factor.

In the absence of specific emissions test data, EPA's AP-42 industrial flare emission factors are used to estimate emissions from flares for a variety of air quality management purposes, including control measure and attainment plan development, air quality permitting, and emission inventory reporting. These proposed changes could have significant and detrimental effects on the Valley's ability to develop accurate attainment plans based on sound science that are effective in bringing our region into attainment. As the local agency charged with improving air quality within the eight county region of the San Joaquin Valley Air Basin (San Joaquin, Stanislaus, Merced, Madera, Fresno, Tulare, Kings, and the central and western portions of Kern County), the District is committed to protecting the health of our residents.

Seyed Sadredin
Executive Director/Air Pollution Control Officer

Northern Region
4800 Enterprise Way
Modesto, CA 95356-8718
Tel: (209) 557-6400 FAX: (209) 557-6475

Central Region (Main Office)
1990 E. Gettysburg Avenue
Fresno, CA 93726-0244
Tel: (559) 230-6000 FAX: (559) 230-6061

Southern Region
34946 Flyover Court
Bakersfield, CA 93308-9725
Tel: 661-392-5500 FAX: 661-392-5585

www.valleyair.org www.healthyairliving.com

Printed on recycled paper.

Based on these concerns, the District respectfully submits the following comments:

- **The proposed revisions to flare emissions factors are not based upon directly measured NOx emissions from flares, and are based upon remote sensing technology measurements from an instrument not calibrated to measure nitrogen oxides.** The wide variety of real-world operating conditions that were used to develop the proposed emission factors are preferable to the highly controlled and artificial conditions used to develop the original emission factors; however, no directly measured NOx emission samples were actually taken as a part of the testing for the revised emission factors. In fact, the tests were conducted with the goal of establishing VOC emission estimates, and not for NOx or other combustion contaminants. As such, we do not believe that the testing was designed adequately to determine NOx emissions. To more accurately establish standard emission factors for flares, EPA should take advantage of actual emissions tests designed to accurately measure specific pollutants such as NOx conducted on flares in the San Joaquin Valley and other regions.

- **The proposed NOx emissions factor for flares is suspect.** The proposed emissions factor of 2.9 pounds per million British thermal units of heat input is larger than an equivalent emission factor for uncontrolled gasoline fueled internal combustion engines or uncontrolled four-cycle rich-burn natural-gas fired internal combustion engines. The combustion temperatures created from engines can approach as high as 4,500 degrees Fahrenheit and thus thermal NOx emissions are generated. This indicates the proposed emissions factor for flares is suspect, since flare temperatures are thousands of degrees lower than engine temperatures in more open combustion environments, and therefore cannot generate the same quantity of thermal NOx emissions.

- **If EPA were to proceed with utilizing the test data (which we believe would not be appropriate), some of the data points should be rejected as statistical outliers.** EPA should also carefully evaluate whether or not the test results from the Flint Hills Resources Port Arthur, TX refinery (FHRAU) test (i.e. tests resulting in a 16 lb/MMBtu NOx value) are valid, and whether or not these results should be averaged in with the other test results since the results are significantly higher than others tests. This value is clearly an outlier and should not be included in the nitrogen oxides emissions average or used for any other purposes. In fact, if the results from this test are excluded, the average emission factor becomes 0.25 lb/MMBtu (still much higher than would be expected) which is an order of magnitude lower than the proposed value of 2.9.

By increasing the NOx emission factor for flares by a factor of > 42 (2.9/0.068), the Valley's NOx emissions inventory will artificially increase to approximately 16 tons per day, potentially affecting the Valley's ability to demonstrate attainment of the national ambient air quality standards. The increase in the emission factor may also unnecessarily subject stationary source facilities to Title V requirements by increasing the facility's potential to emit above major source thresholds. With the potential ramifications faced with the adoption of the proposed flare emission factors, the District believes that additional time is needed by EPA to conduct more research and perform additional testing to support any proposed factor revisions. The District strongly recommends EPA not approve the flare emission factors as proposed.

The District thanks you for EPA's time and effort in considering our comments. Follow-up inquiries can be directed to Mr. Errol Villegas, Program Manager, at (559) 230-6100 or at errol.villegas@valleyair.org. We look forward to working closely with EPA staff as the proposed action is finalized.

Respectfully,

Sheraz Gill
Director of Strategies and Incentives

Garwood, Gerri

From: Sparsh Khandeshi <skhandeshi@environmentalintegrity.org>
Sent: Friday, December 19, 2014 10:55 PM
To: RefineryFactor
Cc: Eric Schaeffer; Mary Greene; Jennifer Duggan; Adrian; 'Hilton Kelley (HiltonKelley5011@gmail.com)'; parras.juan@gmail.com
Subject: EIP Comments on EPA's Emission Factor Proposal
Attachments: Emission Factors Comment [FINAL].pdf

EIP respectfully submits the attached comments on EPA's emission factor proposal. The comments are submitted on behalf of Air Alliance Houston, Communities In-Power and Development Association, Texas Environmental Justice Advocacy Services, and the Environmental Integrity Project.

Best,
Sparsh Khandeshi
Attorney
Environmental Integrity Project
1000 Vermont Ave., NW
Eleventh Floor
Washington DC, 20005
Phone: 202-263-4446
Fax: 202-296-8822

ENVIRONMENTAL INTEGRITY PROJECT

1000 Vermont Avenue, NW
Suite 1100
Washington, DC 20005
Main: 202-296-8800
Fax: 202-296-8822
www.environmentalintegrity.org

December 19, 2014

Honorable Janet McCabe
Acting Assistant Administrator,
Office of Air and Radiation
United States Environmental Protection Agency
Via Email: refineryfactor@epa.gov

Re: Comments on the Proposed New and Revised Emission Factors for Flares and Proposed New Emission Factors for Certain Refinery Process Units and Proposed Determination for No Changes to VOC Emission Factors for Tanks and Wastewater Treatment Systems

I. Introduction

The Environmental Integrity Project (EIP) appreciates this opportunity to submit comments on EPA's emission factor proposal.[1] These comments are submitted on behalf of Air Alliance Houston, Communities In-Power and Development Association, Texas Environmental Justice Advocacy Services, and the Environmental Integrity Project. EPA's emission factor program is vital to the proper implementation of the Clean Air Act.[2] Emission factors are used to estimate emissions from a multitude of industrial processes including flares, tanks (also known as storage vessels), and wastewater treatment plants, and account for about 80% of emissions reporting from all industries.[3] EPA and state regulators use the resulting data to identify and evaluate emission control strategies, determine applicability of permit and regulatory requirements, and assess risks. Because emission factors underlie so many environmental decisions, it is essential for EPA ensure that they are accurate, unbiased, and useable for their intended purpose.

EPA's proposed revision to the nitrogen oxides (NOx) and carbon monoxide (CO) emission factors and the new volatile organic compounds (VOC) emission factor for industrial flares will vastly improve emissions estimations from refineries, petrochemical plants, the oil and gas industry, and the several other industrial sectors that use these devices to dispose of waste gas. Emissions from these sources have a disproportionate impact on communities downwind of these sources, which typically include a high proportion of low income and minority residents.

---

[1] EPA's emission factor proposal includes Proposed New and Revised Emission Factors for Flares, Proposed New Emission Factors for Certain Refinery Process Units and, Proposed Determination for No Changes to VOC Emission Factors for Tanks and Wastewater Treatment Plants. *Available at* http://www.epa.gov/ttn/chief/consentdecree/index_consent_decree.html.

[2] Office of Inspector Gen., U.S. Envtl. Prot. Agency, EPA Can Improve Emissions Factors Development and Management (No. 2006-P-000 17), 24 (Mar. 22, 2006) ("EPA officials describe the emissions inventory as the foundation for the air program, upon which everything else is built.") [hereinafter EPA Can Improve]

[3] *Id*. at 1.

Further, EPA's proposed new emission factors for catalytic reformers (total hydrocarbon (THC)), sulfur recovery units (NOx, CO, and THC), and fluid catalytic cracking units (FCCUs) (hydrogen cyanide (HCN)) will enable facilities to identify and estimate emissions from sources that were previously unaccounted for. The proposed revisions and new emission factors are based on a broad set of data that was collected through rigorous testing at actual operating facilities. While we support these components of EPA's proposal, there are key areas where EPA's proposal is deficient.

As discussed in more detail below, our specific comments are:

- EPA's proposed revised NOx emissions factor for flares is based on a robust data set and will enable facilities to more accurately report emissions. While the emissions tests conducted at Flint Hills Resources Port Arthur AU flare measured NOx emissions that are significantly higher than other PFTIR tests, EPA's statistical analysis demonstrates this data point is not an outlier.
- EPA's proposed new VOC emissions factor for flares is derived from a robust data set. The THC emissions factor, which serves as a proxy for VOCs, is based on a much smaller data set and is not derived from flares at working industrial facilities.
- EPA's proposed new HCN emission factor for FCCUs is representative of actual emissions from these process units. The data was submitted to EPA by the refining industry and includes nine different source tests from eight different process units. The resulting emission factor will help identify a significant source of toxic risk that has previously been invisible to regulators, industry, and the public.
- EPA should provide clear guidance that the new VOC emissions factor for flares should only be used for estimating emissions from flares that achieve 98% destruction efficiency. The agency should clarify that this level of performance depends on maintaining a minimum heat value of 270 btu/scf in typical flares and 380 btu/scf in flares with high hydrogen and/or olefin content in the combustion zone.
- EPA should propose an alternate VOC emissions factor that is representative of emissions from flares that are only required to comply with the current regulatory requirements, 40 C.F.R. § 60.18 and 40 C.F.R. § 63.11(b).
- EPA should propose an alternate VOC emissions factor for certain flares utilized at oil and gas facilities, which the agency has acknowledged only achieve 95% destruction efficiency.
- EPA should utilize the data it has to propose a methane emissions factor for industrial flares. Methane is a potent global warming agent. Industrial flares at refineries and the oil and gas industry are a significant source of this pollutant. A new emissions factor will enable more accurate reporting and provide regulators with the necessary information to account for these emissions in decision-making and develop cost-effective reduction strategies.
- The existing THC emissions factor for flares is lower than the proposed VOC factor. This will result in undercounting of THC emissions because VOCs are a subset of THCs released from a flare.
- EPA must collect and consider available and reasonably obtainable data to properly review the existing emissions factors for catalytic reforming units, FCCUs, sulfur recovery units, hydrogen units.

- EPA failed to adequately review the available data for wastewater treatment plants and storage vessels and either make a determination that revision of the VOC emissions factors is not "necessary" or revise the emission factors.

II. Background

Emissions factors are used to report emissions from a variety of emission sources across many industries; including petroleum refineries, oil and gas facilities, and petrochemical plants. "An emission factor is a representative value that attempts to relate the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant."[4] Emissions factors are necessary to quantify pollution releases from certain industrial sources because of the extreme conditions at the point of release or because there is no discrete point of release for the emissions.

Section 130 of the Clean Air Act requires EPA to review and revise the emission factors for ozone forming pollutants, including volatile organic compounds (VOCs), nitrogen oxides (NO_x), and carbon monoxide (CO).[5] The City of Houston petitioned EPA to improve the quality of the emissions factors used by refineries and petrochemical plants in 2008.[6] The City of Houston was rightfully concerned, explaining that it is home to the largest petrochemical complex in the country, and more than "400 chemical manufacturing facilities, including 2 of the 4 largest refineries in the U.S., emit high levels of pollutants into Houston's air that Houstonians must breathe."[7] In response to Houston's petition, the EPA:

- Sponsored the City of Houston to conduct a DIAL study to measure VOC and air toxic emissions in the Houston Ship Channel (The Shell Deer Park DIAL Study).[8]
- Reviewed a DIAL study performed at the BP Texas City refinery, which was funded in part by a grant from the EPA.[9]
- Published the Emissions Estimation Protocol for Petroleum Refineries to provide additional guidance to facility operators on the proper application of emission factors.[10]

---

[4] U.S. Envtl. Prot. Agency, Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, Fifth Edition, Introduction, at 1 (Jan. 1995) [Hereinafter AP-42 Introduction].

[5] 42 U.S.C. § 7430.

[6] Bill White, Mayor, City of Houston, Request for Correction of Information Under the Data Quality Act and EPA's Information Quality Guidelines (Jul. 9, 2008) [hereinafter Data Quality Act Petition].

[7] City of Houston, Mayor's Task Force on the Health Effects of Air Pollution, A Closer Look at Air Pollution in Houston: Identifying Priority Health Risks, 8 (June 2006).

[8] Letter from Elizabeth Craig, Acting Assistant Administrator, Office of Air and Radiation, U.S. Envtl. Prot. Agency to Bill White, Mayor, City of Houston, Response to City of Houston Data Quality Act Petition (Apr. 7, 2009) [hereinafter EPA DQA Response]. *See also* Loren Raun and Dan W. Hoyt, City OF Houston, Bureau of Pollution Control and Prevention, Measurement and Analysis of Benzene and VOC Emissions in the Houston Ship Channel Area and Selected Surrounding Major Stationary Sources Using DIAL (Differential Absorption Light Detection and Ranging) Technology to Support Ambient HAP Concentrations Reductions in the Community (DIAL Project), 92-93, tbl. 4.4(a) (Jul. 2011) [hereinafter Shell Deer Park DIAL Study].

[9] EPA DQA Response, *supra* note 8. *See also* U.S. Envtl. Prot. Agency, Critical Review of DIAL Emission Test Data for BP Petroleum Refinery in Texas City, Texas, EPA 453/R-10-002 (Nov. 2010) [hereinafter EPA Critical Review BP Texas DIAL Study].

EPA's present emission factor proposal comes in response to a lawsuit filed on behalf of Air Alliance Houston, Communities In-power and Development Association, the Louisiana Bucket Brigade, and Texas Environmental Justice Advocacy Services (TEJAS). Pursuant to Section 130 of the Clean Air Act, EPA has proposed the following new and revised emission factors:

Table A: Proposed New and Revised Emission Factors

Emission Sources	Pollutants
Flares	NOx(revised), CO(revised), VOC
Sulfur Recovery Units	NOx, CO, THC
Catalytic Reforming Units	THC
Hydrogen Plants	NOx
Fluid Catalytic Cracking Units	HCN

The agency did not revise the VOC emission factors for storage vessels and wastewater treatment plants because they claimed that the studies it reviewed cannot be used to update or revise the existing emission factors. EPA also concluded that it did not have sufficient information to propose a new:

- CO emissions factor for Catalytic Reforming Units;
- CO emissions factor for Hydrogen Plants; and
- THC emissions factor for Hydrogen Plants.

EPA is also proposing revisions to the Emissions Estimation Protocol for Petroleum Refineries (Estimation Protocol).

A. Emission Factors Are the Foundation for Air Quality Decisions that Impact Public Health

Emission factors are critical to implementing the Clean Air Act because the resulting emission estimates are used to "develop[ ] emission control strategies, determin[e] applicability of permitting and control programs, ascertain[ ] the effects of sources and appropriate mitigation strategies, and a number of other related applications by an array of users, including federal, state, and local agencies, consultants, and industry."[11] The chart below illustrates many of these applications.[12] While direct measurement of emissions, or representative source specific emission factors derived from stack tests can provide more accurate data and are preferable for estimating emissions, generic emission factors are necessary when these methodologies for estimating emissions are unavailable.[13]

---

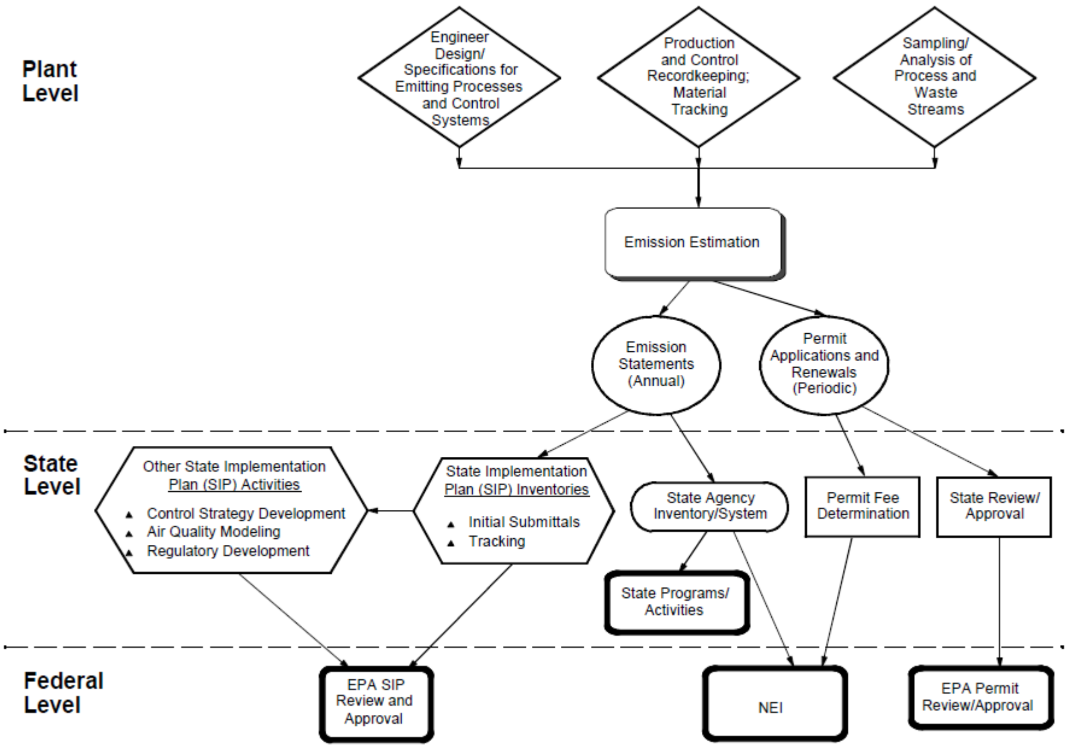
[10] EPA DQA Response, *supra* note 8. *See also* U.S. Envtl. Prot. Agency, Emission Estimation Protocol for Petroleum Refineries, Ver. 2.1.1 (Final ICR Version – Corrected), 1-1 (May 2011) [hereinafter Emission Estimation Protocol].

[11] AP-42 Introduction, *supra* note 4, at 1.

[12] Eastern Research Group, Introduction To Stationary Source Emission Inventory Development, 1.2-2, Fig. 1.2-1 (May 31, 2001) [hereinafter Emission Inventory Development Guidance].

[13] AP-42 Introduction, *supra* note 4, at 3. (Stack tests can only be used to derive meaningful, representative emission factors if the stack testing is conducted under the allowable range of operating conditions for that emissions unit, and if the facility accurately monitors and manages the operating conditions to ensure that the emissions unit operates within the envelope of the original stack test).

Figure 1: Key Relationships for Industry Air Pollutant Emission Estimation



Regulatory Development – Emission Factors are Used to Set Regulatory Limits

EPA's recent risk analysis and technology review of the petroleum refinery sector relied on an emissions inventory that was developed using emissions factors.[14] EPA requested all petroleum refineries to submit emissions data following the guidance of the Estimation Protocol to perform its review.[15] EPA required facilities to identify the estimation methodology used using one of the following four descriptors: "direct measurement," "stack testing," "engineering calculation," and "other."[16] While it is impossible to determine the exact percentage of emissions that were reported using emission factors, the majority of facilities indicated that emissions were reported using engineering calculations or other methodology. EPA largely

---

[14] Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards; Proposed Rule, 79 Fed. Reg. 36880, 36887-88 (Jun. 30, 2014) [hereinafter Refinery NESHAP Proposal].

[15] Refinery NESHAP Proposal, *supra* note 14, at 36887.

[16] U.S. Envtl. Prot. Agency, Petroleum Refinery Emissions Information Collection, Component 2, Part VI. Emissions Inventory Data, 4 (Mar. 28, 2011) [hereinafter Refinery ICR Component 2 Instructions]; U.S. Envtl. Prot. Agency, Refinery ICR Component 2 Reporting Tool, Table Structure for Advanced Data Entry, 2, *available at https://refineryicr.rti.org/Portals/0/Refinery_ICR_Component_2_Table_Structure.pdf*.

compiled the emission inventory as reported by industry, except for making adjustments for HCN emissions from FCCUs.[17] Data from Louisiana confirms that at least 20% of refinery emissions are reported using AP-42 emission factors (emissions reporting trends from Louisiana refineries serve as a fair proxy for the nation because Louisiana accounts for 20% of the nation's refining capacity).[18] Louisiana refineries also reported that nearly 60% of the emissions are reported using "emissions models." These entries may refer to AP-42 derived factors, such as for storage vessels for which EPA has developed the TANKS modeling software from AP-42 emissions factors.[19]

Table B: Emission Estimation Methods Used By Louisiana Refineries (2008)[20]

Calculation Method	**Number of Instances of Reporting Benzene, Toluene, Xylene, and Total VOC Emissions (by Percent)**
Emissions model	59%
EPA emission factors (e.g., AP-42)	19%
Engineering judgment	12%
Material balance	5%
Facility specific emission factor	2%
Direct measurement	1%
Stack test	1%
EPA published criteria	1%
Continuous emission monitors	0.3%
Manufacturer emission factor	0.3%
EPA speciation profile	0.2%
Vendor emission factor	0%
Total number of calculations	**1,197**

Clean Air Act Permitting – Emission Factors Are Used to Predict Emissions for New Source Review Applicability

Beyond rulemaking, emission factors are often used in permitting decisions. For example, Shintech recently submitted a New Source Review application to construct a new ethylene plant in Louisiana.[21] To estimate emissions and determine New Source Review applicability, Shintech estimated emissions from the new heaters, boilers, and flares using AP-42

---

[17] Refinery NESHAP Proposal, *supra* note 14, 36887-888.

[18] U.S. Energy Information Administration, Refinery Capacity Report, 1, tbl. 1 (Jun. 2014).

[19] U.S. Envtl. Prot. Agency, TANKS Emissions Estimation Software; Clearinghouse for Emissions Inventories and Emissions Factors; Technology Transfer Network, http://www.epa.gov/ttn/chief/software/tanks/index.html ("TANKS is based on the emission estimation procedures from Chapter 7 of EPA's Compilation of Air Pollutant Emission Factors (AP-42)").

[20] Louisiana Department of Envtl. Quality, 2008 Emission Inventory for Petroleum Refineries (Data on file with the Environmental Integrity Project).

[21] Shintech, New Source Review/Title V Air Permit Application/Expedited Permit Processing Request, Plaquemine Ethylene Plant -1, EDMS Doc. Id. 9372659 (Apr. 2014).

emission factors.[22] EPA's present proposal has direct bearing on this permit application because the facility used the AP-42 emission factor to estimate NOx emissions from flares.[23] The factor used by the facility assumes that flares produce 0.068 lbs. NOx/MMBtu of gas flared.[24] EPA's proposed revision to the emission factor is 2.9 lbs. NOx/MMBtu, or 42 times more than the current emission factor.[25] Based on the proposed factor, the flare will release 128 tons of NOx per year instead of the 3 tons estimated by Shintech in its application. This change on its own would mean that the new ethylene plant triggers New Source Review permitting requirements.

In addition to the two examples above, emission inventories, which are derived from emission factors, are used by states to demonstrate compliance with the National Ambient Air Quality Standards (NAAQS).[26] In each of these instances, rulemaking, permitting, and NAAQS evaluation, emissions factors are the foundation of important air quality decisions that impact public health. Thus, it is absolutely essential for EPA to ensure that emission factors are accurate.

B. Current Emission Factors are Inaccurate, Underestimate Emissions, and Need Revision

Emissions factors for flares, tanks, and wastewater treatment plants are inaccurate and underestimate emissions. Many scientific studies using remote sensing technologies and airborne measurements confirm that emission factors are inaccurate. EPA's own studies have made similar findings. EPA's evaluation of test data from flares confirms that the existing emission factors underestimate VOC emissions by nearly 400% and NOx emissions by more than 4,000%. Similarly, EPA's review of studies of tank emissions have found that "emissions [are] much higher than expected."[27] The agency review of DIAL measurements of emissions from wastewater treatment systems found that actual emissions were higher than "estimates when the process was operating normally."[28]

Flares:

The existing and proposed revised AP-42 VOC emissions factors for flares assume that flares can achieve 98% destruction efficiency.[29] Studies measuring actual emissions have repeatedly demonstrate that flares frequently do not achieve this level of control. As part of the

---

[22] *See e.g. Id.* at 6-1 – 6-19 ("Emission factors based on EPA's AP-42 Section 13.5 (Industrial Flares) Table 13.5-1 (9/91, reformatted 1/95).

[23] *Id.*

[24] *Id.*

[25] U.S. Envtl. Prot. Agency, Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, Fifth Edition, Chapter 13: Miscellaneous Sources, Industrial Flares, Draft Section 13.5, 13.5-5, tbl. 13.5-2. (Aug. 2014) [Hereinafter Draft AP-42 Section 13.5].

[26] Emission Inventory Development Guidance, *supra* note 12.

[27] U.S. Envtl. Prot. Agency, DRAFT EPA Review of Available Documents for Developing Proposed Emissions Factors for Flares, Tanks, and Wastewater Treatment Systems, 30 (Aug. 2014) [DRAFT EPA Review of Available Documents for Developing of Emissions Factors].

[28] *Id.* at 22.

[29] U.S. Envtl. Prot. Agency, Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, Fifth Edition, Chapter 13: Miscellaneous Sources, Industrial Flares, 13.5 (Sept. 1991); Draft AP-42 Section 13.5, *supra* note 25.

Refinery NESHAP rulemaking, EPA reviewed process data provided by the American Petroleum Industry, the American Fuels and Petrochemical Manufacturers and the American Chemical Council and found that flares only achieve 93.9% destruction efficiency on average.[30] This data, provided by industry, consisted of "flare waste gas and steam flow rate, composition for 38 steam-assisted flares, characterizing different operating conditions by waste gas flow rate, composition, and duration of that operating condition."[31] The lower heat value of the provided data ranged from 300 btu/scf to 2470 btu/scf, which satisfies the minimum heat value requirements found at 40 C.F.R. §§ 60.18, 63.11(b).[32] EPA did not include data from olefin flares and periods where the operating limits did not apply.[33] EIP's analysis of separate PFTIR data collected by EPA from three refineries, two chemical plants, and two flare test facilities show that flares complying with all current regulatory requirements only achieve about 92% destruction efficiency on average.[34] While many of these tests were conducted under high steam rates, EIP limited its analysis to PFTIR readings where the flare was in compliance with the minimum heat values and limits on exit gas velocity pursuant to 40 C.F.R § 60.18; and 63.11(b).[35] Furthermore, EPA's own research has found that refiners and other industrial facilities have an incentive to oversteam the flare to prevent visible emissions.[36] DIAL studies also confirm that flare destruction efficiency is frequently significantly lower than 98%.[37] Finally, EPA's New Source Performance Standards for the oil and gas industry determined that certain flares utilized by the sector only achieve 95% destruction efficiency.[38] Thus, the existing and proposed emissions factor for flares undercounts toxic emissions from the vast majority of industrial flares.

Storage Vessels:

The existing VOC emissions factors for storage vessels drastically underestimate real-world emissions. EPA reviewed several studies as part of the present proposal, including the Alberta DIAL study, the BP Texas City DIAL study, and the Shell Deer Park DIAL study.[39] These studies consistently find that VOC emissions from storage vessels are substantially higher than emissions factors predict.[40] In some cases the difference is more than two orders of

---

[30] Envtl. Prot. Agency, Petroleum Refinery Sector Rule: Flare Impact Estimates, EPA-HQ-OAR-2010-0682-0209, 9 (Jan. 16, 2014) [hereinafter Flare Impact Estimates].

[31] *Id*. at 6.

[32] *Id*. at Attachment 2, 2.

[33] *Id*. at 7.

[34] Earthjustice and Envtl. Integrity Project Comments, Comment submitted by Emma C. Cheuse, Earthjustice and Envtl. Integrity Project on behalf of Air Alliance Houston et al., EPA-HQ-OAR-2010-0682-0568, at 115 (Oct. 2014) [hereinafter Earthjustice Refinery NESHAP Proposal Comments].

[35] *Id*.

[36] U.S. Envtl. Prot. Agency, Parameters for Properly Designed and Operated Flares, EPA-HQ-OAR-2010-0682-0191, 1-1 (Apr. 2012) ("Operators acting cautiously to avoid non-compliance with the visible emissions standards for flares have liberally used steaming to control any potential visible emissions, also resulting in over steaming in some cases") [hereinafter Parameters for Properly Operated Flares].

[37] EPA Critical Review of BP Texas DIAL Study, *supra* note 9, at ES-5.

[38] DRAFT EPA Review of Available Documents for Developing of Emissions Factors, *supra* 27, at 1, tbl. 1-1

[39] *Id*. at 1, tbl. 1-1.

[40] EPA Critical Review of BP Texas City DIAL Study, *supra* note 9, at ES-2, tbl. 1; Shell Deer Park DIAL Study, *supra* note 8, 92-93, tbl. 4.4(a) (Jul. 2011); Allan Chambers and Mel Strosher, Refinery Demonstration of Optical

magnitude.[41] Additionally, a more recent study performed using a combination of Solar Occultation Flux (SOF), Mobile Differential Optical Absorption Spectroscopy (Mobil DOAS), Mobile Extractive Fourier Transform Infrared (Me FTIR), and Mobile White Cell DOAS (MW-DOAS), found that VOC emissions from storage vessels are about 4 to 8 times higher than what is reported using standard emission factors.[42] Also, emissions testing using temporary total enclosures (TTE) at the Sprague Operating Resources tank terminal in Searsport, Maine found that measured emissions from two tanks were "much higher than expected, based on Sprague's emission inventory estimates for the years 2006-2009."[43]

Wastewater Treatment Plants:

The existing VOC emissions factors for wastewater treatment plants also drastically underestimate real-world releases. The Shell Deer Park study found that benzene emissions from the facility's Northwest Wastewater plant was about 4 to 80 times higher than projected during a temporary malfunction. "Emissions from the wastewater treatment facility were also higher than estimates at times when the process was operating normally."[44]

III. EPA's Statutory Duty to Review and Revise Emission Factors and Standard of Review

The Clean Air Act requires EPA to review and, if necessary, revise emission factors for CO, VOCs, and NOx once every three years and establish emission factors for sources for which no such methods have previously been established.[45] EPA must also evaluate "improved emissions estimating techniques."[46]

Final determinations under Section 130 of the Clean Air Act are subject to judicial review under the Administrative Procedure Act (APA).[47] Under the APA, courts must set aside agency actions that are arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law or fail to meet other criteria.[48] EPA's action must embody "reasoned decision making."[49] Amongst other things, reasoned decision making is characterized by a systemic approach to problems and the agency has obtained and considered facts that are available or easily discoverable by conventional means.[50]

Technologies for Measurement of Fugitive Emissions and for Leak Detection, 17, tbl. 8 (2006) [hereinafter Alberta DIAL Study].

[41] *See e.g.* Shell Deer Park DIAL Study, *supra* note 8 (the measured emissions from the Southwest Tanks AP-17 were 132 times greater than emission factors would predict).

[42] FluxSense, Pilot Study to Quantify Industrial Emissions of VOCs, NO_2, and SO_2 by SOF and Mobile DOAS in the Carson Area, 4, tbl. E1. (Mar. 27, 2014) (Attached as Appendix A) [Carson Area SOF Study].

[43] DRAFT EPA Review of Available Documents for Developing Emissions Factors, *supra* note 27, at 30.

[44] *Id*. at 22.

[45] 42 U.S.C. § 7430.

[46] *Id.*

[47] 5 U.S.C. § 702; 5 U.S.C § 704.

[48] 5 U.S.C. § 706(2).

[49] National Lime Ass'n v. EPA, 627 F.2d 416, 454 (D.C. Cir. 1980).

[50] *Id*.

According to OMB and EPA guidelines for implementing the Data Quality Act, emission factors should adhere to a basic standard of quality, including objectivity, utility, and integrity. The objectivity standard "focuses on whether the disseminated information is being presented in an accurate, reliable, complete, and unbiased manner, and as a matter of substance is accurate, reliable, and unbiased."   The utility standard "refers to the usefulness of the information to the intended users." These guidelines provide useful criteria for EPA's review in this particular case.

IV. EPA's Proposed NOx and VOC Emissions Factor for Flares

EPA's proposal includes a revision to the NOx emissions factor for flares and a new VOC emissions factor for VOCs. Both, the revision to the NOx factor and the new VOC emission factor provide improved tools for estimating emissions from flares. The factors have been developed from a significant body of evidence to assure that they are representative of actual conditions. However, EPA should make certain adjustments and clarifications to the new VOC emission factor for flares. As discussed in more detail below, we recommend that EPA:

- Clarify that the VOC emission factor is only representative of emissions from flares that achieve 98% destruction efficiency.
- Propose an alternate VOC emission factor that is based on flare test data showing that facilities that comply with all existing regulatory requirements only achieve 93.9% destruction efficiency on average, and make clear that facilities that do not have the monitoring required to guarantee 98% destruction efficiency utilize the alternate flaring emission factor.
- Propose an alternate VOC emission factor for certain flares installed at oil and gas facilities that is reflective of EPA's determination that these units only achieve 95% destruction efficiency.

A. EPA's Proposed NOx Emission Factor of 2.9 lbs./MMBtu is Based on Accurate Data

EPA's proposed revision to the NOx emission factor for industrial flares is based on representative data and provides a more accurate tool for facilities to report NOx emissions from flares. The revised emission factor is 2.9 lbs. NOx/MMBtu of gas flared.[51] The revised NOx emission factor is based on the average test results from five new Passive Fourier Transform Infrared studies and (PFTIR) and the existing AP-42 NOx emissions factor.[52] The PFTIR studies incorporate 85 test runs and 2075 data points at more than five flares.[53] Further, three of the studies were conducted at actual industrial facilities.[54] The PFTIR data set has also been

---

[51] U.S. Envtl. Prot. Agency, DRAFT Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations, 37 (Aug. 2012) [Hereinafter DRAFT Review of Emissions Test Reports].

[52] *Id*. at 39.

[53] U.S. Envtl. Prot. Agency, AP-42 Fifth Edition, Vol. 1, Chap. 13: Miscellaneous Sources, 13.5 – Industrial Flares, Draft Background Documents, Flare Calculation. (Referenced spreadsheet is part of the background documents supporting EPA's proposed revised NOx emission factor *available at* *http://www.epa.gov/ttn/chief/ap42/ch13/bgdocs/db13s05_8-19-14.zip*) [hereinafter Flare Calculation Spreadsheet].

[54] *See e.g.* Clean Air Engineering, Inc., Performance Test of a Steam-Assisted Elevated Flare with Passive FTIR – Detroit (Nov. 2010) [hereinafter Marathon Detroit PFTIR Study]; Clean Air Engineering, Inc. PFTIR Test of a Steam-Assisted Elevated Flares – Port Arthur (2011) [hereinafter Port Arthur PFTIR Study]; Ineos ABS (USA)

reviewed by an expert panel in the context of developing the proposed new monitoring and operating requirements for flares at refineries.[55] The expert panel included industry experts, environmental consultants, and academics. In general, the panel found that the underlying test data was reliable.[56]

On the other hand, the original AP-42 NOx emission factor for flares is based on a study of extractive measurements at pilot scale test flare.[57] The study was based on only 42 test runs at two different flares, located at a flare test facility.[58] Further, the flare was fed propylene diluted with varying levels of nitrogen.[59] The resulting data is not representative of actual flare operation or emissions because industrial flares are used to combust a mixture of gases that can include a multitude of different chemical compounds. Further, the accuracy of the testing using extractive probes is uncertain. At least one member of EPA's expert panel called into question the reliability of the extractive probe results explaining that it is "at best very difficult and at worst impossible" to place the extractive probe in representative location.[60]

Finally, while the revised emission factor is an improvement, it is likely still biased low because it includes the original AP-42 data in the average. As discussed above, the data used to derive the original AP-42 emission factor is less reliable and accurate than the new PFTIR test data. Including the originaly emission factor as part of the average, the NOx emission factor based is 2.9 lbs./MMBtu. Excluding the original AP-42 emission factor from this analysis, which is 0.068 lbs./MMBtu, would result in the average value increasing to 3.4 lbs./MMBtu. EPA's continued acceptance of the underlying data used to derive the original AP-42 emission factor is unsupported given that the testing was not conducted on flares combusting gas that accurately represents the gas routed to industrial flares.

B. EPA's Proposed New VOC Emission Factor for Industrial Flares Will Improve the Accuracy of Reported Emissions but Needs Clarification.

EPA's proposed VOC emission factor for industrial flares will improve the accuracy of emission estimates because it was developed from several sources and is based on real-world operating conditions. The proposed new emission factor is 0.55 lbs./MMBtu. EPA developed the new VOC emission factor using PFTIR and DIAL data collected from nine different flares.[61] The underlying PFTIR data includes 168 test runs and 3842 data points.[62] The DIAL data is the average of 23 scans taken at BP Texas City.[63] Each of these studies was conducted at flares in

---

Corp., Passive Fourier Transform Infrared Technology (PFTIR) Evaluation of P001 Process Control Device at Ineos ABS (USA) Corp., Addyston Ohio Facility (July 2010) [hereinafter Ineos PFTIR Study].

[55] Carrie Richardson Fry and Jeff Coburn, Peer Review of "Parameters for Properly Designed and Operated Flares," EPA-HQ-OAR-2010-0682-0193 [hereinafter Expert Review Panel Memo].

[56] *Id*. at 101 ("based on my review of the literature the data as presented appear reliable thus any analysis will be reliable").

[57] U.S. Envtl. Prot. Agency, Flare Efficiency Study, EPA-600/2-83-052 (July 1983) [hereinafter Flare Efficiency Study].

[58] *Id*.

[59] *Id*.

[60] Expert Review Panel Memo, *supra* note 55, at 16.

[61] Draft Review of Emissions Test Reports, *supra* note 51, at 44, tbl. 22.

[62] Flare Calculation Spreadsheet, *supra* note 53.

[63] *Id*.

actual use at industrial facilities, combusting normal process gas.[64] And as explained by EPA, is a robust enough data set to develop a more accurate emission factor for VOCs. By way of contrast, the original total hydrocarbon (THC) emission factor included in AP-42 was derived from 42 test runs at two different flares.[65]

While the proposed new emission factor will improve the accuracy of emissions reporting from flares, EPA should provide the additional clarifications and guidance explained below.

EPA Must Clarify that a Flare is Only Guaranteed to Achieve 98% Destruction Efficiency if the Operator Maintains a Minimum Heat Value at the Flare Tip.

The proposed revisions to the AP-42 section on industrial flares must clarify that the proposed emission factor is only representative of flares that achieve 98% combustion efficiency and set forth the operating conditions and requirements that assure 98% destruction efficiency. The proposed VOC emission factor is based on measured emissions where EPA could confirm that the flare was achieving 98% destruction efficiency.[66] Specifically, EPA discarded any PFTIR test data or DIAL scans where the flare did not achieve 98% destruction efficiency.[67] Therefore, the resulting emission factor is only representative of a flare that actually achieves 98% destruction efficiency.

Data from several sources show that flares, complying with the current regulatory requirements, do not achieve 98% destruction efficiency:

1) EPA evaluated process data for 38 steam-assisted flares submitted by the American Petroleum Institute, National Petrochemical and Refiners Association, and the American Chemical Society.[68] This data is from actual flares under normal operating conditions.[69] EPA found, based on the reported steam rates and heat value that the average destruction efficiency for these flares was 93.9%.[70]
2) The PFTIR data that EPA relied on to develop the VOC emission factor includes a total of 693 test runs.[71] EPA only utilized data from 168 of these test runs to develop the new VOC emission factors.[72] Of the lager data set, 351 test runs were performed under conditions where the flare satisfied all existing regulatory requirements and were not otherwise flagged by EPA for having data quality

---

[64] *See e.g.*, Marathon Detroit PFTIR Study, *supra* note 54; Port Arthur PFTIR Study, *supra* note 54; Ineos PFTIR Study, *supra* note 54; Clean Air Engineering, Performance Test of Steam-Assisted Flare with Passive FTIR, Marathon, Texas City (2010); David T. Allen and Vincent M. Torres, TCEQ 2010 Flare Study, Final Report (2010); National Physical Laboratory, Measurements of VOC Emissions from Petrochemical Industry Sites in the Houston Area Using Differential Absorption Lidar (DIAL) during Summer 2007 (DRAFT FOR COMMENT), (2007) [hereinafter NPL BP Texas City DIAL Study].

[65] Flare Efficiency Study, *supra* note 57.

[66] DRAFT Review of Emissions Test Reports, *supra* note 51, at 43.

[67] *Id*.

[68] Flare Impact Estimates, *supra* note 30, at 6.

[69] *Id*.

[70] *Id*. at 6-9.

[71] Parameters for Properly Operated Flares, *supra* note 36, at Appendix B, (Apr. 2012).

[72] Flare Calculation Spreadsheet, *supra* note 53.

problems.[73] Based on this data, the average destruction efficiency measured during these test runs was close to 92%. The 351 test runs identified by facility, test condition, and run number are attached.[74]

3) The test data is confirmed by evaluation of flare emissions at specific refineries. For example, at BP Whiting, EPA enforcement official Pat Foley calculated that the flares released 25 times more pollution than originally reported based on historical operating data.[75] At Marathon, the facility determined that its historical flare combustion efficiency ranged 65-96% and that emissions were 11 times higher than originally reported across all of its refining operations (EPA's enforcement division determined that emissions were actually 12 times higher).[76]
4) Differential Absorption LIDAR studies in at facilities in Houston, Texas and Texas City, Texas both show that emissions flare control efficiency is often lower than previously thought and that actual emissions can be several orders of magnitude higher.[77]

Based on this data, EPA must revise the proposed text of the AP-42 emission factor for flares that reads: "Properly operated flares achieve at least 98 percent destruction efficiency." EPA regulations set out at 40 C.F.R. § 60.18 and 40 C.F.R. § 63.18 set out limits on the minimum heat value of the gas routed to a flare, the maximum exit velocity of the gas, and prohibit visible emissions. The data cited above overwhelmingly show that flares complying with these regulatory requirements do not achieve 98% efficiency. Drawing from this data, EPA recently proposed to augment the standards for refinery flares to assure that they do in fact achieve 98% destruction efficiency. Specifically, the proposed Refinery NESHAP rule set the minimum heat value in the combustion zone at 270 btu/scf for general flares, and 380 btu/scf for flares with high hydrogen or olefin content.[78] These findings are applicable beyond the refining industry, as several of the PFTIR studies reviewed by EPA to develop the parameters for properly operating a flare were conducted at non-refinery flares like chemical plants.[79] Thus, EPA must clarify that the emission factor is representative of a flare achieving 98% combustion efficiency, and that a flare must meet these minimum heat values to be considered "properly operating."

---

[73] Parameters for Properly Operated Flares, *supra* note 36, at Appendix B (EPA reviewed test data from refineries, petrochemical plants, and flare test sites. Appendix B shows all test runs that satisfied EPA's data quality requirements and complied with existing standards).

[74] *See* Earthjustice Refinery NESHAP Proposal Comments, *supra* note 34.

[75] Flare Impact Estimates, *supra* note 30, at 9.

[76] *Id*. at 9 & Attachment 5.

[77] EPA Critical Review of BP Texas City DIAL Study, *supra* note 9; Shell Deer Park DIAL Study, *supra* note 8.

[78] Refinery NESHAP Proposal, *supra* note 14, at 36908, tbl. 3.

[79] *See e.g.*, Ineos PFTIR Study, *supra* note 54; Port Arthur PFTIR Study, *supra* note 54.

EPA Should Propose an Alternate VOC Emission Factor for Flares That Cannot Maintain the Heat Value Required to Guarantee 98% Destruction Efficiency or Do Not Have Sufficient Monitoring to Verify the Heat Value of the Flare Gas.

EPA should propose an alternate VOC emission factor for flares that is representative of flares that comply with the existing regulatory requirements. As discussed above, the data shows that industrial flares that comply with the existing regulatory requirements on flares do not achieve 98% destruction efficiency. The data from the American Petroleum Industry, National Petrochemical and Refiners Association, and American Chemical Society shows that flares only achieve 93.9% destruction efficiency.[80] The industry provided "blinded operating data for steam-assisted flares – both under "standby" and "upset" conditions.[81] Seven companies provided data on 38 flares and a128 operating scenarios.[82] EPA before conducting its analysis removed data for olefin flares and periods when the current regulatory requirements for flares were not applicable (e.g. no flow, or purge only flow).[83] The PFTIR data shows that flares complying with the applicable regulatory requirements achieve about 92% destruction efficiency. EPA should utilize these two data points to propose an alternate emission factor for flares that cannot maintain the minimum heat value at the flare tip to assure 98% destruction efficiency or do not have sufficient monitoring to verify the heat value of the flare gas. EPA should make clear in the AP-42 text that the alternate flare factor is more appropriate when the heat value in the combustion zone of the flare does is not at least 270 btu /scf (380 btu/scf for flares with high hydrogen or olefin content) or the operator cannot verify that these conditions are being met. Further, flare operators could perform their own testing to demonstrate that their flare actually achieves 98% destruction efficiency.

EPA Should Propose an Alternate VOC Emission Factor for Flares at Oil and Gas Facilities.

EPA should propose an alternate VOC emission factor for "pit flares" utilized in the oil and gas sector. EPA's recent oil and gas NSPS and NESHAP rule determined that certain flares, including "pit flares" utilized at oil and gas facilities can only reliably achieve 95% destruction efficiency. The rule describes pit flares as "rather crude" and "because of the nature of the flowback (i.e., with periods of water, condensate, and gas in slug flow)," use of normal flares is not possible. Further, it is not possible to test or monitor for efficiency. Because of these characteristics, "the efficiency of completion combustion devices, or exploration and production flares, can be expected to achieve 95 percent, on average, over the duration of the completion or recompletion."[84] Facilities that apply the proposed new VOC emission factor, which is based on 98% destruction efficiency, would underestimate emissions by 250%. Therefore, the proposed emission factor would be biased low and not be useful for estimating emissions from these facilities. Proposing an alternate emission factor would address this concern and help assure that

---

[80] Flare Impact Estimates, *supra* note 30, at 9.
[81] *Id*. at attachment 2.
[82] *Id*.
[83] *Id*. at 7.
[84] U.S. Envtl. Prot. Agency, Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution; Background Technical Support Document for the Proposed Standards, EPA-HQ-OAR-2010-0505-0045, 4-19 (Jul. 2011).

the VOC emission factor satisfies EPA's own information quality act guidelines for objectivity and utility.

C. EPA Should Propose a Methane Emission Factor for Flares

Refinery and oil and gas industry flares are a significant source of methane.[85] The agency has data on the methane content of refinery flares and oil and gas flares. For petroleum refinery flares, EPA has collected the data as part of the PFTIR testing it used to evaluate combustion efficiency at flares. According to this data, the average methane concentration in flare gas at refineries is 12%.[86] EPA should use this information, in tandem with the appropriate combustion efficiency value to propose an emission factor for methane from refinery flares.

Similarly, EPA should use the data it collected for the Oil and Gas NSPS and NESHAP rule to propose a methane emission factor for flares.[87] The data shows that production natural gas is 82.9% methane by volume and 65.7% methane by weight.[88] Transmission natural gas is 92.8% methane by volume and 86.2% methane by weight.[89] This data is derived from nationwide natural gas sampling conducted by the Gas Research Institute and was used by EPA to estimate emissions of methane, VOCs, and other toxics from the oil and gas sector for the NSPS and NESHAP rule.[90] Developing an emission factor from this data will help EPA better track and account for methane emissions from these sectors in air quality decisions.

D. The Industrial Flare Emission Factor for Total Hydrocarbons Must be Revised

The revised industrial flare AP-42 chapter includes an emission factor for THC that substantially underestimates emissions. Hydrocarbons released from flares include VOCs and other chemicals including methane and ethane. In other words, VOCs are a subset of total hydrocarbons released from flares. Nevertheless, EPA's proposed revision includes a VOC emission factor of 0.55 lbs./MMBtu and a total hydrocarbon emission factor of 0.14 lbs./MMBtu.[91] Because VOCs are a subset of total hydrocarbons and the VOC emission factor suggests greater emissions, it is clear that EPA needs to revise the total hydrocarbon factor. EPA should use the total hydrocarbon data it collected from the PFTIR flare tests to develop a revised emission factor.

---

[85] Oil and Natural Gas Sector: New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutant Reviews; Proposed Rule, 76 Fed. Reg. 52,738, 52,756 (Aug. 23, 2011); Refinery NESHAP Proposal, *supra* note 14, at 36911, 36951.

[86] Design Parameters for Properly Operated Flares, *supra* note 36, at Appendix B.

[87] Heather P. Brown, EC/R, Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking, EPA-HQ-OAR-2010-0505-0084 (Jul. 28, 2011).

[88] *Id.*

[89] *Id.*

[90] *Id.*

[91] Draft AP-42 Section 13.5, *supra* note 25.

V. EPA's Proposed New Hydrogen Cyanide Emission Factor for Fluid Catalytic Cracking Units is Representative and Based on a Robust Data Set.

The proposed hydrogen cyanide emission factor for fluid catalytic cracking units is based on reliable stack testing data. The proposed emission factor is based on nine test reports for eight unique FCCU units.[92] In developing the HCN emission factor, EPA reviewed a total of 22 test reports.[93] EPA received 10 of the test reports pursuant to Component 4 of the 2011 Petroleum Refinery Information Collection Request.[94] EPA requested 10 facilities to submit testing data following detailed instructions on testing parameters and to also include key process information data.[95] The agency received an additional 12 tests pursuant to Component 1 of the ICR.[96] EPA was able to use 5 of the test reports submitted pursuant to Component 4 and 4 of the test reports submitted pursuant to Component 1.[97] This amount of data exceeds the minimum necessary that EPA has relied on in the past to develop emission factors for other industrial sources. Therefore, EPA's HCN emission factor for FCCUs is sufficiently representative of actual emissions.

EPA should also use the tools it has at its disposal to improve on the HCN emission factor for FCCUs. Several of the test reports submitted by industry pursuant to Component 4 of the ICR did not include sufficient process data to enable EPA to utilize the data.[98] This process data includes the feed rate and the coke burn rate of the FCCU during testing. EPA specifically requested this data as part of the ICR.[99] EPA should follow-up with the facilities that did not provide this information. First, industry's failure to provide this data likely is a violation of Clean Air Act Section 114.[100] Pursuant to this requirement industrial facilities are required to comply with EPA's information request. Second, this information should be readily available and the APA requires that EPA review readily available data before finalizing the rule.[101]

---

[92] DRAFT Review of Emissions Test Reports, *supra* note 51, at 16, tbl. 6.

[93] *Id*. at 10, tbl. 1.

[94] Eric Groehl, U.S. Envtl. Prot. Agency, Summary of Fluid Catalytic Cracking Emission Test Reports (Oct. 16, 2012) [hereinafter FCCU Test Reports Summary].

[95] U.S. Envtl. Prot. Agency, Petroleum Refinery Emissions Information Collection, Part VIII. Test Procedures, Methods and Reporting Requirements for the Information Collection Request for Petroleum Refineries (2011) [hereinafter ICR Emissions Testing Instructions].

[96] DRAFT Review of Emissions Test Reports, *supra* note 51, at 10, tbl. 1.

[97] *Id*. at 16, tbl. 6.

[98] U.S. Envtl. Prot. Agency, AP-42 Fifth Edition, Vol. 1, Chap. 5: Petroleum Industry, 5.1 – Petroleum Refining, Draft Background Documents (Test_Data_Sum_HCN_FCCU_2014Aug.xlsm Referenced is part of the background documents supporting EPA's proposed emission factor for HCN released from FCCUs. Column DA, labeled "QA Notes" explains why certain test data was not used) [Draft Background Documents for AP-42 Chap. 5].

[99] ICR Emissions Testing Instructions, *supra* note 95, at 1.

[100] 42 U.S.C. § 7414(a)(1).

VI. EPA's Must Utilize Easily Accessible Process Data to Propose CO Emissions Factors for Catalytic Reforming Units and Hydrogen Plants, Total Hydrocarbon Emissions from Hydrogen Plants, and Improve the Proposed Emissions Factors for Various Refinery Units.

EPA should collect and utilize the production data and any other process data it needs to evaluate and utilize the emissions test data submitted by refineries in response to the Petroleum Refinery ICR. Under the APA, the agency has a duty to review and collect data that is easily retrievable using conventional means.[102] EPA originally requested that all facilities submit relevant process data for the emissions tests EPA requested they perform.[103] As illustrated in the chart below, many facilities did not submit the requested process data that is necessary for EPA to develop emissions factors.

Table C: Summary Chart of Source Test Data Submitted to EPA in Response to Component 4 of the Petroleum Refinery ICR

Emissions Source	# facilities Requested to Test by Process Unit	# of Source Test Reports Received By EPA	Pollutant	# of facilities that submitted test reports by pollutant[104]	# of tests listed in test data summary[105]	# tests that didn't contain production data	% missing production data
CRU	12	10	CO	2	3	3	100%
			THC	1	1	1	100%
FCCU	10	10	HCN	10	10	4	40%
H2P	6	5	CO	3	3	2	67%
			NOx	1	3	1	33%
			THC	2	4	2	50%
SRU	6	6	CO	5	6	5	75%
			NOx	1	1	1	100%
			THC	6	6	5	83%

At least in one case, a facility specifically noted that the data is available upon request.[106] EPA's failure to collect this data substantially impaired the agency's ability to promulgate new CO emissions factors for catalytic reforming units and hydrogen plants, and a new THC emission factor for hydrogen plants. Further, collecting the missing process data would have enabled EPA to broaden the data set for the new emissions factors it did propose for sulfur recovery units

---

[102] *Id.*

[103] ICR Emissions Testing Instructions, *supra* note 95.

[104] FCCU Test Reports Summary, *supra* note 94; Eric Groehl, U.S. Envtl. Prot. Agency, Summary of Catalytic Reforming Unit Emission Source Test Reports (Sept. 27, 2012); Eric Groehl, U.S. Envtl. Prot. Agency, Summary of Hydrogen Production Plant Emission Source Test Reports (Mar. 29, 2012); Eric Groehl, U.S. Envtl. Prot. Agency, Summary of Sulfur Recovery Unit Emission Source Test Reports (Mar. 29, 2012).

[105] Draft Background Documents for AP-42 Chap. 5, *supra* note 98 (includes test data summaries for each of the emission factors proposed by EPA).

[106] *See Id.* (Specifically, ExxonMobil's source test for the Catalytic Reformer Unit states that it did not submit the necessary process data, but that it would provide it upon request from EPA).

(NOx, CO, THC), catalytic reforming units (THC), hydrogen plants (NOx), fluid catalytic cracking units (HCN).

VII. EPA's So-Called Determination that Revision of the VOC Emission Factors for Storage Vessels and Wastewater Treatment Systems is Not Necessary is Arbitrary and Capricious.

EPA's decision not to revise the VOC emission factors for wastewater treatment plants and storage vessels is arbitrary and capricious. Under Section 130, EPA must either (1) make a determination that revision is not necessary or (2) make a determination that revision is necessary and revise the emission factor every three years. EPA may not—as it has done here—punt because it claims it does not have sufficient data to make a determination as to whether revision is necessary or revise the emission factor. EPA's decision not to revise the VOC emission factors for storage vessels and wastewater treatment systems is based on EPA's claims that it does not have sufficient data to revise the emission factors and *not* that revision is not necessary. If this is the case, at a bare minimum, EPA should establish a plan with firm deadlines to collect the data it needs to make a determination and revise the emission factors. However, in this instance, there is readily available data for EPA to make a determination that revision is necessary *and* revise the emission factors. Thus, EPA should proposed new emissions factors that better account for dangerous VOC pollution from storage vessels and wastewater treatment systems.

A. EPA's Decision Not to Revise the VOC Emission Factors for Tanks and Wastewater Treatment Systems is Not a Determination as to Whether Revision of the Emission factors are Necessary.

Under Section 130, EPA must either (1) make a determination that revision of the VOC emissions factors for tanks and wastewater treatment systems is not necessary or (2) make a determination that revision is necessary and revise the emissions factors every three years. Instead of making a determination on the threshold question: *Is Revision of the Emissions Factor Necessary?*, EPA evaluated whether there was enough data to revise the emission factors. Specifically the agency states "the available DIAL study reports do not provide the necessary process operating data by which to normalize the measured emissions in order to develop an emissions factor."[107]

The agency's review of specific studies drew similar conclusions. EPA dismissed the Shell Deer Park DIAL Study explaining that "given the lack of process operating data and occasions where the DIAL scans appeared to include emissions contributions from additional sources . . . it does not appear that the Shell DIAL study can be directly used to update or revise emission factors."[108] This does not address the threshold question that Section 130 requires EPA to answer. EPA draws similar conclusions about the emissions data collected from storage

---

[107] DRAFT EPA Review of Available Documents for Developing of Emissions Factors, *supra* note 27, at 30.
[108] *Id*. at 23.

vessels through the Shell Deer Park DIAL study,[109] and the Sprague Operating Resources emissions test.[110] Therefore, EPA must make a determination as to whether revision of the emission factors is necessary and revise the emission factors if the answer to that question is yes.

B. Revision of the VOC Emission Factors for Storage Vessels is Necessary Because DIAL Studies Consistently Show that the VOC Emission Factors For These Units Undercount Emissions.

Revision of the VOC emissions factors for storage vessels are necessary because the existing factors significantly undercount these dangerous emissions. EPA reviewed three separate DIAL studies. Each concluded that emissions from storage vessels emit more VOCs than predicted by emission factors.

- The Alberta DIAL study "extrapolated VOC emissions for the refinery's storage tanks were projected to be 5,090 tonnes/yr compared to 153 tonnes/yr as reported by Canada's National Pollution Release Inventory."[111]
- The BP Texas City DIAL Study found that the measured emissions from storage vessels were generally substantially higher than emission factors would predict. Based on EPA's analysis, reproduced in the chart below, DIAL measurements were more than 2 times higher than the estimated amount at 5 out of 8 of the tank groupings. Further, only two of the measurements fell within the estimated range of emissions.

Table D: BP Texas City DIAL Study – Storage Vessel Emissions Summary Chart[112]

Source	Source Description	Compound	Average Emissions Measured Using DIAL (lb/hr)	Estimated Emissions Using Standard Estimating Procedures with Actual Conditions at the Time of the DIAL Test (lb/hr)
Tanks 1020, 1021, 1024, and 1025	External Floating Roof tanks storing crude oil	VOC	6.4	1.3 - 1.9
Tanks 1052, 1053, and 1055	External Floating Roof tanks storing crude oil	VOC	16.3	1.8 - 2.3
Tanks 501, 502, 503, and 504	External Floating Roof tanks storing light distillates	VOC	8.6	3.0 - 3.9
Tank 43	Vertical Fixed Roof tank storing fuel oil #6	VOC	2	1.3
			9.3	1.3
Tanks 60, 63, 11, 12, 18, 42, 61, and	Vertical Fixed Roof and External Floating Roof	VOC	9	0.6 - 9.1

---

[109] *Id*. at 20 ("The Shell DIAL study does appear to show that most of the tanks at the Shell Deer Park refinery that were targeted for DIAL measurement scans had higher than expected emissions during the time of the DIAL test. However, given the lack of process data, it does not appear possible to develop the emissions factor methodologies for storage tanks based on the reported Shell DIAL study data").

[110] *Id*. at 30 ("Once again, while the data from the testing at the Sprague facility are interesting, in order to conclude whether revisions to the AP-42 Chapter 7 equations are appropriate, targeted testing would need to be performed").

[111] Alberta DIAL Study, *supra* at 40, at 17, tbl. 8.

[112] EPA Critical Review of the BP Texas City DIAL Study, *supra* note 9.

65	tanks storing various products			
Tanks 54, 55, 56, and 98	Vertical Fixed Roof and External Floating Roof tanks storing various products	VOC	3.1	0.3 - 9.7
Tanks 53 and 55	Vertical Fixed Roof tanks storing diesel fuel	VOC	23.8	4.8 - 5.2

- The Shell Deer Park DIAL Study found that the measured emissions at the storage vessel groups were greater than the estimated emissions 100% of the time. And, in 6 out of 9 of the data points, the measured emissions were more than the estimated emissions by a factor of ten.

Table E: Shell Deer Park DIAL Study – Storage Vessel Emissions Summary Chart.[113]

Source	Compound	Average Emissions Measured Using DIAL (lb/hr)	Estimated Emissions Using Standard Estimating Procedures with Actual Conditions at the Time of the DIAL Test (lb/hr)
Southwest Tanks A-333, A-330, A-332	VOC	20.18	2.15
Southwest Tanks A-325, A-326	VOC	13.15	0.56
South West Tanks AP-17	VOC	42.6	0.46
Southwest Tanks AP-17, AP-16	VOC	51.53	0.39
West Tanks A-310, U-324-R1	VOC	15.8	0.43
CR-3	VOC	27.37	20.67
East Tanks J-327; J-328, J-331, J-332	VOC	37.05	9.52
East Tanks J-327; J-328	VOC	18.07	0.27
East Tanks J-327, J-328, J-331, J-332	VOC	35.98	9.53

This data demonstrates that the emission factors used to estimate emissions from storage vessels are not accurate and cannot be used to make realistic emissions estimates that can be used for air quality planning purposes. EPA should determine, based on this data that it is necessary to revise the emission factors for storage vessels.

EPA's proposed determination that revision of the emissions factors for storage vessels is unnecessary dismisses the findings of these studies citing a lack of data (on the content of the tanks, the condition of the tanks, and the extent to which upwind sources contributed to the tanks), or because EPA concluded that estimated emissions agreed reasonably well after accounting for contributing sources.[114] This out of hand dismissal of this data is arbitrary and capricious.

---

[113] Shell Deer Park DIAL Study, *supra* note 8.

[114] DRAFT EPA Review of Available Documents for Developing of Emissions Factors, *supra* note 27, at 15-16.

EPA Can Obtain Most or All of the Data it Needs.

EPA has cited that defective tanks, inaccurate information on storage vessel contents, and/or insufficient data to determine the contribution of upwind sources makes it difficult to compare emission rates measured using DIAL with emission rates predicted using AP-42 emission factors.[115] EPA has the ability to resolve each of these questions.

To determine if tanks are defective, EPA can:

- Review upset emission reports from Texas' Emission Event Database.[116]
- Request and review the maintenance logs for these tanks from the date of testing to present from the facilities.
- Inspect the tanks in question to determine if they are defective. If EPA finds that they are defective, EPA could conservatively assume that the tanks were also defective at the time of testing.

To determine what exactly was stored in the tanks during the time of testing, EPA can:

- Request emission inventory submissions and the underlying data used to report emissions during the time period of the DIAL.
- Request storage vessel material handling logs from the time period of the DIAL testing.

To determine if additional upwind sources contributed to the measured emissions, EPA can:

- Request information from the authors of the respective studies to determine the range of the DIAL instrument. EPA should have the ability to obtain this information for both the BP Texas City DIAL study as well as the Shell Deer Park Study because both were funded in part by EPA and the agency has worked closely with the study authors to develop the study.[117]
- Review emission inventory data from the facility in question and nearby sources to triangulate other potential sources of emissions.

Measured Emissions Do Not Agree Well With Estimated Emissions.

EPA's Draft Review of the Available Documents for Developing Proposed Emissions Factors for Flares, Tanks, and Wastewater Treatment Systems discussion of the EPA's Critical Review of the BP Texas City Dial study states that "when emissions were projected for all tanks upwind of the scan plan . . . the estimated emissions often agreed well with the DIAL measurements."[118] It is unclear which measurements EPA is referring to specifically, as illustrated in the chart above, only two out of nine measurements fell within the range of

---

[115] *Id.*

[116] *See* TCEQ, Air Emission Event Report Database, *available at* http://www11.tceq.texas.gov/oce/eer/index.cfm.

[117] *See* EPA Critical Review of BP Texas City DIAL Study, *supra* note 9, at ES-1 ("In July and August the Texas Commission on Environmental Quality (TCEQ) and the U.S. Envtl. Prot. Agency (EPA) sponsored testing of numerous "difficult to measure" emission sources at BP petroleum refinery in Texas City."); *Supra* note 7.

[118] DRAFT EPA Review of Available Documents for Developing of Emissions Factors, *supra* note 27, 15-16.

estimated emissions. Further, EPA's calculation of the estimated emissions range for Tanks 60, 61, 63, 65, 11, 12, 18 and 42 is unclear, incomplete, and/or incorrect.

Specifically, EPA's review of the NPL data found that the DIAL scans identified as 399-404 could have captured emissions from tanks 11, 12, 18, 42, 60, 61, 63, and 65.[119] Based on this, EPA modeled that the emissions from this grouping of tanks ranged from 0.6 lbs. to 9.1 lbs.[120] The NPL report found that DIAL scans measured an average VOC emission rate of 9 lbs. per hour.[121] While the measured emissions and EPA's estimated emissions do appear to agree, EPA's calculations are unclear and possibly incorrect. EPA's calculations are included as Appendix D of the Critical Review of DIAL Emission Test Data for BP Petroleum Refinery in Texas City. EPA's calculations are unclear or incorrect because of the following problems:

- Table D-14 appears to be misidentified. Table D-14 states that it models the emissions from Tank 98 and references DIAL scans 11 and 12. Based on the NPL report, these scans targeted Tanks 23, 27, 28, and 29.[122]
- Table D-15 appears to be misidentified. The title states that the table summarizes emissions from Tanks 54, 55, 56, and 98.[123]
- Because of the misidentified tables, it is unclear how EPA calculated the emissions from tanks 11 and 12.
- It is not clear if EPA included the estimated emissions from Tank 98 in the range represented for this tank grouping. If the range does include emissions from Tank 98, EPA should provide an explanation supporting this decision. Based on Figure 2.8 and from the NPL report it appears very unlikely that emissions plume from Tank 98 would cross the path of the DIAL scans 399-404.[124]
- EPA should not have included emissions from tanks 11, 12, 18 as sources contributing emissions to the measured emissions. The NPL study performed DIAL scans that isolated these tanks and measured that the emissions from these tanks were negligible, at less than 1 lb. per hour.[125] Nevertheless, EPA modeled that the emissions from Tank 18 contributed 2.57 lbs. per hour and as discussed above, it is unclear what amount Tanks 11 and 12 were calculated to contribute to the modelling.[126]

C. EPA Did Not Adequately Evaluate the Available Data on Emissions from Wastewater Treatment Facilities and Storage Vessels.

EPA's review of the VOC emission factors is flawed because the agency did not consider all the available data on wastewater treatment system emissions and did not fully evaluate the available data on storage vessel emissions. The agency's review and ultimate determination

---

[119] EPA Critical Review of BP Texas City DIAL Study, *supra* note 9, at 11-12.
[120] *Id*. at ES-2, tbl. 1.
[121] NPL BP Texas City DIAL Study, *supra* note 64, at 27.
[122] BP Texas City DIAL Study, *supra* note 32, at D-15, tbl. D-14.
[123] *Id*. at D-15, tbl. D-15.
[124] NPL Texas City DIAL Study, *supra* note 64, at 27, Fig. 2.8.
[125] *Id*.
[126] BP Texas City DIAL Study, *supra* note 37, at D-10 – D-15.

must be based on the available relevant facts and scientific data.[127] In this case, EPA failed to review available source testing the agency collected on wastewater treatment plants and storage vessels.

Wastewater Treatment Systems

With regards to wastewater treatment plants, EPA requested five facilities to submit testing data for the Enhanced Biodegradation Units, a process used to control emissions from a facility's wastewater treatment system.[128] Each facility was required to test for:

- speciated volatile organic hazardous air pollutants (HAP);
- speciated semi-volatile organic HAP;
- Aldehydes;
- Sulfide (as Sulfur);
- Biochemical Oxygen Demand (BOD); and
- Chemical Oxygen Demand.[129]

It does not appear that EPA reviewed the source test data for wastewater treatment plants as part of its review of the emission factors for wastewater treatment systems. The agency already possesses this data, and the APA requires that EPA consider this data as part of its review.

Storage Vessels

EPA's review of the storage vessel test data it obtained from Global Companies LLC in South Portland, Maine and Sprague Operating Resources LLC in Searsport Maine fails to adequately analyze the data to determine if the VOC emission factors need revision. Each facility was required to directly measure VOCs from one tank storing No. 6 fuel oil and one tank storing liquid asphalt using a temporary total enclosure.[130] The test method enabled the facility to capture all of the fugitive emissions released from the tank and measure the total amount of VOCs released over a thirty day period.[131] EPA's review of the Sprague Operating Resources test report concluded that "emissions were much higher than expected, based on Sprague's emissions inventory estimates for the years 2006-2009.[132] EPA did not perform a similar analysis for the data from Global Companies LLC.[133] Without a thorough review of this data, EPA cannot claim that its review of the VOC emissions factors for storage vessels meets the requirements of the APA.

Further, an additional DIAL study that measured VOC emissions from storage vessels at several refineries in California's South Coast Air Quality Management District after EPA's

---

[127] Panhandle Eastern Pipe Line Co. v. F.E.R.C. 890 F.2d 435, 439 (D.C. Cir 1989). *See also* National Lime, 627 F.2d 416, 454 (D.C. Cir. 1980).

[128] *See* U.S. Envtl. Prot., List of Facilities to Test (Mar. 28, 2011) *available at* *https://refineryicr.rti.org/Portals/0/List_of_Facilities_to_Test.pdf*.

[129] ICR Emissions Testing Instructions, *supra* note 95.

[130] DRAFT EPA Review of Available Documents for Developing of Emissions Factors, *supra* note 27, at 28-30.

[131] *Id.*

[132] *Id.*

[133] *Id.*

proposal measured emissions 3-8 times higher than emission factors would predict.[134] EPA should review this study, in addition to any new data that has become available since EPA's proposed rule, before finalizing its determination on whether revision of the VOC emissions factor for storage vessels is necessary. For these reasons, EPA has failed to conduct a thorough review of readily available emissions data for wastewater treatment plants and storage vessels.

VIII. Conclusion

The new and updated emission factors in the proposed rule should improve emissions reporting from flares and other refinery sources. However, scientific studies and emissions data shows that the proposed and existing emission factors, specifically VOCs for flares, storage vessels, and wastewater treatment plants, are inaccurate and underestimate dangerous emissions.

EIP appreciates this opportunity to submit comments. If you have any questions or would like to discuss our concerns in more detail, please do not hesitate to contact me at the information provided below.

Sincerely,

Sparsh Khandeshi
Attorney
Environmental Integrity Project,
1000 Vermont Ave. NW,
Suite 1100
Washington DC, 20005
202-263-4446
Skhandeshi@environmentalintegrity.org

Adrian Shelley
Executive Director
Air Alliance Houston
2409 Commerce Street
Houston, TX 77003

Juan Parras
Executive Director
Texas Environmental Justice Advocacy Services
6733 Harrisburg Boulevard
Houston, TX 77011

Hilton Kelley
Executive Director
Community In-power and Development Association
1301 Kansas Avenue
Port Arthur, TX 77642

---

[134] Carson Area SOF Study, *supra* note 42.

Appendix A – Carson Area SOF Study

2013

Pilot study to quantify industrial emissions of VOCs, NO_2 and SO_2 by SOF and mobile DOAS in the Carson Area

FluxSense

FINAL REPORT

FluxSense AB

27 March 2014

Date: 2014-03-27

Title: Pilot study to quantify industrial emissions of VOCs, NO_2 and SO_2 by SOF and mobile DOAS in the Bay Area

Authors: Johan Mellqvist[1], Jerker Samuelsson[1], Brian Offerle[1], Samuel Brohede[1], Pontus Andersson[1], Marianne Ericsson[2]

[1]FluxSense AB, Hörsalsvägen 11, SE-41296 Göteborg, Sweden

[2]FluxSense Inc, 113 W G Street # 757, San Diego, CA 92101

E-mail: johan.mellqvist@fluxsense.se

FluxSense AB (www.fluxsense.se) is a spin-off company from Chalmers University of Technology in Sweden. The company has been active for 10 years and has carried out 60+ industrial site surveillances in Austria, Belgium, Denmark, France, Middle East, Netherlands, Norway, Sweden and the US.

FluxSense Inc is a subsidiary residing in San Diego.

[Cover: Visualization of alkane (blue curves) plume transects from SOF measurements taken on October 12, 2013 between 13:30 and 17:15 in Carson and Wilmington, California. Apparent graph height is proportional to the integrated vertical column concentration in mg/m^2. A white arrow indicates the approximate wind direction and speed during the measurements. Winds were light and variable from SW to NW. Image mapped on Google Earth © 2013.]

Executive summary

Overview

In October 2013, column measurements of VOCs, SO_2 and NO_2 were carried out for 2.5 weeks in Carson, California and vicinity, to study direct emissions of these air pollutants from refineries and storage facilities. Two remote sensing techniques, SOF (Solar Occultation Flux) and Mobile DOAS (Differential Optical Absorption Spectroscopy) were used on public roads and along the fence lines of several refineries to estimate facility-wide mass emissions of VOCs, SO2 and NO2. Additional measurements were made over several days by mean of meFTIR (Mobile extractive FTIR) and MW-DOAS (Mobile White cell DOAS) to map ground concentrations of alkanes and aromatic VOCs and complement the SOF data. Using this approach mass flux measurements of aromatic VOCs were demonstrated.

Objective

In this technology demonstration project the main objective was to get an initial estimate of present emission levels of VOCs from one or several refineries in the Carson area, and compare the direct measurements to current reported levels. The project also introduced and demonstrated the capabilities of the FluxSense emission monitoring concept for annual emission report validation and hot spot detection to the environmental authorities of the South Coast Air Quality Management District (SCAQMD).

Background

SOF is a proven technique employed by FluxSense in over 70 fugitive emission studies around the world. In Europe the SOF technique is considered Best Available Technology for measurements of fugitive emission of VOCs and in Sweden it is used together with tracer correlation and optical gas imaging to screen all larger refineries and petrochemical industries annually. In Scandinavia measurement is the standard for emission reporting and in Sweden FluxSense carries out annual emission surveys on most refineries and petrochemical industries, each survey corresponding to about 10 measurement days, often broken down into several periods over the different seasons to better represent mean annual conditions.

For refineries the measured emissions are typically 0.03%-0.1% of the throughput. When compared to emission estimates based on the tanks model and LDAR, the measured emissions are 3 to 10 times greater. The measurements provide the total emission coming from the whole refinery (the bubble), divided into sub parts such as process areas, crude oil storage, product storage tanks, water treatment facilities, flares and loading operations. The estimated uncertainty for the emissions is 30% for the bubble, and higher for the individual parts. The SOF measurements are complemented by tracer correlation measurements at identified hotspots; for instance at individual tanks or loading facilities measurements are made specifically during tank filling or vessel loading to improve the understanding of activity related emissions and their variability. In addition optical gas imaging is carried out on the identified hotspots (super smart LDAR), to identify the exact location of the gas leaks for further evaluation whether abatement strategies can be applied.

The annual measurements makes it possible to establish a baseline emission for the facility and by comparison to previous years it is possible to keep track of the emissions, i.e. to understand whether some parts of the refinery is leaking more relative to last year and whether abatement measures are required. The measurements are also used to evaluate the efficiency of various abatement measures and for tuning flare combustion efficiency.

Results

For the facilities examined in this study, measured VOC emission rates (excluding aromatics and methane) were significantly higher than rates derived from the reported annual emissions. Although this report compares a short time period (a few days to two weeks) with annualized emissions, these results are in line with the vast majority of fugitive emission measurement studies we conducted at other locations. In particular, measured inventories are generally 0.05% or more of facility throughput capacity, a factor of 3 to more than 10 times higher than reported emissions based on standard models, which may be only 0.01% of throughput. For the two Carson refineries (i.e. Tesoro and Phillips66), VOC emissions as a percent of capacity were in the lower range what is usually measured, i.e. between 0.01 – 0.04 % (See Table E1).

The typical uncertainty for SOF measurements is 20-30 % with the greatest source of uncertainty deriving from the interpretation of the wind data. In this study wind information was provided by the Tesoro refinery, in addition to wind data that was collected from two nearby monitoring stations operated by the SCAQMD. Additionally, a limited number of GPS sondes were launched to obtain vertical profiles of wind through the lower atmosphere. During the measurements winds were often weak with large spatial variability due to diurnal effects (e.g. sea-breeze). The limited wind dataset coupled with their large spatial variability makes the uncertainty of the VOC measurements higher than normal (here estimated to be between 40 and 50%). In addition measured emissions are only based on several days of measurements and are probably affected by specific operating conditions at the facilities, including possible stoppages and temporary releases. Thus, measured VOC emissions may not fully represent actual annual average emissions.

If actual throughput is at or near capacity then the facilities in Table E1 are on the low end of VOC emissions relative to throughput. Also, measurements at two other refineries were carried out, i.e. ExxonMobil in Torrance and Phillips66 in Wilmington yielding VOC emission rates of 100 and 170 kg/h, respectively, compared to reported values of 64 and 27 kg/h respectively. Since no nearby wind measurements were available and given the complexity of the wind profiles in the area, these last results are affected by large uncertainties and are only indicative. Finally, an assessment of the aromatic emissions from the Tesoro Carson refinery was carried out, yielding 2.5 and 7.5 kg/h of benzene and toluene, respectively.

Table E1. Comparison of reported and measured emissions from selected facilities.

	VOC				SO_2		NOx	NO_2
Site	Reported*		Measured		Reported*	Measured	Reported*	Measured
	kg/h	% capacity	kg/h	% capacity	kg/h	kg/h	kg/h	kg/h
Tesoro Carson	51	0.003%	204 (±32 %)	0.013%	43	40 (±58 %)	67	39 (±37 %)
Phillips66 Carson	12	0.004%	94 (±32 %)	0.033%	22	30 (±42 %)	34	21 (±43 %)

*Data from SCAQMD 2012

Outlook

The observed difference in fugitive VOC emissions between measurements and estimates appears to be a general issue for the petroleum industry worldwide, and if one would adopt the, in general, higher measured values (factor 3-5) this might create legislative challenges for the industry, for instance with permitting and potential liability issues. To avoid this, measurements and estimates could be done in parallel where the former are used for the official reporting while the latter is done as part of the proactive environmental work aimed at reducing the emissions at the site. If this is carried out for a couple of years, followed by abatement work at the dominant hotspot emissions for an industrial site, combined with adaptive improvements of the emission factors, the estimates and measurements may start to converge.

Acronyms used in this report

API	American Petroleum Institute
bbl	barrel
BPD	barrels per day
DOAS	Differential Optical Absorption Spectroscopy
FTIR	Fourier transform infrared
HYSPLIT	Hybrid Single Particle Lagrangian Integrated Trajectory Model
MeFTIR	Mobile extractive FTIR
MW-DOAS	Mobile White cell DOAS
NO2	nitrogen dioxide
SO2	sulfur dioxide
SOF	Solar occultation flux
VOC	volatile organic compound, used interchangeably for non-methane VOC

Unit equivalents

1 kg/h = 52.9 lbs/day
1 bbl/day = 5.783 kg/h

Definitions

Alkane or Alkanes are considered to be alkane species not including methane.

Table of Contents

1. Introduction

A pilot study was carried out in Carson, California, during October 2013 to measure the gaseous emissions of VOCs, SO_2 and NO_2 from refineries in the area. The main objective of this pilot project was to get a first estimate of present emission levels of VOC from one or several refineries and to compare with current reported levels. The project also aimed at introducing and demonstrating the capabilities of SOF and mobile DOAS to the environmental authorities at the South Coast Air Quality Management District (SCAQMD). A similar project has been conducted in the San Francisco Bay Area for the Bay Area Air Quality Management District (BAAQMD).

Similar measurements conducted elsewhere in Texas (Mellqvist 2009, Johansson 2011, Johansson 2013a, Johansson 2013b., Mellqvist 2007, 2008b, 2010, Rappenglück 2008a, 2008b; De Gouw 2009; Wert 2003; Ryerson 2003) and Europe (France, Netherlands, Sweden) were 5 to 10 higher than inventory values and studies indicated that this may have an impact on the production of tropospheric ozone.

For this pilot study, measurements were conducted for about two weeks in October 2013 along the refinery fence-line at public roads, and facility-wide mass emissions of VOC, SO_2, NO_2 were obtained.

2. Methods

Several optical technologies i.e. Solar Occultation Flux (SOF), mobile DOAS, Mobile extractive FTIR (MeFTIR) and Mobile White cell DOAS (MW-DOAS) have been combined to measure and quantify facility-wide VOC emissions from the Tesoro refinery and to pinpoint the potential sources, Table 1. Meteorological measurements were obtained from various wind stations and from GPS (Global Positioning System) sondes. The instruments were mounted on and inside a dedicated vehicle, with AC power provided by a small gasoline powered generator (Figures 1 and 2). An air conditioner was used to prevent overheating of some of the instruments.

Figure 1. The measurement truck used these measurements.

Figure 2 The SOF and the mobile DOAS systems. The solar tracker (front left) transmits solar light into the infrared spectrometer (mid right with a GPS on top) independent of the vehicle's position.

Table 1 The techniques used and their technical characteristics.

Parameter	SOF	Mobile DOAS	Extractive Infrared Whitecell (MeFTIR)	Mobile UV Whitecell (MW-DOAS)
Compounds	Ethene, Propene, Ammonia, Butadiene, sum of Alkanes CO	NO2 SO2 Formaldehyde	Ethene Propene Acetylene Ammonia Sum of Alkanes Methane Ethane Cyclo hexane CO / CO2 N2O	*BTEX* *SO2* *NO2*
Sensitivity	0.1-5 mg/m2	0.1-5 mg/m2	1-10 ppb	*1-5 ppb*
Flux limit	0-2-1 kg/hr	1kg/hr	0.2-2 kg/hr	*1 -2 kg/hr*
Meas. mode	Vert. Column	Vert. Column	Point Sampler	*Point Sampler*
Light Conditions	Sunny with large patches of clear sky	Daylight with patches of clear sky	24 hr Extractive instrument with internal lamp	*24 hr* *Extractive instrument with internal lamp*
Wind Speed	~2-12m/s	~2-12m/s	~2-12m/s	*~2-12m/s*
Time response/ Sampling Frequency	1-5 sec	1-5 sec	5-15 sec	*1-30 sec*
Typical driving speed while measuring	10-50 miles/hr	10-50 miles/hr	10-35 miles/hr	*10-35 miles/hr*
Complementary activity	Wind measurement from mast, balloon, or LIDAR.	Wind measurement from mast, balloon,or LIDAR.	Tracer gas releases (N2O, acetylene, SF6)	*Operated in parallel with MeFTIR.*

2.1 The SOF method

SOF measurements are carried out using an infrared spectrometer that is connected to a solar tracker (see Appendix I and Mellqvist (2010) for details). The latter is a mirror device that tracks the sun and reflects the light into the spectrometer independent of its position. From the solar spectra it is possible to retrieve the path-integrated concentration (column) in the unit mg/m^2 of various species (for instance, propane, ethylene, propylene and ammonia) between the sun and the spectrometer. The measurement system is built into a van. In order to measure gaseous emissions from a source, the vehicle is driven in such way that the detected solar light cuts through the emission plume, Figure 3. To calculate the gas emission the wind direction and speed is also required and these parameters are usually measured from high masts, towers and GPS balloon sondes. Detection limits down to 0.5 mg/m^2 can be achieved which corresponds to measuring a point source of 0.5 kg/h at a distance of 50 m with an accuracy of better than 3%. The SO method was developed from a number of different research projects at the end of 1990's (Mellqvist 1999a, 1999b; Galle 1999). The method utilizes the sun as the light source and gas species that absorb in the infrared portion of the solar spectrum are measured from a mobile platform. The SOF method has been applied in several larger campaigns in both Europe and in the US (Mexico City 2006, Texas 2006/2009/2011/2012/2013; Le Havre 2008, Rotterdam 2008/2010 and Antwerp 2010) and in more than 60 individual plant surveys over the last 7 years. About 10 international reports and several peer reviewed scientific papers (Mellqvist 2010, Foy 2007, De Gouw 2009, Kim 2011, Parrish 2012, Johansson, 2013a, Johansson 2013b) have been written so far, applying the SOF method for various industrial measurements. The technique has been validated by comparison to other methods and tracer gas releases and it typically has an uncertainty of 30% (Table 1) mostly due to uncertainties in the wind field.

In previous campaign studies it has been found that measured emissions obtained with SOF are 3–10 times higher than those from emission inventory calculations. For instance, during TexAQS 2006, it was shown that industrial releases of alkenes for the Houston Galveston area were, on average, 10 times higher than what was reported by industry (Mellqvist 2010). These results were supported by airborne measurements (De Gouw 2009). For alkanes the discrepancy factor was about 8 (Mellqvist 2007). During similar SOF studies in Rotterdam (Netherlands) in 2008 and 2010 (Mellqvist 2009a), Le Havre 2008 and Antwerp 2011 showed overall discrepancies of 4.2, 4.4 and 7.7, respectively. For Swedish refineries the VOC emissions typically correspond to 0.03–0.09 % of the throughput of oil, compared to a typical value of 0.01% obtained with API estimations. Modelers in the USA have responded to the observed discrepancies by increasing the modeled VOC emissions; for instance TCEQ (Texas Commission on Environmental Quality) increases industrial VOCs by ~6 times in ozone modeling (SIP model) and scientists at the US weather service (NOAA-National Oceanographic Atmospheric Administration) (Kim, 2011) have upscaled VOC emissions based on 2006 SOF data in Texas. This improved the agreement with airborne measurements for both VOCs and ozone significantly.

In Europe the SOF technique is considered as Best Available Technology for measurements of fugitive emission of VOCs (besides DIAL) and in Sweden it is used together with trace correlation and optical gas imaging to screen all larger refineries and petrochemical industries annually, over a time period of about 10 days. The data are used for the annual emission reporting and to follow up on abatement strategies, such as new tank sealings, flare efficiency etc.

Figure 3 In the Solar Occultation Flux method (SOF) gases are measured by observing solar light in the infrared portion of the solar spectrum. The instrument is placed in a vehicle which is moved across the plume. From the accumulated mass measured across the plume the flux of gas is obtained by multiplication with the wind speed, see http://www.youtube.com/watch?v=6cre9q8YAzE

2.2 Mobile DOAS

Mobile DOAS (Differential Optical Absorption Spectroscopy) measurements of scattered solar light in zenith direction were carried out in parallel with the SOF measurements in order to measure formaldehyde, NO2 and SO2. DOAS works in the ultraviolet (UV) and visible wavelength region while SOF works in the infrared region and hence there are large differences in spectroscopy and in the used spectrum evaluation methods. However, both methods measure vertical columns which are integrated along the measurement transect and multiplied by the wind to obtain the flux. The principle of flux-measurements using Mobile DOAS is hence the same as for SOF, although it is not necessary to compensate for any slant angle observations since the telescope is always pointing towards zenith. The DOAS system also works under cloudy conditions in contrast to SOF, although the most precise measurements are conducted under clear sky. The system is explained in appendix I and elsewhere (Johansson, 2013b).

The DOAS method was introduced in the 1970's (Platt 1979) and has since then become an increasingly important tool in atmospheric research and monitoring both with artificial light sources and in passive mode utilizing the scattered solar light. In recent time the multi axis DOAS method (scanning passive DOAS) has been applied in tropospheric research for instance measuring formaldehyde (Heckel 2005). Passive DOAS spectroscopy from mobile platforms has also been quite extensively applied in volcanic gas monitoring (Galle et al., 2002) for SO_2 flux measurements and for mapping of formaldehyde flux measurements in megacities (Johansson 2009). Mobile DOAS has only been used to a limited extent for measurements of industrial emissions. For example, Rivera et al. (2009c) performed SO_2 measurements on a power plant in Spain for validation purposes showing an average agreement of 7 % with continuous emission measurements. The same research group also deployed a mobile DOAS to study emissions from an industrial conglomerate in Tula in Mexico (Rivera 2009d) and measured SO_2, NO_2 and HCHO during the 2006 TexAQS campaign (Rivera 2009a, 2009b). There are other groups in both China and Spain working with mobile mini DOAS systems.

2.3. Mobile extractive FTIR

A Mobile extractive FTIR (MeFTIR) system, (Samuelsson 2005a; Galle 2001), was used to measure ground concentrations of alkanes (including methane). The extractive FTIR system contains a spectrometer of the same type as the one being used for SOF measurements (Bruker IRCube) but utilizes an internal light source (glowbar) instead of the sun. The spectrometer is connected to an optical multi-pass cell (Infrared Analysis Inc.) with 40 m path-length, Figure 4. Atmospheric air is continuously pumped with high flow through the optical cell from the outside, taking the air in from the roof of the van through a Teflon tube. See appendix I for details.

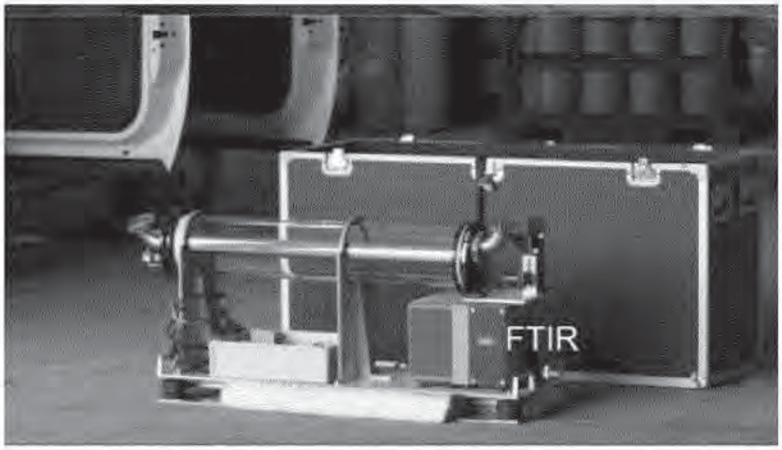


Figure 4 The MeFTIR instrument used in parallel with the SOF system during the campaign. The gas is extracted into the White-cell where it is analyzed by infrared absorption measurements. The residence time in the gas cell and, hence, the measurements time resolution is just a few seconds.

2.4 Mobile White Cell DOAS (MW-DOAS)

A multi-reflection UV system was used to measure ground concentrations of aromatic VOCs including benzene, toluene, and xylenes). In a validation test conducteed in Houston in October 2013 this system was tested against PTR-MS (Proton Transfer Reaction Mass Spectrometer), showing good agreement and sub-ppb sensitivity for benzene and other species (Johansson 2013c). The measurements of aromatic VOCs were carried out using a custom built multi-reflection cell (so called White cell) connected to an ultraviolet lamp and a grating spectrometer (Andor) using optical fibers. The open White cell on the roof of the car is shown in Figure 5, and through 84 reflections an effective optical path of 210 m is obtained yielding good sensitivity for measuring low concentrations of aromatic VOCs.

Measurements are carried out in the wavelength region 250-285 nm and analyzed using the DOAS (Differential Optical Absorption Spectroscopy) retrieval principle using custom software and QDOAS (Fayt 2001). Several aromatic compounds exhibit strong absorption lines in the measured wavelength region. The calibration cross sections for benzene, toluene and p-xylene were obtained from Fally (2009) and the cross sections for styrene and trimethylbenzene from Etzkorn (1999). See appendix I for details.

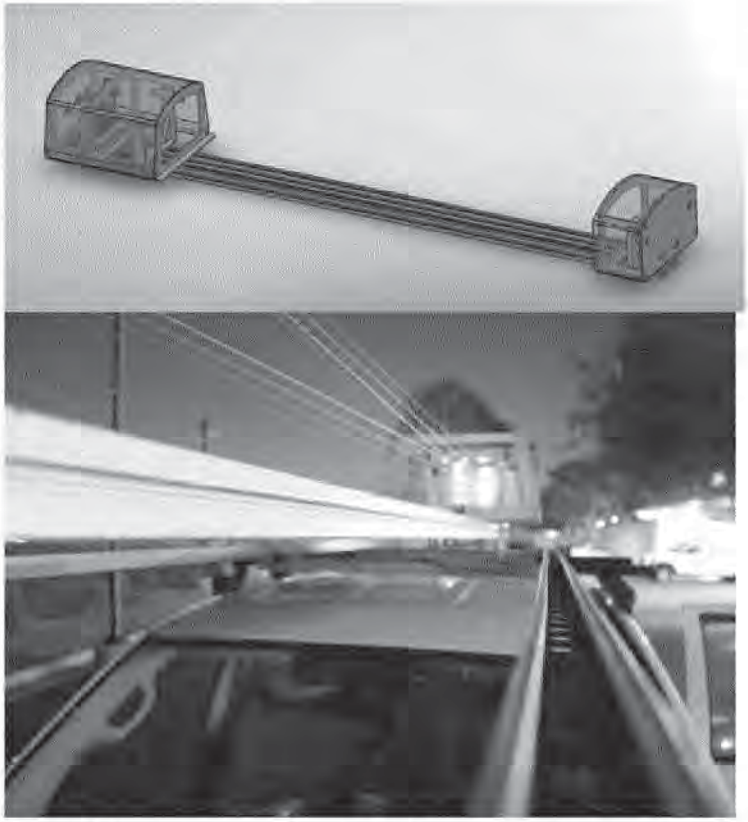


Figure 5 Measurements of aromatic VOCs were carried using a UV multi-reflection cell (White cell) connected to a DOAS spectrometer (MW-DOAS).

3. Measurements

This measurement study was carried out in the Carson area from October 5 to October 16, 2013, Figure 6. Column measurements of VOCs, SO_2 and NO_2 were taken to quantify direct emissions of the above-mentioned species from specific refineries and petrochemical industries. The primary methods used were SOF and Mobile DOAS. Two additional instruments, i.e. meFTIR and MW-DOAS were added to the project to map ground concentrations of alkanes and aromatic VOCs.

The main objective of this pilot study was to demonstrate and carry out flux measurements of VOCs, NO_2 and SO_2 around a refinery operated by Tesoro in the city of Carson. Other refineries were studied, such as Conoco Phillips in Carson and Wilmington. The ExxonMobil refinery in Torrance was also examined.

Accurately gauging the plume speed is typically the greatest source of error in SOF and mobile DOAS measurements. Continuous wind profiles, for instance from a Wind LIDAR, radar wind profiler or, at least, a number of tall masts at each site at the height of tanks, provide the most reliable and useful wind data. The SOF measurements obtained during this pilot project are particularly uncertain due to the lack of adequate wind data.

In this study vertical wind profiles were obtained with GPS meteorological sondes launched from a park just north of the Tesoro Refinery. The main complication, as shown by these profiles (See Appendix), is the gradients within the mixing boundary layer (turning winds versus height). Unfortunately, only a few GPS sondes launches were possible (see Appendix for details) and only limited vertical wind information were obtained. Thus, in most cases only data from three wind masts (one located at the Tesoro site, and two others operated nearby by the SCAQMD) were used for data analysis and interpretation.

The weather conditions for the first 3 days were clear with easterly winds and then the remaining days had low wind speeds with clouds in the mornings and afternoon sea breeze conditions. Due to sea breeze conditions the wind sometimes turned at midday causing high and varying backgrounds of VOCs or NO_2. In one case the wind direction at 300 m was opposite to the ground level wind.

To minimize the problem with varying background values, box measurements of the sites were made, measuring what goes in versus what comes out from the bubble constituting the refinery. In cases with large variability in the background it is however difficult to remove the upwind influence from the downwind measurements making the emission determination more uncertain. In these cases the measurements were omitted.

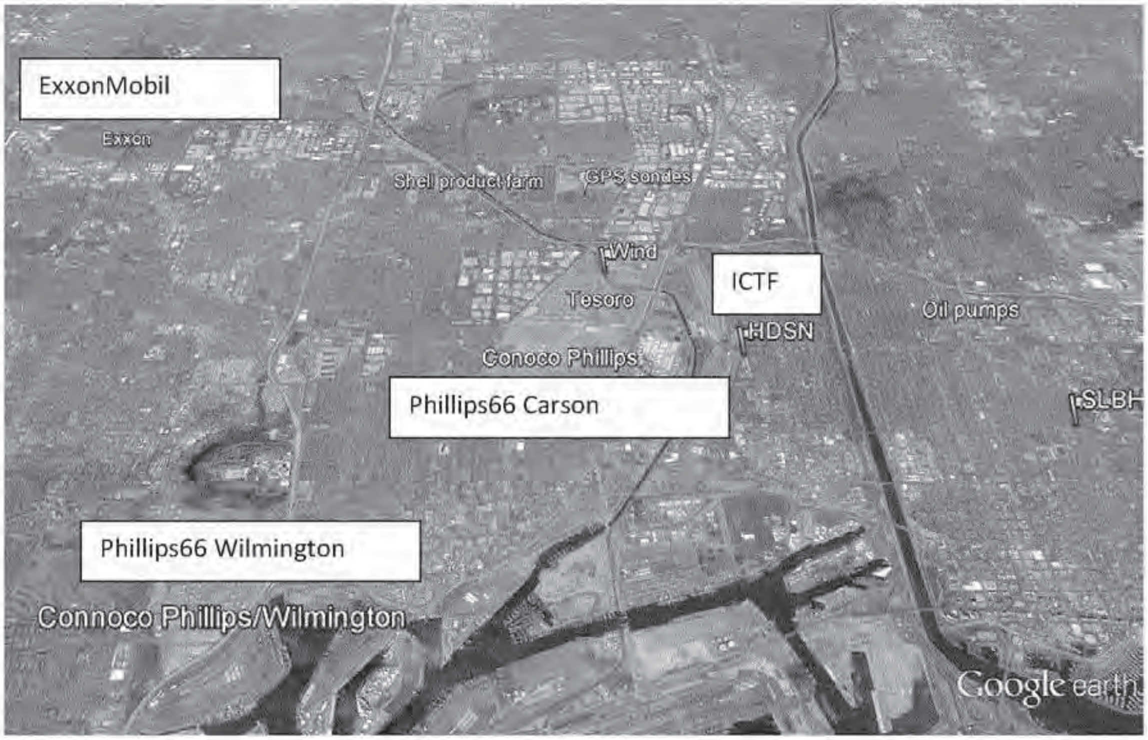


Figure 6 The sites studied are indicated here. The position for the meteorological soundings are indicated as well as the three wind stations (Tesoro, Hudson (HDSN) and South Long Beach (SLBH); the latter two locations are part of the SCAQMD monitoring network). North is towards the top of the image.

3.1 Wind measurements

Wind station data (15 minute averages) collected inside the Tesoro site from a 10 m high mast was used as primary wind information. Two nearby SCAQMD sites (Hudson and South Long Beach stations; here referred to as HSDN and SLBH respectively) were used to provide supporting wind data (also collected using 10 m high wind masts). The latter data were provided as 1 minute values and were compared with the Tesoro site data. In addition, 4 meteorological sondes were launched. The normally accepted height for wind measurements is at least at tank height or higher, since the fugitive emissions downwind a refinery are typically distributed from ground up to 200 m and since the wind field is rather disturbed at below tank height. The wind speeds used in this study are possibly too low, yielding conservative emission figures.

Figure 7 Sounding of the wind height profile by launching a weather balloon (I-met) during the campaign. The balloon drifts with the wind and sends its position measured with a GPS to a receiver.

Figures A7.1 and A7.2 in the Appendix compare the wind data measured at the Tesoro refinery with that collected at the South Long Beach (SLBH) and Hudson (HDSN) stations. The wind speed at Tesoro is approximately 30% higher than that at Hudson. There is also a slightly directional offset, with Tesoro being around 15 degrees less than HDSN. There is no apparent offset in either speed or direction between SLBH and HDSN.

Measured winds were also compared to data obtained from a number of meteorological GPS radiosondes launched from an open location nearby the Tesoro Carson refinery, Figure 7 and 8. These sondes were used to determine instantaneous vertical wind profiles as well as boundary layer heights. A comparison between the sondes and mast measured winds is shown in Figure 9.

Because the location of the Tesoro wind measurements more closely approximates the location of the plume emitted by the refinery, the wind directions measured at the Tesoro plant, corrected for the observed directional offset (15 degrees), were used to calculate fluxes for the two Carson refineries and the Phillips66 Wilmington plant. The Tesoro wind data was not suitable to determine the emission fluxes at the ExxonMobil refinery in Torrance and a fixed wind data recorded at the Torrance Airport (2.6 m/s, 240 degrees plume determined) was used instead.

Because of the short duration of this study and also because wind data was mostly provided by a third party, FluxSense cannot guarantee the accuracy of the wind data nor that the reported wind measurements accurately represent the speed and direction of the measured emission plumes.

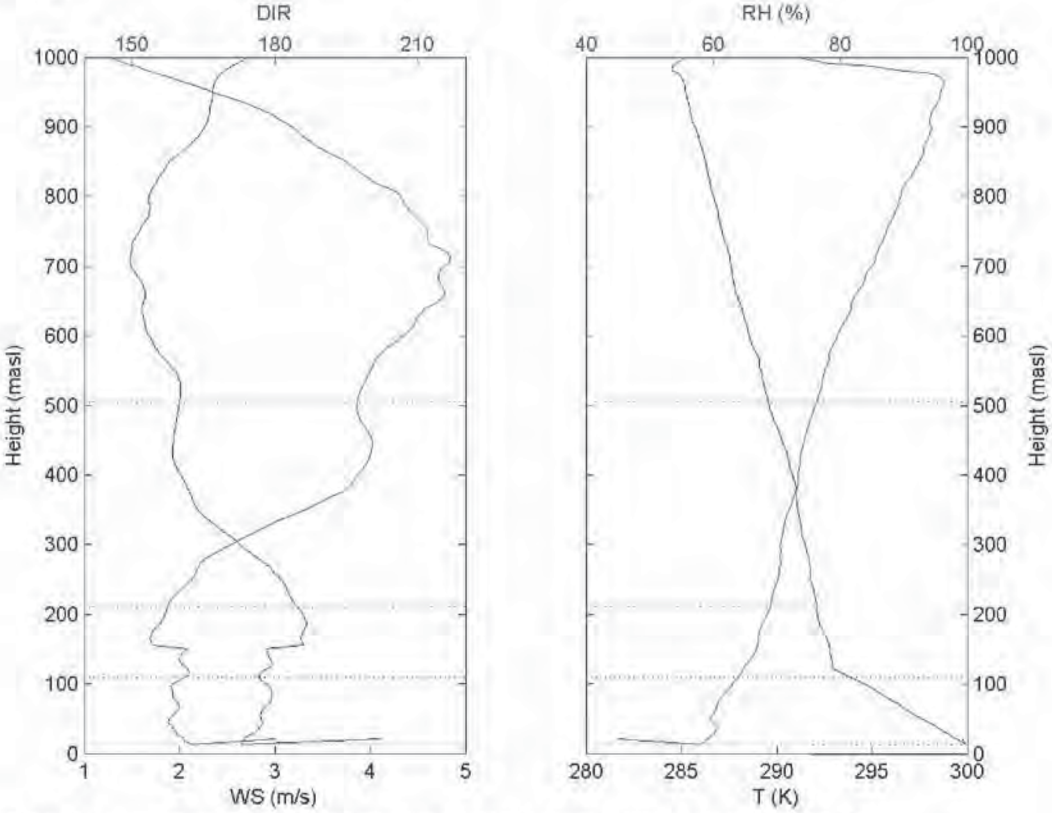


Figure 8 Wind, temperature and relative humidity profiles from radiosonde on 8 October, 13:38.

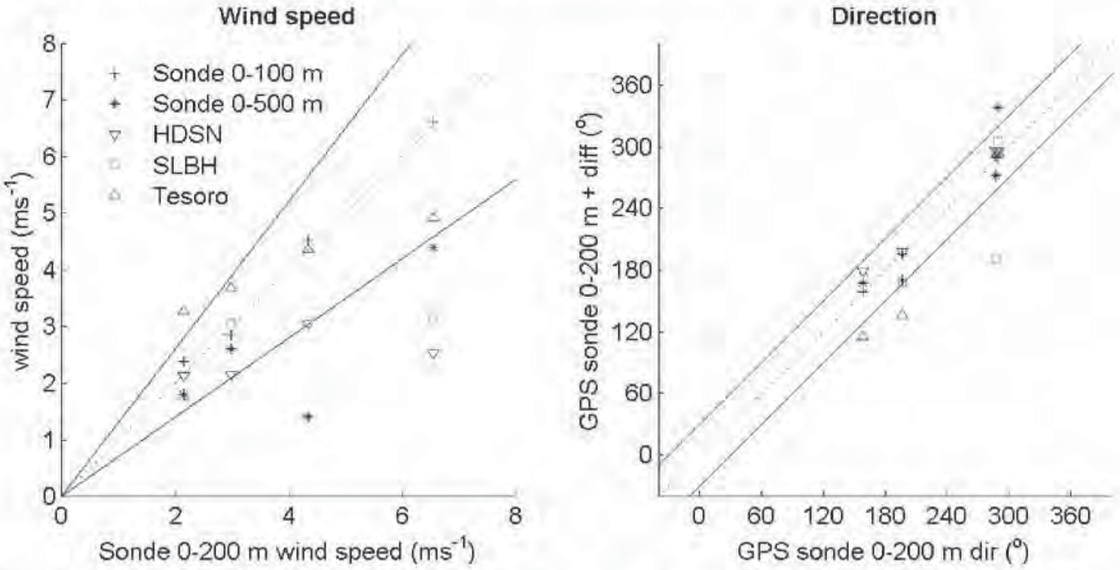


Figure 9 Comparison among vertically average winds and ground based measurements in and around. For wind speed solid lines indicate ± 30% of the 1:1 line (dashed) and for wind direction the solid lines represent ± 30° of the 1:1 line (dashed).

4. Results

Results are presented by area, with primary focus on the two refineries in Carson (i.e. Tesoro and Phillips66). Additionally a few measurements conducted in Wilmington and Torrance (at the Phillips66 and ExxonMobil refinery, respectively) are presented.

4.1 Large scale measurements

Large scale measurements were carried out to investigate the major sources of VOC emissions in the study areas. These measurements, together with the wind soundings and trajectory modeling show that the flow patterns in the Carson area were rather complex with sea breeze circulation occasionally causing reversed flow direction during the middle of the day.

For instance, on October 16 at noon the wind turned from a northerly to a southerly direction during the measurements. Polluted air drifted back and we saw very high columns of VOCs, NO_2 and HCHO while measuring. This is shown in Figure 10 for two times, 10:30 am and 1:30 pm local time on October 16. The same figure shows data from the HYSPLIT dispersion model as contours (Draxler and Rolph 2013) and the SOF data, as blue curves. The simulated source was located on Tesoro.

Another example of a large-scale measurement is shown in Figure 11. This measurement was conducted on October 12 and began by ExxonMobil in Torrance and took approximately 50 minutes to complete.

All in all these measurements shows that flow patterns can be complex in the Carson area and that it is important to carry out measurements both upwind and downwind of the refineries (box measurements).

Figure 10 HYSPLIT dispersion model results (contours) for source located in Carson between 10:30 am and 13:30, on October 16, 2013. Also shown are SOF alkane measurements (blue curves). North is towards the top of the figure.

Figure 11 Large scale measurement of Carson-Wilmington-Torrance performed on October 12, 2013 along with smaller box measurements around the Carson refineries. North is towards the right of the figure

4.2 Emissions from refineries and storage facilities in Carson

4.2.1 Tesoro

The main focus of this study was to carry out fugitive emission measurements from the Carson refinery (former BP), which is the refinery with the highest throughput in the Los Angeles Basin, with a capacity of 265 thousand barrels per day (265 kBPD). Measurements were taken for ten days with a variety of winds. A typical box measurement taken on October 8 with easterly winds is shown in Figure 12. In this case the inflow of VOCs is rather insignificant. Total emissions for Tesoro on this traverse were 112 kg/h. Also seen in the Figure is the one recurring 'hot spot' in the southwest corner of the facility. Figure 13 shows a box measurement with westerly winds and almost insignificant inflow. Results for these measurements are summarized in Table 2. Alkane emissions averaged 204 kg/h over the 10 days and 40 plus measurements performed. A histogram of all measurements is shown in Figure 14.

Figure 12 SOF 'box' measurement of the Tesoro Carson refinery on October 8 at 11:55 am. The shaded area in brown delineates the refinery area while measurements encompass a slightly larger area. Alkane column is shown as a blue curve with the apparent height being proportional to the gas column (5 m equivalent to 1 mg/m^2, max 160 mg/m^2). Wind directions during the measurement are indicated by white arrows. North is to the upper right of the figure.

Figure 13 SOF box measurement of the Tesoro Carson refinery on October 7, at 13:55. Alkane column is shown as a blue curve with the apparent height being proportional to the gas column (5 m equivalent to 1 mg/m^2, max 81 mg/m^2). Wind directions during the measurement are indicated by white arrows. North is to the lower left of the figure.

Table 2 Summary of SOF alkane measurements of Tesoro Carson

Date (mm/dd)	Time Span Start-stop (hhmmss)	Number of Measurements	Alkane Emission±SD (kg/h)	Wind Speed (m/s)	Wind Dir (deg)
10/05	102720 -144904	5	155.8±63.7	1.9-6.4	40-93
10/06	104136 -162424	9	174.4±55.7	1.8-3.9	1-359
10/07	141759 -162318	5	287.3±60.6	4.1-5.7	285-320
10/08	112251 -155724	9	165.8±64.1	1.8-3.3	92-196
10/10	155539 -160356	1	78.7	3.8	195
10/11	132146 -155251	5	257.5±75.1	4.5-5.4	285-311
10/13	150959 -154650	2	175.1±7.6	2.5-2.6	174-179
10/14	111503 -145422	5	285.6±124.5	3.3-4.5	289-332
10/15	154739 -163124	2	162.5±67.2	4.1-4.5	297-300
10/16	141205 -151008	3	210.1±93.6	2.3-4.5	262-309
Average	-	**(total 46)**	**204±86 (42%)**	**3.6**	-

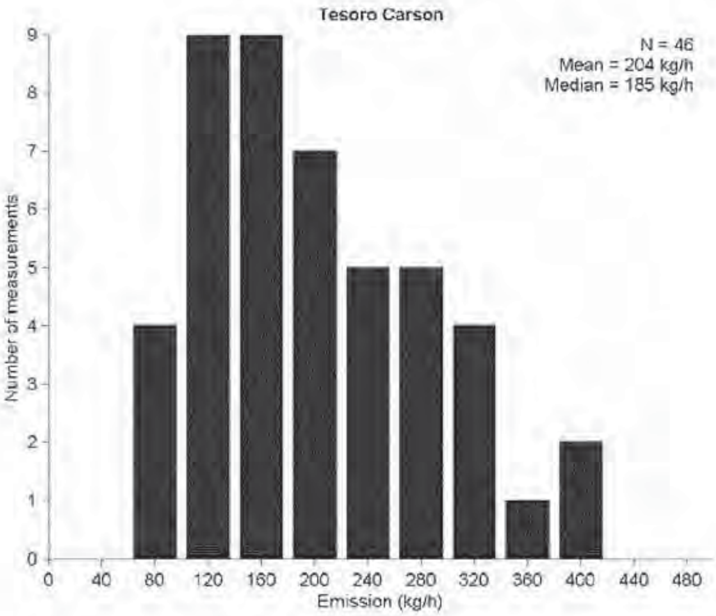


Figure 14 Histogram of SOF measurements.

Quantifying SO_2 and NO_2 emissions from these facilities during the same measurement period is more uncertain due to the shifting of winds with height and the lack of measured vertical wind profiles. As these plumes are from combustion sources and presumably stack releases, the plumes are expected to be at a higher altitude than the VOC plume when measuring near the facility in nearly all the measurements. An example of a measurement from the area is shown in Figure 15. Summaries of DOAS emission measurements are presented in Table 3 and Table 4. Similarly to the alkane measurements, emissions are determined using wind data from the Tesoro refinery except when a sonde launch was made within the hour. Typically, baselines were corrected for background emissions (e.g. from motor-vehicles and other sources for NO_2) thus setting inflow to zero. NO_2 emissions are also affected by plume travel time since source NO is rapidly converted to NO_2 when reacting with ozone. Thus emissions may vary based on the wind speed and distance between the measurement and the source, a distance which is dependent on the wind direction. Emissions averaged approximately 40 kg/h for both NO_2 and SO_2.

Figure 15 DOAS box measurements at Tesoro showing the NO_2 (brown) and SO_2 (pink) plumes. These measurements were taken on October 7, at 13:30. North is to the lower left of the figure.

Table 3 Summary of Tesoro NO_2 measurements

Date (mm/dd)	Time Span Start-stop (hhmmss)	Number of traverses	Emission±SD (kg/h)	Wind Speed (m/s)	Wind Dir (deg)
10/06	120831 -160326	5	38.5±11.3	1.8-2.9	36-356
10/07	141736 -161746	5	55.4±11.9	4.1-5.8	292-317
10/11	161003 -161121	1	18.4	4.9	292
10/12	145254 -145431	1	26.7	3.5	311
10/14	125938 -163027	4	29.0±7.4	4.1-5.3	301-317
10/16	145837 -163738	4	37.5±11.7	2.1-4.9	2-298
Average	-	**(total 20)**	**39.0±14.5 (37 %)**	**3.6**	-

Table 4 Summary of Tesoro SO_2 measurements

Date (mm/dd)	Time Span Start-stop (hhmmss)	Number of traverses	Emission±SD (kg/h)	Wind Speed (m/s)	Wind Dir (deg)
10/05	115132 -145148	4	29.7±8.0	1.9-5.1	79-92
10/06	104205 -141606	6	26.5±4.0	1.8-3.6	8-360
10/07	135921 -153512	6	72.4±36.0	4.0-5.1	292-320
10/11	132232 -145346	4	38.5±17.0	4.5-4.9	287-311
10/14	105135 -161213	6	36.7±9.6	3.1-4.6	295-332
10/15	124745 -132215	2	35.8±1.9	1.8-1.8	28-347
10/16	145837 -163738	4	28.1±7.5	2.1-4.9	2-298
Average	-	**(total 33)**	**40±23 (58 %)**	**3.4**	-

4.2.2 Phillips 66

The Phillips 66 Refinery in Carson is located just south of the Tesoro refinery and has a capacity of 50 kBPD. This site was frequently measured in combination with the adjacent Tesoro facility, see Figure 16. However, due to the proximity of the Kinder Morgan tank farm and the Tesoro Wilmington facility located east of the Phillips 66 refinery, there is an increased possibility of interference depending on wind direction, and thus there were fewer acceptable emissions measurements. Additionally, no on-site wind measurements were available so all emissions are determined using Tesoro wind or sondes. One of the measurements on October 8 is shown in Figure 16, corresponding to an average VOC emission of 68 kg/h. A summary of all measurements is presented in Table 5.

Figure 16 Example of SOF measurements at the Phillips66 Carson refinery (blue shading) on October 8 at about 14:30. The alkane column is shown as a blue curve with the apparent height proportional to the gas column (5 m equivalent to 1 mg/m^2, max 24 mg/m^2). Wind direction during these measurements is indicated by a white arrow. North is to the top of the figure.

Table 5 Summary of SOF alkane measurements of Phillips Carson

Date (mm/dd)	Timespan Start-stop (hhmmss)	Number of Measurements	Emission±SD (kg/h)	Wind Speed (m/s)	Wind Dir (deg)
10/08	111912 -145227	4	62.8±10.2	2.4-3.0	117-196
10/10	155152 -155532	1	101.4	3.3	194
10/11	132402 -163308	4	121.5±15.0	4.1-4.5	294-311
10/16	140857 -141033	1	100.7	3.4	308
Average	-	**(total 10)**	**94±30 (32%)**	**3.5**	-

Emissions of NO_2 and SO_2 from Phillips were also measured on several days. Figure 17 shows one transect measured on October 15. All other measurement data are summarized in Table 6 and Table 7.

Figure 17 DOAS measurements taken at the Phillips refinery showing NO_2 (brown) and SO_2 (pink) emissions plumes (October 15, 16:10). North is to the upper left of the figure.

Table 6 Summary of NO_2 measurements taken at the Phillips 66 refinery in Carson

Date (mm/dd)	Timespan Start-stop (hhmmss)	Number of Measurements	Emission±SD (kg/h)	Wind Speed (m/s)	Wind Dir (deg)
10/07	154748 -154853	1	35.7	5.7	311
10/08	111829 -123259	4	25.1±11.0	1.8-2.8	118-199
10/11	141004 -161303	2	20.0±6.0	3.1-4.9	291-292
10/13	150620 -150715	1	13.3	3.2	158
10/14	122544 -163138	6	20.1±6.2	3.4-5.4	300-327
10/15	160708 -172323	2	27.6±9.8	3.6-5.6	293-296
10/16	155901 -160218	2	8.9±4.8	1.9-2.0	242-250
Average	-	**(total 18)**	**21.0±9.0 (43 %)**	-	-

Table 7 Summary of Phillips SO_2 measurements

Date (mm/dd)	Timespan Start-stop (hhmmss)	Number of Measurements	Emission±SD (kg/h)	Wind Speed (m/s)	Wind Dir (deg)
10/07	153527 -154837	2	43.1±17.2	5.5-5.7	311-317
10/08	111829 -123323	4	24.1±14.2	1.5-2.8	118-199
10/11	132416 -141102	2	36.7±5.2	4.1-4.6	301-311
10/13	135043 -150717	3	26.2±8.7	3.2-4.4	138-158
10/14	105332 -160910	5	32.5±13.4	2.8-5.4	307-328
10/15	161055 -161141	1	40.3	3.8	296
10/16	155901 -160218	2	17.9±5.1	1.9-2.0	242-250
Average	-	**(total 19)**	**30.2±12.6 (42 %)**	**3.7**	-

In addition to the measurements taken at the Tesoro and Phillips66 facilities, upwind measurement allowed for the assessment of emissions from other facilities in the area including Tesoro Wilmington and Kinder Morgan (Figure 18) and a tank farm to the north of Tesoro (Figure 19).

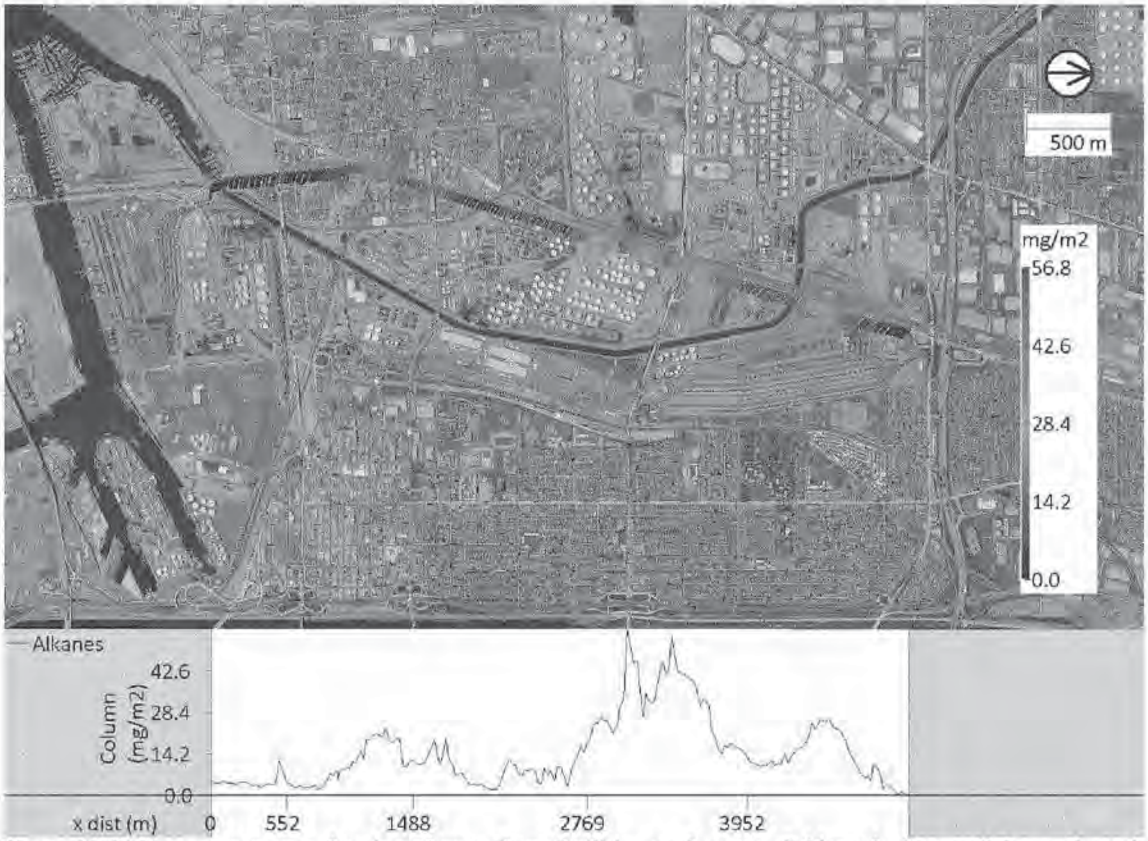


Figure 18 SOF measurements showing plumes from facilities to the east of Alameda Street. Color scale and point size correspond to the plot below the image and indicate alkane column in mg/m^2. The lines point against the wind, i.e. towards the source of the VOC emissions.. In this case HDSN wind is shown. North is to the right in the image.

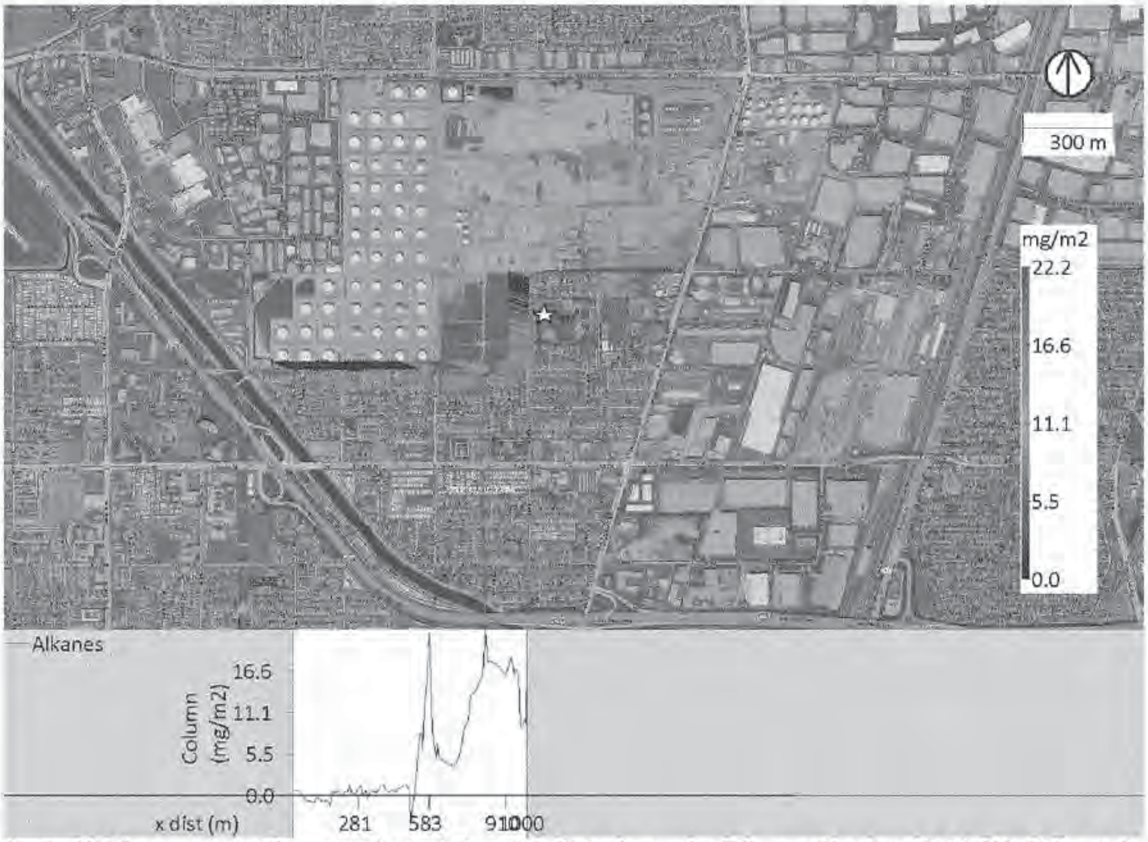


Figure 19 Measurements taken near the tank farm (Shell) to the north of Tesoro (October 14, 14:20). Color scale and point size correspond to the plot below the image and indicate the alkane column in mg/m^2. The lines point against the wind, i.e. towards the source of the VOC emissions.. The wind used was from GPS sonde launched in park just to the right of the measurement (white star).

4.3 Other Areas

During the campaign a few SOF measurements were also carried out at other facilities. However, since no nearby wind measurements were available outside of the Carson area, the following results are only indicative and are based on wind measurements from the Tesoro wind mast and from the two SCAQMD wind stations.

4.3.1 ExxonMobil Torrance

SOF measurements at ExxonMobil were conducted on one Date (mm/dd) with weak west-south-westerly winds. Measurements were conducted of both the total facility and isolating the western portion, indicating VOC emissions of around 100 kg/h for four transect scans, when using wind measurements from Carson. Examples of measurements are shown in Figure 20.

Figure 20 SOF and DOAS measurements made at the Exxon Torrance plant showing alkane (blue) and NO_2 (brown) plumes (October 12, 13:20). North is to the left in the image.

4.3.2 Phillips 66 Willmington

Emissions from the Phillips 66 Wilmington facility were measured more frequently, on three separate days in total (an example is shown in Figure 21). The results indicate VOC emissions of around 170 kg/h, estimated using wind data from the Tesoro Carson wind site.

Figure 21 SOF and DOAS measurements of Phillips 66 Wilmington showing alkane (blue) and NO2 (brown) plumes (October 10, 12:50 pm). North is to the top in the image

4.4. Aromatic emissions

The ratio of the concentration of benzene or toluene to the total alkane concentration can be used in combination with alkane flux measurements to estimate the aromatic emissions for a given site. The ratio of aromatics (e.g. benzene and toluene) to the total concentration of non-methane alkanes was measured on several evenings during the study. Aromatic concentrations of several species were directly measured using the MW-DOAS system. The MeFTIR technique was used to quantify the level of alkanes.

In order to get an accurate measurement it is important to avoid the short peak concentrations (> 15 ppb) of ground based point sources, which would not give a fair ratio compared to the flux measured using the SOF method. Aromatics originating from car exhausts (from the measurement vehicle and in particular the generator, and other traffic sources) must also be avoided. Care has been taken to remove these sources of error when calculating the total out flux from the chosen sites.

4.4.1 Tesoro plant

The Tesoro site was considered for the purpose of this report due to the availability of data from SOF measurements and the possibility of fence- line measurements. Concentrations of alkanes and several aromatic species were measured downwind of the facility on several transects. The upwind perimeter of the plant was also measured to control for possible inflow of gases. Measurements were made during two evenings, October 12 and 13. The wind was from a north-westerly direction and the highest concentrations were measured close to the storage tanks in the southern part of the facility. An example is shown in Figure 22.

Presumably (at least partly due to low wind speed) the levels of aromatics here were high, well above 10 ppb, yet still judged to be representative for the aromatic/alkane mixing found in plumes measured by SOF flux measurements.. The possible inflow of both aromatics and alkanes was measured upwind from the region which resulted in a lowering of the toluene value by 25 %. This adjustment has a larger inherent uncertainty as the levels and the statistics were low. The results from Tesoro facility are presented in Table 8.

Table 8. The results of the aromatic/alkane ratio measurements at the Tesoro plant, 12 and 13 October.

Gas	Ratio % of Alkane	SOF Alkane emissions (kg/h)	Inferred Aromatic emissions (kg/h)
Benzene	1.2 %	204	2.5 (± 50 %)
Toluene	3.7%	204	7.5 (± 50 %)

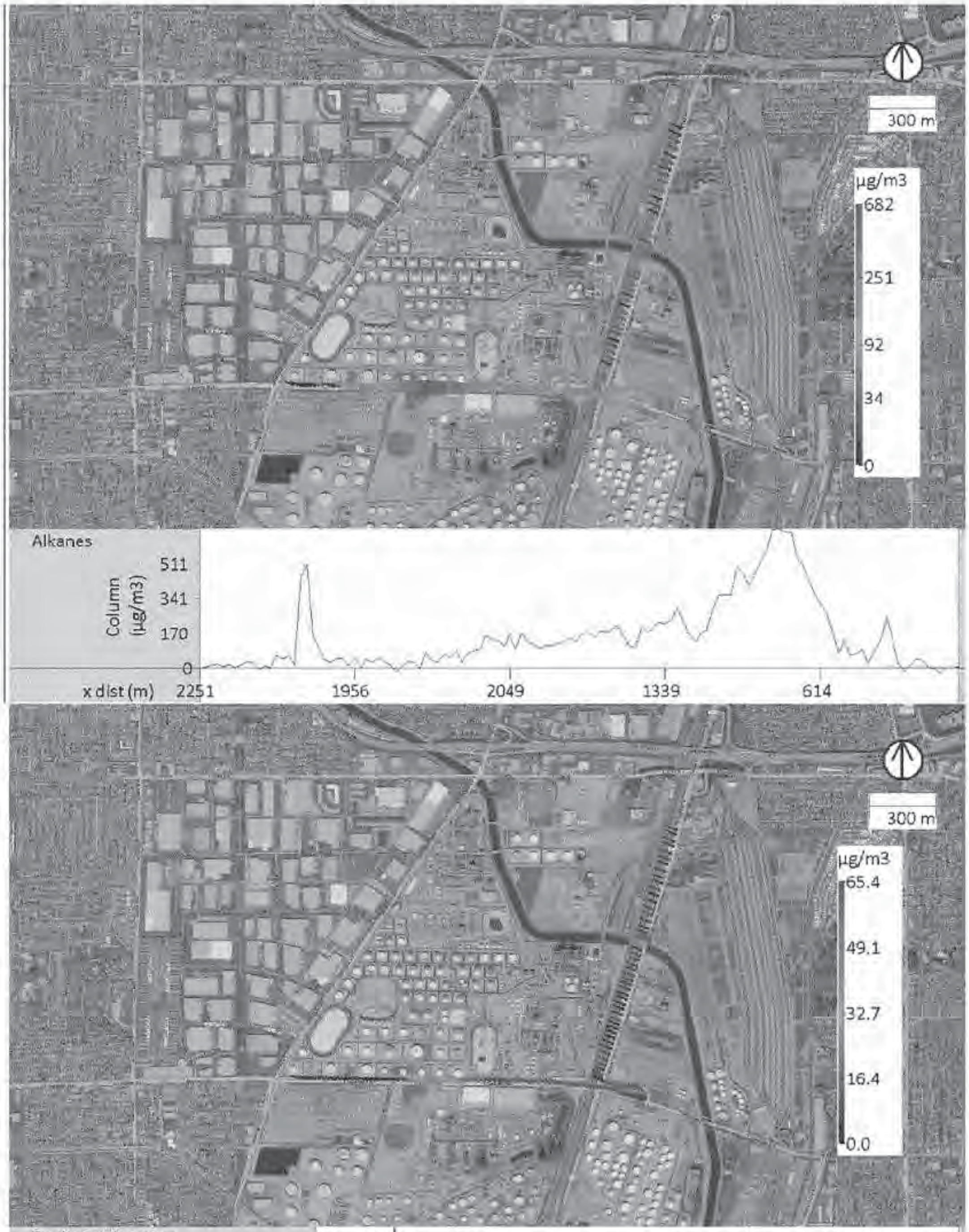


Figure 22 Mobile measurements of the ground concentration of alkanes (upper) and aromatics (lower) downwind of the Tesoro plant in Carson, obtained with MeFTIR and MW-DOAS, respectively (October 13, 19:25).

4.4.2 Oil wells

Mobile concentration measurements of aromatic VOCs and alkanes downwind of oil wells in Signal Hill, Figure 23, were measured by MeFTIR and MW-DOAS, to demonstrate and test the capabilities of these two extractive measurements. The errors are lower for this measurement since the plumes are more local and have higher concentration, making the baseline positioning both easier and less sensitive.

The results are illustrated in Figure 24 and Figure 25, and show that the most abundant gas species in the emission plume from the oil well is butane (about 1000 µg/m3) and that the mass fraction of benzene and toluene to alkanes is 0.7 % and 1.5 %, respectively. The objective was also to quantify the alkane emission from this well by SOF, but since we prioritized measurements in Carson the sun got too low before the measurements could be carried out. However, given the large number of such wells we believe it could be very interesting to estimate the emissions from these sources in the Los Angeles Basin.

Figure 23 Oil well in Signal Hill

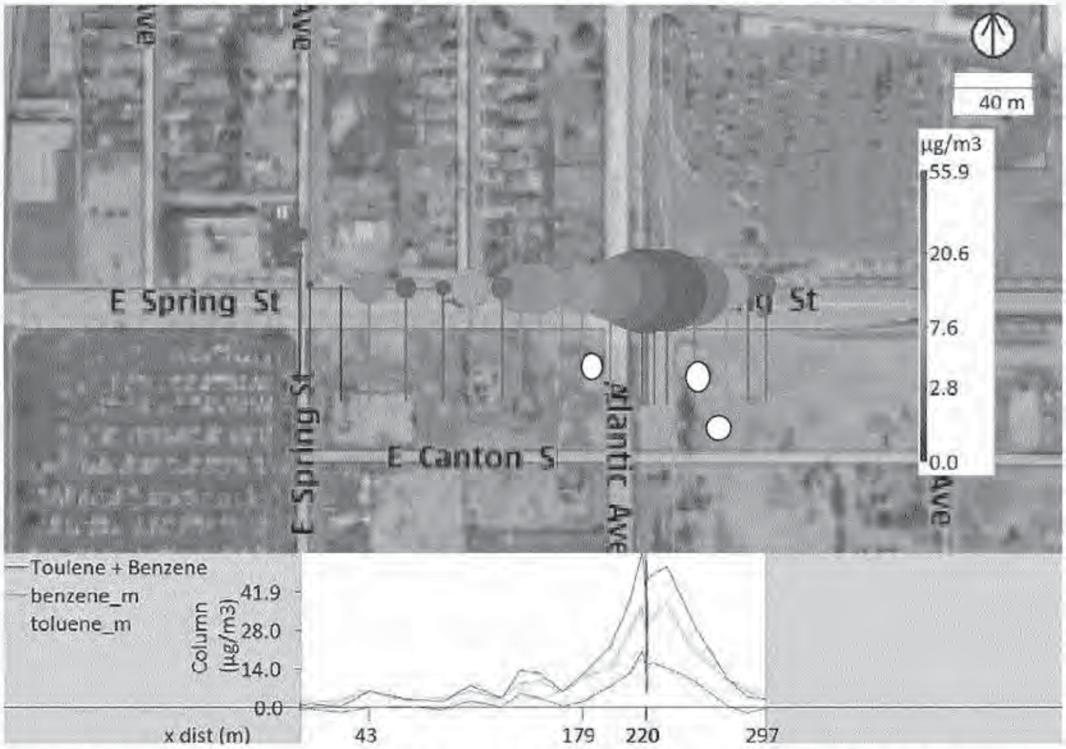


Figure 24 Concentration measurements of aromatic VOCs downwind an oil well in Signal Hill (measurements were conducted on October 13, at 6 pm). The locations of the closest wells are indicated with white circles, (33°48' 40.73'', 118° 11' 06.79'').

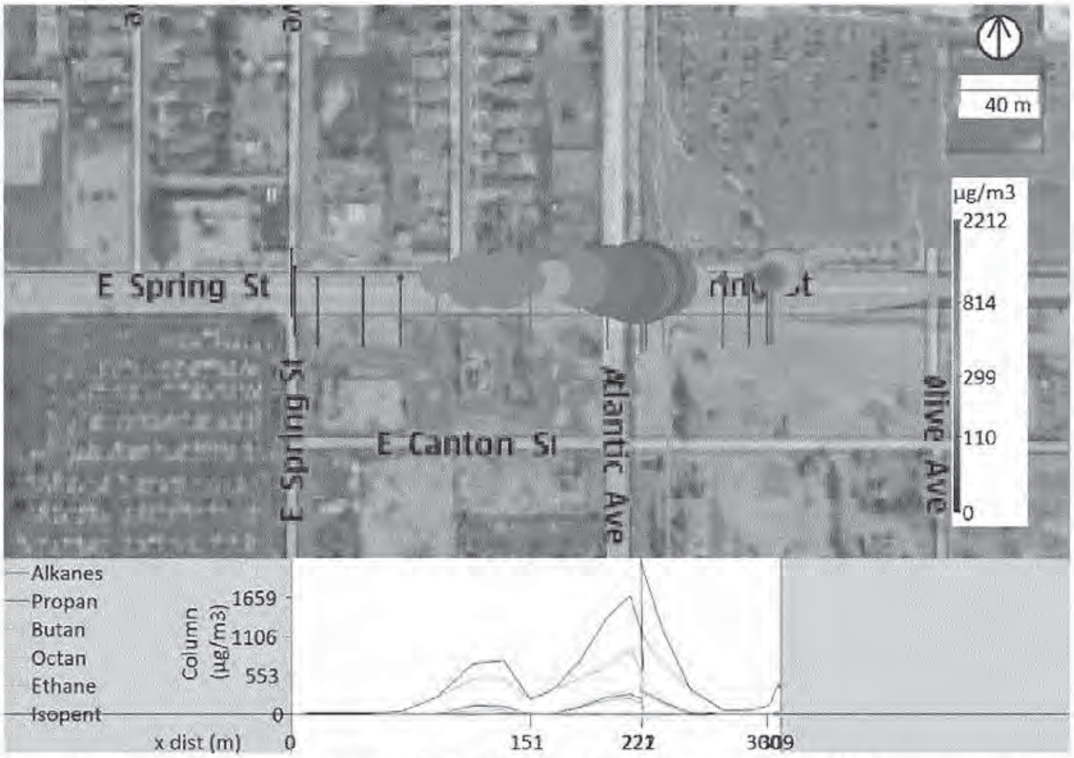


Figure 25 Concentration measurements of alkanes downwind an oil well in Signal Hill (measurements were conducted on October 13, at 6 pm).

5. Discussion and conclusion

The main scope of this work was to demonstrate that optical column measurements can be used to quantify fugitive emissions from refineries of the South Coast Air Basin and to investigate whether these measurements indicate large discrepancies from the reported values based on emission inventories, as observed previous in studies conducted in other part of the United States and abroad (Mellqvist, 2009).

In Table 9 VOC, SO_2, and NO_2 emissions measured over a period of about 10 days are shown for the various study sites. Note that the main focus of our measurements was the Tesoro refinery in Carson, and only limited emission data were collected at the refineries in Wilmington and Torrance, where no detailed wind information was available. Therefore, the emissions estimated at the latter two facilities (100 and 170 kg/h for the Wilmington and Torrance refineries, respectively) are only indicative and are probably affected by high uncertainty. For comparison with the measurements and among sites, the reported annual emissions are shown as hourly figures and as a percent of capacity. It should be noted that the reported emissions are based on annual average values and may not be representative of emissions measured over a shorter timeframe. In addition because SOF measurements can only be made during daylight hours there may be a slight bias in measured VOC emissions. According to a recent study (Johansson 2013b) based on the TANKS model, developed by the US API and EPA, an upper estimate of the effects is 30-40% maximum overestimation in the emissions for an external floating roof EFRT crude oil tank (Mellqvist 2009a), compared to the annual average.

For the facilities examined in this study, measured VOC emission rates were greater than rates derived from the reported annual emissions. This result is not surprising and in some regards may be considered positive. Measured fugitive VOC emissions are often a factor 4 to 10 times higher than reported emissions (Mellqvist 2009a, Johansson 2014). Additionally, measured as a percent of throughput or capacity, VOC emissions are generally at least 0.05% of throughput and often much more (Cuclis 2012). In the current study all facilities are below this level.

Although measured VOC emissions at the Tesoro Carson refinery were 3.5 times higher than reported, this can still be considered as a well maintained site since emissions are only 0.013 % of capacity. Phillips66 Carson, on the basis of fewer measurements and, therefore, less certain statistics had much higher emissions than reported, but even here fugitive VOC emissions were only 0.033 % of capacity, which is a relatively low value with respect to the majority of facilities studied in North America and Europe.

For SO_2 and NO_x the reported emissions were in closer agreement with measured emissions i.e. within 30 % agreement for SO_2 while within 40 % when comparing the measured NO_2 with reported NO_x, consistent with studies elsewhere (Johansson, 2014). The latter discrepancy is expected since the measurements are carried out in proximity of the emission sources and the fact that NO_x is released primarily as NO which is then converted to NO_2 through reaction with ozone.

It is difficult to assess the total uncertainty of the measured emissions due to the complex wind patterns, sea breeze circulation and limited wind measurement sites. Even though these effects were detected and corrected for by measuring in a box around the sites, subtracting downwind and upwind fluxes, the uncertainty increases, especially for weak sources that may become hidden in the high background signals. The typical uncertainty is 30% for the optical column measurements (see Appendix I) but in this case we estimate higher uncertainties, 40-50%.. We recommend that future campaigns include more detailed wind data with additional mast measurements and, if possible, continuous wind profiling (e.g. using IR LIDAR). Overall, these results demonstrate that the SOF method is a suitable remote sensing method for validating refinery emissions and for identifying hot spot locations.

Table 9 Comparison of reported and measured emissions from selected facilities.

	VOC				SO_2		NOx	NO_2
	Reported*		Measured		Reported*	Measured	Reported*	Measured
Site	kg/h	% capacity	kg/h	% capacity	kg/h	kg/h	kg/h	kg/h
Tesoro Carson	51	0.003%	204 (±32 %)	0.013%	43	40 (±58 %)	67	39 (±37 %)
Phillips66 Carson	12	0.004%	94 (±32 %)	0.033%	22	30 (±42 %)	34	21 (±43 %)
Phillips66 Wilmington	27	0.005%						
ExxonMobil Torrance	64	0.007%						

*Data from SCAQMD 2012

The measurements carried out here indicate that the emissions from the South coast refineries are within the expected range when relating to throughput. But there is a significant difference between actual and reported emissions, indicating that the conventional API method of estimating the emissions does not provide reliable values. The problem with under estimation of fugitive emissions by the API model has been admitted publicly by the US EPA on several occasions in the press (Washington post, April 22, 2010) and they claim they are working to resolve this issue.

We believe that the results demonstrate the value of carrying out measurements instead of relying on estimation methods only. In the estimation methods the fugitive emissions from tanks are estimated using the API-model under the assumption that tanks are leak free (well maintained) and to our experience, running measurements elsewhere, this is seldom the case for a whole tank farm. Since the emissions from non-ideal tanks with distinct leakages often are one to several orders of magnitude higher than the modeled leakage rate through the tank sealing, a few malfunctioning tanks will easily increase the total emissions from a tank farm by an order of magnitude.

The SOF measurements demonstrated here can rapidly identify the relevant leaking tanks in a tank farm and then optical gas imaging cameras can be used to find the leakage points, (super smart LDAR). Other source areas for fugitive emissions which are difficult to estimate and instead should be measured are: anomalous emissions from process areas (especially after maintenance stops), flares, loading operations, tank cleaning and drainage operation and water treatment areas.

The observed difference in fugitive VOC emissions between measurements and estimates appears to be a general problem for the industry worldwide, and if one would adopt the, in general, higher measured values (factor 3-5) this would create legislative problems for the industry, for instance with permitting and potential liability issues. To avoid this, measurements and estimates could be done in parallel where the former are used for the official reporting while the latter is done as part of the proactive environmental work aimed at reducing the emissions at the site. If this is carried out for a couple of years, followed by abatement work at the dominant hotspot emissions for an industrial site, combined with adaptive improvements of the emission factors, the estimates and measurements may start to converge.

A significant value of carrying out measurements is the possibility to establish baseline emission for a site and its various subareas and by frequent (annual) measurements the trends can be followed and anomalous emissions can further be reacted upon by abatement measures.

6. Acknowledgements

This work was funded by the South Coast Air quality Management District (SCAQMD).

7. References

California Air Resources Board (CARB), 2009. Recommended Area Designations For The 2010 Federal Sulfur Dioxide (So2) Standard. California Environmental Protection Agency

De Gouw, J.A., et. al. (2009), Airborne Measurements of Ethene from Industrial Sources Using Laser Photo-Acoustic Spectroscopy, Environmental Science and Technology, 43, 2437–2442.

Draxler, R.R. and Rolph, G.D., 2013. HYSPLIT (HYbrid Single-Particle Lagrangian Integrated Trajectory) Model access via NOAA ARL READY Website (http://www.arl.noaa.gov/HYSPLIT.php). NOAA Air Resources Laboratory, College Park, MD.

Etzkorn, T., B. Klotz, S. Sorensen, I.V. Patroescu, I. Barnes, K.H. Becker, and U. Platt, "Gas-phase absorption cross sections of 24 monocyclic aromatic hydrocarbons in the UV and IR spectral ranges," Atmos. Environ. 33, 525-540 (1999).

Fally, S., M. Carleer, and A. C. Vandaele, "UV Fourier transform absorption cross sections of benzene, toluene, meta-, ortho-, and para-xylene", J. Quant. Spectrosc. Radiat. Transfer 110, 766-782 (2009).

Fayt, C. and Van Roozendael, M., 2001. QDOAS 1.00 Software User Manual, BIRA-IASB.

Foy, B., ... Mellqvist, J., et al., Modeling constraints on the emission inventory and on vertical dispersion for CO and SO2 in the Mexico City Metropolitan Are using Solar FTIR and zenith sky UV spectroscopy, Atmos. Chem. Phys., 7, 781–801, 2007

Galle, B.; Mellqvist, J., et al., Ground Based FTIR Measurements of Stratospheric Trace Species from Harestua, Norway during Sesame and Comparison with a 3-D Model, JAC, 1999, 32, no. 1, 147–164.

Galle, B., J. Samuelsson, B.H. Svensson, G. Börjesson, "Measurements of methane emissions from landfills using a time correlation tracer method based on FTIR absorption spectroscopy." Environ. Sci. Technol. 35: 21–25. 2001.

Galle, B., Oppenheimer, C., Geyer, A., McGonigle, A.J.S., Edmonds, M. and Horrocks, L., (2002), A miniaturised ultraviolet spectrometer for remote sensing of SO $_2$ fluxes: A new tool for volcano surveillance, Journal of Volcanology and Geothermal Research, 119 241–254

Heckel, A., A. Richter, T. Tarsu, F. Wittrock, C. Hak, I. Pundt, W. Junkermann, and J.P. Burrows, MAX-DOAS measurements of formaldehyde in the Po-Valley, Atmospheric Chemistry and Physics, 5, 909–918, 2005.

Johansson, M., C. et al, 2009, Mobile mini-DOAS measurement of the outflow of NO_2 and HCHO from Mexico City, Atmos. Chem. Phys., 9, 5647–5653

Johansson, J., et al., 2013a, Quantitative Measurements and Modeling of Industrial Formaldehyde Emissions in the Greater Houston Area during Campaigns in 2009 and 2011, accepted by Journal of Geophysical Research – Atmospheres, 2013JD020159R.

Johansson, J., et al., 2013b, Emission Measurements of Alkenes, Alkanes, SO_2 and NO_2 from Stationary Sources in Southeast Texas over a 5-year-period Using SOF and Mobile DOAS, which has been submitted for possible publication in Journal of Geophysical Research - Atmospheres. accepted by Journal of Geophysical Research – Atmospheres,, 2013JD020485.

Johansson, J., Mellqvist, J., et al., Quantification of industrial emissions of VOCs, NO2 and SO2 by SOF and Mobile DOAS during DISCOVER-AQ, AQRP project 13-0051, AQRP report, Dec 7 2013c

S.-W. Kim,..Mellqvist, J., et al., Evaluations of NOx and highly reactive VOC emission inventories in Texas and their implications for ozone plume simulations during the Texas Air Quality Study 2006S, Atmos. Chem. Phys., 11, 11361–11386, 2011, www.atmos-chem-phys.net/11/11361/ 2011/doi:10.5194/acp-11-11361-2011

Mellqvist, J., Application of infrared and UV-visible remote sensing techniques for studying the stratosphere and for estimating anthropogenic emissions, doktorsavhandling, Chalmers tekniska högskola, Göteborg, Sweden, 1999a

Mellqvist, J och Galle, B., Utveckling av ett IR absorptionssystem användande solljus för mätning av diffusa kolväteemissioner, Rapport till Preems miljöstiftelse juli 1999b.

Mellqvist, J., Arlander, D. W., Galle, B. and Bergqvist, B., Measurements of Industrial Fugitive Emissions by the FTIR-Tracer Method (FTM), IVL report, 1995, B 1214.

Mellqvist, J., Flare testing using the SOF method at Borealis Polyethylene in the summer of 2000. 2001, Chalmers University of Technology. (Available at www.fluxsense.se)

Mellqvist, J., J. Samuelsson, C. Rivera, B. Lefer, and M. Patel (2007), Measurements of industrial emissions of VOCs, NH_3, NO_2 and SO_2 in Texas using the Solar Occultation Flux method and mobile DOAS, Project H053.2005, Texas Environmental Research Consortium., Texas. (http://www.harc.edu/projects/airquality/Projects/Projects/H053.2005)

Mellqvist, J., Johansson, J.,Samuelsson, J., Rivera, C., Lefer, B. and S. Alvarez (2008b), Comparison of Solar Occultation Flux Measurements to the 2006 TCEQ Emission Inventory and Airborne Measurements for the TexAQS II, Project No. 582-5-64594-FY08-06 , TCEQ report., Texas. (available at http://www.tceq.state.tx.us/assets/public/implementation/air/am/contracts/reports/da/20081108-comparison_solar_occultation_flux_measurements.pdf)

Mellqvist, J., et al. (2009a), Emission Measurements of Volatile Organic Compounds with the SOF method in the Rotterdam Harbor 2008, available at www.fluxsense.se

Mellqvist, J., J. Samuelsson, J. Johansson, C. Rivera, B. Lefer, S. Alvarez, and J. Jolly(2010). Measurements of industrial emissions of alkenes in Texas using the solar occultation flux method,J. Geophys. Res.,115, D00F17, doi:10.1029/2008JD011682.

Parrish, D.D., Ryerson, T.B., Mellqvist, J. et al., Primary and secondary sources of formaldehyde in urban atmospheres: Houston Texas region, Atmos. Chem. Phys., 12, 3273-3288, 2012:

Platt, U., D. Perner, and H.W. Pätz, Simultaneous Measurement of Atmospheric CH_2O, O_3 and NO_2 by Differential Optical Absorption, Journal of Geophysical Research, 84 (C10), 6329–6335, 1979.

Rivera, C. et al., (2010), Quantification of NO_2 and SO_2 emissions from the Houston Ship Channel and Texas City during the 2006 Texas Air Quality Study, J. Geophys. Res., 115, D08301, doi:10.1029/2009JD012675

Rivera , C., Application of Passive DOAS using Scattered Sunlight for quantification of gas emission from anthropogenic and volcanic sources (2009a), Dissertation, ISBN 978-91-7385-317-0, ISSN 0346

Rivera, C., J.A. Garcia, B. Galle, L. Alonso, Y. Zhang, M. Johansson, M. Matabuena, and G. Gangoiti (2009b), Validation of optical remote sensing measurement strategies applied to industrial gas emissions, Int. J. Remote Sens., vol 30, no 12, p3191–3204.

Rivera, C., et al. (2009c),Tula industrial complex (Mexico) emissions of SO_2 and NO_2 during the MCMA 2006 field campaign using a mobile mini_DOAS system, Atmos. Chem. Phys., 9, 6351–6361, 2009.

Samuelsson, J., Börjesson, G., Svensson, B., Galle, B., Metan från avfallsupplag i Sverige (Methane from landfills in Sweden), final report to the Swedish Energy Agency, projekt nr P10856-4, December 2005a. In Swedish (www.stem.se), can be ordered from Studsviksbiblioteket, 611 82 Nyköping, Sweden, www.lib.kth.se/SB/service/stemavf.html.

Samuelsson, J., et. al., VOC measurements of VOCs at Nynas Refinery in Nynäshamn 2005b *(Utsläppsmätningar av flyktiga organiska kolväten vid Nynas Raffinaderi i Nynäshamn 2005, in Swedish)*, Bitumen refinery official report to provincial government 2005, Available at: http://www.fluxsense.se

Appendix

A1 The SOF method

A1.1. Introduction

The Solar Occultation Flux (SOF) method utilizes the sun as the light source and gas species that absorb in the infrared portion of the solar spectrum are measured from a mobile platform, Figure A1.1. The method is used to screen and quantify VOC emissions from industrial conglomerates down to sub-areas in individual plants, such as a few tank process area or water treatment areas. The SOF method is usually combined with an extractive FTIR instrument in the same measurement vehicle, by which it is possible to carry out complementary measurements by tracer correlation (Galle 2001), for instance night time measurements of tanks and ship loading operations. Tracer gas is then positioned at the location of the leak and then the ratio of tracer gas and leaking VOC is measured by extracting the gas plume into a gas cell and then analyzing the gas concentrations by infrared spectroscopy.

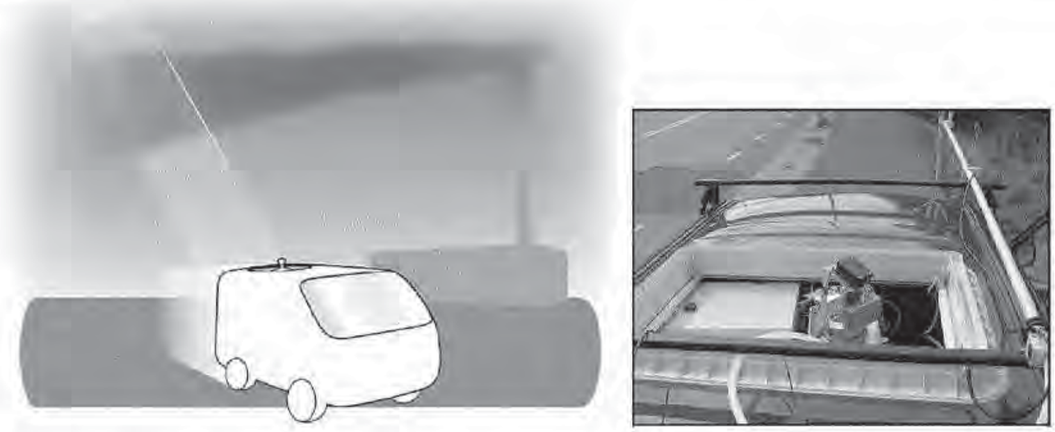


Figure A1.1 In the Solar Occultation Flux method (SOF) gases are measured by observing solar light in the infrared portion of the solar spectrum. The instrument is placed in a vehicle which is moved across the plume. From the accumulated mass measured across the plume the flux of gas is obtained by multiplication with the wind speed. (Illustration Karin Sjöberg).

The SOF method has been applied in several larger campaigns in both Europe and in the US (Mexico City 2006, Texas 2006/2009/2011/2012/2013; Le Havre 2008, Rotterdam 2008/2010 and Antwerp 2010) and in more than 60 individual plant surveys over the last 7 years. About 10 international reports and several peer reviewed scientific papers (Mellqvist 2010, Foy 2007, De Gouw 2009, Kim 2011, Parrish 2012, Johansson 2013a, Johansson 2013b) have been written so far, applying the SOF method for various industrial measurements. The technique has been validated by comparison to other methods and tracer gas releases and it typically has an uncertainty of 30%, Table 1, mostly due to uncertainties in the wind field.

In the various campaign studies it has been found that the measured emissions obtained with SOF are 3–10 times higher than the reported emission obtained by calculations. For instance in a study in Houston, TexAQS 2006, it was shown that the industrial releases of alkenes for the Houston Galveston area, on average, were 10 times higher than what was reported [Mellqvist 2010]. These results were supported by airborne measurements [De Gouw 2009].

For alkanes the discrepancy factor was about 8 [Mellqvist 2007]. Similar SOF studies in Rotterdam 2008 and 2010 [Mellqvist 2009a], Le Havre 2008 and Antwerp 2011 show overall discrepancies of 4.2, 4.4 and 7.7, respectively. For Swedish refineries the VOC emissions typically correspond to 0.03–0.09 % of the throughput of oil, compared to a typical value of 0.01% obtained with API estimations. Modelers in the USA have responded to the observed discrepancies by increasing the modeled VOC emissions; for instance TCEQ (Texas Commission on Environmental Quality) increases industrial VOCs by ~6 times in ozone modeling (SIP model) and scientists at the US weather service (NOAA-National Oceanographic Atmospheric Administration) (Kim, 2011) have upscaled VOC emissions based on SOF 2006 data in Texas. This improves the agreement with airborne measurements for both VOCs and ozone.

Figure A1.2 A SOF transect past a refinery. The staples and colors shows the integrated amount of butane, as retrieved from the solar spectra. After multiplication with the wind velocity the mass flux is obtained.

In Europe the SOF technique is considered as Best Available Technology for measurements of fugitive emission of VOCs (also DIAL) and it is used together with tracer correlation (Galle 2001) and optical gas imaging to screen the refineries annually, over a time period of about 10 days. The SOF technique is also described in the EPA handbook on remote sensing (2011). The data are used for the annual reporting and to follow up on abatement strategies, such as new tank sealings, flare efficiency etc. At the moment a European standard (CEN TC 264/WG 38) is being worked on for SOF and some other methods.

The SOF technique has the smallest uncertainty when carrying out measurements outside the fenceline of the refineries, since the wind field is then less disturbed and most of the emissions plume has had time to distribute itself over considerable height (100-200 m). Box measurements on the fenceline of the refineries are therefore carried out for estimation of the total refinery emission. Then individual measurements are carried out inside the refinery on available roads, for estimation of emissions of subareas such as process area, product tanks, crude oil tanks, water treatment facility, loading/unloading and flaring. The emission values obtained inside the refinery are always rescaled so that their sum matches the emission value measured at the fenceline. In this manner the uncertainty of the wind field close to tanks etc. is minimized. Emission hotspots located with SOF are often studied in more detail using tracer correlation (meFTIR) and OGI.

The SOF measurements are influenced by turbulence in the wind field, causing horizontal shifts in the position of the plume, and it is therefore important to average over several measurements, to remove this effect. In Figure A.1.3 annual emissions measurements on the fenceline of a Swedish refinery are shown as a histogram, showing all emission measurements binned into different emission intervals. The wind variations normally causes an emission curve that follows a normal distribution while a skew shape of these curves is due to intermittent emissions due to tank cleaning etc. The refinery in Figure A1.3 has been measured 12 times since 1989 (DIAL 4 times and SOF 9 times) and with exception for the first occasion the emission has varied within 30%. This is a strong argument that these measurements give a representative value. An issue with SOF measurements is the fact that measurements are only carried out at daytime and in sunny conditions. According to a recent study (Johansson 2013b) based on the TANKS model, developed by the US API and EPA, an upper estimate of the effects is 30-40% maximum overestimation in the emissions for an EFRT crude oil tank (Mellqvist 2009a), compared to the annual average.

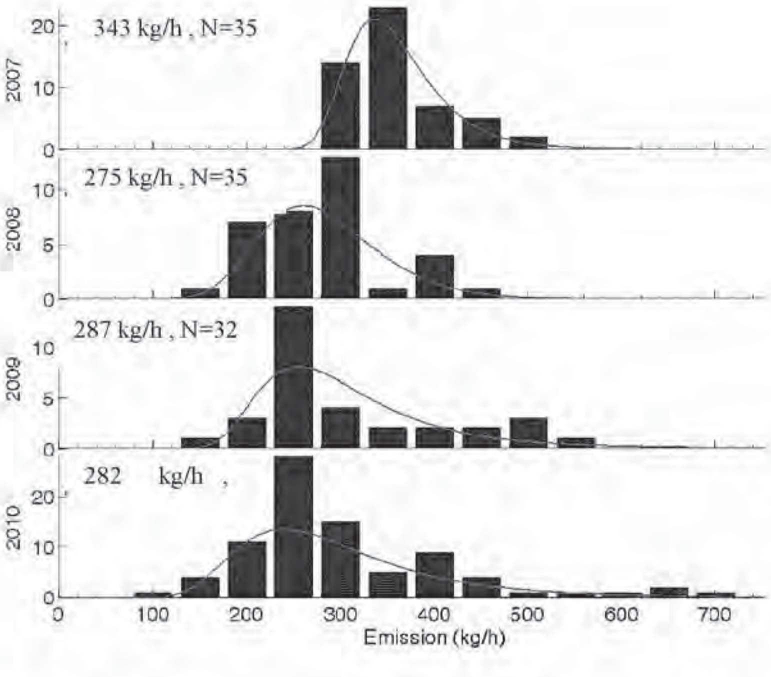


Figure A1.3 Total VOC emission from a refinery over several years. The average emission is given, calculated as weighted average. (Days with large variability are less weighted to minimize the influence of intermittent emissions, weight factor 1/standard deviation of daily emission values). The red curve is a skewed probability function that is fit to the data. The maximum is the most probable emission value.

A1.2 Details of the SOF method

The SOF method is based on the recording of broadband infrared spectra of the sun with a Fourier transform infrared spectrometer (FTIR) that is connected to a solar tracker. The latter is a telescope that tracks the sun and reflects the light into the spectrometer independent of its position. From the solar spectra it is possible to retrieve the path-integrated concentration (column, see Eq. 1) in the unit mg/m^2 of various species between the sun and the spectrometer. In Figure A1.1 a measurement system is shown built into a van. The system consists of a custom built solar tracker, transfer optics and a Bruker EM27 FTIR spectrometer with a spectral resolution of 0.5 cm^{-1}, equipped with a combined MCT (mercury cadmium telluride) detector or an InSb (indium antimonide) detector. Optical filters were used to reduce the bandwidth when conducting alkene and alkane measurements.

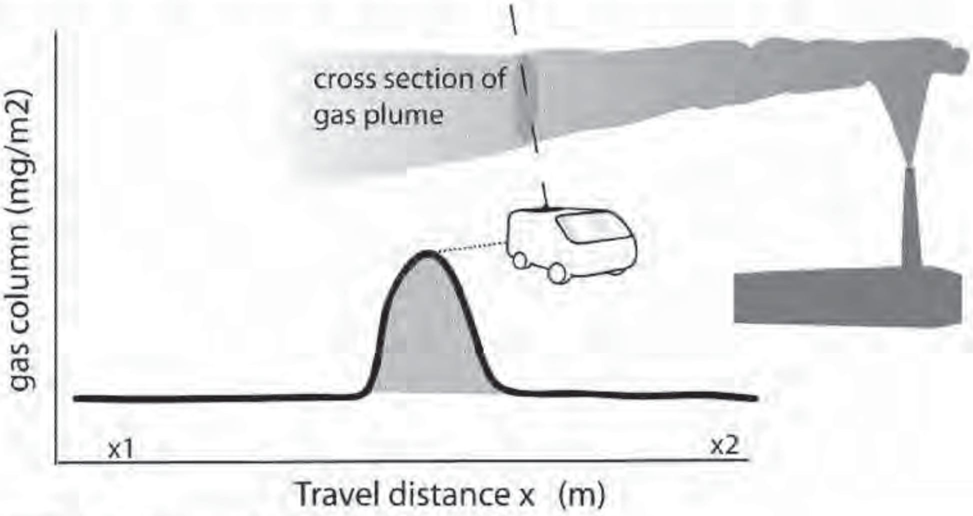


Figure A1.4 Illustration of the SOF measurements.

To obtain the gas emission from a source, the car is driven in such way that the detected solar light cuts through the emission plume, as illustrated in Figure A1.4. To calculate the gas emission the wind direction and speed is also required and these parameters are usually measured from high masts and towers.

The spectral retrieval is performed by a custom software, QESOF (Kihlman 2005b), in which calibration spectra are fitted to the measured spectra using a nonlinear multivariate fitting routine. Calibration data from the HITRAN database (Rothman 2003) are used to simulate absorption spectra for atmospheric background species at the actual pressure, temperature and instrumental resolution of the measurements. The same approach is applied for several retrieval codes for high resolution solar spectroscopy (Rinsland 1991; Griffith 1996) and QESOF has been tested against these with good results. For the retrievals, high resolution spectra of ethene, propene, propane, n-butane, n-octane and other VOCs (e.g. isobutene, 1,3-butadiene) were obtained from the PNL (Pacific Northwest Laboratory) database [Sharpe 2004]. These are degraded to the spectral resolution of the instrument by convolution with the instrument lineshape. The uncertainty in the absorption strength of the calibration spectra is about 3.5 % for the five species.

The SOF system can be operated in two parallel optical modes, one for alkenes and one for alkanes. In this study no measurements of alkenes were carried out since these species usually are emitted from the petrochemical industry rather than refineries.

The alkane optical mode corresponds to measurements in the infrared region between 3.3–3.7 µm (2700–3005 cm^{-1}), using the vibration transition in the carbon and hydrogen bond (CH-stretch). The absorption features of the different alkanes are similar and interfere with each other, but since the number of absorbing C-H-bonds is directly related to the molecule mass, the total alkane mass can be retrieved despite the interference. In the analysis we therefore use calibration spectra of propane, n-butane, and n-octane and fit these to the recorded spectra, using a resolution of 8 cm^{-1}. Aromatics and alkenes also have absorption features in the CH-stretch region, but mainly below 3.33 µm for the most abundant species. A sensitivity study of the SOF alkane retrieval was made for the TexAQS 2006 (Mellqvist 2007), taking into account the typical matrix of VOCs, and this study showed that total alkane mass obtained by the SOF was overestimated by 6.6 %. Here we assume the same uncertainty.

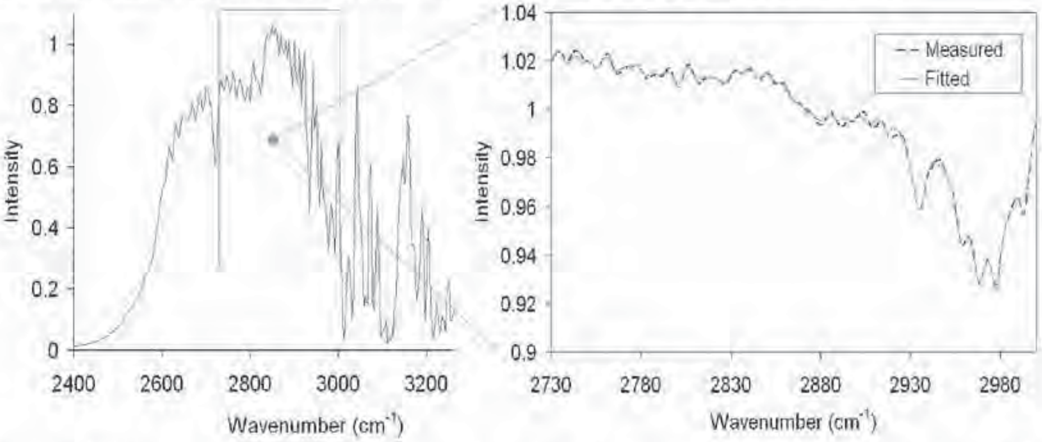


Figure A1.5 Solar spectra in the alkane CH-stretch region, (left) measured downwind a refinery. To the right the measured and the fitted mix of calibration spectra are shown (relative to a clean air background reference), obtained using the QESOF spectral retrieval algorithm.

A1.3 Flux calculation

To obtain the gas emission from a target source, SOF transects, measuring vertically integrated species concentrations, are conducted along roads oriented crosswind and close downwind (0.5–3 km) of the target source so that the detected solar light cuts through the emission plume as illustrated in Figure A1.4. The gas flux is obtained first by adding the column measurements and hence the integrated mass of the key species across the plume is obtained. To obtain the flux this value is then multiplied by the mass average wind speed of the plume, u'_{mw}. The flux calculation is shown in Eq. 1. Here, **x** corresponds to the travel direction, **z** to the height direction, **u'** to the wind speed orthogonal to the travel direction (x), $\mathbf{u'_{mw}}$ to the mass weighted average wind speed and $\mathbf{H_{mix}}$ to the mixing layer height. The slant angle of the sun is compensated for, by multiplying the concentration with the cosine factor of the solar zenith angle.

$$flux = \int_{x1}^{x2} \int_{0}^{Hmix} conc(z) \quad u'(z) \cdot dz\, dx = u'_{mw} \int_{x1}^{x2} column(x)$$

(Eq. 1)

where $u'_{mw} = \dfrac{\int^{Hmix} conc(z) u'(z) \cdot dz}{\int_{o}^{Hmix} conc(z) dz}$ and $column = \int_{0}^{Hmix} conc(z) \cdot dz$

The wind is not straightforward to obtain since it is usually complex close to the ground and increases with the height. The situation is helped by the fact that SOF measurements can only be done in sunny conditions. This is advantageous since it corresponds to *unstable meteorological conditions* for which wind gradients are smoothed out by convection. Over relatively flat terrain with turbulence inducing structures the mean wind varies less than 20 % between 20 and 100 m height using standard calculations of logarithmic wind. This is illustrated for the harbor of Göteborg in Figure A1.6. Here the average daytime wind velocity and wind direction profile for all sunny days during August of 2004 have been simulated [Kihlman 2005a] using a meteorological flow model denoted TAPM (Hurley 2005).

In addition, for meteorological conditions with considerable convection, the emission plume from an industry mixes rather quickly vertically giving a more or less homogeneous distribution of the pollutant versus height through the mixing layer even a few kilometers downwind. In addition to the atmospheric mixing, the plumes from process industries exhibit an initial lift since they are usually hotter than the surrounding air.

The rapid well-mixed assumption agrees with results from airborne measurements made by NOAA (National Oceanic and Atmospheric Administration) (De Gouw 2009) and Baylor University (Buhr 2006) during the TexAQS 2006 in which also SOF measurements were conducted [Mellqvist 2010]. The NOAA measurements indicate that the gas plumes from the measured industries mix evenly from the ground to 1000 m altitude, i.e. throughout the entire mixing layer, within 1000–2000 s (~25 min) transport time downwind the industrial plants. This indicates a vertical mixing speed of the plume between 0.5 to 1 m/s. This is further supported by Doppler LIDAR (Light Detection And Ranging) measurements by NOAA showing typical daytime vertical mixing speeds of ±(0.5–1.5) m/s [Tucker 2007].

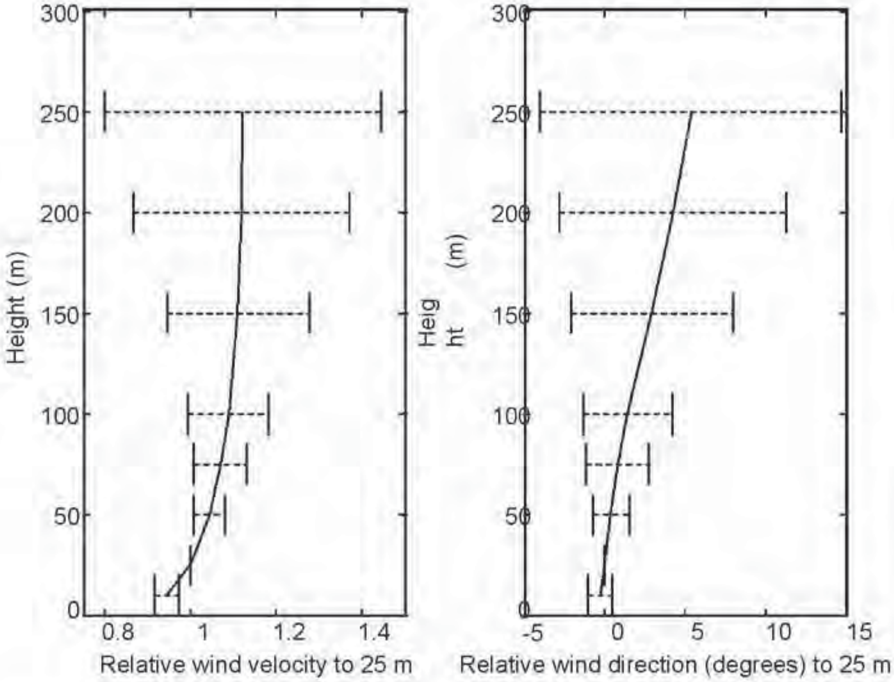


Figure A1.6 Average daytime wind velocity and wind direction profile retrieved by simulation above Göteborg harbor area averaged over all sunny days during a month with a wind-speed of 3–6 m/s at ground. The error bars indicate standard deviation between daily averages [Kihlman 2005a].

In this study, the measurements were conducted downwind of the industries at a typical plume transport time of 100–1000 s. According to the discussion above this means that the emission plumes have had time to mix up to heights of several hundred meters above the ground, above the first 50–100 m where the wind is usually disturbed due to various structures. For this reason we have used the average wind from 0 to 500 m height in the flux calculations.

Figure A1.7 shows a real measurement example illustrating the principle for the SOF and Mobile DOAS measurements. Here a measurement of alkanes, a transect across the plume downwind of a refinery, is shown. The measured gas column of alkanes in the unit mass/area (mg/m^2), as measured by the SOF in the solar light, is plotted versus distance across the plume. The wind was measured simultaneously by a GPS balloon, in the vicinity of the measurement as shown in Figure A1.8 and the 0–200 m value corresponds to 7.9 m/s, while the 0–500 value corresponds to 8.4 m/s. In the flux calculation the columns are integrated across the transect, whereby the integrated mass in unit mass per length unit in the plume (mg/m) is obtained. This value corresponds to an average column value of 48 mg/m2 across the whole transect, over 1300 m. This mass value is then multiplied by the wind speed, to obtain mg/s.

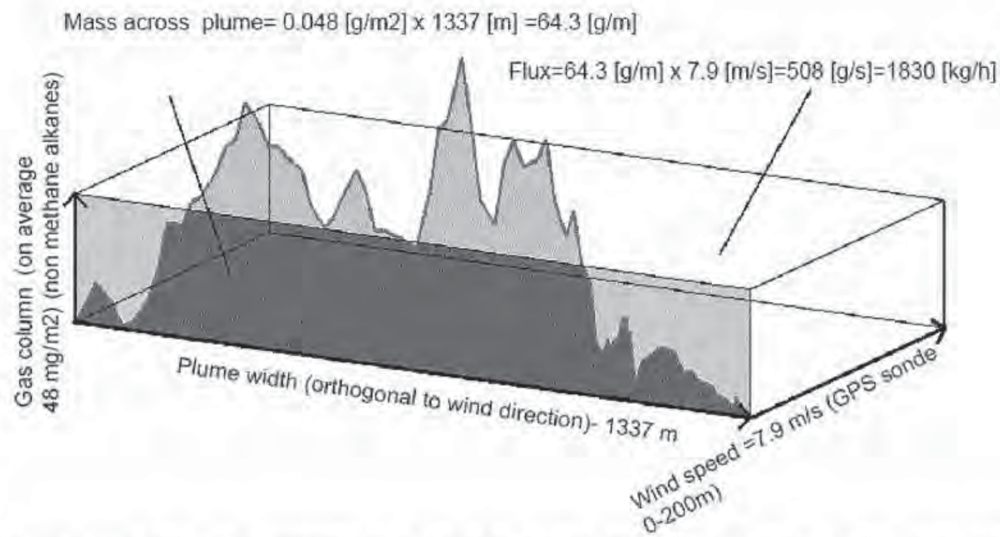


Figure A1.7 Illustration of the flux calculation in the SOF method for a measurement of alkanes conducted downwind of a refinery. The gas column of alkanes, retrieved from the spectra, is plotted versus distance. In the flux calculation the gas columns are integrated along the measurement transect, corresponding to the lilac area. This area, which is the integrated mass of the plume, corresponds to the same mass as an average column of 48 mg/m^2 integrated along the transect of 1337 m. The integrated mass is then multiplied with the wind speed yielding the flux in mass per seconds. Here an average wind speed from ground to 200 m was used corresponding to 7.9 m/s obtained from the GPS sonde.

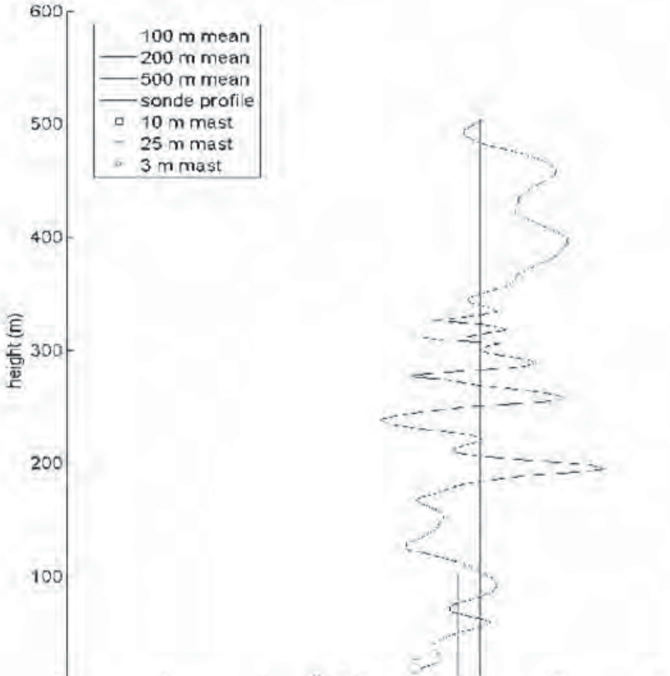


Figure A1.8 Wind profile measured with a GPS sonde less than ten minutes after the alkane transect shown in Figure A1.7above. The wind speed versus height is shown for the balloon measurements in addition to the 0–500 and the 0–200 m average values, and values for several masts at the refinery.

To verify that a measured flux is originating from a specific area upwind of where the emission was detected, another measurement transect needs to be performed upwind of that area to make sure that the emission is not coming from another source further away. If no significant flux is detected on the upwind side, this measurement does not need to be repeated for every downwind transect. If a smaller flux is measured on the upwind side than on the downwind side, the emission from the area in between is the difference between these fluxes. In this case the upwind transect needs to be repeated with every downwind transect. This type of emission measurements is preferably avoided since it might increase the uncertainty. Upwind measurements were performed for all areas during the study, but they are not presented in the result chapter.

A2. Mobile DOAS

A2.1 General

Mobile DOAS (Differential Optical Absorption Spectroscopy) measurements of scattered solar light in zenith direction were carried out in parallel with the SOF measurements, from the same vehicle, in order to measure formaldehyde, NO_2 and SO_2. DOAS works in the ultraviolet (UV) and visible wavelength region while SOF works in the infrared region and hence there are large differences in spectroscopy and in the used spectrum evaluation methods. However, both methods measure vertical columns which are integrated along measurement transects and multiplied by the wind to obtain the flux. The principle of flux-measurements using Mobile DOAS is hence the same as for SOF, although it is not necessary to compensate for any slant angle observations since the telescope is always pointing towards zenith. The DOAS system also works under cloudy conditions in contrast to SOF, although the most precise measurements are conducted in clear sky. The system is explained in Johansson (2013b).

The DOAS method was introduced in the 1970's (Platt 1979) and has since then become an increasingly important tool in atmospheric research and monitoring both with artificial light sources and in passive mode utilizing the scattered solar light. In recent time the multi axis DOAS method (scanning passive DOAS) has been applied in tropospheric research for instance measuring formaldehyde (Heckel 2005). Passive DOAS spectroscopy from mobile platforms has also been quite extensively applied in volcanic gas monitoring (Galle et al., 2002) for SO_2 flux measurements and for mapping of formaldehyde flux measurements in megacities (Johansson 2009). Mobile DOAS has only been used to a limited extent for measurements of industries; Rivera et al. (2009c) did SO_2 measurements on a power plant in Spain for validation purposes. They also made measurements at an industrial conglomerate in Tula in Mexico (Rivera 2009d) and measurements of SO_2, NO_2 and HCHO during the TexAQS 2006 campaign (Rivera 2009a, 2009b). There are also groups in both China and Spain working with mobile mini DOAS.

A2.2 Details of the method

The Mobile DOAS system used in this project, shown in Figure A1.9 and Figure A1.10, has been developed for airborne surveillance of SO_2 in ship plumes [Mellqvist 2008a, Johansson 2013a] but has for this project been modified to also measure HCHO and NO_2. It consists of a UV spectrometer (ANDOR Shamrock 303i spectrometer, 303 mm focal length, 300 μm slit) equipped with a CCD (charge-coupled device) detector (Newton DU920N-BU2, 1024 by 255 pixels, thermoelectrically cooled -70^{0} C). The spectrometer has wavelength coverage of 309 to 351 nm and a spectral resolution of 0.63 nm (1800 grooves/mm holographic grating). The spectrometer is connected to a quartz telescope (20 mrad field of view, diameter 7.5 cm) via an optical fiber (liquid guide, diameter 3 mm). An optical band pass filter (Hoya) is used to prevent stray light in the spectrometer by blocking wavelengths longer than 380 nm.

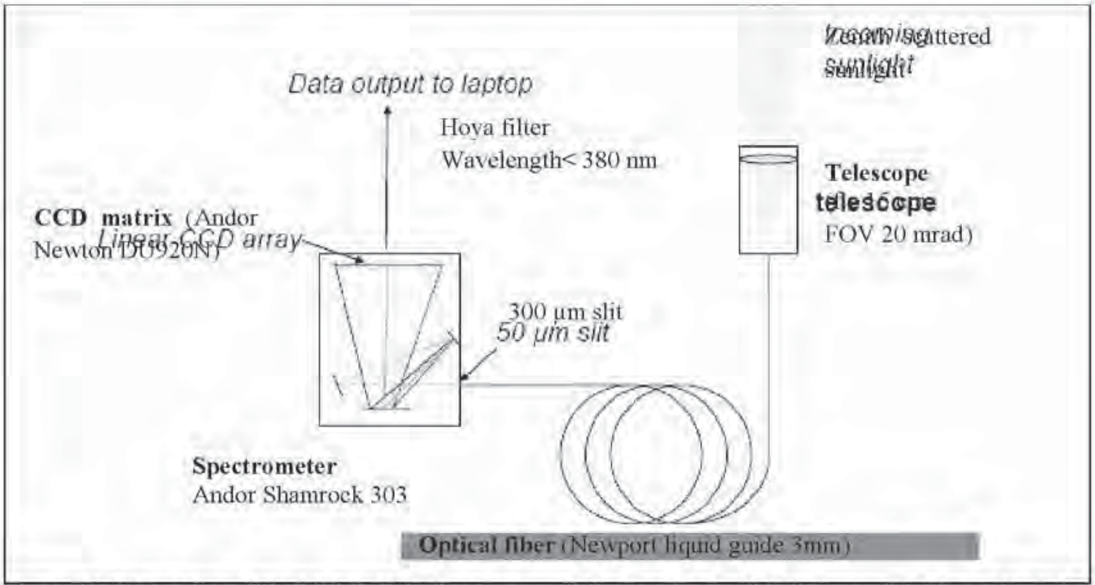


Figure A1.9 Overview of the Mobile DOAS system used. Scattered solar light is transmitted through a telescope, and an optical fiber to a UV/visible spectrometer. From the measured spectra the amount of HCHO, NO_2 and SO_2 in the solar light can be retrieved.

The DOAS system measures ultraviolet spectra in the 308–352 nm spectral region from which total columns of HCHO, NO_2 and SO_2 can be retrieved, Figure A1.11. HCHO and NO_2 are retrieved between 324 to 350 nm, together with the interfering species O_3, O_4 and SO_2. SO_2 and O_3 is then retrieved between 310 to 324 nm together with the NO_2 and HCHO columns obtained from the previous retrieval at 324–350 nm.

In the spectral evaluation the recorded spectra along the measurement transect are first normalized against a reference spectrum recorded upwind the industry of interest. In this way most of the absorption features of the atmospheric background and the inherent structure of the sun is eliminated. Ideally the reference spectrum is expected not to include any concentration above ambient of the trace species of interest, however in urban and industrial areas this is difficult to achieve, and therefore our measurement in this case will produce the difference in vertical columns between the reference spectrum and all measured spectra across the plume for every measurement series. The normalized spectra are further high pass filtered according the algorithms proposed by Platt and Perner (1979), and then calibration spectra are scaled to the measured ones by multivariate fitting. Here we have used a software package denoted QDOAS (Van Roozendael 2001) developed at the Belgian Institute for Space Aeronomy (BIRA/IASB) in Brussels.

The calibration spectra used here for the various gases are obtained from the following: HCHO (Cantrell 1990), NO_2 (Vandaele 1998), SO_2 (Bogumil 2003), O_3 (Burrows 1999) and O_4 (Hermans 1999). In addition to these calibration spectra it is also necessary to fit a so called Ring spectrum, correcting for spectral structures arising from inelastic atmospheric scattering (Fish 1995). The Ring spectra used have been synthesized with a component of the QDOAS software, which uses a high resolution solar spectrum to calculate the spectrum of Raman scattered light from atmospheric nitrogen and oxygen, convolves this spectrum and the high resolution solar spectrum with the instrument lineshape and calculate the ratio between them. One problem with the acquired spectra is the fact that the wavelength scale of the spectrometer was variable with shifts in the wavelength scale for the individual spectra. Even though these shifts were minute, within 0.02 nm, they still cause large residuals when normalizing the spectra to the reference spectrum. To overcome this we have used the QDOAS program, to characterize the wavelength calibration of the spectra by comparing the positions of the solar absorption lines with a high-resolved solar spectrum. This improved the results quite considerably. An example of a fit can be seen in Figure A1.11 in which a calibration spectrum of formaldehyde has been fitted to the measured differential absorbance. This differential spectrum corresponds to a high pass filtered atmospheric spectrum with the features of ozone, NO_2 and spectrum of inelastic atmospheric scattering removed.

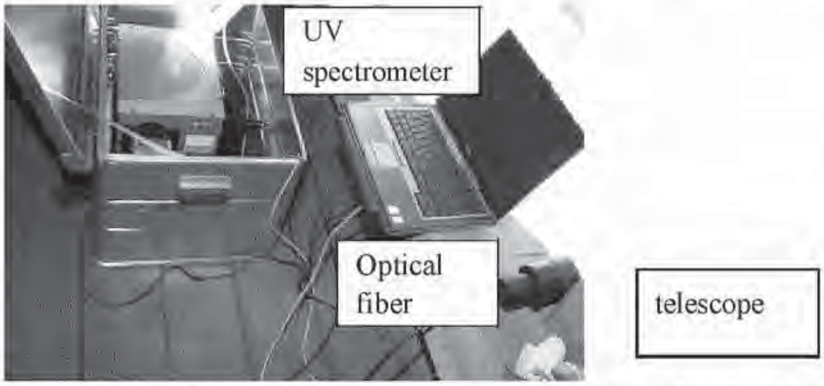


Figure A1.10 The Mobile DOAS system consisting of a UV spectrometer, optical fiber and UV telescope.

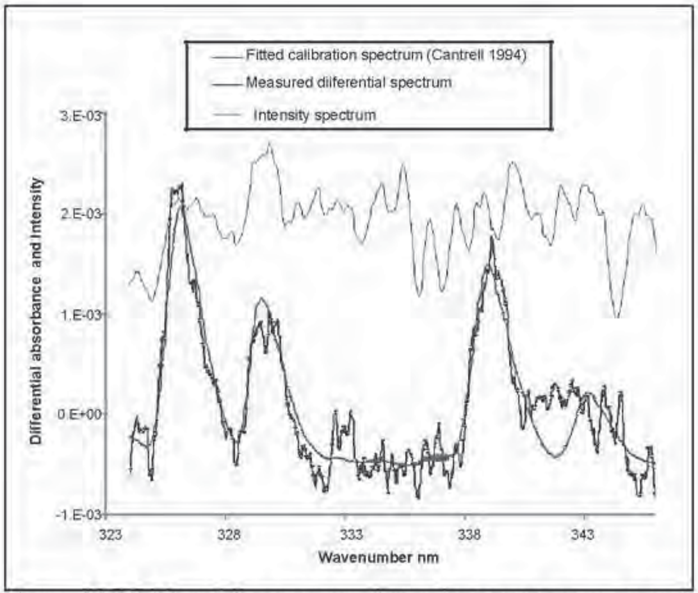


Figure A1.11 Ultraviolet spectrum (Intensity counts versus wavelength) measured south west of HSC by the Mobile DOAS system on May 20 2009, 10:40, adapted from Mellqvist 2010. From this spectrum a formaldehyde column of $3.8x10^{16}$ molecules/cm^2 was derived by fitting a calibration spectrum to the measured high pass filtered absorbance (after subtraction of ozone, NO_2 and inelastic atmospheric scattering).

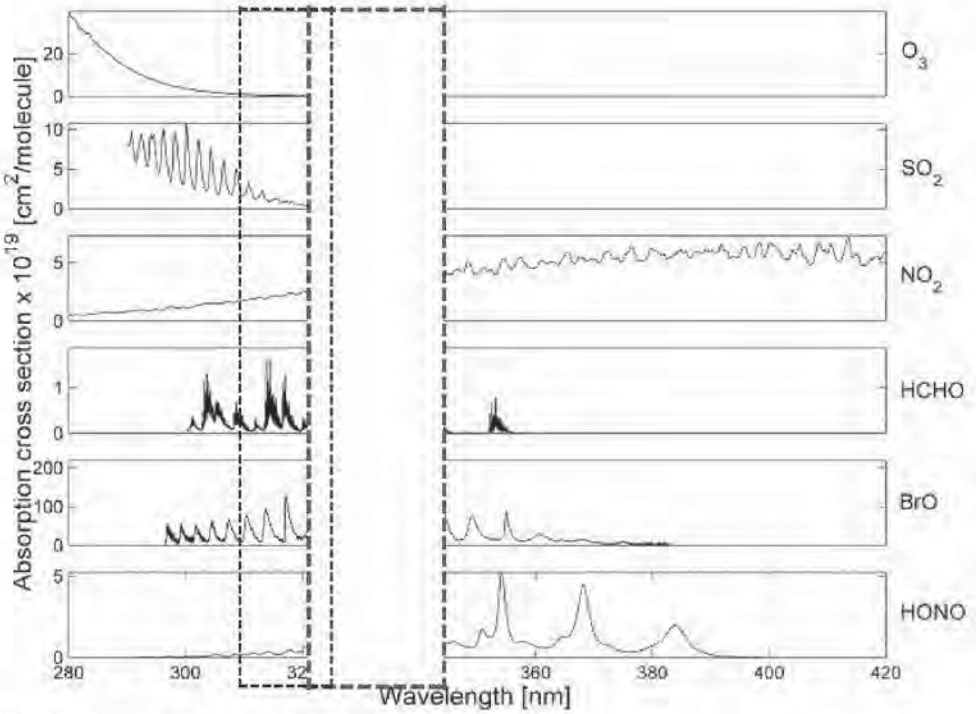


Figure A1.12 Absorption cress section for various species

A3 Mobile extractive FTIR and tracer correlation

Column measurements using SOF are often complemented by mobile extractive measurements using multi reflection absorption in the infrared region (MeFTIR) or UV (White cell DOAS). Such extractive measurements have better speciation than the SOF measurements and by measuring the composition of various VOCs downwind the studied industries it is possible to infer emissions of more species than obtained by the SOF instrument alone. The extractive measurements can be complemented by tracer gas releases at the sources to estimate emissions independently from the SOF.

A3.1 Details of MeFTIR system

The extractive FTIR system contains a spectrometer of the same type used for the SOF system, Bruker IRCube, but utilizes an internal glow bar as an infrared radiation source instead of the sun, and transmits this light through a measurement cell.

The spectrometer is connected to an optical multi-pass cell (Infrared Analysis Inc.) operated at 40 m path- length, Figure A1.13. The transmitted light is detected simultaneously with an InSb-detector (indium antimonide) in the 2.5–5.5 μm (1800–4000 cm^{-1}) region and a MCT (mercury cadmium telluride) detector in the 8.3–14.3 μm (700–1200 cm^{-1}) region. Temperature and pressure averages in the cell were integrated over the cycle of each spectrum. Atmospheric air is continuously pumped with high flow through the optical cell from the outside, taking the air in from the roof of the van through a Teflon tube. A high flow pump is used to ensure that the gas volume in the cell was fully replaced within a few seconds. Spectra were subsequently recorded with an integration time of typically 10 seconds. A GPS-receiver is used to register the position of the van every second.
The concentration in the spectra is analyzed online, fitting a set of calibration spectra based on

the Hitran2000 infrared database (updated to the 2007 edition) (Rothman et al. 2003) and the PNL database (Sharpe 2004) in a least-squares fitting routine [Griffith 1996].

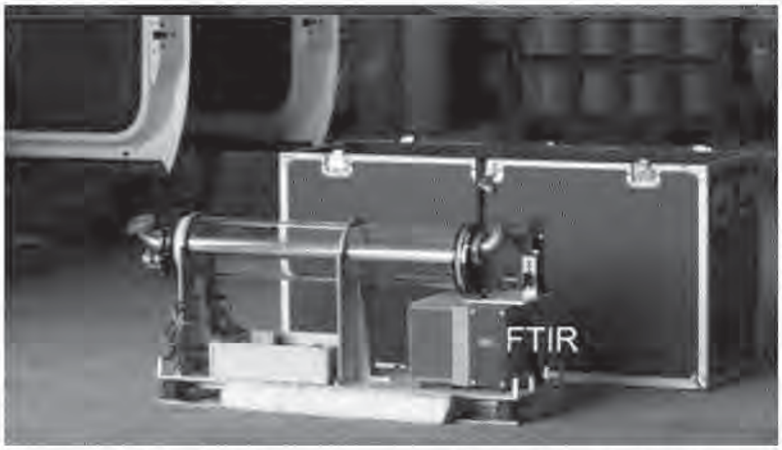


Figure A1.13 The MeFTIR instrument used in parallel with the SOF system during the campaign. The gas is extracted into the White-cell where it is analysed by infrared absorption measurements. The residence time in the gas cell, and hence the measurements time resolution, is a few seconds.

A3.2 Tracer correlation measurements

Tracer correlation involves a common practice of measuring pollutant emission rates while releasing a known concentration of a tracer gas, Figure A1.14. The subsequent simultaneous measurement of this tracer gas and the pollutant of interest downwind from the release provide sufficient information to determine or validate the emissions flux measurements. The release of a known concentration of a tracer gas assists in tracking the plume and sources or sinks of the pollutant of interest into the plume. The majority of tracer gas studies use cell-based technologies, like CRDS (Cavity Ring Down Spectrometers) and FTIR to measure the tracer gas and the compound of interest. However, some studies are expanding the use of tracer gas release to open-path techniques to evaluate the distribution over a large area.

Tracer correlation has been applied at Swedish refineries since 8 years for measurements of isolated features such as water treatment areas, ship or truck loading and individual tank emissions as well as landfills (Galle, 2001, Börjesson 2009, Eastern research group). A mobile extractive FTIR system is then used based on a multi reflection cell coupled to an FTIR in a measurements vehicle. The meFTIR system measures the concentration of gases close to the ground. A 50 m tube can be coupled to the gas analysis cell so one can measure at some distance from the car, for instance high up or in process areas.

To study emissions from a certain tank or other sources, tracer gas is released from the tank and then the tracer and gas is measured downwind of the tank, Figure A13. From this ratio together with the amount of tracer released it is possible to obtain the emission rate from the tank without any measurement of the wind. In this manner it is possible to obtain the emission from the tank, over a full cycle for instance also at night. The uncertainty for meFTIR is estimated to be around 20% for isolated sources.

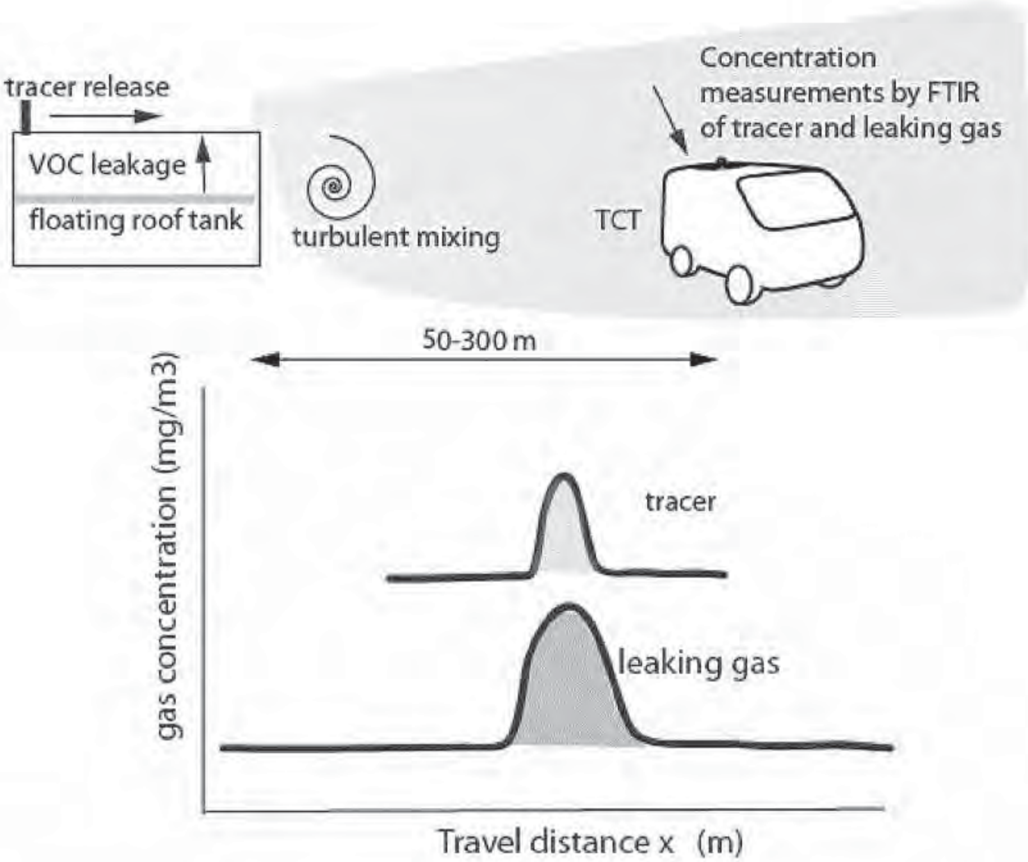


Figure A1.14. Here the meFTIR method, used together with SOF in the measurements van is illustrated when conducting emission measurements from a leaking crude oil tank. Trace gas, usually N_2O or SF_6, is positioned on the upwind side of the tank, and then it mixes with the leaking VOCs from the tanks. The measurements are conducted downwind by driving through the plumes of the tracer gas and the leaking gas. The dilution factor for the trace gas is obtained as the ratio between the tracer release rate and the measured tracer concentration, averaged over the plume. To obtain the emission rate of VOCs the dilution factor is multiplied by the average concentration of VOC over the plume. The assumption here is hence that the leaking gas, leaking through the tank sealing dilutes in the same manner as the tracer, release in one or a few points.

A4 Mobile White Cell DOAS

In addition the concentration measurements of alkanes with the Mobile extractive FTIR above a similar UV system is often used to measure also aromatic VOCs (Benzene, Toluene, and xylenes. In a validation test on Houston in October 2013 this system was tested against PTR-MS, showing good agreement and sub-ppb sensitivity for benzene and other species (Johansson 2013c).

The Mobile White Cell DOAS (MW-DOAS) which is developed by Chalmers University of Technology (Pontus Andersson) and FluxSense AB is based upon the White Cell configuration described by Doussin (1999), Figure A1.15). The cell has a base path of 2.5 m and with 86 reflections the total distance that the light travels is thus 210 m. All mirrors used in the cell have special UV high reflectivity coatings that have a reflectivity of 99.7 % in the wavelength region 250 -280 nm. The light source used is a 75 W Xenon arc lamp coupled into a UV fiber that further transmits the light into the multi reflection cell. After passing through the cell the light is coupled into a fiber bundle transmitting the light into a UV spectrometer (303 mm focal length) equipped with a CCD detector. The spectrometer has wavelength coverage between 243 nm and 286 nm. The wavelength calibration is carried out using a hollow cathode Pb lamp. Several aromatic compounds exhibit strong absorption lines in this region. Measured cross-sections are obtained from the scientific literature (Etzkorn, 1999, Fally 2009). The DOAS analysis was done online using the custom software DOASIS and QDOAS (Fayt, 2001; (Van Roozendael 2001).

Figure A1.15 The MW-DOAS system mounted on the roof of a van, yielding sub ppb sensitivity for benzene and other aromatics.

A5 Measurement uncertainty and quality assurance

A5.1 Measurement uncertainty SOF and Mobile DOAS

The main uncertainty for the flux measurements in the SOF and Mobile DOAS measurements comes from the uncertainty in the wind field. Table A1.1 shows the estimated uncertainties for the flux measurements during a SOF campaign in Houston 2011; these uncertainties are rather typical for SOF and mobile DOAS measurements.

Table A1.1 Uncertainty estimation of the flux measurements (the variability of the sources not taken into account).

	Wind Speed a)	**Wind Direct** b)	**Spectroscopy (cross sections)** c)	**Retrieval error** d)	**Composite flux measurement uncertainty** e)
Alkanes	16–30 %	6–9 %	3.5 %	12 %	21–34 %
Ethene	16–30 %	6–9 %	3.5 %	10 %	20–33 %
Propene	16–30 %	6–9 %	3.5 %	20 %	27–37 %
HCHO	16–30 %	6–9 %	3 %	10 %	20–33 %
SO_2	16–30 %	6–9 %	2.8 %	10 %	20–33 %
NO_2	16–30 %	6–9 %	4 %	10 %	20–33 %

a) Comparing mast wind averages with the 0–500 m GPS sonde averages, the max data spreads 16–30 % (1σ, 30 %)

b) The 1σ deviation among the wind data compared to the 0–500 m sonde is 18°. For a plume transect orthogonal to the wind direction, which is always the aim, this would give a 6 % error. For a measurement in 75° angle the error is 9 %.

c) Includes systematic and random errors in the cross section database.

d) The combined effects of instrumentation and retrieval stability on the retrieved total columns during the course of a plume transect and error of the SOF alkane mass retrieval. Estimated for SOF.

e) The composite square root sum of squares uncertainty

A5.2 Validation and comparisons

The performance of the SOF method has been tested by comparing it to other methods and tracer gas release experiments, according to Table A1.2. In one experiment, tracer gas (SF_6) was released from a 17 m high mast on a wide parking lot. The emission rate was then quantified by SOF measurements 50–100 m downwind the source, yielding a 10 % accuracy for these measurements when averaging 5–10 transects [Kihlman 2005b].

More difficult measurement geometries have also been tested by conducting tracer gas releases of SF_6 from the top of crude oil tanks. For instance, in an experiment at Nynas refinery in Sweden tracer gas was released from a crude oil tank. In this case, for close by measurements in the disturbed wind field at a downwind distance of about 5 tank heights, the overestimation was 30 %, applying wind data from a high mast (Kihlman 2005a; Samuelsson 2005b). A similar experiment was carried out by releasing SF_6 in the process area of a petrochemical plant, using 5 different release points. The SF_6 release was measured 300 m downwind using SOF with meteorological data from a nearby mast. The SOF data were 15% higher than the actual released data, i.e. 2.18±0.3 kg/h compared to 1.89 kg/h.

The SOF method has also been compared against other methods. In another experiment at the Nynas refinery a fan was mounted outside the ventilation pipe, sucking out a controlled VOC flow from the tank. The pipe flow was measured using a so called pitot pipe and the concentration was analyzed by FID (Flame ionization detector) which made it possible to calculate the VOC emission rate, which was 12 kg/h. In parallel, SOF measurements were carried out at a distance corresponding to a few tank heights, yielding an emission rate of 9 kg/h, a 26 % underestimation in this case. Similar measurements from a joint ventilation pipe from several Bitumen cisterns yielded a FID value of 7 kg/h and only 1 % higher emission from the SOF measurements (Samuelsson 2005b).

During the TexAQS 2006 the SOF method was used in parallel to airborne measurements of ethene fluxes from a petrochemical industrial area in Mont Belvieu (De Gouw 2009). The agreement was here within 50 % and in this case most of the uncertainties were in the airborne measurements. The SOF method has not been directly compared to the laser based DIAL method (Differential Absorption LIDAR) (Walmsley 1998) which is commonly used for VOC measurements. Nevertheless, measurements at the same plant in Sweden (Preem refinery) yield very similar results when measuring at different years. Differences have been seen for bitumen refineries however (Samuelsson 2005b). Rivera et al. (2009) did Mobile DOAS measurements of SO_2 on a power plant in Spain and the average determined flux with the DOAS came within 7 % of the values monitored at the plant measurements. All in all the experiment described above is consistent with an uncertainty budget of 20–30 %.

Table A1.2 Validation experiments and instrument comparisons for the SOF technique

Experiment	Comment	SOF kg/h	**Reference kg/h**	**Difference**
Single SF_6 tracer releases from 17 m mast, *(Fransson, 2002)*	SOF measurements on a parking lot 100 m away	2.2	1.97 Tracer release rate from weighing	10%
SF_6 tracer release from the top of crude oil tank (*Samuelsson, 2005*)	SOF measurements 3 tank heights away	13 +5.4	9.5	36%
SF_6 tracer release at VOC leakage points in the process area of an petrochemical plant (Naphta cracker). (*Confidential data*)	SOF measurements 500 m away	2.18±0.3	1.89	15%
Controlled VOC emission from bitumen pipe (Samuelsson 2005)	SOF measurements downwind bitumen tank park	7	7.1	+1%
Controlled VOC emission from crude tank (*Samuelsson, 2005)*	SOF measurements 3 tank heights away. Heated tank with single vent. A fan was mounted and then the flow and concentration was measured in the vent.	9	12 FID+ pitot pipe flow rate	-26%
Large scale ethene emission from Mont Belvieu, E Texas *(Mellqvist, JGR 2009;* *De Gouw, 2009)*	SOF measurements 500m- 3 km downwind and airborne measurements by NOAA	390	480 NOAA WP 3 Orion aircraft	-20% difference
VOC emissions from process area in Preem refinery Gothenburg (*Kihlman 2005*)	Measurements by DIAL in 1999 comparison to SOF in 2005	56±16	56 DIAL 1999	0%

A5.3 Quality assurance

A formalized QA/QC protocol has not yet been adopted for the SOF method or for Mobile DOAS. However, the spectroscopic column concentration measurements is basically the same as a long path FTIR measurement through the atmosphere corresponding to an effective path length of about 5 km for atmospheric background constituents. For such measurements, there is an EPA guidance document (FTIR Open-Path Monitoring Guidance Document," EPA-600/R-96/040, April 1996).

In addition the US-EPA has developed a test method (OTM 10, Optical Remote Sensing for Emission Characterization from Non- Point Sources), (Thoma 2009) for fugitive emission of methane from landfills. This method is based on measuring the gas flux by integrating the mass across the plume and then multiplying with the wind speed. The mass is here measured by long path FTIR or tuneable diode lasers. The OTM 10 is hence quite similar to the SOF method, since it uses long path FTIR but more importantly since it determines the flux in the same principal manner. The spectral retrieval code used in the SOF method (QESOF) (Kihlman 2005a) relies on principles adopted by the NDACC community (Network for the detection of atmospheric composition change. www.ndsc.ncep.noaa.gov), which is a global scientific community in which precise solar FTIR measurements are conducted to investigate the gas composition changes of the atmosphere. Chalmers University is a partner of this community and has operated a solar FTIR in Norway since 1994. The QESOF code has been evaluated against several published codes developed within NDACC with good agreement, better than 3 %.

Even though a formalized QA/QC protocol is missing there are several QA procedures carried out prior to conducting the SOF measurements. This includes checking the instrumental spectral response (usually done by measuring solar spectra and investigating the width and line position of these) and investigating that the instruments measures in the same manner, independent of the direction of the instrument relative to the sun. Usually the instrument is aligned to have the same light response in all directions.

The FTIR instrument, used in SOF, is not calibrated prior to measurements but one instead relies on calibration data from the scientific literature. This is appropriate as long as the instrument is well aligned, and whether the alignment has been sufficient can actually be checked afterwards by investigating the widths and shape of the absorption lines in the measured solar spectra.

Noteworthy is the fact that the spectra are stored in a computer and that the spectral analysis is conducted afterwards which makes it possible to conduct quality control on the data. From this analysis the individual statistical error is obtained for each measurement. Quality control is also conducted by removing "bad" spectra".

For open path DOAS standardization work is carried out which is very similar to this application from a spectroscopic point of view. For instance the US EPA has tested several long path instruments within their environmental technology verification program with good results.

The spectral evaluation used in this study is similar to many other studies since we rely on a software package widely used by the DOAS community (QDOAS) and we use published calibration reference data. The most important issue when it comes to quality assurance is to investigate the lineshape of the spectrometer and the wavelength calibration. During the campaign this was done by regular measurement with a low pressure Hg calibration lamp. The wavelength calibration was also corrected afterwards by comparing the measured spectra to a solar spectrum, and then shifting them accordingly to the difference. The quality of the data can be checked by investigating the spectral fitting parameters and in this way remove bad data.

A6 References

Bogumil, K. et al., 2003, Measurements of Molecular Absorption Spectra with the SCIAMACHY PreFlight Model: Instrument Caracterization and Reference Data for Atmospheric Remote-Sensing in the 230–2380 nm Region, J. Photoch. Photobio. A, 157, 167–184

Burrows, J.P et al., 1999, Atmospheric Remote-Sensing Reference Data from GOME: 2. Temperature-Dependent Absorption Cross Sections of O3 in the 231–794 nm Range, Journal of Quantitative Spectroscopy and Radiative Transfer 61, 509–517

Börjesson, G., J. Samuelsson, J. Chanton, R. Adolfsson, B. Galle, and B.H. Svensson. 2009. A national landfill methane budget for Sweden based on field measurements, and an evaluation of IPCC models. Tellus, 61B: 424–435.

Cantrell CA, Davidson JA, McDaniel AH, Shetter RE, Calvert JG. 1990, Temperature dependent formaldehyde cross sections in the near-ultraviolet spectral region. J Phys Chem, 94:3902–8.

De Gouw, J.A., et. al. (2009), Airborne Measurements of Ethene from Industrial Sources Using Laser Photo-Acoustic Spectroscopy, Environmental Science and Technology, 43, 2437–2442.

Doussin J. F.;Dominique R.; Patrick C., Applied Optics, 38 4145 (1999)

Eastern Research Group, Inc. 2010. Evaluation of Large Area Methane Emission Source Methods: Mobile and Stationary Plume Measurements Using the Tracer Correlation Approach. Final Report for U.S. EPA. May 30

EPA Handbook: Optical Remote Sensing for Measurement and Monitoring of Emissions Flux, December 2011, Office of Air Quality Planning and Standards , Air Quality Analysis Division Measurement Technology Group , Research Triangle, North Carolina, 27711, editor Dennis K. Mikael, http://www.epa.gov/ttn/emc/guidlnd/gd-052.pdf

Etzkorn, T., B. Klotz, S. Sørensen, I.V. Patroescu, I. Barnes, K.H. Becker, and U. Platt, "Gas-phase absorption cross sections of 24 monocyclic aromatic hydrocarbons in the UV and IR spectral ranges," Atmos. Environ. 33, 525-540 (1999).

Fally, S., M. Carleer, and A. C. Vandaele, "UV Fourier transform absorption cross sections of benzene, toluene, meta-, ortho-, and para-xylene", J. Quant. Spectrosc. Radiat. Transfer 110, 766-782 (2009).

Fayt, C. and Van Roozendael, M., 2001. QDOAS 1.00 Software User Manual, BIRA-IASB.

Fish, D.J. and Jones, R.L., 1995. Rotational Raman scattering and the ring effect in Zenith-sky spectra. Geophysical Research Letters, 22(7): 811–814.

Foy, B., ... Mellqvist, J., et al., Modeling constraints on the emission inventory and on vertical dispersion for CO and SO2 in the Mexico City Metropolitan Are using Solar FTIR and zenith sky UV spectroscopy, Atmos. Chem. Phys., 7, 781–801, 2007

Fransson, K., and J. Mellqvist, (2002), Measurements of VOCs at Refineries Using the Solar Occultation Flux Technique, Chalmers University of Technology, Göteborg, Sweden.

Galle, B.; Mellqvist, J., et al., Ground Based FTIR Measurements of Stratospheric Trace Species from Harestua, Norway during Sesame and Comparison with a 3-D Model, JAC, 1999, 32, no. 1, 147–164.

Galle, B., J. Samuelsson, B.H. Svensson, G. Börjesson, "Measurements of methane emissions from landfills using a time correlation tracer method based on FTIR absorption spectroscopy." Environ. Sci. Technol. 35: 21–25. 2001.

Galle, B., Oppenheimer, C., Geyer, A., McGonigle, A.J.S., Edmonds, M. and Horrocks, L., (2002), A miniaturised ultraviolet spectrometer for remote sensing of SO_2 fluxes: A new tool for volcano surveillance, Journal of Volcanology and Geothermal Research, 119 241–254

Gratien, A. et al (2007), UV and IR Absorption Cross-sections of HCHO, HCDO, and DCDO, J. Phys. Chem. A, 111, 11506–1151

Griffith D.W.T., Synthetic calibration and quantitative analysis of gas-phase FT-IR spectra. Applied Spectroscopy, 1996. 50(1): p. 59–70.

Heckel, A., A. Richter, T. Tarsu, F. Wittrock, C. Hak, I. Pundt, W. Junkermann, and J.P. Burrows, MAX-DOAS measurements of formaldehyde in the Po-Valley, Atmospheric Chemistry and Physics, 5, 909–918, 2005.

Hermans, C.et al., Absorption cross-sections of atmospheric constituents: NO_2, O_2, and H_2O, Environ. Sci. Pollut. R. , 6, 151–158, 1999.

Hurley, P.J., Physick W.L., and Luhar A.K., TAPM: A practical approach to prognostic meteorological and air pollution modelling. Environmental Modelling and Software, 2005. 20(6): p. 737.

Johansson, M., C. et al, 2009, Mobile mini-DOAS measurement of the outflow of NO_2 and HCHO from Mexico City, Atmos. Chem. Phys., 9, 5647–5653

Johansson, J., et al., 2013a, Quantitative Measurements and Modeling of Industrial Formaldehyde Emissions in the Greater Houston Area during Campaigns in 2009 and 2011, accepted by Journal of Geophysical

Research – Atmospheres, 2013JD020159R.

Johansson, J., et al., 2013b, Emission Measurements of Alkenes, Alkanes, SO_2 and NO_2 from Stationary Sources in Southeast Texas over a 5-year-period Using SOF and Mobile DOAS, which has been submitted for possible publication in Journal of Geophysical Research - Atmospheres. accepted by Journal of Geophysical Research – Atmospheres,, 2013JD020485.

Johansson, J., Mellqvist, J., et al., Quantification of industrial emissions of VOCs, NO2 and SO2 by SOF and Mobile DOAS during DISCOVER-AQ, AQRP project 13-0051, AQRP report, Dec 7 2013c

Kihlman, M. (2005a), Application of solar FTIR spectroscopy for quantifying gas emissions, Technical report No. 4L, ISSN 1652-9103, Department of Radio and Space Science, Chalmers University of Technology, Gothenburg, Sweden.

Kihlman, M., J. Mellqvist, and J. Samuelsson (2005b), Monitoring of VOC emissions from three refineries in Sweden and the Oil harbor of Göteborg using the Solar Occultation Flux method, Technical report, ISSN 1653 333X, Department of Radio and Space, Chalmers University of Technology, Gothenburg, Sweden.

S.-W. Kim,.Mellqvist, J., et al., Evaluations of NOx and highly reactive VOC emission inventories in Texas and their implications for ozone plume simulations during the Texas Air Quality Study 2006S, Atmos. Chem.Phys., 11, 11361–11386, 2011, www.atmos-chem-phys.net/11/11361/ 2011/doi:10.5194/acp-11-11361-2011

Mellqvist, J., Application of infrared and UV-visible remote sensing techniques for studying the stratosphere and for estimating anthropogenic emissions, doktorsavhandling, Chalmers tekniska högskola, Göteborg, Sweden, 1999a

Mellqvist, J och Galle, B., Utveckling av ett IR absorptionssystem användande solljus för mätning av diffusa kolväteemissioner, Rapport till Preems miljöstiftelse juli 1999b.

Mellqvist, J., Arlander, D. W., Galle, B. and Bergqvist, B., Measurements of Industrial Fugitive Emissions by the FTIR-Tracer Method (FTM), IVL report, 1995, B 1214.

Mellqvist, J., Flare testing using the SOF method at Borealis Polyethylene in the summer of 2000. 2001, Chalmers University of Technology. (Available at www.fluxsense.se)

Mellqvist, J., J. Samuelsson, C. Rivera, B. Lefer, and M. Patel (2007), Measurements of industrial emissions of VOCs, NH_3, NO_2 and SO_2 in Texas using the Solar Occultation Flux method and mobile DOAS, Project H053.2005, Texas Environmental Research Consortium., Texas. (http://www.harc.edu/projects/airquality/Projects/Projects/H053.2005)

Mellqvist, J.,Berg N. and Dan Ohlsson, 2008a, Remote surveillance of the sulfur content and NOx emissions of ships, Second international conference on Harbours, Air Quality and Climate Change (HAQCC), Rotterdam.

Mellqvist, J., Johansson, J.,Samuelsson, J., Rivera, C., Lefer, B. and S. Alvarez (2008b), Comparison of Solar Occultation Flux Measurements to the 2006 TCEQ Emission Inventory and Airborne Measurements for the TexAQS II, Project No. 582-5-64594-FY08-06 , TCEQ report., Texas. (available at http://www.tceq.state.tx.us/assets/public/implementation/air/am/contracts/reports/da/20081108-comparison_solar_occultation_flux_measurements.pdf)

Mellqvist, J., et al. (2009a), Emission Measurements of Volatile Organic Compounds with the SOF method in the Rotterdam Harbor 2008, available at www.fluxsense.se

Mellqvist, J., J. Samuelsson, J. Johansson, C. Rivera, B. Lefer, S. Alvarez, and J. Jolly (2010), Measurements of industrial emissions of alkenes in Texas using the solar occultation flux method, J. Geophys. Res.,115, D00F17, doi:10.1029/2008JD011682.

Parrish, D.D., Ryerson, T.B., Mellqvist, J. et al., Primary and secondary sources of formaldehyde in urban atmospheres: Houston Texas region, Atmos. Chem. Phys., 12, 3273-3288, 2012:

Platt, U., D. Perner, and H.W. Pätz, Simultaneous Measurement of Atmospheric CH_2O, O_3 and NO_2 by Differential Optical Absorption, Journal of Geophysical Research, 84 (C10), 6329-6335, 1979.

Rivera, C. et al., (2010), Quantification of NO_2 and SO_2 emissions from the Houston Ship Channel and Texas City during the 2006 Texas Air Quality Study, J. Geophys. Res., 115, D08301, doi:10.1029/2009JD012675

Rivera , C., Application of Passive DOAS using Scattered Sunlight for quantification of gas emission from anthropogenic and volcanic sources (2009a), Dissertation, ISBN 978-91-7385-317-0, ISSN 0346

Rivera, C., J.A. Garcia, B. Galle, L. Alonso, Y. Zhang, M. Johansson, M. Matabuena, and G. Gangoiti (2009b), Validation of optical remote sensing measurement strategies applied to industrial gas emissions, Int. J. Remote Sens., vol 30, no 12, p3191–3204.

Rivera, C., et al. (2009c),Tula industrial complex (Mexico) emissions of SO_2 and NO_2 during the MCMA 2006 field campaign using a mobile mini_DOAS system, Atmos. Chem. Phys., 9, 6351–6361, 2009.

Rothman et al. (2003), HITRAN 2000, Journal of Quantitative Spectroscopy and Radiative Transfer, vol. 82, pp. 5–44.

Samuelsson, J., Börjesson, G., Svensson, B., Galle, B., Metan från avfallsupplag i Sverige (Methane from landfills in Sweden), final report to the Swedish Energy Agency, projekt nr P10856-4, December 2005a. In Swedish (www.stem.se), can be ordered from Studsviksbiblioteket, 611 82 Nyköping, Sweden, www.lib.kth.se/SB/service/stemavf.html.

Samuelsson, J., et. al., VOC measurements of VOCs at Nynas Refinery in Nynäshamn 2005b *(Utsläppsmätningar av flyktiga organiska kolväten vid Nynas Raffinaderi i Nynäshamn 2005, in Swedish*), Bitumen refinery official report to provincial government 2005, Available at: http://www.fluxsense.se

Sharpe, S., et al. (2004), Gas-Phase Databases for Quantitative Infrared Spectroscopy, *Applied Optics*, *58*(12).

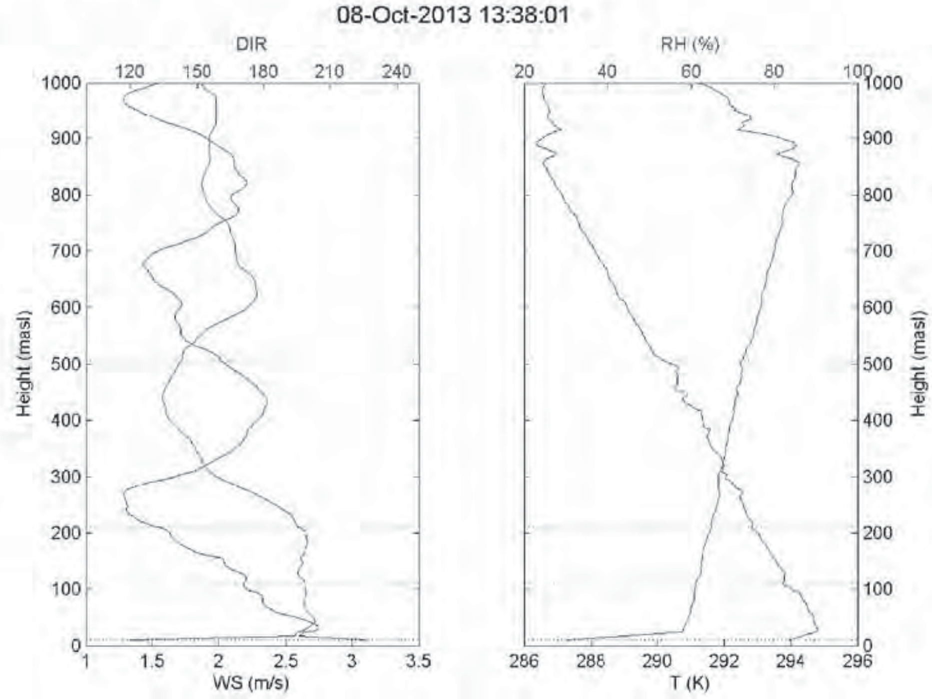
Thoma, E. et al. (2009), Development of EPA OTM 10 for Landfill Applications, in print, Journal of Environmental Engineering

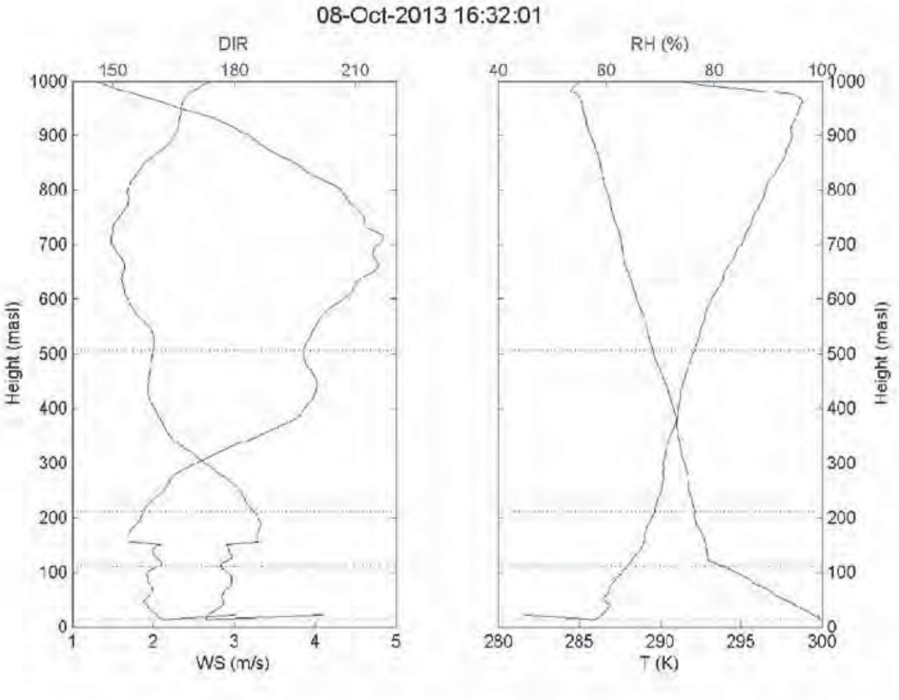
Vandaele A.C., C. Hermans, P.C. Simon, M. Carleer, R. Colin, S. Fally, M.F. Mérienne, A. Jenouvrier, and B. Coquart, Measurements of the NO_2 absorption cross-section from 42000 cm-1 to 10000 cm-1 (238–1000 nm) at 220 K and 294 K, J.Q.S.R.T., 59, 171–184 (1998)

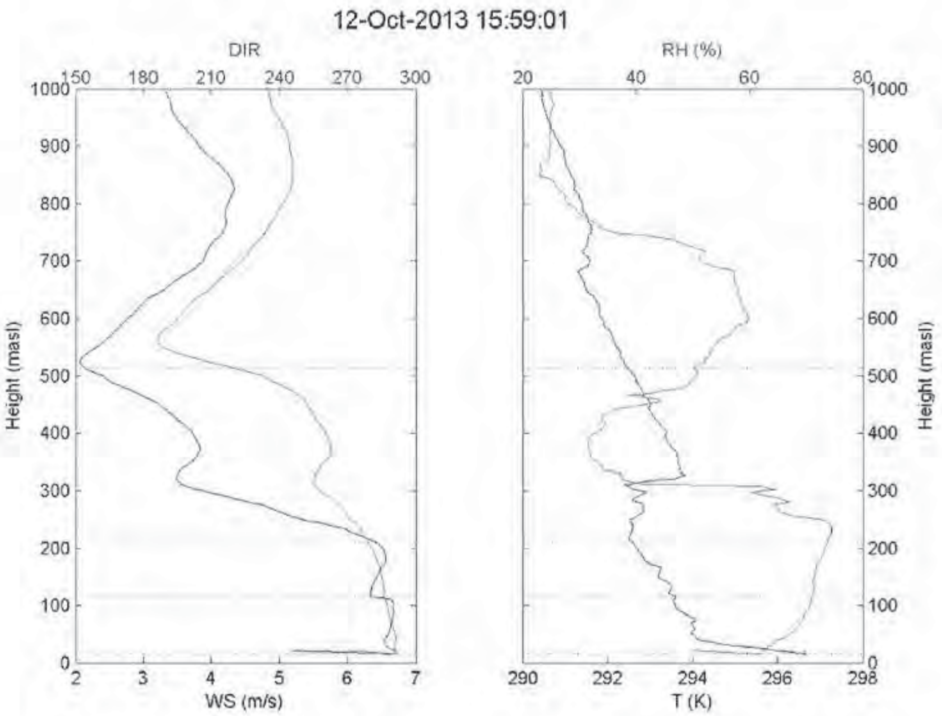
Walmsley, H. L., and S. J. O'Connor (1998), The accuracy and sensitivity of infrared differential absorption lidar measurements of hydrocarbon emissions from process units. *Pure Appl. Opt.*, *7*, 907–925.

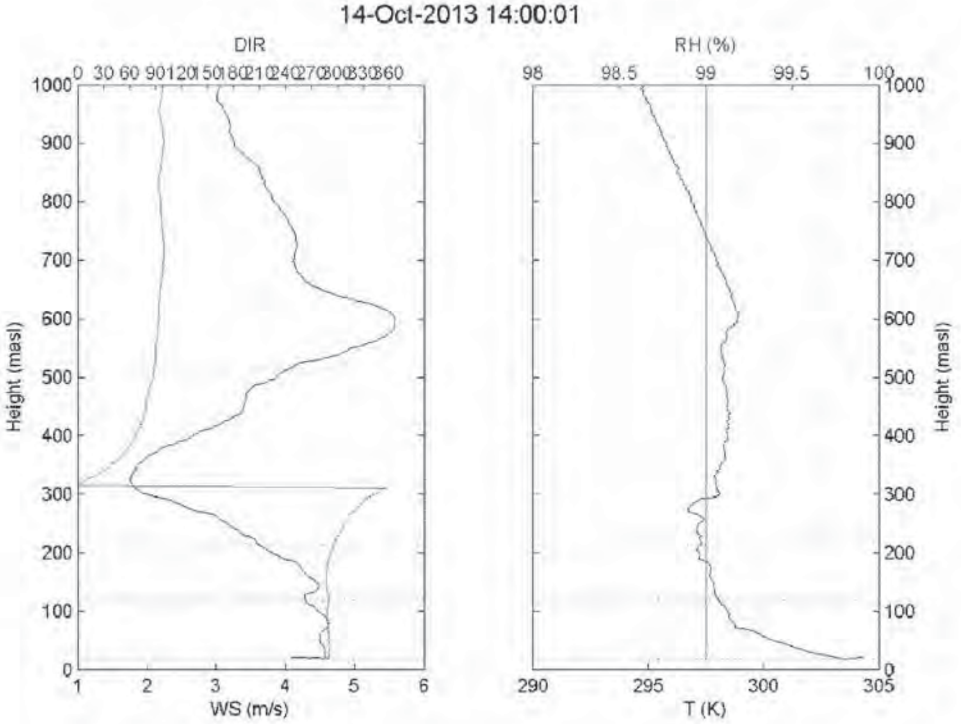
A7 Wind Data and Evaluation

A7.1 GPS wind sondes






12-Oct-2013 15:59:01
DIR
150 180 210 240 270 300
RH (%)
20 40 60 80
Height (masl)
1000 900 800 700 600 500 400 300 200 100 0
2 3 4 5 6 7
WS (m/s)
290 292 294 296 298
T (K)


14-Oct-2013 14:00:01
DIR
0 30 60 90 120 150 180 210 240 270 300 330 360
RH (%)
98 98.5 99 99.5 100
Height (masl)
1000 900 800 700 600 500 400 300 200 100 0
1 2 3 4 5 6
WS (m/s)
290 295 300 305
T (K)

A7.2 Mast Wind Comparison

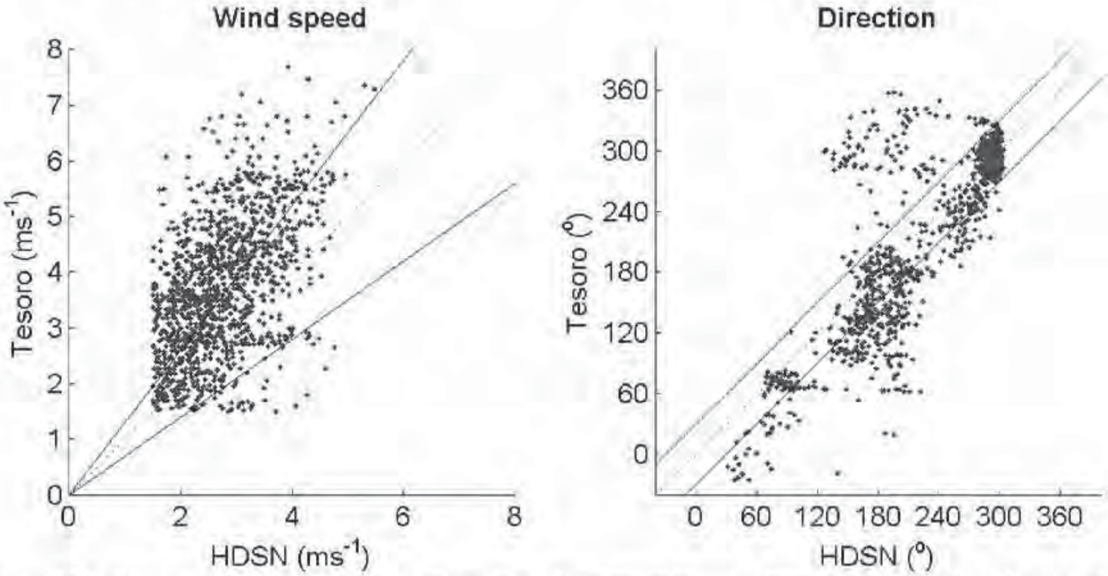


Figure A7.1 . Comparison of 5 minute winds from Tesoro Carson[0] and SCAQMD station HDSN limited to wind speeds greater than 1.5 m/s. Solid lines denote +/- 30 % or +/- 30 from the 1:1 (dashed) line for wind speed and direction, respectively.

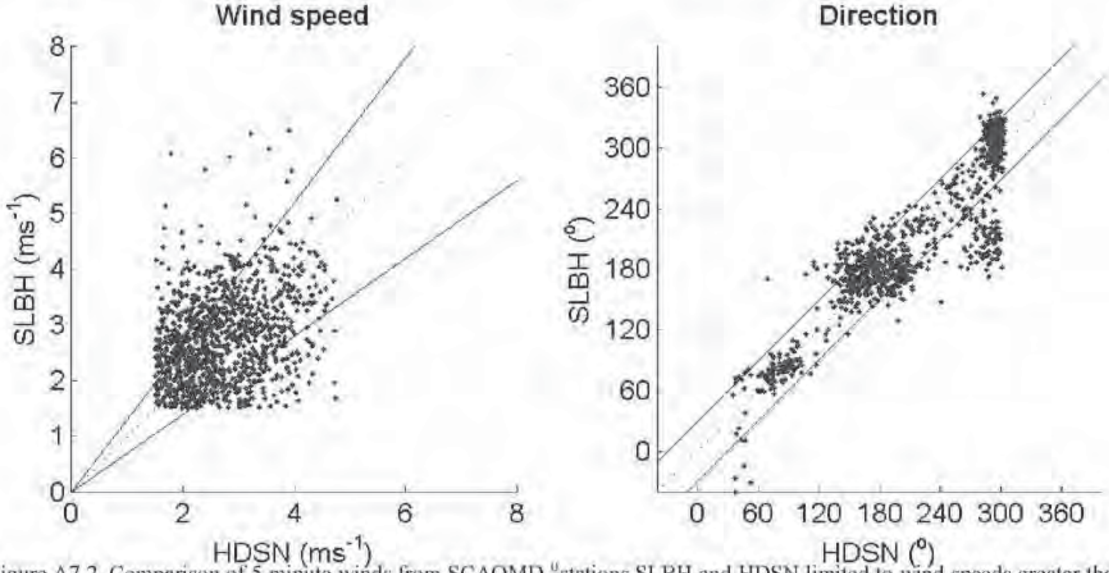


Figure A7.2. Comparison of 5 minute winds from SCAQMD [0]stations SLBH and HDSN limited to wind speeds greater than 1.5 m/s. Solid lines denote +/- 30 % or +/- 30 from the 1:1 (dashed) line for wind speed and direction, respectively.