ENVIRONMENTAL INTEGRITY PROJECT

1920 L Street NW, Suite 800
Washington, DC 20036
p: 202-296-8800 f: 202-296-8822
www.environmentalintegrity.org

COMMENTS ON EPA'S DRAFT "EMISSION ESTIMATION PROTOCOL FOR PETROLEUM REFINERIES"

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Introduction

The Environmental Integrity Project (EIP) appreciates the opportunity to submit comments on the U.S. Environmental Protection Agency's (EPA) draft "Emission Estimation Protocol for Petroleum Refineries" (Protocol) posted for public comment on the Clearinghouse for Inventories and Emissions Factors (CHIEF) website on December 23, 2009. Petroleum refineries are a major source of air pollution in the U.S., releasing large amounts of toxic pollution that pose a serious public health risk to nearby communities and the environment.

EPA relies heavily on the use of emissions factors to develop regional and national emissions inventories and make critical air quality management decisions related to petroleum refineries.[1] "EPA officials describe the emissions inventory as the *foundation for the air program*, upon which everything else is built. Emissions estimates *based on emission factors are used to develop much of this inventory*, and, as such, are *critical measures* woven into the fabric of many air quality managers' *most important decisions*."[2] Emission factors are also widely used to determine the applicability of the New Source Review (NSR) program to new and modified sources.[3] Thus, it is critical that EPA develop and maintain high quality emissions factors for petroleum refineries in order to protect the health of refinery communities and the environment.

EPA's own admissions and scientific studies using remote sensing technologies show that refinery emissions factors can significantly underestimate emissions of hazardous air pollutants (HAPs), volatile organic compounds (VOCs), and other pollutants from air pollution sources.[4] The discrepancies between estimates based on emissions factors and actual emissions can be dramatic. For example, studies conducted

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[1] Office of Inspector Gen., U.S. Envtl. Prot. Agency, EPA Can Improve Emissions Factors Development and Management 4 (No. 2006-P-00017) (Mar. 22, 2006) [hereinafter EPA Can Improve (noting that "[e]missions factors are used for about 80 percent of emissions determinations").

[2] Id. at 24 (emphasis added).

[3] Id. at 16.

[4] See, e.g., Id.; Memorandum from Brenda Shine, U.S. Envtl. Prot. Agency, to U.S. Envtl. Prot. Agency,, Potential Low Bias of Reported VOC Emissions from the Petroleum Refining Industry, Docket No. EPA-HQ-OAR-2003-0146 (July 27, 2007); Allan Chambers et al., Alberta Research Council, Refinery Demonstration of Optical Technologies for Measurement of Fugitive Emissions and for Leak Detection (Mar. 31, 2006).

using remote sensing technologies show that actual emissions of HAPs and VOCs from petroleum refineries can be *100 times greater* than reported emissions.[5]

In 2008, the City of Houston filed a petition under the Data Quality Act (Petition) challenging EPA's use of many of the emissions factors related to refineries and chemical plants because these emissions factors fail to meet EPA's quality guidelines and are inaccurate, unreliable, and biased.[6] In direct response to this Petition, EPA acknowledged the inaccuracy of emissions estimates based on emissions factors and committed to develop a comprehensive protocol that "address[es] all emissions sources and …include startup, shutdown, and malfunction events."[7] EPA stated that the comprehensive protocol will "provide a consistent method for selecting and applying emission factors, where available and appropriate, but also would provide guidance on the use of other emission estimation methodologies that do not rely on emissions factors."[8]

EPA further stated that, "[a]s part of this effort, we would also review specific emission factors and initiate work to refine, revise and develop additional factors and methodologies for emission sources, including but not limited to tanks, flares, delayed cokers, and cooling towers. This effort could include the use of optical remote sensing techniques to quantify emission sources as well as startup, shutdown, and malfunction events that have been difficult to quantify. It will also include a critical review of available remote sensing data, conclusions drawn from the assessment, and an assessment/prioritization of sources for further study."[9] In addition to the development of a protocol, EPA committed to "provide direction on the proper application of emissions factors consistent with non-inventory program goals including clearer guidance and direction on use of more direct quantification tools (e.g., emissions monitoring) in lieu of emissions factors.[10]

Summary

We support EPA's efforts to develop a comprehensive protocol for the estimation of petroleum refinery emissions in order to "improve the consistency, transparency and accuracy of future emission estimates for these facilities."[11] The Protocol takes important first steps toward fulfilling its commitment to the City of Houston. For example, scientific studies using remote sensing technology show that volatile organic compound (VOC) emissions from the coker area can account for 20% of a refinery's total VOC

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[5] See, e.g., Allan Chambers et al., supra note 4.

[6] Bill White, Office of the Mayor, City of Houston, Request for Correction of Information Under the Data Quality Act and EPA's Information Quality Guidelines (July 9, 2008) [hereinafter City of Houston, Data Quality Act Petition].

[7] Letter from Elizabeth Craig, Acting Assistant Adm'r, U.S. Envtl. Prot. Agency Region III, to Bill White, Mayor of Houston (Apr. 7, 2009).

[8] Id.

[9] Id.

[10] Id.

[11] Id.

emissions.[12] Yet these emissions have never been accounted for in emissions inventories. The Protocol addresses emissions from delayed cokers and proposes the first ever emissions factors for coke drum venting, a procedure to estimate emissions from coke water handling, and default assumptions for particulate matter emissions from coke handling.

In other areas, however, the Protocol is a summary of the status quo—even where data shows that existing emissions factors are inaccurate and undercount emissions of toxic air pollution. With respect to storage tanks, flares, combustion sources, delayed coking, and equipment leaks, the Protocol is not consistent with EPA's commitment to the City of Houston because the Protocol does not (1) provide guidance on the use of remote sensing technologies to measure emissions or a critical review of the extensive remote sensing data available; (2) refine or revise inaccurate emissions factors or even disclose potential bias in these emissions factors; or (3) provide guidance on estimating emissions for all sources.[13]

The accurate counting of pollution from storage tanks, flares, delayed coking, and equipment leaks should be a top priority for EPA due to the toxicity of emissions from these process units and the fact the current emissions factors result in drastic under-reporting.[14] The Protocol should:

- Identify and provide guidance on proven remote sensing technologies as a direct measurement method, to verify the accuracy of emissions estimated by other methods, and to identify leaks and other malfunctions and poor operating conditions that impact emissions; and
- Include refined or revised emissions factors where existing emissions factors are inaccurate or, at a minimum, disclose deficiencies in emissions factors that are likely to yield biased emissions data; and
- Include guidance on estimating emissions for all sources related to these process units or, at a minimum, identify all sources of emissions.

We note at the outset that our failure to comment on a specific emission source or emission estimation method does not necessarily indicate agreement with the approach proposed in the Protocol. Due to time constraints, we focused our in-depth review on tanks, flares, combustion sources, and delayed cokers. However, there are other areas of the Protocol that are inadequate. For example, the section on equipment leaks does not disclose the serious errors in existing emissions factors, much less publish refined or revised factors. Section 2 of the Protocol adopts the emission factor methods first published by EPA in 1998 that result in inherently uncertain emissions estimates of

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[12] Spectrasyne, Reflections on 20 Years of DIAL VOC Measurements in the Oil and Gas Industries, [hereinafter Spectrasyne], in U.S. Envt'l Prot. Agency, Second International Workshop on Remote Sensing of Emissions: New Technologies and Recent Work, app. C 22-23 (2008), available at http://www.epa.gov/ttnchie1/efpac/workshops/remotesens08.html.

[13] Craig, supra note 7.

[14] See, e.g., Allan Chambers et al., supra note 4.

VOCs and HAPs.[15] For example, EPA gives 83% (69 out of 83) of the emission factors related to refineries and chemical plants in *Locating and Estimating Air Emissions from Sources of Benzene* a "U" quality rating.[16] A "U" quality rating means "[t]he emission factor was developed from source tests which have not been thoroughly evaluated, research papers, modeling data, or other sources that may lack supporting documentation."[17]

Furthermore, these factors are outdated and do not represent the slate of crudes, internal streams, and products produced by a modern refinery. They do not address inorganic constituents that are commonly found in many refinery streams, such as carbon monoxide (CO) (i.e. hydrogen plant) and hydrogen sulfide (H2S) and reduced sulfur (i.e. sulfur plant, especially acid gas); and are widely misused to estimate emissions of inorganic constituents. Method 21, used to determine compliance, underestimates the concentration of many VOC and inorganic compounds because the monitoring method does not accurately measure the true concentration of all compounds present. At a minimum, the Protocol should include guidance on the use of remote sensing technologies to measure emissions and/or verify the accuracy of emissions estimates and disclose the serious deficiencies in the existing emissions factors for equipment leaks.

In short, while we applaud the steps EPA has taken to address significant undercounting of refinery pollution, the Protocol is not responsive to the data quality issues raised by the City of Houston 2008 Petition. EIP submits that EPA should take the following specific actions to improve the Protocol and ensure the "consistency, transparency, and accuracy" of refinery emissions:

Guidance

1. **Prohibit the use of emissions factors for site-specific purposes or, at a minimum, provide guidance on the proper application of emissions factors for non-inventory purposes.** Despite the fact that EPA routinely cautions against the use of emissions factors for site-specific purposes, the emissions factors are routinely used for non-inventory purposes like calculations to determine NSR and Maximum Achievable Control Technology (MACT) applicability, for setting emission limits, for estimating emissions for air dispersion modeling, and for determining compliance.

2. **Require refinery owners and operators to provide emissions data derived from the highest ranked method or, at a minimum, require refinery owners and operators to submit test data in their possession.** The Protocol only "*requests*" that refinery owners and operators "use the highest ranked method…*for which data are available*." Under the Protocol, most refinery

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[15] See City of Houston, Data Quality Act Petition, supra note 6 (noting the serious flaws in the existing emissions factors for equipment leaks).

[16] See Office of Air Quality Planning and Standards, U.S. Envt'l. Prot. Agency, EPA-454/R-98-011, Locating and Estimating Air Toxics Emissions from Sources of Benzene (1998).

[17] Id.

emissions will be calculated using lower ranked methodologies (i.e. emissions factors) as opposed to higher ranked direct measurement methods because few refinery emissions sources are actually tested.

Storage Tanks

3. **Include a critical review of optical remote sensing methods and provide guidance on the use of these methods as a direct measurement method, to verify the accuracy of emissions estimated by other methods, and to identify leaks and other malfunctions and poor operating conditions that impact emissions.** DIAL and other similar optical remote sensing methods have been used extensively to measure emissions at refineries in Canada, Europe, and most recently in Texas. Yet the Protocol dismisses DIAL and other proven methods of direct measurement out of hand.

4. **Include revised AP-42 tank modeling methods to replace existing modeling methods that are likely to undercount air pollution. At a minimum, the Protocol should disclose the significant deficiencies in the existing tank modeling methods.** Scientists have reported that the AP-42 tank model methods can underestimate VOC emissions from refineries by factors of five to fifty.[18] EPA should revise tank modeling methods to improve crude oil and mid-refined product default parameter data, and account for (1) the effect of poorly maintained seals and roofs on emissions, (2) the effect of high sulfur or corrosive crude on floating roof seals and tank walls, and (3) the leakage of propane and butane past floating roof seals.

   In addition, EPA should revise tank modeling methods to account for site specific variables like wind speed, size, seal condition, seal type, roof height, filling rate, tank movements (i.e. mixing), and vapor pressure of the stored material.[19] Some of these variables are not included in the tank calculations, while others are included as defaults or annual averages, which results in serious errors in estimated emissions.

5. **Provide guidance on estimating emissions for all sources of tank emissions, including tank degassing, tank cleaning, tanks in poor condition, flashing losses, and tanks filled with non-stabilized crude oil.** The Protocol fails to identify these emission sources and include methods to calculate emissions.

Flares

6. **Include a critical review of optical remote sensing methods other technologies that directly measure emissions and provide guidance on the use of these**

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[18] See U.S. Envtl. Prot. Agency, Second International Workshop on Remote Sensing Emissions: New Technologies and Recent Work ix (2008) [hereinafter Remote Sensing Emissions], available at http://www.epa.gov/ttnchie1/efpac/workshops/remotesens08.html.

[19] Spectrasyne, supra note 12.

methods as a direct measurement method, to verify the accuracy of emissions estimated by other methods, and to identify poor operating conditions that impact emissions.

7. **Require refinery owners and operators to assume flare combustion efficiency no higher than 93% unless it can be demonstrated that the flare is achieving higher combustion efficiency. EPA should develop a model of flare combustion efficiency that accounts for wind and other variables.** Flare performance is impacted by meteorological conditions, variable waste gas flow rate and composition, flare physical design, steam and air assist operation, and general maintenance—operating parameters that were not specifically evaluated in previous studies that identified a constant flare combustion efficiency of 98%. Much lower flare combustion efficiencies have been confirmed in simulations, wind tunnel experiments, and full scale investigations that account for these variables.

8. **Include revised emissions factors that account for flare gas composition on emissions of VOC, nitrogen oxide (NOx), carbon monoxide (CO).** Emissions from a flare depend upon the composition of the gas that is burned, but flare emissions factors are based on a dry mixture of propylene and propane, which is atypical.

9. **Include the Ideal Gas Law as a method to estimate VOC and individual hazardous air pollutant (HAP) emissions from flares ahead of Rank 3 emissions factors.** This equation is one of the most commonly used estimation methods, and only requires the molecular weight of the gas flared and the combustion efficiency.

Combustion Units

10. **Require refinery owners and operators to directly measure emissions from refinery boilers and heaters unless a stack test is physically impossible due to a valid constraint (i.e. access or safety issue).**

11. **Rank the stack test method to develop unit-specific emissions factors ahead of a single stack test of three test runs during normal operating conditions.** A single test conducted during normal operations will not provide an accurate estimate of emissions during a full range of operating conditions (i.e. lower load, startup/shutdown). At a minimum, a relationship between emissions and heat input should be developed from stack tests conducted at 25%, 50%, 75%, and 100% load. This relationship, combined with heat input data available for most refinery combustion sources, should be used to estimate emissions.

12. **Establish clear criteria for stack tests that includes, at a minimum, a prohibition on pre-testing and pre-testing maintenance, testing at all loads, and an on-site independent observer for the duration of the test.** Most stack

tests are frequently conducted following maintenance under carefully controlled conditions designed to minimize emissions.

13. **Prohibit the use of AP-42 natural gas boiler emissions factors for refinery heaters and boilers that do not use natural gas and establish refinery fuel gas specific emissions factors and emissions factors for refinery heaters.** The Protocol recommends the use of AP-42 natural gas boiler emissions factors for both refinery boilers and heaters that fire refinery fuel gas when direct measurements are not available. Natural gas is not widely used in refineries, and the composition of refinery fuel gas has a significant impact on emissions. Furthermore, the combustion conditions within a refinery heater are significantly different from refinery boilers, which means heaters and boilers are not likely to produce similar emissions. The absence of appropriate emissions factors for refinery heaters and boilers allows applicants to cherry pick factors that produce emissions data that allows them to net out of new source review (NSR) or establish artificially high emissions limits.

Delayed Cokers

14. **Revise the coker steam vent emissions factors to account for (1) all available stack and DIAL tests, (2) emissions variability during the venting process and as a result of vent pressure, and (3) all pollutants emitted.** We believe that the 29 coke drum venting emissions factors are a very important step in the right direction, but the proposed emissions factors are incomplete and fail to address all available emissions data, variables that impact emissions, and the range of pollutants emitted during the coke drum venting process.

15. **Identify emissions factors for the decoking process for VOC, PM, PM10, PM2.5, H2S, and HAPs.** Although the Protocol admits, and DIAL studies confirm, that VOCs are emitted during the decoking process, the Protocol fails to offer any guidance on how to estimate these emissions or acknowledge that pollutants other than VOCs are released during this process.

16. **Establish emission estimating methods for VOCs from coke storage piles and transport vehicles.** Although VOCs are released from undisturbed coke piles and when coke is transported, the Protocol only proposes emission estimating methods for PM.

17. **Revise the AP-42 emission factor for coke drop emissions to account for typical prolonged dumping on top of previously dumped material.** The Protocol only includes a generic equation for drop emissions that assumes a single drop onto a flat surface or drops onto a conveyor belt continuously moving away from the dropped material. Yet refineries typically drop very large amounts of coke on top of previously dumped material over prolonged periods of time. This type of dumping will suspend coke particles and aerosols that are not considered in the AP-42 drop equation.

18. **Require site-specific silt testing for any calculation that requires silt content.** The coke yard, where material handling operations occur, is generally covered with a layer of coke dust, which increases emissions from material handling operations like front end loader trips, truck trips, and drops. Yet these increased emissions are not considered by the AP-42 equations nor the default variables recommended in the Protocol.

19. **Require site-specific moisture measurements for any calculation that requires moisture content.** The Protocol recommends a default moisture content of 30% for coke drops. Yet the moisture content of coke varies depending on the specific drop operations (i.e. pit to temporary pile, pile to crusher, crusher to terminal pile, terminal pile to truck), with moisture content decreasing with each subsequent drop. In addition, the film of coke dust in the coke yard, the portion subject to disturbance, has a much lower moisture content than the 30% default in the Protocol.

20. **Establish default control efficiencies for material handling operations by type of measure and for the most common combination of measures.** Users of the AP-42 fugitive emissions equations for material handling emissions commonly apply control efficiencies to emissions calculations to account for measures such as sweeping, watering for dust control, truck washing, truck covering, and various types of enclosures. AP-42 contains no guidance on the effectiveness of these various controls. These control efficiencies— ranging from 90% to 99%—are generally unsupported and excessively high, which likely leads to undercounting of emissions from material handling operations.

21. **Establish emissions estimating methods for PM emissions from wind erosion of front-end loaders, crane buckets, trucks, conveyors, and railcars.** These sources can be a major source of fugitive PM emissions and are a common source of nuisance complaints in communities. Yet the Protocol and AP-42 fail to address these emissions.

Incorporating these specific recommendations in the revised Protocol will help ensure that refineries accurately characterize emissions and address the serious data quality concerns raised by the City of Houston Petition.

I. THE PROTOCOL SHOULD PROHIBIT THE USE OF EMISSIONS FACTORS FOR SITE-SPECIFIC PURPOSES OR, AT A MINIMUM, PROVIDE GUIDANCE ON THE PROPER APPLICATION OF EMISSIONS FACTORS CONSISTENT WITH NON-INVENTORY PURPOSES.

The Protocol should expressly prohibit the use of emissions factors for site-specific purposes. In the alternative, the Protocol should provide clear guidance on the use of emissions factors for site-specific purposes. EPA has long maintained that emissions factors should only be used to create area-wide emissions inventories because emissions factors yield unreliable and inaccurate site-specific emissions data.[20] Emissions factors, by definition, extrapolate long-term emissions from assumptions about process unit emissions under "normal" operating conditions.[21] EPA notes that "[b]ecause emission factors essentially represent an average of a range of emission rates, approximately half of the subject sources will have emission rates greater than the emission factor and the other half will have emission rates less than the factor."[22]

Emission factors do not account for site-specific variables such as the age and condition of the source, operating conditions, or environmental variables that can significantly impact emissions.[23] Despite the fact that EPA states that emissions factors should not be used for site-specific purposes and is likely to yield unreliable and inaccurate emissions data in AP-42,[24] the emission factors are routinely used for purposes other than their intended use in emission inventories. These other uses include emission calculations to determine New Source Review (NSR) and Maximum Achievable Control Technology (MACT) applicability, for setting emission limits, for estimating emissions for air dispersion modeling, and for determining compliance.[25]

The Protocol, however, does not expressly prohibit the use of emissions factors for site-specific purposes or provide guidance on the proper use of emissions factors for non-inventory purposes. While we understand that the Protocol 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 *emissions inventories*[,]"[26] the Protocol will likely become the comprehensive source refinery owners and operators consult when estimating emissions for a wide variety of non-inventory purposes. Furthermore, at least one section of the Protocol appears to condone the use of emissions factors for site-specific purposes.[27]

As part of EPA's efforts to improve the emissions factor program, EPA stated it would "provide direction on the proper application of emissions factors consistent with non-inventory program goals including clear guidance and direction on use of more direct quantification tools (e.g. emissions monitoring) in lieu of emissions factors."[28] The Protocol should expressly prohibit the use of emissions factors for non-inventory

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[20] See, e.g., U.S. Envtl. Prot. Agency, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, available at http://www.epa.gov/ttn/chief/ap42/index.html [hereinafter EPA, AP-42 Series] (cautioning that emission factors should be used for site-specific purposes as a "last resort" and noting that "one should be aware of their limitations in accurately representing a particular facility").

[21] Id. at 1–5.

[22] Id. at 2.

[23] Id. 1–5.

[24] Id.

[25] See, e.g., EPA Can Improve, supra note 1 at 15–16.

[26] Protocol, at 1-1.

[27] See id. at 6-8 ("Refineries are expected to have more source-specific information for estimating flare emissions, but these factors may be used for the purpose of modeling or for general emissions estimates.").

[28] Craig, supra note 7.

purposes or, at a minimum, provide clear guidance on the proper use of emissions factors for non-inventory purposes.

II. THE PROTOCOL SHOULD REQUIRE REFINERY OWNERS AND OPERATORS TO PROVIDE EMISSIONS DATA DERIVED FROM THE HIGHEST RANKED METHOD OR, AT A MINIMUM, REQUIRE REFINERY OWNERS AND OPERATORS TO SUBMIT TEST DATA IN THEIR POSSESSION.

EPA should require refinery owners and operators to provide emissions data from the highest ranked method or, at a minimum, require refinery owners and operators to submit test data in their possession. In its response to the City of Houston, EPA stated it would provide "clearer guidance and direction on use of more direct quantification tools (e.g., emissions monitoring) in lieu of emissions factors."[29] The Protocol ranks various emission estimating techniques in the order of preference—Rank 1 is the preferred methodology.[30] Ranks 1 and 2 generally rely on emission testing and lower ranked methods rely on emissions factors.[31]

Although the Protocol identifies direct measurement methods as "preferred" methods, the Protocol only "*requests*" that refinery owners and operators "use the highest ranked method . . . *for which data are available*."[32] A "request" is defined as the "act of asking for something to be given or done, *esp. as a favor or courtesy*."[33] A "request" is not a clear directive (i.e. "an authoritative instruction"[34]) to submit test data. Furthermore, test data is rarely "available" unless the refinery has a permit that includes specific testing requirements, and very few refinery emissions sources are tested pursuant to permits. Under the Protocol, then, most refinery emissions will be calculated using lower ranked methodologies (i.e. emissions factors) as opposed to higher ranked direct measurement methods.

In order to improve the accuracy of refinery emissions data used to make decisions impacting the public health and the environment, the Protocol should require refinery owners and operators to provide emissions data derived from the highest ranked method. At a minimum, the Protocol should require that refinery owners and operators submit test data in their possession.

III. SECTION 3: STORAGE TANKS

Storage tanks are a major source of refinery air pollution—VOC emissions from product and crude storage tanks can account for over 50% of the total VOC emissions from a petroleum refinery.[35] Thus, it is critical that refinery owners and operators

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[29] Id.

[30] Protocol at 1-1.

[31] Id.

[32] Id. (emphasis added).

[33] Dictionary.com, http://dictionary.reference.com/ (emphasis added).

[34] Id.

[35] Spectrasyne, supra note 12.

accurately characterize tank emissions. The Protocol lays out three generic methods to estimate emissions from storage tanks: (1) direct measurement; (2) tank-specific modeling; and (3) two types of default tank modeling.[36] The Protocol acknowledges that only a "limited number of storage tanks" are directly measured and instead recommends that AP-42 “emissions estimation procedures . . . be used to calculate air pollutant emissions from organic liquid storage tanks.”[37]

The Protocol dismisses DIAL and other similar optical remote sensing methods that have been used to measure emissions at refineries in Canada, Europe, and most recently Texas as viable direct measurement methods.[38] Many studies conducted using optical remote sensing technology demonstrate that AP-42 tank modeling methods can substantially underestimate tank emissions due to site-specific variables.[39] Yet the Protocol fails to acknowledge the deficiencies in the AP-42 tank modeling methods, much less revise or refine these estimation methods as EPA promised the City of Houston.[40] Finally, the Protocol fails to include methods to calculate emissions from tank degassing, tank cleaning, tanks in poor condition, flashing losses, and tanks filled with non-stabilized crude oil.

A. The Protocol should include a critical review of DIAL, FTIR, SOF, TCT, and VRPM and provide guidance on the use of these methods as a direct measurement methods, to verify the accuracy of emissions estimated by other methods, and to identify leaks and other malfunctions and poor operating conditions that impact emissions.

The only direct measurement method recommended in the Protocol is enclosing the tank(s) and measuring emissions at a control device.[41] This method does not measure VOC emissions from uncontrolled tanks, but rather from a control device found on some tanks.[42] Very few tanks are enclosed and vented to a control device. In the context of New Source Review (NSR), refinery applicants generally argue that the cost of installing

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[36] Protocol, 3-1.

[37] Id. at 3-2.

[38] Id.

[39] See, e.g., Allan Chambers et al., supra note 4.

[40] See Craig, supra note 7 (noting that EPA “will review existing emission factors, including, but not limited to tanks, flares, and cooling towers, and to refine or revise the emission factors as necessary).

[41] Protocol, 3-1 ("Direct measurements can only be taken from process units that are covered and vented to a control device....Emissions from fixed roof storage tanks may be purged . . . and vented to a control device; these emissions can be directly measured at the outlet of the control device....").

[42] We note that the Protocol's direct measurement method is not a direct measurement—it is an estimate that is dependant upon a default control efficiency. See Protocol, at 3-2 ("The resulting mass flow rates can be corrected for the control device efficiency using the methods described in Chapter 6 (Flares) to estimate the emissions associated with the storage tank(s) that are released to the atmosphere."). As discussed in section IV, the control efficiency method set out in Chapter 6 is not accurate. Thus, the overall accuracy of direct tank measurement is similarly inaccurate and should not be given the top ranking. Furthermore, the Protocol is silent when the control device is not a flare (i.e. thermal oxidizer, carbon column, or direct atmospheric vent). The Protocol should require direct measurement of control device destruction efficiency or develop a new method to determine flare control efficiency based on wind speed or multivariate image analysis. The Protocol should also be revised to address direct measurement when the control device is not a flare.

such a system to satisfy best available control technology (BACT) requirements is prohibitive.[43] Unless such a system is already in place, and they are rare, the cost of installing one would be prohibitive to collect data for an emission inventory. Thus, the Protocol contains no direct measurement method for the vast majority of the tanks that can contribute 50% or more of the VOC emissions from refineries. For all practical purposes, the Protocol specifies tank-specific modeling as the preferred method for estimating tank emissions.

The Protocol should identify optical remote sensing methods like Differential Absorption Light Detection and Ranging (DIAL), Fourier Transform Infrared Spectroscopy (FTIR), Solar Occultation Flux (SOF), Time Correlation Tracer (TCT), and Vertical Radial Plume Mapping (VRPM) as viable direct measurement methods for tanks. The Protocol does not include any of these methods in its hierarchy for estimating storage tank emissions.[44] The Protocol ignores the substantial body of scientific knowledge on optical remote sensing methods,[45] including a key recommendation of EPA's 2008 Second International Workshop on Remove Sensing of Emissions: "Promote remote sensing as a means to adjust emission estimates and reduce emissions."[46]

The Protocol dismisses DIAL as a direct measurement method and fails to discuss any of the other (i.e. FTIR, SOF, TCT, VRPM) optical remote sensing methods that can be used to measure emissions from tanks.[47] Instead, the Protocol states these methods are not a viable option for direct measurement of tank emissions because "these methods do not provide continuous monitoring and have additional limitations (requiring consistent wind direction, etc.)."[48] In the section on equipment leaks, the Protocol rejects all optical remote sensing methods because they are not yet approved by EPA.[49]

This is a serious omission for tanks and other large sources of VOCs and HAPs and is inconsistent with EPA's commitment to the City of Houston to "include a critical review of available remote sensing" as part of its effort to develop the Protocol and consider "the use of optical remote sensing techniques to quantify emission sources."[50]

The DIAL method and other similar optical remote sensing methods have been used extensively to perform emission studies at industrial facilities. The 2006 TCEQ study[51] validated DIAL measurements in a field setting in the United States.[52] The Texas

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[43] See, e.g., E-mail from Colin Campbell, RTP, to Kyrick Rombough, South Dakota Natural Resources Engineering Director, Air Quality Program (Aug. 27, 2008) available at http://denr.sd.gov/Hyperion/Air/20080828DENREmail.pdf.

[44] Protocol, 3-2.

[45] See, e.g.,, H.L. Walmsley, T. Ubbens & S.T. Arnold, Shell Global Solutions, LIDAR Studies of Evaporative Losses from Above Ground Storage Tanks (6th World Petroleum Congress) (June 2000)

[46] Remote Sensing of Emissions, supra note 18, at viii.

[47] Protocol, 3-2.

[48] Protocol, 3-2.

[49] Protocol, 2-1

[50] Craig, supra note 7.

[51] Rod Robinson, et. al., 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 (Feb. 6, 2008) available at

Air Quality Study used DIAL to measure ozone mass flux from the Houston Ship Channel area.[53] DIAL has also been used to measure mass flux of benzene and other VOCs from refineries and other benzene sources in Canada and Europe.[54] These studies indicate VOC emissions 5 to 20 times higher than reported by the same refineries using standard emission factors.[55] The use of DIAL in other places has led to the identification of unknown and underestimated emission sources (e.g., coker operations), allowing the prioritization of emission reduction measures.[56]

In fact, the City of Houston, in partnership with EPA, recently conducted a study at the Shell Deer Park Refinery using DIAL and other optical scanning methods to demonstrate their effectiveness and to evaluate the accuracy of emission factors used in the refining industry. This partnership specifically notes that "[t]he object of this study is not a Shell Deer Park specific result. Rather the objective is to develop information relating to emission estimating on a broader scale to improve existing knowledge of emissions sources and the quantification of related emissions."[57] Testing took place between January and March 2010, and the final report is expected this summer.

Although EPA dismisses DIAL because it does not provide continuous measurement of emissions, some of the optical remote sensing methods are capable of continuous measurement. For example, FTIR has been used to continuously monitor flares and facility fencelines,[58] and EPA and ASTM-approved test methods exist. The optical remote sensing methods in EPA test method OTM-10[59] can provide continuous remote operation at low cost (after installation) for extended periods of time[60] and have been used on refinery sources.[61] Regardless, the continuous measurement capability of an optical remote sensing technology should not be the basis for eliminating these methods from the Protocol.[62] For example, in the section on combustion sources, EPA ranks stack tests—which lasts only 3 hours— between continuous monitoring and an emission factor. Yet EPA dismisses periodic measurement for tanks without a critical review of the extensive optical remote sensing data.

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http://www.tceq.state.tx.us/assets/public/implementation/air/am/contracts/reports/oth/20080206-dial_test_report.pdf.

[52] Remote Sensing of Emissions, supra note 18, at ix ("DIAL measurements were validated in a field setting").

[53] U.S. Envt'l. Prot. Agency & City of Houston, Measurement & Analysis of Benzene & VOC Emissions in the Houston Ship Channel Area 13 (Rev. 1.0 Sep. 2009) available at http://www.epa.gov/region2/capp/City_of_Houston_DIAL_QAPP_10212009_EPA_version_1_final.pdf.

[54] Id.

[55] Id.

[56] Id.

[57] Id.

[58] Remote Sensing of Emissions, supra note 18, at 23-24, app. C, Spellicy presentation.

[59] U.S. Envt'l. Prot. Agency, Optical Remote Sensing for Emission Characterization from Non-Point Sources, [hereinafter Optical Remote Sensing], (June 14, 2006) available at http://www.epa.gov/ttn/emc/prelim/otm10.pdf.

[60] Remote Sensing of Emissions, supra note 18, at 22, app.C, Thomas presentation.

[61] Id. at 26, app. C, Hashmonay presentation.

[62] Protocol, 4–1-4–8.

In short, optical remote sensing methods like DIAL, FTIR, SOF, TCT, and VRPM should be included in the Protocol. These methods have been successfully used in Canada, Sweden and other European countries to measure, verify, and reduce emissions for many years.[63] In addition, at least two studies using optical remote sensing methods have been conducted at U.S. refineries. The Protocol should include a critical review of the available optical remote sensing methods and provide guidance on use of these technologies to directly measure tank emissions, verify the accuracy of emissions estimated by other methods, and identify tanks that are leaking at much higher rates than predicted by tank modeling due to faulty seals and other poor maintenance conditions that impact emissions. These methods are invaluable for detecting increased emissions from non-routine conditions and site-specific variables that are not taken into account by emissions factors and equations.

B. The Protocol should include revised AP-42 tank modeling methods to replace existing modeling methods that are likely to undercount air pollution. At a minimum, the Protocol should disclose the significant deficiencies in the existing tank modeling methods.

As part of its efforts to develop the Protocol, EPA stated that it would "review existing emission factors . . . and [] refine or revise the emission factors as necessary."[64] However, it does not appear that the Protocol publishes revised tank modeling methods. The Protocol recommends that the tank-specific emission estimating procedure in Chapter 7.1 of AP-42 be used to estimate monthly VOC emissions, if direct measurement is not feasible. The Protocol encourages the use of tank-specific inputs "when available," but does not explain what to do when specific input parameters are not available or what effect the use of the generic nomograms and defaults used in Chapter 7.1 will have on emissions estimates.

The AP-42 procedure was developed by the American Petroleum Institute (API), who retains copyright to these equations.[65] It consists of a series of interlinked equations, which are complex and time-consuming to carry out by hand. Thus, it has been set up in

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[63] Remote Sensing of Emissions, supra note 18, at,16, 21, 44, 52 ("Sweden has made considerable progress in cutting emissions at its refineries through a targeted DIAL and more recently SOF survey effort.") ("Mr. Kissel believes that remote sensing has a role in identifying underreported emissions such as unaccounted for operations at known sources (e.g. floating roof landing losses), previously overlooked sources (e.g., leaking heat exchangers), and poorly maintained sources (e.g., failed rim seals on floating roofs).") ("The DIAL system is good for finding sources – especially sources that are not currently recognized as such..") ("In Canada, the IR Camera has been used very successfully in conjunction with DIAL to help pinpoint leak sources seen on DIAL scan lines even when these have been in awkward positions e.g., out of reach from a ladder or platform on a piece of the plant…Since the early 1990s, in Europe, more traditional "sniffing" methods have been used with DIAL for this purpose…") ("Remote sensing is excellent for detecting process upsets or equipment malfunctions. If remote sensing enables a facility to find and fix leaks and other upsets, actual emissions may come closer to estimated ones. Remote sensing can provide additional data to inform the determination of emission factors and address the variability of emission factors.."), ("Remote sensing data can be used to adjust emission estimates and reduce emissions").

[64] Craig, supra note 7.

[65] EPA, AP-42, supra note 20, 7.1-1.

computer models that make the calculations. The most widely used is the EPA Tanks 4.09D model (TANKS), cited in the Protocol.[66] TANKS allows users to enter specific information about a storage tank (dimensions, construction, paint conditions, etc.), the liquid contents (temperature, vapor pressure), and the tank location (nearest city) to obtain meteorological conditions, and generates an air emissions report. The TANKS report gives estimates of monthly, annual, or partial year emissions for each chemical or mixture of chemicals stored in the tank.[67]

The AP-42 tank emission modeling methods have been found to significantly undercount VOC emissions when compared to direct measurement of emissions due to the failure to account for site-specific input parameters and variables that impact tank emissions.[68] For example, the AP-42 tank emission estimating method and the TANKS program have been found to significantly underestimate tank emissions when default parameters are used for crude oil and mid-refined products. VOC emissions from tanks containing gasoline, on the other hand, generally appear to have been accurately estimated in recent studies. Refined gasoline has pipeline specifications and thus, critical input parameters are usually better known so more accurate estimates can be obtained.[69] In addition, site-specific variables like wind speed and poor maintenance that are not accounted for by the AP-42 tank modeling methods can also impact tank emissions.

An extensive study by Shell Oil in Europe of 221 tanks using both DIAL and the AP-42 (i.e., API) procedure concluded as follows:

> "This comprehensive database has enabled several conclusions to be drawn which have a direct consequence for the operation of oil facilities:
>
> 1. In general calculations based on API underestimate emissions by factors of between 2 and 4 for the real facilities in this sample. In some cases the discrepancy may be even higher.

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[66] Protocol, 3-2 ("EPA recommends that the emissions estimation procedures detailed in Chapter 7.1 of AP-42 () be used to calculate pollutant emissions from organic liquid storage tanks. There are many tools available, such as TANKS v4.09D...Because TANKS v4.09D is widely used, Appendix C of this Refinery Emissions Protocol document provides tips and insights on using the TANKS program.")

[67] Office of Air Quality Planning and Standards, U.S. Envt'l. Prot. Agency, User's Guide to TANKS: Storage Tank Emissions Calculation Software Version 4.0 (Sept. 30, 1999) available at http://www.epa.gov/ttn/chief/software/tanks/tank4man.pdf.

[68] See, e.g., Allan Chambers et al., supra note 4.

[69] Russ Nettles, Texas Commission on Environmental Quality (TCEQ), Differential Absorption Lidar (DIAL) Project, in Remote Sensing of Emissions, supra note 18, at app. C, 32, 45 (2008) available at http://www.epa.gov/ttnchie1/efpac/workshops/remotesens08.html (download Remote Sensing of Emissions Workshop, all sections; then unzip file; then open file titled "appendix_C_presntations"); Johan Mellqvist, Industrial Emission Measurements using the Solar Occultation Flux Method, in Remote Sensing of Emissions, supra note 18, at app. C, 101 ("Results from a study where the emissions from tanks have been measured with TCT, calculated with the API model and leak search has been conducted with an infrared camera (FLIR)." The data show good agreement except when multiple leaks were detected.) and 115 ("The discrepancies between measurements and conventional estimates are consistent with differences observed elsewhere, e.g., Sweden").

> 2. 58% of the external floating roof tank emissions result from only 10% of the tanks and these can be readily identified by LIDAR [DIAL]."

In closing their paper, these authors from Shell Oil concluded:

> "1) The total emissions are dominated by a small proportion of high-emitting tanks with measured emission rates at or above the API maximum. Without these few tanks, the average measured emissions are comparable to the API average.
>
> 2) The mean DIAL emission rate for all sites (including the bad tanks) was 4.6 times higher than the corresponding mean API estimate.
>
> 3) The difference, which is due principally to the few bad tanks, suggests **the need to revise the calculations if they are to represent emissions from the average in-service population rather than ideal new installations.**
>
> 4) 58% of the EFR [external floating roof] emissions came from just 10% of the tanks.
>
> 5) A cost-effective approach to emissions reduction is to use measurement to identify the bad emitters and focus maintenance effort on them."[70]

Similarly, scientists at the Second International Workshop on Remote Sensing reported that the AP-42 tank model underestimated VOC emissions by factors of 5 to 50.[71] A DIAL study at a Texas refinery found that VOC emissions from crude tanks ranged from <2 lb/hr (not detected) for one tank up to 22-39 lb/hr for another, with several in between (at <5, 5, 7, 11, and 16 lb/hr) while the TANKS program using crude oil default parameters estimated under 1 lb/hr.[72] Studies in Sweden using DIAL (where all refineries are required to perform DIAL measurements every 2 to 3 years) show that the EPA model underestimates tank emissions by factors of 2 to 5.[73] The DIAL studies have been confirmed in the field by independent groups using a different test method.[74]

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[70] H.L. Walmsley, T. Ubbens & S.T. Arnold, LIDAR Studies of Evaporative Losses from Above Ground Storage Tanks, 6th World Petroleum Congress (June 2000) (emphasis added).

[71] Remote Sensing of Emissions, supra note 18, at ix ("DIAL crude oil tanks measurements were 5-10 times greater than calculated emissions using the TANKS program. Crude oil default parameter data in TANKS, including vapor pressure, need to be investigated.") ("For the Houston Ship Channel, there were 5-50 times greater VOC emissions than reported in the 2004 TCEQ inventory. . . The discrepancies between measurements and conventional estimates are consistent with differences observed elsewhere, e.g., Sweden").

[72] Remote Sensing of Emissions, supra note 18, at 17; Robinson et. al., supra note 51, at 16; Nettles, supra note 18, at app. C, 51-53.

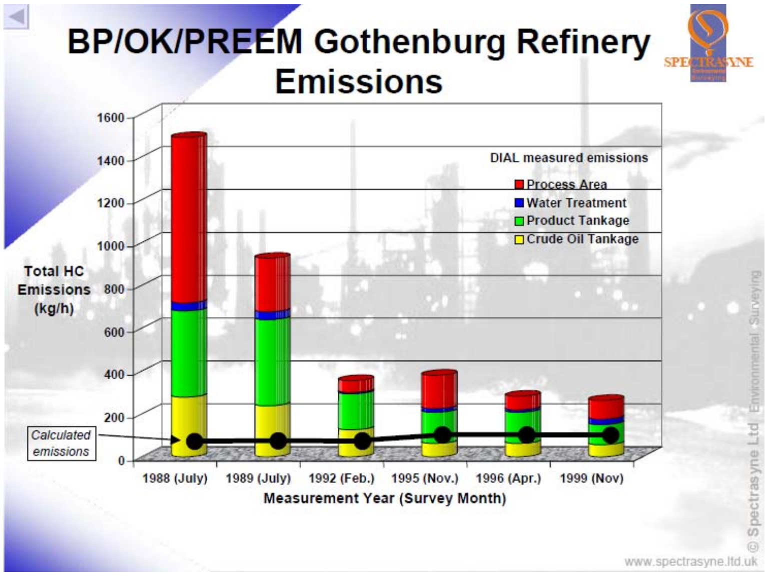
[72] Remote Sensing of Emissions, supra note 18, at 18.

[73] Karin Fransson and Johan Mellqvist, Measurement of VOCs at Refineries Using Solar Occulation Flux Technique, Chalmers University of Technology, Sweden 2002; Nettles, supra note 18, at app. C, 43.

[74] Karin Fransson and Johan Mellqvist, Measurement of VOCs at Refineries Using Solar Occulation Flux Technique, Chalmers University of Technology, Sweden 2002; Nettles, supra note 18, at app. C, 43.

Figure 1 compares DIAL measurements with calculated emissions at one refinery in Sweden. The underestimates are generally due to failure to address tank degradation over time; exclusion of upsets, malfunction, startups and shutdowns; exclusion of some types of emission events; improper input parameters such as built-in defaults and winds that deviate from the average.[75]

Figure 1
Comparison of Measured and Calculated VOC Emissions
From Refinery Storage Tanks[76]



These and other studies—which were not reviewed in the Protocol—concluded that changes in the tank-modeling methods are warranted. These changes include improving crude oil and mid-refined product default parameter data, determining the effect of poorly maintained tank seals and roofs on emissions, determining the effect of high sulfur or corrosive crude now being widely refined on floating roof seals and tank walls, explaining why the TANK model accurately predicts for gasoline tanks but not crude and other product tanks, and determining the leakage of propane and butane past floating roof seals. Yet the Protocol does not address these and other recommendations in the literature.

In addition, the magnitude of VOC emissions depends upon certain site-specific inputs and variables, including wind speed, size, seal condition, seal type, roof height,

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[75] Johan Mellqvist, et. al., Measurements of Industrial Emissions of VOCs, NH3, NO_2 , and SO_2 in Texas using the Solar Occultation Flux Method and Mobile DOAS (Aug. 20, 2007) (rev. Sept. 17, 2007), available at http://www.fluxsense.se/reports/SOFTexas2006.pdf; Technical Memorandum from Brenda Shine, EPA/SPPD, to EPA Docket No. EPA-HQ-OAR-2003-0146 (July 27, 2007).
[76] Spectrasyne, supra note 12.

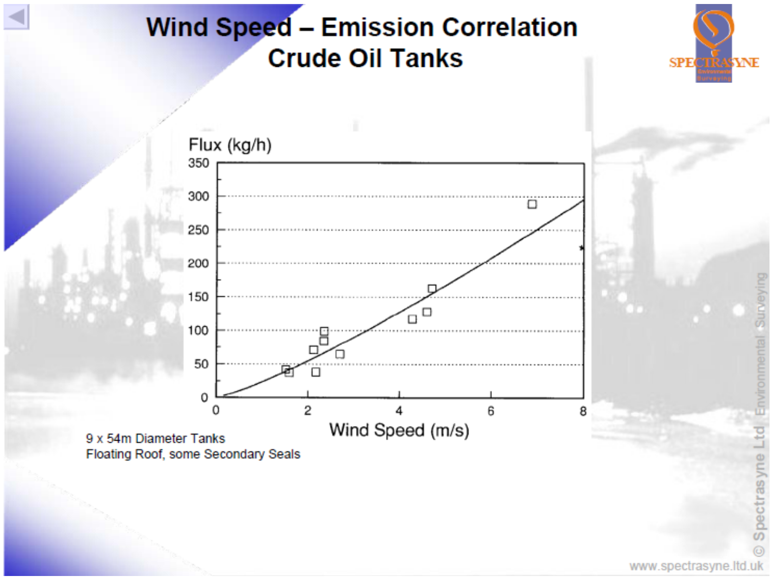
filling rate, tank movements (e.g., mixing), and vapor pressure of the stored material.[77] Some of these variables are not included in the tank calculations -- seal condition, roof height, filling rate, tank movements -- while others are included as defaults or annual averages, resulting in significant errors in the calculations. Although the Protocol provides tips and insights into the use of the AP-42 tank emission estimating procedures and models,[78] the Protocol does not refine or revise inadequate tank emission methods or even include a critical review of the literature documenting deficiencies in the tank modeling methods that lead to inaccurate tank emissions data.

EPA should revise AP-42 tank modeling methods to account for site-specific variables that significantly impact tank emissions as follows:

Wind Speed

Rim seal losses from floating-roof tanks increase significantly with wind speed, roughly in proportion to a constant time the wind speed raised to an exponent, which ranges up to 4.3 for rim-mounted seals.[79] This relationship for tanks as measured by DIAL is shown in Figure 2. The Protocol should be revised to require the use of short-term, site-specific wind data, for the reasons set out below.

Figure 2
Effect of Wind Speed on VOC Emissions from Tanks[80]



Wind Speed – Emission Correlation
Crude Oil Tanks

9 x 54m Diameter Tanks
Floating Roof, some Secondary Seals

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[77] Spectrasyne, supra note 12, at app. C, 28.
[78] Protocol, 3–2-3–3, app. C.
[79] EPA, AP-42, supra note 20, 7.1-23 & tbl. 7.1-8.
[80] Spectrasyne, supra note at 12, at app. C, 25-27.

Due to the relationship between wind speed and emissions, the monthly averaging method in the Protocol underestimates emissions. Tank emissions vary according to the wind speed raised to an exponent which is greater than one for most types of seals. Thus, the average of emissions calculated from hourly average wind speeds for a year would be significantly higher than emissions calculated from the proposed monthly wind speeds. The use of monthly average wind speed data averages out the high emissions events. Actual annual emissions would be much higher. The calculations need to be made on a much shorter time basis, which is readily achievable with an on-site anememoter.

Further, wind speeds vary dramatically over time and with location. Most refineries are located along shorelines, such as the Gulf Coast, the Great Lakes, and the Pacific Ocean, where wind speeds are significantly higher than at inland locations where most of the wind speed data used in the emission calculations are collected. The tank emission estimating procedures do not require site-specific wind speed data. Rather, the methods in the Protocol and AP-42 notes that "[i]f ambient wind speed at the tank site is not available, use wind speed data from the nearest local weather station or values from Table 7.1-9."[81]

On-site anemometers are frequently available at petroleum refineries, but are rarely used to estimate emissions. Most tank emission calculations rely on data for other sites, typically tabulated annual data from a local airport. The wind speed values in AP-42 Table 7.1-9 are average annual wind speeds for selected U.S. locations. The issue is similar for the Tanks 4.09D model, which implements the AP-42 calculations. This model contains a database of meteorological data that includes monthly and annual average wind speed for a collection of pre-selected cities. The user can add other cities.

The Protocol should require the use of on-site anemometers to estimate short-term wind speeds. If an on-site anemometer is not available, one should be installed as on-site wind speed is an important variable in many emission calculations, including, for example, fugitive dust from haul roads and stock piles addressed in Protocol Section 10. Anemometers are inexpensive to purchase, install, and operate.

Further, the AP-42 calculation procedure does not properly model the interaction of wind and rim seals. The amount of VOC emissions from rim seals depends upon the amount of freeboard above the roof (Fig. 3),[82] a parameter that is not included in the AP-42 calculation procedure.

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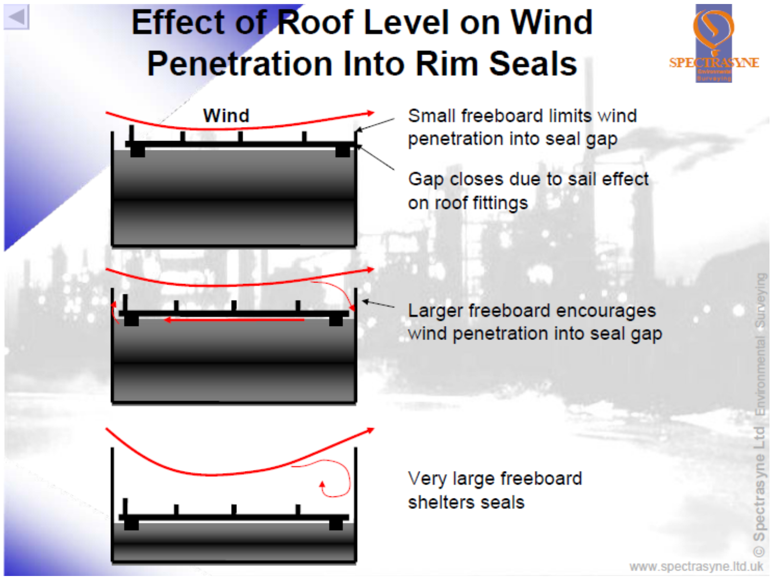
[81] EPA, AP-42, supra note 20, 7.1-33.

[82] Spectrasyne, supra note 12, at app. C, 27.

Figure 3



Effect of Roof Level on Wind Penetration Into Rim Seals

Small freeboard limits wind penetration into seal gap

Gap closes due to sail effect on roof fittings

Larger freeboard encourages wind penetration into seal gap

Very large freeboard shelters seals

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A DIAL study of a well maintained naphtha tank that had vapor controls beyond those included in the AP-42 algorithm (additional wiper seal, gauge pole openings wrapped) emitted 1 to 7 lb/hr of VOC while the TANKS program estimated emissions of less than 1 lb/hr using naphtha default parameters. The apparent cause was wind action blowing vapors between the tank seals even though the tank was full.[83] The Protocol should refine or revise tank modeling methods to address this omission.

Liquid Vapor Pressure

The Protocol recommends that site-specific conditions be used.[84] Emissions from a tank depend most directly upon the true vapor pressure of the stored material. The true vapor pressure is typically calculated from liquid temperature using various nomograms that relate liquid temperature to vapor pressure.[85] It is unclear whether these nomograms when used with site-specific meteorological data constitute "site-specific conditions" under the Protocol.

These nomograms lump together all crudes and all crude stocks, introducing error, as even different crudes and stocks individually can have a wide range of vapor pressures. Further, these nomograms are based on products produced over two decades ago. The industry has changed dramatically since then, resulting in crude and stock properties that are very different today. For example, refineries have retooled to produce reformulated fuels. Many refineries are currently switching to heavy crudes which arrive mixed with diluent. This diluent increases the crude vapor pressure as compared to the

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[83] Remote Sensing of Emissions, supra note 18, at 17; Nettles, supra note 18, at app. C, 42-49.
[84] Protocol, 3-2.
[85] EPA, AP-42, supra note 20, fig. 7.1-13a, 7.1-13b (crude oil), 7.1-14a, 7.1-14b (crude stocks).

defaults, which increases VOC emissions. Thus, the AP-42 Chapter 7.1 equations are not up to date and should be revised to reflect the current market.

As vapor pressure is the key parameter in VOC emission calculations, we recommend that the Protocol be revised to prohibit the use of AP-42 Chapter 7.1 nomograms and equations to estimate vapor pressure and instead require measurement of the vapor pressure of the full range of products and conditions (i.e. temperature) stored in each tank for each period for which emissions are estimated. Vapor pressure is inexpensive and easy to measure and most refineries can do the tests on-site. In the alternative, we recommend that EPA update the existing nomograms and equations used to calculate vapor pressure to include a much wider range of products produced by modern refineries, including heated heavy oil, naphthas, reformate, alkylate, condensates, and gas oils.

<u>Liquid Temperature</u>

If site-specific vapor pressure is not available, TANKS and AP-42 estimate vapor pressure from temperature using nomograms. Many refinery tanks are heated. The Protocol acknowledges that TANKS will underestimate emissions from heated tanks and directs the use of AP-42 equations instead.[86] Thus, for floating roof tanks that store warm process fluids, the Protocol recommends the use of Chapter 7.1 rather than TANKS. The Protocol is silent on how to address this underestimate for other types of tanks.

AP-42 Chapter 7.1 for heated floating roof tanks uses liquid temperature to calculate vapor pressure using the same flawed nomograms. This procedure contains the same problems discussed above for vapor pressure. The underlying nomograms and equations are not representative of the products in the market today and are not product specific. These calculations are further limited as they rely on inputs from default nomograms with upper bound temperatures of 120° F (stocks) to 140° F (crude oil) or an equation that yields only an approximation of vapor pressure.[87] Some tanks are heated as high as 400° F, which is outside of the range of the available vapor pressure estimating methods.

The Texas DIAL study included heated tanks. The average VOC release rate measured by DIAL from two heated tanks was 6 and 9 lb/hr, while the TANKS program estimated less than 1 lb/hr using default parameters.[88] The author of a presentation at the Second International Workshop on Remote Sensing proposed one reason for the

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[86] Protocol, 3-3 (noting that "for intermediate process tanks with floating roofs that store liquids that are generally warmer than ambient temperature, TANKS will underestimate the emissions. Therefore...the equations in Chapter 7.1 of AP-42 should be used directly....").

[87] AP-42, 7.1-16 to 7.1-16.

[88] Remote Sensing of Emissions, <u>supra</u> note 18, at 18; Nettles, <u>supra</u> note 18 at 57 (Tanks 43, 60).

[88] Remote Sensing of Emissions. <u>supra</u> note 18, at 18.

underestimate: the TANKS program has a 100° F upper limit for heated tanks while some tanks can reach 400° F.[89]

If the direct pressure measurement recommended above is not adopted, the Protocol should be revised to require continuous measurement of liquid temperature. The Protocol should also specifically prohibit the use of default liquid temperatures for heated tanks. Temperature is even easier and less expensive to routinely measure than vapor pressure. Due to its importance in determining VOC emissions in the absence of measured vapor pressure, it should not be calculated from outdated nomograms and equations based on materials that are no longer dominant in the marketplace.

Internal Mixing

Mixing takes place in many tanks: two or more crude or process stocks may be blended to form a composite intermediate or finished product.[90] Mixing is accomplished by circulation or in-tank mixes. Refineries, for example, import crude oils from a variety of sources and blend them to meet crude input requirements. Tank contents may be mixed to prevent stratification and achieve uniform properties.[91] Tanks may also be mixed to minimize sludge.[92]

Mixing increases VOC emissions because it increases the vapor in the headspace of a storage tank, but the AP-42 tank emission estimating procedure and TANKS program do not address mixing and the Protocol is silent on this issue. For example, a study at a Texas bulk terminal identified emission plumes during internal mixing in a floating roof tank that were not accounted for in the TANKS program.[93] The Protocol should be revised to identify this issue and provide guidance on how to account for this mixing in the tank modeling methods.

C. The Protocol should provide guidance on estimating emissions for all sources of tank emissions.

The AP-42 Chapter 7.1 calculation procedure and the TANKS program omit several important sources of VOC emissions from tanks. The Protocol recommends that "[s]pecial calculations should be performed to account for tank roof landings, tank degassing, and tank cleaning."[94] The newly revised AP-42 Chapter 7.1 includes calculations for VOC emissions from roof landings. However, neither AP-42 Chapter 7.1 nor TANKS include any method to calculate emissions from tank degassing and tank cleaning. The Protocol fails to disclose this omission and does not offer any guidance on

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[89] Id.

[90] W.F. Bland & R.L. Davidson, Petroleum Processing Handbook 4-85 (McGraw-Hill ed. 1967) (Batch Blending).

[91] Department of Planning, New South Wales Government, Major Project Assessment: Kurnells Refineries Crude Oil Storage Tank (Tank 634) (Oct. 2006) (tank designed to include mixing system to ensure uniform vapor pressure).

[92] P.E. Myers, Aboveground Storage Tanks §§ 15.2.3.1, 614; 16.2.3 (McGraw-Hill ed. 1997).

[93] Nettles, supra note 68, at app. C, 11.

[94] Protocol, 3-3.

how the degassing and cleaning emissions should be calculated. We note that TCEQ has published methods to calculate these emissions.[95] The Protocol should review these and others methods and rank available methods.

In addition, AP-42 Chapter 7.1 and TANKS do not account for increased emissions from tanks in poor condition.[96] Tanks degrade over time. For example, as tanks settle they lose their round shape. This causes tank seals, regardless of their condition, to not fit tightly, allowing leaks. Further, seals fail and may be undetected for long periods of time. Tank emissions are estimated from an assumed distribution of seal gaps for a typical tank population with leak rates past seals with varying degrees of gaps.[97] While this may be representative of a large population of tanks over their lifespan, it is not adequate to calculate VOC emissions from a specific tank for a specific period of time, which is required for emission inventories and other purposes. A few poor performing tanks can emit thousands of tons of VOCs.[98] We suggest incorporating an age factor in the model that increases emissions as tanks age, coupled with a mandatory monthly seal inspection and gap measurement program.

Finally, several other non-routine conditions that occur quite commonly can lead to very high emissions and are not accounted for in the tank calculations. These include: (1) flashing losses, when a liquid with entrained gases experiences a pressure drop or temperature increase, releasing or "flashing" some of the lighter compounds from the liquid; (2) filling a tank with non-stabilized crude oil, which results in the boiling off of non-stable constituents; and (3) elevated wind speed when the tank is full. The Protocol should provide guidance on how to estimate emissions from these important sources of VOC emissions.

IV. SECTION 6: FLARES

Flares are a major source of VOC emissions at petroleum refineries. Surveys in the Houston-Galveston area indicate that flares emit 61% of all highly reactive VOCs—petroleum refineries are responsible for 36% of this total.[99] In other studies, reported flare emissions contributed 8% of the VOC emissions from a large refinery with a coker

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[95] Tex. Comm'n on Envtl,RG-360A, Technical Supplement 6: Aboveground Liquid Storage Tanks (Rev. Jan. 2006), available at http://www.tceq.state.tx.us/assets/public/comm_exec/pubs/rg/rg360/rg-360-05/techsupp_6.pdf.

[96] Smithers et al., The Oil Companies' European Organization for Environment and Saftey, report no. 95/52 VOC Emissions from External Floating Roof Tanks: Comparison of Remote Measurements by Laser with Calculation Methods (1995); Clearstone Engineering Ltd., A Review of Experiences Using DIAL Technology to Quantify Atmospheric Emissions at Petroleum Refineries, Final Report, 16 (Sept. 6, 2006).

[97] EPA, AP-42, supra note 20, at 7.1-123, Reference 15.

[98] Clearstone Engineering Ltd., A Review of Experiences Using DIAL Technology to Quantify Atmospheric Emissions at Petroleum Refineries, Final Report, 15-16 (Sept. 6, 2006).

[99] Tex. Comm'n on Envtl. Quality, Flare Task Force Group Stakeholder Group Meeting (Sept. 18, 21 2009) (unpublished powerpoint presentation), available at http://www.tceq.state.tx.us/assets/public/implementation/air/rules/Flare/091809_FTF_Presentation.pdf; T. Pavlovic et. al., Characterization of Flare Emissions from Refineries in Houston 4 (Aug. 24, 2009), available at http://files.harc.edu/Projects/AirQuality/Projects/H095/H095FinalReport.pdf.

and 2.25% for a small refinery on an annual average basis.[100] Self-reported data from Texas indicate that individual flaring events can release over 100 tons of sulfur dioxide (SO2) and VOCs per event.[101] The Protocol lists six methods to determine emissions from flares:

- Continuous composition and flow rate monitoring of gas sent to flare;
- Continuous flow rate monitoring and periodic gas compositional analysis;
- Continuous flow rate and heating value monitoring;
- Engineering calculations;
- Emission factors based on energy consumption; and
- Default emission factors based on refinery or process throughput.[102]

These recommendations are a good starting point. However, all of these methods are known to underestimate emissions from flares. For example, exhaustive studies in the Houston-Galveston area have demonstrated that very rapid ozone formation is frequently associated with elevated amounts of highly reactive VOCs from episodic emission events like flaring that cannot be explained by current emission inventories.[103] A group of experts convened by Texas to investigate the underestimate in the Houston-Galveston area concluded that "the results of the recently concluded TCEQ DIAL Study specifically indicates that *industrial flare and wastewater emissions of VOCs may be significantly greater than reported by industry to TCEQ*."[104] The Protocol fails to include a critical review of relevant flare studies, omitted important emission estimating methods, and fails to include revised emissions factors.

A. The Protocol should include a critical review of optical remote sensing methods and other technologies that directly measure emissions and provide guidance on the use of these methods.

The Protocol provides no method to directly measure emissions from the flare itself. The two continuous methods ranked 1 and 2 yield only indirect measures of emissions, which are dependant on monitoring the inlet to the flare and rely on a constant combustion efficiency of 98%—an assumption that has been called into question by extensive studies. Direct measurement methods are available and should be added to the Protocol.

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[100] Spectrasyne, supra note 12, at 20-23; David Castiñeira, A Computational Fluid Dynamics Simulation Model for Flare Analysis and Control 2-4 (Ph.D. Thesis, University of Texas, Austin) (May 2006).

[101] E-mail from Eric Schaeffer, EIP, to Ken Hustvedt, EPA, Re: Refinery Emission Data, Subpart Ja Docket, EPA-HQ-OAR-2007-0011 (Sept.25, 2008).

[102] Protocol, 6-2.

[103] See, e.g., http://www.che.utexas.edu/twccc/presentations0206/castineira-talk0206.pdf.

[104] Tex. Envtl. Research Consortium, The 2009 TERC Science Synthesis 12, 120 (June 2009), available at http://files.harc.edu/Projects/AirQuality/Projects/H108/H108ScienceSynthesisReport.pdf (emphasis added).

Despite EPA's commitment to the City of Houston to conduct a "critical review" of optical remote sensing data, optical remote sensing methods were dismissed out of hand. The Protocol acknowledges that "[r]ecent developments in testing protocols, such as the DIAL technique, provide a direct emissions measurement technique for flares." However, the Protocol goes on to argue that "DIAL measurements provide only a snapshot in time."[105] This is the same argument EPA sets forth to dismiss optical remote sensing methods to measure emissions from tanks. As explained in Section III, this is inconsistent with EPA's position with respect to stack tests for combustion sources (i.e. a "snapshot" is sufficient) and it mischaracterizes optical remote sensing methods. For example, FTIR can easily be used continuously. Regardless, the snapshot argument is particularly inappropriate due to the nature of flares. Most flaring emissions occur in sporadic emissions events, which release large quantities of VOCs and other pollutants in a short amount of time. By nature, flaring events are "snapshot" events and are, in fact, suitable for measurement by optical remote sensing methods.

In fact, some optical remote sensing techniques have been successfully applied for direct monitoring of flares, including DIAL and FTIR. For example, Open-path Fourier Transform Infrared (OP-FTIR) was used to measure the combustion efficiency of two very large flares that burned waste gas consisting of over 99% CO saturated with water vapor at a low temperature and low concentrations of other hydrocarbon and sulfur gases. The study used four separate methods to estimate combustion efficiency. Considering all data, the median CO combustion efficiency was about 97%. The average was 87%, with a range of 49-99%.[106] FTIR has also been used to monitor emissions and combustion efficiency from natural gas flares.[107] Other tests by John Zink Co. have demonstrated that Passive Fourier Transform Infrared (P-FTIR) can be used to determine species concentrations and combustion efficiencies in the flare gases, remotely and continuously.[108]

In addition, a new method has been developed that uses simple two-dimensional (2-D) color images (multivariate image analysis or MIA) to monitor flare combustion efficiencies in real-time. A simulation model was developed using several laboratory-scale flares and wind-tunnel flares that incorporate the variables that affect combustion efficiency (e.g., wind, steam, air) as discussed below. This model could be used with flare-specific inputs at other flares, to estimate the impact of steam addition and crosswinds on flare combustion efficiency. This method is fast, accurate, and inexpensive.[109]

Finally, EPA and others have directly measured flare emissions using modified stack testing protocols discussed in Section 4 for combustion sources. In the 1983 study used to develop AP-42 flaring emission factors, EPA used a specially constructed probe

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[105] Protocol, p. 6-1.

[106] Thomas R. Blackwood, An Evaluation of Flare Combustion Efficiency Using Open-Path Fourier Transform Infrared Technology, 50 J. Air & Waste Mgmt Ass'n,1714, 1714 (Oct. 2000).

[107] Rainer Haus et. al., Remote Sensing of Gas Emissions on Natural Gas Flares, 7 Pure Appl. Opt. 853 (1998).

[108] See, e.g., Castiñeira, supra note 100, at 145-47.

[109] Id. at ch. 7.

suspended by a crane over the flare flame.[110] The extracted sample was continuously analyzed.[111] This method could be used to directly measure flaring emissions, although we agree that for many large flares it may be impractical.

These direct flare monitoring methods are the only direct measurement methods that have the potential to accurately measure flaring emissions and they should be included in the Protocol. The Protocol should include a critical review of optical remote sensing technologies and multivariate image analysis and provide guidance on how to use these methods to estimate emissions. For example, the MIA model could be used by refinery owners and operators to measure actual combustion efficiency of specific flares. The actual combustion efficiency would then replace the default 98% factor in emissions factors and equations. In addition, the Protocol should include standard EPA test methods for flares, similar to existing EPA method OTM-10 for optical remote sensing from non-point sources.[112]

B. The Protocol should require refinery owners and operators to assume flare combustion efficiency no higher than 93% unless it can be demonstrated that the flare is operating in stable flame mode or the flare is equipped with wind guards to mitigate the impact of crosswinds on emissions.

The Protocol proposes two indirect monitoring methods for gases sent to the flare: (1) continuous monitoring of the flow and gas composition (i.e. VOCs, total sulfur) and (2) continuous monitoring of flow and periodic monitoring of gas composition. These methods can only be used for VOCs and sulfur dioxide (SO2). The resulting flow and concentration data are then converted into emissions from the flare by assuming 98% of the gases are converted to CO2 and SO2.[113] These methods do not directly measure flare emissions at the emission point, but rather approximate emissions by applying a constant combustion efficiency to flare mass emission inputs. The 98% constant combustion efficiency is widely recognized to be incorrect for many common operating conditions.

Flaring is a high-temperature oxidation process used to burn unwanted gases, mostly hydrocarbons. Over 95% of the flared gas is typically natural gas, propane, ethylene, propylene, butadiene and butylenes. However, typical flare gas composition and flow rate are highly variable since these units are used for non-routine events, such as upsets, shutdowns, and plant emergencies. Emissions from flaring include soot, unburned hydrocarbons, partially burned or altered hydrocarbons, CO, NOx and SO2. This section focuses on hydrocarbons, as they are estimated in the Rank 1 and 2 methods assuming a constant combustion efficiency of 98%.

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[110] Marc McDaniel, Envtl. Prot. Agency, EPA-600/2-83-052, Flare Efficiency Study (July 1983) available at http://www.tceq.state.tx.us/assets/public/implementation/air/rules/Flare/Resource_1.pdf.

[111] Id.

[112] Optical Remote Sensing, supra note 59.

[113] Protocol, 6-2 (noting that flares operated consistent with 40 CFR 60.18 may assume a 98% combustion efficiency).

Combustion efficiency is the fraction of a pollutant that is converted to its fully oxidized state. For VOCs, the fraction of hydrocarbon gases that is totally burned to carbon dioxide (CO2) is the commonly used measure of the flare combustion efficiency. The balance of the VOCs is released unburned to the atmosphere. For sulfur compounds, discussed in the next section, combustion efficiency is the fraction of sulfur compounds that is converted to SO2.

Combustion efficiency is a key factor in estimating flare emissions as emissions increase much more than a small change in efficiency would suggest. For example, if the actual flare combustion efficiency is only 96%, just 2% less than 98%, flare emissions would be underestimated by a factor of two. The Protocol has assumed that combustion efficiency is constant for all pollutants under all conditions, which results in a significant underestimate in flaring emissions.

The two top ranked methods assume a constant flare combustion efficiency of 98% "for properly operated flares" unless direct measurement data are available.[114] As direct measurement is almost never available, 98% would be assumed under the Protocol, regardless of crosswind velocity or operating conditions that affect combustion efficiency. The 98% value is based on AP-42 Section 13.5, Flares, which in turn is based on a 1983 EPA study.[115] An extensive body of experimental studies on flare combustion efficiency has been developed over the past two decades. Based on these studies, it was generally assumed that flares operate with high efficiency—98% and higher. However, these 98%+ control efficiencies were measured at flares burning dry, high heat-content hydrocarbon gases, under low to moderate wind conditions.[116] These ideal conditions rarely exist at refineries.

Numerous recent studies call into question the uniform application of 98% combustion efficiency, however. Flare performance is impacted by operating parameters that were not specifically evaluated in the earlier studies including: meteorological conditions, variable waste gas flow rate and composition, flare physical design, general maintenance, and steam and air assist operation.[117] Liquid droplets, low gas heating values, high crosswinds and too much steam or air injection can reduce the efficiency of flares, resulting in significant emissions. Thus, the constant 98% combustion efficiency is not reliable across the full range of flare operating conditions, and the flare emission calculation methods should be modified to represent actual emissions under field conditions rather than hypothetical conditions that frequently do not occur.

Much lower flare combustion efficiencies due to these factors have been confirmed in simulations, wind tunnel experiments,[118] and full-scale field

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[114] Id. at 6-2, 6-4.

[115] Id. at 6-2.

[116] Castiñeira, supra note 100, at ch. 1 (see literature review) available at http://www.lib.utexas.edu/etd/d/2006/castineirad34242/castineirad34242.pdf.

[117] Tex Comm'n Envtl. Quality, Flare Task Force Draft Report 6 (Sept. 3, 2009).

[118] David Castiñeira, Modeling and Control of Flare Combustion Systems (unpublished powerpoint presentation, University of Texas, Austin), available at http://www.che.utexas.edu/twccc/presentations0206/castineira-talk0206.pdf; David Castiñeira & Thomas

investigations.[119] These factors typically cannot be controlled during flaring emergencies. For example, the most comprehensive study yet of flare combustion efficiency concluded: "First of all, from our simulation models *it is obvious* that current emission inventories from flares *must be updated due to the high inefficiencies* observed at high crosswind velocities."[120]

Crosswind Velocity

Among the many factors affecting combustion efficiency, wind is notable as it cannot be controlled by the operator and has a major effect on combustion efficiency above 5 - 7 mph.[121] Data from the National Weather Service indicates that average annual wind speed in areas with high concentrations of refineries is much higher than these thresholds[122] and gusts can be even higher. Further, flare stacks are typically 50 to 300 feet tall, and wind speed increases exponentially with height above ground surface.[123] Thus, wind is a critical factor to account for when determining combustion efficiency.

Combustion efficiency drops significantly when crosswinds increase.[124] A wind tunnel study found that "wind speed can have a profound effect on efficiency (i.e.

F. Edgar, CFD for Simulation of Steam-Assisted and Air-Assisted Flare Combustion Systems, 20 Energy & Fuels 1044 (2006); David Castiñeira & Thomas F. Edgar, Computational Fluid Dynamics for Simulation of Wind-Tunnel Experiments on Flare Combustion Systems, 22 Energy & Fuels 1698 (2008).

[119] See, e.g., Robinson et. al., supra note 51; Mel Strosher, Theoretical and Observational Assessments of Flare Efficiencies, 51 J.of the Air & Waste Mgmt. Ass'n 1610 (Dec. 2001); Nettles, supra note 18, at app. C, 65-69.

[120] Castiñeira, supra note 100, at 180.

[121] U.S. Envt'l Prot. Agency, VOC Fugitive Losses: New Monitors, Emissions Losses, and Potential Policy Gaps ix, 24, 40 (Oct 25-27, 2006), available at http://www.epa.gov/ttn/chief/efpac/documents/wrkshop_fugvocemissions.pdf ("When the wind speed is greater than five miles per hour, flare efficiency drops significantly. The emission factor for flare estimation is based on a flare operating in still air conditions, hence it is likely to underestimate emissions."); Castiñeira & Edgar, supra note 118, at 565 (In a 25% methane/75% air flame "combustion efficiency significantly decreases for crosswinds about 3 m/s [7 mph]. In fact, increasing unburned hydrocarbon and CO emissions are observed as the crosswind velocity increases to the point where the flame is almost extinguished at 10 m/s [22 mph]").

[122] Galveston, TX (11.3 mph); Houston, TX (7.6 mph); Port Arthur (9.6 mph); Detroit (10.3 mph). See http://lwf.ncdc.noaa.gov/oa/climate/online/ccd/avgwind.html. See also: Envtl. Integrity Project, Smoking Guns: Smoking Flares and Uncounted Emissions from Refineries and Chemical Plants in Port Arthur, Texas (Nov. 2002) available at http://www.environmentalintegrity.org/pdf/publications/Report_SmokingGuns.pdf.

[123] Milton R. Beychok, Fundamentals of Stack Gas Dispersion 100 (3rd ed. 1994).

[124] Mel T. Strosher, Characterization of Emissions from Diffusion Flame Systems, 50 J. of the Air & Waste Mgmt. Ass'n 1723 (Oct. 2000); M.R. Johnson & L.W. Kostiuk, Efficiencies of Low-Momentum Jet Diffusion Flames in Crosswinds, 123 Combust. Flame189 (2000); Robert E. Levy, Lucy Randel, Meg Healy & Don Weaver, Reducing Emissions from Plant Flares, Industry Professionals for Clean Air (2006); University of Alberta, Flare Research Project, Interim Report, November 1996 - June 2000, December 1, 2000; Douglas M. Leahey, Katherine Preston, and, Mel Strosher, Theoretical and Observational Assessments of Flare Efficiencies, Journal of the Air & Waste Management Association, v. 51, December 2001, pp. 1610-1616 (at 1610: "Results of the calculations showed that combustion efficiencies decreased rapidly as wind speed increased from 1 to 6 m/sec [2-13 mph]. As wind speeds increased beyond 6 m/s, combustion efficiencies tended to level off at values between 10 and 15%."); Industry Professionals for Clean Air, Reducing Flare Emissions from Chemical Plants and Refineries. An Analysis of Industrial

efficiency drops by approximately the cube of wind speed) and that having higher jet exit velocities makes the flames less susceptible to these wind effects. As well, the data shows a dramatic decrease in combustion efficiency as the volumetric energy content of the fuel is reduced."[125] Other work indicates that higher exit gas velocity may lead the flame to near blowoff conditions and even to extinction if the gas velocity gets too high.[126] Others have likewise concluded that for high-momentum flares, those with high gas-to- crosswind ratios, the flame is unlikely to attach to the stack, lowering combustion efficiencies.[127]

Combustion efficiency is reduced as high cross wind velocities bend the flame over, allowing significant amounts of fuel to be stripped away from the burner exit. High wind velocity also reduces flame size, which reduces the amount of oxygen entrained into the flame, and allows burning in detached pockets over the tail flame length. These factors reduce combustion efficiency.[128] As explained above for tanks, wind speeds at refineries are often very high due to their coastal locations. We have observed many flares on windy days in which the flame was bent over parallel to the ground and feathered, indicating poor combustion efficiency. Thus, wind is an important factor that is not considered when emissions are estimated using a uniform 98% combustion efficiency.

Other Variables

The Protocol assumes that a combustion efficiency of at least 98% will be achieved if a flare is operated consistent with 40 CFR § 60.18 [New Source Performance Standards (NSPS) for flares]. However, as explained by ConocoPhillips in comments to the TCEQ: “the operating parameter efficiency envelopes have not been developed to account for wind nor the chemical properties of the gases flared nor for the amount of smoke-suppressing steam employed. Recent studies of hydrogen or inerts in the flared gases have demonstrated that energy content (Btu/scf) alone is a poor descriptor even though it is relied upon in the USEPA's 40 CFR 60.18.”[129]

Flares' Contribution to the Gulf Coast Region's Air Pollution Problem, May 23, 2005; David Castiñeira and Thomas F. Edgar, CFD for Simulation of Crosswind on the Efficiency of High Momentum Jet Turbulent Combustion Flames, J. Environ. Eng., July 2008, pp. 561-571.

[125] M.R. Johnson et. al., Efficiency Measurements of Flares in a Cross Flow (May 1999), available at http://www.mece.ualberta.ca/groups/combustion/flare/papers/CombCan99-Efficiency.pdf.

[126] Castiñeira & Edgar, supra note 118, at 567.

[127] David Castiñeira and Thomas F. Edgar, Computational Fluid Dynamics for Simulation of Wind-Tunnel Experiments on Flare Combustion Systems, 22 Energy & Fuels 1706 (2008).

[128] See, e.g., M.R. Johnson & L.W. Kostiuk, Efficiencies of Low-Momentum Jet Diffusion Flames in Crosswinds, 123 Combustion and Flame 189, 199 (2000) ("Results show that increased crosswind speed () adversely affect the combustion efficiency...Gas chromatographic analysis of the products of combustion showed that the inefficiencies result from fuel stripping, and photographic images link this process to the occurrence of the flame burning in detached pockets over its full length and the shortening of the flame tail.").

[129] Comment from ConocoPhillips to Tex. Comm’n on Envtl. Quality (May 9, 2009) (attachment contains James Seebold et. al., Practical Implications of Prior Research on Today's Outstanding Flare Emissions Questions and a Research Program to Answer Them, AFRC-JFRC 2004 Joint International Combustion Symposium), available at http://www.tceq.state.tx.us/assets/public/implementation/air/rules/Flare/Comments_ConocoPhillips.pdf.

Further, 40 CFR § 60.18, rather than assuring 98% combustion efficiency, invites conditions that can reduce flare combustion efficiency. The flare NSPS was designed to address "smoking flares" and thus requires flares to be designed and operated with no visible emissions. Smoke suppression is typically accomplished by injecting steam or air into the combustion zone to promote turbulence to mix and draw more air into the flame.

An operator typically has no way to judge the proper amount of steam or air to add during a release as it depends on many variables that may not be known or cannot be controlled, such as crosswind velocity. Thus, refineries commonly set the steam-to-flared gas ratio high to ensure smokeless operation under high flow conditions. This results in high steam-to-gas ratios during low flow and normal operations and sometimes even during emergency flaring. Thus, efforts designed to comply with 40 CFR § 60.18 (i.e. minimize visible emissions) can actually decrease combustion efficiency.[130]

For example, the 2006 TCEQ study used DIAL to measure emissions from two flares.[131] One was a recently built steam-assisted emergency/process flare serving the ultra cracker. This flare had no visible flame in daylight and appeared to be in compliance with 40 CFR § 60.18.[132] The Protocol states that if a flare operates consistent with 40 CFR § 60.18, it should be assumed to be “properly operating and achieving 98% combustion efficiency.”[133] However, DIAL measured VOC emissions of 88 to 326 lb/hr.[134] The highest combustion efficiency measured during this test was less than 85%.[135]

The TCEQ author concluded that “this problem may be caused by low flow from routine processes being sent to a large steam-assisted emergency/process flare.”[136] These types of situations, routine releases being sent to large steam-assisted emergency flares, are common throughout the refining industry. In the Houston-Galveston area, the TCEQ concluded that flares emitting highly reactive VOCs routinely operate at less than 25% of their maximum design capacity.[137] In response to this and other recent work, both TCEQ and EPA have expressed concerns that flares operated at high turndown and/or high steam-to-flare gas ratios may not routinely achieve the assumed control efficiencies.

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[130] Remote Sensing of Emissions, supra note 18, at 25-26 (In response to a question, Dr. Spellicy explained that the use of steam and air to improve combustion "works only up to a point, after which it becomes counter productive because the assisted air/steam cools the flame"). See also Castiñeira, supra note 100, at ch. 3; Castiñeira & Edgar, supra note 118.

[131] Robinson et. al., supra note 51 at 20, 28-30.

[132] Id.

[133] Protocol, 6-2.

[134] Nettles, supra note 18, at app. C; Texas Commission on Environmental Quality (TCEQ) Differential Absorption Lidar (DIAL) Project, Summer 2007, Texas City, Texas, In: EPA, International Workshop on Remote Sensing of Emissions, New Technologies and Recent Work, 2008, Appendix C, pp. 65-69.

[135] Id.

[136] Remote Sensing of Emissions, supra note 18, at 18.

[137] Tex. Comm’n Envtl. Quality, Flare Task Force Draft Report 4 (Sept. 3, 2009), available at http://www.tceq.state.tx.us/assets/public/implementation/air/rules/Flare/FTF_Draft_Final_Without_Appendices.pdf.

More studies are currently underway at the University of Texas at Austin to investigate flare performance.[138]

The Protocol, however, fails to provide a critical review of the completed studies, noting only that "recent efforts to better characterize flare emissions include efforts to determine whether this combustion efficiency continues to be appropriate for properly operated flares. At this time, sufficient data have not yet been collected and evaluated to support revising this efficiency estimate."[139] Yet there is currently adequate data to conclude that a constant 98% combustion efficiency is not uniformly applicable and a more sophisticated approach to flare combustion efficiency is required. The Protocol should include a critical review of the numerous flare studies that demonstrate that assumption of 98% combustion efficiency will lead to emissions data that significantly undercounts actual pollution from flares.

EPA should use the data from these studies to develop a model of flare combustion efficiency under crosswind conditions that accounts for the heating value of the gas, gas composition, jet velocity, steam or air-to-hydrocarbon ratio, and the burner diameter. In the interim, the Protocol should recommend that refinery owners and operators assume that combustion efficiency is no higher than 93%[140] unless it can be demonstrated that the flare was operating in a stable flame mode or that the flare is equipped with wind guards to mitigate the crosswind effect. We believe this approach is reasonable due to the demonstrated significant underestimation of flaring emissions and the many factors that affect flare combustion efficiency that cannot be controlled by refinery operators and are not addressed in 40 CFR § 60.18 (i.e. wind velocity).

C. The Protocol should be revised to ensure more accurate estimates of sulfur dioxide emissions from flares.

The Protocol assumes the same combustion efficiency for both VOCs and sulfur dioxide (SO2).[141] However, it is conventionally assumed that 100% of the sulfur in flared gases is converted to SO2.[142] The Protocol offers no support for deviating from the standard practice and recommending a combustion efficiency that would underestimate SO2 emissions.

Further, for the Rank 1 method, which relies on continuous measurement of the composition of gases sent to the flare, the Protocol notes that a “reduced sulfur or total sulfur monitor can be used to characterize the sulfur content of the gas being combusted in the flare.”[143] The use of a reduced sulfur monitor would underestimate the amount of

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[138] T. Pavlovic et al., Characterization of Flare Emissions from Refineries in Houston 5, 77-78 (Aug. 24, 2009) available at http://projects.tercairquality.org/AQR/H095.

[139] Protocol, 6-2.

[140] The 93% combustion efficiency value is recommended by TCEQ for its emission inventory when the flare does not satisfy 40 CFR 60.18. We believe it is warranted for all flares, unless contrary evidence is presented.

[141] Protocol, 6-2.

[142] See, e.g., EPA, AP-42, supra note 20, at 3.5-4.

[143] Protocol, 6-2.

SO2 emissions because flared gases may contain both reduced and oxidized sulfur compounds. All of the sulfur in flared gases would be converted to SO2 emissions during flaring, not just reduced sulfur compounds. Therefore, the Protocol should be revised to require only total sulfur monitors for flare gas composition monitoring.

For the Rank 2 method, which relies on periodic measurement of the composition of gases sent to the flare, the Protocol specifically recognizes that total sulfur is the correct metric and recommends determining the average total sulfur-to-H2S ratio of the flare gas.[144] The Protocol also suggests that this ratio method can be applied to the reduced sulfur monitor mentioned in the Rank 1 method to adjust reduced sulfur to total sulfur. We believe caution is warranted in applying this ratio method to flares due to the variability in composition of flared gases. This ratio should only be used for flares that routinely burn gases with a uniform composition. It should not be used for flares that handle emergency releases that may vary significantly in composition. In this latter case, total sulfur should be directly measured, not estimated from a ratio.

D. The Protocol should include emissions factors that account for flare gas composition on emissions of VOC, nitrogen oxide (NOx), and CO.

In Methodology Rank 3, the Protocol proposes two sets of emission factors for total hydrocarbons, carbon monoxide (CO), and nitrogen oxides (NOx), expressed in units of pounds per million Btu (lb/MMBtu) of gas burned. The Protocol also requires continuous monitoring of flare gas flow and gas heating value in Rank 3 and estimates of same in Rank 5.[145] The two sets of emission factors are: (1) those published in 1995 in AP-42, Table 13.5-1 (Protocol Table 6-2) and (2) those published recently by TCEQ (Protocol Table 6-3). In Methodology Rank 6, the Protocol also proposes the AP-42 emission factor for soot from flares (in Protocol Table 6-4) with estimates of energy consumption.[146]

The flare AP-42 emission factors were developed from 1983 tests under ideal conditions, as described above, where a mixture of propylene and propane was burned.[147] The basis of the 2009 TCEQ emission factors, presented for low Btu and high Btu gases, is unknown as it is not disclosed in the document cited[148] in the Protocol,[149] but presumably they are based on some subset of the last two decades of controlled EPA tests. Thus, these factors are not representative of the full range of flare operating conditions, as discussed above and underestimate emissions for a wide range of common conditions including high crosswind velocity, operation at much less than design

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[144] Protocol, 6-4.
[145] Protocol, 6-4 to 6-7.
[146] Protocol, 6-7, tbl. 6-4.
[147] EPA, AP-42, supra note 20, tbl. 13.5-1, note a.
[148] Note that the reference in the Protocol to the TCEQ emission factors is incorrect. It should be: TCEQ, 2009 Emissions Inventory Guidelines, Supplement 4. Instead, it cites the 2008 Guidelines, which do not contain the subject emission factors.
[149] Air Quality Division, Tex. Comm'n on Envtl. Quality, RG360A/09, 2009 Emissions Inventory Guidelines app. A, A-51, tbl. A-6 available at http://www.tceq.state.tx.us/assets/public/comm_exec/pubs/rg/rg360/rg36009/appendix_a.pdf.

capacity, and over steaming, among others. These factors, for example, are routinely used by refineries to report their emissions to regulatory agencies, even though the operators separately report many hours of visible emissions, smoking, and emergency releases, all indicators of incomplete combustion.[150]

In general, emissions from a flare depend upon the composition of the gas that is burned.[151] The AP-42 factors are based on a dry mixture of propylene and propane. Most gases flared in refineries are not dry mixtures of propylene and propane.[152] Flare gases may contain very high concentrations of hydrogen, fuel nitrogen compounds, and CO. Gases that contain high concentrations of fuel nitrogen and hydrogen, for example, emit much higher amounts of NO_x than would be emitted while flaring a propylene and propane mixture. The Santa Barbara County Air Pollution Control District developed an equation to estimate the contribution of fuel NO_x to flaring emissions.[153] Similarly, gases that contain much higher concentrations of CO would emit much higher amounts of CO than indicated by these emission factors. The Protocol should include a critical review of the literature on the effect of flare gas composition on flare emissions and include emissions factors that address the impact of gas composition on VOC, NOx, and CO emissions.

E. The Protocol should include the Ideal Gas Law as an emissions estimation method.

The Ideal Gas Law is a fundamental statement of the relationship among the pressure, temperature, volume, and number of particles in an ideal gas mixture. Flare emissions can be directly calculated using this equation if the volumetric flow rate and molecular weight of the gas are known. These two parameters are frequently known or can be easily determined.

The Ideal Gas Law is one of the most commonly used methods to estimate VOC and individual HAP emissions from flares. The Texas Commission on Environmental Quality (TCEQ), for example, recommends this method for New Source Review emission calculation procedures to determine VOC emissions from flaring.[154] This method is more accurate than an emission factor because it is based on flow rates and molecular weights of the gas being flared, as opposed to an emissions factor based on gas with different properties. The Protocol should be revised to include this emissions estimation method.

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[150] Environmental Integrity Project, supra note 122.

[151] Castiñeira, supra note 100; The John Zink Combustion Handbook, (Charles K. Bukal, Jr. ed., CRC Press, 2001).

[152] Pavlovic et. al., supra note 138, at tbl. 2.3 (summarizing refinery gas composition data).

[153] Steve Sterner, Santa Barbara County Air Pollution Control District, Flare Study, Phase I Report tbl. 3.1.1 (July 1991), available at http://www.sbcapcd.org/eng/dl/other/flarestudyphase1.pdf.

[154] Air Permits Division, Tex. Comm'n Envtl. Quality, New Source Review (NSR) Emission Calculations, available at http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/emiss_calc_flares.pdf

V. SECTION 4: STATIONARY COMBUSTION SOURCES

The Protocol lays out five methods to calculate emissions from refinery combustion sources.[155] All of the methods except the last one require direct measurements using CEMS or stack test data.[156] However, direct measurements of emissions are not readily available for the vast majority of refinery combustion sources, and applicants commonly default to AP-42 emission factors to net out of NSR review, to establish emissions limits, and to determine compliance.[157] Due to the absence of appropriate emissions factors for refinery boilers and heaters, misuse of the limited emissions factors is widespread. The Protocol should clearly require direct measurement of refinery boiler and heater emissions unless a stack test (if CEMS are not available) is physically impossible due to a valid constraint (i.e. access or safety issue).

A. The Protocol should rank the stack test method to develop unit-specific emissions factors ahead of the method that includes a single stack test of three runs during normal operating conditions and establish clear criteria for all stack tests.

The Protocol describes two stack testing methods to develop unit-specific emission factors for combustion sources: (1) the usual single test at normal operations consisting of three test runs and (2) the development of a correlation between emission factor and heat input to account for fluctuations in emissions when load varies.[158] The Protocol does not indicate any preference among these two. We believe the latter should be the preferred method.

A single stack test is nothing more than a 3-hour snapshot of emissions. A test conducted at normal operating conditions may underestimate CO and VOC and overestimate NOx emissions at lower loads and during startup and shutdown. Stack tests are typically conducted following maintenance under carefully controlled conditions to minimize emissions. They are frequently preceded by pretests. A single stack test should not be used to estimate emissions for any purpose unless it can be demonstrated that it represents the full range of operating conditions. At a minimum, a relationship between emissions and heat input should be developed from stack tests conducted at 25%, 50%, 75%, and 100% load. This relationship should then be used with heat input data, which is available for most all refinery combustion sources, to calculate emissions for the desired time period.

In addition, EPA should establish clear criteria for stack tests. These should include: (a) prohibition on pre-testing; (b) prohibition on pre-testing maintenance; (c) testing at all loads; and (d) an on-site independent observer for the duration of the test. These criteria will help ensure that stack test data reflects actual emissions.

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[155] Protocol, tbl. 4-1.

[156] Protocol, 4-1 to 4-11.

[157] See, e.g., Ind. Dep't of Envtl. Mgmt., Technical Support Document for Part 70 Permit for BP Products North America Inc., Whiting Business Unit (No. T089-6741-00453) tbl. C-1 & C-5 (May 1, 2008).

[158] Protocol, 4-10 to 4-11.

B. The Protocol should include emissions factors that account for the composition of different refinery fuels and combustion conditions.

The Protocol recommends the use of AP-42 natural gas boiler emission factors for refinery heaters and boilers that fire different fuels when direct measurements are not available.[159] However, most fired sources in refineries are heaters, with a few boilers mixed in. Most of these fire refinery fuel gas. AP-42 does not contain any emission factors for heaters and boilers fired on refinery fuel gas. This absence of appropriate emissions factors allows applicants to cherry pick among site-specific stack tests and emissions factors to net out of NSR review or to obtain artificially high permit limits.

Emissions from fired sources depend upon the composition of the fuel that is fired.[160] The emission factors recommended in the Protocol are for natural gas, which is not widely used in refineries. Combustion sources in refineries most commonly fire left over process gases, blended with natural gas to increase the heat content. The composition of these gases is highly variable.[161] Refinery fuel gases, for example, have much higher sulfur content, higher nitrogen content, higher hydrogen content, can contain elevated concentrations of CO, and have a higher heating value than natural gas.[162] Some heaters, for example, may use CO-rich regenerator fuel gas as a fuel, which is distinct from natural gas. The impact of these differences on emissions depends upon many factors including specific chemical composition of fuel, type of burner, type of heater, pollution controls, and use of air preheat (common in refineries). These factors may cause higher emissions of SO_2 and $PM_{10}/PM_{2.5}$ and lower emissions of NO_x,[163] VOC (due to higher flame temperature) and CO (due to presence of high concentrations of hydrogen) than firing an equivalent amount of natural gas.[164]

Refinery combustion sources may also burn fuel oil, natural gas, and coke. For fuel oil and natural gas, the refinery section of AP-42 directs the user to Section 1.3, Fuel Oil Combustion, and Section 1.4, Natural Gas Combustion. These two sections only contain emission factors for boilers and have not been updated since 1998. AP-42 contains no emission factors for coke from any type of combustion source.

Furthermore, the AP-42 natural gas emission factors recommended in the Protocol are for boilers, while most combustion sources in refineries are heaters. The combustion conditions within a refinery heater are significantly different from boilers and thus would not be expected to have similar emissions.[165] AP-42 does not contain any

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[159] Protocol, 4-11.

[160] The John Zink Combustion Handbook, supra note 151, at ch. 6.

[161] Id. at 163,,tbl. 5.6, 446, tbl. 14.4.

[162] Id. at.159, 160, 446.

[163] Theresa J. Takacs, Dennis L. Juedes, & I.D. Crane, Method Estimates NOx from Combustion Equipment, 102 Oil & Gas J. 48 (June 21, 2004)

[164] Id.

[165] California Air Resources Board (CARB), Technical Support Document for A Suggested Control Measure for the Control of Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial

emission factors for any combustion source fired on refinery fuel gas or coke or any heater fired on any fuel. These are serious omissions that the Protocol fails to address. The Protocol should be revised to include refinery fuel gas specific emission factors for refinery heaters and boilers.

C. The Protocol should prohibit the use of natural gas boiler emissions factors for refinery boilers and heaters that do not use natural gas.

As explained above, AP-42, the most widely used source of refinery combustion emission factors, does not contain any emission factors for heaters nor the fuels most commonly fired at refineries. This situation is widely exploited to net out of NSR review, obtain generous emission limits, and to determine compliance. The AP-42 natural gas emission factors, for example, underestimate NOx and CO emissions, the two pollutants emitted in the largest amounts from combustion sources, from refinery heaters.

The Protocol did not review other collections of emission factors for these refinery sources. The American Petroleum Institute studied NO_x emissions from these sources in 1979.[166] The API study demonstrated that NO_x emissions from process heaters are highly variable and depend on the degree of air preheat. Two average emission factors were reported, one for natural draft heaters (0.14 lb/MMBtu) and one for mechanical draft heaters (0.26 lb/MMBtu). The higher factor for mechanical draft heaters reflects the fact that the majority of refinery mechanical draft heaters have air preheaters.[167]

In comparison, the AP-42 natural gas emission factor for pre-NSPS boilers, widely used for these heaters, is 0.275 lb/MMBtu. About 90 percent of heaters in oil refineries are natural draft, 8.0 percent are forced draft with no air preheat, and 2.4 percent are forced draft with air preheat.[168] Thus, the AP-42 emission factor significantly overestimates NOx emissions for most refinery combustion sources.

This API data has been analyzed by both the EPA[169] and the California Air Resources Board (CARB)[170] with the same result. Further, EPA's Factor Information Retrieval (FIRE) database includes the 0.14 lb/MMBtu factor from the original API study

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Boilers, Steam Generators and Process Heaters, April 29, 1987; The John Zink Combustion Handbook, supra note 151, at ch. 1, 6.

[166] S.C. Hunter and S.S. Cherry, NOx Emissions from Petroleum Industry Operations, KVB, Inc. for the American Petroleum Institute, API Publications 4311, October 1979 as cited in: California Air Resources Board (CARB), Statewide Technical Review Group, Technical Support Document for a Suggested Control Measure for the Control of Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators and Process Heaters, April 29, 1987 (CARB 1987).

[167] CARB, supra note 165, at fig. VII–6, VII–7.

[168] The John Zink Combustion Handbook, supra note 151, at 11.

[169] R.J. Tidona, H.J. Buening, & J.R. Hart, U.S. Envtl. Prot. Agency, EPA-600/S7-81-169, Emissions from Refinery Process Heaters Equipped with Low-NO_x Burners (Aug. 1982) (This report explains all of the prior field test work, such as the API study, was conducted on heaters equipped with conventional burners); Emissions Standards Division, U.S. Envtl. Prot. Agency, Report EPA-453/R-93-034, Alternative Control Techniques Document – NO_x Emissions from Process Heaters (Revised) , fig. 4–6, 4–7 (Sept. 1993).

[170] CARB, supra note 165, at fig. VII–6, VII–7.

and subsequent EPA and CARB studies for NOx emissions from refinery fuel gas fired heaters. Thus, the Protocol should be revised to acknowledge this refinery fuel gas combustion source emission factor and rank it higher than AP-42 factors.

CO is similar. Refinery fuel gas typically has much more hydrogen than natural gas. Higher concentrations of hydrogen generally produce less CO.[171] Thus, CO emissions from refinery fuel gas fired heaters are typically lower than from natural gas fired sources. We have reviewed many stack tests for refinery sources. Table 1 compares the AP-42 natural gas emission factor with results of 30 stack tests from the State of Washington for BP's Cherry Point Refinery.[172] These stack tests show that CO emissions from refinery fuel gas fired heaters and boilers are much lower than the AP-42 natural gas fired boiler emission factor widely used in permitting.

Table --
CO Stack Tests
At BP's Cherry Point Refinery
Washington
(lb/MMBtu)

Unit	**Date**	**CO**
Boiler 5	7/04	0.028
Vacuum Heater	11/03	0
Boiler 5	8/05	0.057
Isom Heater	11/06	0.005
Boiler 5	8/06	0
DHDS Charge Heater	8/06	0.005
Boiler #5	7/07	0.022
DHDS Charge Heater	10/07	0.006
Reformer Charge Heater	9/07	0.0002
Reformer Charge Heater	9/07	0.0013
Isom Heater	8/07	0.0013
Coke Charge Heater	9/07	0
DHDS Heater	1/08	0.0006
DHDS Heater	8/08	0.010
Boiler #5	10/07	0.054
Isom Heater	9/08	0.0097
AP-42		**0.082**

In sum, AP-42 natural gas emission factors underestimate NOx and CO emissions from refinery fuel gas fired sources. This underestimate can be exploited in permitting to obtain artificially high permit limits or to net out of NSR review by claiming large emission reductions that do not exist. For example, in a NSR netting analyses, a

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[171] The John Zink Combustion Handbook, supra note 151, at 215.
[172] Northwest Clean Air Agency, Cherry Point Stack Test Result.

permittee could use an AP-42 emission factor for sources they propose to shutdown, which shows artificially high emission reductions, with a stack test for modified units, which shows artificially low net increases. This games the system, allowing the applicants to cherry pick from stack tests in their files and inappropriate AP-42 emissions factors. The Protocol should put an end to this practice by prohibiting the use of AP-42 natural gas boiler emissions factors for refinery boilers and heaters that do not fire natural gas and including new emissions factors that account for fuel gas composition and combustion conditions.

VI. SECTION 5: DELAYED COKING UNITS

A delayed coking unit, the most common type of coker in the U.S., converts heavy residuals into lighter products. There are six sources of emissions from the delayed coking process: (1) coker heaters; (2) coker steam vent; (3) coke drum decoking; (4) coke water handling; (5) equipment leaks (e.g., valves, connectors, seals); and (6) coke handling. The coker area, which includes the coker itself, the supporting vacuum unit, and coker water pond, can account for over 20% of the VOC emissions from a petroleum refinery.[173] The coker area is also a major source of benzene, a potent carcinogen.[174] Thus, it is very important that coker area emissions be accurately estimated when not directly measured.

Emissions from coker heaters and equipment leaks are estimated using the procedures discussed in Protocol Sections 4 (Combustion Sources) and 2 (Equipment Leaks) and are not further discussed here. The Protocol proposes the first ever emission factors for coke unit vents (Sec. 5.3), a procedure to estimate emissions from coke water handling (Sec. 7.2.5), and some default assumptions for particulate matter emissions from coke handling (Sec. 11).[175] These are steps in the right direction. These are important sources of emissions and should be included in emission inventories, netting analyses, and limited in permits. However, we believe improvements are possible.

A. EPA should revise the coker steam vents emissions factors to account for all available stack tests, emissions variability during the venting process and as a result of vent pressure, and all pollutants emitted.

At the end of each coking cycle, the drum is steam stripped, cooled, and the gases sent to a blowdown system to recover liquids. Near the end of this process, when the pressure drops to the operating pressure of the gas recovery compressor, the blowdown system is vented to the atmosphere through a steam vent. These emissions are variously called coker steam vent emissions or coker depressurization emissions. We call them steam vent emissions in this section. The gases exiting the vent contain PM, PM_{10}, PM2.5, CO, VOCs, and a variety of sulfur compounds including H_2S.

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[173] Spectrasyne, supra note 12, at 22-23.

[174] Allan K. Chambers et. al., Direct Measurement of Fugitive Hydrocarbons from a Refinery, 58 J. of the Air & Waste Mgmt. Ass'n, 1047 (2008); Allan Chambers et. al., supra note 4.

[175] Protocol, 5-12–5-13.

The Protocol recommends emission factors for the coker steam vent for 29 constituents.[176] The Protocol reports that these emission factors are based on four stack tests conducted by the South Coast Air Quality Management District (SCAQMD) and one test conducted by URS for the EPA pursuant to a Section 114 request (Hovensa). The supporting Excel spreadsheet that we obtained from EPA indicates that an additional test at Citgo was included, but not mentioned in the text nor cited in the references. We believe the twenty-nine emissions factors are a very important step in the right direction, and we strongly support the development of emissions factors for all steps in the coking process. However, EPA should revise the coker steam vent emissions factors to account for all available stack tests, emissions variability during the venting process and as a result of vent pressure, and all pollutants emitted. Our comments are based on supporting data we obtained from EPA.[177]

Incomplete Emissions Data

The stack test data that EPA relied on to develop these emissions factors is incomplete. We are aware of other stack test data for coker steam vents, including two separate tests at Valero Wilmington (an initial with an alleged leaking valve and a retest),[178] one at BP Carson,[179] and a 2009 retest at Exxon/Mobile. Further, EPA has issued Clean Air Act Section 114 requests for information requiring coker steam vent emissions. EPA relies on the tests produced under this request for the Hovensa Refinery in the Virgin Islands and the 2008 test at the Citgo Corpus Christi Refinery, but does not appear to have included the 2007 tests at the Citgo refinery.[180]

Furthermore, steam vent emissions have been measured in three DIAL studies: one in Canada,[181] one at the BP Texas City Refinery,[182] and most recently at the Shell Deer Park Refinery. These tests suggest that coker steam vent emissions are much higher than the proposed emissions factors suggest. There may also be other test data that we are unaware of. Thus, the Protocol should revise its emissions factors to account for all coker steam vent emissions data.

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[176] Protocol, tbl 5-5.

[177] E-mail from Brenda Shine, U.S. Envtl. Prot. Agency, to Jennifer Peterson, Staff Attorney, EIP (March 23, 2010) (on file with author). The next draft of the Protocol should include this very helpful spreadsheet as an appendix.

[178] Southern Cal. Air Quality Management District, Source Test Report 06-250 Conducted at Valero (Ultramar) Refinery - Particulate Matter (PM), Volatile Organic Compounds (VOC), Speciated Hydrocarbons, Aromatic Hydrocarbons, and Sulfur Compound Emissions from a Coke Drum During the Steaming and Venting to Atmosphere Phases (July 22, 2008).

[179] Southern Cal. Air Quality Management Distirct, Source Test Report 06-249 Conducted at BP/ARCO Refinery - Particulate Matter (PM), Volatile Organic Compounds (VOC), Speciated Hydrocarbons, Aromatic Hydrocarbons, and Sulfur Compound Emissions from a Coke Drum Steam Vent (Feb. 20, 2008).

[180] URS Corporation, Source Test Report of the Coker Steam Vent for Non-Methane and Non-Ethane Volatile Organic Compounds, Prepared for CITGO Refining and Chemicals Company LP tbl. 2–7 (Apr. 25, 2008).

[181] Allan K. Chambers et. al., supra note 4.

[182] Robinson et. al., supra note 51.

Test Duration

The venting process can last up to 6 hours. Emissions are released to the atmosphere throughout this period, with the flow rate generally declining over time, but concentrations remaining stable or spiking throughout the duration.[183] The four South Coast Air Quality Management District (SCAQMD) stack tests that the Protocol relied on lasted 5 to 60 minutes and did not capture the entire duration of any of the events. The Hovensa stack tests, on the other hand, lasted 73.4 to 354 minutes and captured the entire venting cycle. The goal of the Citgo test was to capture the entire cycle, but it fell short. The Protocol averaged the results from the four SCAQMD tests and the Citgo test, which do not include the entire venting cycle, with the Hovensa tests, which captured the entire event, without adjusting for vent cycle duration. This underestimates emissions. The subject test results and sampling times are summarized in Table 1.

Table 1
Coke Drum Depressurization
VOC Emissions
Based on Protocol Stack Tests

Test	VOC Lb/Cycle	Test Duration (min)
ConocoPhillips	NR	5
Chevron	11.16	60
ExxonMobil	1.38	11
Shell	5.3	60
Hovensa		
6/3/08	165	258
6/4/08	354	175
6/6/08	73.4	142
6/8/08	123	174
Citgo		
2/24/08	163	42
2/26/08	9.58	46
Protocol	**57**	

Considering only the tests relied on in the Protocol, the average VOC emissions of the South Coast Air Quality Management District (SCAQMD) tests is 5.9 lb/cycle, where the cycle is partial, while the average of the Hovensa tests is 179 lb/cycle and the average of Citgo is 86.3 lb/cycle. Thus, by averaging together the SCAQMD, the Citgo, and Hovensa tests, the higher values for Hovensa, based on the complete venting cycle, are diluted by the incomplete SCAQMD and Citgo tests.

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[183] See Hovensa and Citgo Coker Vent Tests.

The Protocol's coker steam vent emissions factors should only be based on tests that capture the entire venting episode, which would be the Hovensa test, or partial cycle tests adjusted to account for the entire cycle. The SCAQMD and Citgo tests should be excluded from the average, unless the venting duration can be ascertained and the short-term measurement can be reasonably extrapolated to the entire event based on a careful analysis of the Hovensa test. Further, the Citgo test only sampled one of two carbon steel pipes that comprise the coker vent and experienced testing problems with a shepherd's hook probe apparatus.[184] In our opinion, the only representative coker vent test among those considered is the Hovensa test. This test shows that coker vent emissions are much higher than the proposed emission factors in Protocol Table 5-5.

Units of Measure

The emissions are reported as pounds "per cycle." A "cycle" is not defined in the Protocol. It is not obvious from the Protocol whether "cycle" corresponds to the length of time that the test was conducted or assumes an adjustment to a prescribed duration, such as 2 hours. This is important to clarify. As noted above, if venting occurred for 2 hours, for example, and the test lasted only 5 minutes, the emissions should be increased to account for the entire duration. Alternatively, the short-term test should be rejected as not representative of the entire venting cycle.

The coker emissions spreadsheet provided by EPA indicates that "cycle" is the duration of testing, not venting. The duration of venting is an inappropriate metric for reporting coker venting emissions as the cycle time will vary from coker to coker depending on throughput, number of drums, drum size, etc. Pounds per cycle is a reasonable measure for a single coker at fixed operating conditions, but should not be extrapolated to other cokers without considering important operating parameters. The Protocol admits that emissions ultimately depend on the coking vessel void volume, time steaming occurs before venting, initial vent pressure, and the temperature inside the drum at the start of venting. The Protocol argues that these variables are relatively constant and that available data does not allow correlations that account for different process variable.[185] We disagree.

First, the Protocol did not consider all available data. The available data shows emissions are not relatively constant across these variables. The Hovensa test, for example, contains sufficient data to establish a correlation between vent pressure and emissions. Further, the EPA and some state agencies apparently have enough data to set permit limits on coker vent pressure (i.e. SCAQMD and Michigan). Thus, at a minimum, the Protocol should establish a correlation between emissions and vent pressure.

Second, we note that other metrics could be used to develop emission factors for coker steam vent emissions, including pounds per ton of coke or pounds per barrels of throughput. We agree that many factors can affect the magnitude of these emissions, such as coker feed composition, coker throughput, and coker operating conditions.

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[184] Citgo Coker Vent Test, 1-5, 1-7.

[185] Protocol, 5-12–5-13.

However, this is true for any emission factor. An emission factor is a compromise in the face of inadequate test data. Generic emission factors should be expressed in a format that is consistent with standard refinery AP-42 emissions factors, which report emissions per unit of throughput.[186]

Pollutants Omitted

The Protocol reported emission factors for 29 pollutants.[187] However, this list does not include several regulated under the Clean Air Act - PM10, PM2.5, H2S, and total reduced sulfur (TRS). It also omits some HAPs that have been detected in the various tests, such as carbazole, dibenz(a,h)anthracene, and dibenzofuran.[188] The Hovensa tests, for example, measured PM emissions of 61.6 lb/cycle (30.7 - 95.8 lb/cycle)[189] and H2S emissions of 90.2 lb/cycle (13.1 - 150 lb/cycle),[190] emissions that are much higher than for any other pollutant, except methane. Particulate matter and H2S have also been detected at high concentrations in SCAQMD tests, including those conducted at BP/ARCO, Valero, and ExxonMobile. These and other omitted pollutants should be added to the Protocol.

B. The Protocol should provide guidance on estimating emissions for all sources of emissions from the delayed coking process.

Decoking

After the drum is depressurized, the coke is cut out of the drum by drilling with high-pressure water. The drilled coke drops into a pit or pad beneath the coke drum where the free water is separated from the coke. The water is recycled. Vapors and particulate matter fly everywhere when cokers are not enclosed, which is the vast majority of them. The Protocol correctly notes that "fugitive emissions are also released from the delayed coking unit when the coke drum is opened and the coke is cut from the drum." The emissions are released from the top and bottom of the coke drums and from the pit or pad beneath the coker where the coke accumulates. The Protocol goes on to explain, correctly, that "hydrocarbons that were retained in the internal coke pores will be released into the atmosphere." However, the Protocol does not review the relevant literature and offers no guidance on how to estimate these decoking emissions, nor does it acknowledge that pollutants other than hydrocarbons are emitted.[191]

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[186] See, e.g., AP-42, Section 5.1, Petroleum Refining, Table 5.1. This table, for example, expresses emission factors for many similar units in pounds per 1000 barrels of feed ($lb/10^3$ bbl) or pounds per thousand cubic feet ($lb/10^3$ ft^3). See also AP-42, Section 6.1, Carbon Black, a similar process. Table 6.1-2 reports emissions for this industry in units of pounds of pollutant per ton of carbon black.

[187] Protocol, tbl. 5-5.

[188] Hovensa Stack Test, tbl. 2-23.

[189] Hovensa Stack Test, tbl. 1-4.

[190] Email from Christopher Colman, Hess, to Brenda Shine, EPA, (Oct.1, 2008), attaching H2S data from the June 2008 Hovensa stack test, In: Subpart Ja Docket, EPA-HQ-OAR-2007-0011.

[191] Protocol, 5-12 to 5-13.

Decoking VOC emissions have been measured in at least one and perhaps two other studies using optical remote sensing: (1) at a refinery in Canada; (2) at the BP Texas City Refinery; and (3) at the Shell Deer Park Refinery. The only completed study is the Canadian study, which shows that decoking is a major source of VOC emissions.[192] Our analysis of the Canadian study indicates that for every 1,000 barrels of coker feed, about 20 pounds of VOCs are emitted during each hour of drilling. Decoking typically lasts 2 to 5 hours. The Protocol should include a critical review of these studies and provide guidance on estimating emissions from the decoking process.

Other pollutants, besides the hydrocarbons and benzene[193] measured in Canada, are emitted during decoking, including PM, H2S, and HAPs. We are not aware of any similar studies that quantify these and other emissions from decoking. However, based on observation and an understanding of the drilling process, at least H2S and PM emissions are significant and should be quantified. Thus, the Protocol provide guidance on estimating emissions for VOCs, PM, PM10, PM2.5, H2S, and HAP emissions.

Coke Handling Fugitives

After the coke is separated from free water in the pit or pad beneath the coker, it may be transferred to a temporary storage pile to further dewater before it is moved to a crusher and then to a terminal storage pile. From the terminal pile, it is loaded into ships, railcars, or trucks for conveyance to market. These operations—crushing, conveying, dropping, wind erosion of the storage piles—are addressed in AP-42. The Protocol generally mentions these "handling" operations and refers the user first to AP-42, Section 10,[194] and then later, to Section 13 to estimate fugitive particulate matter emissions.[195]

The Protocol makes some coke-specific recommendations as to which variables to use when calculating PM emissions using equations in AP-42 Section 13 (i.e. silt content, moisture content), and proposes emissions estimation methods for PM only. However, the coke that is moved from the pit/pad to the storage pile and transport vehicles contains VOCs trapped in its pores. These are released to atmosphere when the coke is disturbed (i.e. when it is dropped or scooped up).[196]

Drop Emissions

The coke is scooped up by front end loaders and cranes at various points and dropped onto piles or into the crusher. AP-42 contains a generic equation for drop

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[192] Allan K. Chambers et. al., Direct Measurement of Fugitive Hydrocarbons from a Refinery, 58 J. of the Air & Waste Mgmt. Ass'n, 1052, tbl. 3 (2008)

[193] Nettles, supra note 18, app. C ("The DIAL measured 1.5 to 2.1 lb/hr of benzene emissions during the decoking process.").

[194] Protocol, 5-13.

[195] Protocol, 10-1.

[196] Remote Sensing of Emissions, supra note 18, at 16 ("Undisturbed coke storage on site has not been seen to give rise to large emissions, but as soon as the coke is disturbed and new surfaces are exposed, emissions arise.").

emissions.[197] This equation likely underestimates coke drop emissions. This equation is appropriate only for drops of single loads onto a flat surface or drops onto a surface that is continuously moving away the formerly dropped material, as a conveyor would. Coker fugitives involve prolonged dumping of very large amounts of material on top of previously dumped material. This dumping atop dumping suspends coke particles and aerosols that are not considered in the AP-42 drop equation. Thus, the Protocol should address the applicability of this equation to the unique situations in a coke yard.

Coke Yard

The coke yard, where the material handling operations occur, is generally covered with a layer of coke dust. This area is subject to wind erosion emissions if not completely enclosed. The layer of coke would increase emissions from material handling operations, such as front end loader trips, truck trips, and drop emissions. These increased emissions are not considered by the AP-42 equations nor the default variables recommended in Protocol Table 10-1. The Protocol should be revised to require site-specific silt testing for any calculation that requires silt content. Silt testing methods are set out in AP-42, Appendix C.1. These tests are quick and easy to perform. Further, the Protocol should address wind erosion emissions from heavily loaded areas in the emission calculations.

Moisture Content

The drop operations, discussed above, require moisture content. The Protocol recommends a default moisture content of 30% for coke drops.[198] This is not reasonable for all coke drop operations (i.e. pit to temporary pile, pile to crusher, crusher to terminal pile, terminal pile to truck). While 30% moisture content may be reasonable for the initial drop (i.e. coker to receiving pit/pad), this default value is too high for subsequent drops (i.e. after the coke leaves the pit/pad).

Further, a film of coke dust forms on the surface of storage piles, on the surface of working areas and roadways, and on the sides of trucks and railcars. This layer of dust is exposed to winds, drops, and other handling operations unless disturbed. This layer has much lower moisture content than the 30% recommended as a default in the Protocol. The Protocol should include site-specific surface moisture measurements for emission calculations.

Control Efficiency

Facilities that use the AP-42 fugitive emission equations to estimate material handling emissions typically apply a control efficiency to the final calculation to account for measures such as sweeping, watering for dust control, truck washing, truck covering, and various types of enclosures. These control efficiencies are generally unsupported and excessively high, ranging from 90% to 99%, underestimating emissions from these

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[197] EPA, AP-42, supra note 20, at 13.2.4-4.

[198] Protocol, tbl. 10-1.

sources. The Protocol should include default control efficiencies for material handling operations by type of measure and for the most common combinations of measures. The defaults should be at the lower end of the reported range, unless support is provided for a higher value.

Uncovered Vehicles

Wind erosion emissions from the bed of front-end loaders, crane buckets, trucks, conveyors, and railcars can be major source of fugitive PM emissions. They are a common source of nuisance complaints in communities. The Protocol and AP-42 do not address these emissions. The Protocol should provide guidance on how to estimate these emissions.

Conclusion

We strongly support EPA's efforts to improve the accuracy of reported refinery emissions. With respect to storage tanks, flares, combustion sources, delayed coking, and equipment leaks, the Protocol is inadequate and does not (1) provide guidance on the use of remote sensing technologies to measure emissions or a critical review of the extensive remote sensing data available; (2) refine or revise inaccurate emissions factors or even disclose potential bias in these emissions factors; or (3) provide guidance on estimating emissions for all sources. While the Protocol is a significant step in the right direction, the Protocol generally appears to simply provide a summary of the existing inaccurate refinery emissions estimation methods that can dramatically undercount emissions of air pollution.

Thank you for considering our comments.

Respectfully Submitted,

Jennifer Peterson

Jennifer S. Peterson
Attorney
Environmental Integrity Project
1920 L Street NW, Suite 800
Washington, DC 20036
(202) 263-4449
jpeterson@environmentalintegrity.org