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October 28, 2014

U.S. Environmental Protection Agency
WJC West Building (Air Docket), Room 3334
1301 Constitution Ave., NW
Washington, DC 20004

Attention: Docket ID Number EPA–HQ–OAR–2010–0682
submitted via regulations.gov

Re: **Environmental Protection Agency's (EPA's) "Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards: Proposed Rule" at 79 Fed. Reg. 36880 (June 30, 2014).**

To Whom It May Concern:

The American Petroleum Institute (API) and the American Fuel and Petrochemical Manufacturers (AFPM) submit the attached comments on the Environmental Protection Agency's (EPA's) "Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards: Proposed Rule" at 79 Fed. Reg. 36880 (June 30, 2014).

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

AFPM is a national trade association representing more than 400 companies, including a majority of all U.S. refiners and petrochemical manufacturers. AFPM members operate 120 U.S. refineries comprising more than 95 percent of U.S. refining capacity.

Air quality in the United States has improved significantly, continues to improve, and the U.S. oil and natural gas industry has been a key part of that improvement, investing over $268 billion since 1990 toward improving the environmental performance of its products, facilities and operations. In the year 2012 alone, approximately $14.9 billion was expended on environmental protection.

Together, EPA and industry have invested significant time and resources into laying the foundation to inform this rulemaking. Industry aided the development of EPA's refinery information collection protocol and spent tens of millions of dollars in response to a Section 114 Information Collection Request, which collected entire emission inventories from all U.S. refineries and required emission source testing at numerous sites. Those efforts informed EPA's very comprehensive modeling of all air emission sources at refineries that conservatively concluded that the public health is protected with an ample margin of safety. It is in our joint interest to finalize a rule that achieves environmental protection while protecting the competitiveness of U.S. refining. However, this proposal includes requirements that impact every aspect of refining, most of which provide no real benefits at enormous costs, and some of which increase safety and operating risk and even some emissions.

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To respond to this proposal, we have conducted extensive analyses and are submitting hundreds of pages of technical comments on all aspects of this expansive and complex rulemaking. The Agency has proposed rule changes that have implications for our operations that are far more extensive and costly than the Agency anticipated. To address these concerns and adequately fulfill the Agency's statutory obligations, we strongly urge that the Agency take the time to thoroughly and comprehensively respond to our comments prior to completion of a final rule.

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EPA has proposed, in one administrative package, significant and precedent-setting changes to two of the major rules that apply directly to refineries -- part 63 subpart CC (RMACT 1) and part 63 subpart UUU (RMACT 2). At the same time, EPA is implementing a policy and regulatory framework in response to the *2008 Sierra Club* court decision, which overturned the generic startup, shutdown, and malfunction exemption in part 63. Although this rulemaking package applies only to refineries, EPA proposes certain changes that cut across other regulations and create far reaching precedents for future rulemakings involving many NSPS and NESHAP source categories. In addition, this proposal includes changes to part 60 subpart Ja, part 61 subpart FF, part 63 subparts R and Y, and two new methods proposed for addition to part 63 Appendix A. We are extremely concerned that, with this proposal, EPA adds to the list of new regulations impacting refineries; these regulations come with enormous costs and downsides but questionable environmental benefits.

In many instances, EPA has not met all the requirements to sufficiently justify its proposals. EPA has not provided any information in the docket regarding the significant costs associated with many of the controls that would clearly be necessary to meet the proposal. EPA has not provided any data to support some EPA assertions that precedent-setting program enhancements are possible or cost-effective.

EPA needs adequate time to address these comments.

EPA is under a court-ordered deadline to finalize this rule by April 17, 2015. However, that deadline only applies to the provisions of the rule that are subject to the statutory requirements to conduct the 8-year residual risk and technology review. Yet, EPA has elected to propose significant changes in this rule that go beyond this obligation. It is these additional requirements that give rise to a majority of industry concerns. To address the expansive requirements that go beyond this obligation, EPA may need to renegotiate an extension to the deadline to allow adequate time to address substantive comments, such as those contained in this comment package.

EPA needs to address the many substantive issues raised in these comments.

Our industry is vital to the economic strength of our nation. We are committed to continue to work constructively with EPA to identify common sense solutions to these issues so that we may continue protecting our workers and the communities in which we operate. Unfortunately, this proposal would add to the list of new regulations impacting refineries that come with enormous costs and downsides, providing little, if any, environmental benefits. In fact, the following examples demonstrate the unacceptable outcomes if the rule, as proposed, were implemented.

- The proposed ban on releases from atmospheric relief valves and the broadening of the applicability of the flare limits on tip velocity and visible emissions will require the construction of hundreds of new flare systems, in direct conflict with EPA, industry, and the public's shared goal to reduce flaring, greenhouse gas and criteria pollutant emissions. We do not believe EPA envisioned or intended this outcome. This result stems from EPA's failure to 1) use its authority to identify feasible alternative standards impacting critical safety equipment as a result of the agency's mis-application of the 2008 *Sierra Club* decision, and 2) recognize that certain historical flare combustion efficiency standards are no longer relevant based on new data and an improved understanding of flare operations.

- The industry has worked in good faith with the Agency for years to reduce flaring, and more recently to ensure high flare combustion efficiency during periods of flaring. Individual companies have spent hundreds of millions of dollars to install flare gas recovery and flare minimization systems that have greatly reduced flaring events, and with the new flare test data have taken actions to reduce the potential to over-steam their flares. These accomplishments should be recognized as the environmental success that they are. Unfortunately, the proposed rule does not recognize these improvements but rather continues to pile on additional control and monitoring requirements and standards far in excess of what is necessary to address any remaining concerns about excessive steam usage. In addition, EPA's overly conservative standards will result in large quantities of unnecessary supplemental gas being burned. This is wasteful of natural resources and results in an increase in greenhouse gas and criteria pollutant emissions.

- EPA has proposed numerous requirements without identifying or justifying the legal bases for its actions or presenting emission, burden, and cost analyses for comment. For example, while nowhere supported in the record, the Agency has proposed a ban on flaring halogenated compounds. This ban will require the construction of dozens, if not hundreds, of standby emergency-use scrubbers. These will be large-capacity units that must be maintained in a ready mode in case of a rare emergency. EPA must provide the regulated community with sufficient statutory, regulatory, and technical information upon which to comment. A number of these new requirements are claimed to be necessary to improve compliance assurance yet the Agency has not produced any data to support additional control for these hypothetical, and rare, refinery operating scenarios.

- In evaluating the cost-effectiveness of new limitations on vents from delayed cokers, EPA elected not to consider the full range of installation costs provided by industry. EPA likewise elected not to utilize the cost information upon which it based the recent NSPS Ja delayed coker vent limit. Rather, EPA based its analysis on the lowest cost installation. As a result, EPA has proposed standards for existing delayed coker units that are unjustifiably more stringent than those EPA recently established for new, modified, and reconstructed units under NSPS Ja. Not only has EPA failed to perform a proper cost analysis, but the Agency has created the potential to disrupt efforts to comply with the NSPS Ja rule and result in stranded investments, which is very bad policy.

- The proposal contains infeasible compliance dates for many items. A number of requirements that require significant capital investment become effective upon finalization of the rule, and no time is provided to deal with the extensive initial burdens and permitting imposed by the broad rule modifications.

- The proposal establishes a de facto ambient air benzene limit through the proposed fenceline monitoring program, although such limits are not authorized by Section 112 of the Clean Air Act (CAA). The limit is enforced through the imposition of an open-ended corrective action requirement, with no limits on cost or feasibility, and nothing to limit the corrective action to facilities under the control of the refinery. Moreover, the proposed level of the standard has not been demonstrated to correlate with refinery emissions it purports to monitor, nor has it been adjusted for measurement and operating variability.

In conclusion, this significant Agency action will cost our industry well in excess of $20 billion in new facilities plus tens of millions in annual operating costs, increase safety risk and emissions, impact U.S. fuel supplies, create significant precedent for regulated industries beyond refineries, and achieve little if any reduction in emissions. Even without requirements that would result in the addition of hundreds of new flare systems and standby scrubbers to refineries nationwide, the cost of this proposal will still significantly exceed the $100 million per year threshold for major and significant actions. As such, the EPA must meet all of the requirements imposed on such rulemakings by a variety of laws and Executive Orders.

To that end, we again strongly urge the Agency to review the attached analyses and address the many substantive comments contained therein. If EPA needs to renegotiate the timing of the finalization of this rulemaking to address these and other comments, it should do so expeditiously. Our industry remains committed to working constructively with the Agency on developing a common-sense approach toward continued environmental protection, but this objective is unlikely to be achieved if EPA rushes to meet the existing deadline without significantly revising the proposal.

We appreciate your consideration of our concerns. If you have any questions, please contact me at 202-682-8319 or toddm@api.org.

Sincerely,

/s/

Matthew Todd

Attachments

cc Peter Tsirigotis, US EPA
Penny Lassiter, US EPA
Brenda Shine, US EPA

American Petroleum Institute
And
American Fuel and Petrochemical Manufacturers
(API/AFPM)

Comments on
EPA's "Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards: Proposed Rule"
79 Fed. Reg. 36880 (June 30, 2014)

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Executive Summary

Overarching Comments

1. ***<u>EPA should finalize only those aspects of this proposal that address identified risk concerns or that are demonstrated to be cost-effective technology developments.</u>***

EPA's conservative and multi-faceted risk analysis concluded that communities surrounding refineries are protected with an ample margin of safety, leading EPA to propose an acceptable risk designation. In spite of this conclusive risk finding, EPA has proposed many changes to RMACT 1 and 2 that do not meet statutory criteria, are not cost effective, and provide little if any environmental benefit.

Furthermore, the bulk of the costs of this rule will be borne by the large proportion of refineries where the risk is extremely low. In fact, the majority of the reduction in risk comes from just a handful of sites. Yet, the revisions will apply to all major source refineries. Failure to fully consider the costs and impacts of proposed amendments that have no risk impact on the majority of refineries is a fundamental flaw in EPA's approach to this rulemaking.

For each U.S. refinery, EPA conducted source category and facility-wide residual risk assessments that provide conservative estimates of both chronic and acute maximum individual risk posed by emissions of HAP. The potential for both cancer and non-cancer effects was modeled, and an evaluation of the potential for adverse environmental effects was also performed. EPA calculated residual risk in a number of ways, including individual and population inhalation risks using both actual and allowable emissions, multi-pathway exposure and risk screening, and environmental risk screening.

EPA's results at every turn demonstrate that category-specific risks at each refinery are below EPA's presumptive limit of acceptable risk (i.e., cancer risk of less than 100 in a million). Based on this finding, EPA concluded that category risks from both actual and allowable emissions are acceptable. EPA then considered whether the existing MACT standards provide an ample margin of safety. EPA proposes that they do, with certain additional applicability thresholds and controls being imposed on storage tanks.

In accordance with the Section 112(f)(2) of the Act, any requirements added to increase the ample margin of safety must be justified taking into consideration costs, energy, safety, and other relevant factors. EPA determined that only these new requirements for storage tanks met these criteria. This was, in most respects, the same conclusion that EPA reached in a 2008 signed final rule that EPA withdrew and did not promulgate.

Under section 112(d)(6), which directs EPA to review standards and revise them "as necessary" to account for developments in technology, processes, or practices where cost-effective, EPA has identified few actual developments to consider. Yet, EPA's proposal treats section 112(d)(6) as a blank check to make large and small unjustified changes throughout these regulations, despite substantial costs and minimal emission reductions. These changes are proposed, in many cases, without any new technology or process developments as required by section 112(d)(6) and without proper consideration for all statutory criteria.

Section 112(d)(2)-(3) authorizes EPA to establish MACT standards for unregulated emission sources. EPA proposes to regulate several emission types on this basis, even though they are currently regulated. For instance, it is proposed to regulate delayed coking unit coke drum vents under this section even though these vents are already regulated as miscellaneous process vents (MPVs) under RMACT 1. Having already met its statutory obligation under Section 112(d)(2)-(3), therefore, EPA must justify any proposed revisions under Sections 112(d)(6) or (f)(2). EPA has not done so.

Against the backdrop of acceptable risk, this rule, as proposed, is estimated to require in excess of **$20 billion in new investment (and well in excess of the $1 billion that would trigger 'significant' rule review even if investments in new flare systems can be avoided)** for minimal reduction in HAP emissions and risk. It will impose significant new cost and operational burdens on the industry, many of which EPA attempts to justify solely on the basis of speculative compliance assurance concerns. Not only has EPA not provided the statutory analysis and record support to justify these new requirements, it has not met its other legal obligations for pursuing a major rulemaking.

References to Detailed Comments: 1.1, 1.2, 2.2.3.1-3, 2.4.1, 2.7.4, Attachment A

2. ***EPA has proposed many amendments for which no legal basis or emission, cost, or burden estimate has been provided for comment. In the absence of a basis upon which the regulated community can provide comment, these amendments cannot be finalized.***

EPA has proposed numerous requirements without identifying or justifying the legal bases for its actions or presenting emission, burden, effectiveness of the control measure, and cost analyses for comment. EPA cannot propose new or revised requirements without providing the regulated community sufficient statutory, regulatory, and technical information upon which to comment.

Examples of these unsupported requirements include: 1) requiring all fuel gas venting to go to flares meeting proposed §63.670 flare requirements; 2) the ban on routing halogenated vents to a flare; 3) requiring flare automatic pilot reignition systems; 4) changing the FCCU PM opacity emission limit to a unit-specific basis; 5) changing FCCU emission limit averaging times; 6) imposing NSPS Subpart Ja opacity limits on FCCUs that use a tertiary cyclone for PM control; and 7) imposing new and revised requirements for existing continuous monitoring systems.

References to Detailed Comments: 1.5, 1.6, 2.7.6, 2.8, 3.2.1, 3.2.2.1

3. ***Misapplication of the 2008 Sierra Club1 decision cannot be used to justify infeasible or impractical requirements on the use of safety equipment***

EPA has misapplied the 2008 Sierra Club decision to justify imposing infeasible standards on safety equipment such as relief valves, flares, and control device bypasses. These critical safety devices are designed to operate with emissions to the atmosphere under emergency or significant process upset conditions. Prohibiting or otherwise limiting the use of this equipment under standards applicable during normal operations is not required by the court decision and will place operators in the position of operating their units in potential non-compliance in order to protect plant personnel, plant equipment, and the community. EPA should propose alternate limits or work practices for this equipment during these situations, similar to the alternative standards provided for periods of startup and shutdown (S&S) of Fluid Catalytic Cracking Units (FCCUs) and Sulfur Recovery Plants (SRPs) where the standards applicable to normal operation cannot be met.

[1] *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008), *cert. denied*, 130 S. Ct. 1735 (2010).

Sierra Club does not prohibit startup, shutdown, or malfunction emissions or even require that a single standard apply at all times. Indeed, Sierra Club stands for the simple proposition that emission limits under Section 112 must be continuous – that is, that there must be an emission limit (which may be numerical or, where the statutory criteria are met, a work practice) during all periods when the source operates.

EPA's decision to disregard emissions during emergency, upset, and malfunction periods and not consider alternative emission standards during such periods represents a failure to implement statutory requirements and is arbitrary and capricious. Failure to account for malfunction emissions, especially in the case of sources that are designed to handle malfunction and upset emissions safely, is also inconsistent with past EPA policy recognizing that emission standards must account for occasional equipment upsets, malfunctions, and uncontrollable events (e.g., weather events). If the standard applies continuously, then EPA must likewise evaluate emissions on a continuous basis, including emissions during malfunctions.

Reference to Detailed Comments: 1.1.1.3, 1.1.4, 2.4.1, 2.7.4

4. ***The proposed amendments must be modified to allow reasonable equipment maintenance, startup, and shutdown (MSS), without imposing delays that impact fuel supplies.***

The Sierra Club decision requires EPA to establish standards to apply at all times, inclusive of periods of non-routine operation such as MSS. In many instances in this proposed rule, EPA has applied standards based on normal operations to MSS periods without demonstrating feasibility, achievability, or acceptable costs and burdens. EPA should propose alternative standards applicable during these periods that minimize HAP emissions in an achievable and practicable manner consistent with the design of the equipment.

Major examples where EPA failed to propose appropriate standards for MSS emissions include the application of emission standards for normal operations to maintenance and clearing procedures associated with miscellaneous process vents (MPVs) and MSS associated with the full range of FCCU and SRP activities.

Reference to Detailed Comments: 1.1.3, 2.1.2, 3.1, 3.4.1

5. ***The extensive changes in monitoring and associated QA/QC requirements need to be justified and adequate compliance time provided.***

Throughout the rule, EPA proposes new or revised continuous emission monitoring system (CEMS), continuous parameter monitoring system (CPMS), and associated quality assurance/quality control (QA/QC) requirements for existing and new monitoring systems to address hypothetical compliance assurance concerns. These new requirements, which will require equipment upgrades and replacements, impose large costs and operational burdens. Yet, EPA has provided little to no analysis of the potential environmental benefits, costs, or operational and compliance feasibilities and impacts associated with these changes. EPA should repropose these CEMS, CPMS, and QA/QC changes with the necessary supporting justification and analyses for comment. If these requirements are finalized, EPA should provide adequate time to achieve compliance.

Three years compliance time must be provided where instrument replacements or upgrades are required. Even where equipment changes are unnecessary, a minimum of eighteen months is needed for development and approval of new or revised alternative monitoring plans (AMPs), revised operating, monitoring, and maintenance plans (OMMPs), revisions to Consent Decrees and permits, procedure revisions and operator training, etc.

Reference to Detailed Comments: 1.5.

6. ***Alternative compliance options should be provided for situations where sources already have committed to equivalent federally enforceable requirements to those proposed in order to eliminate conflicts and duplication.***

Many refinery flares are subject to flare combustion control requirements that, though differing in details, are accepted by EPA (through Consent Decrees or approved permits) to provide the same destruction efficiency assurance as claimed for this proposal. Compliance with federally enforceable requirements (Consent Decrees and permit conditions) that require control of flare combustion zone properties should be allowed as compliance alternatives to the flare requirements in this proposal.

Similarly, some refineries are required to perform or fund fenceline or property line monitoring or downwind ambient air monitoring for benzene by Consent Decrees or permits and some States have ambient monitors downwind of refineries. Those programs already provide the monitoring for unusual occurrences that the proposed fenceline monitoring program would provide. Thus, those existing programs also should be identified as an allowed alternative compliance option to the proposed program.

Finally, some portions of this proposal are based on State regulations, particularly for cokers and atmospheric safety values (based on California regulations). Compliance with those State rules should be established as compliance with RMACT 1.

Reference to Detailed Comments: 1.4.5, 2.2.3.1.1, 2.7.1.5.

Comments on MACT Subpart CC (RMACT 1)

1. ***The proposed prohibition on atmospheric relief valves should be changed to preventive measures, monitoring, and work practice requirements to avoid forcing construction of approximately 200 new flare systems. Preventive measure and monitoring requirements should not apply to relief valves with little HAP emission potential or where feasibility and safety issues are present.***

Relief valves (RVs) are process safety devices designed to prevent a catastrophic breach of process equipment and loss of containment in the event of an emergency overpressure situation such as a fire, loss of cooling water, or severe process upset. Such releases occur very infrequently and many RVs never release. Citing the Sierra Club decision, EPA proposes to prohibit the direct atmospheric discharge of organic HAPs from RVs, in effect requiring control of all RVs, an action neither compelled nor authorized by statute. EPA did not provide any analysis of potential adverse safety and environmental consequences, risks, costs, or other impacts associated with this prohibition. Because EPA did not justify (and cannot support) the proposed prohibition, EPA should promulgate a work practice standard to apply to atmospheric RVs.

RVs are process equipment currently regulated through the equipment leak provisions. Under normal operating conditions an RV remains closed. The RV releases only if the pressure specified in the design of the RV for its application is exceeded; normally, this only occurs during an emergency or process upset. EPA's proposed standard for RV releases fails to account for the one mode of operation of this very necessary safety device.

While Sierra Club does preclude EPA from exempting malfunction or other unique emissions from regulation, it certainly does not require a prohibition of malfunction or emergency emissions. EPA has not provided any analysis of technical feasibility, potential adverse safety and environmental consequences, risks, costs, or other impacts associated with their proposal to prohibit the use of atmospheric RVs in organic HAP service. As explained in our detailed comments, to comply with the prohibition and thereby guarantee against releases, all atmospheric RVs would need to be routed to flare systems. This would result in the construction of hundreds of new flares, only to sit idle, yet maintaining pilot and purge gas with associated new emissions, waiting for the rare release from an atmospheric RV.

These devices are already highly regulated under safety and risk regulations, and requiring control to address low potential RV releases is unreasonable and arbitrary. Based on data developed by the Bay Area Air Quality Management District (BAAQMD) we have estimated that at least **$12 billion** in investments would be required to construct these new flare systems. In order to prevent unplanned shutdowns of refineries and major disruptions in fuel supplies, at least 10 years would be required for construction of these and the other new flares required to meet the proposed new emergency velocity and visible emissions limits for flares.

API/AFPM is particularly concerned about the inclusion of small atmospheric RVs (i.e., < 2" diameter) in this proposal, because of their large number and typically very small release potential if they do open. These RVs are often located in remote areas where facilities for control may not be available, and they are not amenable to the proposed monitoring requirements. EPA has not addressed the technical feasibility issues, the costs and justification for addressing small RVs, or met the other Section 112(d)(6) requirements. API/AFPM therefore recommends that for small RVs the existing audio, visual and olfactory monitoring required under the equipment leak rules and the existing industry standard design requirements be relied upon for preventing and identifying releases from small RVs.

It is infeasible to broadly define or classify the types of circumstances that result in episodic releases from RVs or to characterize the emissions, making it impossible to establish a numerical standard to apply to the underlying causes of RV actuation. Instead, in order to prevent and minimize the recurrence of episodic emissions from RVs, one must understand and address the underlying causes of the upstream over-pressure that resulted or could result in the necessary operation of the RV. In addition to the current work practice standards that apply to RVs, API/AFPM recommends that EPA establish, for RVs greater than 2 inch diameter, 1) a standard that requires implementation of a base level of measures to prevent atmospheric releases and 2) require continuous monitoring as proposed.

Should a release occur from an RV of any size, API/AFPM recommends that EPA require the refiner to perform a Root Cause Analysis (RCA) and implement Corrective Actions (CAs) as appropriate to prevent a recurrence.

Reference to Detailed Comments: 2.4.1

2. ***Reasonable flare tip velocity and visible emission requirements must be established for emergency flare loads, to avoid forcing construction of hundreds of new flares. The use of these parameters as an indicator of combustion efficiency needs to be revisited, in light of the new flare test data.***

EPA proposes to apply the maximum flare tip velocity and visible emission requirements applicable to normal operating conditions to all flaring events, including those resulting from plant emergencies. Existing refinery flares are not designed to meet these limits under high hydraulic loading. As flares are not amenable to retrofit, refiners would need to redistribute loads, resulting in hundreds of new flares with all of the associated utility consumption (steam, pilot/purge gas, instrumentation) and emissions. API/AFPM has estimated the capital cost for these new flares to be $10-20 billion. EPA has not provided any analysis of the potential adverse safety and environmental consequences, risks, costs, or other impacts associated with this change in applicability of the flare velocity and visible emission standards. In addition, new flare test data has shown that existing limitations on flare tip velocity and visible emission are unnecessary to ensure high combustion efficiency.

Flares are designed for two scenarios. First, flares are designed for normal operating conditions which generally utilize a very small percentage of the flare capacity (~0.1-1%) up to about 20% of the flare capacity. Under this design case, flares comply with the existing EPA requirements for visible emissions and tip velocity. In other words, their capacity to operate in a "smokeless" manner and within the maximum tip velocity limits is limited to this design case. Second, flares are designed to handle the "full hydraulic load*," i.e.,* the emergency relief case when all of the units connected to the flare vent simultaneously. Flares are not designed to meet the visible emission and tip velocity standards at full hydraulic load.

The available flare test work shows that, regardless of the tip velocity, high combustion efficiency will be achieved provided the vent gas has sufficient heat content to keep the flare lit, which can be demonstrated by observing for the presence of flame or through monitoring for an adequate combustion zone heating value.

With regard to visible emissions (particulate matter) from a flare, the recent PFTIR test work has shown that visible emissions are not an indicator of poor destruction efficiency as previously thought. High HAP destruction efficiencies were repeatedly observed when visible emissions were present. Thus, a visible emissions requirement is not needed to demonstrate desired HAP destruction and EPA has a strong basis to eliminate the visible emission requirements entirely from the rule.

API/AFPM recognizes that, to the extent practicable, flares should be operated in a manner which minimizes particulate matter emissions. API/AFPM is supportive of reasonable measures to minimize and monitor visible emissions. However, EPA must recognize that flares cannot meet the proposed visible emission limits when they operate outside of the "smokeless" design range of the flare.

Flares used for emergencies would be unable to comply with the proposed standards by the compliance date, placing operators in the untenable position of operating out of compliance in order to operate safely. We estimate investment costs of **$10-20 billion** to provide compliant flare capacity, substantial annual operating costs, increased net VOC, HAP and GHG emissions (since refinery flares operate continuously, even if no flare gas is routed to them), and up to 10 years to achieve compliance.

API/AFPM recommends that EPA has a strong basis to simply eliminate both the visible emissions and tip velocity requirements from the rule. Should EPA be unwilling to eliminate one or both of these standards, API/AFPM recommends in the alternative that EPA establish feasible standards for flares operating during high load situations.

Reference to Detailed Comments: 2.7.4

3. ***A flare combustion zone net heating value of 200 BTU/SCF as a 3-hour average for steam-assisted flares will assure good combustion efficiency without increasing GHG emissions, at a cost of $6,350/Ton of VOC ($87,300/Ton of HAP). No changes are justified for unassisted or air-assisted flares and they should remain subject to §63.11 if used as RMACT control devices. Many revisions to the details of the EPA proposal are also required to make the proposal feasible and to minimize costs and burdens for flares with little risk of poor combustion.***

API/AFPM supports practicable and cost-effective standards to address EPA's concern that the combustion efficiency of steam-assisted flares may be impaired at excessive steam flow rates. A minimum net heating value in the combustion zone is necessary to ensure high combustion efficiency and thus destruction efficiency. Unfortunately, EPA has proposed a level of control that is excessive and unsupported by the available data for steam-assisted flares. Additionally, EPA provides no credible information to support extending the proposed steam-assisted flare requirements to air-assisted or unassisted flares and thus those flare types should remain subject to §63.11.

EPA proposes two alternative limits on combustion zone properties, depending on the composition of the gas in the combustion zone. On a combustion zone net heating value (CZ-NHV) basis, EPA proposes 270 BTU/SCF as the normal minimum value. Based on a flawed data analysis, EPA also proposes a secondary minimum limit of 380 BTU/SCF applicable to so-called high hydrogen-olefin streams. The need for a separate hydrogen-olefin limit is not supported by the available test data, the scientific literature, or expert opinion and should be removed from the rule.

EPA also proposes that these limits apply as a 15-minute block average. This averaging time is unnecessarily stringent, undemonstrated, likely infeasible, and greatly increases monitoring costs as well as the need for wasteful supplemental gas addition. The demonstrated 3-hour averaging period should be the basis for any limit.

API/AFPM estimates potential emission reductions for the proposed combustion controls as 11,150 TPY VOC and 1280 TPY HAP versus EPA's estimate of 33,100 TPY VOC and 3,810 TPY HAP. API/AFPM also estimates an increase in GHG emissions of at least 121,000 metric tons CO_2e versus EPA's estimate of a 327,000 metric tons reduction, primarily due to the increased natural gas supplementation needed because of the unnecessarily high minimum heating value limits, the dual limit, and unrealistic averaging time proposed.

API/AFPM has estimated the investment costs associated with the proposed combustion control requirements to be approximately **$350 million**. In addition to the capital cost, approximately **$51 million/year** will be required in operating utility cost (excess supplemental gas minus reduced steam value) to meet the proposed overly conservative combustion zone net heating value limits.

The demand for excess gas is exacerbated by EPA's failure to recognize the positive contribution of hydrogen to combustion efficiency. EPA should assign hydrogen a heating value of 1212 BTU/SCF, which is consistent with its treatment in most of the Consent Decrees.

As an alternative to the proposal, API/AFPM evaluated a 200 BTU/SCF, 3-hour average, CZ-NHV limit and concluded that the incremental cost for EPA's proposal versus this alternative is $38,000/Ton VOC and $333,500/Ton HAP. In addition, the API/AFPM alternative eliminates almost all of the GHG emission increase associated with the EPA proposal. Thus, API/AFPM recommends a 200 BTU/SCF, 3-hour average, CZ-NHV minimum (and equivalent alternatives) for steam-assisted flares.

API/AFPM does not agree with EPA's proposal to impose any new requirements on air-assisted and unassisted flares. The flare data collected to date has been almost entirely on steam-assisted flares. Air-assisted and unassisted flares have different designs, capacities, and are typically in different services than steam-assisted flares. The extremely limited supporting data and analyses provided by EPA to support applying the steam-assisted flare limits to these flare types do not reflect the differences between flare types or adequately demonstrate that the proposed limits are appropriate for air-assisted or unassisted flares, or that they will reduce emissions, or are cost effective. API/AFPM recommends that the new standards only apply to steam-assisted flares which represent the bulk of refinery flares and that other flare types remain subject to §63.11.

API/AFPM has enlisted the aid of flare combustion experts who helped develop the PFTIR technology relied upon by EPA in developing this proposal and who have participated in much of the flare test work that has been conducted to date. As described in our detailed comments and attachments, these experts have identified serious issues with EPA's analysis of the flare test data and have raised significant concerns with the proposed requirements.

Reference to Detailed Comments: 2.7.2, 2.7.3, Attachments D-1 – D-4.

4. ***There is no justification, and EPA has provided no analysis to support, the proposal to require costly automatic flare pilot reignition systems and this requirement should not be finalized.***

EPA proposes that all flares be equipped with automatic pilot reignition systems. EPA's justification for this new requirement is twofold: it will enhance compliance assurance and "nearly all refinery flares are already equipped with an automated device to relight the pilot flame in the event it is extinguished.[2]" Both assertions are false. Moreover, EPA has not provided any analysis of the potential adverse safety and environmental consequences, risks, costs, or other impacts associated with this requirement. API/AFPM strongly recommends that the requirement for automatic pilot reignition systems be dropped from the rule.

EPA's assumptions regarding application of this technology are not correct. Indeed, quite the opposite is true: most refinery flares are equipped with manual and not automatic ignition systems and there is no significant problem maintaining pilot flames. Experience shows that, in manned facilities such as refineries, manual reignition systems are effective at safely and quickly reigniting pilots in those rare instances where they are extinguished. Thus, there is no emission reduction or compliance assurance value in imposing this requirement.

This equipment is also expensive to purchase and maintain in a refinery configuration, where flares are typically large diameter, several hundred feet in height and serve many process operations, including emergency relief. We estimate the cost of adding automatic pilot reignition systems across the industry be **$1-2 billion**. Furthermore, accessing a flare tip for reignition system maintenance cannot be safely performed while the flare is in service, potentially requiring an unplanned shutdown of all of the process units serviced by that flare.

Reference to Detailed Comments: 1.5.2.1, 2.7.6

5. ***There is no justification, and EPA has provided no analysis, to support the proposal to ban the flaring of streams containing greater than 1 lb/hr of halogen atoms and that ban should not be finalized.***

The proposal prohibits the flaring of streams containing greater than 1 lb/hr of halogen atoms. Reformers, HF alkylation units, isomerization, and other units may not be able to comply with this new limit for periodic, episodic, and emergency events. EPA has not provided any analysis of the potential environmental benefits, costs, or operational and compliance feasibilities and impacts associated with this requirement nor provided any justification for the selected limit.

[2] See 79 Fed. Reg. 36905 (June 30, 2014)

The proposed prohibition appears to have been taken from the Hazardous Organic NESHAP (HON) rule, where it applies only to process vents during normal operations and not to startup, shutdown, or upset conditions. EPA cites no statutory authority and provides no analysis or justification for applying this limit to the refining industry. This change in the regulatory language is not mentioned anywhere in the preamble or the rulemaking docket and thus there is no record to support its inclusion. Therefore, this requirement cannot be finalized. If EPA believes there are environmental concerns associated with flaring halogen atoms, it must provide justification and take comment on any new standards or requirements.

Reference to Detailed Comments: 2.8.

6. ***It is not cost effective or risk justified to revise the existing standard for coke drum vents (an RMACT 1 MPV). While API/AFPM does not believe EPA can justify lowering the existing MACT standard, we recommend that EPA not set the standard any lower than the NSPS Ja 5 psig limit as determined on a rolling 30-day average basis.***

EPA proposes to change the current MPV requirements for delayed coking units to a new, standalone work practice requirement establishing 2 psig as the maximum pressure limit for discharge of this vent to the atmosphere. EPA claims it never performed a section 112(d)(2)-(3) analysis for delayed coking units during the original rulemaking. EPA's claim is not supported by the record. Consequently, EPA may revise the standard only under section 112(d)(6) if there has been a development in practices or technology and the change is cost-effective. EPA has not identified any such developments for delayed coking units and its cost analysis severely understates the full cost of compliance.

EPA has under-estimated the cost of compliance by an order-of-magnitude by basing their analysis on the least costly compliance approach and failing to consider the extensive data provided by API/AFPM on the full range of costs. In contrast to EPA's $52 million investment estimate, API/AFPM estimates the capital costs of the proposed requirements to be approximately **$400 million**, which equates to >$100,000/ton VOC and >$500,000/ton HAP.

API's cost numbers are consistent with EPA's basis and conclusion in the recent NSPS Subpart Ja rulemaking, where EPA found <2 psig to be cost-ineffective even for new units. Therefore, the same limit would certainly be cost-ineffective for most existing units as we have demonstrated in our analysis. Moreover, the proposed limit conflicts with the new NSPS Ja release limit of <5 psig, potentially undermining API member company investment and compliance strategies for units that have become subject to that rule. Fundamentally, this is very bad policy.

While API/AFPM does not believe EPA can justify lowering the existing MACT standard, we recommend that EPA not set the standard any lower than the NSPS Ja 5 psig limit as determined on a rolling 30-day average basis.

Reference to Detailed Comments: 2.2.3

7. ***The proposed property line monitoring program is not authorized under CAA section 112 and would provide no compliance assurance or other emission benefit and it should not be finalized.***

EPA claims authority under section 112(d)(6) to propose a property line monitoring program for benzene. The proposal would require passive samplers, with samples collected on two-week intervals. If the annual concentration of benzene exceeds 9 μg/m^3 the rule requires the refiner to institute a program to identify and correct the source of the benzene emissions. EPA claims this authority despite the fact it determined there were no developments in technology, processes, or practices applicable to the regulated sources of fugitive HAP emissions this fenceline monitoring program is intended to address. If, as EPA claims, this fenceline monitoring program will demonstrate compliance with equipment leak rules, it amounts to duplicative compliance monitoring. Moreover, the proposed unlimited corrective action requirements effectively turns what EPA calls an "action level" into a new standard – an ambient air HAP standard addressing emissions from the very same sources EPA has already individually regulated. Such a standard is not authorized under section 112.

From a technical perspective, the basic assumption underpinning the proposed program is erroneous; i.e., it is incorrect to assume that refinery fenceline benzene concentrations are correlated with refinery benzene emissions from fugitive sources. The measured fenceline value can be impacted by all benzene emissions in the area, on ambient conditions, on site configuration, on equipment proximity to the fenceline, and on confounding onsite and offsite sources. Many refineries are situated along waterways and highways, where vehicle and marine traffic exhaust emissions may have a considerable impact on fenceline benzene concentrations. Similarly, mobile sources and non-refinery sources within a refinery will contribute to fenceline values. Many potential confounding sources have concentrations that either exceed EPA's proposed threshold, or can be significant contributors to the threshold. The literature shows that sources such as municipal fires and agricultural burning can create benzene emissions greater than the proposed threshold. Roadway emissions, background air near cigarette smokers and near roadway concentrations can all be significant contributors.

In other words, one cannot presume that an elevated concentration at the fenceline indicates a problem with sources regulated by RMACT 1 and 2 inside the refinery fence. Consequently, while an elevated reading may indicate a need for further investigation, the rule must not be written in a way that assumes refinery non-compliance or that mandates corrective action.

Further, EPA has proposed the program on the basis that it provides enhanced monitoring of existing fugitive emission programs. Yet, EPA did not propose any changes to those programs because EPA did not find any cost-effective changes possible. EPA provides no support that this program is cost-effective and EPA did not provide any data that demonstrates that the program could in fact identify any deviations from the existing fugitive emission standards.

The potential for unending corrective action requirements, regardless of the source of an action level exceedance or the cost-effectiveness of particular controls is a particular concern both legally and practically. If EPA finalizes this program, API/AFPM strongly urges EPA to remove the requirement for EPA approval of any corrective action plans and to make it clear that all corrective actions are at the discretion of the site.

Reference to Detailed Comments: 1.3

8. ***The proposed fenceline monitoring program action level takes inadequate account of method and process variability and API/AFPM recommend an action level of 15 µg/m3, if the program is finalized. Many methodology details need to be corrected or clarified.***

The derivation of the proposed action level is flawed and results in an action level that is too low (i.e., will trigger action when the action level exceedance is due to normal variability). The proposed action level of 9 $\mu g/m^3$ (~2.8 ppb) does not appropriately reflect operating, sampling, and measurement variability. An adjustment to the action level is necessary to account for this variability. API/AFPM recommends an action level of 15 $\mu g/m^3$ to avoid unnecessary investigations and corrective actions.

In 2013, industry conducted a three-month pilot fenceline monitoring program which identified a number of technical issues with the methodology. The pilot study report prepared by ERM, Inc., is provided as Attachments B-1 and B-2 to these comments. API/AFPM's extensive recommendations to address the methodology issues are included Comment Section 1.4.

Reference to Detailed Comments: 1.4, B-1, B-2.

9. ***It is unlawful to revise the 1980's open-ended lines (OELs) requirements based on a 2005 EPA reinterpretation, particularly in light of EPA's failure to justify an equivalent change through rulemaking in 2007. The proposed definition of "seal" should not be finalized.***

The proposal creates a new definition of the word "seal" as a "clarification" as applied to plugged or capped OELs. Under this definition, any OEL with a proper plug, cap, or second valve is in violation if that "seal" is found leaking above a leak threshold of 500 ppm. This precedent-setting proposed change would effectively change all equipment leak rules in parts 60, 61 and 63 of the Code of Federal Regulations without proper notice or analysis. EPA has not provided any analysis of the potential environmental benefits, costs, or operational and compliance feasibilities and impacts associated with this requirement. The proposed definition of a "seal" should not be finalized.

It is clear from the history of the current OEL requirements that this new definition is inconsistent with the original 1980's meaning and its interpretation. There is no indication in the record that EPA originally intended to apply a "no detectable emissions" or leak definition to OELs; to the contrary, other provisions in the equipment leak rules containing such provisions demonstrate that the EPA considered when and where to impose such limits during the original rulemakings. The fact that this is a change is further demonstrated by EPA's proposal to monitor OELs in the 2007 NSPS Subpart GGGa rulemaking. It is telling that EPA did not attempt to impose a definition of "seal" in that rulemaking. Furthermore, in finalizing that rule, EPA found no justification on a VOC basis to impose a Leak Detection and Repair (LDAR) program to assure OEL caps and plugs are not leaking above 500 ppm. On a HAP basis, it is even less justified than on the VOC basis that EPA based its past proposal upon. EPA cannot now simply re-interpret the same requirement by promulgating a "clarification" of the meaning of the word "seal" and impose new requirements on that basis.

Furthermore, EPA's proposed approach to OELs in this rulemaking is arbitrarily inconsistent with EPA's traditional approach to fugitive emission work practices. This proposal establishes 500 ppm for controlled OELs as a not-to-be-exceeded emission limitation in addition to the existing cap and plug standard, rather than establishing 500 ppm as a LDAR program action level. It is arbitrary and capricious to establish an emission limitation in the case of OELs when other similar fugitive emission components (e.g., connectors) are regulated through a LDAR work practice standard.

If EPA determines that OELs should become subject to a 500 ppm leak definition, API/AFPM strongly urges EPA to treat these OELs like other pieces of equipment and provide a period of time to repair the leak, rather than considering the leak to be an immediate non-compliance.

Reference to Detailed Comments: 2.4.2

10. ***To avoid prolonging equipment outages and imposing massive burdens on refiners and regulators, miscellaneous process vents (MPVs) associated with MSS activities must be handled generically and their emissions controlled through a generic work practice that allows for release to the atmosphere when the vent is <10% LEL or 5 psig.***

EPA's proposed change in the MPV and "periodically discharged" definitions will effectively subject all refinery equipment to the MPV standards. Any venting from a piece of equipment that is opened to the atmosphere during MSS activities will now meet the definition of an MPV, creating hundreds or thousands of new vents per refinery per year and generating massive on-going burdens that are not reflected in the record, resulting in delayed and extended equipment and process outages. EPA has not provided any analysis of the operational or practical feasibility of applying the MPV provisions to these vents, nor has it analyzed potential environmental benefits, costs, or impacts associated with this requirement. API/AFPM recommends that EPA establish work practice standards for equipment opened during MSS activities.

Many states already provide work practices that regulate these activities and their control in a generic fashion. Under these requirements, these types of vents are routed to control until hydrocarbon concentrations reach low levels, but EPA's proposal does not account for these existing measures or provide an equivalent. Also, EPA's proposed rule does not provide clear criteria for when vents used for MSS can be routed to the atmosphere. Finally, the proposal creates an unnecessary permitting and recordkeeping burden for the industry and the permitting authority. Hundreds or thousands of individual activities, which only occur periodically, may have to be individually permitted and accounted for as unique MPVs.

Since these MPVs are constantly changing, are generally not quantifiable, and are routed to control until hydrocarbon concentrations are low, API/AFPM recommends a general set of work practice requirements based on the approaches used by the States to avoid imposing the permitting, notice and evaluation requirements associated with identifying these vents individually. Key elements of the work practice could include removing process liquids to the extent practical and depressuring smaller volume equipment until a pressure of <5 psig is achieved and/or purging and depressuring to a control device until the vent has a hydrocarbon concentration of less than 10 percent of the Lower Explosive Limit. These standards should provide clear and easily-monitored criteria for when this equipment can be vented to the atmosphere and should not impose the permitting, notice and evaluation requirements associated with identifying these vents as individual MPVs.

Reference to Detailed Comments: 2.1.2.

Comments on MACT Subpart UUU (RMACT 2)

1. ***Proposed alternative HAP standards for FCCUs during startup must be extended and revised to allow these units to startup, shutdown, and operate in hot standby mode, without imposing increased safety risks, steam supply disruptions, or forcing undesirable operational or environmental impacts.***

EPA has recognized that FCCUs are not designed to meet normal operating limits during periods of startup, shutdown, and hot standby. Consequently, EPA has proposed limited alternative standards applicable during some of these periods. However, API/AFPM has identified a number of process safety, operational, and environmental concerns with the proposed alternative standards and recommends revisions and additional alternatives.

For organic HAPs, EPA has proposed a standard of >1% hourly average excess regenerator O_2 that would apply to FCCUs not equipped with a regenerator flue gas boiler. However, most refiners are unable to startup their FCCUs with flue gas boilers in service. There are many reasons for this, including the design of the boiler and the fact that many such boilers are not able to safely and reliably handle the transient FCCU operations that can occur during startup, shutdown, and hot standby.

Reliable and steady boiler operation is critical to the overall refinery steam system and care must be taken to avoid jeopardizing boiler operation to prevent major upsets of the entire refinery process operation. Even those refiners who do start up with a FCCU regenerator flue gas boiler in service cannot routinely meet normal CO limits during this period, while still holding steam production steady. Therefore, API/AFPM recommends EPA's proposed standard of >1% hourly average excess regenerator O_2 apply to all FCCUs, regardless of whether they have a regenerator flue gas boiler or not.

With regard to the proposed alternative standards for metal HAPs, process safety concerns prevent most FCCU electrostatic precipitators (ESPs) from being energized during startup, shutdown, and hot standby. With the ESP de-energized, refiners are generally unable to meet the proposed 30% opacity limit. While FCCUs controlled by wet gas scrubbers (WGS) will normally startup and shutdown with the WGS in service, some of these units may be unable to meet their WGS operating limits/alternative monitoring plan (AMP) requirements during these periods.

Maintaining a minimum average regenerator first stage cyclone inlet velocity represents the best approach for minimizing metal HAPs during these periods. Particulate removal efficiency is a function of the velocity through the cyclones. Consequently achieving a minimum velocity before adding catalyst to the regenerator ensures a base level of control. Therefore, in place of the proposed 30% opacity alternative for ESP equipped FCCUs, EPA should allow all FCCUs the option to meet a minimum hourly average regenerator first stage cyclone inlet velocity of 20 feet per second during periods of startup, shutdown, and hot standby.

Reference to Detailed Comments: 3.1.1

2. ***Proposed opacity limits for FCCUs equipped with third stage cyclone PM controls must be revised to avoid wasteful and unjustified replacement of that control with costly (e.g. $50 million each) new controls.***

For FCCUs equipped with third stage cyclones for PM control, EPA proposes to change the opacity limit in RMACT 2 from 30% with a 6-minute allowance for soot blowing to a continuous site-specific limit based on a performance test every five years. EPA attempts to justify this change based on improved compliance assurance with the PM mass limit for FCCUs operating at 30% opacity. This is an unauthorized change in the stringency of the opacity standard, unachievable on a continuous basis for these units, and will result in hundreds of millions of dollars in new PM controls for units that currently comply with the PM limit.

This change in standard arises in the context of EPA's proposal to align the RMACT 2 operating limits and monitoring requirements for existing FCCUs with those in NSPS Subpart Ja that apply only to new, modified, or reconstructed units. EPA attempts to justify the majority of these changes on a perceived need to improve compliance assurance but without providing evidence of a compliance problem and without any analysis of the potential environmental benefits, costs, or operational and compliance feasibilities and impacts. As a general matter, the proposed alignment of the MACT and NSPS Subpart Ja operating limits and monitoring requirements is an unauthorized change in stringency of the MACT standard.

The most problematic of these changes is the replacement of the 30% opacity limit for FCCUs using a cyclone to control PM with a unit-specific opacity limit derived from a performance test. The basis for this proposal is flawed in at least two respects. EPA has incorrectly assumed that the current opacity limit was established to demonstrate compliance with the mass emission limitation for these FCCUs, when, in fact, it was established as a separate limitation in order to demonstrate that the PM control is being operated and maintained properly.

API/AFPM strongly urges EPA to maintain the current 30% opacity limit for existing FCCUs, not subject to NSPS Ja. As a practicable and cost-effective alternative to address EPA's concern about compliance with the PM mass emission limitation, API/AFPM suggests annual PM performance tests for these units rather than every 5 years.

Reference to Detailed Comments: 3.2.2.1

3. ***The proposed alternative standard for SRP shutdown needs to be extended to startup.***

The proposed rule provides an alternative standard that applies during periods of SRP shutdown. In lieu of meeting the normal emission limits, SRP purge gases can be routed to an incinerator or thermal oxidizer operated at a minimum hourly average temperature of 1200 degrees F and a minimum hourly average outlet O_2 concentration of 2 volume percent (dry basis). API/AFPM recommends that these same alternative limits also apply during periods of startup to account for certain scenarios (discussed in our detailed comments) when an SRP would be unable to start up in compliance with the normal emission limits.

Reference to Detailed Comments: 3.1.2

Comments on NSPS Ja

1. ***EPA should take this opportunity to respond to key NSPS Ja reconsideration Items.***

A number of minor revisions are proposed to NSPS Ja. Some significant issues that API included in its reconsideration petition on the 2012 NSPS Ja amendments require rule revisions and API/AFPM urges EPA to address those at this time.

Specifically we recommend the following be addressed:

- The flare flow meter accuracy specification in NSPS Ja should be made consistent with the instrumentation in general use.
- EPA should use this opportunity to address the inadvertent applicability of fuel gas combustion device requirements to flares that only handle wastewater treatment unit offgas.
- EPA should clarify how to convert the measured H_2S and TRS values in wet flare gas to the dry basis of the standard.
- The NSPS Ja provisions for monitoring tank degassing vapors should be revised to reflect the Alternative Monitoring Plans issued for such activities.
- The oxygen correction equation in NSPS J, Ja and RMACT 2 for adjusting measured pollutant readings to 0% O_2, needs to be adjusted for FCCUs that use oxygen enrichment.

Reference to Detailed Comments: 4.3

1.0 General Comments on The Refinery Sector Rulemaking

1.1 General

There are currently 142 large (major source) and 7 small (area source) petroleum refineries in the United States. There are 36 small businesses that own petroleum refineries[3]. This rulemaking addresses the major source refineries.

1.1.1 General Comments on the Refinery Sector Proposal

1.1.1.1 Risk Concerns Do Not Justify Any Additional Controls.

The current risk analysis reconfirms the conclusion stated in the signed, and subsequently withdrawn, January 2009 risk and technology review that the risks associated with refinery emission sources are acceptable. This is conclusion is unchanged, despite the addition of Refinery MACT 2 source emissions to the analysis and incorporation of updated emission estimates based on EPA's 2011 information collection request (ICR).

After extensive and costly efforts to update emission estimates through the ICR, this risk assessment found that compliance with current emission standards result in acceptable risks. To provide an ample margin of safety, EPA has concluded that an upgrade to storage tank controls, as well as application of controls to some smaller tanks, is justified on a risk basis. EPA has, therefore, proposed those revisions to RMACT 1.

The balance of this proposal is not based on risk reduction and thus must be justified on other grounds and must be achievable and cost effective. Even where a change is claimed to be driven by judicial decisions, EPA must follow the provisions of the CAA in implementing the Court decision, which has not been done in many cases. For instance, extending emission limitations derived for normal operation to Maintenance, Startup, and Shutdown (MSS) periods may be the easiest regulatory path, but[4] that approach is not required and is sometimes not

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[3] US EPA, *Fact Sheet; Proposed Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards*, May 15, 2014

[4] See Comment 1.1.3.2

cost effective or even feasible. Alternative standards must be developed and implemented in such cases.

1.1.1.2 This is a Major and Significant Rulemaking, Imposing Billions of Dollars in Annual Costs. Reviews and Justifications are Required Under the Laws and Executive Orders Applicable to Major and Significant Regulatory Actions.

This proposal is a major and significant Agency action. As proposed, this rulemaking will cost the refining industry billions of dollars per year, increase safety risks, impact fuels production, and create far reaching precedents for future rulemakings involving a great many source categories in both the NESHAP and NSPS arenas. The EPA must meet all of the requirements imposed on such rulemakings by a variety of laws and Executive Orders. To that end, we recommend that EPA complete the consultations discussed below and provide all of the information required for complete reviews under Executive Order 12866, the Regulatory Flexibility Act, the Congressional Review Act, and the Paperwork Reduction Act for comment. As discussed throughout these comments, the reviews done to support the current proposal are incomplete and not a reasonable representation of the precedents, issues, costs and burdens imposed by this proposal.

1.1.1.3 The Proposal Impacts Safety Systems that Protect Workers and the Community. These Must be Fully Vetted, and, Under Executive Order 13650, Coordinated with the Occupational Safety and Health Administration and EPA's Risk Management Office. Releases Required to Prevent Catastrophes Should Not be Prohibited or Declared Violations.

A primary concern with this proposal is the new policy decision that emissions required for safe operation are to be considered violations and therefore prohibited. For instance, this proposal includes a ban on atmospheric safety valve discharges and an extension of the flare normal operation velocity and visible emission limits to emergency situations, thereby making releases required to prevent catastrophes and the flaring of such emergency releases violations. We urge that these proposals be withdrawn and that reasonable and achievable alternative standards, including work practice standards, where appropriate, be set instead.

Significant safety concerns include the following, which are addressed in more detail in the appropriate sections of these comments.

- Requiring control of all atmospheric safety valves increases the chance of a catastrophic equipment failure due to inadequate relieving capacity, particularly during the period between promulgation of these amendments and completion of the new flare systems and installation of the additional safety valves that will be required (which we estimate will take at least 10 years). Some safety valves are infeasible to control, installed on equipment owned by others, or regulated by the Department of Transportation and U.S. Coast Guard.

- Imposing the normal operations velocity limits on flares designed to be used at their hydraulic limit during emergencies will place operators in an untenable position until additional flares can be installed – managing the emergency safely while risking enforcement for violating environmental requirements.

- Proposing to treat RVs on vapor collection systems as potential bypasses, requiring them to be car-sealed closed or otherwise blocked and exposing the system to potentially catastrophic failure.

- Prohibiting the flaring of halogenated streams during emergencies will also force operators to manage the emergency to assure safety while potentially creating environmental violations. Halogen removal systems also have the potential to interfere with emergency release flows and generally do not represent safe practice for emergency relief systems. Failure to route halogenated hydrocarbon streams to a flare during emergencies increases the risk of vapor cloud fires and explosions and exposure of operators and emergency personnel to dangerous materials.

- The prohibition on the use of downstream equipment and control device bypasses during start-up, shutdown, and malfunction, regardless of the safety risk associated with sending those streams to that equipment or those controls, will increase the risk of fire and explosion. In particular, operating Electrostatic Precipitators (ESPs) on FCCUs during SSM has caused injuries and equipment damage, as has operating FCCU Flue gas boilers during starts and shutdowns.

- Disallowing draining of coke drum quench water when needed to allow addition of additional water to adequately cool the coke and the coke drum will increase the risk of burns to workers when the drum is opened.
- Requiring routine instrument QA/QC for unsafe to access instruments puts workers at risk (e.g., the proposed QA/QC requirements for flare pilot thermocouples) and violates OSHA regulations.

1.1.1.4 The Potential Impact of This Proposal on Energy Supplies is Significant and Thus Consultation with The Department of Energy and Review Under Executive Order 13211 is Required.

This is a “significant energy action” as defined under Executive Order 13211 (66 FR 28355, May 22, 2001), because it is likely to have significant adverse effect on the supply, distribution, or use of energy. It is impossible to carry out the required flare modifications and new flare construction within the timeframes proposed. Furthermore, it is not possible to schedule all of the production outages that would be required for compliance in the three years provided.

As we discuss elsewhere, we estimate at least a decade is required to minimize, though not eliminate, lost fuels production while the hundreds of new flares are installed. Since no more than three years is provided for compliance under section 112, ongoing production cutbacks will be required beginning with year 4 after promulgation until the proposed rule requirements can be met. Furthermore, some production cutbacks will be required immediately to allow operation within the flare capacity envelope that avoids violations of the new flare velocity and visibility limits during emergency periods.

In addition to new flares, most existing flares will have to be taken out of service to install the new facilities required for compliance. Flare outages are generally scheduled to coincide with planned unit maintenance/turnaround outages so as to avoid impacting refinery production. This would not be possible under this proposal because of the inadequate time allowed for compliance. At least a decade is required to provide such coordinated outages for an entire refinery. In addition, even such coordination will not prevent production impacts because making the required changes to multiple flares and flare systems cannot be done without extending the length of normal production unit outages and without having additional outages.

Fuels production is also expected to be reduced due to the ban on active purging of semi-regenerative catalytic reformer units (CRUs), increasing cycle times, the ban on bypassing downstream equipment and control devices and the extended times required to permit and control the periodic emissions associated with MSS. While some bypasses will still be required, despite the ban, to protect life and property, other startups, shutdowns and outages will be significantly extended in an attempt to avoid bypasses.

1.1.1.5 A Number of Very Significant Policy Issues Are Raised by This Proposal.

Significant policy issues raised by this rulemaking include the following and require review under Executive Order 12866.

- Rather than setting manageable standards, including work practice standards where appropriate, for the emissions from equipment designed to protect the facility and the community from catastrophic failures, this proposal prohibits such emissions. This prohibition will force refiners to spend billions of dollars and to increase net emissions to control contingencies that infrequently or never happen in order to avoid a violation of the CAA. Such a prohibition is bad public policy and should not be pursued.

- Hundreds of new flares will be required for emergency flaring because of the proposed requirement to comply with the velocity and visible emission requirements that were developed for normal operations during emergencies, even though emergency flaring is infrequent and there is no destruction efficiency impact from this change. It is not in the best interest of the public or the environment to require continuously operating flares for no environmental benefit.

- This proposal unlawfully imposes an ambient air standard for benzene through the proposed fenceline monitoring program. Section 112 of the CAA authorizes the control of emission sources and does not provide authority for establishing ambient air standards. Further, the proposal includes provisions for EPA to direct refiners to change their operations and to attempt to change the operations of others in order to achieve the fenceline limit, without consideration of cost, safety, or operability and without due process for the third party.

- This proposal unlawfully revises the existing section 112(d)(2) floor for 1) delayed cokers (by replacing the Group 1 Miscellaneous Process Vent (MPV) criteria with a work practice requirement), 2) open-ended lines (OEL) (by adding a numeric emission limitation to the current work practice), 3) fluid catalytic crackers regenerator vents (by changing the averaging time for several standards and changing the opacity limit), and

4) for liquid relief valves (by replacing the current work practice requirement with a control requirement) without demonstrating that such changes are justified under the provisions of section 112(d)(6). Such action is not authorized by the CAA and violates the Agency policy on revisiting floors.

- The proposal sets standards, particularly for flares, that are inconsistent with the requirements the EPA and the Department of Justice agreed to in various recent Consent Agreements. It is bad policy to establish requirements that conflict with requirements established under Consent Decrees. For instance, all flare Consent Decrees grant the covered refineries a 3-hour averaging time for the combustion parameter, while this proposal would only allow a 15-minute averaging time. Similarly, this proposal contains different instrumentation requirements than contained in most of the Consent Decrees, meaning sources could not meet both this set of requirements and their Consent Decree requirements with the same analyzer.

- In the case of OELs, EPA is reinterpreting the existing requirement to justify adding an emissions standard, despite the fact that the reinterpretation is clearly at odds with the record for the OEL requirements. Furthermore, the Agency proposed the same change through previous rulemaking and concluded it could not be justified. Reinterpretations cannot be used to bypass rulemaking.

- This proposal creates a definition for and prohibits flaring of halogenated vent streams, without any mention in the preamble or any justification or analysis being provided as required by the CAA and the Administrative Procedures Act.

- This proposal imposes, without any claims of authorization or any analysis, new flare requirements on part 63 subpart R and Y facilities (i.e., gasoline distribution and marine loading) that are part of the RMACT 1 affected source, despite the fact that risk and technology reviews of those two subparts were recently completed and did not identify any such need.

- Similarly, this proposal imposes new flare requirements on part 61 subpart FF (i.e., benzene waste operations) facilities without justifying the change or providing an analysis of the impacts of that change on those facilities or on the potential need for refiners to find alternative subpart FF compliance approaches if the receiving facility will not make the required flare investments.

1.1.1.6 Most of The Costs and Burdens Associated with This Rulemaking Are Not Tabulated and Presented For Comment. The Proposed Revisions That Lack Such Analyses Should Not Be Finalized.

Many proposed changes impose very large costs and burdens (well in excess of several hundred million dollars annually). Since there is no risk basis for any of the proposal other than for the storage vessel requirements, all other rule changes must be demonstrated to be cost effective. Narrow interpretations of judicial precedents or reinterpretations of historical understandings should not be the basis for by-passing full evaluations, as is the case for many of the proposed revisions. EPA should not revise floors and compliance demonstration requirements or add requirements without providing a full justification and cost and emission evaluation for comment.

The EPA estimates, the total capital cost of this proposal to be approximately $240 million, with an annualized cost of approximately $40 million. Based on this incorrect and unsubstantiated estimate, the EPA projects that these proposed standards will have a negligible impact on the costs of petroleum products.[5]

We address the costs and burdens imposed by this proposal in our individual comments, but summarize them here. Overall, we estimate investment costs in the billions and annual costs in the high hundreds of millions. Even if the final rule does not require construction of new flares, investment costs will exceed **$1 billion** and annual costs will significantly exceed **$100 million.** Additional large costs, which we are unable to quantify, will result from lost production due to longer process outages and out-of-sequence outages resulting from rule requirements.

- Costs for additional flares and headers to handle EPA's estimated 12,000 atmospheric RVs that require control under this proposal are not addressed. Instead EPA assumes installation of flow monitors at an industry-wide investment cost of $9.54 million[6]. It is preliminarily estimated that approximately 200 new flares and new header systems may be required instead, at a cost of approximately **$12 Billion**.

[5] Ibid.

[6] In Docket Document EPA-HQ-OAR-2010-0682-0207, page 13, EPA reports a vendor cost of $7500 per monitor. Unrealistically, no installation cost or costs associated with getting the signal transmitted and received are added and no operating costs are assumed.

- Costs for the 500+ existing flares (in addition to those needed for controlling atmospheric RVs) and additional steam generators (e.g., boilers) to maintain existing emergency relief capacity due to the imposition of velocity and visible emissions limits during emergencies will exceed **$10-20 billion** in investment.

- It is unclear whether land will be available for all of these additional flares or if they can be permitted, in light of community concerns over flares. Costs could increase if additional land must be purchased. Operating costs, while not estimated by us, will be significant since these additional flares will require extensive instrumentation upkeep per this proposal's requirements and large volumes of steam and natural gas (for pilots, purge, sweep and assist gas).

- Facilities for treating halogenated vents that previously were flared will require several million dollars of investment for each process unit where halogen releases are possible and much more if emergency releases will also have to be treated prior to release to a flare. Treating emergency releases may impose a high safety risk and thus not be feasible. No discussion of this requirement or any cost, burden, or emissions estimates are present in the proposal or in the backup documents. There are also significant ongoing costs, burdens, and emissions associated with halogen removal, requiring use of caustic (sodium hydroxide) and, in some case, the need for a thermal oxidizer.

- Costs for the proposed reignition pilot systems, pilot monitor upgrades, and the associated flare outages also are not addressed in the rulemaking. Despite the claim in the preamble, most refinery flares will need new equipment installed at the flare tip. This many flare outages cannot be scheduled in a three year window without major production losses due to having to shut down large sections of the refineries to avoid compromising safety because of reduced flare availability in case of emergency. Specific cost estimates for the installation of this system are $3-4 million per flare, plus lost production value due to the process outages required to take a flare out of service. Total refinery investments would be on the order of **$1-2 billion** if this proposal is finalized.

- Our preliminary review indicates the costs, burdens and additional GHG emissions for the proposed flare combustion controls are significantly underestimated, because:

  1) a much larger percentage of flares will need continuous controls than has been estimated by EPA, because the proposed sampling alternative is inadequate to meet the 15 minute compliance time and because of the dual combustion zone limits;

  2) large excesses of natural gas addition will be needed to meet the 15-minute averaging time (if that is even possible) and to meet the higher limits when the hydrogen and olefin contents of the flare gas are unclear, changing or transitioning, and

  3) a BTU analyzer and a GC[7] will both be needed in order to attempt to meet the 15 minute compliance time and dual combustion zone limit.

  API/AFPM estimates an investment cost of approximately **$350 million** versus EPA's estimate of $147 million and an annualized cost of **$116 million** for the proposal. We also estimate the proposal will result in a GHG increase of at least **121,000 metric tons CO_2e** versus EPA's estimate of a 327,000 metric tons reduction.

- Under this proposal, hundreds of new miscellaneous process vents associated with periodic activities will be created at each refinery. No refinery or permitting authority burdens are included in this proposal for evaluating, reporting, and permitting these new vents or for the monitoring, recordkeeping and reporting associated with these new vents. Similarly, the large permitting, recordkeeping and reporting burdens imposed by the proposed changing of the RMACT 1 affected facility whenever fuel gas is sent to a flare that may be temporarily deviating from the new flare requirements (e.g., smoking) are not reflected in the burden estimates.

- EPA estimates fenceline monitoring costs of $5.6 million per year and second year burdens of $1.7 million per year. However, EPA's analysis underestimate the number of samplers required, the analysis costs (by unrealistically assuming the analyses are done in-house),

[7] While EPA assumes no new GC's will be required, the proposal requirements are not consistent with most existing GC's and so they will need to be replaced and GC will be required for most flares where EPA assumed they are unnecessary because of the 15-minute averaging time and the dual standard.

and fails to include any costs for the required RCA analyses. We estimate a program cost of approximately **$23 million** per year.

- Despite specific information from member companies, EPA selected an unrealistic model for estimating the costs of meeting the proposal to impose a <2 psig delayed coker vent release limit. Specific information from our members indicates investments in excess of **$400 million** are likely. Significant permitting, monitoring, recordkeeping, and reporting burdens flow from such investments, and these are not included in the EPA Information Collection Supporting Statement.

- There will be significant monitoring costs that EPA has failed to include on the apparent assumption that current instrumentation would be usable (e.g., for coke drum pressure) and that all of the new QA/QC requirements do not impose any costs or burdens. These proposals contain extensive new instrument specifications and QA/QC requirements that often cannot be met by typical process instrumentation. Thus, it can be expected that many instruments will require replacement or upgrade. We are still evaluating the impact of the newly added continuous emission monitor requirements, but again expect significant replacement and/or upgrade of these instruments will be necessary.

- The requirement to have a visible emissions evaluator available for daily checks and during any smoking incident will likely require additional operators at every refinery. Existing staffing may not accommodate these additional duties without compromising safety and operating reliability. Assuming 30 minutes per flare per day of set-up, observation, scheduling, and recordkeeping time for half[8] of EPA's estimated 510 refinery flares yields a cost of **$4 million per year (40,000 burden hours)** for the industry. Required observations during smoking incidents would add additional cost, as would wait time for flares where regulated material flow is intermittent.

1.1.1.7 The Emission Factor Update Proposal for Flares and Petroleum Refinery Emissions Should Not be Allowed to Prejudice this Rulemaking and Any Emission Factor Changes Must Be Delayed Until After This Rulemaking.

[8] Assumes half of the flares have regulated material flow during any given day and that an observation can be scheduled during that time.

On August 19, 2014, in response to its consent decree with Air Alliance Houston et al.[9] (Consent Decree), EPA posted a notice on its TTN Chief website proposing to revise the AP-42 emission factors for industrial flares and to make no changes to existing factors for liquid storage tanks and wastewater treatment systems. In addition to the emission factors for these three specific emission types required to be reviewed per the Consent Decree, EPA also proposed to add or revise certain AP-42 emission factors for petroleum refinery Fluid Catalytic Cracking Units, Hydrogen Plants, Sulfur recovery plants, Catalytic Reforming Units , and Delayed Coker Units. Concurrently with the proposed AP-42 revisions, EPA posted an updated version (Draft Version 3) of the Emissions Estimation Protocol for Petroleum Refineries (Protocol), which incorporates the proposed AP-42 emission factor revisions and also changes the function of the Protocol document from a Petroleum Refining Information Collection Request (ICR) tool industry to now "provide guidance and instructions to petroleum refinery owners and operators and to federal, state, and local agencies for the purpose of improving emission inventories."

Flares are a major issue in the Refinery Sector rulemaking. EPA's proposal of new emission factors that are the same as those used in the Refinery Sector rulemaking prejudices the evaluation of comments on the Refinery rulemaking since the Emission Factor Consent Decree requires the new emission factors to be finalized prior to finalizing the Refinery Sector rule. Similarly, the emission factor evaluation is prejudiced because the Agency would not want to finalize anything different from the refinery rule basis. Otherwise, it would have to redo the refinery emission analyses and thus be unable to meet the deadlines in that Consent Decree.

As explained in our letter to Assistant Administrator for Air McCabe of September 11, 2014[10], the Emission Factor Review schedule is unreasonable and provides inadequate time for EPA and the public to conduct a proper and thorough review of the emission factors for flares, storage tanks, wastewater systems, and refinery processes. We believe a reasonable schedule would allow at least one year for completing an emission factor review for these sources after the Refinery Sector Rule is finalized and that at least a 180 day comment period must be allowed to provide adequate time for the multitude of interested parties to file sound comments on the new emission factor proposal, including consideration of the comments received on the Sector Rule proposal.

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

[10] Todd, M. to J. McCabe, *Proposed Revisions to Sections 5.1, 8.13, and 13.5 of AP-42 and the Draft Emission Estimation Protocol for Petroleum Refineries - Version 3.0 posted August 19, 2014*, September 11, 2014

1.1.1.8 The Term "Regulated Pollutant" is Widely Used in This Proposal, but is Ambiguous and Should be Replaced with More Specific Language.

The term "regulated pollutant" is widely used in this proposal. That term was developed for use in subparts that contain generic requirements that are widely referenced. Its use in these subparts is ambiguous, since it can easily be interpreted to include substances that are not regulated by these subparts and/or are not regulated by the particular paragraph using the term. Thus, we believe the term should be replaced in every use with an RMACT 1 or RMACT 2 specific term, such as organic HAP, metal HAP, Nickel, PM, etc. Where a generic term is needed such as in certain recordkeeping and reporting requirements we recommend "HAP regulated by the applicable standard in this subpart."

1.1.2 General Part 63 Compliance Date and Compliance Time Comments

1.1.2.1 We Recommend New Subparts CCa and UUUa Be Established to Clarify The Dates On Which Changes Become Effective, the Dates When Current Requirements No Longer Apply, and To Assure That the New and Revised Requirements Are Not Applied Retroactively.

The proposed revisions to part 63 subpart CC and UUU do not <u>clearly</u> apply new and changed requirements prospectively. Considerable revision is necessary to clarify that the new and revised requirements do not apply prior to the effective date or compliance date of this rule, as applicable. Because of the extensive nature of the proposed changes, EPA should finalize the revised rules as new subparts (i.e., part 63 subparts CCa and UUUa), with provisions that clearly identify the date(s) on which they apply and the date(s) on which existing subparts CC and UUU paragraphs no longer apply.

While EPA has included such information in some places in the proposal, those efforts are incomplete and we have pointed out those instances where clarification is needed if new subparts are not promulgated.

1.1.2.2 If Disruption of Energy Supplies Is to Be Minimized, At Least A Decade Is Needed To Add New Flares and Modify Existing Flares.

The proposed revised flare velocity and visible emissions requirements, the requirements to add flare auto-reignition and to upgrade flare pilot monitors, and the atmospheric RV prohibition will require addition of hundreds of new flares and modifications to a large portion of the 500+ existing flares. To avoid significant outages and disruption of fuel production and to maintain required compliant flare capacity for assuring safety during emergency outages, flare outages must coincide with major production unit outages. Because many refinery process units have extended run times and multi-unit outages are difficult to coordinate and arrange, we project it will take about a decade to implement and complete the work requiring flare and process unit shutdowns with minimum fuels production disruption.

Even with maximum coordination of flare and production unit outages, some maintenance outages will have to be extended and some extra production outages will be required to complete all of the required flare and flare header revisions and to complete the tie-ins for new flares and flare header systems.

1.1.2.3 A Minimum of Eighteen Months is Needed to Implement the Changes that do Not Require Capital Investment (e.g., SSM Changes, OEL Revisions, CPMS and CEMS Procedure Changes). Permit and OMMP Plan Revisions Must be Completed and Approved[11] Before Operations Can Legally be Changed to Meet the New Requirements.

In general, EPA provides three years compliance time for requirements where new equipment must be installed. However, no compliance time is allowed for most other requirements (i.e., compliance is required on the effective date of the final amendments). The new compliance requirements will require extensive permit modifications[12] and some of the new requirements will contradict existing permits, Alternative Monitoring Plans (AMPs), Consent Decrees, and State regulations. The proposal must be revised to allow time to modify and obtain approval for permits and to make these other Federally Enforceable requirements consistent.

It appears that refiners are being told to comply with revised SSM and some other requirements as soon as the rule becomes effective. It would be arbitrary and capricious for EPA to require compliance immediately, when CAA section 112(i) allows a compliance deadline of up to three years. Elimination of the SSM provisions of the existing rules, as well as adding provisions prohibiting any release from RVs and <u>any</u> control bypass, will require plants to make significant changes to their facilities and procedures, which would take significant time to

[11] In Comment 3.2.3.2, API/AFPM requests that the requirement to wait for OMMP approval be removed in order to eliminate this impediment to compliance.
[12] In addition to Title V permits, many refineries are subject to the Texas "Maintenance, Startup, and Shutdown (MSS) Permit" requirements. These extensive permits will require significant modification because of the changes to RMACT 1and 2 dealing with MSS activities.

execute and to permit. There is no justification for making such changes in the existing regulations effective immediately.

Because of 1) the extensive nature of the permit revisions required by this rulemaking, 2) the required identification and evaluation of hundreds of new emission sources, 3) the extensive procedural changes associated with the revised SSM requirements, including all new equipment preparation procedures, and 4) the required revision of all monitoring procedures, we believe all requirements must include a compliance time allowance, otherwise refiners will become immediately out-of-compliance with a multitude of existing work practice and procedural requirements as soon as this rule is effective.

While some activities can be started based on the proposal, procedures cannot be finalized, permit revisions applied for, and retraining of site personnel cannot begin until the rule is final. Furthermore, the changes that require permit revisions and OMMP revisions cannot legally be implemented until the revisions are approved. Given the serious problems with this proposal, substantial changes can be expected between the proposed and final rules.

Additionally, we anticipate a great many new alternative monitoring plans (AMPs) will need to be developed and approved before compliance can be achieved, since many of the proposed monitoring requirements are infeasible, inconsistent with Consent Decrees and/or State rules, or unreasonably costly for achieving the required measurement. Approval of these AMPs is historically a very slow process.

A minimum of eighteen months is needed to implement all the changes that involve amending or revising permits, OMMPs, AMPs, Consent Decrees and operating procedures. A minimum of three years is needed for changes requiring investment and 10 years is needed for the changes requiring flare outages. We are particularly concerned that our permitting authorities will not have the ability to revise permits and AMPs in this time frame, given the large number of changes occurring for a large number of facilities concurrently and with the risk of delay due to citizen objections.

1.1.2.4 This is a Major Rulemaking and Therefore the Rule Cannot Become Effective until 60 Days After Publication in The Federal Register In order To Allow Time for Congressional Review.

Under the Congressional Review Act, major rules (>$100 Million per Year) must provide at least 60 days between final publication and the effective date. As we discuss above, the costs of this proposal will exceed $100M/year by several factors. Thus, the rule effective date must be at least 60 days after publication and that date must be specified in the final rule. Furthermore, all sections that specify a compliance date as the date of publication in the Federal Register must be changed to the rule Effective Date.

1.1.3 The Proposal to Extend Standards for Normal Operation to Maintenance, Startup and Shutdown (MSS) Periods Does not Account for the Differences Between Normal Emissions and MSS Emissions. EPA Must Revise Many Existing Floor Determinations to Include MSS Emissions or Set Separate MSS Standards

In proposing to apply existing emission standards to MSS operations, this proposal fails to consider the fact emissions that occur during MSS periods were not used to set the standards; rather, these standards are based on emissions during normal operations. EPA bases its actions on a misapplication of the U.S. Court of Appeals for the D.C. Circuit's decision in *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008), *cert. denied*, 130 S. Ct. 1735 (2010), and on unreasonable or insufficiently supported assumptions about MSS events and emissions during these periods. With only a few exceptions, EPA proposes to extend the normal operations requirements in RMACT 1 and 2 to MSS periods without any justification of its authority to do so other than a general reference to *Sierra Club v. EPA*, and without any apparent factual analysis of the statutory criteria for standard-setting.

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EPA is legally required to reconsider all of the requirements it proposes to extend to MSS operations in order to demonstrate that each requirement is appropriate for MSS situations. EPA has several options for setting MACT standards for such periods, including establishing a design, equipment, work practice, or operational standard under CAA section 112(h) (hereafter referred to as "work practice standards"). We point out throughout these comments situations where either an alternative numerical standard or a work practice standard is required for safety, operational or feasibility reasons. API/AFPM have identified in Comments 2.1.2 and 3.1 those MSS situations where we believe the extension of the normal operating limits to MSS periods is infeasible, unsafe, extends outages, or interferes with unit operability. EPA must conduct a thorough analysis of each of these situations and justify applying the existing emission standards or instead develop an alternative numerical emission standard or 112(h) work practice during MSS.

1.1.3.1 EPA Does Not Have Authority To Arbitrarily Amend Existing MACT Standards To Make Them More Stringent.

While EPA does not make the distinction clear in the proposal, the proposed new MSS provisions in RMACT 1 are changes to the existing MACT standards that EPA promulgated previously, pursuant to CAA sections 112(d)(2) and (3). Other examples of arbitrary revisions of (d)(2) and (3) standards include adding a 500 ppm numerical emission limitation for open-ended lines in RMACT 1 and revising the averaging periods for FCCU standards and changing the opacity limit for some FCCUs in RMACT 2. The CAA does not contemplate or authorize EPA to fill “gaps” or re-determine the MACT floors for previously issued MACT standards, including revising averaging times. Rather, Congress established two distinct procedures for revising original MACT standards: the eight-year review for new developments in control technology under CAA section 112(d)(6), and the review of MACT standards to determine whether more stringent limitations are necessary to protect human health under the CAA section 112(f)(2) “residual risk” review.

EPA’s authority under CAA section 112(d)(6) is to “review and revise as necessary (taking into account developments in practices, processes, and control technologies), emissions standards promulgated under this section no less often than every 8 years.” The EPA has not invoked its section 112(d)(6) authority to support these proposed revisions, but even if it had, section 112(d)(6) does not provide broad authority to reconsider aspects of previously issued MACT standards unrelated to “developments in practices, processes, and control technologies.” Thus, EPA cannot simply revise a MACT determination long after it has been issued, as EPA attempts to do in this proposal. EPA cannot merely change its mind about what standards are required to comply with CAA sections 112(d)(2) and (3), nor can it recalculate a MACT floor based on subsequent performance. *Cf*. *NRDC v. EPA*, 529 F.3d 1077, 1084 (D.C. Cir. 2008) (rejecting contention that CAA section 112(d)(6) requires EPA to “start from scratch” and develop new MACT standards).

Reassessing existing NESHAPs that were based on the MACT floor years ago, and imposing more-stringent requirements, is inconsistent not only with the statute’s careful provision of technology-review and residual-risk authority, but also with Congress’ desire for finality evident in the judicial review provisions of CAA section 307(b). Challenges to MACT standards needed to be raised within 60 days of their promulgation. This provision ensures that regulated entities, EPA, and the public know what emission limitations will apply to a source, rather than having those limitations in a regular state of flux. In the current context, refineries long ago made capital investments and developed operating procedures to meet RMACT 1 and 2 standards. The CAA does not allow EPA to simply revisit the analysis and decisions involved in developing emission standards that meet the requirements of CAA sections 112(d)(2) and (3).

Moreover, as discussed in greater detail below, even if EPA did have authority to revise existing MACT standards, it would have to justify why the decisions reflected in the current standards are wrong and why the new standards meet the required criteria that EPA must satisfy in issuing MACT standards under CAA sections 112(d)(2) and (3). EPA has not made either showing in this proposal.

1.1.3.2 The Proposed SSM Provisions Are Not Required in Order To Be Consistent with *Sierra Club v. EPA*.

EPA has recognized for decades that it is often unreasonable to require sources to meet technology-based emission standards, such as NSPS promulgated under CAA section 111, during SSM periods[13]. That understanding has been a critical piece of most MACT standards as well, through incorporation by reference of the NESHAP General Provisions SSM requirements, inclusion of specific provisions for SSM events in the categorical MACT standards, or both. Despite that fact, EPA proposes that established emission limits in the affected NESHAP, which EPA has issued under CAA section 112 based on normal operations at a time when SSM emissions were excused from compliance with emission limits, would now be applicable at all times, even during SSM events.

EPA suggests that its proposed treatment of emissions during SS&M events is appropriate, even “required,” in order to make the standards “consistent with” the D.C. Circuit’s decision in *Sierra Club v. EPA*. As described by EPA, the D.C. Circuit vacated the SSM exemption[14] under the General Provisions of 40 CFR Part 63, “holding that under section 302(k) of the CAA, *emissions standards or limitations must be continuous in nature* and that the SSM exemption violates the

[13] See 40 C.F.R. § 60.8(c).

[14] Although the D.C. Circuit (and EPA in the preamble to the proposal) referred to the provision vacated in the Sierra Club decision as an "exemption" from hazardous air pollutant standards during SS&M events, in fact other portions of the NESHAP General Provisions impose various requirements that apply to sources both during SS&M events (including the obligation to minimize excess emissions) and in anticipation of and following SS&M events (including requirements to prepare a plan to address SS&M events and to report SS&M events).

CAA's requirement that *some* section 112 standards apply continuously."[15] [Emphasis added]. The D.C. Circuit's *Sierra Club* decision does not, however, compel or even support EPA's proposal simply to apply the same set of standards to both normal operations as well as MSS events.

First, the *Sierra Club* decision interpreted the NESHAPs General Provisions. It did not by its terms address what EPA may or may not include in category-specific MACT standards, and it certainly did not address the specific SSM provisions that EPA included in RMACT 1 and 2. In contrast, opinions where the court was looking at source-category-specific MACT standards have emphasized the need for those standards to recognize and accommodate higher emission levels that occur at times other than normal operations[16].

Second, the *Sierra Club* decision did not say that the same emission limits EPA has derived for normal operations must also apply during SSM events. While a blanket, open-ended exemption from any standard under section 112 is inconsistent with the *Sierra Club* panel's holding that, "there must be continuous section 112-compliant standards"[17], *Sierra Club* does not preclude EPA from applying different standards during SSM events than apply during normal operations. In fact, the opinion acknowledges that section 302(k)'s "inclusion of [the] broad phrase" "any requirement relating to the operation or maintenance of a source to assure continuous emission reduction" in the definition of "emission standard" suggests that EPA can establish MACT standards consistent with CAA section 112 "without necessarily continuously applying a single standard."[18]

There is ample precedent for EPA applying a different standard during SS&M events. The language that the D.C. Circuit considered dispositive in interpreting EPA's standards-setting authority under section 112 — the statement in the CAA section 302 definition of "emission limitation" and "emission standard" that it "limits the quantity, rate, or concentration of

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[15] See 79 Fed. Reg. 36,880, 36,942 (June 30, 2014)

[16] See, e.g., *Sierra Club v. EPA,* 167 F.3d 658, 665 (D.C. Cir. 1999) (Section 112(d) standards based upon the performance of the best-performing facilities are supposed to represent "the emissions control that is achieved in practice" by the best performers, which means that the best-performing facilities will not violate the standards, and that "only results if 'achieved in practice' is interpreted to mean 'achieved under the worst foreseeable circumstances.'").

[17] 551 F.3d at 1027

[18] "Indeed, this reading is supported by the legislative history of section 302(k)." Id. See also id. at 1021 ("accepting that 'continuous' for purposes of the definition of 'emission standards' under CAA section 302(k) does not mean unchanging"); id. (referring to "the CAA's requirement that some section 112 standard apply continuously") (Emphasis added). Moreover, since it was addressing only a generic SSM exemption, the Sierra Club decision did not consider whether EPA, in the context of individual categorical standards, could determine that it is infeasible to apply the same limits, or any limits on the mass or concentration of pollutants emitted at all, during SSM events, or that it would lead to absurd results to do so.

emissions of air pollutants on a continuous basis" — has been in the statute since 1977. Throughout that time, EPA has not required sources to meet NSPS emission limitations under CAA section 111 established for normal operations during SS&M events[19]. In fact, Congress enacted the "continuous basis" language in section 302(k) knowing that EPA's emissions standards under section 111 exempted SS&M periods. There is nothing in the legislative history of the 1977 amendments to the CAA that suggests Congress intended to overturn that practice.[20] Moreover, court decisions both before and after the CAA Amendments of 1977, some of which are cited below, have affirmed the appropriateness of including special SS&M provisions in standards issued under section 111—despite the "continuous basis" language in the definition of "emission limitation." Similarly, there is nothing in the legislative history of the Clean Air Act Amendments of 1990 that suggests Congress meant something completely different when it used the same defined terms, "emission standard" and "emission limitation," in directing EPA to establish MACT standards.

Indeed, EPA has clearly recognized its authority to apply different standards during SSM events. Over the past several years, EPA has issued new and revised regulations that included alternate standards applicable to startup and shutdown emissions.[21] As part of this very rulemaking, EPA

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[19] See 40 C.F.R. § 60.8(c).

[20] Rather, the "continuous basis" language inserted in 1977 related to a debate in Congress about whether sources should be allowed to use temporary or intermittent pollution control technologies, as the D.C. Circuit recognized in Sierra Club v. EPA, 551 F.3d 1019, 1027 (D.C. Cir. 2008), cert. denied, 130 S. Ct. 1735 (2010), citing Kamp v. Hernandez, 752 F.2d 1444, 1452 (9th Cir.1985). See also Conference Report on H.R. 6161 (the CAA Amendments of 1977), H. Rep. No. 95-564 (August 3, 1977) at 129 (requirement to use "continuous emission controls" "clarifies that intermittent or alternative control measures are not permissible means of compliance"), 172; S. Rep. No. 94-717 (March 29, 1976) at 78 (definition of "emission limitation" being amended to clarify that "[i]ntermittent controls or dispersion techniques are unacceptable as a substitute for continuous control of pollutants" and contrasting intermittent controls, which vary based on predicted changes in pollutant dispersion due to meteorological predictions, with continuous controls such as flue-gas cleaning equipment); see also Nat'l Lime Ass'n v. EPA, 627 F.2d 416, 434 n.54 (D.C. Cir. 1980) ("The 'intermittent' controls that concerned Congress were any of those which entailed temporary reductions in emissions when weather conditions were poor."). The language about "continuous reduction" in the definition of "emission standard" did not address what emission limitations apply during SS&M periods, nor EPA's established practice of exempting excess emissions during SS&M events from the performance standards applicable to normal operations. In fact, the legislative history indicates Congress was aware that alternative emission limitations might at times be necessary, even though the emission limitations were established based on the capability of "continuous controls" like scrubbers. See, e.g., S. Rep. No. 94-717 at 78 ("It is recognized that the source controls may not be available to achieve the full reduction required of a particular source under particular circumstances. In such case, supplementary programs can and should be developed.").

[21] *See* 78 Fed. Reg. 10,006, 10,013 (Feb. 12, 2013) (EPA final rule adopting work practices instead of numerical emission limitations for startup and shutdown periods for the National Emissions Standards for Hazardous Air Pollutants (NESHAP) for the Portland Cement Manufacturing Industry.) *See also* 78 Fed. Reg. 7138, 7142 (Jan. 31, 2013) (EPA final rule adopting work practice standards for startup and shutdown periods for the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP.)

requested data through the ICR, noting that the data collected "would also allow EPA to evaluate compliance options for startup and shutdown periods."[22] EPA has used at least some of the information collected in the ICR to develop and propose alternate emissions standards for several startup and shutdown scenarios related to FCCUs and SRUs[23].

Third, the *Sierra Club* decision did not address whether EPA could use a "design, equipment, work practice, or operational standard," as authorized under CAA section 112(h) and included in the definition of "emission limitation" and "emission standard" in CAA section 302(k), in lieu of a numerical emission limitation during SSM events. EPA told the Court that the General Provisions SSM exemption struck down in *Sierra Club* was not an alternative standard based on the work practice standard authority[24]. Indeed, EPA argued in that case that section 112(h) was irrelevant to its authority to exempt excess emissions during SSM events[25].

Thus, EPA cannot hide behind the *Sierra Club* decision as a justification for ignoring its standard-setting obligations under section 112. EPA's SSM proposal does not establish "continuous section 112-compliant standards" that the *Sierra Club* decision concluded are required[26]. Under CAA section 112(d)(2), MACT emission standards must be "achievable." Moreover, if EPA sets the emission standards based on the "best performing 12% of units in the category" (the "MACT floor"), those limitations must on average be "achieved" by the best performers[27].

An emission limitation that applies during SSM events does not meet the requirement of CAA section 112(d)(2) that "emission standards" under that section be "achievable" if, in fact, EPA has not demonstrated that the limitation is "achievable" with available technology, "taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements." Similarly, an emission limitation that applies during SSM events has not been demonstrated to be "achieved" by the best-performing 12% of units in the category under CAA section 112(d)(3) unless EPA can show that those best performers actually meet that emission limitation during SSM events. The Proposed Rule would not establish "continuous section 112-compliant standards" because, as discussed below, EPA has not demonstrated that the emission limitations in the existing MACT standards, if they also applied during SSM events, would comply with section 112.

[22] See 76 Fed. Reg. 5804, 5805 (Feb. 2, 2011).
[23] *See* 79 Fed. Reg. at 36,943-44.
[24] See 551 F.3d at 1028.
[25] *Id*. at 1030 (Randolph, J. dissenting).
[26] See 551 F.3d at 1027.
[27] See CAA section 112(d)(3).

That plain-language reading of the applicable statutory requirements is echoed by extensive case law. The courts have long recognized that a "technology based standard discards its fundamental premise when it ignores the limits inherent in technology."[28] For example, the D.C. Circuit recognized, in *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 398 (D.C. Cir. 1973), a decision reviewing standards under CAA section 111, that "'start-up' and 'upset' conditions due to plant or emission device malfunction, is an inescapable aspect of industrial life and that allowance must be made for such factors in the standards that are promulgated." *Id*. at 399. Similarly, in *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 432 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974), another section 111 case, the court held that SSM provisions are "necessary to preserve the reasonableness of the standards as a whole." *Id*. at 433. In *National Lime Ass'n v. EPA*, 627 F.2d 416 (D.C. Cir. 1980), another case reviewing emission standards promulgated under CAA section 111, the court held that the CAA requirement that NSPS be "achievable" means that the standards must be capable of being met "on a regular basis," including "under most adverse circumstances which can reasonably be expected to recur," including during periods of SSM.[29]

Courts have reached a similar conclusion when considering the analogous Clean Water Act requirements that EPA establish technology-based effluent limitations based on the best available control technology. In one such case, the court held that where EPA knew that there would be periods where a discharger, even with "exemplary use of" the identified best technology, would exceed the effluent limitations because of conditions "beyond the control of the permit holder," EPA had violated the Clean Water Act by failing to provide an "upset provision" to address those periods.[30] See also, e.g., *NRDC v. EPA*, 859 F.2d at 207 (distinguishing between technology-based effluent limitations, where some provision for "upsets" is required, and water-quality-based effluent limitations, which are tied to achieving water quality standards rather than based on available technology, and therefore need not include an upset provision).[31]

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[28] See *NRDC v. EPA,* 859 F.2d 156, 208 (D.C. Cir. 1988).

[29] See 627 F.2d at 431 n.46.

[30] See *Marathon Oil Co. v. EPA*, 564 F.2d 1253, 1273-74 (9th Cir. 1977).

[31] The Weyerhaeuser Co. v. Costle decision EPA cites in the preamble to the Proposed Rule, 590 F. 2d 1011 (D.C. Cir. 1978), does not support EPA's position. See 79 Fed. Reg. at 1711, col. 1. In that case, the court was discussing a "technology forcing" standard, rather than one, like MACT, that is to be based on what is already being "achieved" or has been demonstrated to be achievable. Also, the SSM events that EPA acknowledges are expected to occur at sources subject to the Proposed Standards are a far cry from the unusual "'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication, or

The *Sierra Club* decision does not prevent EPA from adopting emission standards for SSM periods that are different from those required during periods of normal operation. Nor does the *Sierra Club* decision mean that EPA is barred from using a "requirement relating to the operation or maintenance of a source to assure continuous emission reduction" as the emission standard that applies during such events[32]. The *Sierra Club* decision only rejected EPA's assertion that it had discretion to decide not to impose any emission standard covering SSM periods[33] Thus, despite EPA's implications to the contrary, the *Sierra Club* decision expressly recognized that different standards, including non-numerical standards, may (and in some cases must) apply during non-standard operating conditions, such as SSM events.

1.1.3.3 EPA Must Fully Justify Applying the Same Emission Limitations During MSS as During Normal Operations.

EPA must conduct a thorough analysis and determine whether it is representative of the performance of best-performing sources (the MACT floor) to require facilities in these source categories to achieve the same emission limitation during MSS as during normal operations. EPA cannot conclude that special provisions for emissions during MSS are not needed based on "mere speculation.[34]" The default assumption must be that such special provisions *are* needed. EPA previously determined, when establishing the existing standards applicable to refineries, that the best performers on which the MACT standards were based may not achieve those standards during MSS. EPA cannot simply change its mind about this sort of assessment

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insanity" that the Court was considering in the passage quoted by EPA, see id. Industry is not requesting that the MACT standards provide relief from numerical emission limitations during those unusual types of events. Perhaps most importantly, the Weyerhaeuser decision came long before NRDC v. EPA, 859 F.2d 156 (D.C. Cir. 1988) which, as noted above, affirmed the need for an upset provision to address circumstances where compliance with effluent limitations is impossible through no fault of the permittee, and which endorsed Marathon Oil.

[32] See 551 F.3d at 1027.

[33] See *id*. at 1027-28, 1030 (noting that EPA was not claiming that the General Provisions SSM exemption was either an emission standard under CAA section 112(d) or a design, equipment, work practice, or operational standard under section 112(h)). The statement in the majority opinion that "Congress gave no indication that it intended the application of MACT standards to vary based on different time periods," 551 F.3d at 1028: (1) is contradicted by other statements in the opinion, referenced above, that a MACT standard need not continuously apply a single emission limitation, (2) is *dicta*, because that was not the situation presented by the challenged regulations and argued by EPA, (3) ignores the extensive case law about technology-based limitations referenced above, and (4) does not in any event say that the CAA precludes EPA from adopting different emission limitations that apply during SSM events.

[34] See *NRDC v. EPA*, 859 F.2d 156, 210 (D.C. Cir. 1988).

without providing a factual analysis supporting EPA's new conclusion that MACT standards can be achieved as well during all MSS periods[35].

While EPA has proposed alternative standards for three MSS situations (two involving startup of fluid catalytic crackers and one involving shutdown of sulfur recovery plants), those alternatives are too narrow to provide for achievable MSS limitations for those processes. Furthermore, these three alternatives fail to address all of the situations API/AFPM has identified for EPA, where the normal standard is not achievable or is not achievable without incurring significant and unnecessary safety or operating risk or fuel supply disruption.

To the extent emissions data come from required performance tests, the applicable regulations generally prohibit testing during SSM conditions, and require that data not be used for compliance purposes if obtained during a SSM event.[36] To the extent EPA evaluates emissions data collected through continuous monitoring, the applicable regulations often require or allow the source to exclude from its reporting of continuous monitoring data those data reflecting SSM conditions. Also, atypical pollutant concentrations and other stack conditions that may exist during SSM can result in the continuous monitoring system producing unusable data because the pollutant concentration may be outside of the monitoring equipment's span, stack conditions may not meet monitoring system QA/QC parameters, or the data may be truncated on the high end because of limitations of the monitoring equipment.[37] These restrictions on the use of SSM data, even where available, are very informative because they reflect EPA's historical understanding that these periods are often different from periods of normal operation.

It is not apparent from the preamble discussion that EPA has actually analyzed sufficient data on emissions during MSS to justify the conclusion that only these three alternatives are needed. API/AFPM has provided additional data on needed alternative standards in these comments. It is likely that additional alternatives will be needed as experience identifies SSM situations where the normal standards cannot be met.

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[35] See, e.g., *Transactive Corp. v. United States*, 91 F.3d 232, 237 (D.C. Cir. 1996).

[36] See, for example, the NESHAPs General Provisions, which state that performance tests can only be conducted under representative conditions and which specify that: "Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test…." 40 C.F.R. §63.7(e)(1); see also 40 C.F.R. § 60.8(c) (same for performance testing for NSPS).

[37] Note that data from periods when a monitoring system is outside of control limits are required to be excluded from emission averages under the NESHAPs General Provisions. See 40 C.F.R. § 63.8(c)(7)(ii).

1.1.4 EPA Must Consider Malfunctions In Setting Emission Standards or Set Separate Standards for Malfunction Periods.

EPA explains in the preamble that it is not required to consider emissions generated during malfunctions in setting standards. Nonetheless, those same standards apply during malfunctions as well as during normal operations. This illogic leads to the conclusion that any exceedance of the normal operating emissions is a violation, even if the exceedance occurs during a malfunction where meeting the normal standard is impossible.

This illogic takes on even greater urgency in this rulemaking where EPA applies it to critical safety devices. Flares, relief valves, and control bypasses are designed to protect equipment, personnel, and the surrounding community during malfunction operation, though not exclusively in the case of flares. Thus, malfunctions are a "normal" operating mode for these systems. Non-malfunction operations are an alternative mode of operation for flares and in some cases for bypasses. Thus, separate standards are appropriate and authorized for these alternative operating states.

As we discussed in detail in Comment 1.1.3.2, the *Sierra Club vs. EPA* decision does not require EPA to establish the same standards for SS&M periods as for normal operations. EPA must establish a standard for these periods following the standard setting criteria in section 112, unless it can demonstrate that sources can achieve a single standard applicable at all times. We have discussed EPA's application (or non-application) of that duty in Comment 1.1.3 and now address EPA's duty relative to malfunctions.

In this proposal, EPA arbitrarily and without analysis extends normal operating limits to periods of malfunction (e.g., velocity and visible emission limits for flares) and prohibits emissions where there is no normal operating limit to apply (e.g., relief valves). This approach violates EPA's statutory duty. Applying the same emission standards during SS&M periods is not compelled by the statute or by applicable case law, including the *Sierra Club v. EPA* decision. EPA has several options for setting MACT standards for such periods, including establishing a design, equipment, work practice, or operational standard under CAA section 112(h).

1.1.4.1 EPA May Not Disregard Emissions During Periods of Malfunctions in Setting MACT Standards.

The CAA simply does not allow EPA to wholly disregard emissions occurring during periods of malfunction in its development of Section 112 standards as the Agency has proposed to do here. EPA has itself previously stated that it must set MACT floors that the best performing sources can meet "every day and under all operating conditions."[38]. EPA cannot make this determination unless it considers emissions that occur during malfunctions.

EPA's assertion that nothing in CAA Section 112 directs EPA to consider malfunctions in determining the level "achieved" by the best-performing sources is irrelevant. Rather, the statute prescribes a procedure for establishing Section 112(d) standards and it does not provide that EPA may disregard that procedure for periods of malfunction. Indeed, the absence of a reference to specific operating conditions in CAA Section 112 means that *all* operating conditions must be considered in setting the standards.[39] It is unreasonable to interpret Section 112 as providing *carte blanche* for EPA to disregard known and unavoidable operating conditions from consideration in setting CAA Section 112 equipment standards.

As discussed previously, EPA's reliance on *Sierra Club* is misplaced. That decision does not prohibit SSM emissions; rather it prohibits a blanket exemption during these periods that would make emission standards under Section 112 non-continuous. EPA's decision to disregard emissions during malfunction periods and failure to consider alternative emission standards during such periods represents a failure to implement statutory requirements, is arbitrary, and inconsistent with past EPA policy.[40] If the standard applies continuously, then EPA must likewise evaluate emissions on a continuous basis, including emissions during malfunctions.

EPA's "blind-eye" approach for dealing with malfunction emissions in the Proposed Rule is particularly unreasonable in light of the D.C. Circuit's recent opinion in *NRDC v. EPA*, 749 F.3d

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[38] See 75 Fed. Reg. at 63,269 (quoting *Mossville Envtl. Action Now*, 370 F.3d at 1241-42)

[39] While it is true that EPA has a degree of discretion in determining MACT floors, the case cited by EPA for recognizing this discretion makes clear that EPA's prior interpretation has been to consider all operating conditions in setting emission standards. *See Nat'l Ass'n of Clean Water Agencies v. EPA*, 734 F.3d 1115, 1143 (D.C. Cir. 2013) ("<u>EPA believes that it must set MACT floors 'that the best performing sources can meet 'every day and under all operating conditions</u>.''" (quoting 75 Fed. Reg. at 63,269 (emphasis added)).

[40] See Nat'l Lime Ass'n, 627 F.2d at 430 ("Promulgation of standards based upon inadequate proof of achievability would defy the Administrative Procedure Act's mandate against action that is 'arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law.'") (quoting 5 U.S.C. § 706 (1976)).

1055 (D.C. Cir. 2014) in which it vacated EPA's inclusion of a rule-based affirmative defense to emission violations occurring during periods of malfunction. EPA recently explained the importance of the affirmative defense in the absence of an SSM exemption stating:

> While "continuous" standards are required, there is also case law indicating, in many situations, it is appropriate for the EPA to account for the practical realities of technology. For example, in *Essex Chemical v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), the DC Circuit acknowledged that, in setting standards under CAA Section 111, "variant provisions" such as provisions allowing for upsets during startup, shutdown, and equipment malfunction "appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the 'never to be exceeded' standard currently in force."[41]

While EPA questioned whether the cited cases remained legally binding, it noted that decisions "support the EPA's view that a system that incorporates some level of flexibility is reasonable and appropriate."[42]

1.1.4.2 In Regulating Malfunction Emissions, EPA Should Follow the Same Standards Setting Approach Required for MSS Emissions.

When considering emissions from malfunction events, EPA has the same tools at its disposal as when dealing with emissions from startup and shutdown emission periods. Specifically, EPA can: (1) create a record as to why the emission standards applicable during normal periods of operation are applicable during periods of malfunction (consistent with CAA Section 112(d) criteria for setting the floor and beyond the floor limits); (2) establish a different numeric standard under the procedures of CAA Section 112(d); or (3) if a numeric standard is not feasible, establish a work practice standard under CAA Section 112(h).

EPA's assertion that consideration of malfunction emissions would be "difficult" is not a valid justification for the Agency to abandon its statutory obligations or adopt an unreasonable statutory interpretation. This is particularly true given that there is no indication that EPA even attempted to evaluate malfunction data or to craft alternate standards. For example, EPA's ICR associated with the Proposed Rule noted that the data would "allow EPA to evaluate compliance options for startup and shutdown periods," but fails to even mention evaluation of

[41] 79 Fed. Reg. 17,340, 17,347 (Mar. 27, 2014). *See, also, Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375 (D.C. Cir. 1973).
[42] *Id.*

periods of equipment malfunction.[43] Moreover, it is no answer that the task is difficult. Indeed, the structure of CAA Section 112, contemplates that alternative approaches may be needed in just such a situation, providing flexibility in cases where establishing numerical emissions limitations is difficult. In particular CAA Section 112(h) provides that "if it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a hazardous air pollutant or pollutants, the Administrator may, in lieu thereof, promulgate a design, equipment, work practice, or operational standard, or combination thereof . . .."[44]

API/AFPM agrees that it is often infeasible to gather emissions data during malfunctions – either for standard-setting or for compliance-demonstration purposes. Malfunctions are by definition unexpected, so it is not possible to plan to have test equipment in place to measure emissions when one occurs. Even if test or monitoring equipment is in place, emissions during malfunctions invalidate the test results under EPA's approved test methods, often such emissions are not routed to a stack where they can be measured, and malfunction emissions can have very short durations and/or can vary wildly during the event and from one event to another[45].

Rather than supporting EPA's decision to ignore malfunction emissions even at well-operated facilities with the best control equipment, these conclusions should lead EPA to its authority under CAA section 112(h) to prescribe alternative design, equipment, work practice, or operational standards where it is not feasible to set or enforce a numerical emission limit. EPA cannot rationally defend not applying the concept of "best performing" source to malfunctions. This ignores that there are work practices – such as monitoring of operating parameters to identify a malfunction and stopping or cutting back the process – that represent the best practices for minimizing emissions during a malfunction. While the measures that represent these best practices will depend on facility-specific issues, such as process design, pollution control train, and other factors, they nonetheless represent the "the maximum degree of

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[43] *See* 76 Fed. Reg. at 5805.

[44] 42 U.S.C. § 7412(h)(1). That the floor language for existing sources relies on the "average emission limitation achieved by the best performing 12 percent of the existing sources (for which the Administrator has emissions information)" does not allow EPA to deliberately ignore that sources malfunction. EPA has information indicating that the sources that provided the information establishing the floor experience malfunction events and that those emissions exceed the level for which EPA has set the floor. In other words, EPA has information regarding whether these sources "achieved" the emission limitation set by the proposal (i.e., that they have not).

[45] EPA acknowledged these potential obstacles to measuring emissions during SS&M events in the preamble to final emission standards for medical waste incinerators, 74 Fed. Reg. 51,368, 51,394 (Oct. 6, 2009): ("It would be very difficult to do any meaningful testing during such an event because the exhaust flow rates, temperatures, and other stack conditions would be highly variable and could foul up the isokinetic emissions test methods (thus invalidating the testing)."). See also proposed sections 63.1108(b)(4)(ii) and 63.1413(a)(2) (which would prohibit performance testing during malfunctions); n.7 supra.

reduction in emissions of the hazardous air pollutants...achievable...through application of measures, processes, methods, systems or techniques" and reflect "the emission control that is achieved in practice by the best controlled similar source[s]"[46].

Likewise, EPA's concern that consideration of emissions during malfunction events could lead to higher emissions is not a valid justification for the Agency's proposed approach and is misplaced. EPA asserts that "accounting for malfunctions in setting standards could lead to standards that are significantly less stringent than levels that are achieved by a well-performing non-malfunctioning source."[47] [Emphasis added]. However, simply establishing different requirements for malfunction and non-malfunction periods addresses this issue. EPA has done just that historically for RVs and maintains that approach in proposed §63.648(j). However, rather than establishing a standard for pressure releases, which EPA identifies as due to malfunctions, the Agency proposes a prohibition.

Finally, EPA's proposed approach is incompatible with a common sense understanding of malfunction events and, more importantly, how that term is used in EPA regulations. EPA defines "malfunction" as

> any sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.[48] [Emphasis added]

Given that PRDs are designed to operate only in malfunction periods, EPA has simply failed in its duty to develop a meaningful limit that is based on the reality of the covered equipment and that makes sense in the context of the Agency's definition of malfunction.

1.1.4.3 EPA Must Analyze Available Data and Exercise Its Discretion to Set Appropriate Standards For Malfunction Events.

It is possible to gather sufficient representative data reflecting emissions during malfunctions, and EPA is obligated to consider those data in its MACT floor calculations for all operating conditions. To the extent EPA has access to continuous monitoring data for emission units

[46] CAA § 112(d)(2) and (3)
[47] See 79 Fed. Reg. at 36,945
[48] 40 C.F.R. § 63.2 (emphasis added).

covered by RMACT 1 and 2, EPA could have conducted analyses of emissions levels during malfunction events.[49] Also, many types of sources are required by many state agencies to submit deviation reports or malfunction reports when they experience a malfunction that causes an exceedance of an applicable limitation. EPA does not appear to have made any attempt to obtain and analyze such reports, in order to assess what type of requirement might reasonably apply to the subject emission units during malfunctions.

There are several options EPA could use for setting MACT standards under CAA section 112 that would apply during malfunction events. For example, as done in many Refinery Consent Decrees, EPA could establish an emission limitation that applies at all times, but that has an averaging time of sufficient duration that short, infrequent spikes in emissions due to malfunctions would not cause the source to exceed the emission limitation (while at the same time ensuring that the source does not operate in a way that causes frequent, lengthy excursions above the normal controlled emission rate). EPA could have concluded that it has grounds to exercise its authority under CAA section 112(h) to promulgate a design, equipment, work practice, or operational standard, or combination thereof, because it is not feasible to prescribe or enforce an emission standard. EPA might also use these approaches in combination.

There is no indication in the Proposed Rule that EPA gave any consideration to these options, much less conducted the required statutory analysis of the performance of sources during malfunction periods. In short, there are ample reasons to reject EPA's conclusory assertions that it cannot take malfunctions into account when setting MACT standards for the subject source categories. EPA's failure to evaluate these options thoroughly renders the Proposed Rule arbitrary and requires EPA to develop a new proposal.

1.1.4.4 It Is Arbitrary and Capricious To Declare All Malfunctions Violations, Especially In the Case of Safety Critical Equipment Designed to Handle Malfunction Emissions.

Under this proposal, emission limitations apply to equipment upsets and malfunctions although compliance is unachievable or would require unsafe operations. Even equipment designed to operate <u>only</u> during process upsets (e.g., relief valves) are subject to unachievable limitations or prohibitions. Process malfunctions can be minimized, but not eliminated, and their consequences can be handled in ways that minimize safety risk and environmental

[49] Even if the continuous monitoring data are for parameters not regulated by the Proposed Standards, analysis of monitoring data for those other parameters during malfunction events might form a reasonable basis for EPA's assessment of what standards are achieved or achievable during malfunctions.

consequences. By declaring all malfunctions as violations and defining them in terms of the emissions during normal operations or prohibiting them, rather than establishing emission standards appropriate for periods of malfunctions, this proposal discourages safe and efficient operation and requires the addition of expensive facilities that provide no value.

EPA's failure to establish emission standards that consider emissions data from malfunction events is inconsistent with its statutory obligation to conduct a floor analysis and to issue standards at that level or to show using that same emissions data that a more stringent standard is achievable. Because the proposed standards are not achievable – even by the sources used to establish the floor for normal operations – the proposal creates a condition of regulatory impossibility and forces sources to choose between violating the CAA general duty requirement or the proposed standards.[50] EPA may not issue rules that "bake" non-compliance into the standard.[51]

API/AFPM has provided data and information on performance of refinery equipment during periods of malfunction in these comments, where the proposed limits are unachievable and we encourage the Agency to establish alternative standards in those cases. We have suggested alternatives that we believe meet the statutory requirements.

1.1.5 The Proposal to Require the Use of the Electronic Reporting Tool (ERT) is Not Appropriate as the Costs and Burdens Are Additive and Any Benefits are Questionable.

The proposed use of the Electronic Reporting Tool (ERT) is not appropriate because the costs and burdens imposed are additive to the costs of producing and submitting the written report, and there is no benefit that justifies the additional cost. EPA has not developed or articulated a reasonable approach to using information that would be uploaded to the ERT. API/AFPM recommends that EPA remove this portion of the proposal until the ERT is demonstrated to handle all the information from refinery performance tests (rather than only portions), thereby

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[50] In other rulemakings following the *Sierra Club* decision, EPA recognized and attempted to ameliorate this impossibility by codifying an affirmative defense to civil penalties for violations caused by malfunctions. See 79 Fed. Reg. at 36,945 ("In several prior rules, the EPA had included an affirmative defense . . . recognizing that there is a tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emissions standards may be violated under circumstances entirely beyond the control of the source." (emphasis added.). Importantly, this proposed rule does not include any affirmative defense provisions. See id. ((citing NRDC v. EPA, 749 F.3d 1055 (D.C. Cir. 2014), which vacated affirmative defense provisions in the NESHAP for the Portland Cement manufacturing sector).

[51] See Util. Air Regulatory Grp. v. EPA, 134 S. Ct. 2427 (2014) (holding that EPA cannot reject permissible statutory interpretations in favor of one that leads to absurd results); Landstar Express Am., Inc. v. FMC, 569 F.3d 493, 498-499 (D.C. Cir. 2009) ("A statutory outcome is absurd if it defies rationality.").

eliminating the need for both written and electronic reporting and until the Agency demonstrates that it is using the electronic data to develop improved air quality emission factors.

The primary benefit claimed for the use of the ERT is to increase the ease and efficiency of data submittal and improve data accessibility.[52] While API/AFPM generally supports these goals, the reality is the purported benefits are not being achieved and are unlikely to be achieved. There is essentially no likelihood the ERT systems will be able to handle entire part 63 performance tests in the foreseeable future, and the added ERT burden makes submission of reports within the short, required time (60 days) more difficult. In addition to the ERT's inability to handle complete test reports, this requirement does not supersede or replace any state reporting requirements and thus the regulated industry will be subject to dual reporting requirements. The preamble claim[53] that eliminating the recordkeeping requirements for performance test reports is a burden savings is false, since the ERT system cannot handle all part 63 test methods and States and Title V still require these records.

1.2 Residual Risk Analysis Comments.

(Detailed Comments on the Risk Modelling Prepared by Environ are Included as Attachment A-1).

1.2.1 Overview of EPA's Residual Risk Analysis and Conclusions. API/AFPM Encourages EPA to Incorporate All Corrections to Model Input Provided by Facilities and to Re-evaluate the Source Category Risk.

For each refinery, the EPA conducted a facility-wide residual risk assessment that provided estimates of both the chronic and the acute maximum individual risk (MIR) posed by the HAP emissions from each source in the source categories. The potential for both cancer and non-cancer effects were modeled, and an evaluation of the potential for adverse environmental effects for each source category was also performed. EPA calculated residual risk in a number of ways, including individual and population inhalation risks, multi-pathway exposure and risk screening, and environmental risk screening. For example, using the HEM-3 model, EPA calculated inhalation chronic risks from actual and MACT-allowable emissions.

[52] 79 Fed. Reg. 36948 (June 30, 2014)
[53] Ibid.

EPA's results demonstrated that, at every refinery, category-specific risks are below EPA's presumptive limit of acceptable risk (i.e., cancer risk of less than 100 in a million). Based on this, EPA concluded that category risks from both actual and allowable emissions are acceptable. EPA then considered whether the existing MACT standards provide an ample margin of safety. EPA proposes that they do, with certain additional applicability thresholds and controls being imposed on small storage tanks that were excluded from such controls under the existing rule. In accordance with the Section 112(f) of the Act, any new requirements added to increase the ample margin of safety must be justified taking into consideration costs, energy, safety, and other relevant factors. EPA determined that only these new requirements for small tanks met these criteria. No other requirements were found to be cost-effective for increasing the ample margin of safety, reflecting industry's concerted efforts to reduce emissions and the high level of controls currently required by the existing regulations.

In anticipation of this comprehensive residual risk modeling exercise, in 2011 EPA issued a massive Section 114 ICR to every refinery in the country. Refiners were required to provide extensive information on emissions inventories, source characteristics, process configurations, and feedstock properties. Many sites were also required to perform additional stack testing.

To help ensure a consistent and conservative basis for emission reporting for sources where actual emissions data were unavailable, the EPA required the sites to follow an extremely detailed Emissions Estimation Protocol. While there were a number of problems with the Protocol such as EPA's very conservative approach for estimating emissions from wastewater treatment and conveyance systems, it did provide a means to document the basis for all of the reported emissions data.

EPA has made a significant effort to work with individual sites to ensure that the information that was submitted was correct and that obvious errors were addressed, and, in fact, EPA, in their proposal, continues to seek corrections to the data. However, the review by ENVIRON (Attachment A-1) identified some questionable emission and location information in the model input, including some for which individual companies had submitted corrections. API/AFPM urges EPA to incorporate all corrections identified by ENVIRON or submitted by individual facilities and to reevaluate the potential risks from this source category.

1.2.2 Emission and Risk Reduction Potential Are Over-Stated Because the Emission Basis Used For Modelling is Out-of-Date.

The emission estimates used in the risk modelling represent the year 2010 and were developed primarily using EPA's Refinery Emission Estimating Protocol[54]. Numerous comments previously submitted to EPA concerning the Emission Protocol highlighted for EPA the fact that the Protocol emission factors grossly over-state emissions.[55] Furthermore, many of the estimating techniques and factors are new, have been subject to only limited review, and are untested. Of particular concern are the Protocol wastewater Emission Estimating Methodology and the questionable HAP speciation included for streams that have never been estimated before.

Many significant emission reductions have occurred since 2010 and those changes should have been reflected in the emission estimates and risk modeling, since they reflect the pre-Sector Rule situation more correctly than does 2010. Most significant of the changes not reflected in EPA's emission estimates are the reductions anticipated due to NSPS Ja, which has a compliance deadline of November 11, 2015 for most refinery flares and requires substantial reductions in flaring and thus flare emissions. Once the NSPS Ja flare flow work practice and flare gas minimization plan requirements are in place, flaring and flaring emissions will be significantly reduced. EPA estimated a reduction of 3600 tons per year (tpy) VOC from flares[56] as a result of NSPS Ja. Based on 11.5% HAP in flared VOC (EPA's estimate from their ICR data), NSPS Ja would also be expected to reduce flare organic HAP emissions by 414 tpy. We discuss EPA's and our estimates of the appropriate base line flare emissions in more detail in Comment 2.7.3.3.

Other changes that should also have been reflected in the emission basis for the risk modelling include the following:

- EPA states that the floor for the proposed delayed coker work practice standard is based on eight such units having to meet a 2 psig pressure limit[57]. The risk input should reflect

[54] RTI International, *Emission Estimation Protocol for Petroleum Refineries Version 2.1; ICR Response Version*, November 2011

[55] See, for instance, Docket Document EPA-HQ-OAR 2010-0682-0012 (American Petroleum Institute (API/AFPM) And National Petrochemical and Refiners Association (NPRA) Comments on the Draft Refinery Information Collection Request) and Letter from Matt Todd, API/AFPM and David Freeman, NPRA to Brenda Shine, EPA, *Review of the Emission Estimation Protocol for Petroleum Refineries – Review Draft*, March 31, 2010.

[56] See 77 Fed. Reg. 56425 (November 12, 2012), Table 2

[57] See 79 Fed. Reg. 36902-3 (June 30, 2014)

that limit, not their 2010 emissions. Furthermore, the SCAQMD has a rule in place that requires all 8 DCUs in that District to meet a 2 psig limit by late 2017 and those units should have been modelled on that basis as well.

- Consent Decrees specifically addressing flares, a focus of this proposal, have been put in place since 2010 for six Marathon Petroleum Refineries, the Shell Deer Park Refinery, the Flint Hills Port Arthur Refinery, the Countrymark Indiana Refinery, and the BP Whiting Refinery. The reductions in flaring and other emissions resulting from these and other refinery consent decrees should be reflected in the baseline emission and risk estimates.

1.2.3 EPA's Modeling Assumptions Are Overly Conservative and As a Result EPA Has Overstated The Risk Associated with Refinery Emissions.

As EPA explains at length in the preamble, EPA's residual risk modeling is overly conservative and not expected to be a realistic reflection of actual exposure and risks.

In developing the risk assessments for chronic exposures, EPA calculated the MIR for each facility as the cancer risk associated with a continuous lifetime exposure (70 years) to the maximum concentration at the centroid of inhabited census blocks. Individual cancer risks were calculated by multiplying the estimated lifetime exposure to the ambient concentration of each HAP (in $\mu g/m^3$) by its unit risk estimate (URE). The URE used in EPA's risk analysis represents an upper bound estimate of an individual's probability of contracting cancer over a lifetime of exposure to a concentration of 1 $\mu g/m^3$ of air. As EPA correctly points out, "Depending on the characteristics of the industry, these factors will, in most cases, result in an overestimate both in individual risk levels and in the total estimated number of cancer cases."[58]

In an attempt to estimate and model the risk associated with allowable emissions, EPA used their Refinery Emissions Model (REM Model) rather than the ICR-submitted information. The ICR protocol did not specify a method by which to calculate allowable emissions, therefore the methods used by the sites were not consistent across the industry. The REM Model makes a number of conservative assumptions, such as assuming that all allowable emissions are released from the centroid of the facility. As EPA points out "The combined post-processed

[58] Op. Cit., Page 36895

allowable risk estimates provide a high estimate of the risk allowed under Refinery MACT 1 and 2."[59]

EPA goes on to discuss other conservative assumptions that were used to perform both the chronic and acute exposure assessments. For example, the accuracy of the acute inhalation exposure assessment depends on the simultaneous occurrence of independent factors that may vary greatly, such as hourly emission rates, meteorology and human activity patterns. To be conservative, EPA assumed that individuals remain for 1 hour at the point of maximum ambient concentration as determined by the co-occurrence of peak emissions and worst-case meteorological conditions. As EPA states "These assumptions would tend to be worst-case actual exposures as it is unlikely that a person would be located at the point of maximum exposure during the time when peak emissions and worst-case meteorological conditions occur simultaneously."[60]

An additional conservative approach was employed by EPA to develop acute hourly emissions exposure data. EPA determined that the maximum hourly emission rate data collected in the ICR was inadequate. Therefore EPA elected to estimate the hourly emissions based on the reported annual emissions (converted to average hourly emissions in terms of pounds per hour) and then to apply an escalation factor, considering the different types of emission sources and their inherent variability, in order to calculate maximum hourly rates.[61] The escalation factors for these processes ranged from 10 to 60, and reflect EPA's arbitrary and, we believe, excessively conservative attempt to assign an emission variability factor to each source type. This approach deviates from past Risk and Technology (RTR) rulemakings. Where EPA has lacked hourly emissions data or other specific information about the source category processes, it assumed that the 1-hour emission rate for any emission point could be 10 times higher than its average hourly emissions rather than up to 60 times higher as assumed here.[62]

[59] Op. Cit., Page 36889
[60] Op. Cit., Page 36896
[61] OP. Cit., Page 36891
[62] Shine, Brenda, *Derivation of Hourly Emission Rates for Petroleum Refinery Emission Sources Used in the Acute Risk Analysis*, Docket EPA-HQ-OAR-2010-0682-0195, March 15, 2014

EPA made some additional unsupported adjustments to the ICR emissions data set. Based on the stack test data for FCCUs, EPA concluded that, on average, HCN emissions were a factor of 10 greater than the average emission factor provided in the Protocol. Therefore, EPA arbitrarily increased the HCN emissions for FCCUs in the emissions inventory by a factor of 10 for those sites that did not provide actual stack test data.[63]

1.2.4 API/AFPM Has Specific Concerns With EPA's Assumptions Concerning Benzene, Naphthalene, and Other POM Unit Risk Values. At a Minimum, The Unit Risk Factors are Extremely Conservative and Add to the Conservatism of the Risk Analysis.

The percentage contribution of naphthalene and benzene to total cancer incidences in the report were estimated to be 22% and 21%, respectively, with reported emissions of the same being 1.5% and 6.8% of the total emissions of all HAPs from the petroleum refining source category.[64] The EPA attributed 98% of the MIR resulting from equipment leaks and storage tanks to naphthalene and benzene, thus singling out these two HAPs as the major drivers of cancer risk from the Petroleum Refining Source Sector. Therefore, it is appropriate to further investigate the underlying toxicity values used to calculate these risks.

Benzene

The inhalation unit risk value developed for benzene under EPA's IRIS program is a range of values (2.2×10^{-6} to 7.8×10^{-6}). EPA has gone on record that each estimate has equal scientific plausibility.[65] The risk assessment performed in the refinery sector rule for the residual risk calculations utilizes the upper end of this range, biasing towards a greater cancer risk for each $\mu g/m^3$ of exposure to this substance. Often in risk assessments for benzene, the entire range is utilized resulting in a range of cancer risk estimates. As seen by the values in the range, if the lower end of the range had been utilized, the resulting cancer risk estimates may have been 3-4 times lower than those shown in the report.

That being said, EPA often defaults to a more conservative approach when estimating risk and the choice of the upper end toxicity value is conservative. However, given the statement that both the lower and upper end are equally plausible, it would be beneficial to see a balanced approach demonstrating the range of potential cancer risk attributed to this substance,

[63] 79 Fed. Reg. 36888 (June 30, 2014)
[64] Op. Cit., Pg. 36934
[65] http://www.epa.gov/iris/subst/0276.htm

especially when actions are being required by the refinery sector on the basis of the risk calculations.

Naphthalene

For several years, industry and EPA have been working together to resolve the question of whether naphthalene has been inappropriately classified as a possible or reasonably anticipated human carcinogen. In 2007 the multi-stakeholder Naphthalene Research Committee (NRC) was formed as a vehicle to identify and fund scientific studies as part of a multi-year, multi-million dollar program. With input from EPA, this research is designed to help answer questions about naphthalene's mode of action (MOA) and characterize its potential carcinogenicity. Extensive research has been conducted and published in the peer-reviewed scientific literature to help inform the health risks associated with exposure to humans at environmentally relevant concentrations.

EPA's analysis of the possible risk associated with exposure to naphthalene does not take into account the most recent scientific information. The naphthalene unit risk estimate (URE) used in the risk analysis originates from California EPA's Office of Environmental Health Hazard Assessment (OEHHA). This URE, adopted by California EPA in 2004, was established based upon National Toxicology Program (NTP) studies. Of note, EPA dropped its own URE value that same year citing a lack of evidence on naphthalene carcinogenicity in humans. Current research by the NRC has called into question the NTP studies in which the animals were dosed at concentrations exceeding the Maximum Tolerated Dose. These doses resulted in inflammation at or near a 100% incidence in both sexes of both species (mice and rats) that were tested, and suggest that cytotoxicity played a significant role in the tumor responses.[66]

In light of the new evidence, the California EPA URE is outdated and the validity of classifying naphthalene as a human carcinogen is highly questionable. The compelling evidence recently published argues that the evidence used to support the URE adopted by OEHHA is irrelevant to actual human risk. As a result of the NRC work, EPA is performing another IRIS program review of naphthalene carcinogenicity and derivation of cancer risk. This review has been delayed pending the outcome of the naphthalene research program that is in its final stages. This review will consider all the experimental evidence on naphthalene which has been published over the past several years.

[66] Naphthalene Research Committee comments submitted to EPA's IRIS Docket; August 20, 2014

In light of the latest experimental evidence on naphthalene, the use of the OEHHA URE is overly conservative and mischaracterizes the human risk posed by naphthalene. Specifically, the conclusion that naphthalene carries more weight than benzene (22% vs 21%) in driving the cancer risk should be reviewed. Thorough reviews of the scientific literature available following the 2004 development of the OEHHA URE is recommended. Again, the results of the research funded by the NRC suggest that the URE used by EPA in their risk analysis is overly conservative and that development of cancer in humans due to naphthalene exposure may not even be a relevant endpoint. At a minimum, recognition of this uncertainty and the work underway to resolve this uncertainty should have been addressed in the preamble in an effort to provide a balanced representation of the potential risk attributed to this substance.

1.2.5 Although EPA's Analysis Has Overstated The Risk Associated With Refinery Emissions, It Does Not Affect the Agency's Conclusion That Risk Levels Are Acceptable and That Only Additional Controls on Small Storage Tanks Are Justified As a Means To Increase the Ample Margin of Safety

In this proposal, EPA estimated risks based on actual emissions from petroleum refineries. EPA also estimated risks from allowable emissions which the Agency considers to be conservative and, as such, to represent an upper bound estimate on risk from emissions allowed under the current MACT standards for the source categories. The results indicate that both the actual and allowable inhalation and multi-pathway cancer risks as well as the chronic and acute non-cancer hazard risks meet EPA's presumptive limit of acceptability.[67]

EPA evaluated the reduction in risk associated with a number of additional potential controls on storage vessels, equipment leaks, gasoline and marine loading racks, cooling towers and heat exchangers, wastewater collection and treatment systems, FCCUs, flares, and other refinery emissions sources. With the exception of changing the applicability threshold to include controls on small storage vessels, no controls were identified that cost-effectively reduced the levels of risk. And, even in the case of storage vessels, the cost-effectiveness was largely driven by EPA's questionable assumption of credits associated with VOC recovery.

[67] OP. Cit., Page 36939

EPA has appropriately applied the statutory requirements under Section 112(f)(2) in evaluating whether more stringent standards are justified in order to provide an ample margin of safety to protect public health, taking into consideration costs, energy, safety, and other relevant factors. With the one exception of small storage tanks, EPA has concluded that additional controls for increasing the ample margin of safety are not justified. This conclusion is not surprising and reflects the industry's concerted efforts to reduce emissions and the high level of controls currently required by the existing regulations. API/AFPM agrees with EPA's conclusion that, aside from small storage tanks, additional control requirements are not justified under the Section 112(f) considerations.

1.2.6 Risk Modelling Review.

A detailed review of EPA's risk assessment by ENVIRON Corporation was commissioned by API. Risk modeling of the 33 refineries reported by EPA to have the highest cancer and chronic noncancer risk was conducted to assist API in verifying EPA's risk estimates and to identify key risk-drivers at those facilities for further review by API and member companies and correction if warranted. The ENVIRON report is included as Attachment A-1.

1.3 The Proposed Fenceline Monitoring Program Should Not Be Finalized. (Detailed Comments on the Proposal are Included as 1.4 and ERM's Reports Associated With the API/AFPM Pilot Test Program are Included as Attachments B-1 through B-4.)

EPA proposes a new section §63.658 of RMACT 1 to require monitoring of benzene concentrations at the refinery fenceline. EPA argues that this monitoring is authorized under section 112(d)(6) as an advancement in monitoring for detecting fugitive emissions (from sources such as equipment leaks and wastewater treatment and handling)[68]. EPA also claims that fenceline monitoring is justified as a method of assuring that the emission estimates used to evaluate the risk posed by each refinery were accurate[69].

The proposal imposes a two-week rolling annual average maximum benzene concentration action level (9 µg/m^3 annual average) based on a measurement method using 2-week integrated samples from around the refinery fenceline. Exceeding this action level would trigger a root cause analysis and corrective action (RCA/CA). If follow-up monitoring after the

[68] 79 Fed. Reg. 36920 (June 30, 2014)
[69] Ibid.

corrective action indicates a continuing problem, EPA would dictate further actions, with no limitations on what could be required. Further corrective action decisions and requirements would not be delegated to state agencies.

All monitoring results would be posted by EPA on one of their websites. Three years is allowed to begin monitoring and the first compliance annual average would be due one year later. The proposal includes two draft part 63 Appendix A methods that provide the detailed methodologies to be used. Monitor siting and sample collection requirements are included in Draft EPA Method 325A and specific methods for analyzing the sorbent tube samples are specified in Method 325B.

In Comment 1.3.1 through 1.3.8 we provide our comments on this program relative to its legality, justification, and cost as a basis for our recommendation that this portion of the proposal not be finalized. API/AFPM makes this recommendation after careful consideration of the associated docket information, refiners' experiences with various forms of fenceline monitoring, and EPA's reported experience with a one-year pilot study[70]. In addition, API/AFPM sponsored a pilot project in 2013 to evaluate the draft fenceline monitoring methods expected to be incorporated by the EPA into this proposal[71]. Twelve major source petroleum refineries volunteered to collect data for six (6) two-week periods. The program was managed by Environmental Resources Management (ERM) and their report is provided as Attachment B-1 and B-2. Attachments B-3 and B-4 include reports on follow-up analyses performed by ERM.

Section 1.4 of these comments includes our detailed comments on the specifics of this proposal and the two associated Draft Methods for consideration, should the proposed fenceline monitoring program be finalized.

1.3.1 Fenceline Monitoring Should Not Be Finalized Because It is Not Needed to Demonstrate Compliance and Does Not Provide Information on Community Exposures.

There is no correlation between the fenceline maximum benzene value and equipment leak or fugitives emissions and thus this requirement is not a compliance assurance method for those emission types. The fenceline benzene concentration is a function of the location of sources of

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[70] See Thoma, E. D., Miller, M. C., Chung, K.C., Parsons, N. L., and Shine, B.; Facility Fence Line Monitoring using Passive Samplers, at http://cfpub.epa.gov/si/si_public_file_download.cfm?p_download_id=501667

[71] Draft Methods 325A and B, as proposed here are slightly different than the earlier drafts used for the pilot studies, but the pilot study contractor has reviewed the proposed methods and incorporated their thoughts on the differences into their report.

all types within the facility, not just fugitive sources, and will include contributions from mobile and non-refinery sources. Release heights and velocities as well as wind direction and speed variability will be dominant influences on the individual monitor measurements. The fenceline concentration at any given point in time is the result of how far the downwind fenceline is from the centroid of the each benzene emissions source as well as the wind direction, speed and variability. Thus, the fenceline concentration cannot be used to evaluate the emissions rate for sources, even if their contribution could be parsed. Furthermore, even if fenceline benzene levels could be correlated with fugitive emissions, this measurement would simply be a duplication of the source specific monitoring already specified for equipment leaks in RMACT 1, state and local rules and permits.

It is worthwhile to note that EPA has not felt the need to impose such a requirement for other source categories, with essentially the same fugitive emission requirements. In fact, in the Generic and Amino/phenolic Resins NESHAP amendments finalized on October 8, 2014, where very similar requirements to those proposed here are imposed, EPA confirms that existing fugitive emission compliance requirements are adequate to demonstrate compliance, stating "We further believe that the monitoring requirements included in these rules are sufficient to ensure compliance with the standards regardless of whether or when a violation occurs.[72]"

Another stated purpose of fenceline monitoring is to "provide important information to communities concerned with potential risks associated with emissions from fugitive sources," despite EPA's recognition that "currently available emissions and monitoring data do not indicate that risks to nearby populations are unacceptable." Pollutant concentrations "fall off" rapidly with distance from the source (approximately as distance-squared). Also, wind patterns vary, so the fenceline concentration is not an accurate predictor of exposure concentrations. Thus, data collected at the fenceline are not directly applicable to community exposure, and EPA has not proposed how they will take the data gathered at the fenceline and transform it into information that is useful for communities concerned about risks.

1.3.2 The Proposed Fenceline Monitoring Standard is an Unlawful Ambient Air Standard for Benzene.

Section 112 of the CAA only authorizes EPA to establish "emission standards." Specifically, section 112(d)(1) states: "The Administrator shall promulgate regulations establishing <u>emission standards</u> for each category or subcategory of major sources …." Similarly, section 112(d)(6)

[72] 79 Fed. Reg. 60913 (October 8, 2014)

states: “The Administrator shall review, and revise as necessary …, emission standards promulgated under this section ….” The term “emission standard” is defined in CAA §302(k) to mean:

> a requirement established by the State or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction, and any design, equipment, work practice or operational standard promulgated under this Act.

The proposed fenceline monitoring standard would not “limit the quantity, rate, or concentration of emissions” from any given emissions point. To the contrary, it attempts to impose a general concentration limit on the ambient air around a refinery. Nor can it be argued that the proposed fenceline monitoring program is an authorized “design, equipment, work practice or operational standard” under section 112(h). EPA did not cite section 112(h) as authority for the proposed fenceline monitoring standard. Although the proposal has some of the appearance of a work practice, EPA has not shown it to be justified under section 112(h). As such, the fenceline monitoring requirements do not constitute an “emission standard” authorized under section 112.

Instead, the proposed standard constitutes an ambient standard for benzene emissions, which a refinery must meet or perform injunctive relief which may or may not address the source of the benzene. EPA even describes this limit as an ambient air standard in the center column on page 36920 of the proposal preamble, where it says, “in this action, we are proposing a HAP concentration to be monitored in the ambient air around a refinery, that if exceeded, would trigger corrective action to minimize fugitive emissions.” EPA’s claim that this is simply additional “monitoring” is belied by the fact that EPA refers to the action level as a “not-to-be-exceeded” level, imposes EPA-specified additional controls if the standard is exceeded more than once, and requires the action level to be met if sources want to use the Optical Gas Imaging Alternative in proposed §63.661(a)(2). Considered together, the proposed requirements have all the trappings of enforceable standard but, in this case, an ambient standard, which is not authorized under section 112.

1.3.3 By Focusing On Ambient Air Quality, the Proposal Improperly Conflates 112(d)(6) and 112(f) Analyses and Contradicts EPA Findings Under the Latter.

As discussed above, EPA’s proposed fenceline monitoring requirement establishes an ambient air quality standard for benzene, which is not authorized by section 112. Not only is the proposal not tied to any specific emission unit or refinery process, EPA has not supported the requirement with any analysis of health or environmental effects. Consequently, the proposal is arbitrary, capricious and beyond the scope of EPA's authority.

EPA has cited section 112(d)(6) as its authority to impose what it characterizes as new "monitoring" requirements. Even viewed in its best light, measurement of ambient levels of benzene at the fenceline of a facility could be statutorily relevant only to an analysis of whether there is residual risk under section 112(f). Yet, EPA has already conducted its risk analysis and concluded that existing standards do not present risks above the presumptive levels of acceptability and, with modest revisions to tank standards, will provide an ample margin of safety.

EPA's proposal – whether one accepts that it is an ambient air quality standard or simply enhanced monitoring – contradicts EPA risk findings. On the one hand, EPA has found no unacceptable risk, but on the other hand, EPA is trying to impose risk-related requirements using section 112(d)(6) "just in case." Two of EPA's stated reasons for this proposal – confirmation of emission estimates on which the risk analysis was based and providing information to communities concerned about risk – drive home the truth behind this fenceline monitoring proposal. EPA is improperly trying to use section 112(d)(6) to impose additional requirements not justified under section 112(f).

1.3.4 The Proposed Fenceline Monitoring Standard is Unlawful Because It Is Not a Revision To Any Existing MACT Emission Standard.

EPA asserts section 112(d)(6) as authority for imposing the proposed fenceline monitoring standard[73] claiming that the fenceline monitoring would help detect large leaks from a variety of "fugitive" emission sources including tank seals, equipment components, and wastewater operations. Section 112(d)(6) authorizes EPA to "review, and <u>revise</u> as necessary (taking into account developments in practices, processes, and control technologies), <u>emission standards</u> promulgated under this section…."

The proposed standard is not authorized under section 112(d)(6) because:

1. The proposed standard constitutes an entirely new emission standard and is not a revision to any existing MACT emission standard. EPA claims that the proposed standard would help control fugitive emissions "from the petroleum refinery as a whole." Yet, under this rule each of the types of

[73] 79 Fed. Reg. 36951 (June 30, 2014)

"fugitive emissions" cited by the Agency has its own separate and unique emissions standard. This clearly, then, is a new standard that previously did not exist and is not derived from any existing standard.

2. Alternatively, the proposed standard is not a revision to any specific or specified existing emission standard. Instead, it is an unlawful single standard that constitutes a revision to and duplicative addition to several underlying emission standards (e.g., tank standards, LDAR standards, wastewater standards).

EPA further asserts that the fenceline monitoring program is justified under section 112(d)(6):

> Because the requirements and decisions that we are proposing in this action are based upon the emissions inventory reported by facilities in response to the 2011 Refinery ICR, and considering the uncertainty with estimating emissions from fugitive emission sources, we believe that it is appropriate under CAA section 112(d)(6) to require refiners to monitor, and if necessary, take corrective action to minimize fugitive emissions, to ensure that facilities appropriately manage emissions of HAP from fugitive sources.[74]

Again, this is an unauthorized basis for a section 112(d)(6) standard, since there is no demonstration that ICR emission inventories have any bearing on whether there have been "developments in practices, processes, and control technologies."

1.3.5 The Proposed Fenceline Monitoring Standard is Unlawful Because EPA Is Wrongly Applying section 112(d)(6) Twice To The Same Existing MACT Emissions Standards.

EPA states unequivocally that the Refinery Sector Rule proposal incorporates a section 112(d)(6) review of all existing tank, LDAR, and wastewater operation standards, indicating:

1. For storage vessels, "we are proposing to lower the size and vapor pressure threshold and to require additional fittings on tanks…."[75]

2. For LDAR, possible revisions were rejected "as not being cost effective."[76]

[74] 79 Fed. Reg. 36920 (June 30, 2014), left column
[75] 79 Fed. Reg. 36919 (June 30, 2014), center column
[76] 79 Fed. Reg. 36919 (June 30, 2014), right column

3. For wastewater operations, "further wastewater requirements are not cost effective."[77]

Notwithstanding this review, EPA states that it "remain[s] concerned regarding the potential for high emissions from these fugitive sources due to the difficulties in monitoring actual emission levels."[78] EPA cites as examples leaking tank seals and water seals that become dry over time.

EPA then asserts that the proposed fenceline monitoring standard is warranted because it "will identify a significant increase in emissions in a timely manner (e.g., a large equipment leak or a significant tear in a storage vessel seal), which would allow corrective action measures to occur more rapidly than it would if a source relied solely on the traditional infrequent monitoring and inspection methods."[79]

Under this logic, the proposed fenceline monitoring standard effectively represents a section 112(d)(6) review of the proposed outcome of EPA's concurrent section 112(d)(6) review of the same emission standards. Such a concurrent review of the proposed outcome of a section 112(d)(6) review is unlawful because EPA is not reviewing "an emission standard promulgated under this section."

1.3.6 It is Unreasonable and Unlawful To Require Refiners to Take Corrective Action (CA) at Facilities That are Not Part of the Source Category and That They May Not Even Own. CA Requirements Must Be Limited to RMACT 1 Sources.

Proposed §63.658(h) requires CA if the fenceline action level is exceeded, even if the RCA indicates that the cause of the exceedance is not from a stationary source within the refinery (e.g., it is due to a mobile source), is not from a source regulated by RMACT 1 (e.g., it is due to a chemical operation), or is not from a source owned or operated by the refinery. Section 112 of the CAA only authorizes regulation of stationary sources and limits each NESHAP's requirements to only sources in the source category to which that NESHAP applies. Under this proposal, refiners are being asked to take CA in response to emissions from mobile sources, sources that are not even potentially covered by RMACT 1, sources owned by others, and sources physically located outside the refinery. Such a requirement is unlawful. Furthermore,

[77] 79 Fed. Reg. 36920 (June 30, 2014), left column
[78] Ibid.
[79] 79 Fed. Reg. 36920 (June 30, 2014), center column

such a situation could require a refinery to record and publically state emissions profiles from sources not under their control, thereby potentially allowing a neighboring facility to sue a refinery that conducted investigative measurements near their facility and implicated their facility as a benzene source.

The only alternatives to this mandate are 1) to develop site specific monitoring per proposed §63.658(i) that would allow a correction factor to be used in calculating the action level or 2) to make other reductions to offset the impact of the non-RMACT 1 emissions. Neither of these options is reasonable or always feasible. Developing site specific monitoring is a prospective activity and would not alleviate the need for CA for a previous occurrence. Nor is it even feasible for unusual or non-stationary causes (e.g., emissions from mobile sources, emissions from spills, emissions from nearby fires) or offsite sources that cannot be accessed for routine sampling. Nor is it lawful to require refiners to offset benzene emissions from other sources since, as discussed previously, CAA 112 does not authorize an ambient air benzene standard or the imposition of controls to meet such a standard. Since the action level is driven primarily by wind direction and the distance of the emissions from the monitor, it may be infeasible to offset an emission point located near the fenceline maximum sampler.

1.3.7 It Has Not Been Demonstrated That A Fenceline Monitoring Program Adds Any Value.

1.3.7.1 The Proposed Fenceline Monitoring Standard is Arbitrary and Capricious Because It Does Not Adequately Measure The Fugitive Emissions To Which It is Purported to Apply.

EPA asserts that the proposed fenceline monitoring standard is intended to monitor fugitive HAP emissions from affected sources. We assume EPA is referring to the entire collection of fugitive emission sources regulated by RMACT 1[80], not individual fugitive sources (i.e., individual valves, pumps, compressors, etc.). The Agency admits, however, that the proposed monitoring method can be confounded by a number of other HAP emissions sources – e.g., off-site emissions from non-affected sources, emissions from nearby affected sources (other petroleum refineries), emissions from on-site and off-site sources from outside the RMACT 1 source category, and emissions from on-site non-fugitive sources.

[80] RMACT 2 does not address fugitive emissions, so any impact on the fenceline results from RMACT 2 would be an interference with the stated purpose.

The proposed methodology attempts to account for some of these other emissions sources in various ways, including the following:

1. Background benzene levels are estimated as the "lowest measured fenceline concentration." Background is then subtracted from the maximum measured level to determine the maximum fenceline concentration. This is the default method.

2. If the default method does not work for a site, the site is allowed to develop a site-specific plan to determine the appropriate background level and, if the plan is approved by EPA, subtract out the site-specific background level.

3. Affected sources are also allowed to develop a site-specific plan for accounting for emissions from non-affected sources (e.g., HON or other non-refinery sources located within the refinery fenceline), and with EPA's approval of the plan, subtract out these sources.

Affected sources may not, however, account for on-site non-fugitive sources. These proposed adjustments are inadequate because measured fenceline (ambient) benzene concentrations will be due to far more complex and varying factors than EPA proposes to account for, including:

1. Downwash from buildings and other structures located both onsite and offsite.

2. Emissions from other sources that are part of the refinery affected source (e.g., Group 2 sources).

3. Emissions from mobile sources within or passing through the refinery, particularly mobile sources that may operate near the fenceline.

4. Emissions from buildings near the fenceline.

5. Emissions from sources within the refinery that are not owned or operated by the refinery.

6. Local topography.

As a result of all of these interferences and confounders and the inability of the methodology to segregate individual regulated emission sources or even emission types, fenceline benzene levels cannot be used to determine compliance with any of the applicable RMACT 1 standards.

1.3.7.2 The Pilot and Available Ambient Data Demonstrates That The Claim that Fenceline Monitoring Will Show Emission Estimates are Understated is Invalid.

While not claiming that confirming refinery emission inventories provides a legal basis for proposing this monitoring, EPA argues that confirming those inventories will be an important benefit, claiming that various anecdotal information, non-specific measurements, and a few DIAL measurements at refineries suggest refinery emissions are significantly understated[81]. However, the pilot studies undertaken by EPA and the refining industry[82] demonstrate either that there is no such underestimation or that fenceline benzene data cannot be used to validate emission estimates. In either case, confirmation of emission estimates is an invalid argument for imposing this monitoring because mass emission rates from refinery sources are not correlated with refinery fenceline concentrations.

The proposed fenceline benzene action level is 9 μg/m^3 and represents the highest fenceline benzene level for any individual refinery as predicted by EPA's dispersion model at polar rings or census block centroids near the refinery fenceline.[83]

Table A-2 of Attachment B-1 shows the background-corrected benzene concentrations (ΔC) found during the pilot studies.

Table A-2. Overview of Pilot Program Results

		EPA Study (2009)	API/AFPM Study											
			A	B	C	D	E	F	G	H	I	J	K	L
ppb benzene	Max Concentration (Any Point, Any Period)	29.3(1)	0.77	1.2	1.4	0.38	0.68	4.1	6.4	3.9	1.1	0.54	0.82	1.3
	ΔC Max for Any Period	8.6	0.64	0.90	1.2	0.17	0.54	3.9	6.2	3.3	0.91	0.24	0.59	1.1
	ΔC Average(2)	2.5	0.33	0.72	0.89	0.13	0.30	2.10	2.4	1.8	0.51	0.17	0.34	0.66
	ΔC Std. Dev.	2.2	0.19	0.19	0.24	0.05	0.12	1.12	2.0	0.85	0.27	0.02	0.07	0.13
Std. Dev. as % of Mean		86.2%	56.2%	26.8%	27.1%	34.4%	39.2%	53.4%	82.9%	48.4%	52.9%	15.0%	19.6%	19.7%

(1) This value exceeded the demonstrated linearity range of calibration. It was not used in the calculation of the ΔC value.
(2) The EPA Study is the average of 12 months (26 sampling rounds) of data. The API/AFPM Study is the average of 12 weeks (6 sampling rounds) of data. The proposed EPA action level is based on the average of 12 months (26 sampling rounds).

[81] See, for instance Docket Document EPA-HQ-OAR-2010-0682-0210, B. Shine, Fenceline Monitoring Technical Support Document, January 17, 2014, pages 2 and 3.
[82] See Attachment B-1
[83] Docket Document EPA-HQ-OAR-2010-0682-0208, T. Parma and D. Smith, EPA, to Brenda Shine, EPA, *Fenceline Ambient Benzene Concentrations surrounding Petroleum Refineries*, January 7, 2014.

None of the refineries had study-averaged ΔC concentrations (albeit less than a year for the API pilot study) that exceeded the proposed action level of 9 μg/m^3. This data, even though it was collected with a method that does not isolate refinery fugitive emissions and would likely include many interfering sources of benzene, provides some evidence that US refineries are not underestimating emissions.

Furthermore, there is significant ambient air monitoring performed that further supports low benzene concentrations in the vicinity of refineries. For instance, in the Beaumont Port Arthur Area there is a state of the art network of monitoring stations managed by the Southeast Texas Regional Planning Commission Air Quality Group which continuously monitors benzene throughout those communities. In addition, the Texas Commission on Environmental Quality (TCEQ) operates a separate air monitoring station network immediately adjacent to the Total Port Arthur refinery's fenceline. In May 2014, Port Arthur demonstrated 5 consecutive years below 1.4 ppb (approximately 5 μg/m^3) for benzene.

Similarly, the Texas Commission on Environmental Quality recently reported[84] that ambient benzene levels in the Texas City area (where there are several large refineries) typically is <1.4 ppb and that it is proposing to remove that area from its benzene watch list. They state:

> Stationary monitoring data show that annual average benzene concentrations have remained below 1.4 ppbv at each monitoring location in Texas City for two consecutive years. For example, the 2010 and 2011 annual average benzene concentrations were 0.5 ppbv at TCEQ's Texas City Ball Park Monitor; 0.4 ppbv and 0.3 ppbv (respectively) at BP's 31st Street Monitor; 0.6 ppbv and 0.5 ppbv at BP's Logan Street Monitor; and 0.9 ppbv and 0.8 ppbv at Marathon's 11th Street Monitor. The TCEQ determined that monitored concentrations can reasonably be expected to be maintained below levels of potential concern and is proposing to remove benzene in Texas City from the APWL.

Thus, with the existing data, EPA has enough evidence to demonstrate that emissions are not underestimated and the risks posed are not unacceptable.

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84 Texas Commission on Environmental Quality, Air Permits Division, Air Pollutant Watch List Proposed Change, Removal of *Texas City, Benzene*, March 11, 2013, see Announcement Section of http://www.tceq.state.tx.us/toxicology/AirPollutantMain

1.3.7.3 If, As Is Claimed, This Proposal is A Monitoring Technology Improvement Under section 112(d)(6) for Equipment Leak, Storage Tank and Wastewater Emissions, Existing Monitoring for Those Emissions Is No Longer Needed and Must be Eliminated.

For the reasons stated above, we do not believe the proposed fenceline monitoring is a technology development for equipment leak, storage vessel or wastewater sources. However, if these requirements are finalized on that basis, there is no need or regulatory basis for imposing both the fenceline monitoring requirements and the existing individual emission limitation compliance demonstration methodologies. Thus, equipment leaks monitoring using Method 21, storage tank inspection requirements and the monitoring requirements for waste management unit emission controls should be deleted from RMACT 1. Addition of fenceline monitoring on top of the existing MACT requirements goes against the Executive Order 12866 mandate to avoid redundant, costly regulatory requirements that provide no emission reductions.

1.3.8 We Estimate The Annual Cost for 142 Refineries at Approximately $29 Million Versus EPA's Estimate of $6 Million.

EPA estimates the first year installation and equipment costs for the proposed passive tube monitoring system to be up to $100,000 for larger refineries (i.e., 24 sampling locations). They estimate annualized costs for ongoing monitoring to be approximately $40,000 per year, assuming the ongoing sample analyses are performed in-house. In total, EPA estimates an investment cost of $12.2 million and annual operating cost of $3.83 million and a total annualized cost of $5.58 million.

Based on the number of sample locations identified in EPA's and our pilot studies and the significant number of additional samplers required by the revised requirements for subgrouping in the proposed Draft EPA Method 325A, the number of samplers used as the basis for EPA's estimates is significantly understated, perhaps by as much as 100%, depending on how irregular the shape of the refinery boundary might be and whether it has discrete areas. In fact, several refineries will likely have to have multiples of the minimum number of samplers, because they have disjointed property that would have to have the minimum number of samples at each parcel. In addition, §63.658(c)(3) requires one duplicate sample for every ten samples and 2 field blanks per sampling round. Many sites will also add samples to develop site specific background correction data. Thus, 40 samplers per site and 48 samples every 14 days for a large site is a much more reasonable estimate than EPA's assumption of 24 samplers and samples per site.

In addition, the per unit analysis costs will be at least double the EPA estimates because most analyses will be done by outside laboratories in order to meet the QA/QC requirements specified in Draft Method 325B and to minimize inter-laboratory variability. In particular, small refineries would have a hard time handling such a program in-house. With more samples and higher per unit analysis costs, annualized costs are expected to be in the range of $200,000 per year per refinery versus EPA's $40,000 per year estimate. That is, industry costs are likely to be in the range of $23 million per year.[85]

While less significant, there will also be costs incurred for installing and maintaining the required weather station as well as for the fencing, lighting, and other infrastructure associated with locating these samplers at the property boundary.

Finally, we suggest EPA assume the need for one 1 RCA/CAA analysis every two years, with a resource requirement of 48 hours of technical time (3 days of effort is the minimum needed to investigate and analyze any event and document that analysis) and 48 hours of operator time (a minimum amount of field time to locate the source). Using EPA's estimate of $84/hour for technical time, this adds somewhat more than $1 million per year to the industry total cost.

While we have not performed similar analyses for the real time monitoring estimates developed by EPA, we believe they are also significantly understated because they do not reflect the large number of monitors that would be required because of the complex geometry of many refinery property boundaries or the very high costs of maintaining such monitors. Thus, while the costs for the proposed program is understated, we believe the cost of alternative real-time monitoring approaches is even more understated than is reflected in EPA's alternative evaluation.

1.4 Specific Comments on The Proposed Fenceline Monitoring Work Practice.

In section 1.3 of our comments, we outline the lack of authority or justification for the proposed fenceline work practice monitoring program and recommend that it not be finalized. None-the-less, in this section, we provide comments on the specific proposed work practice. These comments add further weight to our position that this program should not be finalized. If a new monitoring program is justified, it must be simple and produce valid and useful data.

[85] One medium throughput refinery reports they will have 42 sample locations and that they have received an estimate of $250,000 for the first year and $200,000 for the second year.

1.4.1 The Fenceline Monitoring Program Action Level Must Reflect Variability. API/AFPM Recommends an Action Level of 15 µg Benzene/m³.

Key to the fenceline monitoring program proposal is the action level that would trigger an RCA/CA. In this proposal the action level has been established as 9 µg/m³ calculated as the difference between the maximum and minimum individual two-week samples for each sampling period, expressed as a one-year rolling average. EPA explains the derivation of this level as follows.

> We selected this proposed fenceline action level by modeling fenceline benzene concentrations using the emissions inventories reported in response to the 2011 Refinery ICR, assuming that those reported emissions represented full compliance with all refinery MACT requirements, adjusted for additional control requirements we are proposing in today's action. … this modeling effort evaluated the annual average benzene concentration at the fenceline, so that this action level applies to the annual average fenceline concentration measured at the facility.[86]

As shown in Table A-2 of Attachment B-1 (reproduced here), the standard deviation around the mean maximum benzene concentration for each site is quite high (over 80% of the mean for the EPA Flint Hills Study and AFPM pilot study facility G). While this may reflect the variability due to changing emissions and wind parameters, it is likely some of this is due to process variability and sampling and analysis variability. Dispersion samplers are sensitive to environmental factors such as wind speed, temperature, and humidity, and as discussed in the next paragraphs, there can be significant inter-laboratory variability.

Table A-2. Overview of Pilot Program Results

		EPA Study (2009)	API/AFPM Study											
			A	B	C	D	E	F	G	H	I	J	K	L
ppb benzene	Max Concentration (Any Point, Any Period)	29.3$^{(1)}$	0.77	1.2	1.4	0.38	0.68	4.1	6.4	3.9	1.1	0.54	0.82	1.3
ppb benzene	ΔC Max for Any Period	8.6	0.64	0.90	1.2	0.17	0.54	3.9	6.2	3.3	0.91	0.24	0.59	1.1
ppb benzene	ΔC Average$^{(2)}$	2.5	0.33	0.72	0.89	0.13	0.30	2.10	2.4	1.8	0.51	0.17	0.34	0.66
ppb benzene	ΔC Std. Dev.	2.2	0.19	0.19	0.24	0.05	0.12	1.12	2.0	0.85	0.27	0.02	0.07	0.13
Std. Dev. as % of Mean		86.2%	56.2%	26.8%	27.1%	34.4%	39.2%	53.4%	82.9%	48.4%	52.9%	15.0%	19.6%	19.7%

(1) This value exceeded the demonstrated linearity range of calibration. It was not used in the calculation of the ΔC value.
(2) The EPA Study is the average of 12 months (26 sampling rounds) of data. The API/AFPM Study is the average of 12 weeks (6 sampling rounds) of data. The proposed EPA action level is based on the average of 12 months (26 sampling rounds).

[86] 79 Fed. Reg. 36925-6 (June 30, 2014)

The results for duplicate samples sent to separate laboratories in the API study indicated one lab (the check lab) consistently reporting higher benzene uptake, by an average of 44%[87], and therefore, would have consistently calculated higher benzene concentrations had it been used for the study samples. Investigation during the course of this work did not identify a reason for this difference. As a result, API/AFPM asked ERM, the pilot study contractor, to conduct a laboratory proficiency test (PT) on the two laboratories used in the API/AFPM pilot fenceline monitoring study in order to confirm whether a systematic bias is occurring. Any such bias is not an issue in the pilot study itself, because all of the sample results were obtained using the same laboratory. However, systemic bias is an issue in estimating the laboratory variability that will occur if this program is finalized and the 142 refineries impacted are sending samples to different laboratories.

The inter-laboratory evaluation was conducted in July 2014. The results show that one laboratory consistently obtained results 20% lower than the spiked standard, while the other laboratory consistently obtained results 5% higher than the standard. It should be noted that all results fall within the QC Performance Acceptance Limits (PALs) of 39.1 ng to 59.6 ng for the certified standard, but the results for the one laboratory are very close to the lower limit. ERM observed that there appeared to be a consistent difference in the recovery of benzene from the sorbent, but the cause of the difference was not identified. ERM's report on this comparison is provided as Attachment B-4.

API/AFPM also asked ERM to evaluate the inherent uncertainty in the laboratory methodology (Draft Method 325B). Their analysis (included as Attachment B-3) calculated an overall uncertainty from application of proposed Method 325B of approximately 63 percent.

This the API/AFPM pilot study results and associated studies suggest significant potential variability (as much as 63%) in the analysis methodology and potential bias on the order of 25% due to with inter-laboratory differences. Additionally, there is variability in sorbent adsorption due to differences in sorbent activity between batches, packing density, weather conditions, particularly humidity, and presence of competing species. The extent of adsorption variability is unknown. API/AFPM therefore suggests a variability adjustment of at least 75% of the action level (7 $\mu g/m^3$ adjustment) is needed to minimize the risk of false action level exceedances from sampling and measurement biases and variability. For convenience and conservatism, we have rounded the resulting 16 $\mu g/m^3$ action level to 15 $\mu g/m^3$ and that is our recommendation for an action level that considers methodology variability.

[87] See Attachment B-1, Section 3.4.3.

Process variability can also be significant over time. The 2010 data obtained in the ICR effort reflects the processes and equipment in place that year. Furthermore, it represents the average emission profile (i.e., leak rate distribution) for the hundreds of thousands of equipment leak components in the refinery and the average emission rate from the point sources for that year. Basing the action level on an annual average, as is proposed, should account for summer/winter effects, but the equipment in a refinery (including the refinery on which the action level is based) and the emissions profile for the equipment leak components in a refinery change year to year and point source emissions vary with production rates, product slate and turnaround schedules. Had a different year been modelled a somewhat different fenceline action level would likely have been set. Furthermore, addition of process units and even pollution monitors and controls, such as those that will be required in response to this rulemaking, will add equipment leak components and emissions[88] that are not accounted for by the modelling of the year 2010. Thus, the proposed action level could also be adjusted for the variability that will occur in refineries as component counts and emission rates vary from year to year. Since the process variability is difficult to define, we do not have a specific recommendation for this adjustment and believe the recommended 15 µg/m^3 may be adequate.

1.4.2 Benzene is the Appropriate HAP to Use for Refineries.

Comment is requested on whether it would be appropriate to require multiple HAP to be monitored at the fence line considering the capital and annual cost for additional monitors, and if so, which pollutants should be monitored[89]. EPA explains their reasoning for using benzene as a surrogate for all HAPs on page 36924 of the preamble. We believe that reasoning is correct relative to the question in the request for comment, though as discussed above it is unclear that benzene fenceline information provides useful and accurate information about fugitive emissions and population exposure.

Benzene is appropriate for refineries because it is the most ubiquitous HAP, present in all refineries, and present in most HAP streams common to basic refinery processes. It is generally one of the higher mass HAP emitted by refineries and thus would be among the easiest to

[88] Even non-leaking components are estimated under EPA procedures at a “default zero” emissions rate and thus adding components will raise equipment leak emission estimates, even if none of the components are “leaking” above the minimum measurable rate.
[89] 79 Fed. Reg. 36924 (June 30,2014)

monitor with samplers. Other HAPs would usually be present in lower concentrations and therefore be harder to analyze and result in more non-detects. Furthermore, longer sample times and multiple samplers and multiple analyses would likely be required if additional HAPs are required, for no improvement in understanding refinery emissions. Additional HAPs would only add to costs, providing no additional information.

1.4.3 Many Problems with The Proposed Methodology Must Be Resolved to Make the Proposal Workable.

Fenceline sampling and monitoring requirements are contained in proposed §63.658 and EPA Draft Methods 325A (sampling) and 325B (handling and analysis of completed samples). A number of issues have been identified and these are discussed below along with our recommendations for addressing the issue. Additional discussion on some of these items is included in the API Pilot Study Report in Attachment B-1.

1.4.3.1 There Are Significant Technical and Clarity Problems With the Proposed Sampling Procedures

1.4.3.1.1 The Refinery Perimeter That is the Basis for This Monitoring Must be Clarified.

1. Proposed §63.658(a) specifies that sampling be done at the property line. Draft Method 325A repeats that in Section 1.1 and defines "fenceline" as the property boundary in Section 3.1. Nonetheless, Method 325A repeatedly refers to the "fenceline or property boundary". It is confusing to mention both, particularly when fenceline is defined as the property boundary in the method itself. We therefore recommend Method 325A refer only to the "property boundary."

2. The refinery "property line" appropriate for sampling may be different than the property line for all continuous property owned by the same corporate entity. For instance, if the refinery is adjoined by a large chemical plant, a natural gas plant, a cogeneration plant or other non-refinery facility owned by the same corporate entity, sampling must be done at the boundary between those facilities in order to be representative of the refinery, since the boundary concentrations may be determined more by the benzene reaching that boundary from the non-refinery operation, which was not considered in developing the program or setting the action level and which the rule does not allow to be adjusted if they are within the monitoring perimeter. The rule must make clear that the property line is the property line of the refinery and that it does not include property owned by the same corporate entity that contains non-

refinery operations unless those operations are considered part of the refinery (e.g., permitted as part of the refinery) or is totally surrounded by the refinery.

3. In some refineries, there are facilities owned and operated by others (e.g., inert gas plants, chemical plants) that are totally surrounded by the refinery. While there are issues, discussed separately, about how to account for any impacts of those facilities on the fenceline measurements, it should be clarified that the fenceline around those facilities is not another refinery property boundary for which monitoring is required. Similarly, public roads and railroad right-of-ways through a refinery should not represent a refinery property boundary for the purposes of defining where sampling is required, if there is refinery on both sides of the road or right-of-way.

4. Because of all the variations in refinery configurations and boundaries, monitors should be allowed to be sited anyplace within the refinery property that encompasses all of the refinery operating processes, wastewater plant, tankage, and loading/unloading facilities.

1.4.3.1.2 Sampler Placement Requirements Must Be Made Consistent and Be Clarified.

1.4.3.1.2.1 General Sampler Placement Issues

1. Proposed §63.658(c) specifies the following.

> The owner or operator shall determine passive monitor locations in accordance with Section 8.2 of Method 325A of Appendix A of this part. General guidance for siting passive monitors can be found in EPA-454/R-98-004, Quality Assurance Handbook for Air Pollution Measurement Systems, Volume II: Part 1: Ambient Air Quality Monitoring Program Quality System Development, August 1998 (incorporated by reference—see §63.14). Alternatively, the owner or operator may elect to place monitors at 2 kilometers intervals as measured along the property boundary, provided additional monitors are located, if necessary, as required in Section 8.2.2.5 in Method 325A of Appendix A of this part.

Section 4.1 of Method 325A states the following.

> 4.1 *General Interferences.* Passive tube samplers should be sited at a distance beyond the influence of possible obstructions such as trees, walls, or buildings at the monitoring site. General guidance for siting can be found in EPA–454/B–13–003, Quality Assurance Handbook for Air Pollution Measurement Systems, Volume II: Ambient Air Quality Monitoring Program, May 2013 (Reference 3) (incorporated by reference—see § 63.14). Complex topography and physical site

> obstructions, such as bodies of water, hills, buildings, and other structures that may prevent access to a planned PS location must be taken into consideration. You must document and report siting interference with the results of this method.

Since Section 8.2 of Draft Method 325A specifies that the samplers be placed at specific radial points along the property boundary or, alternately, at specific distances along the boundary, it is unclear how EPA-454/R-98-004 or Section 4.1 of Method 325A can apply and citing them only adds confusion.

Thus we recommend the second sentence of §63.658(c) be deleted or, if EPA's intent is to allow a siting approach other than the two in Draft Method 325A, it should specifically identify that alternative in this paragraph as being allowed in addition to the two alternatives in Draft Method 325A. If there are other items in the cited manual that sources are expected to follow those should be incorporated into Method 325A. A general citation, such as this, to a large on-line manual, particularly one meant to apply to ambient monitors rather than fenceline monitors, results in confusion and compliance uncertainty.

2. Section 4.1 of proposed Method 325A indicates that samplers "should be sited at a distance beyond the influence of possible obstructions such as trees, walls, or buildings at the monitoring site." Walls, in particular, posed difficulties in the API Pilot Project, as some refineries have long high walls at the property boundary. Other refineries have elevated berms around their perimeter. The handling of these situations needs to be addressed in the method to allow sources to certify compliance and to address the conflict between this Section and the other sections dealing with the siting of the samplers.

API/AFPM recommends that §63.658(c) and Method 325A Section 4.1 be revised to specify that where such obstructions exist the sampler should be placed inside the obstruction at a distance approximately twice the height of the obstruction or, for taller obstructions, such as trees or buildings 25 feet to either side of the obstruction. The requirements in Sections 8.2.2.1.4 and 8.2.2.3 will need to be expressly waived for these situations.

3. Sections 8.2.2.1.4 and 8.2.3.4 call for the samplers to be placed "securely on a pole or supporting structure at 1.5 to 3 meters above ground level." This is an improvement over early, more prescriptive statement, but we recommend that the wording be slightly more specific by specifying that it is the bottom of the diffusive sample cap that is to be 1.5 to 3 meters above ground level.

4. Sections 8.2.2.1.4 and 8.2.2.3 of Draft Method 325A specify that samplers be placed just beyond the intersection where the measured angle intersects the property boundary. However, this would require placing the monitors on other people's property, where authorization would be required and would not be received in many cases, access could not be controlled, and the risk of contamination and confounding exposures increased. In fact, it would frequently require the sampler to be in a road, a water body or railroad right-of-way. This requirement should be clarified to require that the samplers be placed on land just inside the intersection where the measured angle intersects the property boundary (i.e. on refinery property). This clarification is critical to situations where the property boundary is water.

While 8.2.3 is silent on the exact placement of the samplers under Option 2, it would be a useful clarification to also state that the samplers should be placed just inside the property boundary.

5. Notwithstanding the proposed requirement to place monitors "just inside the property boundary", refineries located in geographies subject to large snowfalls may find that locating monitors "just inside" the property boundary will interfere with snowplows that plow snow along the boundary for security reasons. Additionally, snow drifts may be high enough as to obscure samplers. Refineries should be provided with flexibility to site monitors in a manner both horizontally from the fenceline and vertically from grade such that monitoring will occur unobstructed from snowfall, snow drifts, and snow banks.

6. The Draft Method 325A does not address the situation for an irregular-shaped facility when a radial crosses the property boundary more than one time. Where a radial crosses the refinery boundary multiple times the method should specify use of the crossing farthest from the center, unless the multiple crossings are due to disconnected parcels, a common situation we discuss next. This is consistent with how the action level was developed (i.e., by modeling the refinery perimeter).

On page 7 of the Technical Support Document[90], EPA states that a monitor should be placed at every intersection in this situation. That guidance should be deleted, since it is not consistent with proposal and is technically invalid. The proposal and the proposal cost and burden estimates do not call for monitoring at locations other than the refinery outer perimeter. It

[90] Docket Document EPA-HQ-OAR-2010-0682-0210, B. Shine, Fenceline Monitoring Technical Support Document, January 17, 2014

should be noted that, in some instances, third-party operators independently own and operate equipment within the refinery boundaries. These pieces of equipment may be sources of benzene. The proposed rule requires action to be taken, even when the measured results include emissions from these third-party operators. It would be very difficult for the refinery to implement the required additional monitoring on this third-party site.

1.4.3.1.2.2 Sampling Requirements for Disjointed Refineries Need to Be Clarified.

Public access right-of-ways, such as roads and railroads, transect the interior of many refineries. Draft Method 325A does not address how to deal with this situation. Another common situation not addressed by the draft method is when another party owns or operates a parcel of land contained within the boundaries of a refinery. Similarly, refineries often include disconnected parcels[91], and these parcels can be very small (e.g., 10 acres or less). If each disconnected parcel must be treated as a separate subarea, the both sampler siting options in Draft Method 325A would result in an unnecessarily large number of samples extremely close together.

The other situation is if there are disconnected parcels (or remotely located operations) that are separated by large distances from the main process portion of a refinery. For instance, tank farms and marine terminals are sometimes separate facilities connected to the refinery only by pipelines. The land between the two facilities may or may not be owned by the same corporate entity and may or may not contain operations that could emit benzene.

One refiner reports their refinery and marine facility are separated by approximately ½ mile. While the marine facility handles very little HAP it would still have to have the minimum set of samplers, thereby doubling the number of samplers and doubling the cost for their refinery. This is particularly unreasonable since a significant portion of those samplers would have to be along the waterfront.

There is no one-size-fits-all approach to these situations. For instance, it makes a significant difference to ambient benzene concentration interference if a public road through a refinery is a major thoroughfare or a lightly used street. Similarly, it is significant if a third party facility

[91] By "disconnected parcel" we mean two refinery areas that are separated from each other by land containing operations that are not part of a refinery source category, by land owner by others and outside of refinery control or by a river or other water body. For instance, a road or river or land owned by others or owned by the same corporate entity but not involved in refining and not containing Subpart CC or UUU emission points.

within a refinery is a major consumer or producer of benzene versus a hydrogen or inert gas plant. Thus, facilities should be given the choice of including such non-refinery situations within their sampling boundary or setting up separate sample perimeters for each separate refinery area. The extra sampling and analysis costs and increased risk of an action level exceedance due to a smaller perimeter will keep refiners from unreasonably subdividing the facility in such situations. Typically the modelling used to develop the action level did not subdivide refineries or include benzene emissions from non-refinery sources and thus requiring subdividing would lead to false action level exceedances.

1.4.3.1.2.3 Combining Refinery Fencelines or Property Lines Should Be Allowed.

In some cases, two refineries (sometimes with the same owner, sometimes not) adjoin each other or are only separated by a road or railroad. It could be an efficiency and, in some cases would be more representative, if these two refineries could monitor the combined property boundary. Refineries should be provided the option of using the combined boundary, and not monitor the boundary shared by the two refineries, in these situations.

1.4.3.1.2.4 Samplers Should Not Be Required Along Fencelines or Property Lines Where There Are No Occupied Residences within 500 Feet.

Except perhaps for a single sampler to establish background levels, there is no reason to monitor where there is no potential for community exposure, i.e., where no people live. Sampling at fencelines and property lines that abut another industrial facility, an ocean, a river, or other non-residential area provides no information on risks to a community where there might be exposure, particularly since dispersion would quickly reduce any fenceline concentrations to background levels. Additionally, readings along such non-residential boundaries where industrial facilities are located may be confounded by emissions from those facilities and eliminating those sampler locations from the program will reduce the effort associated with false action level exceedances. Thus, we recommend no monitors be required if there are no residences within 500 ft. of the property line. However, the option should be allowed for a few samplers to be along these boundaries if the refinery believes that is the appropriate location for establishing background levels (e.g., if the boundary is along a major water body).

1.4.3.1.3 The Requirements for Extra Samplers Must Be Based on Benzene Sources and Clarified.

Proposed 8.2.2.1.5 and 8.2.3.5 of Draft Method 325A call for extra samplers to be placed near known sources of VOCs that are within 50 meters of the property boundary. Several clarifications are needed, some in §63.658(b) and some in the Draft Method.

1. Proposed §63.658(c)(1) states that "As it pertains to this subpart, known emission source, as used in Section 8.2.2.5 in Method 325A of Appendix A of this part for siting passive monitors means a wastewater treatment unit or a Group 1 storage vessel." This paragraph must be revised to reflect the terminology used in the method and that terminology must be revised to be consistent – The proposed method uses the terms "known sources of VOCs" and "potential emission source" rather than "known emission sources". "Known emission source" should be used exclusively in Sections 8.2.2.1.5 and 8.2.3.5 of the Method, since that is the term defined in §63.658(c)(1). This is also important, because there may be VOC emission sources located near the fence that do not contain HAP and thus the rule and the Method requirements would be in conflict. Without consistent use of one terminology that is defined in the referencing rule, there are likely to be misunderstandings of what is required by Method 325A and claims of violations.

Additionally, the reference in §63.658(c)(1) to "Section 8.2.2.5" should be corrected to "Sections 8.2.2.1.5 and 8.2.3.5."

2. Furthermore, there are wastewater treatment units and Group 1 storage vessels that do not contain benzene (except perhaps at very low impurity levels). Thus we recommend that §63.658(c)(1) only apply to wastewater treatment units that contain at least 10 ppm benzene and Group 1 storage vessels that contain at least 500 ppm benzene in the stored liquid.

3. Because Some Group 1 tanks are quite small and individual portions of wastewater treatment systems may be relatively small, it is also possible that after adding an extra sampler to comply with this requirement, there may be a source between the new sampler and one of the existing samplers.

4. The Method seems to call for the additional sampler to be placed halfway between the otherwise required samplers, even if the "known emission source" is not exactly halfway between the other samplers, but is closer to one than another. This seems appropriate to avoid samplers being too close together and because the nearest point at the property boundary may not be in the predominant downwind position. It would be helpful, however, if

it could be clarified that siting the additional sampler halfway between the existing samplers is EPA's intent.

5. Sections 8.2.2.1.5 and 8.2.3.5 call for placing additional samples "near known sources of VOCs at the test facility." However the intent is to require additional samplers along the property line, where a known source is within 50 meters the property boundary and the source is between the otherwise requires samplers. As proposed, these paragraphs would require samplers throughout the refinery and the wording must be changed to reflect the intent.

1.4.3.1.4 Sampler Spacing For Small Refineries and Very Small Discrete Refinery Areas Need to be Addressed.

It is not reasonable to require sample points to be wastefully close together where fenceline perimeters are small. This is particularly important where refineries are small or where they contain disconnected parcels, where some of the parcels may be very small, but are still required to be monitored. Thus, we recommend that Method 325A specify that samplers need not be placed closer than 500 ft. (versus the normal 2000 ft. interval specified in Option 2) along the fenceline from an adjoining sampler, regardless of whether the radial or linear approach is used and the minimum number of samplers specified in Sections 8.2.2.1.1, 8.2.2.2.1, and 8.2.3.1 be waived. Additional the requirement for additional samplers in Sections 8.2.2.1.5 and 8.2.3.5 should be waived if the 500 ft. minimum spacing criterion is compromised.

1.4.3.1.5 The Requirements for Duplicate Samples and Field Blanks Need to Be Made Consistent.

Proposed §63.658(c)(3) and Section 9.3.1 and 9.3.2 of proposed Draft Method 325A call for one co-located duplicate sample for every 10 field samples per sampling episode and at least two field blanks per sampling episode. However, the note in Section 8.5.5 only calls for one duplicate sample for each monitoring episode and Section 8.5.10 requires one field blank for every 10 samplers, rather than two per sampling episode. These conflicts need to be resolved and made consistent.

1.4.3.1.6 The Sampling Period Should Be Specified as "Approximately" 14 Days.

Proposed §63.658(e) and Sections 1.4, 3.8 and 8.5.9 of Method 325A specify that the length of the sampling episode must be fourteen days. However, all samplers cannot be changed out simultaneously and there is some delay in shutting down a sampler and starting up a replacement, particularly in bad weather, or when sample support, sample holder or security lighting or fencing maintenance is required. Additionally, bad weather or other uncontrollable factors can delay the change-out for a day or two. By the nature of the methodology (two week samples used to develop an annual average) exactly fourteen day samples are unnecessary. Annual average values will not be sensitive to relatively small variations in the sampling time. Nor, are the types of emissions EPA claims they are addressing with this program subject to short-term aberrations that might be missed by short sampling outages. Thus, we recommend that rather than 14 days these paragraphs specify a sample duration of “approximately” fourteen days.

1.4.3.2 The Requirement for Installing a Weather Station Should be Made Optional and the Requirement That the Weather Station Be “Dedicated” to Fenceline Monitoring Removed.

Proposed §63.658(d) and Section 8.3 of proposed Draft Method 325A require establishment of a “dedicated” weather station at or near the refinery. However, there does not appear to be any particular use of the weather station information specified. Nor does the action level calculation rely on any of the weather information. Presumably, it is believed this data will be useful for source apportionment, should an action level exceedance occur. It is likely data from a local NOAA weather station would provide equivalent information for source apportionment purposes and thus there does not appear to be any justification for requiring the refinery to install such a station or to incur the potential recordkeeping compliance liability. Some refineries are required or have opted to have weather stations for compliance with other requirements or for their own use. Therefore, specifying that any weather station used for complying with §63.658(d) be “dedicated” could cause refineries to have to have multiple weather stations. Thus, API/AFPM recommends that the word “dedicated” be removed from proposed §63.658(d) and that this requirement be changed to an optional requirement by revising §63.658(d) as follows.

> (d) The owner or operator may~~shall~~ use a ~~dedicated~~ meteorological station in accordance with Section 8.3 of Method 325A of Appendix A of this part or data from the nearest NOAA weather station.
>
> (1) The owner or operator shall collect and record hourly average meteorological data, including wind speed, wind direction and temperature, if using a refinery meteorological station.
>
> (2) The owner or operator shall follow the calibration and standardization procedures for meteorological measurements in EPA-454/B-08-002, Quality Assurance Handbook for Air Pollution Measurement Systems, Volume IV: Meteorological Measurements, Version 2.0 (Final), March 2008 (incorporated by reference—see §63.14), if using a refinery meteorological station.

1.4.3.3 Comments on The Site Specific Monitoring Plan Requirements.

1.4.3.3.1 Site Specific Monitoring Plans Should Not Be Restricted.

Proposed §63.658(i) provides for requesting approval from the Administrator for a site-specific monitoring plan to account for offsite upwind sources or onsite sources excluded under §63.640(g). It is arbitrary and unreasonable to limit such plans to dealing with only offsite upwind sources or onsite sources excluded under §63.640(g). Since winds are constantly changing “upwind” has no meaning and there is no value in including this criterion. Similarly, it is unreasonable to limit onsite concerns to only sources excluded under §63.640(g). Many onsite sources are not addressed by §63.640(g) and they may need to be addressed in this sampling program. For instance, onsite mobile sources (e.g., automobiles, trucks, and locomotives), onsite laboratories, onsite and offsite spills, and operations subject to NESHAPs other than the HON (which is called out in §63.640(g)), such as the Hazardous Waste Incineration NESHAP, the Boiler and Process Heater NESHAP, or any of the multitude of Chemical NESHAPs. Therefore we recommend “offsite upwind sources or onsite sources excluded under §63.640(g)” be revised to “any sources not regulated under this subpart.”

1.4.3.3.2 Site Specific Monitoring Plans Should Be Effective Immediately.

Site specific monitoring plans require approval by the Administrator, who has 90 days to approve. Sites are forbidden to use the plans until they are approved. If the need for this plan resulted from changes in the onsite or offsite confounding facilities or because of an impact found through an RCA, many additional 2-week results could be high or otherwise questionable while the site specific plan was being developed, submitted, and reviewed. To avoid this unreasonable outcome, we recommend the plan be valid from submission and that sites must revert to their previous plan or submit within 30 days revisions if the new plan is denied.

1.4.3.3.3 Site Specific Monitoring Plan Requirements Should be Clarified.

1. Proposed §63.658(i)(1) is as follows.

> (1) The owner or operator shall prepare and submit a site-specific monitoring plan and receive approval of the site-specific monitoring plan prior to using the near-field source alternative calculation for determining Δc provided in paragraph (i)(2) of this section. The site specific monitoring plan shall include, at a minimum, the elements specified in paragraphs (i)(1)(i) through (v) of this section.

(i) Identification of the near-field source or sources.

(ii) Location of the additional monitoring stations that shall be used to determine the uniform background concentration and the near-field source concentration contribution.

“Near field source” is an undefined term and its use suggests some limitation on what interfering or confounding sources can be addressed through this additional monitoring. There is no sound technical or legal reason for excluding any non-RMACT 1 emissions source that has the potential to bias the measured fenceline benzene level from being addressed through a site specific monitoring plan and we, therefore, recommend the term “near field” be replaced with “interfering or confounding” in this paragraph and at every other occurrence in the proposal.

It may be impossible to identify specific sources. Sources may be multiple, transient and/or vary with wind direction. Nor should it matter whether the correction is being made to address a particular, identifiable source or to address an observed confounding action level impact. Thus, paragraph (i) should be generalized to require only a general description of the sources or emission types that are expected to be addressed by the additional monitoring.

Proposed paragraph (ii) is unclear. The rule spells out how the uniform background correction is to be made (i.e., subtract the lowest measured benzene value for a particular sampling episode). So we do not understand what uniform background correction is being addressed in this paragraph.

2. Proposed §63.658(i)(2) is as follows.

(2) When an approved site-specific monitoring plan is used, the owner or operator shall determine ΔC for comparison with the 9ug/m3 action level using the requirements specified in paragraphs (2)(i) through (iii) of this section.

(i) For each monitoring location, calculate Δc_i using the following equation.

$$\Delta c_i = MFC_i - NFS_i - UB$$

where:

Δc_i = The fenceline concentration, corrected for background, at measurement location i, micrograms per cubic meter (µg/m3).

MFC_i = The measured fenceline concentration at measurement location i, µg/m3.

> NFS_i = The near-field source contributing concentration at measurement location I determined using the additional measurements and calculation procedures included in the site-specific monitoring plan, µg/m3. For monitoring locations that are not included in the site-specific monitoring plan as impacted by a near-field source, use NFS_i = 0 µg/m3.
>
> UB = The uniform background concentration determined using the additional measurements specified included in the site-specific monitoring plan, µg/m3. If no additional measurement location is specified in the site-specific monitoring plan for determining the uniform background concentration, use UB = 0 µg/m3.
>
> (ii) When one or more samples for the sampling episode are below the method detection limit for benzene, adhere to the following procedures:
>
> (A) If the benzene concentration at the monitoring location used for the uniform background concentration is below detection, the owner or operator shall use zero for UB for that monitoring period.
>
> (B) If the benzene concentration at the monitoring location(s) used to determine the near field source contributing concentration is below detection, the owner or operator shall use zero for the monitoring location concentration when calculating NFS_i for that monitoring period.
>
> (C) If a fenceline monitoring location sample result is below the method detection limit, the owner or operator shall use the method detection limit as the sample result.
>
> (iii) Determine Δc for the monitoring period as the maximum value of Δc_i from all of the fenceline monitoring locations for that monitoring period.

Because the term ΔC_i is used for the individual corrected sample results, proposed paragraph (iii) seems to say ΔC for this sampling episode is the maximum value of the corrected sampling rather than the difference between the maximum and minimum corrected values, which how ΔC is defined. That is illogical, since the site specific sampling is intended to correct for backgrounds and confounders in addition to the benzene reaching the site from upwind. The definition of UB in paragraph (i) makes this clear by limiting that term to "the additional measurements specified included in the site-specific monitoring plan" and thus does not include the basic adjustment for upwind sources.

API/AFPM recommends the term ΔC_i be replaced with the term C_i to represent the individual corrected sample concentrations and that ΔC for each sampling episode then be calculated as prescribed in §63.658(f) using the corrected values rather than the as measured values.

3. We also note that there is a wording error in the definition of UB in paragraph (i) that should be corrected here and in the Fugitive Emissions section of the rule preamble (page 36924). The subscripts are missing from the equation in the preamble and the multiplication symbol should be deleted, i.e. "$HFC = Maximum \times (MFC - OSC)$" should be "$HFC = Maximum\ (MFC_i - OSC_i)$." The terminology and symbols that EPA decides on for §63.658(i)(2) should be used consistently in the fugitive emissions section as well to avoid confusion.

1.4.3.4 Data Analysis and Source Apportionment Issues

1.4.3.4.1 Section 63.658(f) Should Specifically Indicate That The Requirements of Section 12 of Proposed Draft Method 325A Are Superseded and Do Not Apply To The Refinery Fenceline Monitoring Program

Section 12 of Draft Method 325A calls for calculating averages of the fenceline data, rather than the ΔC value that is the basis for the action level determination, and calls for other analyses of the data that are not specified by §63.658, discussed or justified in the preamble or backup documents and appear not to be included in the Information Collection Request Supporting Statement. Thus, Section 12 of the Draft Method is superfluous for this purpose and should be clearly over-ridden by §63.658(f) to avoid future claims that it applies.

1.4.3.4.2 Invalid and Biased Data Should be Excluded From the Calculation of Δc.

Proposed §63.658(f)(1) calls for calculating ΔC from the highest and lowest benzene value determined in a particular sampling episode. However, these are not always valid samples. In fact, invalid samples will typically be very high or very low. On page 840 of the published article on the EPA's Flint Hills study, EPA reports examples of outliers that could not be explained and outliers due to probable sample contamination that were not supported by similar readings at adjoining sample points. These measurements were excluded in that study and provision for such exclusions should be added to §63.658(f)(1). A record of excluded data and the reason for the exclusion should be required. Such an allowance is alluded to in the reporting requirements in proposed §63.655(h)(8)(iii), where reports of such exclusions are required, but the fact that such exclusions are allowed needs to also be included in §63.658(f).

In addition to invalid data, there will also be samples for which there is no data because the sample was not analyzed because of contamination, damage, loss in shipping, etc. [92] §63.658(f)(1) clarify that that high and low benzene results are only selected form the available, valid sample results.

Section 9.3.5 of Method 325B discusses the assessment of field blanks, stating: "Field blanks must contain no greater than 1/3 of the measured target analyte or compliance limit for field samples ... Flag all data that do not meet this criterion with a note that the associated results are estimated and likely to be biased high due to field blank background." Guidance is needed in the rule as to how to handle these biased results when calculating averages. Since a root cause analysis of an average exceedance that uses such data is likely to find the exceedance is due to this biased data, we recommend avoiding that unnecessary burden and excluding biased data from the average calculation.

1.4.3.4.3 Up to 60 Days is Needed to Obtain Valid Results and Generating the Rolling Annual Average

Proposed §63.658(f) provides 30 days from completion of each sampling episode to determine if the action level has been met. This is inadequate time (assuming "completion of each sampling episode" means the end of the 14 day period) and up to 60 days should be allowed. Even if one presumes that adequate laboratory capacity is developed to handle the >5000 samples every two weeks that this program will generate, it is reasonable to assume as much as a week for the laboratory to receive the samples and a laboratory turnaround time of at least two weeks. One API/AFPM member reports three weeks as the typical turnaround time for BWON samples sent to an outside laboratory for analysis. Refineries in very remote locations indicate, based on their experience, even three weeks may be inadequate. If all results appear valid, they are immediately transmitted to the refinery, and it is not a holiday week, then it the action level calculation might be able to be completed within 30 days. However, if any of the laboratory results are questionable, if any field follow-up is needed, if there is any delay in data transmission or any other delay, the 30 day requirement could not be met. If QA/QC follow-up is needed it could easily take several weeks to evaluate the problem and determine which results are valid and which are not, particularly if the blank samples and check samples are

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[92] Of the 1,206 samples and duplicates collected for analysis by the primary laboratory in the API study, eight (8) were lost or otherwise not able to be sampled due to damage, etc. This resulted in a data completeness of 99.3 percent. This compares to a data completeness of 97.1 percent for the EPA Flint Hills Study, where the total number of samples was 579.

suspect. Furthermore, considerable time could be required to determine if an unusual result was the result of vandalism or some non-refinery activity. Adequate time must be allowed for careful laboratory analysis and for full QA/QC. API/AFPM therefore requests that the 30 day time period be changed to 60 days.

1.4.3.4.4 The Rolling Average Time Period Should be Made Consistent With The Sampling Periods

In §63.658(f)(3), the annual rolling average is defined as 'the 12-month rolling average' Δc value, but it should be '26 sampling period rolling average' to avoid confusion about the period of time reported for each rolling average point.

1.4.2.4.5 The Handling of Detection Limit Values Should Be Revised.

1. In §63.658(f)(1)(i) and (I)(2)(ii), EPA proposes to use zero as the value for below detection limit (BDL) values for the lowest sample result (and for background and near-field source samples) and use method detection limit as the highest value if all samples are below the detection limit. If no benzene was measured at the property boundary, there would still be a calculated Δc (equal to the detection limit), which seems inaccurate and would mislead the public. To be consistent with other EPA reporting practices such as Toxic Release Inventory, API/AFPM recommends use of half the detection limit for samples below the detection limit where benzene is suspected to be present.

2. EPA uses the undefined term "method detection limit (MDL)." Other common terminology includes the "method reporting limit (MRL)," which, for example is used in the API/AFPM pilot study. EPA should clarify the MDL, by providing a definition.

1.4.4 Root Cause Analysis/Corrective Action Analysis (RCA/CAA) and Corrective Action (CA) Issues

1.4.4.1 If the RCA Finds No Deviations in the Refinery, Then There is No Need to Conduct a CAA or To Take CA.

The proposed approach to RCA/CAA/CA is problematic because off-site sources may cause or significantly contribute to exceeding the action level. API/AFPM recommends that rather than being open-ended, the RCA consist of a review of the emission sources that the fence line monitoring program is designed to enhance. The RCA would consist of a review of the nearby LDAR program components, the nearby wastewater system components, and the nearby tanks. If no deviations are found, then there is no further action should be required. The site should note any nearby, off-site sources that may be contributing to the threshold from a broad list of possible sources provided by EPA. When there are no deviations found, then there are no requirements for further review until the following year. It should be clear in the rule that if the RCA finds no deviations in these emissions control programs, then there is no need to conduct a CAA or CA.

1.4.4.2 The Proposal to Require Approval of a Second CA Plan for a Particular Cause Should Be Deleted.

As discussed in Comment 1.3.2, one of the factors that makes the proposed fenceline action level an ambient air standard, is that CA to achieve that level is required and that if a site's initial CA is unsuccessful, the rule provides that further CA is required and EPA must approve that further CA plan. Thus, EPA would essentially be able to dictate CA, with no bounds on what could be required and no consideration of whether any cost-effective actions are available to assure the "action level" is met. Such a requirement converts a work practice program to an emission limitation and such ambient air limits are not authorized by section 112. LDAR and current work practice programs have no similar requirement for EPA approval. Thus, the requirement for EPA approval of any second CA should be removed from §63.658(h).

1.4.4.3 The Follow-up Average Requirements to Determine if Corrective Action Has Been Successful are Unclear and Should be Clarified.

1. Under proposed §63.658(h), the success of corrective action is confirmed if the "action level" is not exceeded for the next sampling episode following the completion of the corrective action. API/AFPM suggests the basis for determining whether the corrective action has been successful should be the average background corrected maximum benzene concentration for two successive sampling rounds following completion of the corrective action. Two rounds are desirable to provide an allowance for the anticipated meteorological and analytical variability of these measurements. If this average is below the 9action level, the corrective action should be considered successful and any future annual average action level breech would be considered a new occurrence and would not trigger the second corrective action requirements in §63.658(h).

2. An unusually high two-week maximum ΔC value could cause the rolling average to stay high for as long as a year, even though emissions have long since returned to normal. Provisions are needed to remove these high values from the average calculation in such situations and from the follow-up sampling to demonstrate that CA has been successful, so any new occurrences are not missed and so multiple deviations are not accrued because of the same, one time incident.

3. An exceedance during the follow-up monitoring could be due to a totally different cause than the original occurrence. Thus, the conclusion that additional corrective action, directed by EPA, is needed should only be reached if the follow-up maximum benzene value is in the same area of the property boundary as the original maximum value and due to the same root cause. This needs to be clearly spelled out in §63.658(h).

1.4.4.4 The RCA/CAA Examples in Proposed §63.658(g) Should Be Deleted.

§63.658(g) includes examples of data collections that could be done as part of an RCA/CAA in response to an action level exceedance. These are all highly expensive and time consuming alternatives and it is likely any identifiable source will be identified more quickly and through other, less costly and burdensome means. Furthermore, it is unlikely these examples could be completed in the 45 days allowed and, since no burdens are included in the Information Collection Supporting Statement, they are not authorized under the PRA. Thus, these examples serve no purpose and only add confusion and they should be deleted.

1.4.4.5 Many Clarifications Are Needed in Proposed §63.658(g).

1. Because of method variability and the potential that an exceedance is due to a short term episodic emission or confounder, it is likely that in many cases the next rolling average will no longer indicate an exceedance. The proposed §63.658(g) language would appear to still require the RCA/CAA and CA in such cases. Language should be added to §63.658(g) removing the RCA/CAA requirement if the rolling average returns to below the action level prior to completing the RCA/CAA.

2. Members report that the cause of a high ambient concentration of benzene cannot always be determined. This can be the result of exceedances due to short-term episodic incidents or exceedances due to unusual weather conditions or sample contamination. Working with an annual average reduces the likelihood of such a situation, but does not eliminate the possibility that the source of an action level exceedance cannot be identified within 45 days, or perhaps, at all. In fact, an annual average exceedance could be the result of several different unrelated events occurring over the year, making determining a specific cause almost impossible. Language should be added to §63.658(g) to clarify that CA is not required if the source of an exceedance cannot be identified.

1.4.4.6 Corrective Action Should Not Be Required If the RCA Demonstrates the Action Level Exceedance Was Due to an Offsite Source or an Onsite Source That is Excluded by §63.640(g), Is Subject to a Non-Refinery NESHAP, or Is a Mobile Source.

Under the proposal, site specific monitoring plans are allowed where sources have reason to believe a non-refinery source is likely to cause action level exceedances and the site is willing to perform additional monitoring to allow for on-going correction of the property boundary data. However, it is more likely that an action level exceedance will occur due to a mobile source, an offsite source, or a non-refinery source that was not anticipated. EPA cannot require a refinery to perform corrective action on land or facilities it does not own or operate or to reduce refinery emissions to compensate for emissions from those other sources. Thus, the corrective action requirement must be clear that CA is only required if the RCA determines the cause of the exceedance to be from refinery facilities.

1.4.4.7 RCA/CAA Should Not Be Required For Repetitive Exceedances Until The Cause of the Initial Exceedance Is Determined and the Later Exceedances Are Determined to Be Due to Different Causes.

Up to 45 days is provided for completing a RCA/CAA in the event of an action level exceedance. CA may take longer than that, depending on the cause. During that time at least two more rounds of samples will be completed and two additional action level determinations made. If the cause of the original exceedance is not yet resolved, each of these additional exceedances may also exceed the action level. Unless there is data to indicate these exceedances are due to a separate cause (e.g., occur in a different portion of the property), RCA/CAA analysis should be deferred until the initial cause can be identified and only reinstated if the initial cause is determined not to be the cause of the later occurrences. This will be apparent from the results of the follow-up monitoring after the CA is complete.

1.4.4.8 The Wording in Proposed §63.658(h) Must Be Clarified.

Proposed §63.658(h) begins as follows.

> If, upon completion of the corrective actions described in paragraph (g) of this section, the action level is exceeded for the next sampling episode following the completion of the corrective action, the owner or operator shall develop a corrective action plan that describes the corrective action(s) completed to date, additional measures that the owner or operator proposes to employ to reduce

> fenceline concentrations below the action level, and a schedule for completion of these measures. …

At least two clarifications are needed in this sentence, if the fenceline monitoring program and this paragraph are finalized and the examples in paragraph (g) are not deleted as we recommended above. First, the reference to paragraph (g) seems to require that the four example corrective actions at the end of paragraph (g) had to be included in the initial corrective action and have been completed. In general, none of those examples are likely to be needed and certainly not all, so it is unreasonable to require them. That phrase should be reworded to refer to the initial corrective actions rather than to paragraph (g). Second, the action level is an annual average and thus cannot be used to determine if the initial corrective actions were successful. Thus, the trigger for follow-up corrective action should be a one or two round action level evaluation and the appropriate trigger should be specified in place of the term “action level” in its first use in §63.658(h).

1.4.4.9 It Is Not Appropriate to Establish a Standard Time Frame for Corrective Actions.

EPA requests comment on whether it is appropriate to establish a standard time frame for compliance with actions listed in a corrective action plan. Such a time limit is extremely inappropriate. A corrective action plan is specific to the event, the refinery, and the root cause of the event. Time required to complete actions is dependent on the complexity of the action; permitting and permit approval; whether equipment can be taken out of service immediately or only during a turnaround, availability of repair equipment, materials and skilled labor to complete the action, etc. Thus, no one-size-fits-all time frame can be established. Even the Consent Decrees (CDs) applicable to refineries do not include such a time limit.

1.4.4.10 Times to Develop and Approve CA Plans Should Be Equal.

EPA is allowed 90 days to approve CA plans, while facilities are only allowed 60 days to develop those plans. If the approval requirement is maintained (See Comment 1.4.4.2) facilities should also be allowed at least 90 days to develop their CA plan. Developing the plan is certainly more time consuming than reviewing it.

1.4.5 EPA Should Provide for Alternative Monitoring through the Use of Other Fenceline and Ambient Monitoring Systems that Meet Community Needs.

The monitoring portion of this proposal should not be imposed on refineries with open-path monitors along the fenceline or ambient downwind monitoring stations, even if the perimeter monitoring does not include the entire fenceline. Some petroleum refineries have, or may have in the future, federally-enforceable obligations to install, maintain, and operate population-oriented ambient air monitoring systems. Typically, these programs focus on the prevalent wind situation and, because of cost or other obstacles (e.g., adjoining water bodies), do not require monitoring around an entire refinery perimeter (e.g., require fenceline monitoring or an ambient monitor only in the prevalent downwind direction.).

Similarly, many areas have area monitoring networks operated by monitoring consortiums or government entities that provide downwind data or data for an entire area. For example, facilities in the Beaumont/Port Arthur Texas area, the Texas City Texas area and the Houston Region fund state of the art ambient air monitoring networks which continuously monitor ambient benzene levels. In addition, the Texas Commission on Environmental Quality operates a separate air monitoring station network in the same area, with several monitoring stations positioned immediately adjacent to refinery fencelines. Many other refineries also have permitted benzene monitoring requirements to meet community needs and no additional monitoring requirements can be justified. The monitoring programs already in place in Texas, California, Michigan, and Louisiana are all examples of existing monitoring programs that should all be acceptable alternatives. There is no value in effectively duplicating the information from these existing continuous monitors. Refineries in this position should not be required to perform the proposed monitoring.

Since the proposed fenceline monitoring program is not “monitoring” in the traditional section 112 sense, specific provisions should be included in §63.657 to allow refineries to propose AMPs for review and approval by EPA or the delegated State authority. This would allow for efficiencies and reduced costs and burdens should a refinery have valid reasons for performing different or additional monitoring along their property line.

1.4.6 Any Fenceline Monitoring Program Should be Suspended or the Sampling Frequency Reduced if Performance Demonstrates That It is Unlikely the Action Level Will be Exceeded at a Particular Refinery.

If the fenceline monitoring program is to check for undetected leakage or emissions (i.e., confirm compliance and emission estimates), there is no need to monitor all year. As with Method 21 monitoring, there are diminishing returns for reducing the period between compliance checks. Thus, after an initial period is completed to establish that the normal baseline of a particular refinery is below the action level, less frequent monitoring should be allowed. To that end, we recommend that, after two years of demonstrating a background corrected maximum fenceline annual average concentration below the action level, monitoring frequency be reduced to one 2 two week period every quarter. If the background corrected annual average benzene concentration based on the quarterly monitoring exceeds the action level, a return to every two week monitoring would be required along with meeting the RCA/CA requirement. The reduced frequency would be available again after one year of meeting the action level.

1.4.7 API/AFPM Concurs With EPA's Understanding That Three Years is Needed to Put a Fenceline Monitoring Program in Place, But Believe That Timing is Unclear in the Proposed Rule Language.

EPA indicates on page 36951 of the proposal preamble that "Considering all of the requirements needed to implement the fenceline monitoring system, we are proposing to provide 3 years from the effective date of the final rule for refinery owners or operators to install and begin collecting ambient air samples around the fenceline of their facility following an approved (if necessary) site-specific monitoring plan." However, nothing in §63.658 indicates that sources have three years to comply. Proposed Table 11 appears to be the only place this compliance schedule is indicated and it is buried in the Table and difficult to decipher. API/AFPM, therefore, requests that the initial compliance date (three years after the final rule effective date) be added to §63.658(a) if this program is finalized.

Instituting this program for all 142 major source US refineries will require considerable time. In addition to the basic program needs (defining sample locations; developing procedures and training personnel; procuring samplers, weather guards[93], sampler mounts, etc. and installing them; procuring and installing the required weather station; and locating and contracting an acceptable laboratory), substantial time will be needed to develop site specific alternative background plans and to obtain EPA approvals.

There were a very limited number of laboratories identified in the U.S. that were able to perform the necessary analyses for the API Pilot Project. The primary laboratory was required to implement extraordinary measures to accommodate the samples from the refineries in the program. Clearly, considerable time and effort will be needed to qualify additional laboratories and to expand the capacity of existing laboratories to handle the samples from 142 refineries.

1.4.8 Fenceline Monitoring Recordkeeping and Reporting Issues

1.4.8.1 It Will Be Misleading to the Public to Post Individual Sample Results.

The pilot studies show that individual sampler data may vary greatly. While intended to be an indicator of changes in emissions, wind direction and speed are likely more critical determinates of the measured value. Furthermore, as discussed previously, inter-laboratory variability appears significant. Thus, individual samples can vary greatly but have no significance. Thus, there is very little useful information that can be gleaned from the raw data and posting it simply invites misunderstandings. Even the average values for the individual episodes showed tremendous variability in the pilot studies. For instance the standard deviation around the means for the 9 API and 1 EPA refinery varied from a low of 19% to a high of 180%.

The fenceline concentration action level is not an emissions limit, does not imply risk, and cannot be used to demonstrate that a refinery is in or out of compliance with any emission limits. Thus, release of the individual data will mislead the public. Refineries, state agencies, and perhaps EPA staff will need to spend a significant amount of effort qualifying and defending

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[93] Commercially available weather guards meeting the specifications of proposed Method 325A are not available and had to be fabricated for the API/AFPM/AFPM Pilot Project. We recommend that the Method be revised to allow equivalent weather guards.

the data in an effort to respond to questions based in invalid interpretations of this information and to prevent frivolous lawsuits.

1.4.8.2 If EPA Posts Fenceline Monitoring Data, It Must Appropriately Caveat The Information, Only Report Validated Results, and Include Capability for Refiners to Provide Information for Posting Along With the Information.

On page 36927 of the proposal preamble, EPA states that the raw fenceline monitoring data "will be made available to the public through the EPA's electronic reporting and data retrieval portal." Simply, posting the raw data and the averages can mislead the public; a situation we are sure EPA does not intend. Thus, we believe, EPA should, similar to what has been done with the NATA, provide, on every page of the data, an explanation of the uncertainties and issues associated with this information. EPA should also explain on its public fenceline website that the action level is not based on a health risk to the public and that any individual data points above the action level are not an indication that the facility out-of-compliance with any applicable requirement or permit.

We also recommend EPA provide perspective by posting comparative values from EPA and World Health Organization studies on the same website. For example, indoor air levels of benzene in a home with a smoker can be greater than the proposed action level: smoker's home are at levels of 10.5+ $\mu g/m^3$. Also, outdoor concentrations of benzene from house fires, nearby agricultural burning and from wood burning fireplaces can all exceed 11 $\mu g/m^3$. There are many sources that also approach the proposed action level that EPA should post on their website. These include background indoor air benzene levels of 7 $\mu g/m^3$; EPA near roadway studies in Raleigh, NC showing benzene levels of 2 $\mu g/m^3$ at distances of 40 meters from the highway (closer to a highway the levels would be higher)

Furthermore, space should be provided for a facility to provide explanatory information for any two week set of data. For instance, if a high value is associated with vandalism, or a benzene release from outside the facility, or a mobile source being parked next to the sampler, there should be a mechanism for the facility to provide that explanation. Similarly, missing or invalid data could be explained (e.g., hurricane, contaminated sample, QA/QC failure). API/AFPM would be happy to assist in suggesting appropriate caveats.

Additionally, §63.655(h)(8)(i) should be clarified to only require reporting of valid data. Where the laboratory QA/QC invalidates a sample result or the sample is otherwise known to have been invalid, that result should not have to be reported through this unfiltered system.

1.4.8.3 Inadequate Time is Provided for Data Submission. Up to Seventy-five Calendar Days Should be Allowed.

As discussed in Comment 1.4.3.4.3, 60 days is required to obtain quality assured results for any two week sampling period. Proposed paragraph 63.655(h)(8) however, only provides 45 calendar days for submitting the raw data and results for the previous reporting period. Thus, there will be cases where quality assured data will not be available for the last two week sampling period of the previous reporting period and possibly for the one before. API/AFPM therefore requests that up to 75 calendar days be allowed for this submission.

1.4.8.4 The Reporting Period Needs to Be Clarified.

Proposed §63.655(h)(8) calls for reporting results "after the end of each semiannual reporting period." However, the (h) section of §63.655 covers various notice and report requirements, so it is unclear what "semiannual reporting period" is referenced. We presume the intent is for this period to match the periodic report reporting period, but that is not stated. Furthermore, since this information is reported through the EPA's CDX, it is unclear if the reporting period can be adjusted by mutual consent, as the periodic report period can. API/AFPM suggests this paragraph be modified to clarify that the fenceline monitoring semiannual reporting period is the same as the semiannual periodic report reporting period.

1.4.8.5 There is No Justification for the Required Daily Weather Records and this Recordkeeping Requirement Should be Deleted.

Proposed §63.658(d)(1) requires hourly average records for meteorological data, including wind speed, wind direction and temperature and proposed §63.655(i)(8)(iii) requires a record of daily unit vector wind direction, calculated daily sigma theta, daily average temperature and daily average barometric pressure measurements. Neither daily unit vector wind direction or daily sigma theta are defined or explained, so it is unclear what is required. Nor does the rule use any of this information and it is therefore unclear how this burden is justified.

API/AFPM recommends EPA explain how the burdens associated with these recordkeeping requirements are justified, rather than just generating the information if needed for source apportionment or that these recordkeeping requirements be deleted. If they are maintained, the terms "daily unit vector wind direction" and "daily sigma theta" should be defined and their units specified.

1.4.8.6 The Wording of Proposed §63.655(i)(8)(v) Should Be Clarified.

Proposed §655(i)(8)(v) requires, for samples that will be adjusted for background, a record of the location of and the concentration measured simultaneously by the background sampler, and the perimeter samplers to which it applies. The word "simultaneously" could be interpreted to mean that all samplers must start and stop at the same time; a physical impossibility and not a significant issue for two week samples that provide concentration results. Thus, this wording should be changed to call for the background concentration to be measured over "approximately" the same two week sampling period as the samples it is used to correct.

1.4.9 The Following Typographical and Grammar Corrections are Needed in Proposed §63.658 and Draft Methods 325A and B, in Addition To Those Cited Elsewhere.

1. It appears §63.658 references are based on earlier versions of Draft Methods 325A and B and that as a result references are incorrect. We have pointed out the specific reference errors we have noticed, but recommend a careful review of all references to those methods prior to publication of the final rule and methods, particularly if further changes to the methods are made in response to comments.

2. The reference in the last sentence of paragraph §63.658(c) to placing monitors at 2 kilometers intervals, should be corrected. Section 8.2.3 of Draft Method 325A specifies spacing intervals that depend on the overall length of the refinery fenceline, but in no case would that spacing be 2 km.

3. The reference in the last sentence of paragraph §63.658(c) to Section 8.2.2.5 in Method 325A should be to Section 8.2.3.5. Also, the same proviso would apply to the radial method in the first sentence and for consistency it should be included and reference Section 8.2.2.1.5 of Method 325A.

4. Section 8.4.1 of Method 325A still states that "sample collection may be performed for periods from 48 hours up to 14 days." It is assumed that EPA intended to revise section 8.4.1 to be consistent with the other sections that were revised to specify 14 days.

5. Section 8.5.5 of Draft Method 325A calls for the sampler to be placed on a pole at a height of 1.5 to 2 meters. This is inconsistent with the specifications in Section 8 and should be changed to 1.5 to 3 meters.

6. The term “near field” is undefined and unnecessary and only serves to add confusion and therefore should be deleted. The calculation procedures should simply address “background” and “confounder” corrections.

7. §63.658(i)(1)(3) ‘Diffusion *tub* monitoring’ should be ‘*tube*.’

8. §63.658(c)(2) ‘Site specific monitoring *plant*’ should be ‘*plan*.’

1.5 Comments on the Proposed New and Revised CPMS, CEM and Other Monitoring and General Data Handling Requirements in RMACT 1 and 2.

Proposed §63.671 and Table 13 contain monitor and data handling specifications that apply to the instrumentation required to comply with the proposed new flare requirements in §63.670. Both of these sections are proposed to apply to RMACT 1 and 2, RMACT 1 Subpart R and Y facilities and flares handling refinery materials subject to part 61 subpart FF, part 60 subpart VV and part 63 subpart H.

Proposed §63.644(a) and (c)(1)(i) of RMACT 1 imposes the new Table 13 requirements on monitoring equipment associated with the control of Group 1 MPVs by combustion and on the flow meter now required in any potential bypass of an MPV control and where a carseal or lock and key approach is not used to prevent flow.

Proposed §63.1572 of RMACT 2 imposes requirements from a proposed new Table 41 on parameter monitoring equipment and greatly expanded requirements for CEMS via proposed revisions to Table 40.

1.5.1 General Monitoring Related Comments

1.5.1.1 EPA has Not Justified or Accounted for the Costs and Burdens Associated with the Proposed New and Revised Monitoring System Requirements and These Requirements Should Not be Finalized. If Finalized, Three Years is Needed for Compliance and Clearly Identified Applicability Dates are Needed to Assure That The Changes Are Not Interpreted to Apply Retroactively.

In a new Table 13 proposed for addition to RMACT 1 and in significantly revised Tables 40 and 41 to RMACT 2, requirements for monitoring equipment and monitor Quality Assurance/Quality Control (QA/QC) are added (imposed through §§63.644(a) and 63.1572(c)). EPA has made no demonstration to justify these changes under §63.112(d)(6) or (f)(2), including evidence that compliance assurance problems justify these extensive changes, or provided the costs and burdens imposed by these additional requirements for review and comment. The existing requirement that "All monitoring equipment shall be installed, calibrated, maintained, and operated according to manufacturer's specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately" should be maintained and the proposed additional requirements should not be finalized. EPA cannot promulgate these unnecessary requirements unless they are 1) reproposed along with full justifications and detailed cost estimates for the replacement and upgraded monitors that will be required and for the large, new ongoing burdens, 2) three years is provided for replacing or revising existing instruments to meet these new requirements, and 3) applicability dates are added indicating when the new requirements apply and when the old requirements no longer apply. Three years is needed to allow evaluation of the many monitors currently in use, to design and installation of upgrades and/or replacement monitors as needed, to revise procedures, OMMPs and permits to reflect these changes, or to obtain alternate monitoring approvals where the requirements are infeasible or not appropriate.

Our comments on some of the specifics of the proposal follow.

1.5.1.2 The Applicability of RMACT 1 Table 13, RMACT 2 Table 41 and the RMACT 2 Table 40 Revisions Must Be Clarified and A Start Date Added to Each Table.

It appears RMACT 1 Table 13 is intended to apply to all continuous monitors required by RMACT 1. We are concerned that, based on a claim that these requirements reflect what EPA "always intended", the requirements in RMACT 1 Table 13, RMACT 2 Table 40 and RMACT 2 Table 41 will be inaccurately claimed to have always applied. These new requirements cannot legally be applied retroactively. Nor does the proposed rule language in §63.644(a) and (c) and in §63.671 apply Table 13 to all continuous monitors required by RMACT 1. Rather, the RMACT 1 Table 13 is proposed to only apply to flare instrumentation required by §63.670, monitoring of combustion controls used for Group 1 MPV compliance, and to the proposed flow monitoring for potential Group 1 MPV bypasses.

Therefore, API/AFPM recommends that a paragraph be added below the title for RMACT 1 Table 13 and RMACT 2 Tables 40 and 41 to indicate that these tables only apply after the compliance date for these amendments. Additionally, the RMACT 1 Table 13 paragraph should clearly indicate that the table only applies to monitoring instrumentation for flares as specified in §63.671, for Group 1 MPV combustion controls as specified in §63.644(a), and for monitors used to monitor for flow in potential bypasses around Group 1 MPV control devices as specified in §63.644(c).

Finally, the changes to Table 40 should be included in a new Table (e.g., Table 40a) with a clear applicability date for the new requirements specified. We discuss the required timetable in our next comment.

1.5.1.3 Eighteen Months to Three Years Is Required to Implement New and Revised CPMS, CEMS and COMS Requirements.

While some of the equipment to which §63.671, RMACT 1 Table 13, and RMACT 2 Tables 40 and 41 apply has a three year compliance period (e.g., some §63.670 requirements), that is not true for most of the monitoring required by RMACT 1 and 2. Where new, replacement, relocated or significantly revised instrumentation is required to meet the new requirements, three years is necessary. Where existing instrumentation is able to meet the new requirements with little revision, eighteen months, at a minimum, is needed to develop the required monitoring plan, revise procedures and permits, obtain approval for alternative monitoring plans, and to implement the maintenance, QA/QC and other requirements specified. As we point out in the following comments, there are significant differences between the requirements proposed here and the requirements established by NSPS Ja, State rules, and instrument manufacturers. Thus, a great deal of existing instrumentation will require upgrades, if not replacement, and all new procedures.

1.5.1.4 Delay Provisions Should Be Provided Where Control Device or Process Shutdowns Are Required To Meet the Monitoring Requirements.

Flares typically service many process units, and shutdown or partial shutdown of a flare or its header system often requires that some or all of those process units serviced be shutdown, since it is unsafe to operate without adequate emergency relief capability. Though less common, the same is true for some shared combustion controls used to control some Group 1 MPVs.

Shutdown of individual process units can also have significant production and steam impacts and safety risks. Some of the proposed QA/QC requirements could require process and/or control device shutdowns (e.g., accessing flare tips, cleaning pressure taps, replacing thermowells). The impacts and costs of such shutdowns simply cannot be justified solely because of monitoring QA/QC issues, since there are generally reasonable alternatives to the excessive requirements imposed by this proposal. Thus, we recommend a general delay provision to the next scheduled shutdown be provided for those situations where a process or control device shutdown is required to complete a QA/QC activity.

1.5.1.5 RMACT 1 Table 13 and RMACT 2 Table 41, If Retained, Should be Made Consistent Based on The Least Burdensome Requirement in Each Table.

Proposed RMACT 1 Table 13 and RMACT 2 Table 41 are inconsistent for monitor types to which they both apply (i.e., temperature, pressure, and flow). These inconsistencies range from fairly minor points (e.g., using metric units in one table and English units in the other) to less minor differences (e.g., calling for performance evaluations in one and calibration checks in the other) to major differences (e.g., calling for daily pressure tap checks in RMACT 1 Table 13 and weekly checks in RMACT 2 Table 41). Such differences are confusing, lead to compliance and enforcement problems, and demonstrate the arbitrary nature of the proposed QA/QC requirements. As we propose in comment 1.5.1.6.1 below, the QA/QC requirements should be removed from both Tables and addressed through the required monitoring plans. If that is not done, the requirements should be consolidated on the least frequent or least onerous requirement from either table where that requirement can be justified (since even that goes beyond industry standard and manufacturers recommendations), and language should be changed such that the same terminology is used in both tables. Non-QA/QC requirements in both tables need to be corrected to use identical language, units, and terminology.

1.5.1.6 Comments on Proposed RMACT 1 Table 13 and RMACT 2 Table 41 QA/QC Requirements.

1.5.1.6.1 Proposed RMACT 1 Table 13 and RMACT 2 Tables 40 and 41 QA/QC Requirements Should Be Deleted in Favor of Their Inclusion In a CPMS Monitoring Plan.

Proposed §63.671(b) of RMACT 1 requires a CPMS monitoring plan for each CPMS associated with flare monitoring to address QA/QC. §63.644(a) of RMACT 1 requires "All monitoring equipment shall be installed, calibrated, maintained, and operated according to manufacturer's specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately …" The existing RMACT 2 requires an operation, maintenance, and monitoring plan, which is required by §63.1574(f) to include monitor QA/QC information. §63.1572(c)(1) contains the same language as §63.644(a), but that language is proposed for deletion. There is no excuse for treating instrument requirements differently in these two rules, and doing so will only increase burdens and compliance liability.

Despite the logic and proven results of relying on manufacturer's recommendations and field experience, as these two rules currently require, this proposal specifies instrument QA/QC requirements in Table 13 of RMACT 1 and Tables 40 and 41 of RMACT 2. It is wasteful and confusing to have both. Furthermore, as discussed in our next comment, some of these requirements differ from the QA/QC requirements specified for this same flare instrumentation in part 60 subpart Ja. The proposed requirements in the Tables reflect an outdated and theoretical understanding of process instrumentation and do not reflect the capabilities of modern instrumentation or refinery experience. Because of the diversity of situations, the vast array of instrument technologies now available, the experience industry has developed in assuring high quality measurements, and the most efficient match with current practices and other applicable QA/QC requirements, a plan approach is the best way to deal with CPMS QA/QC and to assure the highest quality measurements with the least burden. API/AFPM has been advocating that position for many years and again request that EPA maintain that approach in these rules rather than replacing it with unnecessary and highly burdensome detail that may or may not be appropriate to any given installation. In this case, we recommend that the §63.671(b) plan requirement be extended to all CPMS required by the RMACT 1, that §63.1572(c)(1) not be deleted, and that all monitor QA/QC requirements be removed from the regulatory text and Table 13 of RMACT 1 and Tables 40 and 41 of RMACT 2.

In particular, where a QA/QC plan is required a rule should not also specify required QA/QC. The plan approach allows QA/QC requirements to be tailored to each specific CPMS and allows consideration of knowledge of the process and the historical performance of instruments in that particular service. Thus, the imposition of burdensome requirements can be limited to only the monitors where the burden is justified, instead of applying them to the majority of instruments where they are unnecessary. For instance, if one in a hundred pressure instruments have problems with sample point plugging, under the plan approach burdensome checks to assure the sample tap is not plugged can be limited to that one monitor instead of applying that burden to a hundred monitors, as Tables 13 and 41 would require. Furthermore, the plan approach can be adjusted as needed; so, for instance, if blowback steam is added to a pressure sample point with a plugging history, the frequency of checking that sample point can be reduced. The Table 13 and 41 approach allows no such adjustments.

RMACT 2 already requires such plans and they are already in place and reflected in site permits and have been providing successful compliance assurance for decades. EPA has put forth no justification for overlaying the proposed new prescriptive requirements on top of those existing plans or for imposing the burdens on sources and regulators for modifying existing plans or for imposing the costs and burdens for additional QA/QC in the face of the existing, successful RMACT 2 compliance assurance program.

If EPA finalizes the proposed RMACT 1 Table 13 and RMACT 2 Tables 40 and 41 QA/QC requirements, then monitoring should be removed from the current operation, maintenance, and monitoring plan provisions throughout the current RMACT 2; and the proposed monitoring plan requirements for RMACT 1 should not be finalized, since these plans would only be documenting the requirements already specified in these rule tables.

1.5.1.6.2 Manufacturer's QA/QC Recommendations Should be Allowed in Place of the Generic QA/QC Requirements in RMACT 1 Table 13 and RMACT 2 Tables 40 and 41.

For some types of CPMS, manufacturers recommend QA/QC procedures and RMACT 1 and 2 requires their use[94]. Furthermore, other rules and permits applicable to this same equipment commonly include a requirement that manufacturers' recommendations be met. Where such procedures are available and appropriate to the actual installation, sources should be allowed

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[94] See §63.8(c). See, also, §63.644(a), §63.1572(c), and §63.1574(f)(2)(x).

to use these methods in place of the generic QA/QC requirements included in RMACT 1 Table 13 and RMACT 2 Table 41. This is an example of where use of a plan, rather than prescriptive one-size-fits-all requirements, greatly improves the quality of the outcome.

1.5.1.6.3 The Requirement to Check for Pressure Tap Obstructions Should be Replaced With The Requirement in Proposed §63.671(b)(5)(iii) to Check That The Pressure Instrument is Responding.

RMACT 1 Table 13 calls for daily checks and RMACT 2 Table 41 calls for weekly checks for pressure tap obstructions. Proposed §63.671(b)(5)(iii), which applies to flare instrumentation, calls for daily checks that the instrument is responding. This is a much more reasonable check and covers the situation of a plugged pressure tap; thus, we recommend that this requirement replace the pluggage check item in RMACT 1 Table 13 and that a similar check be added to RMACT 2 Table 41 in place of the pressure tap plug check. If the pressure tap requirement is maintained, it should be changed to a weekly check and the resulting emissions to the atmosphere or to the flare, should be specifically authorized.

Checking for pluggage of a pressure tap generally requires purging the pressure sensor, thereby releasing VOC and HAPs to the atmosphere. These emissions and the personnel risk (burn and exposure) they generate have not been addressed in the rulemaking record and are not justified by the low likelihood of pluggage for most pressure CPMS. Pressure tap pluggage would be highly unusual in a refinery flare system or other combustion based control device. Generally, the lack of pluggage is adequately indicated by the fact that the pressure reading is varying. In services where pluggage is a problem, the problem is usually readily apparent and occurs repeatedly. Thus, only where there is a history of pluggage is any action needed other than assuring the pressure reading varies; a check that is already required by proposed §63.671(b)(5)(iii). Where pluggage is a problem, engineering fixes (such as adding blow back steam or nitrogen) are usually preferable to daily or other routine checks because they avoid environmental releases and potential personnel exposure.

The costs and burdens for these unnecessary and wasteful checks have not been considered in the rulemaking record and are significant. We estimate a typical incremental burden of 30 minutes per day of operator time for each pressure CPMS subject to this requirement. For delayed cokers, there are an average of 3.2 drums per unit and approximately 80 units resulting in an annual industry burden of over 46,000 hours per year for this one set of pressure instruments. Even allowing for some efficiency due to the nearby location of coke drum pressure instruments, we would expect this requirement to add at least 23,000 hours of burden per year for just this one set of instruments for this one requirement. No burdens are included in the RMACT 1 Information Collection Supporting Statement for any instrument QA/QC (except perhaps as part of the lump sum estimate of flare instrument maintenance costs). Since no emission reduction is associated with this activity, the cost per ton of emissions reduction is infinite.

1.5.1.6.4 The Redundant Monitor Provision in RMACT 1 Table 13 Should Be Clarified and Extended to RMACT 2 Table 41.

RMACT 1 Table 13 allows relief from certain QA/QC flow meter requirements if "redundant" sensors are available. It is unclear what this term means, particularly relative to flow monitors. In response to a similar question relative to a similar requirement in NSPS Ja, EPA has stated the following:

> Any meter or collection of meters that can provide a continuous measure of the cumulative flow at the location of the required flare flow meter would qualify as a "redundant flow sensor" in §60.107a(f)(1)(iv). The purpose of the inspection requirement is to ensure that the flare flow measurements are not lost due to physical or operational integrity problems with the required flow monitor, particularly issues that could be avoided with appropriate preventive maintenance. If the flow measurement can be determined by summing the flow from a series of other meters, then the required flow measurement would not be lost if the primary flow meter is lost, and the quarterly inspections are not required.[95]

We request this same clarification be made in the response to comments or that the regulatory text be revised to make clear what a redundant flow monitor is. Additionally, we request that it be clarified that a redundant temperature or pressure monitor would be one that would measure the required temperature or pressure, even if it is not located on the same pressure tap or in the same thermowell.

Alternatively, to alleviate the need for clarification, EPA should replace the word "redundant" with "alternative" in Table 13.

The proposed redundant monitoring provision is of equal value for RMACT 2 monitoring systems; we, therefore, request that the QA/QC provisions in proposed RMACT 2 Table 41 be revised to include the same redundant monitoring exception, with the clarifications discussed in the previous item.

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[95] Letter from P. Tsirigotis, EPA to Matt Todd, API/AFPM, *NSPS Ja Clarifications and Corrections,* August 27, 2013, Response to Question 14.

1.5.1.6.5 Manometers Are Unsafe to Use and Should Not Be Required For Pressure Instrument Calibration.

RMACT 1 Table 13 and RMACT 2 Table 41 require the use of manometers to calibrate pressure CPMS. For safety reasons manometers only used in very few cases, such as pitot tubes and annubar calibration checks. NIST traceable digital instrumentation is used instead, for most pressure instrument types. All references to the use of manometers should be removed from these tables. Because these calibration practices change over time, plants should be allowed to determine the appropriate technology to be used for calibration, based on recommendations from instrument manufacturers.

1.5.1.6.6 Annual Calibration is All That is Required for Pressure Monitors.

Several companies make electronic pressure test devices that are used in conjunction with a hand pump. Annual calibration is performed in most cases, so moving to weekly or daily would be a big, wasteful change. Typically, there is a pressure gauge in addition to a transmitter for a specific pressure reading and the operators check the gauges regularly. If there is a significant difference between the pressure gauge and the control room reading a work order is created to have the transmitter and gauge checked.

1.5.1.6.7 The Requirements To Check Continuity on Wiring and Electrical Connections and Visually Check for Corrosion are Pointless, Have Not Been Addressed in the Record and Cannot Be Finalized.

For most other instrument transmitters, if the continuity fails on any wiring the signal will no longer show in the control computer and a work notification will be created to fix the problem. For temperature indicators, the visual corrosion inspection requirements in Table 13 and the "continuity" checks in Table 41 are superfluous. When the electrical signal fails for any reason the operators will see it and write a work order to check/repair the instrument. For most non-critical temperature indications, run-to-failure is the normal industry practice. The replacement of critical temperature indicators is typically done on a turn-around cycle to prevent failure during normal operation.

If EPA believes there is any justification for these high burden requirements in a modern facility, it should estimate costs and burdens, identify the justification, and publish those analyses for comment. Since no such analyses were provided as part of this rulemaking record, these changes to RMACT 1 and 2 cannot be finalized.

1.5.1.7 RMACT 1 and 2 Must Specifically Authorize The Additional Flaring Required for Compliance.

In order to avoid flare outages, hot taps are used, where they can be done safely, to install instrument taps and sample points on flare lines. Such hot taps require large flows of gas to cool the piping. Calibrating and performance testing various instruments as required under the QA/QC provisions can also require relatively frequent excess flows to the flare. Checking pressure taps daily or weekly would also require daily or weekly flows to the atmosphere or flare. In some cases, these flows will be too remote, too variable, or too low in BTU content to recover as fuel gas.

NSPS Ja requires minimizing flare emissions, so RMACT 1 and 2 need to have language specifying that flows to the flare required to comply with RMACT 1 and 2 QA/QC requirements or to install RMACT 1 and 2 required instrumentation are considered base emissions for the purpose of establishing the basis for the NSPS Ja 500,000 scf/d flare excess flow trigger. Additionally, these flare flows should not be counted in determining whether a flare meets the “emergency flare” criterion in NSPS Ja of 4 releases per year or less.

1.5.2 Comments Specific to Proposed Flare Monitoring Requirements.

1.5.2.1 A Safety Over-Ride Must Be Provided For §63.671 and Table 13 Requirements Where Flare Access Is Required.

The requirements in proposed §§63.644(a)(2), 63.670(g), 63.671 and Table 13 require extensive QA/QC activities that are not safe to perform on an in-service flare. In particular, flare pilot thermocouple monitors are generally not safely accessible while the flare is in service (even if it is not burning at the moment). Similar concerns apply to the flare tip portions of ignition and reignition systems. Ignoring these concerns would also ignore OSHA’s standards for release of hazardous energy, an unacceptable trade-off. In most cases, refineries maintain a safe zone around the perimeter of a flare to avoid potential injuries, should the flare unexpectedly be ignited. For instance, one refiner reports that they do not allow any maintenance or inspection work within a 150-foot radius of the flare without extreme safety measures in place. Thus, the proposed §63.670(g) and the proposed revisions to §63.644(a)(2) should not be finalized, and a general exception should be added to §63.671 and Table 13 to allow an exception for any QA/QC requirement that requires accessing an in-service flare or flare tip.

Flares typically have many pilots and multiple pilot monitoring devices (typically thermocouples) for each pilot, thus, even if some pilot monitors are out-of-service, there are almost always enough operating monitors to assure the presence of at least one pilot flame (the applicable requirement). Furthermore, the Table 13 requirements for temperature CPMS are unworkable and unnecessary for flare pilot monitors, where the purpose of monitoring is to indicate the presence of a flame. An accurate reading of the flame temperature is not required, since any temperature reading above a few hundred degrees indicates a pilot flame is present.

1.5.2.2 The Flare Flame Monitoring Language In the Existing §63.644(a)(2) and in §63.11(b)(5) Should Be Maintained and Flare Pilot Monitors Should Not Be Converted to CPMS.

§63.11(b)(5), which currently specifies the flame monitoring requirements for refinery flares used as RMACT 1 control devices states the following:

> Flares shall be operated with a flame present at all times. The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

This language provides for monitoring for the presence of a flame by monitoring for the presence of a pilot flame using “a thermocouple” or monitoring for a flame using an equivalent device. It specifically does not call for the use of a temperature monitor or temperature CPMS. Flare pilot thermocouples have never been treated as CPMS because, as discussed above, it is unnecessary, it requires many days to shutdown and access a flare tip safely, and a flare and process outage in order to perform CPMS QA/QC has a tremendous impact on production and cannot be justified. The existing language relative to flare pilot monitors in §63.644(a)(2) is consistent with §63.11(b)(5) as are the associated recordkeeping requirements. These requirements were carefully developed and worded not to impose CPMS requirements. Consistent with the historical treatment of flare pilot thermocouples, the existing language in §63.644(a)(2) should be maintained, the language in §63.11(b)(5) should replace proposed §63.670(g), and language should be added to §63.671 to exclude flare pilot monitors from all requirements of that section.

1.5.2.3 Flare Flame Monitoring Language in RMACT 1 and 2 Should Be Revised to Be Clear That Only One Pilot Flame Must Be Lit.

If the wording from the current §63.11(b)(5) is not exactly maintained, any new or revised wording needs to be clear that only the presence of a pilot flame is required. Most refinery flares have multiple pilot flames and multiple monitors. Requiring that all pilots be lit is a major change that has not been evaluated or justified and has significant cost and fuels supply impacts that cannot be justified.

Proposed §63.670(g) requires:

> The owner or operator shall continuously monitor the presence of the pilot flame(s) using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot flame(s) is present.

Use of the phrase "the pilot flame" rather than "a pilot flame" and the phrase "using a device" rather than "using devices" suggests all pilot flames must be lit at all times and that a single monitor must monitor all pilot flames. Such a change from the current requirement is neither technically justified nor supported in the rulemaking record and, in fact, is inconsistent with how the pilot requirement is stated in proposed §63.670(b) and at other locations in the two RMACT rules, which use the "a pilot flame" terminology. To clarify what is required we suggest the wording of proposed §63.670(g) and §63.644(a)(2) be revised, as follows, to match the existing §63.644(c) wording.

> The owner or operator shall continuously monitor the presence of ~~the~~a pilot flame(s)~~ using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot flame(s) is present~~.
>
> Where a flare is used prior to [THE DATE 3 YEARS AFTER THE DATE OF PUBLICATION OF THE FINAL RULE AMENDMENTS IN THE **FEDERAL REGISTER**], the presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.
>
> …

This terminology issue also occurs in RMACT 2. The wording in the following locations all refer to "the pilot flame" and/or "a device" and all should be revised to be clear that only one pilot must be lit: §63.1568(c)(3)(ii)(B); Table 9 (Item 2.b.ii); Table 11 (Item 3.f.1); Table 14 (Item 2.d); Table 16 (Item 1); Table 18 (Item 1.a); and Table 21 (Item 1).

1.5.2.4 Proposed §63.671 Should Not Apply to Remote Sensing Monitors Such as Infrared and Ultraviolet Pilot Monitors and Visible Emission Video Monitors.

Nothing in proposed §63.671 or Table 13 deals with remote sensing instruments such as video cameras, ultraviolet flame sensors, or infrared flame sensors and it will cause confusion and unreasonable compliance liability to try to impose requirements from that section and that table on these types of instruments. Thus, §63.671(a) should clearly limit Table 13 applicability to only the instrument types specified in the table.

1.5.2.5 Since Neither The NSPS Ja Flare Flow Meter Sensitivity Specification Nor the Proposed RMACT 1 Table 13 Accuracy Specification Can Be Met By Standard Flare Flow Instrumentation, We Recommend That The Accuracy Specification From the Shell Deer Park Consent Decree Be Specified in Table 13 of This Rule and in §60.106a(a)(6)(i)(B) of NSPS Ja.

Flare gas flow meters are currently in place or on order as specified by EPA in NSPS Ja, which EPA has made immediately applicable to most refinery flares. These meters should not have to be replaced or duplicated due to differences in the requirements in subpart Ja and in this proposal or the infeasibility of meeting either specified requirement.

Proposed RMACT 1 Table 13 specifies an accuracy of ±5 percent over the normal range of flow measured or 280 liters per minute (10 cubic feet per minute), whichever is greater, for gas flow monitors. In §60.106a(a)(6)(i)(B), NSPS Ja specifies a flare flow sensor with a measurement sensitivity of no more than 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. As we indicated in our NSPS Ja Reconsideration Petition, it is unclear what "measurement sensitivity" means in §60.106a(a)(6)(i)(B) and, that, if it means "accuracy" a ± 5% criterion cannot be met for all potential flows in large diameter flare headers.

The standard instrumentation used for monitoring flare flow is a dual range ultrasonic flow meter. More recently, optical instruments have become available and are being used for this service. Manufacturers typically specify ultrasonic meter accuracy as ±5% from 1 feet per second (fps) flow to the top of the range (200-400 fps) and ±10-20% from 0.1 fps to 1 fps. Optical meters are quoted by the manufacturer as having better accuracy than ultrasonic flow meters, but are unproven, and their long term reliability is unclear. Furthermore, replacing the widely used ultrasonic meters with optical meters just to obtain minor improvements in low flow accuracy cannot be justified. Such a requirement would be extremely costly and require flare and process outages, costs that were not justified or even considered in this rulemaking.

These flow accuracy specifications are also inconsistent with those in the South Coast Flare Rule and in many Refinery Consent Decrees. API/AFPM therefore recommends that the accuracy specification from the Shell Deer Park Consent Decree be specified in Table 13 of this rule and in §60.106a(a)(6)(i)(B). Specifically Appendix 1.10 of the Shell Deer Park Consent Decree specifies the required flare flow meter accuracy as "± 20% of reading over the velocity range of 0.1–1 ft./s and ± 5% of reading over the velocity range of 1–250 ft./s." This action would also resolve this issue under our NSPS Ja reconsideration petition.

1.5.2.6 Ultrasonic and Optical Flare Gas Flow Meters Can Only Be Calibrated at the Factory, and, Thus, The Requirement For Annual Calibration of Gas Flow Monitors Cannot Be Applied to Those Meter Types.

RMACT 1 Table 13 requires annual performance evaluations of gas flow meters and RMACT 2 Table 41 requires semi-annual calibration. Both Tables require checks if the flow exceeds the meter range for 24 hours. However, ultrasonic and optical meters are calibrated at the factory and cannot be field calibrated. Rather, they can be checked to validate the factory calibration. Furthermore, these are both "in-situ" monitors and there are no mechanical connections to check for leakage. Thus, these flow monitor types should be excluded from the flow monitor QA/QC requirements in these tables and manufacturers recommendations used, via the monitoring plan, instead.

1.5.2.7 All Required CPMS Outages Should Be Specifically Allowed.

Proposed §63.671(a)(4) lists activities during which a CPMS may be off-line. However, not all activities required by §63.671 and Table 13 are covered. For instance, outages associated with the required Table 13 check of pressure CPMS taps for plugging and the §63.671(b)(5)(iii) daily response checks would not be allowed by proposed §63.671(a)(4). We recommend this paragraph be generalized by adding a phrase to cover any outage required to comply with this rule or the procedures specified in the CPMS monitoring plan (e.g., manufacturer's recommendations or activities required by applicable Performance Standards).

For the flare gas flow meter, any activity required to meet the requirements of part 60 subpart Ja must also be allowed and any flow out-of-control periods due to required temperature and pressure correction instrument outages must be allowed.

The excessive QA/QC requirements of this proposal will result in significant monitor outage and sources cannot be penalized for the lack of monitoring when they are following the requirements of the regulation.

1.5.2.8 The Proposed Flare Gas Chromatograph (GC) Calibration Requirements are Infeasible and Unnecessary and Must Be Revised.

Proposed §63.671(e)(2) requires the following for calibration of flare composition GCs which are used to calculate flare gas heating value and hydrogen and olefin contents.

> (2) The calibration gases must meet one of the following options:
>
> (i) The owner or operator must use a calibration gas or multiple gases that include all of the compounds that exist in the flare gas stream. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, the owner or operator must calibrate the instrument on all of the gases.
>
> (ii) The owner or operator must use a surrogate calibration gas consisting of C1 through C7 normal hydrocarbons. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, the owner or operator must calibrate the instrument on all of the gases.
>
> (3) If the owner or operator chooses to use a surrogate calibration gas under paragraph (e)(2)(ii) of this section, the owner or operator must comply with the following paragraphs.
>
> (i) Use the response factor for the nearest normal hydrocarbon (i.e., n-alkane) in the calibration mixture to quantify unknown components detected in the analysis.
>
> (ii) Unknown compounds that elute after n-heptane must either be identified and quantified using an identical compound standard, or the owner or operator must extend the calibration range to include the additional normal hydrocarbons necessary to perform the unknown hydrocarbon quantitation procedure.

1.5.2.8.1 Proposed §63.671(e)(2)(i) is Infeasible And Must Be Revised.

This paragraph requires that the GC calibration gas or gases include all of the compounds that exist in the flare gas stream [emphasis added]. Most refinery flares can receive gases containing hundreds of compounds, and it is, therefore, impossible to include all of them in the calibration gas. Furthermore, such a calibration gas would be useless. If, for instance, there are 100 species in the flare gas composition, the calibration gas would need to contain appropriate concentrations of each species. For the more reactive species, such as olefins, placing all of them in one bottle at concentrations less than 1% (which is typical for most olefins in flare gas) would result in the inability to maintain the concentration of most of the reactive species. This would reduce the usable life of the calibration gas to weeks versus 1 to 3 years for normal calibration gases. In addition it would be difficult if not impossible for calibration gas suppliers to provide certified gases with the typical concentration ranges necessary to properly calibrate a GC for flare gas.

In addition, $C4^+$ species' heating value and flammability limits are not very different per Table 12 of the proposal. All of the C4 species in the Table have heating values between 2690 BTU/SCF and 2968 BTU/SCF and the LFL varies from 1.6 to 2.0. These spreads will have no significant impact on the calculated heating value or LFL if a single value is used or if only 1,3-Butadiene[96] is singled out. With low concentrations and the same heating value contribution, there is no reason for §63.671 requiring resolution of C5+ species, much less C6+ species.

Thus, the GC requirements and the associated calibration requirements should focus on the species that matter for determining compliance (i.e., hydrogen, olefins and C1 through C3) and allow grouping of higher carbon number species. API/AFPM proposes that §63.671(e)(2)(i) be revised to call for a calibration standard that includes H_2, hydrocarbons through C3 that could be present in concentrations above 1%, 1,3-Butadiene, n-butane and n-pentane.

1.5.2.8.2 Proposed §63.671(e)(2)(ii) Also Should Be Revised.

As an alternative to (e)(2)(i), this paragraph allows use of a surrogate calibration gas consisting of C_1 through C_7 normal hydrocarbons. Since Table 12 of the proposal treats all C_5+ the same and, in general, the higher the carbon number the less volatile the compound, there is no need

[96] 1,2-Butadiene is a minor isomer of butadiene and always present in minor concentrations and is difficult to separate from 1,3-Butadiene by GC. There is negligible impact from ignoring it for this analysis.

to calibrate above C_5. Experience shows that calibration gas blends for HRVOC type GCs (the light gases, H2 thru C_5+) are challenging to prepare in a single compressed gas cylinder because the concentrations of each compound is relatively low versus the potential concentration range in the flare gas stream. Adding C_6 and C_7 components will push these gas blends to become infeasible in a single compressed gas cylinder. Calibration of a GC with more than one cylinder is a challenging task for on-line GCs. For consistency, then, and based on experience, we request §63.671(e)(2)(ii) be revised to only require calibration using normal hydrocarbons through n-pentane, when this alternative is used.

1.5.2.8.3 Proposed §63.671(e)(3)(ii) is Technically Infeasible and Unnecessary and Should be Deleted.

Proposed §63.671(e)(3)(ii) reads as follows.

> Unknown compounds that elute after n-heptane must either be identified and quantified using an identical compound standard or the owner or operator must extend the calibration range to include the additional normal hydrocarbons necessary to perform the unknown hydrocarbon quantitation procedure.

This paragraph presumes that there are particular heavy compounds present in flare gas and that some of those will show up repeatedly on the composition GCs used to develop the process GC analysis. That is an invalid assumption. Refinery flare gas compositions vary extensively in both species present and their concentration and thus there are potentially many compounds that elute after n-heptane (or n-pentane as we recommend above), but which may or may not be present and, if present, are unlikely to have a significant concentration. Thus, there is no way of knowing what these compounds are or limiting how high a carbon number standard must be used.

Since these species are all treated as C5+ in the calculations and their volatility is relatively low, their exact concentration has no significant impact on the calculated flare gas heating value or flammability limit, and there is no value in wasting time on identifying even what carbon numbers are represented, much less individual species. Thus, we recommend this paragraph be deleted.

1.5.2.9 The Speciation Required by The Proposal for Flare Gas Composition Needs to Be Clarified and Table 12 Adjusted Accordingly. It Is Impossible and Unnecessary to Monitor for Every Species that Could Be Present in Flare Gas and The Specified Speciation Cannot Be Accomplished in The 15 minutes Specified.

1.5.2.9.1 The Flare Gas Speciation Required by The Proposal Needs to Be Revised.

Proposed §63.670(j)(1) requires "the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring (i.e., at least once every 15-minutes), calculating, and recording the individual component concentrations present in the flare vent gas." Proposed §63.671(o)(1) requires "The olefins concentration shall be determined as the cumulative sum of the following flare gas constituents: ethylene, acetylene, propylene, propadiene, all isomers of n- or isobutene, and all isomers of butadiene."

These requirements could be read to require that every component of flare gas be continuously monitored, an unnecessary and impossible requirement. Even if limited to just C5 minus components, it is unnecessary to individually monitor every component in order to calculate the flare gas heating value and molecular weight. Nor is it necessary to measure individual olefins in order to measure the total olefin content with reasonable accuracy.

The typical on-line Gas Chromatograph (GC) is challenged to speciate the light gases (N2, O2, CO, CO2), H2, C1, C2's, C3's, C4's and C5+ grouping within 15 minutes. As proposed, it is likely that compliance will not be possible with just a single gas chromatograph as EPA claims and which claim is the basis for the cost and burden estimates provided in support of this proposal. Nor would the existing GCs used for CD compliance be adequate, again as EPA assumes. To reduce cycle time and simplify the analysis without impacting the quality of the heating value, molecular weight, and olefin content selected grouping should be allowed, at the refinery's discretion. Rather, multiple gas chromatographs or a BTU analyzer plus a gas chromatograph will be required, even if the proposed 15-minute averaging time does not require it both analyzer types.

In order to limit the composition requirements to what may be accomplished with a single gas chromatograph within the required 15 minute cycle time, we recommend the following component list be adopted. Major process GC vendors indicate C4-olefin grouping is required to meet the 15 minute cycle time. Such grouping will have little impact on the data use, since the C4 olefin heating values are quite close[97], and these components have to be summed to determine the total olefin content anyway.

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[97] Per Table 12 of the proposal the heating values are: isobutene 2957 BTU/SCF, c-butene-2 2830 BTU/SCF, and t-butene-2 2826 BTU/SCF. A heating value for butene-1 is not included in the table but is 2717 BTU/SCF. A combined, weighted heating value is typically 2876 BTU/SCF used.

Specifically we recommend the following speciation be spelled out in §63.670(j)(1):

1. Hydrogen
2. Oxygen
3. Nitrogen
4. Carbon Dioxide
5. Carbon Monoxide
6. Methane
7. Ethane
8. Ethene (aka: Ethylene)
9. Acetylene
10. Propane
11. Propene (aka: Propylene)
12. 2-Methylpropane (aka: iso-Butane)
13. Butane (aka: n-Butane)
14. Butenes (including butene-1, isobutene, c & t-butene-2)
15. 1,3 butadiene
16. Pentane plus (aka: C_5 plus) (*i.e.*, all HCs with five Cs or more)

§63.670(j)(1) should also clarify that additional species, such as hydrogen sulfide, may also be measured as long as the cycle time limit (15 minutes) is not exceeded. This is an important point, because many existing flare gas chromatographs also measure hydrogen sulfide and/or measure additional components. Additionally, §63.670(j)(1) should allow Items 2, 3 and/or 4 to be grouped and reported as a single value, since they have the same heating value (0 BTU/SCF).

Propadiene and 1,2-Butadiene are included in the proposed §63.671(o)(1) olefins list, but these are minor components that are difficult to resolve from methyl acetylene and 1,3-Butadiene respectively and thus are typically left unresolved. Leaving them unresolved will have no significant impact on the quality of the olefin content measurement, but will simplify the analysis, improve the chromatograph service factor, and be consistent with Texas Highly Reactive VOC requirements.

Allowing flexibility will also reduce conflicts between these requirements and existing consent decree and State requirements. Many Texas refineries are subject to the Texas Highly Reactive VOC regulations and have been required to install gas chromatographs on their flare gas to monitor for the reactive VOC species of concern under that regulation. Those GCs monitor the species listed above, through $C5^+$. Under this proposal, it appears that the flare gas GCs must separate C6 from C7 and, per §63.671(e)(3), possibly higher carbon number compounds. Higher carbon number species heating values are not very different and they are all treated as $C5^+$ in the heating value calculation per Table 12 of the proposal. With low concentrations and the same heating value contribution, there is no reason for §63.671 to require resolution of C5+ species, much less C6+ species. As discussed above, this could easily force refineries to have to add separate GCs to meet these requirements, when the HRVOC GC provides more than adequate data for calculating heating values and estimating olefin and hydrogen contents. Such a duplication or replacement would be wasteful and unjustified. If this rule requires a different list of species than is required by Texas, the rule should specifically allow HRVOC compliance as an alternative, without having to comply with the additional requirements of §§63.670, 63.671 and Table 13.

1.5.2.9.2 Table 12 Needs to Be Revised to Match the Required Speciation.

Proposed Table 12 provides heating values and other parameters to be used in calculating combustion zone values and limits. As proposed, the Table provides values for each individual specie in the §63.670(j)(1) list of species that must be measured, except butene-1 is not included. If the final rule includes a requirement to individually measure buten-1, it should be added to the table.

More importantly, as discussed above, grouping and other changes to the §63.670(j)(1) list are required to make it achievable in 15 minutes and consistent with existing GCs used for CD and State regulation compliance. With incorporation of our suggested changes in the rule, Table 12 should be revised to match (e.g., weighted heating values and LFLs should be provided for butenes).

1.5.2.10 The Requirement in Proposed Table 13 That Performance Specification 9 of Part 60 Appendix B Apply to Gas Chromatographs Used to Measure Flare Gas Heating Value Needs Modification.

Section 6.2 of Performance Spec 9 requires that the sample conditioning system be maintained at 120 °C (248 °F), presumably to assure that no heavy hydrocarbons condense in the sample system, since this method applies to GCs that could have a wide range of compositions. Since flare gas temperature is typically much lower than 120 °C, condensation of heavy hydrocarbons is not an issue, and flare GC sample systems would typically be designed for lower temperatures. Lower temperature designs save investment. API/AFPM, therefore, request that Table 13 waive this temperature specification for flare gas GC sample systems in PS 9 and require the temperature specification from the Shell Consent Decree instead. Namely, maintenance of temperature of ≥135 °F for the sample transport line and ≥125 °F for the sample conditioning system.

Lower maintenance temperatures will improve reliability and service factor because heaters do not have to work as hard to maintain the higher temperature in day-to-day operation and especially after maintenance activities where the heaters are trying to bring the system back to the proposed high operating temperature. A typical approach to maintaining 200+ °F in a sample conditioning system involves air bath heaters which utilize plant air, already a strained resource in most plants. A sample conditioning system temperature of 125-135 °F can be readily achieved with electric heaters that are cost effective and reliable.

1.5.2.11 If Not Deleted in Favor of Use of A Monitoring Plan (See Comment 1.5.1.6.1), the Flare Flow Monitor QA/QC Requirements Should Defer to Those in Part 60 Subpart Ja.

Proposed Table 13 imposes separate QA/QC requirements for flare flow, temperature and pressure monitors. Some of those requirements are waived for individual flow, temperature, or pressure monitors if there is a redundant flow, temperature, or pressure monitor. NSPS Ja waives the inspection requirements for the temperature and pressure monitors associated with the flow monitor based on whether there is a redundant flow monitor.

The probability of failure of pressure and temperature monitors for flare gas is extremely low, and these monitors have not been needed to assure high availability of flare flow measurements for the flare flow monitoring currently in place. Thus, we do not believe there is any justification for deviating from the part 60 subpart Ja requirements. Furthermore, the visual inspection requirements are somewhat different under this proposal than they are in part 60 subpart Ja.

It is unreasonable, wasteful, and confusing for this regulation to impose different QA/QC requirements for flare flow instrumentation (and the associated pressure and temperature monitors) than is imposed by the newly promulgated part 60 subpart Ja. Thus, we recommend that 1) the specific flare QA/QC requirements under this regulation be left for the monitoring plan, where it can be established as identical to the part 60 subpart Ja requirements, 2) this rule specifically defer to the part 60 subpart Ja QA/QC requirements for flares, or 3) that the requirements in this rule be made identical to those in part 60 subpart Ja. Suggestion 3 is least preferred, since this rule requires some non-flare CPMS.

1.5.2.12 Other Comments on Proposed §63.671.

1. Proposed §63.671(b)(3)(i) requires that the CPMS monitoring plan list the manufacturer and model number for all monitoring equipment components. This should be limited to the monitoring instrument itself by deleting the word "all." It makes no sense to include, and would be difficult to gather, information on the sample system structural supports, piping and valves, signal cable and data transmission components, and central data system components.

2. Proposed §63.671(b)(3)(v) reads as follows: "Span of the analyzer. The span must encompass all expected concentrations and meet the requirements of paragraph (b)(10) of this section." Most CPMS do not measure concentrations, so this requirement must be limited to those that do or generalized to cover other parameters. If it is generalized, it must be made clear that the Table 13 accuracy requirements only need to be met for the normal range (as specified in Table 13) and not all expected values (as specified here). Generally, the Table 13 accuracy specifications cannot be met at the extremes of values that instruments can measure. This is particularly true for flare flow meters, which cannot meet ±5% accuracy below about 1 foot per second flow, but can measure with less accuracy down to about 0.1 ft./sec. Also, there is no paragraph (b)(10); thus this reference must be corrected.

3. Proposed §63.671(b)(3)(vi) deals with analyzers and it should be clarified just which analyzers it includes or it should be generalized by substituting "CPMS" for "analyzer."

4. Proposed §63.671(b)(3)(vii) and (4)(i) require that the monitoring plan identify the parameter detected by the parametric signal analyzer and the algorithms used to convert these values into the operating parameter monitored to demonstrate compliance. Monitoring instruments convert a voltage, amperage or other electronic reading into an output signal that is then transmitted to a digital computer system for display and recording. The algorithms for converting the measured value to the specified parameter are built into the instrument and

data system electronics and often are not be available to the refinery. Nor is it clear what value it adds to have such information in the CPMS plan, since it is not something that can be changed. It certainly provides no compliance assurance information. This requirement should be deleted or justified and, if maintained, it should only be required where it is available to the refinery and is not confidential business information of a third party.

5. Proposed §63.671(b)(5)(ii) calls for daily checks for indications that the system is responding and allows use of internal check systems, as long as the owner or operator checks the internal system results daily for proper operation and the results are recorded. Most digital data systems have such checks and alarm if there are indications that an instrument is not responding. It is wasteful to require an operator check and record. Thus, this paragraph should be modified to allow having an alarm as an alternate to an operator check.

6. Proposed §63.671(b)(5)(iv) requires that the CPMS monitoring plan include a spare parts inventory. This is an ambiguous, wasteful, burdensome and unnecessary requirement and should be deleted. It is ambiguous because it is unclear what is covered. The definitions of CEMS and CPMS are broad; thus this requirement could be interpreted to include computer spare parts, electrical spare parts, data transmission spare parts, etc. Typically spare parts information is maintained in various systems at sites and in generic documents (e.g., spare parts lists for pressure transmitters in general, spare parts lists for compression tubing and fittings used for CEMS and CPMS sample systems, spare parts for instrument cable systems used to transmit field data to control computer systems, process computer spare parts), but not gathered into one place and not specific for a particular CEMS/CPMS.

Furthermore, having such a list serves no purpose. Sources generally do not maintain spare parts inventories for the instruments themselves, but instead have suppliers that provide needed parts on a fast track basis. This is much more efficient than maintaining on-site parts inventories and actually provides better availability of repair materials than if a source were to maintain an inventory of a few spare parts.

Finally, maintaining these lists for individual CEMS/CPMS, rather than through centralized systems is wasteful and burdensome and the compliance liability associated with keeping such a list current is unwarranted.

1.5.3 Comments Specific to Proposed MPV Monitoring Requirements.

1.5.3.1 Applying RMACT 1 Table 13 Requirements to MPV Combustion Control Monitoring is Wasteful and Unnecessary, Is Not Authorized by the CAA, and Should Not be Finalized.

It is proposed to amend the second sentence in §63.644(a) as follows.

> All monitoring equipment shall be installed, calibrated, maintained, and operated according to manufacturer's specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately and must meet the applicable minimum accuracy, calibration, and quality control requirements specified in table 13 of this subpart.

No explanation or justification for overlaying additional requirements on existing RMACT 1 monitors that have been successfully applied since 1995 is provided. Except perhaps for the new monitors proposed for flares in §§63.670and 63.671 and which we discussed above, there is no basis for this change for other Group 1 MPV controls. There is no change in instrumentation proposed for monitoring combustion controls other than flares and no demonstration that there are compliance assurance problems that justify the large additional burdens imposed by Table 13 or that justify the change-out of perfectly good existing monitoring instrumentation to meet arbitrary new Table 13 accuracy requirements. Nor has there been a change in monitoring instrumentation that might authorize these revisions under section 112(d)(6) and this change is not reflected in the cost and burden analyses for this rulemaking. It is not authorized, wasteful and unnecessary to impose Table 13 requirements on existing Group 1 MPV controls, and the proposed change to §63.644(a) should not be finalized.

1.5.3.2 The Applicability of RMACT 1 Table 13 to Coke Drum Pressure Taps.

The term "continuous parameter monitoring system (CPMS)" is used in discussing the coker vent pressure monitor in §63.657(b) of RMACT 1, but Table 13 requirements are not applied to that monitor by that paragraph. Since Table 13 is clearly referenced for flares and Group 1 MPV combustion controls and in the one place a bypass continuous flow monitor is proposed, we have taken the lack of a reference to Table 13 in §63.657(b) as meaning that the Table 13 requirements do not apply to coker vent pressure monitors. If Table 13 is intended to be applicable to the coker vent pressure monitor, there are serious safety and operability issues with applying Table 13 requirements to that vent that need to be addressed. Our concerns relative to coker vent pressure taps include the following.

- Coke drum overhead pressure taps are kept free of coke using blowback steam. Turning that steam on and off to perform the required daily check for plugging would ultimately lead to plugging of the pressure tap, steam leaks, and increased risk of burns.
- Coke drum overhead pressure taps are not active when the coke drum is open for coke cutting and there is no reason to check the pressure tap when the drum is open. Thus, daily checks are not always possible and that requirement should only apply when the coke is being deposited in the drum through the time the drum vent has been opened to the atmosphere.

1.5.3.3 The Proposed Revision to the Pilot Monitoring Requirements in §63.644(a)(2) Put People at Great Risk and This Proposed Revision Cannot Be Finalized.

As we discuss in Comment 1.5.2.1, flare tips cannot be safely accessed when the flare is in service. The proposed revisions to §63.644(a)(2) put people at great risk, because they require accessing the flare tip frequently. The current language should, therefore, be maintained.

1.5.4 Comments Specific to Proposed RMACT 2 Monitoring Requirements.

1.5.4.1 The Proposed Table 41 Accuracy Requirement for Flow Meters is Infeasible for Fluid Catalytic Cracker Units (FCCU).

The gas flow rate accuracy requirements in proposed Table 41 are even less feasible for FCCUs than they are for flare gas flow measurement. FCCU regenerator stacks are typically larger in diameter than almost any flare header (8 to 12 foot diameters are typical). It is infeasible to measure 10 CFM in such large diameter stacks. Nor are instruments available that can measure the entire flow regime with ±5% accuracy. For FCCUs, a typical and reasonable accuracy requirement is ±5% over the normal flow range, if an instrument is used.

Because of the difficulty in measuring flow in such large ducts, the blower speed or power is often monitored and the air flow is based on the blower design curve. This monitoring alternative should be provided to avoid forcing the installation of questionable flow monitors. If flow monitoring is required and the Table 41 specification is not changed, all new FCCU flow instrumentation involving multiple instruments will be required. In addition to very high capital costs, this new instrumentation will require out-of-sequence FCCU outages and associated production loss.[98]

1.5.4.2 FCCU's Should Be Allowed to Use Their Existing O_2 Analyzers When Using the Alternative CO/Organic HAP Standard and, If Maintained, the CPMS O_2 Accuracy Requirement Should be Less stringent that the O_2 CEMS Requirement, not More Stringent.

For FCCUs that elect to comply with the alternative organic HAP limit during periods of S&S and hot standby, the proposed rule requires the site to also install, operate, and maintain an O_2 CPMS to measure and record the oxygen content in the catalyst regenerator vent. Most FCCUs already have oxygen analyzers in the regenerator vent as required by EPA's GHG Mandatory Reporting Rule (GHG MRR) and sites should be allowed to use these analyzers and not be forced to replace them with expensive CPMS.

EPA has not provided any technical justification for requiring sites to replace their existing FCCU regenerator vent oxygen analyzers with an O_2 CPMS. The existing analyzers have been installed, and are operated and maintained, in accordance with the requirements of the GHG MRR, and there is no basis to suggest that the accuracy of these analyzers is not adequate for RMACT 2. This is especially true given the fact that the alternative excess oxygen limit will only apply during a very small percentage of the total operating time, i.e. only during periods of S&S and hot standby which, on average, may only occur a few hours a year.

The requirement in Proposed Table 41 for the O_2 CPMS is TWICE AS STRINGENT as the current PS-3 requirement for O_2 CEMS. It requires that an O_2 CPMS must have an accuracy of at least ±1 percent of the range (.25% O_2), while part 60 Appendix B Performance Specification 3 section 13 specifies that an O_2 CEMs have a calibration drift (accuracy) of 0.5% O_2.

API/AFPM recommends that EPA allow sites to demonstrate compliance with the excess oxygen alternate standard using oxygen analyzers meeting GHG requirements and that the Table 41 accuracy specification be deleted.

[98] FCCU outages are massive undertakings, involving years of planning, scheduling large cranes. and armies of workers. These outages require extensive scheduling and lead times to redirect feeds and provide for replacement product supplies and usually many other process units must be shutdown coincidently because of the loss of the FCCU steam production. Every such shutdown also risks equipment damage due to the thermal cycling of the equipment.

Recommended language (Shown as revisions to the proposed new §63.1565(b)(1)(iv)):

§63.1565 What are my requirements for organic HAP emissions from catalytic cracking units?

(b) * * *

(1) * * *

(iv) If you elect to comply with the alternative limit for periods of startup in paragraph (a)(5)(ii) of this section, you must also install, operate, and maintain an oxygen monitor to continuously~~a continuous parameter monitoring system to~~ measure and record the oxygen content (percent, dry basis) in the catalyst regenerator vent.

1.5.4.4 EPA Should Not Reference NSPS Ja in Table 41 for Coke Burn Monitors, Since Those Requirements are Different Than the Existing Requirements (Which Have Not Been Deleted), Since EPA has Not Justified The Additional Cost and burdens and Potential Instrument Replacements.

In Table 41, EPA proposes to require that CO_2, O_2, and CO monitors for coke burn-off rate meet the requirements of 40 CFR 60.105a(b)(2). Yet, Table 41 already contains requirements for CO and O_2 monitors and there are differences between the two sets of requirements, including a significant increase in the frequency of performance testing the monitors. Furthermore, it is unclear that existing monitors will meet the new requirements and, thus, some may have to be replaced.

Since EPA provides no justification for imposing NSPS requirements on existing units and the new requirements conflict with existing requirements, the changes should not be finalized. API/AFPM recommends that if EPA believes these changes are necessary they develop a justification including cost estimates for any required replacements, provide three years compliance time, and publish their justification for comment.

1.5.5 The Flow Meter Accuracy Specifications in NSPS Ja Need to Be Clarified and Made Consistent With Table 13 of RMACT 1.

Proposed §60.106a(a)(6) and (7) impose requirements for flow monitors used in some SRPs to calculate flow rate weighted values. As for NSPS Ja flare flow monitors, this proposed language specifies that the meters have a "measurement sensitivity of no more than 5 percent of the flow rate or 10 cubic feet per minute." As we have argued since NSPS Ja was promulgated, this terminology is unclear and confusing[99]. "Measurement sensitivity" is not commonly used instrument terminology and it is unclear whether it is referring to instrument accuracy or the minimum detection limit of the instrument. While achievability is still an issue, the terminology has been clarified in proposed RMACT 1 Table 13, where the gas flow meter accuracy specification is "±5 percent over the normal range of flow measured or 280 liters per minute (10 cubic feet per minute), whichever is greater." We request the proposed NSPS flow meter specifications in §§63.106a(a)(6) and (7) and that the same clarification be made to §63.106a(f)(1)(ii).

1.6 The Proposal to Eliminate the Route-to-Fuel Gas Exemption Imposes Costs and Burdens for No Benefit and Should Not Be Finalized. If a Change is Needed Fuel Gas Vents Should Be Addressed Directly.

EPA is addressing concerns over the combustion of refinery fuel gas in flares by proposing to remove the affected facility and MPV definition exceptions in RMACT 1 and the affected facility exception in RMACT 2 for Group 1 emission points routed to fuel gas if <u>any</u> fuel gas is subsequently routed to a flare that is not <u>in compliance</u> with the new RMACT 1 flare requirements. Corresponding changes to RMACT 1 Table 10 Footnote 1 are also proposed. These changes are apparently proposed because of a concern that Group 1 emission points (i.e., emissions that require control) may avoid adequate control if they are sent to a fuel gas system and the fuel gas system then sends some gas to a flare that may not be achieving 98% destruction efficiency (EPA's intent for flare control devices).

[99] Also, see our discussion of the achievability of this specification relative to flares in Comment 1.4.2.5 and relative to FCCUs in Comment 1.4.4.1.

1.6.1 Specifics of the EPA Proposal.

EPA proposes to revise §63.640(d)(5) and the MPV definition exception as follows (and to make a corresponding change to footnote i of Table 10) as follows:

> (d) The affected source subject to this subpart does not include the emission points listed in paragraphs (d)(1) through (d)(5) of this section.
>
> …
>
> (5) Emission points routed to a fuel gas system, as defined in §63.641 of this subpart, <u>provided that on and after [THE DATE 3 YEARS AFTER THE DATE OF PUBLICATION OF THE FINAL RULE AMENDMENTS IN THE FEDERAL REGISTER], any flares receiving gas from that fuel gas system are in compliance with §63.670</u>. No other testing, monitoring, recordkeeping, or reporting is required for refinery fuel gas systems or emission points routed to refinery fuel gas systems.
>
> …
>
> Miscellaneous process vent means … Miscellaneous process vents do not include:
>
> (1) Gaseous streams routed to a fuel gas system<u>, provided that on and after [THE DATE 3 YEARS AFTER THE DATE OF PUBLICATION OF THE FINAL RULE AMENDMENTS IN THE FEDERAL REGISTER], any flares receiving gas from the fuel gas system are in compliance with §63.670</u>;
>
> …

Similar to the proposed changes to §63.640(d)(5), it is proposed to revise §§63.1562(f) and (f)(5) as follows.

> (f) This subpart does not apply to:

…

> (5) Gaseous streams routed to a fuel gas system<u>, provided that on and after [THE DATE 3 YEARS AFTER THE DATE OF PUBLICATION OF THE FINAL RULE AMENDMENTS IN THE FEDERAL REGISTER], any flares receiving gas from the fuel gas system are in compliance with §63.670</u>.

Thus, these exceptions would now only apply if gas from that fuel gas system is routed only to flares that are "in compliance" with the new RMACT 1 flare requirements, which include visible emission, flare tip velocity limits, and combustion parameter limits.

1.6.2 This Hypothetical Problem Does Not Require Rule Changes and the Proposed Changes Have Not Been Justified.

There is little regulated HAP that reaches the atmosphere due to poor combustion of fuel gas in flares because of:

- the requirements in NSPS Ja to minimize flaring;
- the small amount of regulated HAP that is flared from fuel gas systems;
- the high average flare destruction efficiencies, especially in light of the current emphasis on steam reduction; and
- the imposition through this proposal of combustion control requirements on the refinery flares most likely to receive fuel gas flows (i.e., general refinery flares with routine flows).

This proposal appears to be a costly and burdensome approach to addressing a theoretical but generally non-existent problem. We note that EPA has failed to provide any explanation of the legal authority on which it is relying for this new requirement. In the preamble, the discussion of this new requirement is located in a section entitled "What actions are we taking pursuant to CAA sections 112(d)(2) and 112(d)(3)?" So, presumably this new requirement constitutes a new standard under sections 112(d)(2)/(3), but this is just a guess because EPA provides no further explanation or analysis. Even assuming that is the authority for this new requirement, EPA has not provided the explanation and analysis needed to understand how this new provision satisfies the requirements of sections 112(d)(2)/(3). For example, EPA does not identify the best performing source or sources. EPA does not calculate a MACT floor. EPA does not set a standard based on consideration of the mandatory statutory factors (such as consideration of the cost of any "above the floor" alternatives). In short, EPA has effectively proposed a flare performance standard for flares in which fuel gas is combusted, but has not asserted any factual or legal justification for this new standard. The failure to provide such justification violates EPA's obligation under section 307(d)(3) to provide an explanation in the proposed rule of the basis and purpose for this requirement. In any event, the proposed requirement is unlawful because it would arbitrarily and with no justification convert countless internal process streams into MPVs – which they clearly are not.

1.6.2 Background and Precedents for the Flaring of Fuel Gas.

General information on fuel gas systems at 32 refineries with more than 180 refinery flares has been gathered to identify some of the implications of this change. That information is summarized as follows.

1. Most refineries have multiple fuel gas systems and many refineries have flares that do not receive Group 1 RMACT 1 or 2 streams and thus would not be RMACT 1 or 2 control devices subject to proposed §63.670.
2. A few refineries provide fuel gas to third party operations or to chemical operations or to power/steam generation operations at or near their site. Some refineries report they have fuel gas systems that receive gas from chemical operations.
3. At least one refinery of the 32 has flares that are dedicated to non-HAP containing processes.
4. Use of gas from fuel gas systems as flare purge and/or sweep gas is reported by several refineries. Other than for that use, fuel gas flaring is not generally continuous and in many refineries happens less than monthly.
5. Process upsets (including flare gas recovery outages) and short term fuel gas imbalances (including due to startups and shutdowns) are the primary reasons for flaring refinery fuel gas.

Additionally, most refinery flares are or will shortly be subject to the recently amended NSPS Ja. That rule requires an extensive effort to minimize and manage flaring and as a result it can be anticipated that flaring of fuel gas will be minimized by the time any RMACT 1 or 2 requirements apply. The NSPS Ja requirements specifically require minimization of flare gas recovery outages and flaring during such outages.

EPA dealt with this same concern relative to process vents in a constructive way in 2001 in the Hazardous Organic NESHAP (HON) rule. The HON process vent provisions were then incorporated into the Miscellaneous Organic NESHAP rule. Section 63.107(i) of subpart F of the HON rule removes the route-to-fuel gas exemption for process vents that are deliberately routed to non-compliant flares in order to avoid control requirements, as follows:

> (i) The gas stream would meet the characteristics specified in paragraphs (b) through (g) of this section, but, for purposes of avoiding applicability, has been deliberately interrupted, temporarily liquefied, routed through any item of equipment for no process purpose, or disposed of in a flare that does not meet the criteria in §63.11(b), or an incinerator that does not reduce emissions of organic HAP by 98 percent or to a concentration of 20 parts per million by volume, whichever is less stringent.

It is worth noting that, unlike in this proposal, the HON and MON approach does not change the HON or MON affected source or address the fuel gas exemption for other types of emission points (e.g., equipment leaks, storage). Furthermore, EPA makes clear in the following preamble discussion, that temporary flare excursions would not void the process vent route-to-fuel gas exemption. EPA explains the basis for this language in the §63.107 proposal[100] as follows:

> … gas streams that are used as fuels are normally not subject to the ''process vent'' requirements of the HON. However, we are concerned that an owner or operator might interpret this to allow routing a gas stream to a substandard flare or incinerator (one that was not designed to achieve the destruction efficiency required by subpart G) and saying the stream is not a process vent. Regardless of whether combustion of the gas stream in a substandard flare or incinerator is a fuel use, it is also a form of emission control that does not comply with the standards of subpart G. Consequently, paragraph (i) specifies that streams used in this manner are not exempt from any ''process vent'' requirements that would otherwise apply. We wish also to clarify that the wording ''a flare that does not meet the criteria in section 63.11(b) or an incinerator that does not reduce emissions of organic hazardous air pollutants by 98 percent or to a concentration of 20 ppm by volume'' in paragraph (i) is intended to describe the design characteristics of the flare or incinerator, not the actual performance at any given moment. An excursion, in which a flare or incinerator temporarily fails to achieve those requirements, would not cause the gas stream to trigger the process vent requirements.

[100] See 65 Fed. Reg. 3172 (January 20, 2000)

At the time of the HON rulemaking, there was only one set of flare requirements in the Federal rules, so most flares, whether in a refinery or not and whether they were control devices or not would meet the specified "design" criteria. Under the proposed RMACT 1 amendments, flares that are RMACT 1 control devices will have to continuously meet and demonstrate compliance with a variety of requirements that other flares will not have to meet and will not be instrumented to demonstrate. Additionally, in this proposal the route-to-fuel gas exception would be based on a flare's continuous compliance, which would be a 15-minute time period for the combustion control and a 6-minute period for visible emission compliance) rather than flare design. Under the HON and MON approach short, inadvertent flare deviations would not void the route-to-fuel gas exception. Thus, the current proposal is quite different than the HON and MON solution.

Furthermore, it is important to recognize, as discussed in our comments on the flare requirements, that the destruction efficiency requirement for most flared streams is 95%, not 98%. Thus, the likelihood of a deviation is small even if the intent of having the flare achieve 98% destruction efficiency isn't met. Only RMACT 1 MPVs have a 98% destruction efficiency limit emission limitation and this vent type is a small proportion of the streams requiring control. For instance, it would be typical for the largest number of streams requiring control in a refinery to be from equipment leaks (e.g., sample point, pump and compressor seals), which carry a 95% destruction efficiency requirement. It was recognized in the equipment leak rulemakings that flares would likely achieve 98%, but that only provided additional assurance that the 95% control requirement would be met when these streams were sent to a flare.

1.6.3 Implications and Concerns with The Proposed Restrictions on the Flaring of Fuel Gas

Constant confusion and compliance liability will be incurred by this proposed change because it is unclear what gases routed to fuel gas might be construed as emission points. Most refinery fuel gas is process gas that is directed to fuel as part of the process design, because that is the optimum use of that gas. That gas was not designed to be released to the atmosphere or to the flare, but might have to be routed to a flare briefly during MSS or upset conditions. Such streams have always been treated as process gas and not as "emissions points." The route-to-fuel gas exception was put in place to recognize that situation, to encourage recovery of additional byproduct process gases by eliminating the burdens associated with identifying them as potential emission points, and to minimize burdens on regulators and industry. EPA, regulators and refiners have limited the scope of permits and rules to streams that were intended to be sent to the atmosphere or to a control device, because that is a manageable subset of all refinery gas streams and because those are the streams with more than negligible emission potential.

For these same reasons, it was recognized in the development of the refining and chemical rules that fuel gas systems are processes that generate fuel gas for internal and sometimes external use. Fuel gas is a refinery product just as gasoline is a refinery product. Use of fuel gas internally does not change that fact. Just as the gaseous feeds to an alkylation unit are process streams, not emission points, gases routed to a fuel gas system are process gases. As with any refinery process unit, a gas stream sent to a flare from a process unit is a potential emission point and must be evaluated per CAA and RMACT procedures and controlled if determined to be Group 1. The gas within the process unit, however, is not subject to these burdensome requirements, because there is little potential for atmospheric release and combustion as fuel gas is beneficial. This proposal overturns all of that history and policy and essentially makes any gas stream routed to fuel gas into an emission point and makes the fuel gas system into a closed vent system rather than the process it actually is and has been recognized to be in RMACT 1.

This scenario could trigger <u>immediate</u> applicability of RMACT 1 or 2 evaluation and control requirements, including permitting, closed vent system and control device requirements for gas streams routed to that fuel gas system. Under this scenario, hundreds or thousands of streams per refinery could be impacted and hundreds or thousands of violations instantly generated from one short flare non-compliance incident. Just the paperwork associated with demonstrating each of these gas streams are or are not emission points would be a tremendous drain on industry, State and Federal resources. All combustion devices using refinery fuel gas could immediately become RMACT 1 or 2 control devices and sections of the fuel gas process piping could change instantaneously from process piping equipment leak requirements to closed vent system equipment leak requirements, since gas streams that might be construed to be Group 1 would be conveyed to those combustion devices through the fuel gas system. Presumably, as soon as the flare returned to a compliant state, these changed requirements would disappear and the original requirements would be reinstated.

Flares that are not RMACT 1 or 2 control devices that <u>could</u> under <u>any</u> eventuality receive gas from a refinery fuel gas system for any amount of time would have to meet all of the costly and burdensome §63.670 requirements at all times, in order to try to maintain the exemption for the many streams in a refinery that are or could be routed to fuel gas.

It is likely that most fuel gas flaring will be to flares that are RMACT 1 or 2 control devices. Therefore, it is unlikely other flares will receive significant amounts of HAP from the flaring of fuel gas or that much HAP emission reduction would be obtained from imposing the new combustion control requirements on those flares. But, because of the consequences of losing the exemption, refineries would have to invest in and control these flares even though they are not RMACT 1 control devices. In addition, non-refinery flares, third party flares, and refinery flares that are dedicated to non-HAP use (e.g., dedicated to non-HAP pressure storage) would have to meet the RMACT 1 flare requirements if refinery fuel gas could ever reach them.

1.6.4 API/AFPM Offer a Suggestion that Parallels the HON Approach and Minimizes the Wasteful Burdens Should EPA Proceed.

Only refinery flares should be subject to RMACT 1 or 2 flare requirements. There is no legal, logical, or environmental basis for imposing large costs and operating burdens on non-refinery flares because of the potential for a small amount of regulated HAP to reach that flare via a fuel gas system.

In order to address the theoretical concern that Group 1 emission points might evade control by being routed to a fuel gas system and then to a flare with inadequate destruction efficiency, we recommend fuel gas vented from a fuel gas system that might contain what would otherwise be Group 1 vents, be defined as a Group 1 vent. Our suggested language for that approach follows.

Our suggested language also limits the flares impacted to refinery flares in order to avoid the legal and management issues associated with attempting to impose costly RMACT 1 requirements on flares not owned or operated by the refinery. An hours per year criterion (based on various flare CDs) is used to avoid imposing the costly refinery flare requirements and the burdens associated with this change on flares that only receive refinery fuel gas occasionally or due to unusual circumstances.

Furthermore, fuel gas is often used as sweep, purge, assist gas and sometimes as pilot gas for flares and our proposed language would exclude these streams from imposing the Group 1 requirements on their own, as the amount of these uses is minimized per NSPS Ja requirements.

Alternate RMACT 1 Language to Address this Concern.

(NOTE: Suggested numbering based on current rule.)

§63.641 Definitions

Flared fuel gas means gas vented from a Group 1 refinery fuel gas system to a refinery flare, except that gas that is routed to a flare from a Group 1 refinery fuel gas system as flare assist gas, purge gas, sweep gas or pilot gas up to the volume specified in the applicable 40 CFR part 60 subpart Ja flare management plan or, if the flare is not subject to subpart Ja, the record specified in §63.555(i)(5)(iii) of this subpart, is not considered flared fuel gas for the purposes of this subpart.

Group 1 refinery fuel gas system means a refinery fuel gas system which for more than 300 hours per calendar year receives gas from emission points that would require control of Table 1 organic HAP under the provisions of §63.642 through 63.653 of this subpart if the gas were not routed to a fuel gas system.

Refinery flare means a flare located in a refinery.

Refinery fuel gas system means a fuel gas system or the portion of a fuel gas system located in a refinery.

§63.643 Miscellaneous Process Vents

(c) The owner or operator of a Group 1 refinery fuel gas system as defined in §63.641 shall comply with the requirements of paragraphs (a)(1) of this section for any refinery flare receiving flared fuel gas from a Group 1 refinery fuel gas system for more than 504 hours in a calendar year.

§ 63.655 Reporting and recordkeeping requirements.

(i)(5) Flared fuel gas records

(i) Maintain a record of each refinery fuel gas system and indicate which are Group 1 refinery fuel gas systems as defined in §63.641.

(ii) For each refinery flare that is not subject to §63.670 of this subpart, maintain a monthly record of the number of hours that flared fuel gas was vented to that flare in that month.

(iii) For each refinery flare that is not subject to 40 CFR part 60 subpart Ja, maintain a record of whether that flare uses gas from a Group 1 fuel gas system as assist, pilot, purge or sweep gas and the maximum normal flow rate of gas from each Group 1 refinery fuel gas system used for each purpose.

NOTE: Renumber current proposed (i)(5) through (i)(11) to (i)(6) through (i)(12).

Similar language could be added to RMACT 2 if a clear reference to the RMACT 1 approach cannot be identified.

1.6.5 If The Proposed Approach Is Finalized, Despite the Negatives, It is Critical that The Wording of Proposed §§63.640(d)(5), 63.1562(f)(5) and Exception 1 To The MPV Definition Be Revised.

The proposed revisions require "compliance" with §63.670. As a result the affected facility and MPV exceptions could be lost for any 15 minute period where compliance is not being achieved while fuel gas is routed to that flare. Loss of those exceptions for even 15 minutes would trigger the massive burdens of creating new MPVs and revising the affected facility. Failure to meet a flare requirement should only result in a deviation for that flare. Thus, the appropriate requirement for loss of the affected facility and/or MPV exception should be based on routing to a flare that is neither "subject to §63.670" or voluntarily "subject to §63.670" during any period when refinery fuel gas is routed to that flare, rather than "in compliance with §63.670." This will still result in a large expansion in the number of flares that will have to install continuous controls for virtually no value, but it would avoid the huge burdens associated with unplanned, short changes in the affected facility and the control requirements for many short term MPVs.

1.7 General Recordkeeping and Reporting Comments

1.7.1 Applicability Dates Are Needed for New Reporting Requirements.

Proposed §63.655 contains dozens of proposed changes that require new or different information be included in reports. No applicability dates for any of these proposed changes are included (except for flares). Therefore, if finalized, these changes should be put in separate paragraphs and a start date included (e.g., the effective date of the rule) and the current wording retained and an end date added. This will eliminate any confusion about retroactive application of these requirements. As discussed in Comment 1.1.2.3, eighteen months will be needed to put most of the new recordkeeping and reporting systems in place and to obtain permit, AMP, and OMMP approval for the changes.

1.7.2 The Proposed Recordkeeping and Reporting Requirements for Failures to Comply are Unclear and Should be Clarified.

The proposed recordkeeping and reporting requirements for malfunctions resulting from the removal of the historical SSM approach are contained in proposed §63.655(g)(12) (Reporting) and (i)(11) (Recordkeeping). These requirements are unclear and, in some respects unnecessarily wasteful and require clarifications and streamlining as follows.

As discussed in Comment 1.1.1.8, the term "regulated pollutant", used in these two paragraphs, is imprecise and could be interpreted to cover criteria pollutants and HAPs not regulated by RMACT 1 (e.g., metal HAPs). Thus, these paragraphs could be interpreted to require emission estimates for pollutants not regulated by RMACT 1. Since RMACT 1 deals with organic HAPs, API/AFPM recommend the term regulated pollutant be replaced with "organic HAP' in these sections (and elsewhere in RMACT 1).

We also don't understand what "number of failures" refers to in these paragraphs, since the failure to meet an applicable standard is by its nature a single occurrence. If this is referring to the number of failures of a particular emission limitation over some time period, the time period should be indicated. Furthermore, the record of the time, date, and duration of each failure provides that information and would seem to provide a count of such occurrences. Thus, we believe the "number of failures" should be deleted from this record requirement.

Finally, it is unclear how to apply these requirements to work practice deviations, the bulk of RMACT 1 failures. In those cases there are likely no excess emissions to estimate and no information as to when the failure started, only when it was identified. For instance, a failure to perform a required inspection likely has no emission impact and the failure may only be discovered after the time the inspection was due and the inspection requirement may have been to perform the inspection within some calendar period (e.g., an annual inspection). Thus, the proposed requirements, with the clarifications discussed above, should only be applicable to failures involving excess emissions. For other failures, the requirement should be to report the failure to follow the work practice and identification of the time period when the work practice action should have been performed.

1.7.3 Seventy-two Hours Is Needed to Produce Some Older Paper Records.

It is proposed to amend §63.655(i) as follows.

> (i) *Recordkeeping.* Each owner or operator of a source subject to this subpart shall keep copies of all applicable reports and records required by this subpart for at least 5 years except as otherwise specified in paragraphs (i)(1) through (11) of this section. All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours. Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, flash drive, floppy disk, magnetic tape, or microfiche.

We appreciate EPA's recognition of the digital state of our world and support this proposed revision in general. However, some required records are difficult to digitize or were created before digital records became prevalent and older records may not, therefore, be readily available within 24 hours, including, for instance, performance test reports, RCA/CAA reports testing to support site specific monitoring alternatives, original fenceline monitoring reports, original instrument and equipment drawings and specifications for older equipment, older tank records, etc. In some cases, those reports may take up to 72 hours to be brought to the site. Thus we request the 24 hour availability requirement be limited to 2 year old records and up to 72 hours provided for records older than 2 years or that the current provisions in §63.10(b) be maintained and applied to both RMACT rules.

This would also provide better consistency with §63.1576(i) which references §63.10(b)(1), which requires records to be maintained onsite for 2 years and then allows them to be maintained offsite.

1.7.4 Approval Should not be Required for Data Compression Systems Meeting Rule Requirements.

Paragraphs §63.655(h)(5)(iii) and 63.1573(d)[101] specify requirements for use of digital data compression systems. While such systems were fairly new in 1994, they are standard now and data compression meeting the requirements listed in these paragraphs is standard. Data compression is critical to assuring adequate data storage and response time, because of the

[101] Currently §63.1573(c), but proposed to be renumbered).

vast amount of data obtained by digital process data systems and the large number of parameters monitored in a modern process operation. Many requests for approval to use such systems have been submitted under RMACT 1 and 2 and approved and we believe the burdens associated with obtaining such approval is longer justified if the criteria listed in each paragraph is met. API/AFPM therefore request that the requirement for obtaining approval to use these standard systems be changed to maintaining a record that such a system is being used.

2.0 Comments on Proposed Part 63 Subpart CC (RMACT 1) Amendments

2.1 General Comments on Proposed RMACT 1 Amendments

2.1.1 API/AFPM Supports the Concept of Having a Table to Help Clarify Compliance Dates For The Various Provisions in RMACT 1. However, the Proposed Table 11 Does Not Accomplish That Purpose And Needs to be Deleted.

The proposed Table 11 is very confusing because it deals with requirements at the Section level (e.g., §63.640). For instance, item (i) of sections 2, 3 and 4 of Table 11 specify specific dates for compliance with requirements in §§63.640 through 63.653, while item (ii) indicates compliance with those same paragraphs is not required until three years after these amendments are promulgated. Yet, individual paragraphs within the sections have been added, deleted, or revised at various times and the indicated dates only apply to the revisions made at that time.

We found it is virtually impossible to use the table to determine the compliance date for revised requirements or new requirements added to a section. The Table seems to work where entirely new sections are added (e.g., §63.670 and 63.671), but, for instance, provides no help on the compliance dates for associated recordkeeping and reporting requirements added to the existing §63.655.

As we recommend in our general Comment 1.1.2.1, we think the revisions proposed are so comprehensive that the compliance dates can only be clarified by establishing new subparts (i.e., subparts CCa and UUUa).

2.1.2 Separate Standards are Needed in RMACT 1 for Certain Maintenance, Startup and Shutdown (MSS) Situations.

On page 36944 of the preamble, EPA explains their logic for extending normal emission limits to RMACT 1 emissions types as follows.

> We believe that the requirements that apply during normal operations should apply during Maintenance, Startup and Shutdown. For Refinery MACT 1, these emission sources include process vents, transfer operations, storage tanks, equipment leaks, heat exchange systems, and wastewater. Emission reductions for process vents and transfer operations, such as gasoline loading racks and marine tank vessel loading, are typically achieved by routing vapors to thermal

> oxidizers, carbon adsorbers, absorbers and flares. It is common practice to start an APCD prior to startup of the emissions source it is controlling, so the APCD would be operating before emissions are routed to it. We expect APCD would be operating during Maintenance, Startup and Shutdown events in a manner consistent with normal operating periods, and that these APCD will be operated to maintain and meet the monitoring parameter operating limits set during the performance test. We do not expect Maintenance, Startup and Shutdown events to affect emissions from equipment leaks, heat exchange systems, wastewater, or storage tanks.
>
> …
>
> For shutdown of a process; the residual emissions in a storage tank are vented as part of the cleaning of the storage tank. We evaluated degassing controls as a control alternative for storage vessels and do not consider these controls to be cost effective (see memorandum *Survey of Control Technology for Storage Vessels and Analysis of Impacts for Storage Vessel Control Options,* Docket Item Number EPA–HQ–OAR–2010–0871–0027). Based on this review, we are not proposing specific standards for storage vessels during startup or shutdown.

MSS emissions were not considered in developing the RMACT 1 emission limitations. API/AFPM concurs that the normal limits are equally applicable to equipment leak emissions, heat exchanger system emissions, and floating roof tank emissions. We disagree, however, that the normal emission limits can be achieved for other emission types under all MSS situations. We discuss the main situations where the normal RMACT 1 emission limits cannot be achieved at all or where they cannot be achieved without significantly extending process outages in this section. For these situations, EPA must establish alternative standards for MSS periods.

2.1.2.1 Reasonable Criteria For Releasing MSS Vents[102] to the Atmosphere are Required to Prevent Impacting Fuels Production and Causing Unsafe Operation. It Must be Clear When These Vents May be Released to the Atmosphere.

With normal emission limitations now proposed to be applied to MSS vents, even though these vents were not considered in establishing those limits, the rule must make clear when control requirements no longer apply. For instance, during shutdown of equipment, process vents and

[102] Most of these vents would be classified as MPVs under the proposed MPV definition revisions, except those associated with storage tank would be classified as storage tank vents.

equipment clearing vents generally can no longer be controlled if inert gas purging or steaming is no longer reasonably effective at reducing the hydrocarbon or HAP content of the vent, only low levels of HAP remain in the stream, or the stream properties are such that the control could no longer be accessed or be effective. Nothing in the proposal would appear to relieve sources of the requirement to meet the control requirements in these situations (e.g., the rule could be read to continue to require removal of 98% or 95% of the organic HAP in the vent even) nor allow the vent to be routed away from control even if regulated material is no longer present (see Comment 2.6 relative to the ban on bypassing controls even if the bypassed material does not contain regulated material). Nor is any provision made for routing streams away from control if it is unsafe to continue to send them there (e.g., too much air present). On this point, API/AFPM recommends a general exception be provided where it is unsafe to route equipment purging vents to a particular control device during startup or shutdown.

The proposed extension of the MPV definition to episodic[103] MSS vents and elimination of the SSM exception for storage tanks will create hundreds or thousands of new vents per refinery per year and generate massive on-going burdens that are not reflected in the record and which will result in delayed and extended equipment and process outages. Since these MPV are constantly changing, are generally not quantifiable, and are routed to control until the hydrocarbon content has been reduced to low levels, API/AFPM recommends a general set of work practice requirements, based on State requirements, that does not impose the permitting, notice and evaluation requirements associated with identifying these vents individually.

Every time a vessel is opened for inspection or maintenance each vent point will have to be evaluated as a potential MPV or storage tank vent[104]. If a particular vent point (e.g., bleeder) used for MSS handles material that is initially > 20 ppm HAP, then it is a MPV. If there is a potential to emit ≥ 72 lbs./day of VOC then it is a Group 1 MPV and must be controlled. If there is a potential of < 72 lb/day VOC release, then it is a Group 2 MPV and subject to recordkeeping requirements. In a refinery there would be tens or more such activities per day associated with normal maintenance and inspection and during turnarounds, there could be hundreds of such MPVs. Similarly, during a startup, air is removed from vessels and equipment using inert gas (typically nitrogen). Once oxygen levels in the equipment are safe, the inert is depressured to the atmosphere and hydrocarbon is introduced to displace the inert. In order to avoid

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[103] Periodic releases are distinguished from episodic releases as vents that are associated with specific activities (e.g., catalyst regeneration) where the vent is released from the same location each time the event occurs and the vent characteristics are generally similar from occurrence to occurrence.

[104] Storage tank vents would require control if the tanks is a Group 1 Tank, but the new vent would require individual identification and permitting.

shutdown of flare gas recovery and/or depressing flare gas heating values the inert is often continued to the atmosphere until hydrocarbon is detected at the vent. The stream is then diverted to control (e.g., the flare) and once all inert is gone the vent is blocked or diverted to a process disposition.

Inert gas or steam purging is used, where appropriate, to remove hydrocarbon from equipment. These techniques are effective initially, but quickly reach a point of diminishing returns, particularly if residual liquid or sludge is present (which is almost always the case where hydrocarbons heavier than C_3 are present) and continued purging only extends process downtimes and causes excessive natural gas addition at the flare receiving the purge[105]. Because of the inordinate costs for extending refinery process outages and adding wasteful amounts of natural gas to flares, EPA also should include language allowing release of a vent to the atmosphere that otherwise would require control under RMACT 1 when the vent only contains low levels of hydrocarbon (and, thus, even lower levels of HAP). A lower explosive limit (LEL) of <10% or a 5 psig pressure on the vessel are typically taken as the indicator of this condition in State rules. Hydrocarbon and HAP criteria are unworkable, because they cannot be determined quickly in the field and very low concentrations generally cannot be reached in reasonable times and without wasting vast quantities of inert gas and natural gas.

In summary, for most types of controls, there are points in the final stages of shutdown where the vent has inadequate pressure to reach the control. For most combustion controls, there are points where the inert content of the vent is so high that sending it to that control can be unsafe[106] and/or upset the operation of the combustion device or, for flares, require wasteful and excessive natural gas addition. For other types of controls, (e.g., condensers) control efficiency can fall below required levels at very low vent stream flows or hydrocarbon contents. RMACT 1 needs to provide reasonable criteria for when vents can be released to the atmosphere.

Having a clear LEL and pressure criterion is particularly important when clearing or purging equipment that is remotely located, such as many storage tanks and their related pumps, piping and instruments. In these locations, control alternatives, utilities, and analysis options are very limited. For storage tanks, in particular, their low pressure design and large volume prevent aggressive purging techniques.

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[105] In many cases, the piping does not allow segregation of shutdown streams from other streams that go to flare gas recovery (i.e., does not allow these vent to be routed directly to the flare) and thus venting large volumes of inert gas can force the entire flare gas recovery stream to be vented to the flare rather than used as fuel gas.

[106] It is can be unsafe to send inert gas to combustion devices, because the flames can be snuffed out and explosively reignite once the fuel returns to combustible levels.

States have dealt with these episodic vents by establishing them as a special class of process vent with limited recordkeeping requirements and subject to a work practice standard, rather than the normal MPV requirements. A key element of these work practices is clear identification of the criteria for releasing these vents to the atmosphere and for routing these vents to control after hydrocarbon is reintroduced.

Similar to what was done in the Polymer and Resins 1 NESHAP for flares (see §63.485(w)) and has been done by the States, EPA should provide language in RMACT 1 making it clear that control requirements do not apply during shutdown periods where the process vent has inadequate pressure to reach the control device (generally established as 5 psig under State regulations). Even if the equipment contains pure hydrocarbon, there is little HAP in a vessel at 5 psig that would justify using extreme measures or extending outages.

API/AFPM proposes the following for incorporation into the Sector rule.

Add to §63.641:

> *Group 1A Miscellaneous Process Vent* (Group 1A MPV) means an episodic miscellaneous process vent occurring only during maintenance, inspection, startup, or shutdown of equipment which is used for discharging hydrocarbon or inert gas from process vessels or equipment and which the owner or operator has designated as being Group 1A.

Revise §63.643(a):

> (a) The owner or operator of a Group 1 miscellaneous process vent as defined in §63.641 shall comply with the requirements of either paragraphs (a)(1) or (a)(2) of this section. The owner or operator of a Group 1A MPV as defined in §63.641 is only required to comply with the requirements paragraph (a)(3) of this section and §63.655(i)(12) of this subpart for that vent.

Add §63.643(a)(3):

> (3) A Group 1A MPV shall not be discharged to the atmosphere unless the vent has a lower explosive limit of <10% or the equipment associated with the process vent has been drained of liquid to the extent practicable and has been depressured to a control device, other process unit or appropriate storage vessel to a pressure of 5 psig or less. Verification that an equipment pressure of 5 psig or less has been reached or of the LEL value of the vent shall be determined using measurement devices appropriate to the operation being performed.

Add §63.655(i)(12):

(12) Records shall be kept and reports submitted as specified in (i)(12)(i) and (i)(12)(ii) of this section for Group 1A MPVs. No other requirements in §63.655 apply to Group 1A MPVs.

(i) For Group 1A MPVs, a weekly record shall be kept of the information in (12)(i)(A) and either (12)(i)(B) or (12)(i)(C).

(A) the process unit or equipment identification where a Group 1A MPV was located, and

(B) the pressure or LEL value, as applicable, at the time of discharge to the atmosphere and, if hydrocarbon is present, on return to the process or control, or

(C) a statement that all Group 1A MPV met the atmospheric discharge requirements in §63.643(a)(3) and for any Group 1A MPV during the week that did not meet the requirements on discharge to the atmosphere or, if hydrocarbon is present, on return to the process or control, an identification of that Group 1A MPV and the LEL or pressure reading, as applicable, at the time of discharge to the atmosphere or return to the process or control.

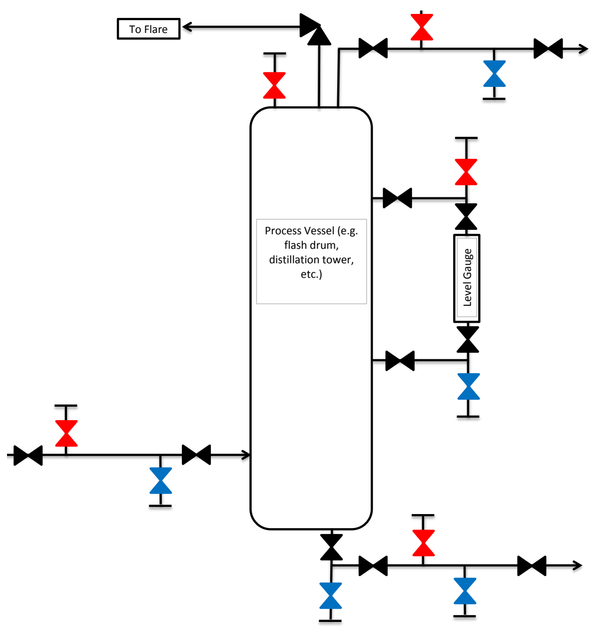
(ii) For a Group 1A MPV that did not meet the requirements of §63.643(a)(3) on discharge to the atmosphere or, if hydrocarbon was present, return to the process or control, report in the next periodic report an identification of that Group 1A MPV and the LEL or pressure reading at the time of discharge or return to the process or control.

2.1.2.2 RMACT 1 Should Specifically Allow Equipment Maintenance and Depressuring Openings to Be Identified Generically.

Operating permits typically handle equipment maintenance, depressuring, and purging vents generically, since there are potentially thousands of points from which such vents can be released and the characteristics of these vents vary each time and as they depressure, depending on the specifics of a particular maintenance activity, turnaround or process outage and the fact that the control requirements appropriate for these steams are typically identical (e.g., control per normal requirements until a specific condition, such as a pressure or LEL value, is achieved).

For instance, Figure 2.2.2 shows one process vessel and its directly associated piping. Depending on whether the vessel, the gauge glass, and/or individual sections of associated piping must be hydrocarbon-freed for a particular maintenance or construction activity, there are at least 10 potential MPVs associated with S&S of this one vessel. Different valves and different numbers of valves will be used for different events, depending on the specifics, to route the vapors to control and ultimately to open the vessel to the atmosphere. There are hundreds of such vessels and thousands of isolatable sections of piping in a refinery.

Figure 2.2.2 Example of the Issue.
Some or all valves in red and blue (and others not shown) could be S&S MPVs for a particular S&S event.



RMACT 1 requirements require identification and characterization of each individual MPV, recordkeeping, reporting and thus permitting. Given that vent locations are often selected in the field as equipment purging is being started and can vary from event to event and the constantly changing stream characteristics as the equipment is purged, such requirements are impossible to meet. Nor is it reasonable to force equipment outages to be extended and production to be lost in order to try to capture the last few molecules of VOC and HAP.

Demonstrating that a particular vent no longer is an MPV is an impractical option, as well. Testing for stream composition to demonstrate that a particular vent no longer contains 20 ppm HAP (an MPV criterion) cannot be performed in the field in the time required to avoid extending downtimes or efficiently manage outages and many streams cannot be reduced to this HAP level until the equipment can be opened and clingage, sludges, etc. are physically removed. Nor is there any reasonable way to quickly identify vent streams that do not meet the 72 lb/day Group 1 criteria, particularly since the VOC content of the stream is constantly being reduced as the equipment is purged.

We therefore request that sources be allowed to address these types of episodic sources generically as allowed in current permits and state rules. For instance, the sector rule could identify all equipment vents that occurred during a maintenance, startup, or shutdown (MSS) activity and are compliant with the work practice discussed in the next comment as being a new category of MPV (we suggest “Group 1A MPV”) without individual identification or characterization.

2.1.2.3 Startup of Equipment Must Also be Addressed.

Some equipment that is controlled to combustion devices is too large and/or designed for too low a pressure to reasonably allow oxygen-freeing with inert gas. For other equipment the volume of inert gas required to air-free the equipment would interfere with safe and/or efficient operation of a combustion control device, flare gas recovery system or fuel gas system if all the gas were all routed there. For refineries, this situation would typically occur for storage tanks, large process vessels, or groups of process vessels. In such cases, hydrocarbon must be used to displace the inert gas (or air in some cases) and the vapor space vented to the atmosphere until the vent contains enough hydrocarbon to support combustion (i.e., can be safely used as fuel or natural gas supplementation in a flare is justified). In many cases, the piping does not allow startup streams from other streams that go to flare gas recovery (i.e., does not allow these vent to be routed directly to the flare) and thus venting large volumes of inert gas can force the entire flare gas recovery stream to be vented to the flare as low BTU value precludes use as fuel gas. Similar to the relief discussed in the previous comment, Provisions must be included to allow such startup venting (i.e., bypass around control) until the LEL exceeds 10%.

2.1.2.4 Bypassing of Carbon Adsorbers Should Be Allowed When Steaming Equipment to Remove Residual Hydrocarbon.

Carbon adsorption controls are widely used to control remotely located, small and/or dilute or low pressure emission sources, such as waste management unit vents and certain tankage. Carbon adsorption generally cannot be used during shutdown of this equipment if steam is present (e.g., during hydrocarbon-freeing equipment) because the water will damage the carbon and/or prevent adsorption of hydrocarbons and/or cause desorption of already adsorbed hydrocarbons. In such cases, good air pollution practice is to bypass the carbon beds to prevent damage to the carbon and desorption of previously adsorbed hydrocarbons. API/AFPM recommend language be added to RMACT 1 clarifying that carbon adsorption controls may be bypassed when the equipment they control is being steamed for hydrocarbon-freeing purposes.

2.1.3 Interactions and Overlaps of Subpart CC with The Marine Vessel and Gasoline Distribution NESHAPs Must Be Addressed.

As discussed in Comment 5.1, the new combustion control flare requirements cannot be applied to dedicated part 63 Subparts R and Y flares (flares that do not also receive refinery gas) even though those facilities are part of the RMACT 1 affected source, since those flares are not similar to refinery flares in their use and in many cases in their design, they were not considered in developing the proposed combustion control requirements, and the risk and technology reviews of those subparts did not identify or justify revising the flare requirements.

2.1.4 Interactions and Overlaps with Other Part 60, 61 and 63 Rules Must Be Addressed and/or Clarified.

2.1.4.1 RMACT 1 Requirements For Flares Should Supersede §§63.11 and 60.18 Wherever Both Apply.

With the addition of expanded flare requirements to subpart CC, many refinery flares will be subject to the subpart CC requirements and, because other rules apply, the requirements of §§60.18 and/or 63.11 for flares. In order to avoid conflicts and confusion and eliminate unnecessary and wasteful burdens, compliance with the RMACT 1 flare requirements should be considered compliance with §§60.18 and 63.11 for flares, where §63.670 also applies. We suggest addition of a paragraph (s) to §63.640 as follows.

> (s) After the dates specified in Table 11 of this subpart for compliance with §63.670, compliance with §63.670 is considered compliance with §§60.18 and 60.11 flare requirements imposed by any part 60, 61, or 63 subpart, for flares subject to §63.670 and §§60.18 and/or 63.11.

2.1.4.2 API/AFPM Supports Clarifying the Overlap Between RMACT 1 and part 61 subpart Y for Benzene Storage Tanks.

API/AFPM supports the proposal to address benzene tankage that is subject to both part 61 subpart Y and RMACT 1. Meeting the RMACT 1 storage vessel requirements is more than equivalent to meeting the subpart Y requirements and it is an efficiency to only have deal with RMACT 1 burdens in such situations.

2.1.4.3 The Overlap of subpart CC and part 60 subpart VVa Should Be Addressed.

Subpart CC provides for the use of either part 63 subpart H or part 60 subpart VV for meeting equipment leak compliance requirements. However some refinery units are subject to subpart CC and part 60 subpart VVa, without being subject to subpart GGGa. As is done for part 60 subpart GGGa, we recommend that proposed §63.640(p)(2) also provide that if both RMACT 1 and subpart VVa apply, compliance with subpart VVa is only required.

2.2 Miscellaneous Process Vent (MPV) Issues

2.2.1 Concerns with the Proposed Revisions to the Definition of Miscellaneous Process Vent.

It is proposed to make significant changes to the definition of MPV. We have many concerns with the proposed changes. The proposed revisions are as follows.

> *Miscellaneous process vent* means a gas stream containing greater than 20 parts per million by volume organic HAP that is continuously or periodically discharged ~~during normal operation of~~from a petroleum refining process unit meeting the criteria specified in § 63.640(a). Miscellaneous process vents include gas streams that are discharged directly to the atmosphere, gas streams that are routed to a control device prior to discharge to the atmosphere, or gas streams that are diverted through a product recovery device prior to control or discharge to the atmosphere. Miscellaneous process vents include vent streams from: caustic wash accumulators, distillation tower condensers/accumulators, flash/knockout drums, reactor vessels, scrubber overheads, stripper overheads, vacuum pumps, ~~(~~steam~~)~~ ejectors, hot wells, high point bleeds, wash tower overheads, water wash accumulators, blowdown condensers/accumulators, and delayed coker vents. Miscellaneous process vents do not include:
>
>> (1) Gaseous streams routed to a fuel gas system, provided that on and after [THE DATE 3 YEARS AFTER THE DATE OF PUBLICATION OF THE FINAL RULE AMENDMENTS IN THE **FEDERAL REGISTER**], any flares receiving gas from the fuel gas system are in compliance with §63.670;
>>
>> (2) Relief valve discharges regulated under §63.648;

(3) Leaks from equipment regulated under § 63.648;

(4) ~~Episodic or nonroutine releases such as those associated with startup, shutdown, malfunction, maintenance, depressuring, and catalyst transfer operations;~~ [Reserved]

(5) In situ sampling systems (on-stream analyzers) until [THE DATE 3 YEARS AFTER THE DATE OF PUBLICATION OF THE FINAL RULE AMENDMENTS IN THE **FEDERAL REGISTER**]. After this date, these sampling systems will be included in the definition of miscellaneous process vents;

(6) Catalytic cracking unit catalyst regeneration vents;

(7) Catalytic reformer regeneration vents;

(8) Sulfur plant vents;

(9) Vents from control devices such as scrubbers, boilers, incinerators, and electrostatic precipitators applied to catalytic cracking unit catalyst regeneration vents, catalytic reformer regeneration vents, and sulfur plant vents;

(10) Vents from any stripping operations applied to comply with the wastewater provisions of this subpart, subpart G of this part, or 40 CFR part 61, subpart FF;

(11) ~~Coking unit vents associated with coke drum depressuring at or below a coke drum outlet pressure of 15 pounds per square inch gauge, deheading, draining, or decoking (coke cutting) or pressure testing after decoking~~ Emissions associated with delayed coking unit decoking operations;

(12) Vents from storage vessels;

(13) Emissions from wastewater collection and conveyance systems including, but not limited to, wastewater drains, sewer vents, and sump drains; and

(14) Hydrogen production plant vents through which carbon dioxide is removed from process streams or through which steam condensate produced or treated within the hydrogen plant is degassed or deaerated.

The definition is further modified by the proposed revision of the definition of periodically discharged, a term used in the MPV definition, as follows.

> *Periodically discharged* means discharges that are intermittent and associated with routine operations~~. Discharges associated with~~, maintenance activities, startups, shutdowns, malfunctions, or process upsets~~ are not considered periodically discharged miscellaneous process vents and are therefore not regulated by the petroleum refinery miscellaneous process vent provisions~~.

2.2.1.1 The Proposed Revisions to the MPV and Periodically Discharged Definitions Need Applicability Dates and Clarification.

It is proposed to redefine MPVs to include all gas stream containing greater than 20 ppmv organic HAP that are continuously or periodically discharged from a petroleum refining process unit by revising exceptions and adding a broad definition of "periodically discharged." This is a significant expansion of the universe of MPVs. A large number of additional vents will now be identified as MPVs. In order to confirm that this change does not apply retroactively or immediately on promulgation of the final rule this change must be indicated as becoming effective as of a specific date. We make specific recommendations as to the needed compliance time in Comment 2.2.2.)

MPV exceptions 1, 2, 4, and 11 are proposed for modification without indicating an applicability date for the change or the date when the current language no longer applies. As a result, these changes would appear to be retroactive and would be unworkable where, as discussed below, compliance time is needed. API/AFPM recommends adding applicability dates for each addition to the exception language and maintaining the old language and adding a deactivation date for that language in each entry.

2.2.1.2 The Proposed Revisions to the MPV Definition Examples Need Clarification.

Vacuum pumps are proposed to be added as examples of an MPV. It needs to be clarified that it is only the vacuum pump exhaust that is a potential MPV. Leakage from a vacuum pump seal or from pump fittings are equipment leaks, subject to equipment leak requirements.

Similarly, high point bleeders are proposed for addition to the MPV definition. This addition is very confusing and should not be finalized. A high point bleeder is a type of open-ended line regulated as an equipment leak component by §63.648 and thus the high point bleeder itself and any leakage is not an example of an MPV. Venting from a high point bleeder could be an MPV or a bypass around control depending on the situation. Thus, a high point bleeder is a poor example of an MPV and adding it will only cause confusion.

Further, API/AFPM recommends that these proposed additions not be finalized at all, since they only serve to confuse. All of the other examples of MPVs are vent materials that are released through a valve, whether a high point bleeder, a low point bleeder or another opening (e.g., steam ejector exhaust). It is the material vented, not the piping component through which the venting occurs that is considered in deciding whether a stream sent to control device or to the atmosphere is an MPV. For instance, it doesn't matter whether a distillation overhead is released through a vacuum pump, a high point bleeder, or a valve off the side of a tower, it still is a potential MPV. On the other hand, if pure nitrogen is released through a high point bleeder it is not an MPV. Furthermore, by listing these equipment types the definition suggests that venting from other equipment types may not generate an MPV. Having these specific examples of equipment included only confused the definition and thus they should not be added.

2.2.1.3 MPV Route-to-Fuel Gas Exception (Discussed Generally in Comment 1.6).

The §63.640(d)(5) affected facility exception applies to emission points that are routed to fuel gas, including emission points that would otherwise be MPVs and our comments (in Comment 1.5) on the proposed change to that paragraph also apply to making the proposed change to the "route to fuel" exception in the MPV definition. The fact that the current rule repeats the "route to fuel gas exception" in several places indicates its importance and the potentially large impact of these proposed revisions. It is virtually impossible for all flares potentially receiving gas from a refinery fuel gas system to always be "in compliance" with §63.670, particularly if §63.670 does not apply to a particular flare because the flare in not a refinery flare (e.g., it is a flare in an associated chemical facility) or because it is a flare that does not normally receive gases that require control under RMACT 1. Thus, as discussed in Comment 1.6, this proposed revision should not be finalized and the routing of fuel gas to flares should be addressed directly.

2.2.2 Eighteen Months to Three Years of Compliance Time Is Required for Implementing the MPV Changes

2.2.2.1 Eighteen Months to Three Years of Compliance Time Is Required to Achieve Compliance For The Newly Added MPVs.

Significant time will be required to identify the large number of vents associated with periodic and episodic activities, particularly MSS activities, determine if they are Group 1, provide controls and monitoring for those that are Group 1, and revise permits and operating procedures (including new instrument procedures to comply with the newly applicable Table 13) to reflect these new MPVs. At least eighteen months is required where controls and adequate instrumentation already exist (assuming no permitting delays). Three years is required if the vent is Group 1 and is currently uncontrolled or under controlled or, if adequate control is existing, but new instrumentation is needed to meet the new requirements in proposed Table 13[107].

2.2.2.2 Up to Three Years Compliance Time is Required where New Instrumentation or Existing Instrumentation Upgrades or Replacement is Needed and a Minimum of Eighteen Months is Needed to Implement Revised Procedures, AMPs and CD Provisions Where Existing Instruments Are Adequate.

As discussed in Section 1.5.3 of these comments, major revisions are proposed to the requirements for Group 1 MPV control and potential bypass monitoring. Additionally, a large number of new Group 1 MPVs will be created under the revised MPV definition and they will need to be controlled as well as monitored per rule requirements. Three years is required to design, purchase, and install the new instruments required for controlling the new MPVs and any replacement instruments required for existing MPV controls because existing instruments cannot meet the new requirements. As discussed in general, eighteen months is required to bring all other instruments up to the new requirements, change procedures, train personnel, and revise permits, obtain and/or revise AMPs, and revise Consent Decrees.

2.2.3 Delayed Coking Unit (DCU) Coke Drum Vents.

(Detailed Comments on Coker Vent Emissions Model are Included as Attachment C-1 and a Summary of the API/AFPM Coker Vent Pressure Survey is Included as Attachment C-2)

2.2.3.1 There Is An Existing RMACT Standard for Coke Drum Vents. Therefore, Changes Must Be Evaluated Under Section 112(d)(6) or (f)(2) Rather Than (d)(2).

The July 15, 1994 RMACT 1 proposed rule[108] defines the petroleum refinery source category "to include equipment specifically used to produce fuels, heating oils, or lubricants by separating petroleum or separating, cracking, or reforming unfinished petroleum derivatives." The proposal further explains that the petroleum refinery source category selected for regulation by RMACT 1 includes, and specifically identifies, "process units for thermal cracking." Specifically,

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[107] See Comment 1.5.3 for a discussion of the new instrumentation requirements for MPVs.

[108] 59 Fed. Reg. 36130 (July 15, 1994)

DCUs are process units for thermal cracking. This broad coverage was finalized in August 1995[109] and a definition of "petroleum refining process unit" was promulgated.

DCUs are petroleum refining process units because they are classified under SIC 2911 that separate, and crack intermediate petroleum streams by thermal cracking. Some exclusions are specifically enumerated in the RMACT 1 (e.g., sources subject to the Hazardous Organic NESHAP). Delayed coking is not excluded.

Over the course of the purging, cooling/quenching and venting steps in the decoking process, coker overhead gas (a single emission point) is controlled with similar options as other regulated streams. The coker overhead gas, specifically, has three dispositions depending on the point in the decoking process and the value of the gas in the stream. Early in the decoking operations, the overhead gas is particularly hydrocarbon rich and is thus routed to the fractionator (i.e. returned to process). As the decoking operations continue, the concentration of hydrocarbon is reduced and it is no longer appropriate to return to process via the fractionator and so the stream is controlled via the closed blowdown system. Within the closed blowdown system, hydrocarbons may be separated from water and recovered, flared or similarly controlled as an MPV. Once the coker pressure limit is achieved (15 psig in RMACT), the stream may be vented to atmosphere. In summary, the single coker overhead gas stream has three potential dispositions, depending on the characteristics of the gas stream at a given point in the process.

1. Returned to process (hydrocarbon rich)
2. Controlled (uneconomical to return to process because highly steam diluted, but still required to be controlled per RMACT)
3. Uncontrolled (<15 psig as measured in the coke drum – the source generation of the stream)

In Docket Document EPA-HQ-OAR-2010-0682-0203[110], DCU vents, were articulated as one among the collection of many MPVs within the regulated source. The authors note that "coking unit vents associated with coke drum depressuring at or below a coke drum outlet pressure of 15 pounds per square inch gauge [psig], deheading, draining, or decoking (coke cutting) or pressure testing after decoking" are exempted from the MPV definition in RMACT 1 and conclude that this means that these DCU vents were not subject to an RMACT 1 emission

[109] 40 Fed. Reg. 43244 (August 18, 1995)
[110] Coburn, J. and S. Johnson, RTI to B. Shine, EPA, *MACT Analysis for Delayed Coking Unit Decoking Operations,* September 20, 2013

limitation. However, that conclusion is false and, in fact, supports the conclusion that these vents are regulated. Otherwise the vents would have been excluded in total, not just when emissions were considered de minimis. It is clear that if these vents are discharged to the atmosphere at a pressure above 15 psig, they would need to be evaluated as MPVs and controlled if the Group 1 criterion were met.

This type of exemption is consistent with the general approach applied to the RMACT 1 rulemaking. Applicability thresholds for levels of control requirements were established throughout the rule. There were similar thresholds such as in establishing an exception for process vents of <20 ppm HAP, vents from control and treatment devices, and in excluding storage vessels of <40 cubic meters from the storage vessel definition. The DCU exclusion means the DCU was included in the MPV MACT floor analysis but that EPA concluded the appropriate level of control for these vents would be met if the vent was discharged at 15 psig or less. Therefore, the conclusion in Docket Document EPA-HQ-OAR-2010-0862-0203 that there is not an applicable MACT standard for HAP emissions from the DCU drum vent is invalid.

The Final Rule Background Information Document[111] for RMACT 1 addresses the definition of MPV and indicates that coker decoking emissions were included in the floor analysis. Commenters requested that EPA to expand the definition to specifically include a threshold, "below which delayed coker decoking emissions may be vented to the atmosphere without control." EPA responded in the affirmative and added the 15 psig exception to the definition of MPV in the final rule. In its response EPA states "The EPA has elected to set the pressure at or below which emissions from coke drum depressuring do not require control at 15 psig to encourage vapor recovery." The corollary is that coker vents are controlled down to 15 psig because that is the point at which emissions are *de minimis*.

The language in §63.657(a) of the current proposal says, "Each owner or operator of a delayed coking unit shall depressure each coke drum to a closed blowdown system until the coke drum vessel pressure is 2 pounds per square inch gauge (psig) or less prior to venting to the atmosphere, draining or deheading the coke drum at the end of the cooling cycle." This implies that the Agency continues to view venting to the closed blowdown system as control, where a pressure is indicative of a threshold at which atmospheric venting becomes allowable.

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[111] US EPA, *National Emission Standards for Hazardous Air Pollutants Petroleum Refineries - Background Information for Final Standards*; EPA-453/R-95-015b, Office of Air Quality Planning and Standards, Research Triangle Park, NC. July 1995, pages 5-1 to 5-3.

Therefore, a revision of the pressure threshold is a revision to the standard rather than a new floor analysis.[112]

A party that believes the agency failed to set a floor that adequately regulated the DCUs at the time of that rule making should have sought remedy through a petition for reconsideration and/or review. Adjustments to the existing standard to reflect more stringent standards as part of the 8 year review cycle must be handled pursuant to section (d)(6) or (f)(2).

In short, in the existing MACT standard, EPA defined the DCU vent as an MPV and established standards applicable to DCU vents that satisfy the MPV criteria. The fact that, under certain conditions (e.g., below 15 psig, while the vent is routed to the fractionator), a DCU vent ceases to be an MPV does not mean that the DCU vent is not subject to an existing MACT standard. It simply means that EPA determined – as it did with many other types of MPVs and many other types of standards – that the MACT standard ceases to apply when certain conditions are met. In other words, the 15 psig criterion is an integral element of the existing DCU MPV standard. If EPA changes the 15 psig criterion, the effect of that action is to change the existing DCU MPV standard. Because it is a change to an existing standard, EPA has no choice but to implement the change through section 112(d)(6). Invoking sections 112(d)(2)/(3) would result in imposing "MACT on MACT," which EPA is not authorized to do under section 112. Once a standard has been set under sections 112(d)(2)/(3), section 112(d)(6) is the only authority that may be used to revise that standard.

2.2.3.2 A Section 112(d)(6) Analysis Shows that Changing the Current Standard is not Justified.

If EPA were to agree that it had already set a MACT floor for DCU vents in the original rulemaking, EPA had indicated that it would consider whether a revised standard under 112(d)(6) is justified. API submits that it is not. API estimates, described in detail in Attachment C-1, identify a cost-effectiveness of $596,000/ton HAP for a 2 psig standard and $349,000/ton HAP for a 5 psig standard. This is consistent with the cost effectiveness estimates provided by

[112] It makes no difference that the existing standard expresses the 15 psig criterion in the context of defining the DCU MPV while the proposed 2 psig criterion is expressed as a "work practice" standard. These are labels with no real distinction because the effect of both the 15 and 2 psig criteria is to establish a pressure threshold below which the DCU vent is subject to no further emissions control requirements. So, if EPA believes it must fill a regulatory "gap" created by the 15 psig criterion, the EPA has failed to fill that gap by effectively revising the criterion from 15 psig to 2 psig because there will still be a "gap" below 2 psig. This reveals that EPA's statutory analysis is self-contradictory and, thus, plainly inconsistent with the statute and unreasonable.

API member companies to EPA and OMB. Phillips 66[113] reported cost effectiveness in the range of $400,000-600,000/ton HAP per ton of HAP to achieve 2 psig.

Therefore, neither a 2 psig nor a 5 psig standard is justified and should not be finalized. Detailed methodology regarding cost and emissions estimates and cost effectiveness are provided in Attachment C-1.

2.2.3.3 Coker Emissions are Not Cost Effective and the Sector Risk is Acceptable and Thus a Section 112(f)(2) Standard is Not Justified. Furthermore, Coker Emissions Do Not Significantly Impact Risk.

API agrees that if EPA were to conclude that it had already set a MACT floor for DCU vents in the original rulemaking, section 112(d)(6) is the appropriate section to consider revisions to that standard. Component 2 of the Refining ICR required submission of an emissions inventory, calculated using EPA specified procedures, for all petroleum refineries. The accompanying Emissions Estimating Protocol included emission factors for delayed coking unit coke drum vents. Based upon that Protocol, in the absence of CEMS or site-specific data, the emission factor provided in the Protocol was to be used.

The Protocol overstated PAH concentrations, a risk driver for cokers, by approximately an order of magnitude. One reason for the overestimate was that the Protocol predated the required stack tests from the ICR, which clearly demonstrated that the data set used to develop the Protocol was an outlier. A detailed description of emissions estimating methodology is presented in Attachment C. Where ICR emission factors were used, the risk may be significantly overstated. Although this only applies to some cokers, it is important to consider when tallying the total number of people that will be moved from one risk category to the next as well as considering total incidences of cancer.

Furthermore, Comment 1.2.4 includes a discussion on the significant conservatism applied to the employed toxicological values for naphthalene and benzene. For example, the cancer unit risk estimate (URE) which EPA used for naphthalene does not take into account the most recent scientific information. Results of the research funded by the Naphthalene Research Council suggest that the URE used by EPA in this document is overly conservative and that development of cancer in humans due to naphthalene exposure may not even be a relevant endpoint.

[113] See EO 12866 Meeting 2060-AQ75 at http://www.reginfo.gov/public/do/eoDownloadDocument?pubId=&eodoc=true&documentID=5

Even if one accepts the conservative selection of toxicological values and the base case emissions as described by EPA, the proposed revision to the DCU standard of 2 psig is not cost effective and proposes to address a very small risk of 0.05 incidences per year nationwide according to EPA estimates. Most importantly; however, is that even if one accepts all of the modeling conservatism described above, the incidences are still overstated by approximately 65% by virtue of EPA having included cokers that already are or will be subject to a federally enforceable not-to-exceed limit of 2 psig[114]. Approximately 64% of the cancer incidences reductions were attributed to units located in the SCAQMD district.

2.2.3.4 Since EPA Correctly Concluded That it is not Feasible to Prescribe or Enforce an Emission Standard Specifically For Coke Drum Vents Any Revision to the Existing MPV Standard Would be Pursuant to Section 112(h).

EPA incorrectly concluded in the proposal that delayed coking units are not already subject to a sections 112(d)(2)/(3) based standard. They are in fact regulated by the MPV standard if their release meets the Group 1 MPV control trigger, the fact that the rule provides relief from having to determine if the MPV Group 1 criterion is met if the coke drum vent is released at a pressure below 15 psig, not-with-standing. Thus, in replacing the generic MPV standard with a coker specific standard, the coker-specific standard must be adopted under section 112(d)(6). Moreover, regardless of the authority for the coker-specific standard, we agree with EPA's analysis and conclusion that such a standard can only be a work practice adopted under section 112(h).

Having said that, EPA has made a fundamental legal error in the proposed coker vent standard. As noted above, the Agency made it abundantly clear that the standard must be a work practice standard under section 112(d)(6) because "it is not feasible to prescribe or enforce an emission standard for the DCU steam vent because the application of a measurement methodology for this source is not practicable due to technological and economic limitations."[115] Yet, in establishing that work practice standard, EPA conducted a floor analysis and a MACT determination according to the requirements of sections 112(d)(2)/(3). So, EPA is arbitrarily and unlawfully using the MACT standard setting approach for a standard where the Agency

[114] The legislative history for CAA Section 112 indicates that recent best performers (i.e., those recently determined to have the lowest achievable emissions rate (LAER)) should be removed from consideration in setting the MACT floor. See Senate Debate on the Clean Air Act Amendments of 1990 Conference Report (Oct. 27, 1990) (statement of Sen. Durenburger) reprinted in 1 LEG. HISTORY at 870-71.
[115] 79 Fed. Reg. at 36902 (June 30, 2014)

determined that the MACT standard setting approach cannot be used. At a minimum, EPA is obligated to provide an explanation of how section 112(d)(6) can or should be construed to require or allow the use of the section 112(d)(2)/(3) MACT standard setting approach in setting a work practice under section 112(d)(6). The failure to provide an explanation of the legal authority for this standard setting approach violates the Agency's obligation under section 307(d)(3) to provide an explanation of the basis and purpose for the proposed rule.

2.2.3.5 The Proposed Definition for Decoking Operations Includes Several Internal Inconsistencies and Should be Clarified.

The proposed definition of "decoking operations" in §63.641 is as follows.

> *Decoking operations* means the sequence of steps conducted at the end of the delayed coking unit's cooling cycle to open the coke drum to the atmosphere in order to remove coke from the coke drum. *Decoking operations* begin at the end of the cooling cycle when steam released from the coke drum is no longer discharged via the delayed coker vent to the unit's blowdown system but instead is vented directly to the atmosphere. *Decoking operations* include atmospheric depressuring (venting), deheading, draining, and decoking (coke cutting).

The second sentence of the proposed definition refers to "steam released from the coke drum is no longer discharged via the delayed coker vent to the unit's blowdown system." But the definition of delayed coker vent is limited to vapors that go to the blowdown system, so there is an internal inconsistency in the statement. Use of the term delayed coker vent adds nothing to the meaning of that sentence so we recommend it be deleted.

Therefore, API/AFPM recommends the following revision to the proposed definition of decoking operations and to proposed exception 11 to the MPV definition.

> *Decoking operations* means the sequence of steps conducted at the end of the delayed coking unit's cooling cycle to open the coke drum to the atmosphere in order to remove coke from the coke drum. *Decoking operations* begin at the end of the cooling cycle when steam released from the coke drum is no longer discharged ~~via the delayed coker vent~~ to the unit's blowdown system but instead is vented directly to the atmosphere. *Decoking operations* include atmospheric depressuring (venting), deheading, draining, and decoking (coke cutting).

2.2.3.6 The Proposed Definition for Delayed Coker Vent is Confusing and Should be Clarified and Made Consistent with the Changes Needed in The Definition Of Decoking Operations Discussed Above.

The proposed definition of "delayed coker vent" in §63.641 is as follows.

> Delayed coker vent means a vent that is typically intermittent in nature, and usually occurs only during the cooling cycle of a delayed coking unit coke drum when vapor from the coke drums cannot be sent to the fractionator column for product recovery, but instead is routed to the atmosphere through the delayed coking unit's blowdown system. The emissions from the decoking operations, which include direct atmospheric venting, deheading, draining, or decoking (coke cutting), are not considered to be delayed coker vents.

The coke drum overhead is not typically "routed to the atmosphere through the delayed coking unit's blowdown system." Instead, the coke drum overhead is routed to the closed blowdown system for recovery to the fractionator, fuel gas, or for routing to a control device (i.e., a flare) until such time as a particular drum overhead pressure is achieved, at which time the coke drum overhead vapor is routed directly to atmosphere. The proposed definition seems to imply that sometimes the stream goes to atmosphere via the blowdown system.

API/AFPM suggests the following revision to the proposed delayed coker vent definition to clarify these points.

> *Delayed coker vent* means a vent that is typically intermittent in nature, and usually occurs only during the cooling cycle of a delayed coking unit coke drum when vapor from the coke drums cannot be sent to the fractionator column for product recovery, but instead is routed to ~~the atmosphere through~~ the delayed coking unit's blowdown system. The emissions from ~~the~~ decoking operations, which include direct atmospheric venting, deheading, draining, or decoking (coke cutting), are not considered to be *delayed coker vents*.

2.2.3.7 Any Attempt to Synchronize MACT Standards with NSPS Ja Must Result in a Coker Depressurization Release Criterion of 5 psig.

EPA solicited comment regarding synchronicity with the recently finalized NSPS Ja as it pertains to delayed coking units. API/AFPM believes that any synchronization should be achieved through proposing RMACT 1 revisions to reflect the 5 psig depressurization standard in NSPS Ja.

In the recent NSPS Ja rule making, EPA determined that 2 psig was not cost-effective for new, reconstructed or modified units. Retrofit of all existing units would further escalate costs and is thus even less cost effective. EPA cannot ignore the conclusion in NSPS Ja and certainly cannot ignore the cost basis used in reaching that conclusion as they have done in this case. According to the docket in this rulemaking, EPA arbitrarily selected one bit of cost information from the large amount of cost data provided to them to develop an unreasonable cost estimate, which also does not reflect the data available to the Administrator or the data used in the NSPS Ja rulemaking.

2.2.3.8 The Standard Should Be A Rolling 30-day Average Per DCU and It Should be Clear That The Vent Pressure Can Be Rounded to One Significant Figure When Determining Compliance.

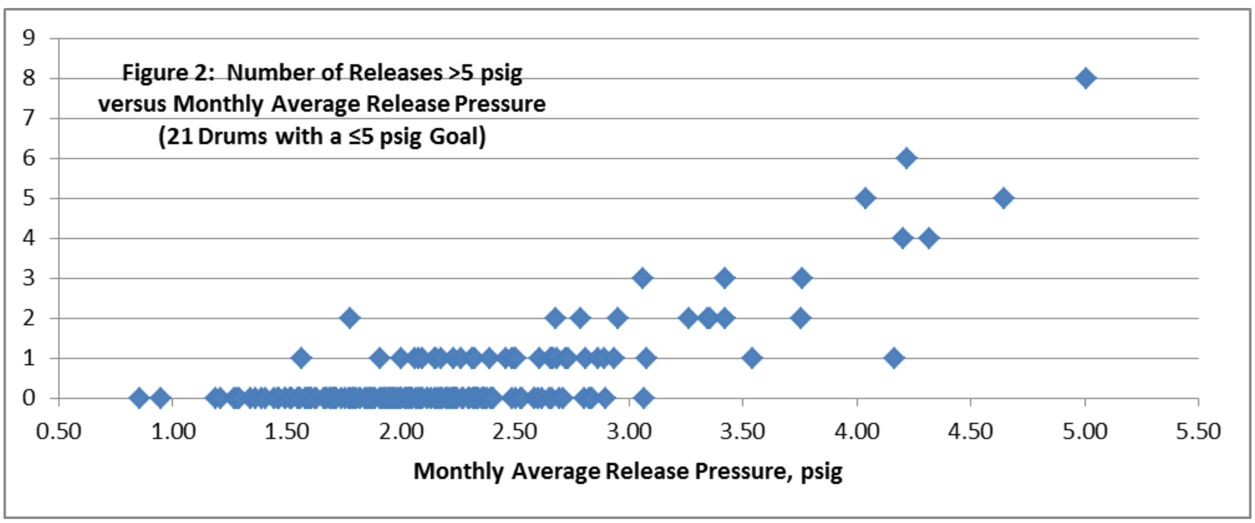
An instantaneous standard is unnecessary to address HAPs with chronic health impacts and adds cost and compliance challenges. Health impacts considered under the NESHAP rules are chiefly based on a 70 year exposure. Chronic health impacts are not materially affected by short term variability, but instead depend on the average concentration of exposure over a 70 year lifetime.

The NSPS standard (e.g. NSPS Ja) addresses pollutants that contribute to photochemical smog and particulate matter formation. The nature of the NAAQS standards requires that pollutants be controlled in a manner that would prevent rapid photochemical processing of those pollutants. Because of the timescales of the photochemical processing, reduced instantaneous emissions from some sources may be necessary. Similarly, the SCAQMD coker rule addressed photochemical smog specifically. Rapid ozone formation can occur on the order of hours, and so drum to drum variability could be considered a factor if coker vents were considered contributors to regional smog formation. Control on a timescale of photochemical relevance is unnecessary to address HAPs.

Thus, there is no health based or environmental reason for requiring an instantaneous limit (e.g., monthly average for the DCU). Furthermore, the cost effectiveness is further diminished without providing an averaging period.

API conducted a survey in 2011, gathering information from operators of 39 DCUs on their typical vent pressure. A summary of the survey and results is included as Attachment C-2. For the 39 DCUs, the reported vent pressures averaged 5.2 psig and the reported range was 0.5 psig to 17 psig. That survey found considerable variability in vent pressures. Figure 2.2.1, below, illustrates that variability. Even drums achieving a monthly average vent pressure of 3 psig, had occasional releases exceeding 5 psig. Thus, an absolute limit versus an average limit will require additional investment to reduce variability or will require that cycle time be lengthened at times resulting in unaccounted for costs.

Figure 2.2.1 The Vent Pressure Criterion Should Be a Monthly DCU Average.



For a 5 psig monthly average limit, coke drums would be expected to operate significantly below 5 psig in order to minimize the number of individual occurrences that exceed 5 psig or where cycle time must be extended to achieve 5 psig and thereby to meet the limit on average.

This concern is further illustrated by the following example. Three DCUs report the following data for a number of typical vent releases over a roughly three month period.

Table 2.2.1: Example current vent pressure data

	DCU A	DCU B	DCU C
Average	2.2	2.1	2.1
Minimum	0.9	0.3	1.1
Maximum	5.9	5.4	5.7
Std. Dev.	1.0	1.0	1.0

In these examples, not-to-exceed 2 psig limit would require addressing the variability indicated in the Table and the root cause of the higher release pressures, likely requiring significantly larger investments.

For a 2 psig not-to-exceed limit, reducing variance will be critical, since drums can only safely operate about 1 psig below that limit. Some cycle time impacts are likely in this situation. Furthermore, due to process variations and flare gas recovery cycling impacts, the back-pressure that must be overcome can vary by 0.5 to >2 psig on even a well-run flare gas recovery system. Thus, an absolute limit requires facilities to overcome this variability (e.g., additional compression).

As discussed in Attachment C-1, a cost survey conducted by API in November 2013 found general consensus that investment costs would be reduced for an average versus a not-to-exceed value, but only a few DCU's provided specific cost estimates. Essentially, it appears that where a DCU already operates close to a do-not exceed limit, an investment of $1-3M might be totally avoided if the limit were expressed as an average. For example several DCUs report that their 30-day average vent pressure is currently < 2 psig, but they have instances where flare gas system back pressure is sometimes > 2 psig. If they have to meet a do-not-exceed 2 psig limit, they would have to invest in steam eductor systems or additional gas compression for each coker at a cost of millions of dollars.

2.2.3.9 An Alternate Work Practice Standards Is Appropriate for Water Over DCUs.

Water overflow delayed coking units are a type of DCU design that employs a unique process operation in which the coke drum filled with water and overflowed. This capability must be designed into the DCU. Drum overhead pressure is not necessarily a reliable indicator of the extent of bed cooling in this type of operation due to unit piping and instrument configuration and location. For some water overflow DCUs, capital investment will be required to comply with an overhead pressure target, even when water is overflowing the drum and the water temperature is below the boiling point of water.

For typical DCUs, EPA correctly concluded that the coke drum vent pressure prior to the drum vent being routed to the atmosphere is the appropriate parameter to use as a threshold for an atmospheric depressurization work practice.

Water overflow DCUs; however, are typically different in a several ways.

1. The fundamental engineering design allowing for water overflow is unique to water overflow DCU in that they are designed to overflow the coke bed with water for some period of time during the quench cycle.

2. They add water faster per ton of coke on average over the coke drum fill time.

3. They get more overall cooling in a shorter time by continuing to overflow water for a given time.

With water overflow, the mass flow is much larger than any steam flow. Therefore the water overflowing the drum will a) be representative of the temperature in the top of the coke drum, b) easily condense any steam purge steam into the water, c) cool metal quickly, and d) much more quickly overcome the insulating effect of any coke build up on the thermowell.

Thus, water overflow DCU's should be allowed to comply with the 2 psig depressurization work practice standard if equipped to make that demonstration or, as an alternate, demonstrate compliance with work practice standard precluding atmospheric venting prior to water overflow and an overhead temperature of 220 ^{o}F. Furthermore, it should be clearly identified that water overflow drums, where water is routed to an atmospheric tank, while vapors are recovered to the closed blowdown system, are permissible.

2.2.3.10 DCU's with Very Short Vent Times Should be Considered Compliant.

An average atmospheric vent time of less than 20 minutes should be established as an alternative standard and considered to have satisfied the depressurization work practice. Short depressurization time is indicative of a well-cooled bed and low vent emissions, even if the initial release pressure is somewhat above a specified do-not-exceed limit. Such an alternate would allow for reduced investment in those cases where excess emission risk is minimal, but back pressure fluctuations are sometimes encountered. The 2010 ICR acknowledged the *de minimis* emissions emitted by DCUs with such short vent times and provided that these units need not perform stack tests. Short duration vented cokes (defined as those with average vent duration times of less than 20 minutes on a monthly basis) should be considered to be compliant.

2.2.3.11 Compliance With the South Coast Air Quality Management District Rule 1114 Should Be Deem Compliance with Proposed §63.657.

The South Coast Air Quality Management District Rule 1114 is at least equivalent to this proposal. API/AFPM therefore requests that compliance with that regulation be established as a compliance alternative to the requirements in §63.657.

2.2.3.12 There Is No Basis for Limiting Quench Water Drainage During the Quench Cycle and "Double Quenching" is Sometimes Necessary. That Proposal Should Not be Finalized

It is proposed in §63.657(a) not to allow draining a coke drum until the 2 psig vent pressure limit is reached. Theory would say that the reverse flow of water through a coke bed that occurs by draining the bed allows the water to contact additional hot coke, reducing cracked vapor emissions. This is not unexpected, given that the act of draining increases void volume in the coke drum, which results in 1) pressure reduction, 2) reverse flow improves cooling of the bed, and 3) heavier volatiles can be reabsorbed by the cooler coke in the lower portion of the bed, which acts like a charcoal filter. The fact that depressurization time is reduced when draining supports this theory of improved coke bed cooling and reduced cracked vapor emissions. Further controlled testing and sampling is needed to validate this thesis, but the proposed ban on such draining would foreclose the emission reductions that appear to occur as the result of this activity.

Furthermore, draining quench water while venting has been shown to significantly reduce drum cycle time. Test data that one API member has obtained shows that draining before or during venting significantly reduces coke bed depressurization time and other members report they typically use this technique to reduce quench cycle time. Limiting such venting would therefore increase cycle time and where a DCU is a refinery limit, it would reduce coke and gasoline production. Thus, API advocates that the proposed work standard allows draining prior to achieving the overhead pressure criterion.

This proposed ban also imposes a safety risk by prohibiting “double quenching of hot drums.” In some cases, a coke drum does not cool properly during the initial quench and overhead temperature cannot be reduced to the allowable release limit. In such a case, a significant quantity of quench water must be drained to allow fresh, cold quench water to be added to provide a second “double” quench. Without that capability the drum would sit idle for indefinite periods of time, while waiting for it to eventually cool down and once it reached the pressure limit it would be opened, but still contain hot spots that could cause safety concerns as the coke is removed from the drum.

Deheading criteria generally include several of the following, depending on configuration and instrumentation:

1. Gallons of water added per ton of coke
2. Gallons of condensed steam recovered in the blowdown system
3. Pressure
4. Coke drum skin temperatures
5. Process outlet temperatures

Disallowing “double quenching” of the coke bed, by partial drain and refill compromises the ability for an operator to meet criteria 1) and 2) above. In order to maintain a safe operation under this restriction, both of the following may be necessary.

1. Perform a ‘soak’, where the operator waits, allowing the water to percolate into the coke bed and allowing additional water to be added. This is very time intensive, and will result in feed rate cuts or loss of coke drum life due to shortened warm-ups.

2. Install upgraded top head facilities to allow complete and total remote operation of the top head and coke cutting operation to mitigate the safety risk created by inability to perform periodic double quenches. This entails slide valve, auto drill stem guide, autoshift coke cutting tool, drill stem monitoring, coke drum acoustic monitoring, and steam blowout equipment. In addition, coke cutting times will be extended to allow high-pressure steam releases to subside.

2.2.3.13 Reasonable Pressure Instrument Specifications and QA/QC Requirements Must be Included in the Rule and There Must Be Consistency with the Instrumentation Requirements Specified in the Greenhouse Gas Reporting Rule.

Reasonable pressure instrument specifications and QA/QC requirements must be included in the rule and consistency with the instrumentation requirements specified in the Greenhouse Gas Protocol achieved. To avoid costly addition of all new instrumentation, pressure instrument spans should cover the entire typical range of pressures encountered at coke drum overheads (typically up to 100 psig and 1000 °F) and specified accuracy must coincide with standard instrumentation and the Greenhouse Gas Protocol. Inadequate span requirements cause unnecessary outages, since, under EPA's proposed QA/QC requirements, pressure instruments have to be replaced or at least recalibrated, if over ranged. Furthermore, unreasonable accuracy specifications, as have occurred in the NSPS Ja rulemaking, can make it infeasible to comply or require installation of all new instruments in addition to the existing process instruments.

2.2.4 The proposed Revisions of §63.644(c) Should Not Be Finalized or Must Be Clarified. The Relief Valve Exception Must Not Be Removed From This Paragraph. Compliance Time Must Be Provided.

§63.644(c) deals with Group 1 MPVs using a vent system that contains bypass lines that could divert a vent stream away from the control device used for compliance.

It is proposed to revise §63.644(c) by adding language that makes <u>any</u> flow through a Group 1 MPV potential bypass a violation. To eliminate duplication, we comment on that portion of the proposed revision in Comment 2.6, since the change is proposed to also apply to Group 1 storage vessel control bypasses.

EPA proposes to remove the exception from §63.644(c) monitoring requirements for RVs required for safety on MPV vapor collection systems. Since relief paths cannot be blocked (even by a flow meter) this is an unsafe and potentially catastrophic change that cannot be finalized. EPA has proposed §63.648(j) to address RVs and thus the exception for equipment subject to §63.648 might be adequate for excluding RVs from §63.644(c). However, 3 years is provided for the RV monitoring requirements in §63.648(j) to be met and there may be a question as to whether the §63.648 exception applies prior to that RV compliance date. Furthermore, controlled RVs (e.g., RVs routed to a flare) are excepted from §63.648(j)(1)-(3) and thus there may be a question as to whether the §63.648 exception applies to controlled RVs. Since the impact of misunderstanding the applicability of §63.644(c) to this critical safety equipment is dire and the current rule calls them out separately from §63.648 regulated equipment, we strongly suggest that the separate §63.644(c) exception for RVs be maintained.

It is also proposed to remove high point bleeds, open-ended valves or lines, and pressure relief valves needed for safety reasons from the list of exceptions to the requirements of §63.644(c), presumably meaning that these types of equipment are subject to the §63.644(c) monitoring requirements unless they meet the exception of being subject to §63.648. However, this change is unclear and should be clarified or the existing language left unchanged.

High point bleeders themselves are equipment leak components (open-ended lines) subject to $63.648 and must be capped or plugged or double-valved when not in use. A 500 ppm emission limit is proposed to be added to the high point bleeder requirements in that section. Such bleeders have been excluded from the vent bypass monitoring requirements historically, because of the huge burdens associated with monitoring the thousands of such components, when they are normally sealed and any use is reported under the OEL provisions. Opening of such a bleeder to the atmosphere with Group 1 material present would also be a reportable deviation under Title V. Thus there is no value in imposing the monthly inspection requirements associated with §63.644(c). Removing this exception imposes large costs and burdens and EPA has not identify the basis for this change, how it is authorized, the emissions impact, if any, or the costs and burdens of the change. This revision cannot be finalized without providing that information for comment.

Furthermore, the proposed revisions are another example of a change that could be misconstrued to be retroactive and adequate compliance time is not provided. API/AFPM therefore requests that the old language be retained and an effective date be added to the new language. Where a CPMS flow meter will now be required, three years is needed to engineer, procure, and install that system and thus the effective date should be three years after promulgation for such situations.

2.3 Storage Vessel and Transfer Operation Issues.

It is proposed to revise RMACT 1 to cross-reference the corresponding storage vessel requirements in part 63 subpart WW (including requirements for guidepole controls and other fittings as well as inspection requirements) rather than the requirements in part 63 subpart G, and to revise the definition of Group 1 storage vessels to include storage vessels with capacities greater than or equal to 20,000 gallons but less than 40,000 gallons if the maximum true vapor pressure is 1.9 psia or greater and to include storage tanks greater than 40,000 gallons if the maximum true vapor pressure is 0.75 psia or greater.

With adequate compliance time these revisions can be accomplished at reasonable cost.

2.3.1 General Storage Vessel Issues

2.3.1.1 The Format for Introducing the New Storage Vessel Requirements Must Be Improved. Applicability Dates are Needed for the New Requirements.

API/AFPM recognizes the difficulties in crafting rule language revisions to incorporate new requirements and clearly articulate a transition period for compliance with newly adopted requirements. This requires retaining the prior standards while adding the new standards. We endorse the approach of adding a new section (*i.e.*, §63.660) for the new standards, and adding a statement at the beginning of the prior standards (*i.e.*, §63.646) explaining that this section will no longer apply after demonstration of compliance with the new section. However, we suggest further clarification would be appropriate in the applicability section of the rule.

It would be very helpful if the compliance schedule provisions in §63.640(h) alerted the reader to the separation of the prior and new standards for storage vessels in sections §63.646 and §63.660, respectively. API/AFPM suggests the following revision to §63.640(h)(2).

> (h) Sources subject to this subpart are required to achieve compliance on or before the dates specified in table 11 of this subpart, except as provided in paragraphs (h)(1) through (3) of this section.
>
> (1) Marine tank vessels at existing sources shall be in compliance with this subpart, except for §§63.657 through 63.661, no later than August 18, 1999, unless the vessels are included in an emissions average to generate emission credits. Marine tank vessels used to generate credits in an emissions average shall be in compliance with this subpart no later than August 18, 1998 unless an extension has been granted by the Administrator as provided in §63.6(i).

(2) Existing Group 1 floating roof storage vessels meeting the applicability criteria in item 1 of the definition of Group 1 storage vessel shall be in compliance with §63.646 at the first degassing and cleaning activity after August 18, 1998, or August 18, 2005, whichever is first. Existing floating roof storage vessels that meet the definition of Group 1 storage vessel (item 1 or 2) in §63.641 shall be in compliance with §63.660 according to the schedule specified in Table 11 and in subpart WW. Existing fixed roof storage vessels that meet the definition of Group 1 storage vessel (item 2) in §63.641 but not the definition of Group 1 storage vessel (item 1) shall be in compliance with §63.660 according to the schedule specified in §63.660(d).

2.3.1.2 The Periodic Reporting Requirements in §63.655(g) for Storage Vessels Need To Be Clarified and Corrected.

The periodic reporting requirements for storage vessels are in need of editing for clarity as well as for correcting minor typographical errors.

1. It is confusing that §63.655(g)(1) indicates that information related to gaskets, slotted membranes, and sleeve seals is not required for compliance with §63.646, yet §63.655 (g)(2)(i)(B)(1) and (g)(3)(i)(C)(1) both reference gaskets and slotted membranes among the items to be reported for compliance with §63.646. While the applicability to these items is identified as pertaining to storage vessels associated with new sources, it's still rather confusing. It's clear that these items were intended to be excluded for storage vessels associated with existing sources under §63.646, in that §63.646(c) excludes the requirements in §63.119 for gaskets, slotted membranes, and sleeve seals, and §63.646(e) excludes the inspection provisions in §63.120 for these items. It would be helpful to edit §63.655(g) to clarify the various scenarios by stating in the same paragraph(s) when these items apply and when they do not.

2. It would be helpful if the reporting requirements in §63.655 were more clearly identified in terms of compliance with §63.646 versus §63.660.

3. The provisions of §63.119(b)(1) & (2) with respect to allowing the floating roof to rest on the leg supports were deemed by EPA to be sufficiently unclear as to warrant a clarifying note within the rule. It would be helpful if a portion of that note were repeated in §63.655(g)(2)(i)(A)(1), so that this section reads more coherently.

4. The reference in (g)(2)(i)(A)(2) to (g)(2)(i)(C) should refer to (g)(2)(i)(A)(3).

5. The language referring to gaskets and slotted membranes for sealing openings through the floating roof should be edited to be consistent with the language of §63.119. The term "slotted membrane" should be more fully expressed as a "slotted membrane fabric cover", and it should be identified as being specific to roof drains in external floating roofs which empty into the stored liquid. A similar control device is specified in §63.119 for sample wells in internal floating roofs, but in this case it is referred to as a "slit fabric cover."

6. The reference to (g)(2) through (5) in §63.655(g)(1) should be to (g)(2) and (3).

7. Paragraph §63.655(g)(4) is unnecessary if paragraphs §63.655(g)(2) & (3) are complete and self-contained.

API/AFPM suggests the following revisions to §63.655(g)(1) through (g)(4).

> (1) For storage vessels, Periodic Reports shall include the information specified for Periodic Reports in paragraph (g)(2) ~~through (g)(5)~~and (g)(3) of this section. ~~Information related to gaskets, slotted membranes, and sleeve seals is not required for storage vessels that are part of an existing source complying with §63.646.~~ Upon a demonstration of compliance with the standards in §63.660, the standards in §63.646 shall no longer apply.
>
> (2) Internal floating roofs.
>
> (i) Compliance with §63.646. An owner or operator who elects to ~~comply with §63.646 by using~~ use a fixed roof and an internal floating roof or ~~by using~~ an external floating roof converted to an internal floating roof to comply with §63.646 shall submit the results of each inspection conducted in accordance with §63.120(a) of subpart G in which a failure is detected in the control equipment.
>
> (A) For vessels for which annual inspections are required under §63.120(a)(2)(i) or (a)(3)(ii) of subpart G, the specifications and requirements listed in paragraphs (g)(2)(i)(A)(1) through (3) of this section apply.
>
> (1) A failure is defined as any time in which the internal floating roof is not resting on the surface of the liquid inside the storage vessel and is not resting on the leg supports (the floating roof may be allowed to rest on the leg supports for purposes such as routine storage vessel maintenance, inspections, petroleum liquid deliveries, or transfer operations); or there is liquid on the floating roof; or the seal is detached from the internal floating roof; or there are holes, tears, or

other openings in the seal or seal fabric; or there are visible gaps between the seal and the wall of the storage vessel.

(2) Except as provided in paragraph (g)(2)(i)(A)(3)~~(C)~~ of this section, each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made or the date the storage vessel was emptied.

(3) If an extension is utilized in accordance with §63.120(a)(4) of subpart G, the owner or operator shall, in the next Periodic Report, identify the vessel; include the documentation specified in §63.120(a)(4) of subpart G; and describe the date the storage vessel was emptied and the nature of and date the repair was made.

(B) For vessels for which inspections are required under §63.120(a)(2)(ii), (a)(3)(i), or (a)(3)(iii) of subpart G (i.e., internal inspections), the specifications and requirements listed in paragraphs (g)(2)(i)(B)(1) and (2) of this section apply.

(1) A failure is defined as any time in which the internal floating roof has defects; or the primary seal has holes, tears, or other openings in the seal or the seal fabric; or the secondary seal (if one has been installed) has holes, tears, or other openings in the seal or the seal fabric; or, for a storage vessel that is part of a new source, the gaskets for covers or lids no longer close off the liquid surface from the atmosphere; or, for a storage vessel that is part of a new source, the ~~slotted membrane~~ slit fabric cover for a sample well, if present, has more than a 10 percent open area. Requirements related to gaskets, slit fabric covers, and sleeve seals do not apply for a storage vessel that is part of an existing source.

(2) Each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made.

(ii) Compliance with §63.660. An owner or operator who elects to ~~comply with §63.660 by using~~ use a fixed roof and an internal floating roof or an external floating roof converted to an internal floating roof to comply with §63.660 shall submit the results of each inspection conducted in accordance with §63.1063(c)(1), (d)(1), and (d)(2) of subpart WW in which a failure is detected in the control equipment. For vessels for which inspections are required under §63.1063(c) and (d), the specifications and requirements listed in paragraphs (g)(2)(ii)(A) through (g)(2)(ii)(C) of this section apply.

(A) A failure is defined in §63.1063(d)(1) of subpart WW.

(B) Each Periodic Report shall include a copy of the inspection record required by §63.1065(b) of subpart WW when a failure occurs.

(C) An owner or operator who elects to use an extension in accordance with §63.1063(e)(2) of subpart WW shall, in the next Periodic Report, submit the documentation required by §63.1063(e)(2).

(3) External floating roofs.

(i) Compliance with §63.646. An owner or operator who elects to ~~comply with §63.646 by using~~ use an external floating roof to comply with §63.646 shall meet the periodic reporting requirements specified in paragraphs (g)(3)(i)(A) and (B) of this section.

(A) The owner or operator shall submit, as part of the Periodic Report, documentation of the results of each seal gap measurement made in accordance with §63.120(b) of subpart G in which the seal and seal gap requirements of §63.120(b)(3), (b)(4), (b)(5), or (b)(6) of subpart G are not met. This documentation shall include the information specified in paragraphs (g)(3)(i)(A)(1) through (4) of this section.

(1) The date of the seal gap measurement.

(2) The raw data obtained in the seal gap measurement and the calculations described in §63.120(b)(3) and (b)(4) of subpart G.

(3) A description of any seal condition specified in §63.120(b)(5) or (b)(6) of subpart G that is not met.

(4) A description of the nature of and date the repair was made, or the date the storage vessel was emptied.

(B) If an extension is utilized in accordance with §63.120(b)(7)(ii) or (b)(8) of subpart G, the owner or operator shall, in the next Periodic Report, identify the vessel; include the documentation specified in §63.120(b)(7)(ii) or (b)(8) of subpart G, as applicable; and describe the date the vessel was emptied and the nature of and date the repair was made.

(C) The owner or operator shall submit, as part of the Periodic Report, documentation of any failures that are identified during visual inspections required by §63.120(b)(10) of subpart G. This documentation shall meet the specifications and requirements in paragraphs (g)(3)(i)(C)(1) and (2) of this section.

(1) A failure is defined as any time in which the external floating roof has defects; or the primary seal has holes or other openings in the seal or the seal fabric; or the secondary seal has holes, tears, or other openings in the seal or the seal fabric; or, for a storage vessel that is part of a new source, the gaskets for covers or lids no longer close off the liquid surface from the atmosphere; or, for a storage vessel that is part of a new source, the slotted membrane fabric cover for a roof drain that empties into the stored liquid, if present, has more than 10 percent open area. Requirements related to gaskets and slotted membrane fabric covers do not apply for a storage vessel is part of an existing source.

(2) Each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made.

(ii) Compliance with §63.660. An owner or operator who elects to ~~comply with §63.660 by using~~ use an external floating roof to comply with §63.660 shall meet the periodic reporting requirements specified in paragraphs (g)(3)(ii)(A) and (B) of this section.

(A) For vessels for which inspections are required under §63.1063(c)(2), (d)(1), and (d)(3) of subpart WW, the owner or operator shall submit, as part of the Periodic Report, a copy of the inspection record required by §63.1065(b) of subpart WW when a failure occurs. A failure is defined in §63.1063(d)(1).

(B) An owner or operator who elects to use an extension in accordance with §63.1063(e)(2) or §63.1063(c)(2)(iv)(B) of subpart WW shall, in the next Periodic Report, submit the documentation required by those paragraphs.

~~(4) An owner or operator who elects to comply with §63.646 or §63.660 by using an external floating roof converted to an internal floating roof shall comply with the periodic reporting requirements of paragraph (g)(2)(i) of this section.~~ Reserved.

2.3.2 Small Storage Vessels Should be Included in the Storage Vessel Definition if a Pressure Exception is Not Added to the Proposed Atmospheric RV Requirements.

The definition of a storage vessel in RMACT 1 contains an exclusion for "[v]essels with capacities smaller than 40 cubic meters." This exclusion has not been an issue in the past. Under this proposal, however, the pressure/vacuum (PV) vent on these small tanks would be MPVs or, if the tank is controlled with a closed system, RVs and would be subject to evaluation under those sections and potentially control. We discuss this issue relative to the RV situation in Comment 2.4.1.7. Thus, these smaller vessels, which are permitted as tanks and were considered tanks in the development of RMACT 1, should be clearly identified as storage vessels in RMACT 1.

2.3.3 Comments on Other Proposed Storage Vessels Requirement Changes

2.3.3.1 Requirements for Floating Roof Deck Fittings Need to Be Clarified.

The requirements for floating roof deck fittings are in need of editing for clarity and completeness, as well as for correcting minor typographical errors.

1. The flexible enclosure control option is allowed under the STERPP[116] for internal floating-roof tanks as well as for external floating-roof tanks. The proposed language to revise RMACT 1 limits this option to external floating-roof tanks, but there is no rationale given for this limitation. We assume this to simply be an oversight, and we request that the flexible enclosure control option be allowed for both internal floating-roof tanks and external floating-roof tanks. If this is a purposeful change, the cost impact for internal floating roof tanks using this control to make this change and the justification should be provided and published for comment. This issue pertains to §§63.640(n)(8)(vii) and (n)(10)(vii), with respect to the overlap provisions, and to §63.660(b), with respect to citations to Subpart WW.

To effectuate this change API/AFPM suggests the following revisions to §63.640(n)(8)(vii).

> (vii) To be in compliance with § 60.112b(a)(1)(iv) or § 60.112b(a)(2)(ii) of this chapter, guidepoles in floating roof storage vessels must be equipped with ~~guidepole~~ controls as described in Appendix I: Acceptable Controls for Slotted

[116] The Storage Tank Emission Reduction Partnership Program, STERPP, was a voluntary EPA/Industry program to address emissions from tank slotted guidepoles. See 65 FR 19891 (April 13, 2000)

> Guidepoles Under the Storage Tank Emissions Reduction Partnership Program (available at http://www.epa.gov/ttn/atw/petrefine/petrefpg.html).

API/AFPM suggests the following revisions to §63.640(n)(10)(vii).

> (vii) To be in compliance with §61.271(a)(6) or §61.271(b)(3) of this chapter, guidepoles in floating roof storage vessels must be equipped with ~~guidepole~~ controls as described in Appendix I: Acceptable Controls for Slotted Guidepoles Under the Storage Tank Emissions Reduction Partnership Program (available at http://www.epa.gov/ttn/atw/petrefine/petrefpg.html).

2. The citation to Subpart WW in §63.660(b) should be to §63.1063(a)(2)(viii) for slotted guidepoles, rather than to §63.1063(a)(2)(vii). The citation in the STERPP agreement is expressly for the use of the flexible enclosure as a control option for slotted guidepoles, and the referenced paragraphs (A) and (B) are found under §63.1063(a)(2)(viii). We assume the citations to §63.1063(a)(2)(vii) to be in error, and we request that the citations be corrected.

Additionally, control options for a ladder that has at least one slotted leg were specified in the proposed Uniform Standards, but were left out of these proposed revisions. The proposed options included a ladder sleeve, the effectiveness of which was demonstrated to EPA prior to proposal of the Uniform Standards, and no rationale is given for the omission of this control option in this proposal. We assume this to be an oversight, and we request that the control options from the proposed Uniform Standards be included here.

API/AFPM suggests the following revisions to §63.660(b).

> (b) In addition to the options presented in §§63.1063(a)(2) and 63.1064, a Group 1 storage vessel complying with the requirements in Subpart WW may comply with the control option listed in §63.660(b)(1) and, if equipped with a ladder that has at least one slotted leg, shall comply with one of the control options listed in §63.660(b)(2).
>
> (1) In addition to the options presented in §§63.1063(a)(2)(viii)(A), 63.1063(a)(2)(viii)(B), and 63.1064, a~~n external~~ floating roof storage vessel may comply with §63.1063(a)(2)(viii) using a flexible enclosure system as described in item 6 of Appendix I: Acceptable Controls for Slotted Guidepoles Under the Storage Tank Emissions Reduction Partnership Program (65 FR 19893).
>
> (2) Each opening through a floating roof of a Group 1 storage vessel for a ladder that has at least one slotted leg must be equipped with one of the control device configurations specified in paragraph (b)(2)(i), (ii) or (iii) of this section.

(i) A pole float in the slotted leg and pole wipers for both legs. The wiper or seal of the pole float must be at or above the height of the pole wiper.

(ii) A ladder sleeve and pole wipers for both legs of the ladder.

(iii) A flexible enclosure device and either a gasketed or welded cap on the top of the slotted leg.

2.3.3.2 Requirements for Storage Vessel Control Devices

The existing RMACT 1 storage vessel provisions cite §§63.119 through 63.121, where the requirements for use of a closed vent system and control device are specified in §63.119(e). Paragraph §63.119(e) includes 1) a provision to grandfather control devices that were installed on or before December 31, 1992 and achieve at least 90% effectiveness, and 2) a provision that addresses planned routine maintenance. The proposed change in §63.660 to invoke the requirements of Subpart SS does not include these provisions from §63.119(e)[117], and no rationale or analysis is presented to justify removal of these provisions and no compliance time is provided if a grandfathered control device must be upgraded. If the grandfathering provision specified in §63.119(e)(2) is not preserved in the revisions to the rule, then a control device that has been in compliance with this provision will need to be either upgraded or replaced. Consistent with CAA section 112(i), 3 years should be allowed for upgrade or replacement of an existing control device. The provisions for planned routine maintenance in §63.119(e)(3) and (e)(4) are needed to allow for the routine maintenance necessary in order to maintain control devices (and in some cases closed vent systems) in good working order. These paragraphs from §63.119(e) should be carried over into the new requirements of §63.660(i).

API/AFPM suggests the following revisions to proposed §63.660(c) to maintain grandfather provision.

> (c) For the purposes of this subpart, references shall apply as specified in paragraphs (c)(1) through ~~(6)~~ (7) of this section.
>
> * * * * * * * * * * * * * * * * *
>
> (6) All references to the "required control efficiency" in subpart SS of this part mean reduction of organic HAP emissions by 95 percent or to an outlet concentration of 20 ppmv.

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[117] Subpart SS contains the recordkeeping and reporting requirements associated with the planned routine maintenance provisions, but relies on the referencing subpart to contain the planned routine maintenance provision itself.

(7) If the owner or operator can demonstrate that a control device installed on a storage vessel on or before December 31, 1992 is designed to reduce inlet emissions of total organic HAP by greater than or equal to 90 percent but less than 95 percent, then all references to the "required control efficiency" in subpart SS of this part mean reduction of organic HAP emissions by 90 percent or greater.

API/AFPM suggests the following revisions to proposed §63.660(i) to maintain the planned routine maintenance provision[118].

(i) Owners or operators electing to comply with the requirements in subpart SS of this part for a Group 1 storage vessel must comply with the requirements in paragraphs ~~(c)(1) through (3)~~ (i)(1) through (5) of this section.

(1) If a flare is used as a control device, the flare shall meet the requirements of §63.670 instead of the flare requirements in §63.987.

(2) If a closed vent system contains a bypass line, the owner or operator shall comply with the provisions of either §63.985(a)(3)(i) or §63.985(a)(3)(ii) for each closed vent system that contains bypass lines that could divert a vent stream to the atmosphere. Use of the bypass at any time to divert a Group 1 storage vessel to the atmosphere is an emissions standards violation. Equipment such as low leg drains and equipment subject to §63.648 are not subject to this paragraph.

(3) If storage vessel emissions are routed to a fuel gas system or process, the fuel gas system or process shall be operating at all times when regulated emissions are routed to it. The exception in §63.984(a)(1) does not apply.

(4) Periods of planned routine maintenance of the control device, during which the control device does not meet the specifications of paragraph (c)(6) or (c)(7) of this section, as applicable, shall not exceed 240 hours per year.

(5) The specifications and requirements in paragraphs (c)(6) or (c)(7) of this section for control devices do not apply during periods of planned routine maintenance.

[118] This suggested language also addresses the current typographic error in proposed §63.660 where "(c)(1) through (3)" is mistakenly referenced rather than "(i)(1) through (3).

2.3.3.3 EPA Should Allow In-service Inspections of Internal Floating Roof Tanks.

On page 36914 of the preamble, EPA requests comment on the subpart WW allowance for the every 10 year internal floating roof inspection to be done with the tank in service if there is visual access to all the deck components. In revising the RMACT 1 storage vessel requirements, this inspection provision will become available to refiners. Subpart WW was first promulgated in 1999[119] and has been widely applies since that time through various rules. Our understanding is that this inspection alternative has been used without problem, where vessel conditions allow, and that there is no indication that seal or fitting failures have gone undetected. Performing inspections in this way avoids significant hazardous waste generation, shutdown emissions, the operating risk associated with having tanks out of service, and is much less costly than performing an out-of service inspection. To require a facility to incur the otherwise unnecessary emissions associated with tank cleaning, when the inspection can be performed adequately with the storage vessel in service, is unjustifiable and less favorable for the environment. Thus, API/AFPM recommends EPA not take any action that would interfere with this proven subpart WW provision.

2.3.3.4 The Bypass Monitoring Requirement in §63.660(i)(2) Need to Be Clarified to Match Those Applicable to Potential MPV Bypasses.

1. Proposed §63.660(i)(2) includes language that makes <u>any</u> flow through a Group 1 storage vessel vent system potential bypass a violation. API/AFPM comments on that portion of the proposed revision in Comment 2.6, since it is similar to the provision impacting potential Group 1 MPV control bypasses.

2. §63.644(c), which addresses MPV bypass monitoring, contains exceptions to the bypass monitoring requirements as follows:

> Equipment such as low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, pressure relief valves needed for safety reasons, and equipment subject to §63.648 are not subject to this paragraph.

[119] 64 FR 34918, June 29, 1999.

While revisions to these exceptions have been proposed and we comment extensively on those proposed changes in Comment 2.2.4, it is important that §63.660(i)(2) contain the same exceptions as are finalized for §63.644(c). There is no logical reason for treating these two situations differently and equipment that is subject to other RMACT 1 requirements or is required for safety should not also be considered potential bypasses and subject to these sometimes conflicting requirements as well.

3. The citation in §63.660(i)(2) to §63.985(a)(3)(i) or (ii) should be to §63.983(a)(3)(i) or (ii).

2.3.3.5 Editorial Corrections Are Needed in §63.660(d) to Clarify the Compliance Timing for Storage Vessels That Become Group 1 as a Result of These Amendments.

§63.660(d) pertains to equipping a fixed-roof storage vessel with controls, if it has not been subject to control prior to these amendments. The specified control could be achieved by routing the vapors to a control device or by installing a floating roof. However, the citation to "the requirements of §63.1062" could be construed as being applicable only to the installation of a floating roof. It would be apparent that the control requirements in question could be either routing to a control device or installing a floating roof if this phrase were changed to read "the requirements of this section," in that the introductory text of this section (§63.660) addresses complying with either Subpart WW (for installing a floating roof) or Subpart SS (for routing vapors to a control device). In addition, the term "storage vessel fixed roof" in §63.660(d) should read "fixed roof storage vessel." Thus, API/AFPM suggest the following editorial revisions to proposed §63.660(d).

> (d) For an existing ~~storage vessel~~ fixed roof storage vessel that meets the definition of Group 1 storage vessel (item 2) in §63.641 but not the definition of Group 1 storage vessel (item 1) in §63.641, the requirements of ~~§63.1062~~this section do not apply until the next time the storage vessel is completely emptied and degassed, or [THE DATE 10 YEARS AFTER PUBLICATION OF THE FINAL RULE AMENDMENTS IN THE **FEDERAL REGISTER**], whichever occurs first.

2.3.3.6 Typographical Corrections Are Needed in §63.640(n).

There are minor typographical errors that need to be corrected in §63.640(n)(8) and (n)(10), as follows.

(8) Storage vessels described by paragraphs (n)(1) and (n)(3) of this section are to comply with 40 CFR part 60, subpart Kb except as provided for in paragraphs (n)(8)(i) through ~~(n)(8)(vi)~~ (n)(8)(viii) of this section. Storage vessels described by paragraph (n)(2) electing to comply with part 60, subpart Kb of this chapter shall comply with subpart Kb except as provided in paragraphs (n)(8)(i) through ~~(n)(8)(vii)~~ (n)(8)(viii) of this section.

* * * * * * *

(10) Storage vessels described by paragraph (n)(1) of this section are to comply with 40 CFR part 61, subpart Y except as provided in paragraphs (n)(10)(i) through ~~(n)(8)(vi)~~ (n)(10)(viii) of this section. Storage vessels described by paragraph (n)(2) electing to comply with 40 CFR part 61, subpart Y shall comply with subpart Y except as provided for in paragraphs (n)(10)(i) through ~~(n)(8)(vi)~~ (n)(10)(viii) of this section.

2.4 Equipment Leak Issues.

2.4.1 The Proposed Prohibit on Atmospheric Safety Valve Releases Should Be Replaced with A Reasonable Program Aimed at Minimizing Such Releases.

It is proposed to add §63.648(j) to address RVs in organic HAP gas or vapor service. Proposed §63.648(j)(1) deals with RV leakage during periods when the RV is not releasing and is essentially the same as the existing requirements imposed by RMACT 1. We have no comments on proposed paragraph (j)(1).

Proposed §63.648(j)(2) and (3) deal with pressure releases. Paragraph (j)(2) is similar to the existing requirement to demonstrate that the RV has returned to a <500 ppm leakage within 5 days after a pressure release or, if the RV is a rupture disk or a relief valve equipped with a rupture disk, to replace that disk within 5 days after the release. Proposed paragraph (j)(3) specifies that RVs in organic HAP service "may not be discharged to the atmosphere." This prohibition is new and is the focus of Comment 2.4.1.2. Proposed paragraph (j)(3) also imposes new release monitoring, recordkeeping and reporting requirements for atmospheric RVs in organic HAP gas or vapor service. Most of our concerns about the monitoring requirements as expressed in our comments on the proposed Uniform Standards[120] have been addressed in this

[120] API/AFPM Letter to Dockets EPA-HQ-OAR-2010-0868, EPA-HQ-OAR-2010-0869, EPA-HQ-OAR-2010-0870, EPA-HQ-OAR-2010-0871, Re: Environmental Protection Agency's (EPA's) "*National Uniform Emission Standards for Storage Vessel and*

proposal. We provide some additional comments on situations where continuous instrumental monitoring is not feasible and/or not justified in Comments 2.4.1.3 through 2.4.1.7, which primarily address those situations which we believe should not be subject to some of the proposed pressure relief requirements. Comment 2.4.1.8, contains the API/AFPM suggestions for a work practice appropriate for addressing atmospheric RVs.

Finally, proposed paragraph (j)(4) identifies RV situations that are exempt from the requirements of (j)(1) through (3). Our comments on this paragraph are included in Comments 2.4.1.9 and 2.4.1.10. Comments on other RV issues are contained in Comments 2.4.1.11 through 2.4.1.13.

2.4.1.1 EPA Must Address the Safety Issues Resulting from The Proposed Prohibition on Atmospheric Relief Valves and Coordinate With The Occupational Health and Safety Administration and the EPA Risk Management Office.

RVs are safety devices needed to protect personnel, plant equipment, and the public. Prohibiting atmospheric releases will require routing RVs to existing and new flares thereby imposing massive, unnecessary costs to control releases during very rare events, increasing emissions due to the operation of new flares, and potentially increasing the safety risk associated with these events. Establishing a work practice standard, in conjunction with the general duty requirements in RMACT 1, is legally justified, would avoid interfering with RV operations during emergencies and would avoid wasteful investment and increased emissions to address emissions that may never occur or that occur infrequently.

In order to comply with the proposed prohibition on RV releases to atmosphere, refineries would have to build multiple new flares because it is generally infeasible to route RVs to existing flares. Factors affecting the feasibility of routing to an <u>existing</u> flare include:

a. The existing flare system must have sufficient additional hydraulic capacity for both the individual relief loads and the common mode relief loads, without raising the backpressure on other relieving RVs.

Transfer Operations, Equipment Leaks, and Closed Vent Systems and Control Devices; and Revisions to the National Uniform Emission Standards General Provisions" March 16, 2012 at 77 Fed. Reg. 17898, September 24, 2012.

b. The flare sterile area[121] must be adequate for an increase in individual or common mode flare loads;

c. The flare must be able to meet the other applicable regulatory requirements (e.g., smokeless operation, velocity, combustion zone heating value) at the increased load.

d. Relief valves may have to elevated so that they free draining and are sloped into the flare header. Increasing the height will increase the inlet pressure loss which may violate the 3% rule and also lead to RV instability (e.g. chatter with the potential for loss of containment).

e. Compatibility of fluids (freezing issues from fluids that can auto-refrigerate with water containing streams for example, hot and cold stream).

For non-thermal relief, liquid RVs, the flare system must also meet the following requirements, as applicable.

a. The flare header piping and structure must be adequate to support a liquid full situation;

b. The flare knockout drums have sufficient capacity for the identified liquid overfill relief rate;

c. The flare piping is strong enough to handle flow regimes associated with the liquid relief (e.g., slug flow) and any coincident vapor flows to the flare;

d. The flare system has adequate capacity to vaporize and/or recover the liquid and is designed to handle any associated cold (e.g., brittle fracture) and hot (e.g., rapid vaporization) safety issues, and

Because of the safety implications of this change, this proposal requires coordination with the Occupational Safety and Health Administration and the Risk Management Plan (RMP) Group at EPA to assure there are no inconsistencies between this proposal and the OSHA Process Safety Management (PSM) Requirements and CAA 112(r) RMP requirements and current update effort

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[121] Due to the thermal radiation reaching the ground during a major flaring event, which can happen at any time and without warning, an area around the base of an elevated flare is treated as a no entry zone. This area is often referred to as the sterile area. Providing this sterile area is the reason flares require significant plot space, which often is unavailable near the equipment the flare serves and which will be a major concern if new flares are required as a result of this rulemaking.

in the context of Executive Order 16350[122] that the impacts of this proposal are appropriately coordinated with safety related requirements.

2.4.1.2 Atmospheric RV Releases Cannot Legally Be Declared Violations or Prohibited. The Agency Must Delete the Prohibition from Proposed §63.648(j)(3) and Set a Reasonable Work Practice Standard Aimed at Minimizing Emissions from Gas or Vapor RV in Organic HAP Service.

Proposed §63.648(j)(3) begins as follows.

> (3) Pressure release management. Except as specified in paragraph (j)(4) of this section, emissions of organic HAP may not be discharged to the atmosphere from relief valves in organic HAP service, and on or before [THE DATE 3 YEARS AFTER THE DATE OF PUBLICATION OF THE FINAL RULE AMENDMENTS IN THE FEDERAL REGISTER], the owner or operator shall comply with the requirements specified in paragraphs (j)(3)(i) and (ii) of this section for all relief valves in organic HAP service.

It is important to note that the three years mentioned in paragraph (j)(3) is only provided for complying with the monitoring requirements, though as we discuss below, it will take much more than three years to comply with the proposed prohibition. The proposed prohibition on atmospheric RV releases would apparently be effective immediately.

The basis for this prohibition is explained in the preamble[123] as follows.

> Refinery MACT 1 recognized relief valve discharges to be the result of malfunctions. Relief valves are designed to remain closed during normal operation and only release as the result of unplanned and/or unpredictable events. A release from a relief valve usually occurs during an over pressurization of the system. However, emissions vented directly to the atmosphere by relief valves in organic HAP service contain HAP that are otherwise regulated under Refinery MACT 1.
>
> Refinery MACT 1 regulated relief valves through equipment leak provisions that applied only after the pressure relief occurred. In addition the rule followed the EPA's then-practice of exempting startup, shutdown and malfunction (SSM)

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[122] Executive Order 16350 was signed by President Obama on August 8, 2013 and is entitled "Improving Chemical Facility Safety and Security"

[123] 79 Fed. Reg. 36912 (June 30, 2014), left column.

> events from otherwise applicable emission standards. Consequently, with relief valve releases defined as unplanned and nonroutine and the result of malfunctions, Refinery MACT 1 did not restrict relief valve releases to the atmosphere but instead treated them the same as all malfunctions through the SSM exemption provision.
>
> In *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008), the Court determined that the SSM exemption violates the CAA. See section IV.E of this preamble for additional discussion. To ensure this standard is consistent with that decision, these proposed amendments remove the malfunction exemption in Refinery MACT 1 and 2 and provide that emissions of HAP may not be discharged to the atmosphere from relief valves in organic HAP service. To ensure compliance with this amendment, we are also proposing to require that sources monitor relief valves using a system that is capable of identifying and recording the time and duration of each pressure release and of notifying operators that a pressure release has occurred. Pressure release events from relief valves to the atmosphere have the potential to emit large quantities of HAP. Where a pressure release occurs, it is important to identify and mitigate it as quickly as possible.
>
> …
>
> As defined in the Refinery MACT standards, relief valves are valves used only to release unplanned, nonroutine discharges. A relief valve discharge results from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause that requires immediate venting of gas from process equipment in order to avoid safety hazards or equipment damage. Even so, to the extent that there are atmospheric HAP emissions from relief valves, we are required to follow the Sierra Club ruling to address those emissions in our rule, and we can no longer exempt them as permitted malfunction emissions as we did under Refinery MACT 1. Our information indicates that there are approximately 12,000 pressure relief valves that vent to the atmosphere (based on the ICR responses) and that the majority of relief valves in the refining industry are not atmospheric, but instead are routed to flares (see letter from API/AFPM, Docket Item Number EPA-HQ-OAR-2010-0682-0012).

This logic has many flaws, which we discuss in the next.

Furthermore, it is important to note that, while claiming there is significant HAP release potential, EPA makes no claims that there are, in fact, significant amounts of HAP released from RVs or that there is any risk impact from these typically short, very infrequent occurrences that would justify the billions of dollars in investments and operating costs this proposed prohibition imposes.

This kind of vaguely supported, imprecise regulation does not meet the requirements for rulemaking under the CAA, especially where EPA's proposed actions would restrict the use of devices which EPA acknowledges are essential to avoid safety hazards or equipment damage.[124] In fact, this prohibition directly violates the general duty provision in proposed §63.642(n) of RMACT 1, which requires that "the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety..." [Emphasis added] While this general duty applies to owners and operators, EPA must allow for safe operation of refineries by not prohibiting such operations.

Also, because facilities already provide reports for unpermitted releases pursuant to other regulatory requirements (e.g., other NESHAPs, Title V reporting, EPCRA and CERCLA), EPA is both on notice of such releases and had plenty of data at hand to analyze RV releases in the manner required of it by law.

2.4.1.2.1 It is False to Claim That all RV Releases Are Due To Malfunctions and That Emissions Vented Directly to the Atmosphere by Relief Valves in Organic HAP Service Contain HAP That Are Otherwise Regulated Under Refinery MACT 1.

The lynch pin of the preamble argument for this prohibition is "Refinery MACT 1 recognized relief valve discharges to be the result of malfunctions." This statement belies the fact that RVs are designed precisely to allow for the immediate venting of gas from process equipment in order to avoid safety hazards or equipment damage and thus releases are not "excess emissions" but "normal" operation of these devices. While the release may be due to a process upset, the regulatory definition of malfunction requires excess emissions. No explanation is provided to explain the basis for RV discharges being malfunctions in the regulatory sense and

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[124] See Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co., 463 U.S. 29, 43, 103 S. Ct. 2856, 77 L. Ed. 2d 443 (1983) (holding that an agency must examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made). See also, Panhandle E. Pipe Line Co. v. FERC, 890 F.2d 435, 439 (D.C. Cir. 1989) (The agency must show that it has taken a "hard look at the salient problems before it.") (quotation marks and citations omitted).

not vents for which an emission limitation would not be established following the normal procedures applicable to vents operating normally. When a RV is operating as intended and expected, logic indicates that release is not a malfunction (under even the common meaning of malfunction), at least of the RV, so even EPA's new-found refusal to recognize "malfunctions" would not justify suddenly prohibiting all venting from RVs. Moreover, releases from RVs essentially and by design cannot be avoided, at least in some situations, so prohibiting any emission from a RV runs directly afoul of the courts' admonition to EPA that it must establish emission standards that have been achieved, including under the worst foreseeable circumstances, or are achievable considering cost and other factors.

The definition of malfunction in §63.2 of the part 63 General Provisions, which is typical of the definition applicable to most Federal air rules, is as follows.

> *Malfunction* means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

This definition was put into place in April 2003[125] to replace the original definition, which was:

> *Malfunction* means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

The intent of this change, which was made as a clarifying change in response to comments received, is indicated on pages 32592-3 of the preamble to that final rule, as follows, and was intended to put into regulatory language EPA's interpretation of the previous malfunction definition[126].

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[125] See 68 Fed. Reg. 32586 (May 30, 2003).

[126] At 67 Fed. Reg. 72881 (Dec. 9, 2002), center column, the proposal preamble states "We recognize that some sources are concerned that the requirement to periodically report malfunctions may be interpreted to require reporting of minor problems that have no impact on emissions. However, we do not construe the provision in this manner. Under our regulations, ''malfunction'' is defined as ''any sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner.'' See 40 CFR 63.2. Only those events that meet this definition would be subject to the reporting requirement. During an event that meets this definition, the facility is not required to comply with otherwise applicable emission limits, and the SSM plan must specify alternative procedures which satisfy the general duty to minimize emissions. Minor or routine events that have no appreciable impact on the ability of a source to meet the standard need not be classified by the source as a malfunction, addressed in the SSM plan, or

> …, we stated in the proposal that minor or routine events that do not have a significant impact on the ability of a source to meet the standard need not be classified as a malfunction, addressed by the SSM plan, or included in periodic reports. We think there is no reason to classify an event as a malfunction if it does not cause, or have the potential to cause, the emission limitations in an applicable standard to be exceeded.

While most RV pressure releases are due to malfunctions or upsets, as thought of in the common vernacular, not all, whether to the atmosphere or not, meet the part 63 malfunction definition criterion of causing or having the potential to cause the emission limitations in the applicable standard to be exceeded. Furthermore, as indicated in the §63.2 malfunction definition and the §63.641 RMACT 1 relief valve definitions[127], releases may not be malfunctions if they are due to operator error, poor maintenance, or careless operation.

EPA has diligently worked over the years to significantly narrow what events are considered malfunctions. This effort continued in the recent Generic MACT amendment proposal[128], where on page 1711 of that preamble more than half a column is spent explaining how narrow the definition of malfunction is. EPA cannot reverse the narrowness of the §63.2 malfunction definition and decades of precedents by arbitrarily announcing in this preamble that RV discharges are due to malfunctions.

Relative to the excess emissions criterion in the malfunction definition, RVs are specifically excluded from the current RMACT 1 MPV definition and thus there is no RMACT 1 process vent emission limitation applicable to a RV pressure release[129]. Rather, the RMACT 1 emission limitations for RV pressure releases are contained in §60.482-4 of part 60 subpart VV and §63.165 of part 63 subpart H. This requirement is essentially the same as that proposed in these amendments as §63.680(j)(2) and requires that within 5 days after a pressure release

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included in periodic reports. Thus, if a source experiences a minor problem that does not affect its ability to meet the applicable emission standard, the problem need not be addressed by the SSM plan and would not be a reportable ''malfunction'' under our regulations."

[127] The definition of "relief valve," in §63.641 of RMACT 1 includes malfunctions as only one type of relief valve release. That definition is as follows.

> *Relief valve* means a valve used only to release an unplanned, nonroutine discharge. A relief valve discharge can result from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause that requires immediate venting of gas from process equipment in order to avoid safety hazards or equipment damage.

[128] See 79 Fed. Reg.1676 (January 9, 2014)

[129] In some cases, State regulations or permits impose a limit that could result in a release being considered a malfunction under State law, but that would not make it a malfunction under parts 60, 61 or 63.

Method 21 monitoring be performed to demonstrate that leakage has returned to <500 ppm or that a rupture disk be replaced within 5 days. These emission limitations impose no mass or removal requirement on the RV release. Thus, under the current RMACT 1 an atmospheric gas-vapor RV excess emission can only occur if the <500 ppm demonstration or rupture disk replacement is not completed successfully within the 5 day period. Since excess emissions or the potential for excess emissions is a necessary condition for having a malfunction, there is almost no possibility of an RV release being due to a malfunction under RMACT 1.

The preamble statement that emissions vented directly to the atmosphere by relief valves in organic HAP service contain HAP that are otherwise regulated under Refinery MACT 1 is also incorrect. Since, as we discuss above, RV emissions are regulated as equipment leaks and are specifically excluded from being MPVs in the definition of MPV, there is not a mass or rate emission limitation applicable to such releases and thus such releases are generally not otherwise regulated. The only situation where an RV release might be construed as releasing otherwise regulated material is if the equipment that the RV protects also has a Group 1 MPV. In that case, the RV release could be construed as a bypass of that Group 1 MPV around control. That however, represents a small portion of RV situations and cannot be generalized as is apparently done in this preamble. As we recommend below, RVs should continue to be handled in the equipment leak section of RMACT 1 and that an alternative work practice standard be established for atmospheric RVs to address EPA's concerns about the adequacy of the current 5-day emission limitation.

2.4.1.2.2 It is Inaccurate to Claim That The Sierra Club Decision Requires this Prohibition.

EPA already set standards for RVs. It may revise the existing standards only under section 112(d)(6) authority and only if warranted under that section. RVs already are subject to MACT standards, covering potential leakage during periods when the RV is not releasing and requiring leak checks/rupture disk replacement after a RV lifts. Since EPA already has set MACT standards for RVs, EPA may revise these standards only under the authority of section 112(d)(6). Section 112(d)(6) allows EPA to revise an existing MACT standard only "as necessary (taking into account developments in practices, processes, and control technologies)." EPA has not made a showing in the proposed rule that a revision of the existing standards is "necessary" upon consideration of the specified factors. Therefore, no change to the existing standards is warranted.

In any event, EPA has no authority to set a HAP emissions limit of zero for atmospherically vented RVs. Prohibiting emissions to the atmosphere from RVs is tantamount to setting a zero emissions limit for them. EPA has no authority to do so under section 112. Petroleum refineries must be equipped with RVs. They are safety devices that must be installed to prevent catastrophic conditions that could damage the plant and result in injury to employees and nearby communities. They are mandated by fire protection codes and they are effectively mandated by the OSHA PSM rule and section 112(r) of the CAA.

As explained below, it is not possible to route all RVs to a closed vent system equipped with a control device. Thus, it is not possible to prevent emissions from atmospherically vented RVs. Although exceedingly rare, conditions can arise that are not reasonably foreseeable and not reasonably preventable – e.g., severe weather, cooling water loss, etc.

The *Sierra Club* SSM case does not prohibit EPA from setting standards for RVs. That case simply says that MACT-based standards must apply at all times. The case does not say that EPA is prohibited from setting different standards for different source types or different modes of operation.

EPA claims that it cannot set emissions standards for RVs, but that is exactly what it has done be prohibiting emissions from RVs. Thus, EPA's legal justification for the proposed zero-emissions standard for atmospherically vented RVs is fatally flawed.

EPA asserts that emissions from RVs, by definition, are caused by malfunctions. EPA claims that it cannot set a standard for RVs because: (1) "CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of section 112 standards"; and (2) "accounting for malfunctions in setting emissions standards would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category, and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur." Yet, a prohibition on emissions from atmospherically vented RVs <u>is</u> an emissions standard. Therefore, EPA has done what it claims it cannot. EPA's legal justification is inherently contradictory and, therefore, fatally arbitrary.

Moreover, EPA has not provided sufficient justification for a zero-emissions standard. A zero-emissions standard must be based on one of the available standard-setting procedures under section 112. EPA's justification is inadequate because the Agency fails to identify which standard-setting mechanism authorizes the standard. EPA's justification also is inadequate because EPA fails to demonstrate how a zero-emission standard would be warranted under the potentially applicable standard-setting procedures. As we argue above, since a MACT standard already exists for RVs, section 112(d)(6) is the only available authority to make a technology-based revision to the existing standard. It is well established that a section 112(d)(6) standard must be cost effective and technically feasible. A zero-emission standard is plainly not cost effective or always technically feasible. Therefore, such a standard cannot be justified. Although we would disagree, EPA might assert that a zero-emission standard might be grounded in section 112(d)(2)/(d)(3). But, the zero-emission standard still fails since the floor for atmospheric RVs is certainly not zero emissions.

2.4.1.2.3 Because The Application of Emission Measurement Methodology Is Not Practicable Due to Technological and Economic Limitations for the Atmospheric RV Subcategory of Equipment Leaks, Application of a Work Practice Standard Is Allowed by CAA section 112(h).

Because the timing, nature, and extent of RV emissions are inherently unpredictable, there is ample justification for EPA to conclude that it is not technically or economically practicable to measure RV emissions. Thus, work practice standards can and should be prescribed.

EPA states that it is not proposing a standard for emissions that result from RV releases because: (1) "CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of section 112 standards"; and (2) "accounting for malfunctions in setting emissions standards would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category, and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur."[130]

As we point out above, the assertion that these releases are malfunctions is false, so the first tenet of EPA's explanation is false. The second tenet is valid relative to releases from atmospheric RVs, but is not a basis under Section 112 for not developing a standard. Rather it is the basis for developing a work practice standard rather than a numerical emission limitation, as provided in section 112(h). All of the emission characteristics cited by EPA lead to the conclusion that the application of emission measurement methodology is not practicable due to technological and economic limitations and thus a work practice standard (as we detail below) is authorized by the CAA.

RV releases fall squarely within the intent of section 112(h) to address situations where it is not feasible to capture the emissions and route them to a control device and it is not practicable to measure the emissions when the RV functions for its intended purpose. Any limitations established under CAA for RVs, consistent with the best performing RVs, would necessarily need to address *releases* from RVs, not *violations* of emission limitations, because the RV was not malfunctioning, but rather functioning correctly.

[130] Op. Cit., page 36944

2.4.1.2.4 It is False to Claim that The Only Costs of This Prohibition are Monitoring Costs. If a Work Practice Approach is Not Provided, Costs For Additional Flare Systems To Control Atmospheric RVs Would Be in the Billions of Dollars and Take a Decade to Install.

EPA estimates[131], based on ICR responses, that there are 12,000 atmospheric safety valves in refineries and estimates the investment cost for the monitoring portion of the proposal at $9.54M (roughly $7,500 per installation), with an annualized cost of $1.36M per year. Existing process instrumentation would allow monitoring for releases (e.g., by determining if the operating pressure approaches the RV set point) for those RVs where such process instrumentation exists. For individual RVs, costs for that monitoring would involve, for each individual RV, the burdens associated with identifying the pressure point that indicates a potential release and adding appropriate computer alarms. This might involve 8-16 hours of technical time per RV. For RVs where process instrumentation is unavailable a new monitor will be needed. EPA cites a cost of $7,500 per installation, based on a 2011 estimate by Hancy[132]. In late 2011 and early 2012, API/AFPM and APFM surveyed its members. The cost per wireless RV monitoring system based on the API member survey ranged from $12,000 to $16,700, or an average cost of about $14,350, approximately double the estimate used in this rulemaking. The API survey also found that some of our members report wireless systems have not proven usable in many locations and are unusable for liquid valves. One refinery reports a cost of $75,000-100,000 per installation was incurred to meet California monitoring requirements. Hard wired instrumentation would be particularly costly in outlying areas in refineries, which typically include more atmospheric RVs than do process areas and where access to a flare header is more available[133]. In addition, traditional flow monitors cannot be used for liquid relief valves, without them potentially interfering with the safe operation of the valve.

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[131] Op. Cit.,. page 36912, right column.

[132] Hancy, C. 2011. Analysis of Emissions Reduction Techniques for Equipment Leaks. Memorandum from Cindy Hancy, RTI International, to Jodi Howard, EPA/OAQPS, Docket No. EPA-HQ-OAR-2010-0869-0029, December 21, 2011.

[133] Additional detail on monitoring costs and the API/AFPM/APFM survey were provided in our Attachment 3 Subpart J Item 5 of our comments on the Proposed Uniform Standards Rule. See API/AFPM Letter to Dockets EPA-HQ-OAR-2010-0868, EPA-HQ-OAR-2010-0869, EPA-HQ-OAR-2010-0870, EPA-HQ-OAR-2010-0871, *Re: Environmental Protection Agency's (EPA's) "National Uniform Emission Standards for Storage Vessel and Transfer Operations, Equipment Leaks, and Closed Vent Systems and Control Devices; and Revisions to the National Uniform Emission Standards General Provisions" March 16, 2012 at 77 Fed. Reg. 17898*, September 24, 2012.

While EPA has included costs for monitoring, albeit low costs, no costs are estimated for controlling these relief valves. In prohibiting emissions from these valves, EPA is essentially prohibiting safe operations and putting equipment and personnel at risk. The only way to avoid that unsafe situation and comply with a prohibition would be to make use of the proposed §63.648(j)(4) exception for relief valves routed to control (Note, as discussed in Comment 2.4.1.9, relief valves routed to a process or to fuel gas should also be excluded.). Thus, the proposed ban requires control of 12,000 relief valves, not monitoring.

RVs that are likely to relieve or that have small relief volumes versus flare system capacity are often already controlled. However, large RVs, particularly those with low set pressures, that have little likelihood of ever relieving (e.g., those that would relieve only in a fire contingency or a total cooling water failure) and which have large relieving loads compose a class of RVs that are often routed to the atmosphere because it is unreasonable to incur the extreme costs for huge flares and flare headers if there is little or no likelihood of an event occurring. Where there is some likelihood of smaller events involving equipment where large relief loads are also possible, it is common to have a primary RV that is routed to control and additional RVs with somewhat higher set pressures routed to the atmosphere. These “stepped” systems would not be allowed under this proposal since releases from the uncontrolled valves would be banned as discussed above.

Routing large atmospheric RV releases to control devices is very costly, not cost effective, and raises safety and environmental concerns. API/AFPM believe efforts must be focused on cost effective mechanisms to reduce the likelihood of a release and to identify through their release history the RVs that deserve increased attention. In general, RVs are routed to the atmosphere because:

1. releases are very infrequent (in fact most RVs never release),
2. routing large RVs into flare header systems raises system backpressure during emergencies and thus can create additional safety problems, particularly for RVs with low set pressures,
3. addition of flares to provide added emergency capacity increases net annual emissions because of the continuous pilot, purge and sweep gas combustion required and generate noise and light pollution,
4. these controls require very large investments (millions of dollars per RV) in new flares and flare header systems, and
5. space may not be available for siting new flares, and 6) the surrounding community objects to the addition of flares.

Because the primary contingency that must be addressed (other than fire) is plant-wide (or at least area-wide) utility failure, flare systems must be sized for the simultaneous release of many RVs at once and to prevent unsafe backpressures from occurring during such events. Thus, controlling additional RVs generally requires large flare header system investments to reduce backpressure during large simultaneous releases and even additional flare capacity investments. Additionally, because of the flare system backpressure during such occurrences, costly additional relieving capacity and equipment nozzles are often required, not only for the equipment with the atmospheric RV, but for other equipment with RVs relieving into the same header system. If the process material is light (i.e., primarily C_4 minus) auto-refrigeration leads to cold safety concerns and the flare system must be constructed with costly alloys. In some cases, instrumentation approaches are helpful in minimizing the required flare capacity demand, but while such approaches are deemed acceptable, they are inherently somewhat riskier than direct atmospheric or flare relief.

Some equipment requires so much relieving capacity that it is essentially unrealistic to control it. For instance, one refinery reports that the eight RVs on their atmospheric Crude Distillation Tower has a relief load of approximately 10 times their existing site flare capacity. Just the engineering associated with controlling large atmospheric RVs is substantial, because the impacts of the additional backpressure on all other connected RVs must be evaluated and addressed. Failing to deal with increased flare system backpressure caused by adding RVs to a flare header system can lead to equipment failure and personal risk during emergencies.

In 2005, the Bay Area Air Quality Monitoring District (BAAQMD) evaluated requiring control of the 324 atmospheric safety valves at the 5 refineries in the District. They concluded that approach would require addition of seven flares and have an investment cost of $192 Million ($17.9 Million annualized over 20 years), with a cost effectiveness of $890,000-1,500,000 per ton of VOC reduced[134]. Scaling the BAAQMD data to the 12,000 atmospheric RVs EPA estimates, would result in a national investment cost of $7.1 Billion 2005 dollars ($663 Million annualized over 20 years) and require construction of 209 new flares. These costs and the number of new flares would be increased significantly due to the imposition of the 400 ft./sec velocity limit discussed in Comment 2.7.4, which did not apply to the BAAQMD flares. This

[134] Douglas, Victor and Crockett, Alexander, BAAQMD, Proposed Amendments to Regulation 8, Rule 28: Episodic Releases from Pressure Relief Devices at Petroleum Refineries, Staff Report, November 2005, Pages 35-38. This cost effectiveness assumes no existing spare flare system capacity, a situation that is generally true and will be totally true under the proposed extension of the 400 fps velocity limit to emergencies. Even if 100% spare flare capacity was assumed the BAAQMD estimated costs of $10-80 million for new piping.

impact has not been included in these cost estimates, but could increase the number of new flares and the costs by 20-400% depending on how much this limit impacts the capacity of a particular flare. Refinery construction costs have increased by approximately 60% since 2005 and a current investment estimate would approach $12 Billion as a result of this prohibition.

Additional large costs will accrue from the production losses associated with process shutdowns to install the new flares and header systems and to add nozzles and RVs to equipment because of the requirement for additional relief area to compensate for the added backpressure of relieving into a flare system rather than the atmosphere. It is likely as much as 10 years would be required to make this investment taking advantage of planned process outages. Even in that time period, fuels production losses would be substantial due to the need to extend downtimes to accommodate this work.

The CAA requires that the Agency consider these costs and the increased emissions associated with adding flares, among other issues, in establishing an emission limitation. Logic also requires the Agency consider the negative impact of this requirement on its significant efforts to reduce flaring and flare emissions. The rulemaking record needs to clearly identify that this proposal requires installation of additional flares and it must inform the public of that impact. No such analyses have been performed in support of this proposal to prohibit atmospheric pressure releases.

2.4.1.2.5 API/AFPM Recommends a Root Cause Analysis/Corrective Action Approach as the Work Practice Standard.

The common practice in the refining industry, per the OSHA PSM regulation[135] and EPA's RMP (section 112(r)) requirements, for dealing with atmospheric RV releases is to investigate any release and follow-up on the results of that investigation. In order to prevent and minimize the recurrence of episodic emissions from RVs, one must understand and address the underlying causes of the upstream over-pressure that resulted or could result in the necessary operation of the RV. In addition to the current work practice standards that apply to RVs, API/AFPM recommends that EPA establish a standard that requires refiners to implement a base level of preventative release measures. This would include:

1. basic process controls (e.g., distributed control system),

[135] Very detailed processes are already in place that determine when an atmospheric RV is chosen as an appropriate level of protection; procedures are in place to review that choice when there is a change through the management of change process; and any time a level of protection is exceeded (whether it is an atmospheric RV or one that goes to a flare) PSM requires that an RCA be conducted and appropriate corrective actions taken.

2. instrumented alarms (e.g., pressure, temperature or level alarms) coupled with operator action,
3. documented and verified routine inspection and maintenance programs,
4. safety instrumented systems (e.g., instrumentation that automatically initiates valve closure isolating the heating medium or feed),
5. disposal systems (Discharge all or some portion of PRVs (i.e. staged pressure relief valves) to flare and/or scrubbing system),
6. provide redundant equipment (e.g., backup instruments, spare pumps with auto-start, etc.),
7. increase vessel design pressure (increase design to limit number of contingencies that will lift a PRV), and
8. systems that reduce fire exposure on equipment (e.g., deluge system or fireproofing that reduce heat flux)

Should a release occur, API/AFPM recommends that EPA require the refiner to perform a Root Cause Analysis (RCA) and implement Corrective Actions (CAs) to prevent a recurrence, similar in fashion to the RCA/CA requirements for flares under the recently promulgated NSPS Ja. We also encourage the Agency to coordinate this work practice with PSM requirements to avoid wasteful and burdensome overlaps and duplications[136]. We suggest possible work practice regulatory language, incorporating the various recommendations suggested in this section in Comment 2.4.1.8.

2.4.1.3 As With Proposed §63.648(j)(1) and (2), Proposed §63.648(j)(3) Should Only Address Gas and Vapor RVs in Organic HAP Service.

While proposed §63.648(j)(1) and (2) clearly apply only to gas and vapor RVs in organic HAP service, it appears §63.648(j)(3) may apply to liquid RVs in organic HAP service as well. Liquid RVs are very different from gas RVs and 1) are clearly already regulated by section 112(d)(2) and thus would have to be justified under section 112(d)(6), 2) present much less

[136] We note that the NSPS Ja RCA/CA requirements constitute work practice standards applicable to emissions from malfunctions. This further demonstrates that there is no basis for EPA to assert in this rule that it cannot set standards for emissions attributable to malfunctions.

environmental risk relative to the increased safety risk resulting from requiring control of those not already controlled, and 3) are much more difficult and costly to safely monitor, if such monitoring is feasible at all. Thus, their inclusion is not warranted and certainly has not been justified. The work practice requirements associated with the PSM and RMP programs and the audio, visual and odor monitoring already required by the applicable equipment leak rules are more than adequate to assure these RVs are properly handled.

2.4.1.3.1 Proposed §63.648(j)(3) Should Not Apply to Liquid RVs in Organic HAP Service.

Proposed §63.648(j) applies §63.648(j)(1) and (2) requirements to RVs in organic HAP gas or vapor service, but appears to apply the (j)(3) monitoring requirements to all RVs in organic HAP service, whether they are in gas or liquid service. As discussed previously, (j)(3) would also declare any release to the atmosphere to be a violation. Exclusions from the (j)(3) requirements are contained in §63.648(j)(4), which is discussed separately in Comment 2.4.1.9 below.

No explanation is provided in the rule preamble for applying the §63.648(j)(3) requirements to PRDs in liquid service and the current proposal does not include the basis for revising the currently applicable work practice emission limitation. Under RMACT 1, liquid RVs are currently subject to §60.482-8 of part 60 subpart VV (or §63.169 of part 63 subpart H). That section is as follows.

> §60.482-8 Standards: Pumps and valves in heavy liquid service, <u>pressure relief devices in light liquid or heavy liquid service</u>, and connectors. [Emphasis added]
>
> (a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors, the owner or operator shall follow either one of the following procedures:
>
> (1) The owner or operator shall monitor the equipment within 5 days by the method specified in §60.485(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.
>
> (2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.
>
> (b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.
>
> (c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9.

> (2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.
>
> (d) First attempts at repair include, but are not limited to, the best practices described under §§60.482-2(c)(2) and 60.482-7(e).

Thus, EPA must demonstrate this change is justified and demonstrated in practice under the provisions of CAA section 112(d)(6) and no such demonstrations have been made. No basis is provided for overriding these section 112(d)(2) sensory leak check requirements and converting the current liquid RV work practice requirement into a prohibition and violation. If EPA proceeds with imposing atmospheric RV monitoring requirements despite there being no legal basis for such monitoring (see our previous comment), such monitoring must be limited to RVs in gas-vapor service.

Liquid/thermal RVs are typically used to protect piping and equipment from rupture due to the thermal expansion of liquid within an isolated section of piping/equipment (blocked-in by closing valves on both ends). The risk of over pressure does not come from process or pipeline operating conditions, but instead from the increasing pressure of the contained liquid as its temperature increases due to atmospheric conditions. By the nature of this concern these RVs are often located in difficult to access and/or remote locations and not associated with equipment which is continuously monitored for process reasons. The amount of liquid that must be released to prevent over pressure (pipe/equipment rupture) in such cases is very small and the duration of such a release is very short. These thermal expansion relief valves typically must discharge only a few fluid ounces of liquid to return the equipment back into a safe pressure range and thus are typically small (e.g.,< 2 inch diameter). As a result, liquid/thermal relief RV releases are typically very small and very infrequent (generally do not occur when the equipment is in use). As proposed, the §63.648(j)(3) monitoring requirements would apply to all liquid RVs, including those in heavy liquids service, with essentially no air emissions potential at all.

Implementing proposed §63.648(j)(3) instead of the current work practice requirements could prove both challenging and expensive (e.g., addressing the multitude of liquid RVs in piping associated with tank farms or loading areas that are not co-located with a process unit). Even the monitoring requirements would be difficult and costly to achieve, since the acoustic monitors EPA assumed for such monitoring are not usable for liquid thermal relief valves and normal flow monitors would not only be very expensive, but could interfere with the safe operation of the RV. It is unclear that flow monitoring is even feasible for all liquid RVs; as far as we know there is no precedent for such a requirement.

Given the high cost of continuously monitoring these liquid/thermal RVs, their low likelihood of ever relieving and their minimal release potential, the existing work practice emission limitation provisions of §60.482-8 and §63.169 of part 63 subpart H are more than adequate and appropriate for this class of RV. The record for this rulemaking does not show that continuous instrumental monitoring is required, authorized or justified for liquid RVs and that portion of the proposal, therefore, cannot be finalized.

2.4.1.3.2 If Proposed §63.648(j)(3) Applies to Liquid RVs, Those Routed to Process Drains Should be Excluded Just As Gaseous RVs Routed to Control Are Excluded.

If §63.648(j)(3) applies to liquid RVs in the final rule, an exclusion should be added to §63.648(j)(4) for liquid RVs that are routed to a wastewater drain system or to a waste management unit meeting the requirements of RMACT 1, as was recently done in the National Emission Standards for Hazardous Air Pollutant Emissions: Group IV Polymers and Resins; Pesticide Active Ingredient Production; and Polyether Polyols Production[137].

Such drain systems contain and control any hydrocarbon emissions from liquids routed to them, until the hydrocarbons can be destroyed or recovered and are the liquid equivalent of gas handling closed vent systems and control devices or return of a regulated gas to a process, including a fuel gas process.

Such an exclusion is also consistent with the BAAQMD treatment of thermal relief RVs, by far the most common type of liquid RV. The BAAQMD rule provides:[138]

> The provisions of this rule <u>shall not apply to thermal relief valves</u> that are vented to process drains or back to the pipeline.

2.4.1.4 RVs Under 2 inch diameter Should Be Excluded from the Recommended Monitoring and Preventive Measures Requirements.

There are many small atmospheric RVs in refineries that pose little release risk and would be costly, difficult, or infeasible to monitor or to outfit with equipment based preventive measures. We discuss the major categories of these RVs briefly in this comment. In essentially all cases these RVs and any other low risk RVs have a diameter of ≤2 inch. Excluding these from

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[137] See §§63.1331(a)(9)(iv), 63.1363((b)(4)(iv) and 63.1434(c)(4) and as amended.

[138] BAAQMD Regulation 8, Rule 28: Episodic Releases From Pressure Relief Devices at Petroleum Refineries and Chemical Plants, December 21, 2005.

the equipment related portions of the proposed work practice, but not the RCA/CAA portion, focuses the costs for additional hardware on those RVs that would have higher emissions in the event of a release while still addressing the smaller valves in the event of a release to the atmosphere from one of them.

The largest population of atmospheric RVs is those in thermal relief service. We discussed this category of ≤2 inch liquid RVs in Comment 2.4.1.4, above. Monitoring these RVs is generally infeasible and, where feasible, would be inordinately expensive relative to any release potential. Furthermore, since they do not protect against process related contingencies, equipment based preventive measures are impractical.

Another significant category of ≤2 inch atmospheric RVs are those on instruments, such as on process analyzers. These are typically very small (e.g., ¼ inch) and protect against blockage within the instrument. Again, monitoring and equipment based preventive measures are infeasible or inordinately expensive relative to the potential release risk.

2.4.1.5 Atmospheric Relief Valves on Portable and Mobile Should Also be Excluded from the Relief Valve RV Control and/or Monitoring Requirements. Coordination with DOT and the Coast Guard is Required if Equipment Regulated by Those Agencies is Made Subject to This Requirement.

Portable tanks are often used to store catalysts, process additives and other low volume materials and often are equipped with relief valves. These containers are typically replaced with a full container when the one in service is emptied, often by third party suppliers, who also own the containers. Mobile tankage, including trucks, railcars, and marine vessels are also typically equipped with relief valves. The RVs on this mobile equipment (and often those on portable containers) are regulated by the Department of Transportation (DOT) or the Coast Guard (for marine vessels) and prohibiting their release to the atmosphere and modifying them to allow monitoring requires at least consultation with those Agencies and likely revision of their regulations. No such consultation and coordination appears to have been performed. Furthermore, the openings on these tanks would typically not be sized large enough to route to a flare under the industry inlet loss standard calculation for a RV.

Loading and unloading of this equipment is regulated under the various air regulations that deal with transfer operations and/or receiving tankage. The risk of a release at other times is very low since these tanks are not an active part of a process. Furthermore, these RVs are sized for release to the atmosphere since that is the only option during transport and thus routing to another disposition would reduce their ability to relieve in the case of a fire or other emergency. The increased safety risk, their temporary nature, their need to be easily moved, and their construction make it difficult to route these RVs to control or to continuously monitor them. Based on the foregoing, relief valves on portable and mobile containers, particularly those regulated by DOT and/or the Coast Guard, should be excluded from these requirements.

2.4.1.6 Atmospheric Relief Valves on Temporary Equipment Should Also be Excluded from the Relief Valve RV Control and/or Monitoring Requirements.

Various pieces of equipment are used by refineries for short periods of time to allow for equipment maintenance (e.g., temporary storage or temporary pump), as temporary controls (e.g., portable thermal oxidizer or diesel engine for degassing a tank), or to temporarily offset equipment issues, such as fouling or internal damage (e.g., temporary exchanger to provide additional cooling). All of this equipment will have RVs, designed for atmospheric release. This equipment, by its nature, will not be in a location that is already equipped with closed vent system (CVS) connections or monitoring instrument connections. In some cases, the need for this temporary equipment will not have been anticipated. Even where small distances are involved such connections likely could not be designed and installed in the time the equipment is in use, nor could the RVs be resized for relief to a closed system quickly, and the expense for these changes certainly cannot be justified for the low risk of a release in that short time. Thus, API/AFPM requests that RVs on temporary equipment (i.e., equipment that is in use for less than 12 months) be excluded from the new atmospheric RV pressure relief requirements.

2.4.1.7 Low Pressure RVs and RVs Handling Oxygen-Containing Vapors Should be Excluded from the RV Control and/or Monitoring Requirements.

Pressure/Vacuum (P/V) vents on storage vessels that are controlled with closed vent systems routed to control (whether for compliance with regulation of not) often serve as RVs for those vessels, should the CVS system be blocked. Typically these type vents are excluded from RV requirements by excluding RVs with a design relief pressure of<2.5 psig from the definition. While the definition of relief valve in RMACT 1 would exclude storage tank PV vents in their normal service (diurnal pressure relief), it would not exclude them on tanks controlled with a CVS and control device. Thus, a specific exclusion for RV's with a design release pressure below 2.5 psig needs to be added to the RV definition.

In addition, there are technical challenges in applying the 500 ppm LDAR standard definition to the P/V vent on a fixed-roof tank. These weighted-pallet type P/Vs do not close to that standard of leak tightness, while higher set point RVs do not provide adequate protection against tank failure.

Similarly, some RVs protect equipment in services where oxygen is present, such as in most wastewater management units. These RVs cannot be routed to combustion controls without potentially explosive results and generally have such low levels of condensables present that routing to other types of controls is ineffective. Thus, the RV definition should also be modified to exclude RVs where unsafe levels of oxygen are present.

2.4.1.8 API/AFPM Recommended Work Practice For Atmospheric Gas or Vapor RVs in Organic HAP Service.

Based on the discussion in Comments 2.4.1.2 through 2.4.1.7 API/AFPM Proposed the follow work practice specifics for gas and vapor RVs in organic HAP service that are not excluded by §63.648(j)(4).

Add to §63.641:

Corrective action means the design, operation, and maintenance changes that an owner or operator will implement consistent with good engineering practice to reduce or eliminate the likelihood of the recurrence of an event.[139]

Corrective action analysis means a description of all reasonable interim and long-term measures, if any, that are available, and an explanation of why the selected corrective action(s) is/are the best alternative(s), including, but not limited to, considerations of cost effectiveness, technical feasibility, safety, and secondary impacts.

Force majeure means an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that results in a relief valve discharge. Examples of such events are acts of nature, acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility.

Relief valve discharge means, for the purposes of this subpart, a release directly to the atmosphere of more than 72 lbs. of VOC[140] in a 24 hour period through a relief valve in organic HAP gas or vapor service.

[139] The recommended corrective action, corrective action analysis, and corrective action definitions have been kept general to allow there use for other work practice requirements, besides their recommended use for atmospheric RVs.
[140] 72 lbs VOC release in 24 hours is the criterion for control of MPVs in RMACT 1.

Prevention Measure means a reliable component, system, or program that will prevent releases from relief devices. Examples of prevention measures include, but are not limited to:

1. basic process controls (e.g., distributed control system),
2. instrumented alarms (e.g., pressure, temperature or level alarms) coupled with operator action,
3. documented routine inspection and maintenance programs,
4. safety instrumented systems (e.g., instrumentation that automatically initiates valve closure isolating the heating medium or feed),
5. disposal systems (i.e., discharge all or some portion of RVs (e.g., staged relief valves) to a flare),
6. redundant equipment (e.g., backup instruments, spare pumps with auto-start, etc.),
7. increase vessel design pressure (increase design to limit number of contingencies that will cause a RV discharge),
8. systems that reduce fire exposure on equipment (e.g., deluge system or fireproofing that reduce heat flux), and
9. operator training on release prevention.

Root cause analysis means an assessment conducted through a process of investigation to determine the primary cause, and any other contributing cause(s), of an event.

Revise proposed §63.648(j)(3) as follows:

(3) *Pressure release management*. Except as specified in paragraph (j)(4) of this section, emissions of organic HAP may not be discharged to the atmosphere from relief valves in organic HAP gas or vapor service, and on or before [THE DATE 3 YEARS AFTER THE DATE OF PUBLICATION OF THE FINAL RULE AMENDMENTS IN THE FEDERAL REGISTER], the owner or operator shall comply with the requirements specified in paragraphs (j)(3)(i) and (ii) of this section for ~~all~~ relief valves in organic HAP gas or vapor service.

(i)(A) A root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a relief valve discharge.

(B) If a single event results in more than one relief valve discharge, a single root cause analysis and corrective action analysis may be conducted.

(ii) Each owner or operator that operates equipment with relief valves that are subject to this section shall implement the corrective action(s) identified in the corrective action analysis conducted in accordance with the applicable requirements in paragraph (3)(i) of this section.

(A) All corrective action(s) must be implemented within 45 days of the relief valve discharge for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If an owner or operator concludes that corrective action should not be conducted, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the discharge.

(B) For corrective actions that cannot be fully implemented within 45 days following the relief valve discharge for which the root cause and corrective action analyses were required, the owner or operator shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.

(C) No later than 45 days following the relief valve discharge for which a root cause and corrective action analyses were required, the owner or operator shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

(D) Corrective action(s) for a second relief valve discharge from a particular relief valve, not attributable to force majeure, in five years must include the addition to that relief valve of an additional preventative measure to those required by paragraph (iii)(A) of this section, if applicable, or imposition of one preventive measure if that relief valve is excluded from the requirements of paragraph (iii)(A) by paragraph (iii)(C).

(iii) Except as specified in paragraph (j)(3)(iii)(C), relief valves in organic HAP gas or vapor service shall meet the requirements of paragraphs (3)(iii)(A) and (B).

(A) Each owner or operator that operates equipment with relief valves that are subject to this section shall implement at least three preventative measures as defined in §63.641 of this subpart. Operator training and documented routine inspection and maintenance programs may count as only one of the three required prevention measures.

(B) The owner or operator must equip each relief valve in organic HAP gas or vapor service with a device(s) or use a monitoring system that is capable of: 1) identifying the ~~pressure release~~relief valve discharge; 2) recording the time and duration of each ~~pressure release~~relief valve discharge; and 3) notifying operators immediately that a ~~pressure release~~relief valve discharge is occurring. The device or monitoring system may be either specific to the ~~pressure~~ relief device itself or may be associated with the process system or piping, sufficient to indicate a ~~pressure release~~relief valve discharge to the atmosphere. Examples of these types of devices and systems include, but are not limited to, a rupture disk indicator, magnetic sensor, motion detector on the ~~pressure~~ relief valve stem, flow monitor, or pressure monitor.

(C) The owner or operator is not required to comply with paragraph (j)(3)(A) or (B) (if applicable) of this section for relief valves of less than or equal to 2 inch relieving diameter or with a relief set pressure of less than or equal to 2.5 psig, or for relief valves on portable or mobile equipment, relief valves regulated by the Department of Transportation or the U.S. Coast Guard, or relief valves that contain oxygen or reactive materials that would result in a risk of explosion if routed to a combustion device.

~~(ii)~~(iv) If any relief valve in organic HAP service vents or releases to atmosphere as a result of a pressure release event, the owner or operator must calculate the quantity of organic HAP released during each pressure release event and report this quantity as required in §63.655(g)(10)(iii). Calculations may be based on data from the relief valve monitoring alone or in combination with process parameter monitoring data and process knowledge.

Revise associated recordkeeping and reporting consistent with this work practice.

2.4.1.9 Proposed §63.648(j)(4) Should Be Clarified to Exclude Relief Valves That Are Routed to a Process or Fuel Gas as the Current RMACT 1 Does.

Proposed §63.648(j)(4) excludes from the proposed RV release prohibition, release monitoring, and leak monitoring provisions those RVs that are routed to a control device. However, most leakage from RVs is routed to process dispositions including to fuel gas systems. As done throughout RMACT 1 and in the referenced equipment leak rules (part 60 subpart VV and part 63 subpart H), these alternatives need to be specifically included in §63.648(j)(4). In these situations, as with RVs routed to control devices, leakage and releases will not directly reach the atmosphere and thus leakage and release requirements are not appropriate. Furthermore, recovery of this leakage is environmentally beneficial relative to destruction in a control device and should be, and has historically been, encouraged.

Eliminating the route to process and route to fuel gas alternatives would create substantial problem, because it would essentially eliminate the exception for most currently controlled RVs, since most controlled RVs are routed to fuel gas. The piping and maybe the disposition would have to be modified for most existing installations to allow the monitoring required by this proposal if these RVs were no longer excluded. Compliance time, costs, and burdens for such changes are not addressed in this rulemaking and are not justified, in any case, and thus there is no legal basis for not allowing the same control options as allowed by the current RMACT 1.

2.4.1.10 The Proposed Change in the Control Device Emission Limitation for Equipment Leaks in §63.648(j)(4) From 95% to 98% Is Not Authorized, Has Not Been Justified, and Cannot Be Finalized.

Proposed §63.648(j)(4) requires that the CVS and Control Device systems used for RVs that are exempted from the §63.648(j)(1) through (3) requirements meet the requirements in §63.644. §63.644, which is titled "Monitoring Provisions for Miscellaneous Process Vents" and contains requirements that reflect those determined to be appropriate for RMACT 1 Group 1 MPVs (i.e., 98% control). However, those requirements are more stringent than those determined to be applicable to equipment leaks in the RMACT 1 rulemaking (i.e., 95% control) and those are the requirements that §63.648(j)(4) must reference unless the change has been justified under the provisions of section 112(d)(6). RVs are clearly identified as being an equipment leak source in RMACT 1 and they are specifically excluded from the MPV definition. Even in the proposal, RVs complying with §63.648(j)(4) are excluded from the MPV definition. No analysis or justification is presented for changing the equipment leak control device emission limitation from 95% to

98% and thus §63.648(j)(4) cannot reference §63.644, but must reference the same control provisions as are referenced today (i.e., §§60.482-10 and 63.172).

2.4.1.11 There Is No Valid Reason to Add a Method 21 Monitoring Requirement to Proposed §63.648(j)(2)(ii) or to Remove The Current Delay-of-Repair Provision.

Proposed §63.648(j)(2)(ii) reflects the requirements currently imposed by RMACT 1 for rupture disk RVs and RVs that have a rupture disk associated with a valve to assure no leakage when the relief valve is not relieving. The proposed language, however, imposes a new monitoring requirement not in the existing rule and does not include language referencing the delay of repair provisions. Neither of these changes is explained in the preamble and neither is justified; therefore we request these changes not be finalized.

In general, rupture disks are not used in refineries as RVs, but are used upstream of a valve to assure that there is no leakage when the RV is not relieving. Therefore, monitoring serves no purpose and the current equipment leak rules, including RMACT 1, do not require such monitoring. This proposal would impose a 5 day Method 21 monitoring requirement in addition to the 5 day rupture disk replacement requirement. There is no emission or compliance basis for this change, since leakage is not possible.

Under RMACT 1, delay-of-repair of an RV system that includes a rupture disk is allowed if the conditions in §60.482-9 or §63.171, as applicable, are met. This provision is critical for rupture disk RV systems, because it may take a process shutdown to change the rupture disk. In such cases, there is little environmental reason not to allow delay because the rupture disk is a voluntary option and the facility could have just the RV, as long as the <500 ppm limit was met. Therefore, §63.648(2)(ii) should include the delay-of-repair language from NSPS VV and HON, or provide that after a pressure release the owner/operator must within 5 days either replace the rupture disk <u>or</u> demonstrate a leak rate of <500 ppm. This would be equivalent to including the current delay-of-repair requirements for this particular situation.

2.4.1.12 At Least 10 Years is Required to Route All Atmospheric RVs to Flares.

Under this proposal, the prohibition on atmospheric RVs would become effective immediately. However, as discussed, this proposal will require construction of billions of dollars in new and revised facilities and more than 200 new flare systems (and many others to meet the proposed velocity limit during emergency conditions) and even three years will not be adequate. In fact, it is likely more than three years will be needed just to obtain construction permits and Greenhouse Gas (GHG) reviews for all of the additional flares required, given the unpopularity of flares and the emissions increases they involve. If the prohibition proceeds 10 years must be provided. If our recommended work practice approach is adopted up to 3 years is needed to install required monitoring instrumentation and the preventive measures and e18 months is required to develop procedures and systems, train personnel, and institute the recommended RCA/CA approach.

2.4.1.13 Other Comments Related to RVs

1. It is proposed to add a new paragraph (vii) to §63.655(f)(1) to address NOCS reporting requirements relative to RV monitoring. However, this paragraph appears to require information for RVs that are not required to be monitored (i.e., RVs excluded from monitoring by §63.648(j)(4)). The proposed §63.655(f)(1)(vii) needs to be revised to only address RVs in organic HAP service that are subject to the §63.648(j)(3) monitoring requirements. There is no justification or need for listing those RVs that are routed to a process, a fuel gas system, or control.

2. It is proposed to add a new paragraph (10) to §63.655(g) to address periodic reporting requirements for RVs. Again, this paragraph appears to apply to all RVs and not just those subject to monitoring. The §63.655(g)(10) introductory paragraph needs to be revised to only apply the requirements in this section to RVs that are not excluded from the requirements of §63.648(j)(1) – (3) by §63.648(j)(4).

3. Proposed §63.655(g)(10)(ii) reads as follows.

> (ii) For relief valves in organic HAP gas or vapor service subject to §63.648(j)(2), report confirmation that all monitoring to show compliance was conducted within the reporting period.

This wording suggests that monitoring of all RVs to show compliance is required in each semi-annual reporting period. No such monitoring frequency is specified in §63.648(j). Thus, §63.655(g)(10)(ii) should be revised as follows.

> (ii) For relief valves in organic HAP gas or vapor service subject to §63.648(j)(2), report confirmation that ~~all~~any monitoring required to be done during the reporting period to show compliance was conducted~~ within the reporting period~~.

4. Proposed §63.655(g)(10)(iii) requires reporting information on any pressure release to the atmosphere that occurred during the reporting period. It calls for reporting "estimate of quantity of substances released." However, "substances" is an ambiguous word and would include materials that are not pollutants and are not HAPs. Section 112 deals with HAPs and thus this reporting requirement should be limited to estimates of releases of organic HAPs regulated by RMACT 1. Other CAA rules and rules authorized under other statutes are already in place to obtain information on releases of other substances.

2.4.2 It is Unlawful, Arbitrary and Unjustified to Revise the Current Emission Limitation for Open-ended Lines.

EPA is proposing to add §63.648(a)(3) as follows.

> (3) On and after [THE DATE OF PUBLICATION OF THE FINAL RULE AMENDMENTS IN THE FEDERAL REGISTER], for the purpose of complying with the requirements of §60.482-6(a)(2) of this chapter, the term “seal” or “sealed” means that instrument monitoring of the open-ended valve or line conducted according to the method specified in §60.485(b) and, as applicable, §60.485(c) of this chapter indicates no readings of 500 parts per million or greater.

The purpose of this addition is explained in the proposal preamble[141] as follows.

> Refinery MACT 1 requires an owner or operator to control emissions from equipment leaks according to the requirements of either 40 CFR part 60, subpart VV or 40 CFR part 63, subpart H. For open-ended valves and lines, both subparts require that the open end be equipped with a cap, blind flange, plug or second valve that “shall seal the open end at all times.” However, neither subpart defines “seal” or explains in practical and enforceable terms what constitutes a sealed open-ended valve or line. This has led to uncertainty on the part of the owner or operator as to whether compliance is being achieved. Inspections under the EPA’s Air Toxics LDAR initiative have provided evidence that while certain open-ended lines may be equipped with a cap, blind flange, plug or second valve, they are not operating in a “sealed” manner as the EPA interprets that term.
>
> In response to this uncertainty, we are proposing to amend 40 CFR 63.648 to clarify what is meant by “seal.” This proposed amendment clarifies that, for the purpose of complying with the requirements of 40 CFR 63.648, open-ended valves and lines are “sealed” by the cap, blind flange, plug, or second valve when there are no detectable emissions from the open-ended valve or line at or above an instrument reading of 500 ppm.

[141] Later

This provision is proposed to be effective upon publication of the final rule, but based on EPA's claim this is what the word "seal" always meant, would appear to apply retroactively as well.

Promulgating a new interpretation of the word "seal" relative to the OEL work practice impacts every equipment leak work practice in part 60, 61, and 63 and in most State rules and operating permits. This unique interpretation of the requirement to "seal" an OEL with a cap or plug is incompatible with the historical interpretation of this requirement by affected facilities and by the Agency and would reverse the decision arrived at in the recent part 60 subparts VV and VVa rulemakings to not impose an LDAR work practice requirement in addition to or instead of the current equipment requirement. This proposed change would add new, costly, and burdensome work practice requirements, none of which are discussed in the preamble, docket, or PRA Information Collection Request. As a "clarification" of the meaning of the existing OEL RMACT 1 OEL requirement, it would appear to apply to all equipment leak rules and permits containing similar language, also retroactively, imposing massive costs and compliance liability without notice and comment rulemaking.

The entire argument provided in the preamble in support of this proposed change is specious. In the thirty four years this requirement has been in the air rules its meaning has been totally clear. It is only since 2005, when EPA inspectors began asserting this new interpretation that there has been any question about the meaning. If any clarification is needed, it is that the meaning of sealed in this requirement is the same as it was from when it was first promulgated in 1983 until 2005 and how it is currently interpreted by everyone except a few EPA inspectors. This paragraph should not be finalized.

EPA has just confirmed that this is a change and not a restatement of the intent when the provision was promulgated in the final National Emission Standards for Hazardous Air Pollutants: Generic Maximum Achievable Control Technology Standards; and Manufacture of Amino/Phenolic Resins rulemaking.[142] EPA explains in the preamble response to comments that "This [definition] is consistent with how OECA has interpreted the term "seal" during their inspections and is not, as asserted by the commenters, a new requirement." In fact, as explained below, OECA only began interpreting this 1980s requirement this way in 2005, confirming that this is a new interpretation without a regulatory basis. EPA then states "However, to address concerns from the commenters on retroactive compliance, we have added in the final rules that the clarification of the definition of "seal" does not apply until the effective date of the final rules, and therefore will not apply retroactively." Clearly, if a requirement did not apply in the past it is a new requirement."

[142] 79 Fed. Reg. 60916-7 (October 8, 2014)

2.4.2.1 EPA Cannot Legally Replace or Supplement the Broadly Applicable Current OEL Equipment Standard with a New Emission Limitation Standard by Re-interpreting the Meaning of "Seal" in this Rulemaking.

EPA is proposing to "clarify" the equipment leak provisions regarding OEL by adding a definition of the word "seal," relative to the applicable OEL requirements, in §63.648(a)(3). This new definition calls for demonstrating <500 ppm leakage (a condition generally referred to as "no detectible emissions") by monitoring, without changing the requirement to have the OEL capped or plugged. The proposal does not specify any specific monitoring requirements. By claiming this change is only a clarification of current requirements, EPA would 1) make this interpretation applicable retroactively, 2) set a precedent applicable to all OELs in all industries subject to any similar OEL equipment leak requirement, and 3) bypass the need to cite a CAA authorization for this change to the existing section 112(d)(2) standard or meet the process requirements associated with such a change, including providing emission reduction, cost and burden estimates in the record and the associated PRA Information Collection Request (ICR).

Promulgating the proposed language in this rulemaking essentially imposes that "interpretation" retroactively on all refineries and on the thousands of facilities that are subject to similarly worded OEL requirements under any equipment leak rule or permit condition, since the basis for this action is EPA's position that this is what was meant all along[143]. This new interpretation does not comport with EPA's or regulated industry's historical understanding of this requirement and the proposed revision therefore constitutes an illegal change in the requirements for OELs. Such a change can only apply prospectively and must be supported by a CAA authorization and a record that complies with CAA, APA and PRA requirements.

Since the change is described as applying to part 60 subpart VV and part 63 subpart H, it presumably would apply immediately and retroactively to any rule referencing these highly cited subparts, even if it was not presumed to apply to any similar language in other equipment leak subparts. Yet, nothing in this proposal notifies other subpart VV or H subject industries (e.g., chemical, polymer, oil and gas) of this change. Nor does the cost and burden analyses presented to support this proposal address these other industries facilities, much less address all of the facilities subject to equipment leak provisions that are virtually identical.

[143] Part 60 subparts VV, VVa, GGG and GGGa and part 63 subparts TT and UU are the primary other Federal equipment leak rules applicable to the refining and chemical industries and these rules contain the same OEL equipment standard as in RMACT 1.

If the Agency moves forward with this new interpretation of the term "seal" it must repropose, identify the CAA authority for this action, provide cost and burden estimates for this change for all industries subject to equipment leak rules, remove any hint of retroactivity, and follow all the procedures associated with Executive Order 18266, the Regulatory Flexibility Act, etc. since the industry-wide implementation of this new interpretation will certainly make this change a significant and major rulemaking in its own right under those and other regulations.

Moreover, the proposed definition of "seal" is flawed and unwarranted for two further reasons. First, there is no basis for EPA to assert that the proposed definition merely "clarifies" an established interpretation of the term "seal." None of the MACT standards in place before this proposal include such a provision or have stated state or suggest that a "sealed" OEL is one with detectable emissions below 500 ppm. Similarly, EPA has not issued any sort of definitive guidance or interpretation setting out this position. In fact, in the when EPA attempted to provide such "clarity" in a rule (in proposed amendments in NSPS VV in 2006), the Agency plainly presented the new approach as a proposed <u>change</u> to the existing rule.[144]. The fact that EPA has recently finalized such a definition in a parallel rulemaking[145] is not precedential since that rulemaking has not yet passed the window for challenge.

In any event, it is not reasonable for EPA to assert that the existing rules could have been interpreted such that an OEL is "sealed" only if periodic instrumental monitoring demonstrates less than 500 ppm VOC. In and of itself, the term "seal" does not denote such precision. Even in the context of the broader leak detection and repair ("LDAR") rules in which the OEL provisions reside, the bare term "seal" cannot reasonably be construed as imposing some fixed numeric leak definition to be demonstrated with periodic monitoring. The fact that other aspects of the existing LDAR rules <u>do</u> specify such requirements is not, as EPA suggests, evidence that the same definition should be applied to OELs. Instead, EPA's decision not to include such a precise definition of "seal" in the existing rules, in the context of broader LDAR rules that include such precision for other purposes, is a clear signal that the term "seal" cannot reasonably be construed to implicitly incorporate a numeric leak definition and corresponding periodic monitoring requirement.

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[144] *See* 71 Fed. Reg. 65302, 65305 (Nov. 7, 2006) for a discussion of the proposed change to NSPS VV. The final rule (without the proposed change to the OEL provisions) was published at 72 Fed. Reg. 64860 (Nov. 16, 2007). Note that that OEL provisions in NSPS VV are identical in all relevant respects to the OEL provisions at issue in this Proposal. *Compare* 40 C.F.R. §§ 60.482-6(a)(1) and (2) with § 63.1033(b).
[145] 79 Fed. Reg. 60913 (October 8, 2014)

In short, there is no support in the record or otherwise for EPA's assertion that this proposed provision would simply clarify an established interpretation. The proposed definition of "seal" is new and, if finalized, may be implemented only prospectively.

Second, contrary to EPA's assertions in the Proposal, the requirement to cap OELs was never a "zero emissions" standard in the first instance. Instead, as explained in detail below, the requirement is and always has been considered a work practice in the form of an equipment standard. EPA has expressly rejected the idea that a capped open ended line should be treated as a potentially leaking component that should be subject to an LDAR-like periodic leak detection requirement. The existing rules specify that an OEL must be capped with a device that seals the opening. Acceptable capping devices include a cap, blind flange, plug, or second valve. Under existing rules, installation of one of these devices satisfies the obligation to "seal" an OEL. Imposing a "zero emissions" standard with periodic monitoring would transform the work practice into a numeric emissions limitation.

Since OELs are already subject to a MACT standard, EPA must show that imposing a new emissions limitation is justified according to the criteria of § 112(d)(6) – including, for example, an assessment of the costs of imposing the new standard, an estimate of the emissions reductions expected to be achieved, and an explanation of how the costs are reasonable in light of the expected emissions reductions. EPA has provided no such justification in the Proposal. Therefore, the Proposal fails to satisfy § 112(d)(6) and fails to satisfy EPA's obligation under § 307(d)(3) to present with the Proposal a summary of the factual data on which the proposal is based, the methods used to obtain and analyze the data, and the legal basis for the proposal.

2.4.2.2 The 2007 Rulemaking Decision Previously Made on this Issue Cannot Legally be Reversed Through Interpretation.

In 2006[146], EPA proposed to add a "no detectible emissions" limit and monitoring requirement for OELs to part 60 subpart VV, one of the two subparts referenced from RMACT 1 for equipment leaks. EPA provided emission and cost estimates to support the proposed limit and monitoring in a 2007 Notice of Data Availability (NODA)[147]. This action demonstrates that EPA believed as recently as 2007 that this change requires rulemaking. The proposed monitoring was not finalized in either part 60 subpart VV or VVa when that proposal was promulgated[148].

[146] 71 Fed. Reg. 65317 (November 7, 2006)
[147] 72 Fed. Reg. 37157 (July 9, 2007)
[148] 72 Fed. Reg. 64860 (November 16, 2007)

As EPA explained "[t]he proposed requirement to monitor OEL has not been included in the new standards because this requirement has been determined to not be cost-effective. The cost-effectiveness for SOCMI was found to be $3,800/ton for 25 tons/year of VOC emission reductions. For petroleum refineries, the cost-effectiveness was found to be $14,700/ton for 2.4 tons/year of VOC emission reductions. Taking the low emission reductions into consideration, the Agency has determined that monitoring OEL is not BDT."[149] Clearly, on a HAP basis the cost effectiveness would be much worse than on a VOC basis. EPA has not properly considered the cost or compliance liability implications of this proposal and provided those analyses for comment.

2.4.2.3 The Proposed New Definition of "Seal" Does Not Comport with The OEL Rulemakings or With the Regulated Community or Agency Interpretation Over the Past 34 Years.

The part 63 subpart H and part 60 subpart VV OEL standards are equipment standards not emission limitations or work practice standards. As such they do not impose any emission limitation or monitoring requirements and, in particular, do not impose a "< 500 ppm" limit, as the proposed seal definition would. It is clear from the historical record that EPA originally considered imposing a leak detection and repair program on OELs and decided against it and that the OEL requirement has never used the term "seal" in the way proposed here, despite the recent (i.e., since 2005) enforcement actions that have claimed otherwise.

- The OEL requirement was first promulgated in the part 60 subpart VV standard in 1983[150]. The part 60 subpart VV requirements for OELs use similar language to that in part 63 subpart H and in most other equipment leak standards, including use of the word "seal." In the Background Information Document for that original rulemaking, the OEL requirements are discussed in section 4.2, which deals with equipment specifications, rather than in section 4.1, which deals with leak detection and repair standards. The preamble to the proposal indicated that the OEL requirement is an operational standard[151] and reports that alternatives were considered that included monitoring requirements for OEL caps and plugs, but were rejected.

[149] 72 Fed. Reg. 64868 (November 16, 2007)
[150] 48 Fed. Reg. 48328 (October 18, 1983)
[151] 46 Fed. Reg. 1141 (January 5, 1981)

- In evaluating the application of the NSPS VV equipment leak requirements to refineries through NSPS GGG, EPA considered, in response to a comment, applying the valve emission limit and monitoring program to OELs, but specifically decided against taking that action or imposing a leak detection and repair program. They explained their decision as follows.[152]

> Open-ended valves are not included in the valve standards because leak detection and repair for open-ended valves does not represent BDT. Leak detection and repair would achieve less emissions reduction and may cost more to implement than the equipment and operational standards for open-ended valves because of repeated inspections of nonleaking sources. The use of a leak detection and repair program for the control of VOC emissions from open-ended valves or lines would be inappropriate.
>
> The standards for open-ended valves provide refineries with the flexibility to add either a cap, plug, blind flange, or a second valve depending upon the individual application. Pump case valves, for example, could be double valved to avoid the risk of premature failure of the welded connection at the pump case caused by frequent removal of a cap or plug.

- In 1986, Larry Kercher of EPA Region V summarized the NSPS VV requirements in Applicability Determination NR 11 (July 29, 1986). In that determination, the author clearly distinguishes three types of requirements imposed by subpart VV, as follows.

> In general, the standards require: (1) a leak detection and repair program for valves in gas/vapor and light liquid service and pumps in light liquid service; (2) equipment for compressors, sampling systems, and open ended lines, and (3) no detectable emissions (500 ppm as determined by Reference Method 21) for relief valves in gas/vapor service during normal operations.

Thus, the OEL requirements in subpart VV were clearly identified by EPA as equipment requirements and not “no detectible emissions” requirements.

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152 See Petroleum Fugitive Emissions – Background Information for Promulgated Standards, EPA-450/3-83-015b, October 1983, page 2-54.

- This issue was also addressed relative to subpart H on pages 8 and 9 of the 1997 EPA Question and Answer guidance document for the HON rule[153], as follows:

  Issue: Monitoring of caps and plugs on open-ended lines.

  Question: According to section 63.167, owners or operators are required (with limited exceptions) to prevent emissions from open-ended lines by installing a cap, blind flange, plug, or a second valve. Does subpart H require periodic monitoring of all these items for leaks?

  Answer: Subpart H does not require periodic monitoring of caps, blind flanges, or plugs and probably will not require monitoring of a second valve. The reasons for these answers differ, but all begin with the basic point that subpart H requires periodic monitoring only of "equipment."

  1. Caps and plugs: The definition of "equipment" in section 63.161 does not include caps or plugs.
  2. Blind flanges: The definition of "equipment" does not specifically mention flanges, but it does include "connectors." The term "connector" is also defined in subpart H. Many flanges are connectors; i.e., they join two pipe lines or a pipe line and a piece of equipment. However, blind flanges do not. Therefore, they are not equipment.
  3. A second valve: The definition of "equipment" includes valves. However, subpart H applies only to equipment that is in OHAP service at least 300 hours in a calendar year. The EPA does not anticipate that a second valve, when used as the mechanism to prevent emissions from an open-ended line or valve, will be in OHAP service for that many hours. Thus, subpart H will probably not often require periodic monitoring when a second valve is used.

[153] See “Questions and Answers for Subparts H and I of Part 63, Hazardous Organic NESHAP (HON) Equipment Leak Provisions” (May 7, 1997), at http://www.epa.gov/ttn/oarpg/t3/memoranda/honq_aco.pdf

- In 1998, EPA's Office of Enforcement and Compliance Assurance issued a set of inspection manuals for fugitive emission sources[154]. In detailing the requirements applicable to OELs (for instance, on page A-21 of the Refining manual and page A-22 of the SOCMI manual) it is indicated that there is no applicable leak definition for OELs under NSPS subparts VV, DDD, GGG, KKK, and QQQ or part 61 subparts J and V or part 63 subparts H, I and CC or parts 264 and 265 subparts BB[155].
- As discussed in the previous comment, in 2006[156], EPA proposed to add a "no detectible emissions" limit and monitoring requirement for OELs to part 60 subpart VV. This action confirms that the requirement to seal an OEL with a cap or plug did not already include such a 500 ppm limit or monitoring requirement, as is now claimed. Emission and cost estimates to support the proposed monitoring are provided in a 2007 Notice of Data Availability[157] to support the 2006 proposal, demonstrating that such analyses are required to impose a no detectable emissions limit and monitoring for OELs. The proposed monitoring was not finalized in either part 60 subpart VV or VVa, when that proposal was promulgated.
- Until the mid-2000s, EPA issued a multitude of OEL citations for failing to cap or plug an OEL. Only since about 2005 have some of these citations identified a failure to meet a "no detectible emissions" limit as a parameter. Furthermore, in most cases, EPA continues to cite facilities for failing to have a cap or plug in place, without consideration of whether that OEL is leaking at more than 500 ppm. Under this proposed new interpretation, each failure would apparently now be two violations - one for failing to meet the equipment standard and one for failing to meet the 500 ppm emission limitation imposed through this new interpretation.

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[154] See Inspection Manual Federal Equipment Leak Regulations for the Chemical Manufacturing Industry: Volume I: Inspection Manual; Volume II: Chemical Manufacturing Industry Regulations; Volume III: Petroleum Refining Industry Regulations; EPA/305/B-98/011, December 1998

[155] Note part 63 subparts TT and UU were not included in these manuals, since they had not been promulgated at that time.

[156] 71 Fed. Reg. 65317 (November 7, 2006)

[157] 72 Fed. Reg. 37157 (July 9, 2007)

- As recently as March 20, 2014, EPA's Office of Enforcement stated in describing the injunctive relief being obtained through a Consent Decree settling an enforcement action "Monitor open-end lines ("OELs") even though OELs are not required to be monitored under current regulations.[158]"

2.4.2.4 If It Is Demonstrated that Further Control of OELs is Authorized and Justified, The Appropriate Requirement Would Be The Typical Leak Detection and Repair Program (LDAR) Use for Equipment Leaks, Including an Annual Monitoring Requirement and the Normal 5/15 Repair Provisions.

The proposed definition of "seal" requires that a source demonstrate that the OEL is sealed by instrumental monitoring, but does not specify any details of that monitoring. In order to demonstrate an OEL is leaking at <500 ppm, monitoring would certainly be required (on some undefined frequency). This uncertainty is an artifact of trying to impose a work practice requirement through a definition, rather than through regulatory language, and it results in the proposed work practice requirements being unclear and arbitrary.

Given the large number of OELs in refineries and chemical plants, the costs and burdens for monitoring OELs, even infrequently, are substantial, estimated by some refineries to be as high as 20% of their current entire LDAR program cost. These costs and burdens are not addressed in the rulemaking record for this proposal or the ICR for even refineries, much less for all of the other industries impacted by the reinterpretation. Nor does the record include any information on the likely emission reductions associated with this change. The 2007 NSPS VV and GGG rulemaking record suggests any emission reductions would be minimal.

None-the-less, should additional control requirements be shown to be justified and authorized, they should be patterned on the other LDAR programs applicable to equipment leak components. Such a program was proposed in 2006[159] and we recommend it be the basis for any additional OEL controls, if such a program can be justified and after an appropriate notice and comment rulemaking.

[158] See Flint Hills Resources, Port Arthur Clean Air Act Settlement at http://www2.epa.gov/enforcement/flint-hills-resources-port-arthur-clean-air-act-settlement.
[159] 71 Fed. Reg. 65317 (November 7, 2006)

2.4.1.5 If an LDAR program for OELs is Added or the Proposed Definition of "Seal" is Finalized, the Existing Cap and Plug Requirement Must Be Revised to Clarify That It Is Not a Deviation For The Cap or Plug to be Missing Unless Leakage is over 500 ppm.

Under the current RMACT 1 OEL requirements, failure to have a cap or plug in place is a reportable deviation. EPA is proposing to specify that up to 500 ppm leakage is allowed from the interface of a cap or plug with the OEL. Thus, if this proposal is finalized, up to 500 ppm leakage is acceptable. Thus, the current rule language must be revised to specify that if a missing cap or plug is found, sources have 24 hours to monitor the opening and determine if the leakage exceeds 500 ppm. If so, a deviation from the cap or plug requirement would be identified. If not, no deviation would be identified and the source would have to install a cap or plug.

2.4.2.6 If This Proposal Is Finalized At Least Two Years is required For Its Implementation.

While we see no legal or environmental reason for finalizing proposed §63.648(a)(3), should it be finalized, we recommend at least two years be provided for compliance. In order to monitor OELs, those in organic HAP service will need to be identified, tagged and incorporated into monitoring programs and monitoring routes. Since refinery monitoring programs are massive undertakings, involving hundreds of thousands of components, it is a complex task and very costly to incorporate new families of components into the monitoring and repair systems. A year is needed to complete that incorporation. Because of the massive nature of these programs, efficiency requires that monitoring must be spaced out over time. For an annual monitoring frequency, a repeat cycle will take a year. Thus, we recommend a compliance time of at least two years be allowed, should this definition be finalized.

2.4.3 Comments on Optical Gas Imaging

2.4.3.1 API/AFPM Supports the Proposal to Allow Optical Gas Imaging (OGI) in Place of Method 21 and Encourages EPA to Act Quickly on the Required Part 60 Appendix K.

It is proposed to allow OGI in place of Method 21 monitoring for RMACT 1 equipment leaks when Appendix K to part 60, which would provide the approved methodology, is finalized. API/AFPM continues to strongly support this approach, assuming it can be used in place of the very burdensome and costly Method 21 monitoring.

OGI will not be employed routinely unless actual leak concentrations can be determined without using Method 21. Method 21 concentrations are used to determine emissions from equipment leaks, where these emissions are required for emissions inventories. Many refiners use this data and correlation equations to calculate emissions. If EPA were to include leak/no leak factors in the OGI protocol to determine emissions from equipment leaks, emissions would artificially increase as compared to using Method 21 and correlation equations. Until such time as concentrations can be directly determined using OGI, refiners will continue to use and States will continue to require Method 21 to calculate emissions from equipment leaks.

2.4.3.2 Proposed §63.661(a)(2) Should Not Be Finalized

Proposed §63.661(a)(2) requires that the owner or operator be in compliance with the fenceline monitoring provisions of §63.658 in order to make use of the OGI alternative, if the other conditions specified in §63.661(a) are met. This condition is arbitrary, ambiguous, and impractical and should not be finalized.

This proposed criterion is arbitrary because there is no logical or demonstrated relationship between compliance with the proposed fenceline monitoring program and the OGI monitoring program. The proposed fenceline monitoring program in §63.658 is a work practice, so being “in compliance” has to do with whether you performed the tasks required by the work practice and has nothing to do with what fenceline annual average benzene value is measured or whether the specified action level (see Comments 1.3.1 and 1.3.2) is exceeded[160]. OGI is a work practice used to identify leaks from specified types of equipment. There is no technical or logical basis for linking compliance with the tasks in the fenceline work practice program with the tasks in the OGI program.

Ignoring the fact that compliance with these work practices are not linked to emissions, these two work practice programs are not related. Fenceline monitoring deals with an annual average benzene measure for the entire site and OGI deals with short term measurement of a multitude of hydrocarbons from hundreds of thousands of individual potential leak sites. Whether or not a site meets the annual average benzene fenceline action level provides no indication of the status of leakage of any hydrocarbon and short term leakage from individual leak sites has no bearing on the fenceline annual average benzene level. Without a technically

[160] In fact, as proposed an exceedance of the action level can only be a temporary situation, since the rule would require corrective action to reduce the benzene level to below the action level.

sound and demonstrated link between these measurements there would be no basis for linking these two programs, even if compliance with them was somehow linked to emissions.

It is also unclear how this criterion would be applied. The fenceline program deals in two week periods. Thus, compliance status could change every two weeks, but the refinery would not know that status for up to 30 days. OGI will be performed for short intervals at various locations in the refinery periodically, so it is unclear how one would know what the fenceline monitoring compliance status is before a particular OGI is performed. It is also unclear what it would mean if fenceline program non-compliance occurred in between OGI runs for a particular portion of the refinery, but the fenceline monitoring program was in compliance for the two week period during which the OGI scan for that portion of the refinery was performed. Would a fenceline non-compliance only impact the OGI activities for the two weeks of the non-compliance or all OGI activities for an entire cycle of site OGI measurements?

Finally, it is unclear how one could move in and out of the OGI program every two weeks from a practical standpoint. Presumably, when OGI is not being used one must do Method 21 monitoring, but the whole point of OGI is to save the effort associated with Method 21 monitoring. Furthermore, Method 21 monitoring typically takes more than a two week period to complete for any particular unit and takes at least a quarter to complete for an entire refinery. Thus, it would be impossible to switch back and forth for unplanned two week periods, making the use of OGI impractical and therefore forcing sources to simply remain with Method 21 monitoring and not to use the OGI alternative.

2.4.3.3 Relative to OGI, Proposed §63.640(p)(2) Needs to Be Clarified.

The second sentence in proposed §63.640(p)(2) reads as follows.

> Owners and operators of equipment leaks that are subject to the provisions of 40 CFR part 60, subpart GGGa and subject to this subpart may elect to monitor equipment leaks following the provisions in § 63.661, provided that the equipment is in compliance with all other provisions of 40 CFR part 60, subpart GGGa.

It is unclear just which provisions in part 60 subpart GGGa (and through it subpart VVVa) may be replaced by OGI and which still apply. We request that the individual sections be identified as has been done relative to part 60 subpart VV and part 63 subpart H in proposed §63.661(a)(1). Furthermore, the last part of the sentence should be revised to match the wording in §63.661(a)(1) and indicate that facilities still have to comply with the other provisions of subpart GGGa, but not that a facility must be “in compliance” with those other provisions. As discussed in the previous comment, requiring compliance means that sources would have to move in and out of OGI for short periods if a non-compliance occurred. For instance, under the proposed language a failure to perform a single weekly pump check somewhere in the refinery or to have a required record of that check would eliminate the refineries ability to use OGI anywhere at the site. Presumably, if all pump checks and pump check records were performed the following week, OGI would again be permitted, though that is also unclear. Such short term, unplanned switching between OGI and Method 21 is unworkable.

2.4.3.4 Other Comments on Proposed §63.661.

In proposed 63.661(b)(3) paragraph (a)(3) should be referenced, not (a)(2).

2.5 Wastewater Issues

2.5.1 The New Flare Requirements Should Not Be Imposed on Flares through the Wastewater Provisions. Changing the Current Wastewater Standard from 95% DE to 98% Has not Been Justified. The Costs of Imposing the New Flare Requirements on Non-refinery Facilities was Not Considered.

In proposed §63.647(c), it is proposed to apply the new flare provisions to Group 1 refinery wastewater streams where a flare is used to comply with §§61.340 through 61.355 of part 61 subpart FF. However, §61.349(a)(2) establishes 95% removal as the requirement for RMACT waste management unit control devices and the requirements in §60.18 as the removal criterion for flares. Thus, imposing §63.670 and it's presumptive 98% destruction efficiency, is a change in the standard established in the RMACT 1 rulemaking, that has not been justified under CAA section 112(d)(6). Nor has any showing been made that 95% removal is not being achieved by flares complying with §60.18 and that the change is therefore necessary to improve compliance assurance.

Many refinery wastewater streams that require control are treated in facilities owned and/or operated by others. For instance, some refinery wastewater streams are mixed with non-refinery wastewater streams and treated in facilities owned and/or operated by nearby chemical facilities. Other refinery wastewater streams are sent to commercial waste facilities for treatment in compliance with subpart FF requirements. As proposed, §63.647(c) would appear to require any flares at these non-refinery facilities to meet the proposed §63.670 requirements. In most cases, this will drive those facilities to refuse to accept and treat refinery subpart FF streams and impose large costs on refineries to install additional wastewater treatment facilities and even hazardous waste incinerators of their own. Costs could be tremendous, with negligible or no benefits. Thus, the proposed new §63.647(c) should not be finalized and the existing §63.647(c) should be maintained.

2.5.2 API/AFPM Supports the Conclusion that No Changes are Justified Under 112(d)(6) or (f)(2) to the RMACT 1 Wastewater Provisions.

As discussed in the preamble[161], there is no risk driver or technology improvement that would justify revisions to the RMACT 1 wastewater provisions. Application of part 60 subpart FF already imposes stringent treatment and control requirements on refinery wastewater.

2.6 Comments on Proposed Revisions to Requirements on Group 1 Potential Vent System Bypasses.

It is proposed to revise §§63.644(c) and 63.660(i)(2) to prohibit bypasses to the atmosphere and, in §63.644(c), to impose continuous flow monitoring requirements in place of the existing flow indicator requirements for potential bypasses from MPV vent systems and to require a flow alarm and release estimates and reporting when an MPV flow occurs. These new requirements are proposed to be effective immediately.

2.6.1 Most Flows Though Vent System Bypass Lines are Not Violations and There is No Basis For Arbitrarily Declaring That They Are. Arbitrarily Prohibiting <u>All</u> Bypass Flows Would Make Refineries Inoperable.

In proposed §§63.644(c) and 63.660(i)(2), it is proposed to arbitrarily declare <u>any</u> flow through a bypass from a Group 1 MPV vent system or a Group 1 storage tank CVS as a violation, thereby prohibiting use of these bypasses. For instance, in proposed §63.644(c) it states "Use of the bypass at any time to divert a Group 1 miscellaneous process vent stream is an emissions standards violation." However, in most cases such bypasses are done purposely (e.g., as part of a startup or shutdown, control device maintenance, or for some other process purpose) and the bypassed material is routed to a process, a fuel gas system or an alternative control device. While these flows will be detected by the current flow indicators and the proposed flow monitoring, removal of a car seal or opening of a lock, no atmospheric release occurs in such cases and flow through these connections is not an indicator of an uncontrolled release to the atmosphere and certainly is not a violation. Thus, the proposal to declare <u>any</u> flow through a bypass a violation is arbitrary and unsupportable and that proposed language must not be finalized.

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[161] LATER

Even when there is flow to the atmosphere through a bypass, there is not necessarily a violation. For instance, flow through such bypasses to the atmosphere often occurs during startup or shutdown of a process or a particular piece of process equipment and such venting generally contains primarily air or nitrogen. Once a vent stream is primarily nitrogen it can no longer support combustion and must be bypassed around combustion controls to avoid upsetting their operation[162]. Alternative controls may not be feasible and certainly are not justifiable for the minimal HAP release potential in these situations. Use of bypasses are required to maintain refinery operability and clearly cannot be declared a violation if refinery operations are to continue. We deal with the need for an alternate standard to address these types of MSS bypasses in Comment 2.1.2.

Under other circumstances, Group 1 vents may not be going to the vent system at the time other gases in the vent header are bypassed or the flow through the bypass is a start-up or shutdown stream that does not occur during normal operation and is not a Group 1 stream. This situation can readily occur for intermittent Group 1 vents and during MSS situations. These flows are not violations and the proposal to declare <u>all</u> flow through bypasses as a violation is invalid.

As required in 63.655(g)(6)(iii), records of any potential bypasses to the atmosphere must be included in the Periodic Report. Thus, EPA will have (and already gets) the information needed to determine if a violation has occurred. There is no legal or logical basis for pre-determining that all bypasses are violations. Evaluation of the reports for each incident is the appropriate basis for determining if a violation has occurred.

Furthermore, prohibiting bypasses and thereby declaring <u>all</u> bypasses to be violations complicates the management of any unavoidable bypass and required bypasses associated with MSS (See Comment 2.1.2). Control is not always feasible, because of the properties of the stream or the control device and if EPA believes there are feasible controls available for bypassed streams, a CAA justification for imposing them must be provided and cost estimates and emission impact estimates for the to install such control must be provided for comment.

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[162] While this problem can be avoided for flares, it is environmentally unsound and violates the General Duty to purposely burn streams that are primarily nitrogen in flares because of the excess GHG, CO, NOx and HAP emissions resulting from unnecessarily burning hydrocarbons to offset nitrogen's lack of heating value.

To clarify the applicability of §§63.644(c) and 63.660(i)(2) the wording should be revised to only apply the requirements to bypasses that route Group 1 streams to the atmosphere or to a control that does not meet the applicable control requirements of RMACT 1 to that type of emission when they are handling streams that meet Group 1 requirements and are not exempted under the equipment leak work practice. Similarly, bypasses to another process or to fuel gas should be specifically excluded from the requirements in these paragraphs.

2.6.2 Bypasses Around Control to The Atmosphere Are Not A Significant Problem and Reporting Under Federal and State Rules and Facility Permits is Already Required.

Any bypass to the atmosphere of a Group 1 stream, as indicated by the flow indicator required under the existing RMACT 1 for any potential CVS bypass, already has to be recorded and reported under RMACT 1 requirements, under permit reporting requirements, and under a variety of Federal and State release reporting requirements. EPA provides no data and we know of no data from the ICR effort or state emission reports that indicate unplanned bypasses to the atmosphere are frequent or common.

If an unpermitted release to the atmosphere occurs due to a bypass occurrence (or any other cause) reporting of the release and an estimate of emissions is required under EPA Release Reporting Rules, under State Release Reporting Rules and under Federal and State Permit Deviation Reporting requirements. Thus, this proposal adds no new information and only significantly increases the instrumentation costs and burdens associated with these infrequent events.

2.6.3 Defining a Bypass as Allowing Air Intrusion Into a Control Device is New, Unjustified, Technically Flawed, and Ambiguous and Should be Deleted.

In proposed §§63.644(c) and the associated recordkeeping and reporting requirements, bypasses are identified as including occurrences of air intrusion into a control device. This is a new provision and, as far as we know, has never been considered a bypass in the past. No explanation for its addition is provided and, since it does not involve emissions the atmosphere it is unclear how such a definition is justified or authorized. From a technical standpoint, air is added to many combustion control devices to allow combustion to occur and, in the case of flares to improve combustion. In fact, this same proposal regulates air-assisted flares, which presumably would now be prohibited, since the air addition would presumably be a disallowed bypass. Some regulated vent streams include air or oxygen (e.g., some tank vapor spaces and waste treatment unit vapors) and presumably would also not be allowed under this proposal.

Air intrusion into process vapor streams is an issue where it creates a safety concern due to the amount of air or how it is introduced into the process stream or the control. Finally, the phrase is ambiguous, since it would appear any amount of air intrusion would be considered a bypass. Thus, minute, unpreventable leakage into a vacuum system through fittings could be construed a bypass under this terminology, although the leakage is unplanned, uncontrollable, and has no impact. For all of these reasons, a bypass under RMACT 1 must only deal with releases of Group 1 streams to the atmosphere without their passing through a compliant control device, being routed to a process (including the fuel gas process) or being allowed under special circumstances, such as during identified Maintenance, Startup and Shutdown scenarios, and all proposed language associated with air intrusion in this proposal must be deleted.

2.6.4 There are Significant Legal, Technical and Cost Issues Associated With Installing Flow CPMS in Bypass Lines.

2.6.1.1 Flow Monitoring Was Available in the Initial RMACT 1 Rulemaking and Does Not Represent New Technology and Thus is Not Authorized Under section 112(d)(6)

There is no evidence presented in the record to demonstrate this change reduces emissions or increases compliance assurance or is there any indication that the costs and burdens of replacing the current compliance monitoring has been tabulated, published for comment, and justified. Furthermore, since “any” flow is reportable and flow indicators can be equipped with an alarm just as easily as can a flow meter, a flow meter provide no faster indication that there is flow than does an indicator. Finally, no such change is proposed for other potential bypasses and there is no precedent for such a change in other regulations. Thus, there is no legal basis for this proposed change.

2.6.1.2 There are Feasibility and Cost Issues With Requiring Flow Monitors Instead of Flow Indicators.

Proposed §63.644(c) requires flow CPMS in potential Group 1 MPV bypasses and Table 13 requires that flow CPMS installations meet the following requirements.

> Select a representative measurement location where swirling flow or abnormal velocity distributions due to upstream and downstream disturbances at the point of measurement are minimized.
>
> [Meet an accuracy requirement of] ±5 percent over the normal range of flow measured or 280 liters per minute (10 cubic feet per minute), whichever is greater.

Potential bypasses typically have a valve or valves at the point they take-off from the main process line and then an outlet line to the release point. Meeting the swirling flow or abnormal velocity distribution requirements will require revisions of those outlet lines to install long straight meter runs. Such piping revisions come at a significant cost in the typically congested areas where these bypasses are typically located.

The second criterion is to meet the specified accuracy requirement at normal flow. But normal flow is zero. On the other hand, bypass flow may be high. If the meter is set for no or low flow it may serve as nothing better than a flow indicator when there is a bypass and if it is set for the bypass flow it will miss low flows, which are presumably the real interest in having a flow monitor. Table 13 also imposes monthly and quarterly QA/QC requirements that make no sense if there is no flow. It also imposes an annual performance check, which cannot be performed without flow, so one would either fail to perform the required check or have to bypass material to get a flow, which is, under this proposal a violation and would not be good air pollution control practice, in any case.

For the above reasons, a flow CPMS is technically impractical for this service and costly to install and thus not justified versus the existing flow indicator requirement. It is only proposed to require flow monitors for MPVs, while flow indicators remain the requirement for all other emission types. There is no difference between process vent and other bypasses and no technical or compliance basis for changing from flow indicators to flow monitors for any bypass.

2.6.5 Compliance Time and Applicability Dates are Required for the Changes in Bypass Monitoring Requirements.

New flow meter installations and piping revisions will be required wherever flow indicators are currently used for MPV bypass monitoring to meet the Table 13 requirements for these new flow monitors. Such installations must be engineered and three years will be required to make this conversion, if it is finalized.

Furthermore, the prohibition on routing MPV and storage vessel bypasses to the atmosphere will require installation of controls, where such controls are feasible. At least three years is required to identify feasible controls, obtain permits, complete designs, and construct facilities.

Additionally, applicability dates are needed in §63.644(c), if it is finalized to indicate when the flow monitor requirements take effect and when the flow indicator requirements are no longer applicable. It is critical to distinguish current versus future compliance requirements by having clearly articulated applicability dates in the final rule.

2.6.6 Other Comments Related To The Proposed Bypass Provisions.

1. Proposed §63.644(c)(1)(i) and a Table 10 proposed revision requires that the flow monitor "record the volume of the gas stream that bypassed the control device …" However, flow monitors measure flow rates, not volumes and thus this wording is imprecise. The wording should be that the monitor "record the flow rate of the gas stream" and that the estimated volume be calculated from the flow rate data.

2. Proposed §63.655(i)(4) contains the recordkeeping provisions associated with the proposed bypass monitoring requirements. The introductory paragraph appears to apply the recordkeeping requirements to all closed vent system bypasses not just those regulated by §§63.644(c) and to include drains and vents, which are specifically excluded from monitoring by those paragraphs. Thus, we recommend §63.655(i)(4) be revised as follows.

> (4) For each closed vent system that contains bypass lines that are required to be monitored by §§63.644(c)~~could divert a vent stream away from the control device and to the atmosphere, or cause air intrusion into the control device~~, the owner or operator shall keep a record of the information specified in either paragraph (i)(4)(i) or (ii) of this section when Group1 streams are present, as applicable.

3. Proposed §§63.655(g)(6)(iii), 63.655(i)(4)(ii), and Table 10 should all be revised, for the reasons discussed in Comment 2.6.3, to remove references to air intrusion events. Also, as discussed in Comment 2.6.1 most flows through bypasses do not involve regulated materials or releases to the atmosphere and there is no reason to require records or reports unless regulated materials are present and are not routed to a process, fuel gas system or compliant control device. Thus, we recommend that all of these provisions be revised to only require records and reports when a regulated material is bypassed to the atmosphere.

2.7 Comments on Proposed Flare Requirements.

(Details of the API/AFPM Modelling of the 2010 Refinery Steam-Assisted Flare Data are Included as Attachment D-1 and Reports By CleanAir Engineering on Flare Emission Testing and Flare Characteristics are Included as Attachments D-2 Through D-4)

2.7.1 Introduction and General Comments

2.7.1.1 Introduction

Flares are used extensively in refineries to control VOC and HAP emissions. In most refineries, flares and flare headers are designed to control emergency emissions in order to prevent equipment damage and personnel injury, though, as discussed in Comment 2.4.1, some emergency emissions are routed to the atmosphere because of their characteristics and low probability of occurrence. While emergencies that require use of a flare's full hydraulic design capacity are rare, availability of that capacity when needed is critical. Nothing in RMACT 1 should interfere with the reliability of flares as a critical safety tool. For instance, changes that increase flare header backpressure and changes that force operators to choose between safety and environmental compliance must be avoided. No justification has been provided for forcing the construction of tens of billions of dollars in new flares and headers just to meet the new visible emission and flare tip velocity limits during emergency operations. We discuss these issues, as appropriate, throughout these comments.

While flares are designed for emergency loads, many are also used for controlling potential VOC and HAP emissions. In this use, typically a small portion of a flare's capacity is used. When coupled with the NPSP Ja flare standards, which become effective November 2015, the majority of refinery flares will be equipped with flare gas recovery or otherwise operated with little routine vent gas flow. In addition to changes already made to comply with CD requirements, the NSPS Ja requirements, the State and industry focus on improving steam control, will reduce the potential for excess HAP and VOC emissions from flares to extremely low levels. It is critical that EPA recognize and consider the impacts of current and future requirements and provide viable alternative methodologies appropriate to the different flare operating scenarios. That is not accomplished in this proposal because of the restrictions attached to the lower cost alternatives.

Given the significant changes EPA is proposing for flares used to meet RMACT 1 and RMACT 2 control requirements, API/AFPM supports the proposal to consolidate the flare requirements for those flares in the new, proposed §63.670. It is important to recognize however, that not all refinery flares are used as MPV control devices (the only emission type requiring 98% control), consequently the new requirements should only deal with those flares that are used to control MPVs. Other refinery flares only have to meet the 95% destruction efficiency imposed on other emission types. We comment on the proposals to impose the §63.670 requirements on other vent types and other source categories elsewhere in these comments.

Within the refining industry the majority of flares are steam-assisted. Consequently steam-assisted flares have been the focus of EPA's testing program. EPA is prematurely applying new requirements to air-assisted, pressure-assisted, and unassisted flares. EPA has not collected adequate performance data on which to establish or justify limits, has not properly considered the differences in design and use between these flare types and steam-assisted flares, and EPA has not properly evaluated the costs and potential benefits associated with these flare types meeting limits derived for steam-assisted flares. Multi-industry technical flare groups are working with EPA to collect this information, and EPA should give these groups time to conduct their work. It is not good science or sound policy to be establishing potential regulatory precedents in this rule that could inappropriately and adversely impact other flare types in other industries. Thus, §63.670 should only apply to steam-assisted flares used as RMACT 1 or 2 control devices and air-assisted, pressure-assisted, and unassisted refinery flares used for RMACT 1 or 2 compliance should remain subject to part 60 subpart Ja and §63.11 of the part 63 General Provisions.

2.7.1.2 EPA Has Failed to Recognize or Discuss the Massive Costs Imposed by the Flare Portion of This Proposal. Investments Will Be in The Billions of Dollars and Annualized Operating Costs in the Hundreds of Millions.

EPA has significantly underestimated the costs, burdens and additional criteria pollutant, air toxics and GHG emissions resulting from the new flare velocity, visible emission, and combustion control requirements in this proposal. As discussed in detail later in this section, EPA has not accounted for or has grossly underestimated the following costs:

- Production losses associated with flare outages to tie-in new flares and modify existing flares;

- The costs of 500+ new flares (billions of dollars plus millions of dollars per year of operating costs, assuming a 50%+ derate of the 500 existing refinery flares and $20-40M investment for each new flare) that will be necessary to replace the down-rate in flare capacity to meet visible emissions and velocity limits during emergencies. This is in addition to the 200+ new flares needed to control atmospheric relief valves in organic HAP service;

- The costs for new automatic pilot ignition system ($1-2 Billion if all flare are required to add these systems);

- The cost of the supplemental gas ($77 million/year) has been greatly underestimated. Excessive supplemental gas will be required in order (1) to meet the proposed 15-minute averaging period (if this is even possible), (2) to meet the higher combustion zone net heating value limits when the hydrogen and olefin contents of the flare gas exceed the threshold or are unclear, changing or transitioning, and (3) to adjust for EPA's failure to recognize hydrogen's contribution for improving combustion efficiency;
- The costs of the new flare combustion control equipment will result in an annualized cost of total $65 million (See Comment 2.7.3.4.4.1);
- The costs to provide visible emissions evaluators for daily checks and during any smoking incident (greater than $4 million/year assuming $84.95/hr for technical personnel and 30 minutes per day per flare for half of EPA's estimated 510 refinery flares); and
- The costs for replacement/upgrades of existing flare instrumentation to meet inconsistent RMACT 1 CPMS and CEMS requirements (See Comments 1.5.2.5, 1.5.2.8, and 1.5.2.9).

2.7.1.3 A decade is needed to add the new flares and modify existing flares as this proposal requires, if disruption of energy supplies is to be minimized.

The proposed flare tip velocity and visible emissions limits during emergency events and the proposed requirement to install automatic pilot ignition systems will require addition of a large number (i.e., >500) new flares as well as outages and modifications to a large portion of existing flares. To avoid significant disruption of fuel production and to maintain required flare capacity availability for assuring safety during emergency outages, flare outages must coincide with major production unit outages. It takes about a decade to accomplish such coordination.

Similarly, where new flares are being installed because of the down-rating of existing flare capacity imposed by this proposal, production unit outages will be required to allow connection of the new flares to the existing header systems. Shutdown of the production units routed to that existing header will be required to allow the tie-ins, since those production units cannot safely operate without the required flare capacity being available. It takes about a decade to allow maximizing the overlap of these tie-in outages with scheduled production unit maintenance outages.

Even with maximum coordination of flare and production unit outages, some maintenance outages will have to be extended and some extra production outages will be required to complete all of the required flare and flare header revisions and to complete the tie-ins for new flares and flare header systems.

Construction of the large number of new flare systems required for compliance with the new requirements might be accomplished in somewhat less than a decade (excluding tie-ins), if permits are received in a timely manner, there are no community objections to the new flares, and spacing for the new flares is available. As it is unlikely these three conditions will be met in most cases, the construction of the required new flares will take at least a decade.

2.7.1.4 EPA Should Clarify That Refinery Flares are Only Subject to the §§63.670 and 63.671 Requirements When They Are Receiving Group 1 RMACT 1 or Regulated RMACT 2 Vent Streams.

It is important to recognize that not all refinery flares are used as RMACT 1 or 2 control devices and that even where they are RMACT 1or 2control devices that use may be intermittent, consequently the new requirements only apply to refinery flares when they are being used to control regulated vent streams. Refinery flares cannot legally be regulated through RMACT 1 or 2 at other times and other requirements apply at other times and for flares that never receive RMACT 1 or 2 regulated streams.

Examples of refinery flares that never receive RMACT 1 or 2 regulated vent streams include:

- Flares that receive fuel gas where there are no Group 1 *emission points* (as defined in §63.641) routed to that fuel gas system. Only flares that receive gas from fuel gas systems that contain what would be RMACT 1 Group 1 emission point gas if not sent to a fuel gas system should be subject to the RMACT 1 flare requirements. For instance, gas flared from natural gas fuel gas systems and smaller dedicated fuel gas systems that use process gas as fuel for that processes' combustion devices would not be subject to this requirement. (See Comment 1.6).
- Dedicated acid gas flares;
- Dedicated hydrogen plant flares;
- Flares that are dedicated to non-HAP pressure storage (e.g. propane/butane spheres).

2.7.1.5 Compliance With the Combustion Control Requirements in an Applicable Post-2011 Refinery CD Should Be Considered Compliant With The Combustion Control Requirements of §63.670.

Since 2012, at least four refinery companies have entered into consent decrees with EPA that impose flare combustion control requirements along the lines of this proposal, particularly relative to combustion controls. These refiners have made significant investments and are incurring large costs to comply with those CDs. The EPA and the Department of Justice accept that the CD requirements assure 98% DE and so state in most CDs and even make 98% DE a requirement in some. However, there are relatively small inconsistencies and conflicts between the CD requirements and those proposed here, such as in the type, value, and averaging period of the combustion efficiency parameter. In some cases the value for the combustion zone parameter is higher in this proposal than in the applicable CD and in other cases lower. As a result, the combustion control limits (e.g., CZ-NHV) that must be met are different between the two sets of requirements. Furthermore, meeting the CD requirements does not always meet the requirements proposed here and vice-versa. Thus, one cannot just control to either the CD or this rule and must constantly shift between them, even though meeting either one would assure the intended flare DE. This leads to an impossible control and compliance situation and will cause many apparent, but false, deviations under this rule or under the CD and use of additional and unnecessary natural gas supplementation. Such compliance ambiguity is untenable and must be addressed in this rulemaking.

Since 1) CDs are difficult to revise and require Court approval of changes; 2) CD requirements were developed for each specific flare; 3) investments have been made based on the CD requirements; and 4) EPA has already agreed that the CD requirements assure good destruction efficiency (i.e., 98% DE), API/AFPM recommend that compliance with the combustion control requirements in an applicable 2011 or later refinery CD be considered compliance with the applicable §63.670 subparagraphs, i.e. (e), (f), (i), (j), (l), (m), (n), and (o). Similarly, requirements that survived termination of such a CD and are incorporated into a federally enforceable permit. Should also be considered compliance with the applicable §63.670 subparagraphs, i.e. (e), (f), (i), (j), (l), (m), (n), and (o).

In addition, EPA should specifically allow Alternate Monitoring Plans (AMPs) for flares. This would be needed in particular for facilities that may elect to meet alternate requirements such as those in a CD that applies to others but not to the facility in question. For example, this may be the case for a facility that was part of a company that negotiated a CD but which was sold to another corporate entity prior to finalizing the CD; in a case such as this, the equipment may have been purchased and possible installed for compliance with the CD prior to the CD becoming effective. A facility in this situation should not need to re-engineer equipment that has already been purchased, due to differences between its already-purchased equipment and that which would be needed for compliance with the other requirements of this rule.

2.7.1.6 EPA should provide overlap provisions for flares that will be subject to §63.670 of this rule and §60.18 and §63.11.

As proposed, §63.11 of the General Provisions no longer applies via RMACT 1 and 2 once a flare becomes subject to §63.670. However, many refinery flares are subject to the requirements of §60.18(b) and/or §63.11 because they handle regulated material subject to various part 60 or 61 standards and/or part 63 standards other than RMACT 1 or 2. Thus, in revising RMACT 1 it must be made clear that compliance with the new RMACT 1 flare requirements will constitute compliance with §60.18 and §63.11 requirements, including any associated recordkeeping and reporting requirements, that may apply to that flare through other regulations.

Addressing this conflict is important because there are elements of §60.18 and 63.11 that conflict with or are inconsistent those of §63.670. For example, in §60.18 averaging times are not specified and could be viewed as instantaneous or otherwise inconsistent with §63.670. §60.18 also requires that flares are operated and maintained in conformance with manufacturer recommendations, while §63.670 specifies particular operating and maintenance requirements.

2.7.1.7 It is Unclear What Flares are Air-Assisted Flares.

No definition of Air-assisted flare is proposed. Rather, the following definition of assist air is proposed for §63.641.

> *Assist air* means all air that intentionally is introduced prior to or at a flare tip through nozzles or other hardware conveyance for the purposes including, but not limited to, protecting the design of the flare tip, promoting turbulence for mixing or inducing air into the flame. *Assist air* includes premix assist air and perimeter assist air. *Assist air* does not include the surrounding ambient air.

This definition appears to include air assist that is used to improve combustion in some flares, where air addition is the only combustion improver and other flares where air and steam are both added as combustion improvers. A specific definition of "air-assisted flare" is needed to distinguish those flares from steam-assisted flares, with some air addition. Furthermore, it must be clear that the air addition is for the purpose of aiding combustion, not incidental air addition due to entrained air in the steam, from process sources, or leakage of instrument air.

2.7.2 There Is No Justification For Imposing The Proposed, Revised Requirements on Air-assisted, Pressure Assisted, and Unassisted Flares and These Should Remain Subject to §63.11.

According to EPA[163], based on ICR data, approximately 80% of the elevated flares in refineries are steam-assisted, 10% are air-assisted, and 10% are unassisted. The ICR and API/AFPM's own information indicates that air-assisted and unassisted flares tend to be used in isolated locations (e.g., at tankfields and loading racks) and situations (e.g., loading) where flows are intermittent, utilities and access to data systems may be limited, and flare gas compositions are typically well characterized compared to general refinery flares.

Air-assisted and other flare types (e.g., pressure-assisted, unassisted) are frequently found in other industry sectors such as chemicals and O&G production. To avoid setting adverse precedents based upon hastily developed standards that EPA has completely failed to justify, EPA should not proceed with combustion efficiency limits for these types of flares at this time. Rather, EPA should continue to work with these other industry sectors and collect the performance data and cost information required to establish meaningful, data driven standards.

2.7.2.1 There Has Been No Demonstration That Air-assisted Flare Requirements Need To Be Revised or That The Proposed Revisions are Cost Effective and Thus Air-Assisted Flares Should Remain Subject to §63.11.

API/AFPM, like EPA, recognizes that in theory air-assisted flares can be "over-assisted" and EPA has gathered very limited data from PFTIR studies that demonstrate this effect under artificial test conditions. However, EPA does not provide and we know of no data demonstrating that such occurrences are common or even occur in practice, if §63.11 requirements are being met. Air-assisted flares typically only have to meet the 95% DE applicable to storage, loading, equipment leak and wastewater emissions, though there is no data to demonstrate that they fail to meet EPA's 98% DE intent as long as the current 300 BTU/SCF minimum flare gas heating value in §63.11 is met. No justification is presented for imposing the 98% DE intent applicable to MPVs on flares that do not handle MPVs. Air-assisted flares are much lower capacity than the large steam-assisted flares typical of refineries and are designed for well-defined and

[163] Docket ID EPA-HQ-OAR-2010-0682-0206 *Petroleum Refinery Sector Rule: Operating Limits for Flares*, Dec 12, 2013, page 9.

limited services (e.g., loading of products) at relatively well defined rates and thus typically are not operated at high turndown with large excesses of air. Thus, the assumption made by EPA that the emissions impacts they forecast for steam-assisted flares are applicable to air-assisted flares is invalid.

Despite a long theoretical discussion, the data in the docket does not show that the dilution factor approach proposed is any better correlated with CE and DE than is the stoichiometric ratio approach originally considered by EPA and found lacking[164]. Four sets of CE data are available for air-assisted flares from two studies. As demonstrated in Figures 5 and 6 of Docket Document EPA-HQ-OAR-2010-0682-0206, there is clearly no consistency between these very limited data sets and thus no basis for using them for rulemaking.

It is also clear from EPA's own analysis that air-assisted flares are different from steam-assisted flares and that the available data is inadequate for regulation. EPA recognizes in the April 2012 technical report, Parameters for Properly Designed and Operated Flares, that it inadequately treated air-assisted flares by attempting to predict vent gas destruction efficiency via solely the stoichiometric air ratio. By concluding that the flame is a diffusion flame and the flare tip diameter is a major function in predicting the amount of perimeter assist air required, EPA also implicitly recognizes that the flare tip region is not well mixed. Thus, the amount of perimeter air required will be a function of flare tip design, vent gas and perimeter assist air velocity, among other possible factors. EPA also implicitly admits this point by using inconclusive terms in the preamble (page 36907), such as "suggest", "makes sense" etc. Additionally, at low tip velocities both vent gas and perimeter air flows may be only barely turbulent, or possibly even laminar. In such cases much of the assist air will not enter into the combustion process, and thus the equations proposed for calculating CZ-NHV are incorrect.

In addition to providing no demonstration that an emission reduction or increased compliance will result from this proposal for air-assisted flares, EPA has provided no demonstration that cost effective control methodologies are available, particularly since there is no steam savings credit available. For steam-assisted flares, steam savings can provide a return on the substantial investment needed to control the flare tip heating value. No such credits are available for air-assisted flares.

Air-assisted flares are constructed differently from steam-assisted flares and details of monitoring and control approaches have not been identified by EPA and shown to be feasible or cost effective, particularly for existing installations. Unlike for steam-assisted flares, air-

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[164] Op. Cit., page 18.

assisted flares typically have air blowers that are close-coupled to the flare stack. Thus, there is no mechanism for installing flow meters or control stations between the blower and the flare stack. Air is typically controlled by varying the blower speed and the air flow estimated as the blower design flow at the fan speed. In the absence of flow meters, fan speed and the blower design curve are used to estimate air flow. Because of their nature and the equipment typically available when air-assisted flares were installed, the blower speed is typically controllable only at a couple of increments.

For instance, the blower may only have controls to operate at an off, low speed, and high speed setting. In order to meet the proposed combustion control requirements for these flares while still preventing smoking, the blower motors and motor controllers will need to be replaced to allow continuous blower speed control. Flow meters may be required unless use of design curves is allowed. EPA has estimated $164,000 investment per air-assisted flare for air flow monitoring and control. No information on the development of these estimates is provided, but they typically should include costly digital control system and electrical system modifications. As we discuss in Comment 2.7.2.1, one API member has developed scoping quality cost estimates for a few air-assisted flares that indicate a cost in excess of $2,000,000 per flare will be required for air control, including the rental of a temporary flare while flare modifications are installed. This cost, is in addition to the costs associated with monitoring the flare gas heating value and H_2/olefin content as required by §63.670. Nor does it appear natural gas supply and addition controls been included in the cost estimates, a significant cost since natural gas is not already available in many of the remote areas where air-assisted flares are located.

2.7.2.2 No Need or Basis for Revising The Flare Gas Requirements for Unassisted Flares Has Been Demonstrated and Thus These Flares Should Remain Subject to §63.11.

By definition, unassisted flares cannot be over-assisted and there is no data demonstrating that unassisted refinery flares do not typically meet the 95% destruction efficiency generally applicable to the types of emissions this flare type typically handles (i.e., storage and transfer emissions) or, for that matter, that they fail to meet EPA's 98% DE intent. Nor has EPA provided any demonstration that adding natural gas to raise flare gas heat content is cost effective for these flares. Clearly, adding natural gas with little or no change in DE would increase GHG emissions. Unassisted flares are lower capacity than the large steam-assisted flares typical of refineries, are designed for well-defined services at well-defined rates, and thus typically are operated regularly and at relatively high rates compared to their design capacity. As a result they may, in fact, handle just as much VOC and HAP in a year, as a large steam-assisted flare.

Thus, the assumption made by EPA that the emissions impacts they forecast for steam-assisted flares are applicable to unassisted flares is invalid.

Nor does the limited data EPA has included in the record demonstrate that any change is justified in the current 200 BTU/SCF flare gas limit. The one available dataset for unassisted flares shows that the current limit achieves more than 98% DE and EPA had to include extraneous steam-assisted flare data in their analysis in order to suggest a change is needed[165]. EPA explains the addition of the steam-assisted flare data to the analysis by stating:[166]

> [A] steam-assisted flare will become unassisted if the assist steam is turned off.
>
> …
>
> the data for steam-assisted flares covers a much broader range of operating conditions than the data for non-assisted flares. Therefore, the operating limits established for steam-assisted flares are expected to ensure compliance over this broader range of operating conditions. Based on the data for steam-assisted flares, it is evident that a 200 Btu/scf NHV_{cz} limit would not ensure compliance with the 98 percent destruction efficiency requirement at all times.

The fallacies with this argument include the following:

1. Steam-assisted flares and unassisted flares have totally different designs and there is no engineering basis for extrapolating from one design to the other and because of the design differences a steam-assisted flare does not become an unassisted flare when the steam is off[167].
2. Unassisted flares do not have assist gas that dilutes the flare gas or changes its heating value or mixing characteristics at the tip.
3. Unassisted flares are lower capacity than steam-assisted flares and typically handle known, well characterized flare gas, so they do not operate over the wide range of conditions common for steam-assisted flares and this is another significant difference between an unassisted flare and an assisted flare with the steam off.

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[165] Op. Cit., page 25.
[166] Ibid.
[167] Flow and mixing characteristics at the tip of a steam-assisted flare with no steam addition are totally different than at an unassisted flare tip for the same flare gas situation, because the steam-assisted flare is designed for the addition of steam and is typically much larger diameter than an unassisted flare tip and thus the steam-assisted flare tip has a different geometry, open area and pressure drop than an unassisted flare tip.

4. Unassisted flares typically only have to achieve 95% DE to meet the emission limitation applicable to the flare gases they handle.
5. The test data specific to unassisted flares shows >98% DE at 200 BTU/SCF[168].

EPA has provided no data in the record to demonstrate that natural gas addition is cost effective for unassisted flares, since they have not evaluated unassisted flares separately from assisted flares. The record contains no estimate of the expected VOC and HAP emission reductions or GHG emissions increases resulting from the addition of natural gas to reach the proposed limits and the data for unassisted flares in the docket does not indicate any significant change in DE will result from a 270 BTU/SCF or 380 BTU/SCF limit versus the existing 200 BTU/SCF limit. Nor does it appear natural gas supply and addition controls been included in the cost estimates, a significant cost since natural gas is not already available in many of the remote areas where air-assisted flares are located.

2.7.2.3 Pressure Assisted Flares Should Not Be Subject to §§63.670 or 63.671.

Pressure-assisted flares utilize the pressure and velocity of the flare gas stream, up to sonic velocities, to create turbulent mixing and induce voluminous quantities of air to assure complete combustion. These flare tips emit reduced levels of radiation and can be placed at lower, less visible elevations, and thus can be less costly to install and maintain than elevated flares and thus are becoming popular where space is available. Pressure assisted flare tips are also used as part of ground flare arrays, where there may be small first stage that operates continuously and may be assisted, but pressure assisted stages are activated as load increases.

On page 7-2 of its summary of flare information for the peer technical review[169], EPA concluded that there is inadequate information to identify the operating parameters that would assure good combustion in these flares. They state:

> Because of lack of performance test data on pressure-assisted flare designs and other flare design technologies, and given the uniqueness in design of pressure-assisted flare designs from non-assisted, steam-assisted, and air-assisted flares (and across the population of pressure-assisted flares), it seems likely that the observations made in this report for non-assisted, steam-assisted, and air-

[168] Op. Cit., Figure 10.
[169] Docket ID EPA-HQ-OAR-2010-0682-0191, US EPA, *Parameters for Properly Designed and Operated Flares - Report for Flare Review Panel*, April 2012, page 7-2

assisted flares, cannot be applied to pressure-assisted flare designs or other flare design technologies. Also, test data are not available to form general conclusions on operating parameters that represent good combustion for these other flare designs.

The peer review panel supported EPA's analysis of the available information. Thus, by EPA's own analysis there is no technical basis for applying proposed §§63.670 and 63.671 to pressure assisted flares and we therefore request that they be excluded from the new requirements and that EPA develop and propose separately requirements for this type of flare.

2.7.3 Comments on the Proposed Combustion Control Requirements.

Proposed §63.670(e) imposes continuous flare tip combustion parameter requirements. Three alternative parameters are specified, as follows.

- The combustion zone net heating value (CZ-NHV) must be ≥270 BTU/SCF or if, 1) the concentration of hydrogen in the combustion zone is >1.2 vol%, and 2) the cumulative concentration of olefins in the combustion zone is > 2.5 vol%, and 3) the cumulative concentration of olefins plus hydrogen in the combustion zone is > 7.4 vol%, the CZ-NHV value must be ≥270 BTU/SCF.

- The combustion zone lower flammability limit (CZ-LFL) must be ≤0.15 vol fraction or if, 1) the concentration of hydrogen in the combustion zone is >1.2 vol%, and 2) the cumulative concentration of olefins in the combustion zone is > 2.5 vol%, and 3) the cumulative concentration of olefins plus hydrogen in the combustion zone is > 7.4 vol%, the CZ-LFL value must be ≤0.11 vol fraction.

- The combustion zone combustibles concentration (CZ-C) must be ≥0.18 vol fraction or if, 1) the concentration of hydrogen in the combustion zone is >1.2 vol%, and 2) the cumulative concentration of olefins in the combustion zone is > 2.5 vol%, and 3) the cumulative concentration of olefins plus hydrogen in the combustion zone is > 7.4 vol%, the CZ-C value must be ≥0.23 vol fraction. (Note: As we discuss in Comment 2.7.3.6.1, this is not a viable alternative since EPA places a 60 ft./sec velocity limit on flares using this option.)

The proposal adds an additional set of criteria for air-assisted flares such that these flares must meet one of the three combustibility parameters AND an associated dilution parameter. We discuss the lack of data to support regulating air-assisted flares separately and strongly recommend that any combustion regulation only address steam-assisted flares.

In this section (2.7.3) we comment on the proposed combustion zone requirements and their claimed emissions and cost impacts. We focus on the CZ-NHV alternative limits in this analysis, as EPA did in their analysis, but believe those results are representative of all three approaches.

To support our initial analysis of flare issues, API/AFPM gathered actual operating data (typically a year's worth from 2010) from 24 steam-assisted flares at 9 refineries owned by 6 different companies. Study details are provided in Attachment D-1. Details of EPA's study of a broader set of flares that included the same 24 refinery flares and 14 non-refinery flares are provided in Docket Document EPA-HQ-OAR-2010-0682-0209[170] . Data on the 14 non-refinery flares is not pertinent to a refinery flare rulemaking, so those flares were not included in the analyses reported here. We evaluated the costs and emission impacts of reducing steam and, where necessary, adding natural gas, to achieve various heating values at the flare tips for the 82 operating scenarios identified for these 24 refinery flares. The results of our initial analysis of these flares were presented to EPA and are included in the above cited docket document. EPA indicates they used this data, other industry data, and data developed through the Petroleum Refinery ICR data collection effort in developing the final proposal. Our comments are based on an updated analysis of this data, our evaluation of the ICR flare data, and the information presented by EPA to explain its proposal and the specifics of EPA's proposal, which are quite different from the basis for our original analysis.

Our evaluation is focused on steam-assisted flares, since this represents the vast majority of refinery flares (~80%) and, as discussed previously, the available data does not demonstrate air-assisted or unassisted flares do not meet the 95% destruction efficiency floor applicable to the types of emissions routed to such flares or the 98%[171] DE intent established by EPA.

Finally, API/AFPM enlisted the aid of flare combustion experts, Scott Evans and Robert Spellicy, who helped develop the PFTIR technology and have participated in much of the flare test work that has been conducted to date. These experts identified serious issues with EPA's analysis of the flare test data and raised significant concerns with the proposed requirements. Their reports are included as Attachments D-2 though D-5 to these comments.

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[170] Coburn, J. (RTI International) to Bouchard, A. and Shine, B. (EPA), *Petroleum Refinery Sector Rule: Flare Impact Estimates*, January 16, 2014, Docket EPA-HQ-OAR-2010-0682-0209, Attachment 2.

[171] A destruction efficiency of 98% corresponds to a combustion efficiency of 96.5% and a destruction efficiency of 95% corresponds to a combustion efficiency of approximately 93.5%.

2.7.3.1 The Claim That Flares Must Meet a 98% Destruction Efficiency (DE) at All Times (i.e., Every 15 Minutes) is Invalid. This Significant Change in the RMACT 1 112(d)(2) and (d)(3) MACT Floor Cannot Be Finalized as Proposed.

On page 36905 of the proposal, EPA argues that flares have historically been expected to provide 98% DE and that that was the basis for establishing the floor for RMACT 1 MPVs and then claims that "these amendments are necessary to ensure that refineries that use flares as [Air Pollution Control Devices] meet the MACT standards at all times when controlling HAP emissions." [172] Page 36942 specifically states:

> In this proposed rule, under CAA sections 112(d)(2) and (3), we are proposing operating and monitoring requirements to ensure flares achieve the 98-percent HAP destruction efficiency identified as the MACT Floor in the initial MACT rulemaking in 1995.

The fallacies with this claim and the use of it to set the flare combustion control requirements are:

1) the unsupported extension of the historical expectation, which was a typical operation expectation, to an every 15 minute minimum requirement,

2) the incorrect claim that the MACT floor for MPVs was established as 98% at all times, when, in fact, it was a daily average, and

3) the imposition of this MPV floor (98% DE) for emission types with a 95% DE floor.

It is the historical flare performance expectation and the 1995 MACT floor that should be the basis for the averaging time that applies to the 98% DE intent for flares, since compliance must be demonstrated with the historical intent and the RMACT 1 MPV floor, not with an arbitrary expectation of control device capabilities as is proposed.

While 98% DE may have been EPA's overall intent for flares, in fact, the floor for flares used to control RMACT 1 MPVs was the requirements in §§63.11 and 60.18, which do not specify a DE requirement and reflect normal operations (since both part 60 and part 63 excluded SSM from normal emission limits.) Furthermore, the RMACT 1 MPV floor for non-flare combustion

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[172] They make a similar incorrect claim on page 36912 of the preamble, stating "we are proposing operating and monitoring requirements to ensure flares achieve the 98-percent HAP destruction efficiency identified as the MACT Floor in the initial MACT rulemaking in 1995."

devices was established as 98% DE or 20 ppm TOC as a daily average (for continuous compliance) or a 3-hour average (for performance tests) and that floor would be the flare floor, had it been possible to measure stack emissions for flares. Page 14 of Docket Document EPA-HQ-OAR-2010-0682-206 specifically states that the intent is "that the flare achieves an equivalent performance to other thermal destruction devices that can be used to comply with the refinery NESHAP." Imposing a 15 minute average on flares is not "equivalent" to the performance requirement for other combustion devices. Finally, the RMACT 1 floor for emission types other than MPVs is 95% DE, typically as a daily average or 3-hour average.

The §63.11 minimum heat capacity and maximum velocity work practice limits were originally proposed during the NSPS VV rulemaking in the early 1980s and were expected to result in at least 98% VOC DE during typical operation. This was the basis on which these work practices were set[173] and they were more than adequate to achieve the 95% DE required for NSPS VV emission sources and, in fact, 95% DE is still the intent for all emission types except process vents, for which a 98% DE floor was set.

On page 36905 of the preamble, EPA cites its statement in the RMACT 1 final rule preamble about the basis for establishing the 98% MPV limit for MPVs in RMACT 1 as follows.

> … data analyses conducted in developing previous NSPS and the [National Emission Standards for Organic Hazardous Air Pollutants (40 CFR part 63, subparts F, G, and H)] HON determined that combustion controls can achieve 98-percent organic HAP reduction or an outlet organic HAP concentration of 20 ppmv for all vent streams. (59 FR 36139, July 15, 1994).

However, the HON rule and subsequently the RMACT 1 rule established the 98% DE as a daily average for combustion controls, when determined continuously by parameter monitoring and as a three hour average when demonstrated by performance test[174]. Proposing a 15 minute average instead of a daily average, or at worst a three hour average, on flares is a clear, unauthorized change in the RMACT 1 emission limitation for MPVs and thus could only be authorized under section 112(d)(6), a showing that has not been made and is not possible since there is no data to show that a 15 minute average would meet (d)(6) criteria or is even feasible, much less "achieved in practice" as required by section 112(d)(3).

[173] 48 Fed. Reg. 48334 (October 18, 1983)
[174] See §63.655(g)(6)(i).

On pages 36909 and 36910, the Agency argues that that the potential for rapidly changing flare conditions justifies such a short averaging time, while in the same discussion admitting that the instrumentation is incapable of allowing control on this time scale and explaining that they have therefore imposed a mathematical construct (feed forward calculations) to provide relief when the data falsely shows a deviation. We discuss the fallacies with this artificial calculation approach in Comment 2.7.3.6.2. All of this, however, misses the point that it is compliance with the MPV floor that must be demonstrated, not some newly imposed limitation based on claimed control device monitoring capabilities. Changing the averaging time established in 1995 for the MPV floor is a significant change in the stringency of the MPV limitation established pursuant to §section 112(d)(2)and (3) and cannot be done without demonstrating that it is achieved in practice and meets all of the CAA section 112(d)(6) criteria, including cost effectiveness.

Considerable field testing has been done recently to evaluate the combustion efficiency (CE), and thus the DE, of steam-assisted refinery flares. This field testing confirms the original early 1980s small diameter flare testing studies that showed CE and DE are degraded if the heating value of the flare gas at the flare tip is low, either due to process effects (e.g., dilution of hydrocarbon with nitrogen used in gas freeing equipment) or over addition of steam. It was those 1980 studies which were the basis for the current 200 (unassisted flare) and 300 (assisted flare) BTU/SCF flare gas heating value (prior to assist gas addition) criterion. The 300 BTU/SCF limit was presumably meant to adjust the 200 BTU/SCF minimum for the typical dilution impact of assist gas on the heat content of the flare gas. In finalizing those limits, EPA specifically considered the issue of over-steaming and concluded it was not likely to significantly impact the overall performance of flares[175]. That is, in establishing the intent of 98% DE for flares in the 1980s EPA looked at it as a typical or average value, not as an instantaneous or even a short term target. Imposing a 15 minute average for the parameters that indicate CE and DE is an unjustified change to the original flare performance expectation.

The issues relative to flare combustion, then, are 1) is low heating value at the flare tip a common enough occurrence to require additional compliance assurance beyond the §63.11 requirements and 2) does the minimum heating value limit need to be revised to provide reasonable assure that 95% destruction of HAP is achieved (98% for MPVs) as a daily or three hour average. We believe that EPA has failed to demonstrate that the minimum heating value

[175] See US EPA, *Distillation Operations In Synthetic Organic Chemical Manufacturing- Background Information For Proposed Standards*, EPA-450/3-83-005a, December 1983, pages 4-15 to 4-19.

limit needs to be revised, but they have demonstrated that for some steam-assisted flares, the risk of not achieving that minimum heating value at the flare tip is high enough to require additional compliance assurance (i.e., by moving the point of determination for the heating value to the flare tip for steam-assisted flares).

2.7.3.2 Poor Destruction Efficiency is not a Widespread Problem.

In Docket Document EPA-HQ-OAR-2010-0682-206[176], it is attempted to explain the need for the proposed new flare operating requirements. While extensive data from the testing of steam-assisted flares is presented and it indicates that poor combustion can occur if flares are over-steamed, nothing is provided that indicates the prevalence of over-steaming during normal operation or the potential impact of that over steaming.

While the 24 refinery flares for which API/AFPM obtained 2010 data cannot be demonstrated to be representative, it does provide some insight into the prevalence of the concern for steam-assisted flares. The overall DE for the 82 operating scenarios studied by API/AFPM was 96.2% using the EPA relationship for CE and CZ-NHV.

Since 2010, EPA has promulgated NSPS Ja, which will require flow monitoring of flare gas and flare gas minimization. EPA's flare initiative (imposed through Consent Decrees) and State efforts have addressed the over-steaming issue and thus operations have improved from the 2010 study and it is clear that >98% DE is already being achieved by steam-assisted refinery flares. Thus, there is little justification and little potential HAP emission reduction to be achieved by overly stringent combustion control requirements. In fact, addition of natural gas beyond the minimum necessary to achieve the minimum intent will result in unnecessary emissions of criteria pollutants and greenhouse gases.

As discussed in Comments 2.7.2.1 and 2.7.2.2, there is no data showing that air-assisted or unassisted flares in refineries are not achieving the DE required by RMACT 1.

2.7.3.3 The Base Line Flare HAP Emissions Are Overstated. API/AFPM Estimates 2015 Refinery Baseline Flare Emissions of 22,300 TPY VOC and 2,560 TPY HAP versus EPA's 2010 Estimate of 38,600 TPY VOC and 4440 TPY HAP.

Details of the baseline and post-control emission estimates are provided in Docket Document EPA-HQ-OAR-2010-0682-0209 and the comments in this section are based on that document

[176] Coburn, J. (RTI International) to Bouchard, A. and Shine, B. (EPA), *Petroleum Refinery Sector Rule: Operating Limits for Flares*, December 12, 2013, Docket EPA-HQ-OAR-2010-0682-0206.

and our own revised calculations, which are discussed in Comments 2.7.3.4, 2.7.3.5 and Attachment D-1.

Base line refinery flare Volatile Organic Compound (VOC) emissions for 2010 were calculated by EPA to be between 9,500 and 15,200 tons per year (TPY), with a mid-range value of 12,600 TPY based on the refinery flare emissions reported for that year under the GHG reporting rule and assuming a 98% flare DE. The range is based on assuming different ethane (non-VOC) concentrations in the flare gas, ranging from a low of 5% to a high of 20%, with a mid-range value of 12%. EPA reports that the mid-range estimate is consistent with the value derived from the 2010 data collected in the Refinery ICR effort as reported on page 5 of Docket Document EPA-HQ-OAR-2010-0682-0209 and EPA therefore settled on this value as their baseline VOC estimate for refinery flares. Flare Volatile Organic HAP (VOHAP) emissions were estimated to be 11.5% of the flare VOC from the ICR emission inventories (Component 2), resulting in a 2010 baseline VOHAP estimate of 1,450 TPY. These were the base line estimates used by EPA to evaluate their combustion control proposal.

However, this 2010 base line must be adjusted before serving as the basis for Sector Rule estimates. On September 12, 2012, EPA finalized amendments to NSPS Ja, the Petroleum Refinery New Source Performance Standard[177]. Those amendments impose requirements on refinery flares that significantly impact emissions[178] and the Sector Rule base line must be adjusted for those impacts since the compliance date for the NSPS Ja requirements is November 15, 2015. The NSPS Ja rule includes special modification provisions for flares that will make most refinery flares subject prior to the Sector Rule compliance date for flares. Furthermore, EPA has taken credit for the impacts of the NSPS rule monitoring requirements in developing the Sector Rule cost estimates and it therefore must take account of those impacts on the emissions side.

EPA estimated in the preamble to the NSPS final rule that the flare requirements would reduce flare emissions by 3600 tons per year of VOC. While this is a fifth year estimate (i.e., 2017), that is still before the expected 2018 compliance date for the Sector Rule. Correcting the Sector Rule 2010 baseline emissions estimate for NSPS Ja impacts, reduces the VOC baseline to 9000 TPY VOC and 1035 TPY HAP. This adjustment applies to all flare types, since the NSPS Ja requirements address flow to the flare, regardless of whether the flare is unassisted, air-assisted, or steam-assisted.

[177] 77 Fed. Reg. 56422 (September 12, 2012)

[178] Primarily through a flare gas minimization requirement and a work practice requirement that imposes root cause analysis and corrective actions if flow to a refinery flare or collection of refinery flares exceeds 500,000 SCF above baseline in a day.

In addition, since 2010, several refiners have entered into flare consent decrees with EPA[179]. The agreements with Marathon, Shell Deer Park, Flint Hills Port Arthur, Countrywide and BP Whiting covers 48 flares (about 10%) of refinery flares and required reductions that are claimed by EPA to achieve 98% DE for those flares. Because of the overlap between the CD requirements and NSPS Ja requirements a quantitative adjustment cannot be made to the Sector Rule base line for their impacts. However, the base line should be somewhat further reduced and the impacts of the CD must be reflected in the cost and emission reduction estimates.

After establishing the base line HAP emissions from the GHG emission reports, EPA adjusted those emissions to reflect their estimation, apparently based on their analysis of the API/AFPM dataset, that refinery flares were achieving 93.9% DE in 2010, rather than the 98% DE on which the GHG emission report was based. On this basis the EPA estimated base line for refinery flares was increased form 12,600 TPY VOC to 38,600 TPY and from 1450 TPY HAP to 4440 TPY[180]. Applying the NSPS Ja reductions discussed above, API/AFPM would estimate the adjusted base line should be 27,600 TPY VOC and 3,170 TPY HAP.

The 93.9% DE estimated by EPA was derived from EPA's analysis, using the calculation procedure described in Comment 2.7.3.4.1.2, on the 2010 data provided by API on 38 flares. EPA reports they adjusted the API/AFPM dataset, by removing two olefin plant flares and some individual operating scenarios that they believe represent only purge gas operation. Thus, the dataset used by EPA apparently included 12 chemical industry flares in addition to 24 refinery flares. While API/AFPM supports not applying the new requirements to purge gas only operations (See Comment 2.7.1.4), it is incorrect to remove it from this analysis for the following reasons; 1) purge gas is included in the flare gas flows for all operating scenarios, 2) steam reductions and possibly natural gas addition will be required to meet the proposed emission limitations if flare minimum steam rates dilute the purge gas significantly, 3) GHGs and other combustion byproducts are generated from purge gas combustion and are reflected in the GHG basis for flare emissions used by EPA to estimate emissions in their analysis, 4) some purge gas does contain some VOC, and 5) the control scheme will have to operate at all times because some regulated material may be present and because events can happen at any time

[179] Flare specific consent decrees now cover 22 flares at 6 Marathon refineries, 12 flares at the Shell Deer Park Refinery, 10 flares at BP Whiting, 3 flares at the Flint Hills Refinery and 1 flare at CountryMark Refining.

[180] Docket EPA-HQ-OAR-2010-0682-0209, page 9 Table 4.

with no warning. Thus, deleting those operating scenarios that "appear" to be purge gas only from this analysis biases the results.

In the discussion of this base line DE in Docket Document EPA-HQ-OAR-2010-0682-0209[181], EPA reports some anecdotal information from their Office of Enforcement and argues it suggests their 38,600 TPY VOC basis is conservative and that emission could be much higher. However, the anecdotal information cited all comes from enforcement efforts that have resulted in CDs and thus those facilities are now subject to requirements that EPA claims will assure 98% DE. Therefore, the cited anecdotal information actually indicates that the average DE should be higher than EPA assumed, since many flares that may have been achieving lower DEs are now achieving at least 98%.

In our analysis of the API/AFPM flare data set, we have only used data from the 24 refinery flares in the data set, so as not to skew the results by including flares in other source categories. We discuss our analysis of that data set in more detail in Comments 2.7.3.4, 2.7.3.5 and in Attachment D-1. Since 2010, there have been significant changes in flare operations due to the promulgation of NSPS Ja, State and industry efforts, and finalizing a significant number of refinery flare CDs. While a quantitative adjustment of the 24 refinery flare set is not possible we believe the changes since 2010 will result in a higher nationwide average DE than indicated by the 24 flare data set. As detailed in Attachment D-1, our analysis of the 24 refinery dataset indicates an overall average destruction efficiency of 95.2% for steam-assisted flares. The difference between the API/AFPM and EPA estimates appears to be due to limiting the API/AFPM analysis to the 24 refinery flares in the data set, using the entire set of operating scenarios available for these 24 flares and using a best fit CE versus CZ-NHV equation based on averaged PTFIR data. Our calculations using the same CE versus CZ-NHV equation and CE to DE adjustment as EPA used yield a 96.2 DE for the 24 flare dataset.

In Table 3 of Docket Document EPA-HQ-OAR-2010-0682-0209 EPA reports that approximately 10% of refinery flares are unassisted and 10% air-assisted. While unassisted and air-assisted flares typically have less capacity than steam-assisted refinery flares, they typically are in services where they are used more regularly (e.g., storage and loading) and thus, in this world of minimized flare use, may have similar annual VOC and HAP emissions to steam-assisted flares. No air-assisted or unassisted flares are included in API/AFPM Refinery flare dataset. However, it is assumed for calculating nationwide impacts that the improvements in steam-assisted flare DEs calculated from the API/AFPM dataset applies to air-assisted flares as well. However, since unassisted flares cannot be over-assisted, we have assumed 10% of the baseline

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[181] Page 9.

VOC and HAP is unaffected by this proposal. In Comment 2.7.3.5, we have separately considered the impact of increasing the flare gas heat content requirement from 200 BTU/SCF to 270/380 BTU/SCF.

Adjusting for the impact of NSPS Ja as discussed earlier in this comment would reduce the EPA base line estimate from 38,600 TPY VOC to 27,600 and from 4,440 TPY HAP to 3,170 TPY. Adjusting for a DE of 95.2% in place of EPA's assumed 93.9% DE for 90% of the NSPS Ja adjusted baseline emissions results in a base line emissions estimate of 22,300 TPY VOC and 2,560 TPY HAP.

2.7.3.4 API/AFPM's Evaluation of The Proposed 270/380 BTU/SCF 15-Minute Average CZ-NHV Approach Indicates Overstated Emission Reductions, Understated GHG emissions and Costs.

EPA proposes to allow any of the three combustion zone parameters described in Comment 2.7.3 to be used to demonstrate continuing compliance. All are calculated as a 15 minute average and all having dual limits, based on the olefin, hydrogen and olefin plus hydrogen content of the flare gas. The parameters that may be used for a particular flare depend on the type of monitor used to determine the flare gas composition and heating value. A grab sample alternative to determining flare gas properties is provided for flares where continuous monitoring is not justified.

Unfortunately, the flexibility that EPA claims to provide is misleading, because of the proposal of a dual standard, the 15-minute averaging time, the tip velocity limit associated with the CZ-C alternative, and other limitations imposed. Furthermore, as we discuss in Comment 2.7.3.4.4, the cost and burden assumptions used by EPA to evaluate this proposal are invalid, because they assumed the proposed flexibility would allow costs to be minimized. Overall, we believe EPA has failed to strike a balance between ensuring good combustion efficiency without requiring refiners to add unnecessary supplemental gas where in many cases the flare is in fact already operating at high combustion efficiency. This conservatism will result in unnecessary and wasteful additions of supplemental gas and increases in CH_4 and CO_2 (as well as criteria pollutants) emissions unnecessarily. EPA should revise these operating parameters in a manner which strikes this balance. API/AFPM recommends 200 BTU/SCF CZ-NHV and equivalent as a 3-hour average in Comment 2.7.3.5 to achieve this balance.

In Comment 2.7.3.4.1 we address the basis used by EPA to establish their proposal and in Comment 2.7.3.4.2 the practicalities of implementing the proposal. We have addressed the emissions basis against which this proposal is measured in Comment 2.7.3.3. In Comment 2.7.3.4.3 and 2.7.3.4.4 we evaluate the true emissions impacts and costs of the proposal and in Comment 2.7.3.5 we compare the proposal to what API/AFPM believe is the more appropriate limitation (i.e., 200 BTU/SCF CZ-NHV in the combustion zone as a 3-hour average). We use the CZ-NHV as the basis for our comments for relative simplicity, but the conclusions and comments apply to all three alternative, essentially equivalent, parameters.

On page 36912 of the preamble, EPA summarizes their estimate of the impact of the flare combustion control requirements. They estimate emissions from flares will be reduced by approximately 3,800 tpy of HAP, 33,000 tpy of VOC, and 327,000 metric tons per year of CO_2e. On page 36952, Footnote 42 they provide more detail on the GHG emissions, stating that the flare operational and monitoring requirements are projected to reduce methane emissions by 29,500 tpy while increasing CO_2 emissions by 260,000 tpy, resulting in a net GHG reduction of 327,000 metric tons per year of CO_2e, assuming a global warming potential of 21 for methane.

2.7.3.4.1 The Proposed Combustion Zone Limitations Are Based On Invalid Data Analysis and Overly Conservative Choices and Represent an Unlawful Change in the MPV Floor.

EPA does not appear to fully understand the PFTIR technology and the method by which the data are produced. EPA's improper manipulation of the data has resulted in flawed calculations and invalid conclusions. Scott Evans and Robert Spellicy, who helped develop the PFTIR technology and have participated in much of the flare test work that has been conducted to date, have prepared a report, included as Attachment D-2, on EPA's use of the PTFIR data for this rulemaking. This report describes in detail the problems with EPA's analysis of the available flare combustion efficiency data.

It is important to note that PFTIR is a technology, not a method. The method consists not only of the hardware but also the data analysis algorithms both included in software and manually applied in final spreadsheet analysis. This total method is what was validated during the PFTIR flare testing. In conducting their analysis for this rule, EPA recalculated combustion efficiencies using their own data analysis algorithms which are different from those validated during the flare tests. In effect, EPA has altered the validated method without providing any evidence that they have conducted any sort of validation testing on their modified method.

In addition, the data analysis techniques used by EPA cannot be technically justified. The validated PFTIR method requires a combination of both spectroscopic and statistical techniques to assess data validity. EPA's approach attempts to "simplify" the analysis by bypassing the spectroscopy and developing arbitrary criteria and algorithms based solely on statistical analysis. EPA presents no evidence in their analysis that they attempted to assess the data by examining individual spectra as is done in the validated method.

Unfortunately, as described in the attached Evans/Spellicy report, EPA's approach has resulted in incorrect and misleading results. In particular, proper analysis of the data demonstrates that EPA's more stringent operating limit for low olefin/high hydrogen conditions cannot be supported. The combustion efficiency under these conditions is no different from other conditions.

2.7.3.4.1.1 One Minute PFTIR Data Should Not be Used to Establish CE Correlations.

In Docket Document EPA-HQ-OAR-2010-0682-0206, correlations are identified between CE and CZ-NHV, CZ-LFL and CZ-C for steam-assisted, air-assisted and unassisted flares based on one minute PFTIR data. We believe the use of one-minute data is invalid and these evaluations should be based on CE values averaged over the same time period as the composition data. There are two primary problems with the use of one minute data. First, the PFTIR measurements represent slices of the flare plume that depend on manual positioning of the beam. Thus each one minute measurement represents a different slice of the plume as the operator moves the beam and as the flame shape and location varies with wind and flow conditions. In fact, any one minute slice may actually measure a part of the plume where significant combustion has not yet occurred because that area is fuel rich or a location where fuel and combustion products are diluted to background levels. Neither of these one minute measurements is an accurate representation of the overall combustion efficiency being achieved during that one minute. Averaging these measurements over a longer time period provides a more precise representation of the overall CE being achieved.

Flare gas composition, the key data for calculating flare tip gas properties is only obtained every 15 minutes at best. By using 15 minute averages, two composition measurements (one at the beginning of the 15 minutes and one later in the 15 minute period or just after the start of the next 15 minutes) could be averaged to provide a much better representation of the flare tip gas properties than is available using a single composition for each of 15 one minute periods.

Furthermore, EPA's stated intent for this proposal is that flares achieve 98% DE as a 15 minute average, not that they achieve 98% DE as a one minute average. Just as setting a 15 minute average for flares changes the stringency of the floor versus the floors 3-hour and daily average basis, setting the combustion zone limitation based one-minute averages rather than 15 minute averages, results in further tightening of the MPV floor. The net effect is that this proposal is based on a flare achieving 98% DE every minute, rather than achieving the MPV floor requirement of 98% DE as a 3-hour or daily average. This may be part of the explanation for why the proposed limits result in so many false negatives versus so few false positives, as discussed in our next comment.

2.7.3.4.1.2 The Correlation EPA Used for Relating CE and CZ-NHV Is One of Several Possible Data Fits and Several Need to be Considered in Evaluating the Appropriate CZ-NHV target. The Equation EPA Used to Relate CE and DE Is Not Consistent With Combustion Theory and Should Be Revised.

In Docket Document EPA-HQ-AOR-2010-0682-0209, it is reported that the available flare data appears to suggest a snuff point of the flare at a CZ-NHV value of 80 BTU/SCF and a CE of 96.5 percent (assumed to be equivalent to 98 percent DE) at a CZ-NHV value of 270 BTU/SCF. The following equation was then established by EPA to determine CE as a function of CZ-NHV at CZ-NHV's above 80 BTU/SCF. A CE of 0 was assumed for CZ-NHVs below 80 BTU/SCF.[182] The docket document is unclear what CE is assumed if the CZ-NHV equals exactly 80 BTU/SCF.

$$\%CE = \frac{-11.6 + 0.145\ CZNHV}{1 + (-11.6 + 0.145\ CZNHV)}\ 100\%$$

where:

%CE = combustion efficiency, percent.
CZNHV = net heating value of the gas in the flare's combustion zone, BTU/SCF.

We believe the form of this equation is reasonable, but that the exact CE values that correspond to various CZ-NHVs and the 0 and 96.5% CE are incorrect, because, as discussed above and in Attachment D-2, one minute PFTIR data is not an accurate measurement of overall flare combustion efficiency for that minute and thus cannot be used to accurately relate CE and CZ-NHV.

As part of EPA's 2012 flare technical review effort, EPA developed a data set from available flare tests of CE and CZ-NHV data points representing reasonable averaging periods (from 6 minutes to 30 minutes) and that data set is currently the best for developing a CE correlation with CZ-NHV and should be the basis for relating CE and CZNHV, not the one minute data from these tests, which has no chance of being representative of the actual flare CE. Resulting from the technical review, peer reviewer A provided a curve fit[183], similar in shape to the one used by

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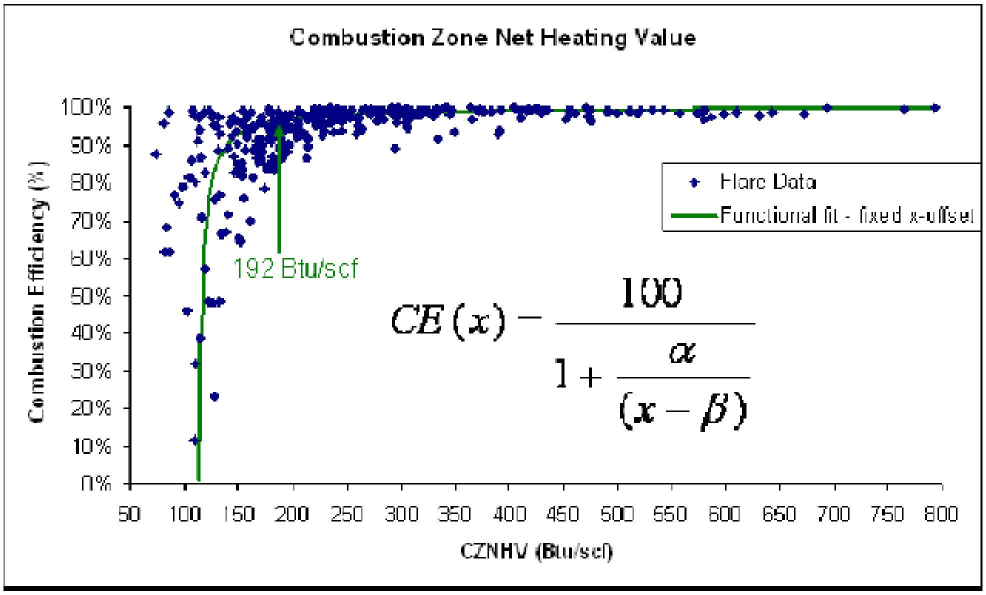
[182] Coburn, J. (RTI International) to Bouchard, A. and Shine, B. (EPA), *Petroleum Refinery Sector Rule: Flare Impact Estimates*, January 16, 2014, Docket EPA-HQ-OAR-2010-0682-0209, pages 7 and 8.
[183] Fry, C. and Coburn J. (RTI International) to Bouchard, A. and Shine, B. (EPA), *Peer Review of "Parameters for Properly Designed and Operated Flares"*, July 3, 2012, Docket Document EPA-HQ-OAR-2010-0682-0193, Attachment A

EPA, but based on the technical review data set. That plot and resulting best fit equation are as follows.

Figure 2.7.1 CE/CZNHV Correlation by Peer Reviewer A
from Attachment A of the EPA Flare Peer Review Report[184]



Reviewer A explains this graph and the results as follows.

> The data is plotted as CZ-NHV vs. combustion efficiency [] and fit to the inset function. The function essentially interpolates between two lines – one representing good combustion efficiency and one rapidly approaching zero combustion efficiency. The particular fit adjusted the variable β to 114 (to fit the low combustion efficiency data visually) and then used the Microsoft® Excel solver to derive the best fit for α, in this case 2.85. (One could use the regression technique for both α and β.) Interestingly, the fit crosses 96.5% combustion efficiency right around 200 Btu/scf.

[184] Ibid.

Using the Microsoft® Excel solver to fit both α and β, yields an α value of 10.58 and a β value of 75.13. Because this equation represents the relationship between CE and CZ-NHV for the best available data set and is statistically derived, it is the basis for API/AFPM's evaluation of available refinery flare information. We also note that this equation yields lower DEs for a given CZ-NHV above 200 BTU/SCF than either the alternate solved only for the α value and the EPA equation. Specifics are described in Section D.2 of Attachment D-1.

Because of the measurement capabilities available, flare performance studies measure CE, which is a measure of how much hydrocarbon is oxidized to CO_2. The DE of a flare will be somewhat higher than the CE because some hydrocarbon is only partially oxidized (to CO) rather than fully converted to CO_2. As explained in the docket[185], the difference between CE and DE at 98% DE is estimated to be 1.5%. Thus, a CE of 96.5% is generally accepted as being indicative of a DE of 98% (EPA's intent for flares).

On page 8 of Docket Document EPA-HQ-OAR-2010-0682-0209, it is reported that DEs were calculated from CEs as follows.

For %CE ≤ 97.98 percent,

$$\%DE = \%CE \times \frac{98}{96.5}$$

For %CE >97.98 percent,

$$\%DE = 99.5\%$$

No explanation is provided explaining the basis for this relationship or why it is projected that the amount of CO produced is projected to drop as the CE drops. Combustion chemistry would predict the opposite (i.e., more CO and other partial oxidation products would be produced as CE drops). However, the relationship between CE and complete oxidation for flares is unclear and thus API/AFPM has assumed that 1.5% CO production is typical at all CE's and thus we have used the following equation to relate CE and DE, up to 98% CE. No CO production is assumed if the CE is 0 (i.e., CZ-NHV is <75.13).

$$\%DE = \%CE + 1.5\%$$

[185] Coburn, J. (RTI International) to Bouchard, A. and Shine, B. (EPA), *Petroleum Refinery Sector Rule: Operating Limits for Flares*, December 12, 2013, Docket EPA-HQ-OAR-2010-0682-0206, page 13

2.7.3.4.1.3 Neither The Scientific Literature Nor The Available Flare Test Data Support EPA's Claim of an Adverse Hydrogen-Olefin Interaction on CE.

In the preamble to the proposal[186], the EPA has suggested that the flare test data provided in the 2012 peer review document[187] supports two CZ-NHV limits based upon the constituents in the flare vent gas. As a result, EPA has proposed requiring vent gas with the following characteristics to meet a CZ-NHV limit of 380 BTU/SCF, rather than a limit of 270 BTU/SCF:

- Olefin content > 2.5 volume percent, <u>and</u>
- Hydrogen content > 1.2 volume percent, <u>and</u>
- Combined olefin and hydrogen content, > 7.4 volume percent

EPA's supporting rationale for this dual-tier approach is presented in Docket Document EPA-HQ-OAR-2010-0682-0206, *Petroleum Refinery Sector Rule: Operating Limits for Flares*[188].

In an effort to evaluate the basis and validity of EPA's proposed limits, API/AFPM commissioned a comprehensive analysis by Scott Evans of CleanAir Engineering, consisting of an examination of peer-reviewed literature related to olefin combustion, a review of olefin and hydrogen treatment in recent flare consent decrees, and an analysis of flare combustion efficiency data from recent studies. The results of this analysis are attached to these comments as Attachment D-3 "The Relationship Between Olefin and Hydrogen Vent Gas Content and Flare Combustion Efficiency."

In summary, based on analysis of the data as well as a thorough review of available scientific literature, Evan's has concluded the following:

1. EPA has not provided any evidence that the assumed hydrogen/olefin effect actually exists. In actuality, analysis of the data demonstrates that a hydrogen/olefin interaction does not explain the observed low combustion efficiency in their targeted range.

2. The hydrogen/olefin criteria proposed in the RSR rule fail to reliably distinguish between conditions leading to good combustion and conditions leading to bad combustion. Statistical analysis demonstrates that EPA has developed their limit based on random differences in the data.

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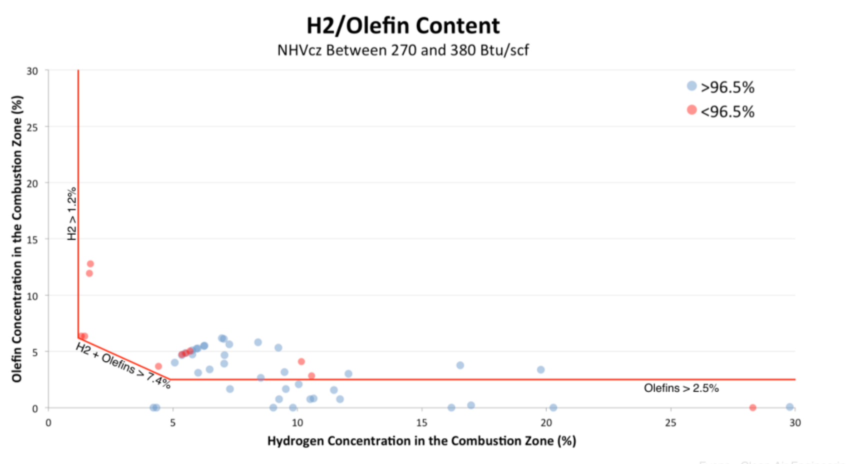
[186] See 79 Fed. Reg. 36906-36909 (June 30, 2014).
[187] Docket ID EPA-HQ-OAR-2010-0682-0191, US EPA, *Parameters for Properly Designed and Operated Flares - Report for Flare Review Panel*, April 2012
[188] Ibid.

3. EPA does not appear to fully understand the PFTIR technology and the method by which the data are produced. EPA's improper manipulation of the data has resulted in flawed calculations and invalid conclusions.

4. Proper analysis of the data demonstrates that EPA's more stringent operating limit for low olefin/high hydrogen conditions cannot be supported. The combustion efficiency under these conditions is no different from other conditions.

To highlight one example from the report, Figure 2.7.2 below (Figure 7 from the report) shows the hydrogen/olefin constituent distribution for all test data where the CZ-NHV fell between 270 and 380 BTU/SCF. The blue data points that fall above the line are points when the performance indicators (i.e., CZ-NHV, CZ-LFL, or CZ-C) suggest non-compliant performance but where in fact the CE is greater than 96.5%.

Figure 2.7.2 EPA's proposed hydrogen/olefin limit



The four red data points on the left of graph are from the upset operation category where the flare was purposely put in an upset mode for the sole purpose of conducting the test. These data are not indicative of normal operation, and for the purpose of establishing flare operating limits that are to apply during normal operations, these data should be set aside. Since these low CE data points are effectively isolated based on their vent gas hydrogen/propylene content, it may be reasonable to assume there is some kind of hydrogen/propylene effect is at work here. However, this is not the only possible explanation for the low CE, but it is a reasonable assumption given the data. This was also the conclusion drawn during the drafting of the flare consent decrees. Nonetheless, these data are relevant only to the specific upset conditions as tested, and limited only to hydrogen-propylene interaction.

As shown in Figure 2.7.1, low CE data points fall directly over or very close to high CE data points. If vent gas with identical hydrogen/olefin concentrations can at certain times result in high CE and other times in low CE, it is not reasonable to assume that a hydrogen/olefin effect is the cause. Since all six of the red data points in the normal operating category are within the hydrogen/olefin region and fall on top of or very close to blue data points, there is no support in the data for any hydrogen/olefin effect in the normal operating category.

One also observes that of the 33 points within the hydrogen/olefin boundary, 23 of these are blue indicating good combustion. The data clearly show that the hydrogen/olefin criteria in the proposed rule captures far more high CE data points than low points in the normal operating category. As discussed above, every blue data point within the hydrogen/olefin zone, is a false negative, and every red dot is a false positive. There are many more false negatives than false positives, indicating a very conservative and unbalanced analysis of the data. Therefore these limits will require refineries to add unnecessary supplemental gas since the flare is, in fact, already operating at high CE. Adding unnecessary gas is a waste of resources and results in increased emissions of NOx and CO_2.

In summary, neither the scientific literature nor the available flare test data support a separate higher operating limit based on an alleged hydrogen-olefin interaction. As demonstrated in the paper by Evans, there is no evidence that such a hydrogen/olefin effect even exists. Currently, there is no single unifying treatment of flare combustion efficiency that will describe 100% of the data. The regulatory approach taken for flares should acknowledge the current state of the science for flare CE, and accept that there will be outliers to any of the existing theoretical treatments of the impact of vent gas composition on CE. EPA should be striving to strike a balance between ensuring good CE for the majority of flaring events without requiring refiners to add unnecessary supplemental gas when in fact the flare is already operating at high CE. Adding unnecessary gas is a waste of resources and results in increased emissions of NOx and CO_2.

2.7.3.4.1.4 Using The Thermodynamic Heat Content for Hydrogen Biases the Analysis of Emissions Associated with the Proposal and The Amount of Natural Gas Supplementation Needed for Compliance. The Final Rule Should Assign Hydrogen a Heating Value of 1212 BTU/SCF.

Hydrogen is well characterized as an aid to flare gas combustion because of its wide flammability range. As a result it is often assigned an artificial heating value (i.e., 1212 BTU/SCF versus its thermodynamic value of 274 BTU/SCF) in calculating the heating value of flare gas mixtures. For instance, the Marathon and Shell Deer Park flare consent decrees specify the use of this artificial hydrogen heating value. This proposal reverts to the use of the thermodynamic value, thereby adding significant additional conservatism to the CZ-NHV limit proposal, forcing excess natural gas addition for compliance, and creating conflicts for the flares subject to requirements based on a 1212 BTU/SCF value (in fact, this change would require those with consent decrees to increase natural gas supplementation, thereby increasing costs and GHG emissions, even though EPA has accepted that compliance with those CDs assures 98% DE).

In this proposal, the value of hydrogen has not only been discounted by requiring use of its thermodynamic heating value in the CZ-NHV calculation, but by also imposing higher combustion zone heating values for flare gas with hydrogen and olefin above certain values. As discussed in Comment 2.7.3.4.1, there are only a few data points – all taken during a major upset flaring scenario - that suggest a hydrogen-propylene interaction while the preponderance of the available data does not. Furthermore, there is no data supporting a reversal of EPA's previous evaluation of the data supporting the use of a 1212 BTU/SCF value for hydrogen. Consistent with EPA's previous position, then, this final rule should assign hydrogen a heating value of 1212 BTU/SCF in evaluating the CZ-NHV of flares.

EPA stated on page 2-168-9 in the February 1994 Background Information Document for the Initial Part 63 General Provisions promulgation[189] "It should be noted that the EPA believes that 98 percent destruction can be obtained if the flare gas contains a sufficient amount of hydrogen, even when the gas stream does not meet the minimum heating value and maximum exit velocity requirements of §63.11(b)"[190]. Significant supporting data for the importance of hydrogen in aiding combustion and the lack of a hydrogen/olefin inhibition is EPA's 1998 amendments to §§60.18 and 63.11. These amendments provided relief from the 200 BTU/SCF minimum requirement for flare gas heat content on high hydrogen flare gas routed to unassisted flares.[191]

In the 1998 rulemaking for unassisted flares containing greater than 8 vol% hydrogen, sources were given a choice of meeting the existing heat content requirement or an exit velocity that was based on the hydrogen content of the flare gas. This decision was, in fact, primarily based on test work done on hydrogen/ethylene gas mixtures. Any hydrogen/olefin inhibition would have shown up in these tests. Instead, it was determined that greater than 99% destruction of ethylene occurred if the hydrogen content was greater than 8%, even if the heating value of the

[189] EPA-450/3-91-019b

[190] US EPA, General Provisions for 40 CFR Part 63: National Emission Standards for Hazardous Air Pollutants for Source Categories, Background Information for Promulgated Regulation, EPA-450/3-91-019b, February 1994, Pages 2-168-9.

[191] These amendments only addressed unassisted flares, since that was the only interest of DuPont, the company that petitioned for the change and funded the test work.

flare gas was below the historical 200 BTU/SCF limit. Key quotes from that rulemaking[192] are as follows:

Page 24437, center column – Destruction Efficiency Summary and Reduced Emissions Resulting from Addressing High Hydrogen Flares

> The test program demonstrated that these hydrogen fueled flares achieved greater than 98 percent destruction efficiency. Further, the EPA judged the conditions of the test program to be universally applicable under the specifications contained in these amendments. Therefore, this notice provides the background and rationale for this action to add specifications for hydrogen fueled flares to the existing flare specifications. … EPA believes that hydrogen-fueled flares meeting the operating specification in this amendment will achieve the same control efficiency, i.e., 98 percent or greater, as flares complying with the existing flare specifications. Further, these specifications will result in reduced emissions of carbon monoxide, nitrogen oxides, and carbon dioxide formed during the combustion of supplemental fuel necessary for hydrogen-fueled flares to comply with existing regulations.

Page 24440, bottom of left column and center column – Reasons Why Hydrogen Heating Value is Different from Organics

> 1. The Heat Content of Hydrogen
>
> The heat content of a substance is a measure of the amount of energy stored within the bonds between atoms in each molecule of the substance. Hydrogen is a simple molecule consisting of two hydrogen atoms held together by weak, hydrogen bonds, thus resulting in a low heat content. In comparison, organic chemicals are larger chains (or rings) of carbons with hydrogens and other atoms attached to them. These molecules are held together with a combination of ionic, covalent and hydrogen bonds, which contain substantially more energy (i.e., higher heat content) than the hydrogen bond in the hydrogen molecule.

[192] 63 Fed. Reg. 24436 (May 4, 1998)

2. The Difference in Combustion Between Hydrogen and Organics

The first phenomenon to explain the difference in combustion between hydrogen and organics is related to the thermodynamics of the combustion reaction. In order for the hydrogen atom to react in the combustion/oxidation reaction, the weak hydrogen bond between the two hydrogen atoms must first be broken. Because there is less energy holding the hydrogen atoms together, less energy (heat) is required to separate them. Once the hydrogen bonds are broken, the hydrogen atoms are free to react in the combustion reaction.

The second phenomenon explaining the difference in combustion between hydrogen and organics is due to hydrogen's upper and lower flammability limits. The flammability limits are the minimum (lower) and maximum (upper) percentages of the fuel in a fuel-air mixture that can propagate a self-sustaining flame. The lower and upper flammability limits of hydrogen are 4.0 and 74.2 percent, respectively, which is the second widest range of lower and upper limits of substances typically combusted in flares (Docket No. A–97–48, Item No. II–I–2).

The third phenomenon explaining the difference in combustion between hydrogen and organics is the relative difference in diffusivity between hydrogen and organics in air. Diffusivity refers to how easily molecules of one substance mix with molecules of another. Further, the quicker the fuel and air in a flare mix, the quicker the combustion reaction occurs. The measure of how quickly a substance mixes with another substance is expressed in terms of the diffusivity coefficient. The larger the diffusivity coefficient, the quicker the mixing. The diffusivity coefficient for the mixture of hydrogen and air is an order of magnitude higher than those for the mixture of air and volatile HAP with readily available diffusivity coefficients. Therefore, hydrogen is more diffuse in air compared to organics and more quickly enters the flammability range than organics.

Page 24441, bottom of left column and center column – Selection of Ethylene as the Test Organic

> 5. The Selection of Ethylene as the Surrogate for HAP to be used in the testing
>
> For this study it was desired to select a surrogate for HAP that was more difficult to destroy than the volatile HAP present in the large scale flare waste streams, and which could be measured at a concentration of 10 parts per billion by volume and higher. In general, the difficulty of destruction for organics increases as the molecular weight decreases, but the limit of detection decreases as the molecular weight decreases. It is obvious then that there may be some compromise necessary in selecting a surrogate for HAP.
>
> In order to compare the relative difficulty to destroy various species, a linear multiple regression model was used that calculates a destruction temperature using parameters describing the molecular structure, autoignition temperature, and residence time as inputs to the model. The destruction temperatures obtained are theoretical temperatures for plug flow reactors to achieve specified destruction allowing a comparison to be made among various chemical species to estimate relative destructibility (Docket No. A–97–48, Item No. II–I–14). As a first step the destruction temperatures were calculated for all the chemical species that were identified as present in DuPont's full-scale flare waste streams. The next step was to calculate destruction temperatures for the surrogates for HAP under consideration. (The results from this analysis are presented in Tables 4–3 and Table 4–4 of Docket Item II–I–14).
>
> In comparing the model's destruction temperature estimates for candidate surrogates for HAP present in DuPont's flare streams, the best choice as a surrogate was methane, but the detection limit was too high to be accepted for the field study. The next choice was methanol but not only is the detection limit high, it is a HAP and it is also a liquid at ambient temperatures, presenting handling difficulties. The next candidate considered was ethylene which was selected for the study. It has a higher destruction temperature than all the organic HAP in the study, except methanol, and has an acceptable limit of detection. Therefore, the most difficult to destroy substance was chosen for the study that was feasible to use.

The significant impacts of this change, which reflects the prevalence of hydrogen in refinery flares, are indicated in the footnotes to Table 2.7.10 below. Using the API/AFPM 2010 flare data set the estimated average DE result changes from 95.2% to 97% when using a hydrogen heating value of 1212 BTU/SCF and the calculated DE after applying the proposed combustion limits is raised from 98.2% to 98.9%.

In summary, flares with a significant amount of hydrogen present tend to operate at higher combustion efficiency with lower combustion zone net heating content. Hydrogen has a significantly larger flammability range than hydrocarbons and is thus not directly comparable on a net heating value basis. This has not been accounted for in the construction of the limits in this proposal. There are numerous flares in refinery applications that may be utilized to manage a large amount of hydrogen, particularly during a process upset or other emergency conditions. As such, the flare would be operating at high combustion efficiency, but the computational artifact resulting from the numerically low net heating value ascribed to hydrogen would result in the paradoxical and unnecessary addition of supplemental gas to the flare. Thus, API/AFPM strongly recommends that the calculation for net heating value in the combustion zone allow for an adjustment for hydrogen to 1212 BTU/SCF to account for the beneficial nature of hydrogen to flammability and that the unnecessary and wasteful supplementing of gas for the sole purpose of overcoming the numerical value associated with hydrogen net heat content be avoided.

2.7.3.4.1.5 The Emission Limits Should Be Set to Provide an Equal Chance of False positives and Negatives.

In picking exactly where to set the CZ limits, EPA reports that it purposely picked values that result in “very few” instances where the operating limit was achieved but a CE of <96.5% (<98% DE)[193]. As discussed in Comment 2.7.3.4.1, the result of this skewed choice is a large number of false negatives. Since a false negative is a reportable deviation under this proposal and under Title V, it is arbitrary and unreasonable for EPA to knowingly bias the data analysis in this way. This is particularly true, since as EPA indicates in this same citation the combustion efficiency deviations for false negatives are relatively small.

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[193] Coburn, J. (RTI International) to Bouchard, A. and Shine, B. (EPA), *Petroleum Refinery Sector Rule: Operating Limits for Flares*, December 12, 2013, Docket EPA-HQ-OAR-2010-0682-0206, page 15, first bullet.

EPA suggests[194] that the risk of false negatives is reduced by allowing use of any of the three performance indicators for demonstrating compliance. No data is provided to support this supposition and since the limits were selected in similar ways, it is unclear why this would be true. Furthermore, as discussed elsewhere, all three alternatives are only available with a full suite of continuous instrumentation, which EPA does not forecast in their cost estimates for all flares.

2.7.3.4.2 Operating Practicalities Must Be Considered When Establishing and Evaluating Flare Control Requirements.

2.7.3.4.2.1 At least a three hour averaging period is needed to account for instrument and control response time.

As discussed in the Comment 2.7.3.1, this proposal arbitrarily sets the averaging time for the proposed combustion control compliance parameter at 15 minutes, with no apparent consideration of the RMACT 1 floor for combustion devices or the original intent (i.e., typical operation) of the flare combustion intent. In addition to not reflecting the floor or original intent, this averaging time provides no allowance for the response time of control systems, the variability of flare gas or monitoring capabilities. No current refinery flare CD has less than a three hour averaging time and our members who operate under those CDs report that even with a 3-hour average and reasonable compliance margins, deviations can occur due to unexpected flare gas variability. Thus, based on real experience and EPA concurrence in the CD process, a three hour averaging time is the minimum practical and that is the minimum averaging time that can be considered demonstrated and thus may be legally specified under this rule. While the RMACT 1 floor for combustion devices (and the flare 98% DE intent) is clearly a daily average (as specified for non-flare combustion devices in RMACT 1 and 2) EPA might be able to justify a 3-hour average for flares if they can show that flare variability is such that a three hour average is required to assure compliance with a daily average 98% DE intent and that the development of reliable process GCs since §60.18 was first promulgated now makes a 3-hour continuous compliance demonstration possible.

The key impacts of the 15-minute averaging time versus a three hour or daily averaging time include the following. Even then, it is likely deviations will occur simply because the control

[194] Ibid., second bullet.

system is incapable of managing a 15 minute average, using once every 15 minute heat content and composition data.

- Requires both GC and a BTU analyzer to obtain data rapidly enough to try to maintain a 15 minute average.

- Requires a large compliance margin to allow for the large variability that can occur within one measurement cycle (i.e., 15 minutes).

- Where the chance of exceeding the H2/olefin limits is reasonably high, will cause some flares to unnecessarily always operate at the higher limit (using excess supplemental gas) because of an inability to be comfortable that the H2/olefin content is known.

- Will result excessive monitor outages because of the many 15 minute periods when no data is available due to required QA/QC.

- Requires calculation artifices to attempt to correct for the fact that compliance cannot be determined until the averaging period is over. (See Comment 2.7.3.6.2.)

2.7.3.4.2.2 The Rule Must Clarify That it is Not a Deviation if Flare Gas Flow was Too Short to Allow the Control System to Respond.

The regulation must deal with the situation where regulated material composition could not be measured and thus could not be controlled. This would happen if flow to the flare occurred for a short time and that time happened to be between GC or BTU sampler intakes or grab sample collection or the event ends before the compositional information is available to the control system. With a GC it will take between 15 and 30 minutes for the first analysis of an event to be available to the control system. We discuss this issue further and the calculation, recordkeeping, and reporting impacts of this issue in Comment 2.7.3.6.2 and 3. In that case, the rule must specifically identify such situations as compliant.

Control systems require information to respond. In this case, the needed steam and supplemental gas rates depend on the heating value of the gas being combusted. These rates would generally be at the minimum required based on that required to assure good purge gas combustion or minimums established to protect the flare tip and assure rapid response if flow is needed. If flare gas flow starts, the steam and supplemental gas would ramp up based on experience and any information from upstream meters, but could not be raised too much, since “over-steaming” could hurt combustion efficiency. Thus, it is not possible to assure compliance until a BTU analysis or GC analysis is completed and there is a basis for the controls to adjust the steam and supplemental gas. If the event is over before a scheduled sample intake occurs and analysis is completed, there is no data for the control system to use to assure compliance.

It is likely, typical process knowledge will be adequate in most cases, but not in all cases and sources should not be penalized because the limit averaging period does not allow adequate time to demonstrate compliance.

2.7.3.4.2.3 A Compliance Margin Should Have Been Included in The Evaluation of the Proposal.

Experience operating under CD requirements (though with a 3-hour averaging time) indicates a significant compliance margin is needed to cover flare gas and instrument response time and variability. Operators would be therefore be expected to operate to a target of approximate 110% of the minimum limit in order to provide a reasonable assurance of compliance in light of the variability of the system and instrument and control response times. Therefore the 270/380 BTU/SCF CZ-NHV proposal should be evaluated as 300/420 BTU/SCF to reflect that operating compliance margin. Similarly, we have evaluated API/AFPM's suggested 200 BTU/SCF limit at 220 BTU/SCF.

Additionally, the evaluations of the proposed limits assumed that sources would instantaneously be able to change from the 270 limit to the 380 limit as hydrogen and olefin contents of the flare gas changed. In the real world, in order to avoid non compliances, sources will operate to the higher standard whenever there is doubt as to the hydrogen and olefin content of the flare gas. This will be common in flares where higher values are not unusual because of daily GC outages required for QA/QC activities, GC maintenance, response time of the GC and provision of a compliance margin on the hydrogen/olefin content (i.e., sources will operate at the higher limit if they are close to the hydrogen/olefin trigger.) As a result, there will be significantly more natural gas addition to flares than assumed by EPA. We have attempted to evaluate the impact of this issue by evaluating the extreme case (i.e., operating to a 380 BTU/SCF limit at all times).

2.7.3.4.3 The Estimated Emission and Steam Reductions Claimed By EPA Are Significantly Overstated and The Natural Gas and GHG Increases Are Significantly Understated.

2.7.3.4.3.1 Summary of EPA Estimates

EPA summarizes the impact of the proposed flare combustion control requirements on page 36912 of the preamble, as follows.

> … these proposed operational and monitoring requirements for flares at refineries have the potential to reduce excess emissions from flares by approximately 3,800 tpy of HAP, 33,000 tpy of VOC, and 327,000 tonnes per year of CO_2e. The VOC compounds are non-methane, nonethane total hydrocarbons. According to the Component 2 database from the Refinery ICR, there are approximately 50 individual HAP compounds included in the emission inventory for flares, but many of these are emitted in trace quantities. A little more than half of the HAP emissions from flares are attributable to hexane, followed next by benzene, toluene, xylenes, and 1,3-butadiene. For more detail on the impact estimates, see the technical memorandum *Petroleum Refinery Sector Rule: Flare Impact Estimates* in Docket ID Number EPA–HQ–OAR–2010–0682. [Emphasis Added]

In the referenced Docket Memorandum (Docket Item 0209), the derivation of these estimates is explained. The EPA "adjusted" API dataset used for estimating the base line DE, was evaluated to determine the overall DE when applying the proposed 270/380 BTU/SCF minimum CZ-NHV to each operating scenario. Steam was reduced and natural gas was added to achieve the minimum CZ-NHV, as established by determining the hydrogen/olefin content at the flare tip at a CZ-NHV value of 270 BTU/SCF. The overall DE was then used to calculate from the estimated base line VOC and HAP contents for all refinery flares the emission reductions that would be attributable to this proposed set of CZ-NHV limits. The result of this analysis (DE = 99.1%) was taken as the impact of the standard, as proposed (i.e., allowing a choice of continuous analyzers and grab samples for determining heating values and compositions), which they identify as Control Alternative 1. A second alternative, Control Alternative 2, which assumes continuous composition monitors on all flares was assigned a somewhat higher DE (99.3%) on the basis that continuous monitoring would allow tighter control. The results of this portion of the EPA analysis are presented in Table 5 of Docket Document EPA-HQ-OAR-2010-0682-0209 as follows.

Table 5. Nationwide Flare Control Efficiency and Emission Reduction Estimates for Flare Control Alternatives (All Flares)

Control Alternative Description	Average Destruction Efficiency (%)	VOC Emissions (tons/yr.)	HAP Emissions (tons/yr.)	VOC Emission Reductions (tons/yr.)	HAP Emission Reductions (tons/yr.)
Baseline	93.9	38,600	4,440		
1. 270 Btu/scf; Engr. Calcs	99.1	5,500	630	33,100	3,810
2. 270 Btu/scf; Monitors Only	99.3	4,200	480	34,400	3,960

EPA then evaluates the impact of the Control Alternative 1 on GHG emissions, starting with the 2010 baseline reported under the GHG reporting rule, which is based on an assumed 98% DE for flares and takes into account the reduced GHG emissions associated with less steam assist and the increased GHG emissions associated with adding supplemental natural gas as estimated from EPA's analysis of the API dataset. The results of the GHG analysis is presented in Table 6 of the Docket Document, as follows.

Table 6. Nationwide Flare GHG Emissions for Control Alternative 1 (All Flares)

Description	Average Destruction Efficiency	CO_2 Emissions (tonnes/yr.)	CH_4 Emissions (tonnes/yr.)	N_2O Emissions (tonnes/yr.)	CO_2e Emissions[a] (tonnes/yr.)
Baseline	93.9	3,514,000	31,400	35.1	4,185,000
Control Alternative 1					
Emissions based on improved destruction efficiency	99.1	3,711,000	4,600	37.1	3,819,000
Steam savings (12 MMlb/yr./flare)[b]		(158,000)			(158,000)
Natural Gas Use (860 klb/yr./flare)[b]		197,000			197,000
Total for Control Alternative 1		3,750,000	4,600	37.1	3,858,000
Net GHG Impacts for Control Alternative 1					(327,000)

a CO_2e calculated using GWP of 21 for CH_4 and 310 for N_2O.
b MMlb/yr./flare = million pounds per year per flare: klb/yr./flare = thousand pounds per year per flare.

Our evaluation of each of these estimates is presented in our following comments.

2.7.3.4.3.2 API/AFPM Estimates Potential Emission Reductions for the Proposed Combustion Controls as 11,150 TPY VOC and 1280 TPY HAP Versus EPA's Estimate of 33,100 TPY VOC and 3,810 TPY HAP.

Following EPA's estimating approach we evaluated the steam reductions and supplemental natural gas additions needed to achieve the proposed minimum CZ-NHV values for the 24 steam-assisted refinery flares in the API dataset. As discussed in Comment 2.7.3.3 our analysis uses a significantly different nationwide baseline than EPA used because our analysis corrects for the impact of NSPS Ja and only addresses refinery flares in evaluating the DE. We also adjusted the analysis to reflect a compliance margin, which as we discussed in Comment 2.7.3.4.2.3, is required to meet the minimum CZ-NHV values at all times. Thus, we evaluated the 270 and 380 BTU/SCF proposal as requiring operating targets of 300 and 420 BTU/SCF, respectively. This roughly 10 percent allowance is what API/AFPM estimates is the minimum necessary to try to achieve compliance based on CD experience. However, the actual allowance may have to be much higher, because there is no experience with a 15 minute average requirement; all flare CDs specify a three hour averaging time. We applied the results of this analysis to 80% of the baseline, since roughly 10% of the baseline emissions are associated with unassisted flares, which have not been demonstrated to have DEs below EPA's 98% intent and which are not amenable to over-assisting and 48 (roughly 10%) of steam-assisted refinery flares are already subject to CDs that achieve the results anticipated for this proposal and thus their impacts should not be attributed to this rulemaking.

This analysis does not address the problems associated with the dual standard. It assumes the control systems will be able to instantly adjust if the H_2/olefin concentration increases above the trigger for the higher limit and instantly revert to the lower limit if the concentration falls below the trigger. Given the variability of flare gas and the response time of the monitors and controls and the 15-minute averaging time, it is highly unlikely that the system can meet this assumption. Thus, it should be expected that some flares will be operated to the higher limit at all times or other flares will operate to the higher limit whenever there is doubt about the H_2/olefin level.

The API/AFPM analysis, detailed in Attachment D-3, yields the results shown in Table 2.7.4. For comparison, the same analysis was performed for the 300 and 420 BTU/SCF case using the EPA CE versus CZ-NHV equation. Those results are shown in Table 2.7.5. Because the EPA curve estimates a higher DE than the best fit curve for any CZ-NHV, the baseline emissions are less than estimated based on the API/AFPM curve and thus the EPA curve actually predicts slightly lower emissions reductions for the proposed CZ-NHV limits.

Table 2.7.4. API/AFPM Nationwide Flare Control Efficiency and Emission Reduction Estimates for Proposed Refinery Flare Combustion Control Requirements

Control Alternative Description, including Compliance Margin	Average Destruction Efficiency (%) (Assisted Flares)	VOC Emissions (tons/yr.)	HAP Emissions (tons/yr.)	VOC Emission Reductions (tons/yr.)	HAP Emission Reductions (tons/yr.)
Baseline	95.2	22,300	2,560		
300/420 (270/380) BTU/SCF*	98.2	11,150	1,280	11,150	1,280

*Controlled DE applied to 80% of baseline emissions since 10% of refinery flares are unassisted and 10% already achieve 98% DE due to CDs.

Table 2.7.5. API/AFPM Nationwide Flare Control Efficiency and Emission Reduction Estimates for Proposed Refinery Flare Control Requirements (Using EPA CE vs CZ-NHV Equation)

Control Alternative Description, including Compliance Margin	Average Destruction Efficiency (%) (Assisted Flares)	VOC Emissions (tons/yr.)	HAP Emissions (tons/yr.)	VOC Emission Reductions (tons/yr.)	HAP Emission Reductions (tons/yr.)
Baseline	96.2	17,650	2,030		
300/420 (270/380) BTU/SCF*	99.1	6,870	790	10,780	1240

*Controlled DE applied to 80% of baseline emissions since 10% of refinery flares are unassisted and 10% already achieve 98% DE due to CDs.

As we discussed in Comment 2.7.3.4.1.4, hydrogen was given its thermodynamic value of 274 BTU/SCF in the above evaluations, but it assists in combustion because of its wide flammability and thus should be given a value of 1212 BTU/SCF. Table 2.7.6 shows the impact of using the 1212 BTU/SCF hydrogen value for the proposal.

Table 2.7.6 API/AFPM Nationwide Flare Control Efficiency and Emission Reduction Estimates for Proposed Refinery Flare Control Requirements (Hydrogen at 1212 BTU/SCF)

Control Alternative Description, including Compliance Margin	Average Destruction Efficiency (%) (Assisted Flares)	VOC Emissions (tons/yr.)	HAP Emissions (tons/yr.)	VOC Emission Reductions (tons/yr.)	HAP Emission Reductions (tons/yr.)
Baseline	96.7	15,300	1,760		
300/420 (270/380) BTU/SCF*	98.9	7,140	820	8160	940

*Controlled DE applied to 80% of baseline emissions since 10% of refinery flares are unassisted and 10% already achieve 98% DE due to CDs.

2.7.3.4.3.3 API/AFPM Estimates the Potential GHG Impact of this Proposal as a Net Increase of At Least 111,700 Metric tons per year CO_2e Versus EPA's Estimate of a 327,000 Metric tons per year CO_2e Reduction.

EPA estimated GHG impacts starting from the 2010 flare GHG emissions reported under the GHG Reporting Rule (tabulated in Table 1 of Docket Document EPA-HQ-OAR-2010-0682-0209) and adjusting for their estimated 93.9 average DE, versus the 98% DE assumed under the reporting rule. Thus, for CO_2, the Table 1 value of 3,670,000 metric tons becomes 3,514,000 metric tons and, for CH_4, the Table 1 value of 10,400 metric tons becomes 31,400 metric tons. As discussed in Comment 2.7.3.3, adjusting the VOC baseline for the impact of NSPS Ja and a DE of 95.2 (the DE obtained when only refinery flares from the API dataset are used evaluated), rather than the 93.9 DE estimated by EPA, reduces the VOC baseline from 38,600 TPY VOC to 22,300, or 42%. Since VOC emissions correlate roughly with total flare gas combusted API/AFPM has applied that same percent reduction to the GHG baseline in Table 6 of Docket.

The emissions impact of the proposal in raising the average DE from 95.2 to 98.2 was recalculated following EPA's approach and applied to 80% of the baseline GHG emissions, since 10% of refinery flares are unassisted and 10% of steam-assisted refinery flares are already meeting 98% DE, consistent with the EPA approach for these calculations of assuming air-assisted flares behave as if they were steam-assisted.

EPA derived steam reduction and natural gas addition amounts from the API dataset. They settled on a steam reduction of 12 million lb/year per flare and an average natural gas addition of 860 thousand lb/year per flare, though it is unclear from the Docket discussion how many flares they assumed would be impacted. Our analysis of the 24 refinery flare dataset indicated 11.7 million lb/year per flare steam reduction versus EPA's 12 million lb/year per flare, but found that natural gas addition would be 1,620 thousand lb/year per flare versus EPA's estimate of 860 thousand lb/year per flare. Most of this difference is likely due to the impact of the 10% compliance margin.

In estimating GHG impacts, EPA converted the CO_2 generation reductions at a boiler due to the steam reductions. Since the CO_2 generation calculation is not included in the docket and we do not know how many flares EPA assumed were impacted, we have simply used a ratio from the EPA numbers and applied that to the steam reduction rate estimated from the API/AFPM evaluation of the 24 steam-assisted refinery flares in the data set. API/AFPM believes the steam reduction would impact less than 70% of refinery flares since steam reductions would not occur for the 20% of refinery flares that are unassisted or air-assisted or for the 10% of steam-assisted refinery flares subject to CDs. Some portion of that 70% would also not see any significant steam savings because they only receive high emergency flows where steam requirements for smoke control exceed steam availability. However, the percent of refinery flares in this situation cannot be reliably estimated.

GHG impacts due to the increase needed in natural gas to the flares were also taken as the ratio of natural gas addition from our analysis of the 24 refinery flare API dataset to the EPA estimate. In this case we would assumed natural gas addition would be applicable to 80% of refinery flares, since unassisted flares and the 10% of flares already subject to CDs would not require supplementation, but since we did not know how many flares EPA applied their GHG estimate to we did not make this adjustment. Unlike EPA, we accounted for the unburned CH_4 from the supplemental natural gas (based on the controlled flare DE of 98.2%) as well as the CO_2 formed.

Table 2.7.7 API/AFPM Nationwide Flare GHG Emissions Estimate for Proposed Refinery Flare Combustion Control Requirements

Description	Average Destruction Efficiency	CO_2 Emissions (tonnes/yr.)	CH_4 Emissions (tonnes/yr.)	N_2O Emissions (tonnes/yr.)	CO_2e Emissions[a] (tonnes/yr.)
Baseline	95.2	2,038,000	18,200	20.3	2,427,300
Control Alternative 1					
Emissions based on improved destruction efficiency	98.2	2,083,000	9099	20.7	2,280,500
Steam savings (11.7 MMlb/yr./flare)[c]		(154,000)			(154,000)
Natural Gas Use (1,620 klb/yr./flare)[c]	98.2	371,000	2420		421,800
Total for Control Alternative 1					2,548,300
Net GHG Impacts for Control Alternative 1					121,000

a CO_2e calculated using GWP of 21 for CH_4 and 310 for N_2O.
b Controlled DE applied to 80% of baseline emissions since 10% of refinery flares are unassisted and roughly 10% already achieve 98% DE due to CDs.
c MMlb/yr./flare = million pounds per year per flare: klb/yr./flare = thousand pounds per year per flare.

Thus, based on the 24 flare API data set, including recognition that flares will be operated with at least a 10% compliance margin and recognition that natural gas supplementation will result in a small percentage of the added methane being released uncombusted, API/AFPM estimates this proposal will result in at least a 121,000 metric tons per year increase in CO_2e emissions. Actual impacts will likely be larger because the uncertainty in the H_2/olefin content will cause flares to be operated to the higher CZ-NHV limit for a larger percentage of the time than assumed in either EPA's or API/AFPM's analysis.

2.7.3.4.4 The Monitoring and Control Investment and Operating Costs are Understated in the Proposal. API/AFPM Estimates an Investment of At Least $343 Million Versus EPA's Estimate of $147 Million and Annualized Costs of $118 Million Versus EPA's Estimate of $36.3 Million.

Per Tables 6 and 14 of the proposal preamble, EPA estimates that a total investment of $147 million will be required for flare monitoring equipment to comply with the combustion control requirements in this proposal and that the total annualized cost will be $36.3 million per year. This estimate is Control Alternative 1 from Docket Document EPA-HQ-OAR-2010-0682-0209[195] and the comments on this section address that alternative. Overall, the costs estimated by EPA for that alternative are inadequate, because they only considered costs for flares with routine flow, even though the requirements apply to all refinery flares, and they do not reflect the impact of the proposed 15-minute averaging time, the dual combustion zone limit or operating with an adequate compliance margin to assure compliance.

As discussed elsewhere in these comments, a great many new flares will be required under this proposal. The cost estimates associated with those flares include the monitoring and controls needed to comply with §63.670 and thus this comment only deals with existing flares.

2.7.3.4.4.1 Investment Costs

EPA evaluated two cost alternatives in Docket Document EPA-HQ-OAR-2010-0682-0209[196] for meeting the proposed 270/380 BTU/SCF CZ-NHV proposal.

> Alternative 1 – Allowing continuous monitoring or engineering calculations/grab samples.
>
> Alternative 2 – Requiring continuous monitoring for all flares.

Under Alternative 1 EPA assumed emergency only flares would not install continuous monitoring and would demonstrate compliance using engineering calculations, while they would under Alternative 2. EPA developed per unit estimates for most types of monitors and controls and API/AFPM accepts they are reasonable. However, we believe the assumptions made about the number of each type of monitor or control do not reflect the requirements of the proposal and thus the per flare and nationwide cost estimates are significantly understated.

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[195] Coburn, J. (RTI International) to Bouchard, A. and Shine, B. (EPA), *Petroleum Refinery Sector Rule: Flare Impact Estimates*, January 16, 2014, Docket EPA-HQ-OAR-2010-0682-0209.
[196] Ibid..

The EPA investment cost summary from Table 10 of Docket Document EPA-HQ-OAR-2010-0682-0209 is reproduced below and Table 2.7.7 provides API/AFPM's summary.

Table 10 Calculation of Costs for Control Alternative 1 for all Flares at Major Source Refineries (in 2010$) (Investment Section)

Monitoring Equip. or Material	Capital Equipment Cost ($/flare)	Annualized Cost ($/yr./flare)	Number of Flares	Nationwide Capital Equipment Cost (MM$)[g]	Nationwide Total Annualized Cost (MM$/yr.)[g]
GC	980,000	141,500	0[a]	0	0
HC Analyzer	180,000	61,000	0[a]	0	0
Calorimeter	105,000	30,000	85[a]	8.93	2.55
Flare Gas Flow Meter	440,000	80,750	0[b]	0	0
Steam Controls/Flow Monitor	684,000	124,300	190[c]	130.0	23.62
Air Controls/Flow Monitor	164,000	52,000	37[d]	6.07	1.92
Engineering Calculation Costs	7,000	13,160	267[e]	1.87	3.51
Nationwide Total Investment			510[f]	**147**	**31.6**

a Assumed all refineries elect to install a calorimeter if needing a monitor. Number of flares needing a monitor is 88 (from Table 9).
b Assumed all routine flow flares already have a flow monitor to comply with NSPS Ja.
c Number of steam-assisted flares with routine flow but without full FGRS from Table 9.
d Number of air-assisted flares with routine flow but without full FGRS from Table 9.
e Number of non-routine flares (225 from Table 3) plus number of routine flow flares with fuel FGRS (42 from Table 8). 225+42=267
f Total number of all flares at petroleum refineries from Table 3.
g MM$ = million dollars; MM$/yr. = million dollars per year.

A major issue in estimating the cost of alternative 1 is the number of GCs, calorimeters and HC analyzers. Since use of the THC combustion zone parameter limits flares to 60 fps exit velocity, that alternative is unlikely to be used and thus no HC analyzers will be needed. Because of the proposed 15-minute averaging time, dual limit, and specifics of the GC requirements in the regulation, we believe most routine use steam-assisted flares will require both a GC and a calorimeter. Based on the ICR data collected by EPA and reported in Table 9, 190 steam-assisted refinery flares do not have full FGRS and of these 63 do not currently have heat content monitors. Thus, we estimate 63 flares will require both a GC and a calorimeter. Of the 123 flares with existing heat content monitors, most of these monitors will be GCs. Assuming 75% of these flares would add a calorimeter and 25% a GC, we would estimate 92 calorimeters will need to be added and 31 GCs, for a total of 155 calorimeters and 94 GCs. Because of the 15-minute averaging time, this additional instrumentation would be required for fares already subject to a CD (which has a three hour averaging time).

Furthermore, as discussed in Comment 1.5.2.9, the GC specifications in the proposal cannot be met by a single GC or by the GCs typically in place to meet State, CD, and permit requirements, as EPA assumed for is cost analysis. Thus, API/AFPM anticipates most of the existing GC installations will have to be supplemented. Based on the information in Attachment 3 to Docket Document EPA-HQ-OAR-2010-0682-0209, we would estimate a cost of $500-600,000 to add a second GC to an existing analyzer system, adding tens of millions to the cost of this proposal and additional maintenance and QA/QC costs and burdens. Because of our uncertainty as to the number of GCs in this situation, the likely revisions EPA will make to address the issue, and the likely wide variability in the cost of addressing the issue, we have not included these costs in our estimate, however.

Because of the large liability associated with a violation every 15 minutes, the requirement to comply if any fuel gas is flared or the flare is used for compliance under referenced rules, we believe a significant portion of the "non-routine" flares and flares with "full FGRS" will also conclude that continuous monitoring is required. In footnote e to Table 10 EPA estimates 267 such flares. API/AFPM believes it is reasonable to assume at least 25% of these flares (67) will add a calorimeter and continuous steam control and another 25% (67) will automate the steam control on flares that only have large manual valves today, but rely on sampling for the heat content and H_2/olefin content. On the other hand 48 refinery flares already have such controls, because of the existing CDs, so we have reduced the number of steam controls needed to 286. We have reflected all of these revisions in Table 2.7.7.

The EPA estimate assumes only the 37 air-assisted flares with routine flow will require flow monitoring and control. However, compliance with the new requirements will require more precise control of air assist rates than is possible with the typical step-wise blower systems typically present on air-assisted flares, particularly in order to meet the requirements on a 15 minute basis. Thus, it should be assumed all 59 air-assisted flares will require control and flow monitoring upgrade.

In addition, the estimate of $164,000 per air-assisted flare for air control is totally unrealistic. Cost estimates by an API member suggest costs in excess of $2 million per air-assisted flare to provide continuously variable and controlled air flow. Major items apparently not included in the EPA Table 10 analysis are 1) approximately $500,000 for a temporary flare to be used while the existing flare is modified[197], 2) approximately $250,000 for a new blower and variable speed

[197] A temporary flare is needed not only for process reasons, but also because much of the work must be done in the flare

motor, since the motor typically cannot be changed without changing out the blower assembly, 3) $200,000 for the variable speed drive and PLC controller (to operate the variable speed motor as a function of flare gas flow and properties), and at least $500,000 for the associated engineering, electrical, instrument, duct and civil work needed for these installations. Because these are scoping estimates based on a few specific flare installations, we have not included this cost in our cost analysis, but qualitatively this information suggests extremely high cost ineffectiveness air-assisted flares, since costs are particularly high, there are no steam saving credits, and because air-assisted flares are typically lower capacity than steam-assisted flares, less emission reduction.

Missing from the EPA cost estimate is the cost of supplemental natural gas flow monitoring, control and supply. Estimating this installation at $100,000 and assuming this control is required for all unassisted, air-assisted and 25% of steam-assisted flares adds 208 such installations. It is important to note this supplementation need will not be addressed by adding this gas at upstream locations on the flare header because it needs to be added after the FGRS and not included in the flare gas flow subject to the NSPS Ja flow limit; thus separate control stations will be needed.

Table 2.7.8
API/AFPM Calculation of Costs for Control Alternative 1 for all Flares at Major Source Refineries (in 2010$)
(Investment Section)

Monitoring Equip. or Material	Capital Equipment Cost ($/flare)	Annualized Cost ($/yr./flare)	Number of Flares	Nationwide Capital Equipment Cost (MM$)[g]	Nationwide Total Annualized Cost (MM$/yr.)[g]
GC	980,000	141,500	94	92.1	13.3
HC Analyzer	180,000	61,000	0	0	0
Calorimeter	105,000	30,000	222	23.3	6.7
Flare Gas Flow Meter	440,000	80,750	0	0	0
Steam Controls/Flow Monitor	684,000	124,300	286	195.6	35.5
Air Controls/Flow Monitor	164,000	52,000	59	9.7	3.1
Natural Gas Controls/Flow Monitor	100,000	18,000	208	20.8	3.7
Engineering Calculation Costs	7,000	13,160	200	1.4	2.6
Nationwide Total Investment				**343**	**65.1**

g MM$ = million dollars; MM$/yr. = million dollars per year.

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radiation zone and it cannot be safely accomplished if the flare is not totally out-of-service.

2.7.3.4.4.2 Operating Costs

Operating costs associated with monitoring and control are included in the annualized costs for those investments and thus were included in the previous comment. Costs for supplemental natural gas and savings associated with reduced steam are discussed in this comment. The portion of Table 10 from Docket Document EPA-HQ_OAR-2010-0682-0209 is reproduced below. Our comment on these estimates and our estimates follow.

Table 10 Calculation of Costs for Control Alternative 1 for all Flares at Major Source Refineries (in 2010$) (Operating Cost Section)

Monitoring Equip. or Material	Annualized Cost ($/yr./flare)	Number of Flares	Nationwide Total Annualized Cost (MM$/yr.)[g]
Average Natural Gas Costs per Flare to Meet NHV_{CZ} Targets	98,660	190[c]	18.75
Steam Costs (Savings) per Flare for Steam Controls to Meet NHV_{CZ} Targets	-73,770	190[c]	-14.02
Nationwide Total Utility Operating Costs	**24,890**		**4.7**

c Number of steam-assisted flares with routine flow but without full FGRS from Table 9.
g MM$/yr. = million dollars per year.

As discussed previously, API/AFPM's analysis of the 24 steam-assisted refinery flare dataset yield nearly the same steam savings as EPA estimates (11.7 million lb per year per flare versus 12 million lb per year per flare). Valuing this steam at $6.12 per 1000 lb yields a steam savings of $71,600 per year per flare. However, API/AFPM estimates natural gas supplementation to require at least 1,620 thousand lb/year per flare versus EPA's estimate of 860 thousand lb/year per flare. Using EPA's natural gas price of $5 per million SCF, yields a cost of $185,800 per year per flare versus EPA's estimate of $98,660 per year per flare.

In Table 10 for Control Alternative 1, EPA includes no cost for steam savings or natural gas supplementation for those flares that do not have routine flow. On the other hand, they include an estimate of half the routine flow impact in Table 11 for Control Alternative 2 (all flares have continuous automatic controls). Neither of these assumptions is correct.

Unless this proposal is modified, many SSM vents and fuel gas releases to flares will be subject to control requirements. Thus, under this proposal more refinery flares than currently are subject will become subject to the proposed §63.670 set of combustion zone requirements.

EPA indicates that in Control Alternative 2 it assumed that non-routine flares (including flares with full FGRS) would see half the steam savings and add half as much natural gas as flares with routine flow (i.e., half the steam savings and half the natural gas costs estimated from their API dataset analysis.) Since the requirements are the same for all flares and the API included routine and non-routine flow steam-assisted flares, there is no basis for such a discount. Ten of the 24 refinery flares in the dataset had significant flow less than 300 hours per year and most had significant flows for a small percentage of the year. If anything, it is routine flow operations that are under-represented in that dataset. Whether steam and natural gas are manually controlled or automatically controlled is more a function of the facility knowledge of what is going to a particular flare than whether flaring is routine or not. For instance, equipment clearing is a planned activity and inert levels and vent rates can be controlled to some degree, so manual control of flares receiving such vents is often adequate. Similarly, flares that handle loading operations or storage tank vents know when loading or unloading is occurring and the properties of the vent streams, so manual flare controls are adequate. On the other hand, a general refinery flare that receives flow only when there is a FGRS trip or when a turnaround generates large and varying inert gas loads will require automated control, even with a 3-hour averaging time. Since the API database is the only information available, the steam savings from that analysis should be applied to all steam-assisted flares except the 48 already subject to CDs, and natural gas costs added for all steam and air-assisted flares except the 48 already subject to CDs. Since there is no data on unassisted flares, the amount of natural gas addition required to meet the proposed 270/380 BTU/SCF criterion instead of the current 200 BTU/SCF criterion is unknown and we have opted, therefore, not to try to include that additional natural gas use in this analysis.

Table 2.7.9
API/AFPM Calculation of Costs for Control Alternative 1 for all Flares at Major Source Refineries (in 2010$)
(Operating Cost Section)

Monitoring Equip. or Material	Annualized Cost ($/yr./flare)	Number of Flares	Nationwide Total Annualized Cost (MM$/yr.)[g]
Average Natural Gas Costs per Flare to Meet NHV_{CZ} Targets	185,800	413[a]	76.7
Steam Costs (Savings) per Flare for Steam Controls to Meet NHV_{CZ} Targets	-71,600	354[b]	-25.3
Nationwide Total Utility Operating Costs			**51.4**

a Total number of assisted refinery flares from Table 11 of Docket Document EPA-HQ-OAR-2010-0682-0209, less 48 (assisted flares already subject to CDs).
b Total number of steam-assisted refinery flares from Table 11 of Docket Document EPA-HQ-OAR-2010-0682-0209, less 48 (assisted flares already subject to CDs).
g MM$/yr. = million dollars per year.

2.7.3.5 Comparison of Proposal and API/AFPM Alternative Proposal

2.7.3.5.1 A Combustion Zone Net Heating Value (CZ-NHV) of 200 BTU/SCF as a Three Hour Average and Equivalent CZ-LFL and CZ-C Alternatives (in combination the "API/AFPM Alternative") Is all That Is Justified to Provide a Reasonable Assure of 98% Destruction Efficiency for Steam-Assisted Refinery Flares

On page 36907 of the preamble, it is claimed that the current flare gas heating value requirement "only considers the gas being combusted in the flare and nothing else (*e.g.,* no assist media)" and "[t]he General Provisions, however, solely rely on the net heating value of the flare vent gas" as part of the argument as to why revised limits are needed. However, these claims are false. There are separate flare gas minimum heating values in §63.11(b) because the 1980's testing for assisted flares was performed with assist gas present at normal values and thus a different minimum flare gas heating value was found to be needed than was found for unassisted flares. The current §63.11 300 BTU/SCF minimum flare gas heating value for flare gas accounts for the dilution impact of normal steam or air assist gas and since 0.5 mole of assist gas per mole of flare gas was a typical assist gas rate, the 300 BTU/SCF is totally consistent with the 200 BTU/SCF minimum value found for unassisted flares in those studies. Thus, the current requirements reflect EPA's conclusion from the 1980s flare studies that a combustion zone heating value of 200 BTU/SCF provides reasonable assurance of a 98% DE and the current General Provisions minimum flare gas heating values take normal assist gas ratios into account.

By moving this 200 BTU/SCF minimum to the combustion zone and controlling assist gas for steam-assisted flares, rather than relying on an assumed 50% dilution, improved compliance assurance is obtained in light of tendency for sources to over-steam in an effort to assure no visible emissions. The obvious question, then, is whether the newer test data indicated a combustion zone heating value higher than 200 BTU/SCF is justified in order to provide further assurance that the 98% DE intent is being achieved. EPA has concluded that a higher combustion zone minimum value is justified and that is what is proposed. API/AFPM has evaluated a 220 BTU/SCF operation (200 BTU/SCF limit with 10% compliance margin) in a parallel fashion to the evaluation of the proposal and concludes that the incremental impact of the higher proposal cannot be justified. The following Tables, paralleling those from the 300/420 BTU/SCF evaluation, summarize the result of the API/AFPM 220 BTU/SCF analysis.

Table 2.7.10. API/AFPM Nationwide Flare Control Efficiency and Emission Reduction Estimates for Proposal and API/AFPM Alternative Refinery Flare Combustion Control Requirements

Control Alternative Description, including Compliance Margin	Average Destruction Efficiency (%) (Assisted Flares)	VOC Emissions (tons/yr.)	HAP Emissions (tons/yr.)	VOC Emission Reductions (tons/yr.)	HAP Emission Reductions (tons/yr.)
Baseline	95.2[a]	22,300	2,560		
300/420 (270/380) BTU/SCF*	98.2[b]	11,150	1,280	11,150	1,280
220 (200) BTU/SCF	97.8[c]	12,640	1,450	9,660	1,110

a 96.2% using the EPA CE/CZ-NHV curve; 97.0% with hydrogen at 1212 BTU/SCF.
b 99.1% using the EPA CE/CZ-NHV curve; 98.9% with hydrogen at 1212 BTU/SCF.
c 98.8% using the EPA CE/CZ-NHV curve; 98.8% with hydrogen at 1212 BTU/SCF.

Table 2.7.11 Nationwide Flare GHG Emissions Estimate for API/AFPM Alternative Refinery Flare Combustion Control Requirements

Description	Average Destruction Efficiency	CO_2 Emissions (tonnes/yr.)	CH_4 Emissions (tonnes/yr.)	N_2O Emissions (tonnes/yr.)	CO_2e Emissions[a] (tonnes/yr.)
Baseline	95.2	2,038,000	18,200	20.3	2,427,300
Control Alternative 1					
Emissions based on improved destruction efficiency	97.8	2,077,000	10,313	20.7	2,300,000
Steam savings (9.3 MMlb/yr./flare)[c]		(122,000)			(122,000)
Natural Gas Use (890 klb/yr./flare)[c]	97.8	203,000	1624		237,100
Total for Control Alternative 1					2,415,100
Net GHG Impacts for Control Alternative 1					(12,200)

Table 2.7.12
API/AFPM Calculation of Costs for API/AFPM 200 BTU/SCF, 3-hour Average, Alternative for all Flares at Major Source Refineries (in 2010$)
(Investment Section)

Monitoring Equip. or Material	Capital Equipment Cost ($/flare)	Annualized Cost ($/yr./flare)	Number of Flares	Nationwide Capital Equipment Cost (MM$)[g]	Nationwide Total Annualized Cost (MM$/yr.)[g]
GC[a]	980,000	141,500	0	0	0
HC Analyzer	180,000	61,000	0	0	0
Calorimeter	105,000	30,000	85[b]	8.9	2.6
Flare Gas Flow Meter	440,000	80,750	0	0	0
Steam Controls/Flow Monitor	684,000	124,300	219[c]	149.8	27.2
Air Controls/Flow Monitor	164,000	52,000	59	9.7	3.1
Natural Gas Controls/Flow Monitor	100,000	18,000	208	20.8	3.7
Engineering Calculation Costs	7,000	13,160	200	1.4	2.6
Nationwide Total Investment				**190.6**	**39.2**

a Assumes GC requirements made compatible with existing GCs.
b Assumes only flares without heat content capability add that capability through use of calorimeters (matches EPA Alternative 1 assumption).
c Assumes that the 3-hour averaging time and elimination of the dual limit reduces the number of non-routine steam-assisted flares that need full steam control from 50% to 25%.
g MM$ = million dollars; MM$/yr. = million dollars per year.

Table 2.7.13
API/AFPM Calculation of Costs for Control Alternative 1 for all Flares at Major Source Refineries (in 2010$)
(Operating Cost Section)

Monitoring Equip. or Material	Annualized Cost ($/yr./flare)	Number of Flares	Nationwide Total Annualized Cost (MM$/yr.)[g]
Average Natural Gas Costs per Flare to Meet NHV_{CZ} Targets	102,100	413[a]	42.2
Steam Costs (Savings) per Flare for Steam Controls to Meet NHV_{CZ} Targets	-56,900	354[b]	-20.1
Nationwide Total Utility Operating Costs			**22.1**

a Total number of assisted refinery flares from Table 11 of Docket Document EPA-HQ-OAR-2010-0682-0209, less 48 (assisted flares already subject to CDs).
b Total number of steam-assisted refinery flares from Table 11 of Docket Document EPA-HQ-OAR-2010-0682-0209, less 48 (assisted flares already subject to CDs).
g MM$/yr. = million dollars per year.

2.7.3.5.2 The Incremental Reductions Between The Proposal and The API/AFPM Alternative Are Clearly Not Justified.

Based on the considerations discussed in Comments 2.7.3.3 through 2.7.3.5, API/AFPM has recalculated the cost effectiveness of the proposal on a VOC and HAP basis as follows.

Cost Effectiveness $_{EPA}$ (VOC) = \$118,000,000/year ÷ 11,150 Tons/year = **\$10,600/Ton VOC**

Cost Effectiveness $_{EPA}$ (HAP) = \$118,000,000/year ÷ 1,280 Tons/year = **\$87,300/Ton HAP**

The API/AFPM alternative cost effectiveness is as follow.

Cost Effectiveness $_{API/AFPM}$ (VOC) = \$61,300,000/year ÷ 9,660 Tons/year = **\$6,350/Ton VOC**

Cost Effectiveness $_{API/AFPM}$ (HAP) = \$61,300,000/year ÷ 1,110 Tons/year = **\$55,200/Ton HAP**

Thus the incremental cost effectiveness of the API/AFPM Alternative to the proposal is:

Incremental Cost Effectiveness (VOC) = \$56,700,000/year ÷ 1,490 Tons/year = **\$38,000/Ton VOC**

Incremental Cost Effectiveness (HAP) = \$56,700,000/year ÷ 170 Tons/year = **\$333,500/Ton HAP**

Thus, the incremental reductions between the proposal and the API/AFPM alternative are clearly not justified.

2.7.3.6 Comments on the Specifics of The Proposed Flare Combustion Control Requirements.

2.7.3.6.1 Placing a Velocity Limit of 60 fps on Flares Using The Total Hydrocarbon Compliance Option Eliminates This As A Viable Alternative for Demonstrating Compliance With The Combustion Efficiency Limits.

Flares that demonstrate compliance with the combustion efficiency parameters using a total hydrocarbon analyzer for compositional analysis are inappropriately constrained to a maximum flare tip velocity of 60 fps.

§63.670(d) states "For each flare, the owner or operator shall comply with either paragraph (d)(1) or (d)(2) of this section, provided the appropriate monitoring systems are in-place. If a total hydrocarbon analyzer is used for compositional analysis as allowed under section (j)(4) of this section, then the owner or operator must comply with paragraph (d)(1) of this section.

(d)(1) Except as provided in paragraph (d)(2) of this section, the actual flare tip velocity (Vtip) must be less than 60 feet per second when regulated material is being routed to the flare. The owner or operator shall monitor Vtip using the procedures specified in paragraph (i) and (k) of this section.

As discussed in Comment 2.7.4.3 the 400 fps restriction on flare tip velocity is without a strong technical basis and is unnecessary for ensuring high combustion efficiency. Placing a limit of 60 fps on flares where a total hydrocarbon analyzer is used for compositional analysis will have the effect of eliminating this for many flares as a viable alternative for demonstrating compliance with the combustion efficiency limits.

2.7.3.6.2 The Required "Feed Forward" Compliance Determination is Unworkable and Should Not Be Finalized.

On page 36910 of the proposal preamble, EPA explains the required combustion calculation approach as follows.

> Given the short averaging times for the operating limits, we are proposing special calculation methodologies to enable refinery owners or operators to use ''feed forward'' calculations to ensure compliance with the operating limits on a 15-minute block average. Specifically, the results of the compositional analysis determined just prior to a 15-minute block period are to be used for the next 15-minute block average. Owners or operators of flares will then know the vent gas properties for the upcoming 15-minute block period and can adjust assist gas flow rates relative to vent gas flow rates to comply with the proposed operating limits.

There are many problems with this calculation approach.

1. The most serious issue is that it does not address the problem it is purported to correct. If flare gas properties are varying so quickly that a particular GC measurement would show that the previous 15 minutes were a deviation from the flare combustion limit, then it is varying enough that setting the steam and assist gas rates based on that value is equally likely to cause the next 15 minute period to be out of compliance. Under the credible evidence rules an owner/operator could not ignore an indicated non-compliance if the measurement at the end of a 15 minute period showed an unacceptable heating value or H_2/olefin ration. This calculation artifice does not make up for the lack of a reasonable averaging time that is consistent with the underlying emission limitation and control capabilities.

2. This calculation approach forecloses adjusting for known changes between heat content data points (e.g., flow rate changes, heat content changes from a BTU analyzer, and even composition changes based on upstream flow rate data and known events), since that would compromise the compliance demonstration. However, if the flare gas rate changes during that 15 minutes, the steam rate and/or assist gas rate will need to change. Furthermore, if there is an event or process change, such as losing a flare gas recovery compressor, routing fuel gas to the flare, starting or stopping a nitrogen purge, switching a coke drum to the flare, or starting or stopping a regeneration to the flare, the controls could not be adjusted for these known impacts without causing a calculated non-compliance. Finally, modern control schemes are quite sophisticated and use multiple data points to anticipate changes and rates of change and this calculation procedure forecloses use of such tools, since compliance is linked to the last measurement without consideration of its rate of change or other available data.

3. While the composition information is nominally available on a 15 minute basis, results are not actually available every 15.00 minutes as this calculation procedure seems to assume. The composition data will actually become available at changing times throughout the 15 minute period (since the cycle time will be <15 minutes) and some 15 minute periods will have two composition data points, or for the BTU and total hydrocarbon alternatives, where repeat times are shorter, there will be multiple values in all 15 minute periods. The proposed calculation does not accommodate such variable data cycles. Similarly, this calculation approach does not fit composition data gathered through the grab sampling alternative.

4. This approach does not accommodate use of a BTU analyzer for heat content and a GC for H2/olefin concentrations, the likely approach sources will use to try to deal with this short averaging time. With such a dual measurement approach there will be 2 or 3 heat content determinations for each H_2/olefin determination and the times of these measurements relative to each other will vary.

5. The hydrogen and olefin contents used for determining which limit applies for any 15 minute period are specified to be the average concentrations in the combustion zone. Those concentrations depend not only on the concentrations of these components in the flare gas, but on the steam and supplemental gas rates during the 15 minute period. While the waste gas concentrations are only measured roughly every 15 minutes, the steam and assist gas rates may be varied more quickly than that, as heat content data from a BTU analyzer is available or upstream or event information indicates a change in flare gas rate and/or composition. Thus, it is unclear how a reliable 15 minute average concentration can be determined as required in §63.670(o) prior to each 15 minute period, so the applicable parameter limit can be determined and the proper control parameters set. This confusion clearly pushes source to operate to the

higher limit unnecessarily, wastefully increasing natural gas supplementation and GHG emissions.

2.7.3.6.3 The Calculations Must Address How to Handle Time Periods When there Is No Flare Gas Flow and Periods When There is No Regulated Material Flow.

The proposal does not deal with the calculation of combustion zone parameters where there is no flare gas flow and/or regulated material flow during an averaging period or where the only flow is less than the averaging period. These situations will be common, regardless of the final averaging period specified, since many refinery flares only receive flare gas intermittently and §63.670 only applies when a flare is being used to control a Group 1 vent or, under this proposal, fuel gas.

Generally, API/AFPM recommends that no average be calculated when there is no flow to a flare for the entire averaging period and those averages be recorded and reported as "no flow", rather than zero. Similarly, "no regulated material flow" should be recorded where there is no regulated material flow to the flare within an averaging period. Where there is some flow or some regulated material flow to a flare during an averaging period, the average should be calculated based on the cumulative flow and the combustion zone properties associated with that flow (i.e., no flow periods should not be included in the average, since any assumed combustion properties would be incorrect and would invalidate the calculated average). For instance if flow a particular flare only occurred for 30 minutes in an hour, the three hour average would be the average value for those 30 minutes. Otherwise the remaining 150 minutes of the three hours would have to be taken as zero and would yield a false indication of a failure to meet the minimum combustion zone properties.

For flares with purge gas, similar recordkeeping to the above should be allowed if the purge gas and pilot gas are natural gas. However, if purge gas and/or pilot gas do not consist of regulated material, their volume and combustion zone contributions should be included in the calculations for any averaging period where regulated material was present and "no regulated material flow" recorded if no regulated material was sent to the flare during that averaging period.

2.7.3.6.4 Comments on The Proposed Sampling Approach for Determining Flare Gas Heating Value and Hydrogen/olefin Content.

The proposal would allow sampling and laboratory analysis, rather than continuous monitoring for flares where continuous monitoring is not justified. The use of grab samples for flares where flare gas composition is well known, and particularly where that composition is high heating value is a significant cost and burden saving. Unfortunately, there are a limited number of such flares in refineries, because even where a flare is dedicated to one or a few well known services, low heating value equipment preparation streams are often sent there as well.

Ideally, this approach should be used for refinery flares that only receive flare gas during emergencies, major refinery startups or shutdowns and/or unusual flare gas recovery outages. However, that use is unreasonable because of the short averaging time proposed and the high heating value that must be maintained if the H_2/olefin content of the flare gas is not clear. If there is any chance that the flare gas might have a low heating value, refiners would have to send large excesses of natural gas to the flare to assure a very high heating value and rush out and catch a flare gas sample quickly, to have evidence that the emission limitation was exceeded, in case the flaring event is, as hoped, very short. Since sample results would take hours, at best, the potential for multiple deviations (4 per hour of flaring) would exist. Thus, there will be a tendency to install continuous analyzers on flares that have flow periodically, and reserve the grab sampling approach for flares that have flow only during emergencies. The other problem that may ultimately force the use of continuous analyzers on these flares is the GHG emissions that result from the excess natural gas used to assure compliance with the higher heating value limit.

2.7.3.6.5 EPA Should Not Require Continuous GCs for All Refinery Flares

On page 36909 of the proposal preamble, EPA asks for "comment on the additional benefits that using a GC offers and whether it would be reasonable to require a GC on all refinery flares." Not only do we believe GC's should not be required, we believe the proposal already essentially requires them (though they are not included in the cost estimates) and EPA should revise the rule to allow the use of the heat content, total hydrocarbon and the grab sampling alternatives in the final rule.

In order to comply with a proposed 15-minute averaging time and determine which hydrogen and olefin emission limitation alternate applies, both a continuous GC and a heat content or total hydrocarbon analyzer will be required. Since the GC cycle time for the analyses specified is 15 minutes and the flare gas can vary more quickly than that, the more responsive heat content or total hydrocarbon analyzer is also needed. The total hydrocarbon alternative emission limitation option is not a viable alternative under the proposal because it is only allowed if the flare accepts a velocity limit of 60 fps, which is not a viable restriction. Thus, the most likely combination is a GC and a heat content analyzer. As we discussed in Comment 2.7.3.4.4, the cost estimates supporting this proposal assumed only a heat content analyzer and no GC, and then only for 37% of refinery flares. We believe many more refinery flares will be forced to install the complete suite of instruments even though they will be idle most of the time, because without a GC they will have to use the higher emission limitation during any event, requiring large excesses of natural gas addition, and because use of the sampling alternative would require samples every 15 minutes to have a chance of avoiding multiple 15 minute deviations. Even the BAAQMD approach of collecting composite samples during an event would be inadequate to avoid the risk of multiple deviations because of the analysis lag time, without instantly adding massive amounts of natural gas to assure the highest potentially applicable emission limitation is achieved regardless of the heat content of the flare gas.

In explaining the reason for this comment solicitation, EPA states the following[198].

> [U]se of a GC can improve refinery flare operation and management of resources. For example, use of a GC to characterize the flare vent gas can lead to product/cost savings for refiners because they could more readily identify and correct instances of product being unintentionally sent to a flare, either through a leaking pressure relief valve or other conveyance that is ultimately routed to the flare header system. In addition, an owner or operator that chooses to use a GC (in lieu of one of the other proposed monitoring alternatives) will be more likely to benefit from the ability to continuously fine-tune their operations (by reducing assist gas addition and/or supplemental gas to the flare) in order to meet any one of the three operating limits. Furthermore, some facilities are already required to use a GC to demonstrate compliance with state flare requirements.

These arguments for requiring a continuous GC are fallacious and they clearly do not address the cost differential for a GC versus grab sampling, heat content, and total hydrocarbon analyzers. Process gas chromatographs require a shelter, utilities and extensive upkeep that is not required for the other options. Thus requiring a GC adds at least $500,000 in investment per installation and at least $20,000 in annual upkeep per GC versus the alternatives.

The use of a GC to characterize the source of flare gas may be possible, but EPA cannot justify a continuous GC at the flare versus grab samples from upstream flare branches and sophisticated laboratory analysis. Under NSPS Ja, unusual flare gas rates will be identified and if they exceed 500,000 SCFD above normal a root cause analysis and corrective action (RCA/CA) is required). Grab sampling at various locations and laboratory analyses will inform that RCA/CA and nothing would be added by requiring a continuous GC in this rule. Furthermore, the continuous GC required by §63.671 only monitors components that are common to a great many refinery processes and only monitors them just before the flare and thus would not provide information that could be used to locate a leak into the flare system.

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[198] 79 Fed. Reg. 36909 (June 30, 2014)

The second claim is that a continuous GC "will be more likely to benefit from the ability to continuously fine-tune their operations (by reducing assist gas addition and/or supplemental gas to the flare) in order to meet any one of the three operating limits." This might be true in some cases, if the GC wasn't already required, just to have a chance to meet the proposed limits. If the averaging time is changed to 3-hours or daily and the dual limits removed, then there may be cases where the incremental costs of a GC might be justified, but in those cases refiners will install those units for economic reasons. In most cases, the large incremental costs for a continuous GC will not be justified. The incremental steam and natural gas savings resulting from the presence of a GC will not justify the large investment and operating costs of a GC versus the other alternatives.

2.7.3.6.6 If Air-Assisted Flares are Included, Blower Motor Speed and Design Air Flow Data Should Be Specifically Allowed as the Basis for Estimating Assist Air Flow.

Because the air blowers are typically integral to the flare stack in an air-assisted flare, flow meters generally are not installed, but rather fan speed and the blower design curve are used to estimate air flow. This approach should be specifically allowed as an alternative to assist gas flow monitoring for air-assisted flares.

Unlike for steam-assisted flares, air-assisted flares typically have air blowers that are close-coupled to the flare stack. Thus, there is no mechanism for installing flow meters or control stations between the blower and the flare stack. Air is typically controlled by varying the blower speed and the air flow estimated as the blower design flow at the fan speed. Because of their nature and the equipment typically available when air-assisted flares were installed, the blower speed is typically controllable only at a couple of increments. For instance, the blower may only have controls to operate at an off, low speed, and high speed setting. In order to meet the proposed combustion control requirements for these flares, the blower motors and motor controllers will need to be replaced to allow continuous blower speed control. The costs for this change and associated electrical system modifications have not been included in the cost estimates presented in this proposal. Depending on the location of the air-assisted flare these costs and the costs for installing required new digital control systems will greatly outweigh the saving associated with not installing an assist air flow meter.

2.7.3.6.7 API/AFPM Agrees That It Is Unnecessary To Consider Pilot Gas in Calculating Combustion Zone Characteristics.

On page 36911 of the preamble, EPA explains that pilot gas does not mix with other gas at the flare tip before being consumed in the pilot flame and is typically a small component of the gas at the tip and thus it is unnecessary to include it in the combustion zone calculations. We concur with this conclusion and appreciate the simplification provided by not including pilot gas in the monitoring and calculation requirements.

2.7.3.6.8 Pipeline Natural Gas Should Be Defined and The Composition Should Allowed to Be Set Based on Sampling.

Proposed §63.670(j)(5) states the following.

> (5) Direct compositional monitoring is not required for pipeline quality natural gas streams. In lieu of monitoring the composition of a pipeline quality natural gas stream, the following composition can be used for any pipeline quality natural gas stream.
>
> > (i) 93.2 volume percent (vol %) methane.
> >
> > (ii) 3.2 vol % ethane.
> >
> > (iii) 0.6 vol % propane.
> >
> > (iv) 0.3 vol % butane.
> >
> > (v) 2.0 vol % hydrogen.
> >
> > (vi) 0.7 vol % nitrogen.

1. It is assumed that "pipeline natural gas" means natural gas received from outside the plant by pipeline or produced at the plant for sale as natural gas, but that should be made explicit by adding a definition.

2. The proposed composition to be assumed for pipeline natural gas is problematic, because it represents extremes that could lead to poor control decisions. If large supplemental gas flows are required to meet the specified CZ-NHV, the relatively large hydrogen component and nitrogen component in this presumed composition could lead to false steam reductions and supplemental gas additions and the high propane and butane concentrations could lead to unrealistic flare VOC estimates. Thus, we recommend that results from weekly pipeline natural gas samples be allowed as an alternative to use of the presumed composition.

2.7.3.7 Temporary Flares Should be Excluded from the Proposed Requirements and Subject to an Alternative, Simplified Set of Requirements.

Temporary (often rented) flares are used in degassing tanks[199] and similar occasional equipment preparation uses, where a permanent flare connection is not available and as temporary replacements for permanent flares, while the permanent flare is being maintained. Use of temporary flares is required where the need is infrequent and flare headers are not already available (e.g., tank degassing), or where process outages and, potentially fuel supply disruptions might occur if an alternative flare was not made available. These units can be equipped with basic monitoring (e.g., flow) and manual controls (e.g., assist gas flow, if any), but cannot readily be equipped with sophisticated compositional monitors or automatic steam and/or supplemental gas supply or control.

Thus, we recommend the following

> §63.670(s) *Temporary Flares as allowed by the Administrator.* Temporary flares are exempt from the requirements of this section if the flares meet all of the following requirements:
>
> (1) Each temporary flare must be used for less than twelve months; after twelve months, the unit is a permanent, stationary source, and subject to the requirements of §63.670. Use of another temporary flare for the same purpose within three years is considered a permanent, stationary source and is subject to the requirements of §63.670.
>
> (2) Each unit must only be used during process vessel and tank de-pressurization, short-term maintenance events, as a temporary replacement for a permanent flare, force majaure occurrences, or other instances as allowed by the Administrator.
>
> (3) Each unit shall comply with the requirements of §63.11.

[199] NSPS Ja sulfur requirements for tank degassing are addressed Comment 4.3.3.

2.7.3.8 The Proposed Provisions for Establishing Flare Specific Operating Limits Should be Simplified to Reduce Burdens and Speed Their Review and Approval and Should Specifically Include Provisions to Utilize Dynamic Operating Limits

Rather than taking the approach of complying with static operating limits, the majority of the flares that are subject to consent decrees comply with dynamic operating limits, e.g. a CZ-NHV limit that changes based upon the composition of the waste gas. This approach requires a GC in order to obtain an on-line measurement of the composition of the gas and the ability to program and dynamically control the rate of steam and supplemental gas addition to achieve the calculated operating limits. Should a site be willing to invest in this level of monitoring and control, the rule should provide the site the ability to establish and comply with dynamic operating limits as allowed in the consent decrees without going through the burdensome procedures required in §63.670(r).

2.7.3.9 EPA Should Provide An Alternative to the Proposed Combustion Controls that Accounts for the Removal of HAPs Through Flare Gas Recovery.

EPA must recognize the benefits of flare gas recovery and include an option in the final rule to allow refineries to include the removal of HAPs from the flare in a flare gas recovery operation in demonstrating that 98% destruction or recovery of HAP has been achieved. It is critical that EPA provide viable and reasonable alternatives to the proposed net heating value (NHV) options proposed. We recommend that EPA include an alternative that allows a facility to seek approval of other monitoring requirements than those proposed in §63.670 if the overall removal of HAP from miscellaneous process vents can be demonstrated to be greater than 98 percent using an alternative methodology.

2.7.3.10 The Rule Language Should be Flexible Enough to Permit Direct Combustion Efficiency Measurement as a Potential Future Compliance Option.

While cost-effective instrumentation capable of directly measuring flare combustion efficiency on an ongoing basis is not currently commercially available, there is active research in the area with promising candidates emerging. Support to develop this technology should continue and rule language should be flexible enough to permit direct combustion efficiency measurement as a compliance option once it is available.

Direct measurement of flare combustion efficiency as a tool for assuring high combustion efficiency for flares has been the focus of several recent technology development efforts. These methods have been used for relatively short term studies, but would not, in their current form, be suitable for a permanent installation. Once commercially proven, however, they might be viable, cost effective alternatives to the monitoring being proposed in this rulemaking, particularly for new flare installations.

2.7.4 EPA's Proposed Extension of Flare Tip Velocity and Visible Emission Requirements To Emergency Flaring Ignores Technical Realities and Is Contrary to the CAA.

It is proposed to extend the velocity and visible emission limits in §63.11 to flare operations during emergencies. EPA's reliance on the *Sierra Club* decision to justify extending normal operations requirements to emergency situations is misplaced and disregards EPA statutory standards-setting obligations. Since refinery flares were not designed for meeting those limits during emergency periods, a huge number of new flares and steam boilers will be needed to comply. Furthermore, in light of the new combustion control requirements velocity or visible emission limits are not required to demonstrate HAP destruction. The available data demonstrates that HAP and VOC destruction efficiencies are maintained at emergency release velocities as long as a flame is present and the new combustion zone requirements, which apply to all flare operations, assure adequate heat content to maintain a flame. Thus, there is no scientific or compliance assurance basis for retaining the existing limits or, if they must be retained, for extending their applicability. Complying with the new combustion zone requirements provides compliance assurance at any velocity.

2.7.4.1 EPA's Proposed Standard For Flares Fails To Recognize That Tip Velocity and Visible Emissions Limitations Have Not Been Achieved and Are Not Achievable During Periods of Malfunction or Emergencies – Even By the Best Performing 12 Percent of Sources.

On page 36904, EPA states that they are "proposing under CAA section 112(d)(2) and (3) to amend the operating and monitoring requirements for petroleum refinery flares." EPA has historically taken the reasonable position that it must set MACT floors "that the best performing sources can meet 'every day and under all operating conditions.'"[200] Section 112 specifically requires EPA to set standards that have been achieved by the best performing

[200] See Nat'l Ass'n of Clean Water Agencies, 734 F.3d at 1143 (quoting 75 Fed. Reg. at 63,269).

sources and are achievable considering cost and other factors. In direct contrast to this mandate, portions of the proposed work standard for flares have not been achieved by the best performing sources and are unachievable during certain flaring events.

While the currently proposed and existing operating and monitoring requirements for flares include a limit on flare tip velocity, this limit was not established considering flare emissions associated with high hydraulic load, such as during significant malfunction or upset events. Rather the flare tip velocity was established based on the normal hydraulic load that flares would be expected to experience during non-SSM periods. Similarly, the proposed emission standard for flares includes a limitation on visible emissions from flares that does not consider the higher hydraulic loads associated with malfunction and upset events. It is well documented that emergency flare emissions associated with malfunction events can sometimes exceed the typical hydraulic load of the flare, and, in fact, flares are designed with that in mind. At these higher hydraulic ranges, the existing flare tip velocity standard and visible emissions prohibition are unachievable, even though the flare can still operate within the required destruction deficiencies and within its maximum designed hydraulic load.

EPA is required under section 112 to demonstrate that compliance with proposed flare standards is compliant with the statute for all operating conditions. If the generally applicable flare standards (or parts thereof) have not been achieved and are not achievable for certain operating conditions, as is true in this case, EPA must either establish a numeric emission standard in accordance with section 112(d)(2)-(3) or, if that is not feasible, establish a work practice standard under section 112(h) that is achievable under these operating conditions.

2.7.4.2 Refinery Flares Are Not Designed to Meet The Proposed Tip Velocity and Visible Emission Limits During Emergency Releases and The Regulations Have Never Required That They Do So.

The proposed limits would have significant adverse impacts on the principles and practices embodied in industry standards for flare design. These limits are unachievable for existing flares, and the new requirements will place flare operators in a situation of potential non-compliance in order to safely operate their refinery. Complying with the new velocity limits at all times would require hundreds of additional flares to be installed. Industry data suggests a 50-80% flare capacity debit for this change, resulting in more than doubling of the number of flares in the industry (i.e., adding at least 500 new, larger capacity flares), at an estimated cost in excess of $10-20 billion[201], and at least a decade to implement. Meeting the visible

[201] Assuming $20-40 million for each new flare, knockout drum and associated piping and facilities. Data from API/AFPM

emissions requirements requires addition of massive new steam generation facilities that would not only involve billions more investment, but would result in large emission increases, since this equipment would have to operate continuously to assure rapid response in emergencies, and would lead to adding additional flares to offset the additional hydraulic load imposed by the steam.

The tip velocity and visible emission limits should be dropped, especially under conditions where the hydraulic loading exceeds the design case flow rates. Compliance with new requirements to maintain a minimum net heat content in the combustion zone is adequate for ensuring high levels of HAP destruction under all operating conditions.

The industry standard for flare design, API Standard 537 "Flare Details for General Refinery and Petrochemical Service" addresses the mechanical design, operation, and maintenance of flare equipment. In addition, API has developed a set of flare datasheets which can be found in Appendix E of the Standard. The use of these datasheets is standard practice in the industry, and provides a concise, uniform means of recording and communicating design information.

The Committee that governs this Standard is comprised of industry representatives responsible for flare operations and the vendors who perform the actual flare design and oversee the construction of the flares. This Committee is extremely concerned about the significant adverse impacts the proposed requirements on tip velocity and visible emissions would impose on the principles and practices embodied in the Standard, at no environmental benefit, and they have provided input to these comments on the potential issues raised by this proposal.

It is important to understand that flares are designed to be smokeless and to maintain a flare burner tip velocity of ≤ 400 fps up to the "design case". Typically this case is between 20 and 50% of the full hydraulic capacity of the flare. However, flares must be capable of safely handling the situation where all of the safety relief valves simultaneously discharge to the flare system. This situation rarely if ever occurs (catastrophic power outage, large fire, site-wide loss of steam or cooling water) but none-the-less the flare system has to be designed to handle this load.

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members indicate costs for recently constructed and planned new flares is the range of $30-60 million depending on the flare capacity and piping specifics.

Five Committee flare designers (vendors) have independently studied the impact on flare design if they were required to meet the 400 fps tip velocity limit in all circumstances. Visible emissions impacts are harder to quantify and were not directly addressed in these analyses. The designers completed datasheets for steam-assisted flares ranging from 250,000 to 1,000,000 lb/hr of flow. A datasheet on a 250,000 lb/hr air-assisted flare was also completed. The results of these separate analyses were very similar, and are summarized in Table 2.7.14 below[202].

Table 2.7.14 – Summary of Flare Vendor Analyses on Impact of New Tip Velocity Limit on Flare Design

Effect on flare tip size	Increase in flare diameter varies from 33% to 80%.
Stack height increase	20-40ft (based on 243ft stack) for increased radiation
Purge gas (nitrogen)	80% increase
Purge gas (fuel gas)	Over a 200% increase
Steam assist required	180 -380% more steam assist required.
CO2 produced	Over a 200% increase in CO2 produced
Turndown ability of flare	This would significantly increase the amount of time that the flare tip would operate in low turndown conditions and increase the relative effect of turndown operation. This could cause increase in emissions, increased supplemental gas requirements and decreased flare tip life (see life of flare tip)
Structural loading – (wind load on a larger tip)	This would contribute to a 50% to 150% increase in the flare stack weight and structural loading. Not as simple as just putting on a larger tip (see Part A designer A committee comments).
Life of flare tip	Difficult to generalize, but if as an example if a tip has a four year run between maintenance, plan for 3years i.e. increased plant turnarounds.
Number of pilots required.	+1 to 2 additional pilots required.
Estimate of tip replacement cost.	Flare tip replacement costs would increase by 50% to 150% due to increased tip diameter requirement. Note this does not include work to actually be able to install the larger flare tip in the first place. Also see structural considerations.
Air assist flares	Not technically feasible to retrofit an existing air assist flare to meet 400fps “Bulldoze and start again”.

The above table identifies the dramatic and costly impacts on flare design that would be necessary to achieve the tip velocity limit at all times. The large costs and increased emissions associated with the increased size of the flare tip and the height of the flare stack, the increase in the consumption of utilities (pilot/purge gases, steam), and the shortened tip life and consequently more unit downtimes cannot be justified for such rare emergency occurrences.

[202] Gilmartin, Tom, *Minutes from the July 10, 2014 Meeting of the API Task Force 537*, July 11, 2014.

Given the impracticality, engineering challenges, and huge costs of retrofitting existing flares to meet the new limits, most refineries would elect to build new flare systems.

Based upon our analysis, more than 500 new large flare systems would be required with a capital cost in excess of $10-20 billion, because design smokeless flare capacities are less than 50% of the flare hydraulic capacity and generally much less.. EPA has not included the massive costs associated with these new flare systems in the rule record. There are no anticipated benefits in HAP combustion efficiency associated with these investments, and in fact one would expect a significant increase in net emissions (i.e., criteria pollutants, air toxics and GHGs) due to the increase in purge gas and the consumption of utilities to keep the flares lit and operating safely. There would also be large emissions generated by the additional steam generation facilities required to control visible emissions at the flare hydraulic limit.

2.7.4.3 Velocities In Excess of 400 ft./sec. and/or The Presence of Smoke Do Not Imply A Reduced Combustion Efficiency.

The tip velocity and visible emission limits should be dropped, especially under conditions where the hydraulic loading exceeds the design case flow rates. Compliance with the new requirements in this proposal to maintain a minimum net heat content in the combustion zone is adequate for ensuring high levels of HAP destruction under such conditions.

The API 537 Committee has discussed whether the current 400 fps flare tip velocity limitation is a reasonable parameter that avoids flare burner lift off.[203] Four flare designers (from 4 separate flare vendors) all reported they do not consider 400fps as being a limitation in preventing flare burner lift off. Two reported they design flares for hydraulic loads up to sonic velocity and two reported they design hydraulic loads up to 80% of sonic velocity.

Overall the designers stated that while they adhere to the 400 fps tip velocity requirement for the normal design case [because of historical EPA rules], in their view there were no proven data to support this limit. Until now this had not been problematic because the velocity limits did not apply to start up, shutdown and emergency cases.

Similarly, smoke from a flare does not imply that a flare is operating with reduced combustion efficiency. A single study reported reduced hydrocarbon destruction efficiency measured for heavier, unsaturated hydrocarbons and noted a correlation between propensity to smoke and reduced combustion efficiency.[204] However, a recent comprehensive literature review noted

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[203] Ibid.

[204] Straitz III, J. F. *Hydrocarbon Processing*, 56, 1977, 131

that there were deficiencies in the instrumentation and wind interference with gas sampling and, "the very low combustion efficiency reported during smoking tests has been contradicted by subsequent studies."[205]

Romano concluded that contributors of low combustion efficiency included excess steam or flaring high volumes of low heating value gases, but that "smoking flares do not necessarily indicate inefficient hydrocarbon combustion."[206]

Past and recent studies measured combustion efficiency of flares under the range of conditions from excessive assist gas addition to smoking and found smoking flares, in all cases, operated with combustion efficiencies greater than 98%. [207]

A recent computational evaluation by Castiñeira and Edgar on flare combustion efficiency[208] noted that, "it is important to remark that smoke does not necessarily indicate a significantly inefficient combustion." That paper also cited previous work by Seebold[209] stating that soot formation typically comprises less than 0.5% of unburned hydrocarbons and that smoking flares can have a combustion efficiency of greater than 99%.

API/AFPM also commissioned Scott Evans of CleanAir Engineering to review the available information on flare velocity limits and his report is included as Attachment D-4 and his conclusions are summarized as follows.

> Current flare velocity limits restrict flare operation above 60 fps and prohibit operation entirely above 400 fps. This paper reviewed data from the data sets used to establish those federal regulatory velocity limits as well as recent high velocity flare test results.
>
> All of the data collected, including the data used previously to set current limits as well as recently collected data, show that high velocity flaring results in high flare combustion efficiency (>96.5%). Previous limits were based solely on lack of data at higher flare exit velocities. There is no indication either in the 1980's

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[205] Gogolek, P.; Caverly, A.; Schwartz, R.; Seebold, J.; Pohl, J. "Emissions from Elevated Flares – A Survey of the Literature." Report prepared for the International Flaring Consortium, April 2010

[206] Romano, R. R. *Hydrocarbon Processing*. *62*, 1983, 78

[207] See McDaniel, M. "Flare Efficiency Study." EPA-600/2-83-052, 1983; Cade, R. and Evans, S. "Performance Test of a Steam-Assisted Elevated Flare with Passive FTIR." Report, May 2010; Allen, D. T. and Torres, V. M. "TCEQ 2010 Flare Study Final Report." August 2011 at http://www.tceq.texas.gov/assets/public/implementation/air/rules/Flare/2010flarestudy/2010- flare-study-final-report.pdf

[208] Castiñeira, D. and Edgar, T. F. Energy & Fuels. 20¸ 2006, 1044

[209] Seebold, J. "Efficiency of Industrial Flares: The Perspective of the Past." ARFC Symposium, 2003

> studies or the more recent flare studies that high velocity flaring contributes to poor combustion efficiency.
>
> The data on high velocity flaring is consistent with combustion theory, which shows that high velocity flames result in better air entrainment and mixing and so result in higher combustion efficiency. Limits on high velocity flaring are unnecessary and, in fact, counter-productive.

The billions of dollars in investments that would be required for new flare systems with no demonstrated benefits in terms of combustion efficiency cannot justify application of the tip velocity and visible emission limits during emergency events. Consequently, the tip velocity and visible emission limits should be dropped. This is not justified under any conditions and especially under conditions where the hydraulic loading exceeds the design case flow rates. Compliance with new requirements to maintain a minimum net heat content in the combustion zone is adequate for ensuring high levels of HAP destruction under all conditions.

2.7.4.4 API/AFPM Recommends That The Velocity Limit for Flares Be Removed or, As An Alternative, The Equation Representing the Minimum Heat Content That Assures High DE at Higher Velocities Be Revised to Reflect a Requirement for 600 BTU/SCF for Exit Velocities Above.

Under the proposed rule, the maximum flare tip velocity limits would apply to all flaring episodes including major SSM and emergency events. Because a prohibition of flare exit velocities greater than 400 fps is not necessary to ensure high CE (and thus DE), we offer the following recommendations for revision to the proposal that will be protective of the environment because high DEs will be assured and no new flares (and their resulting emissions) will be needed.

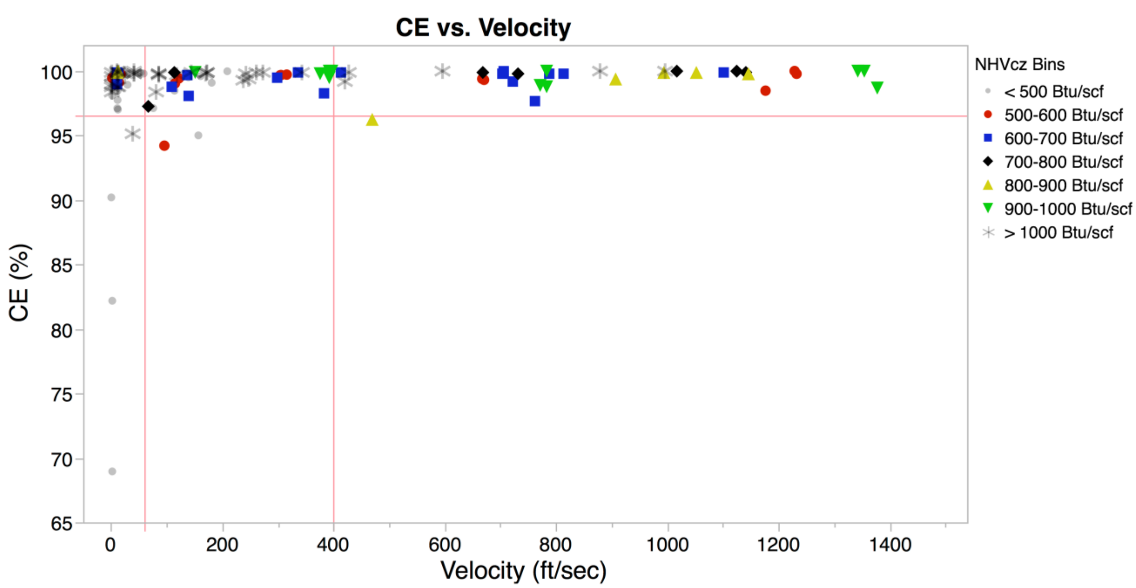
The 1984 flare study by Pohl (propane/N2 mixture, 3 inch diameter steam-assisted flare, no pilot) showed that at high velocities, flares maintained high CE until the flame was extinguished. Because those tests only spanned a range up to 400 fps, a 400 fps max limit was imposed in the regulations.

More recently, the relationship between tip velocity and CE was evaluated during the PFTIR flare tests at Marathon Garyville (2.4-inch diameter, pressure and steam-assisted ground flare with pilot). Similar to Pohl, the data show that at high velocities (> 60 fps up to sonic velocity), flares maintain high combustion efficiency until the flare flame is extinguished.

Unlike Pohl which stopped at 400 fps, the Marathon data was collected at velocities in excess of 1100 fps. Again, no gradual decline in CE was observed. Both tests demonstrated that, provided that there is adequate heat content in the flared gas to maintain a flame, the flare operates at high CE. The fundamental difference between the high velocity data and the low velocity data is that low velocity flares can exhibit a gradual decline of CE as a function of declining heat content. <u>For a low velocity flare, a lit flame can exhibit a range of flame qualities associated with a range of flare CEs, depending on heat content. For a high velocity flare, any lit flame necessarily operates with high CE because a deficiency in heat content results in immediate extinguishment of the flame.</u> Figure 2.7.3 shows all publically available high velocity data, where CE as a function of velocity is plotted. All of the data is binned by similar CZ-NHV. High CE is consistently observed for flares at high exit velocities provided that enough heat content is present to support combustion. Flares with at least 500-600 Btu/scf show high combustion efficiency at high velocity. Each of these flares also maintained a visible flame during these periods of high velocity. At the point that the heat content was insufficient to support combustion, the flame was extinguished. Thus, a compliance monitoring strategy for periods at high velocity could be to conduct periodic visible observations of the flare to ensure that the flame is maintained.

Figure 2.7.3

Combustion efficiency measurements of flares as a function of exit velocity binned by combustion zone net heating value of the flare gas.



Thus, API/AFPM recommend that the tip velocity requirements be removed entirely from the rule. In the low velocity regime, the new flare combustion efficiency requirements are more than adequate to ensure high CE and DE. In the high velocity regime we recommend adding a requirement to maintain a lit flame. This additional requirement will ensure that should the flare experience high velocity periods, the CE is maintained.

API/AFPM appreciates, however, that it may be difficult for EPA, philosophically, to remove numerical requirements that have become conventionalized over time across multiple rules. As an alternative, API/AFPM recommends that a new equation representing required heat content as a function of velocity be developed on a combustion zone heating value basis, with maximum of 600 BTU/SCF (above 400 fps). API/AFPM is evaluating the details of this approach and will provide additional detail in the near future.

2.7.4.5 API/AFPM Recommends A Work Practice Approach to Managing Visible Emissions from Flares.

Scott Evans of CleanAir Engineering has reviewed visible emission considerations relative to the application of this proposal to refinery flares and reached the following conclusions.

> While its good practice to minimize visible emissions from a flare, recent test data has confirmed that the presence of smoke is not an indication of poor hydrocarbon destruction. Flare combustion efficiency tests from the 1980's through recent tests show that a smoking flare has high combustion efficiency. Proper operation of assisted flares significantly reduces periods of smoking while maintaining high combustion efficiency. Most flares operate today with very few smoking issues. However, EPA's proposed Refinery Sector Rule introduces new requirements that unnecessarily complicate compliance while not providing additional environmental benefit.
>
> Flare monitoring for visible emissions beyond what is required today is not necessary. Once the automated assist control systems required by the rule are in place and operating properly, smoking events will be minimized. Having plant personnel in a "stand-by" mode monitoring for flare smoking that may never happen or will be rapidly mitigated, is wasteful and adds no additional environmental protection.
>
> The existing definition of a smoking flare in Method 22 leads to ambiguities and does not take into account combustion occurring in the non-visible portion of the combustion zone. The existing definition may lead to flare operators unnecessarily increasing steam leading to potentially lower combustion efficiency. In light of the new test data and emphasis on flare operations, Method 22 is outdated and warrants updating.

> Unless a feasible alternative work practice is provided, the removal of the SSM exemption means most existing flares may be out of compliance with the visible emissions requirements during a full relief scenario. Additional flare capacity would likely need to be added to prevent non-compliance.

The full report is included as Attachment D-5.

If EPA believes that a visible emissions standard is necessary, even with the proposed combustion control requirements in place, API/AFPM recommend the following two part approach.

With the exception of the combustion in a flare of process upset gases[210] or gas that is released to the flare as a result of other emergency malfunctions[211], flares shall be designed for and operated with no visible emissions (except for periods not to exceed a total of 5 minutes during any 2 consecutive hours).

During the combustion in a flare of process upset gases or gas that is released to the flare as a result of other emergency malfunctions, if the visible emissions from the flare exceed 5 minutes in 2 hours, the owner or operator will take corrective action to minimize the visible emissions and their duration, consistent with good engineering practice and safe operation, and ensure high CE per §63.670(e).

We discuss the visible monitoring requirements associated with monitoring for visible emissions Comment 2.7.5 below and those comments would apply to this recommendation as well. In summary, it is impractical and wastefully costly to require Method 22 monitoring for flares and video and visual monitoring should be specified for determining the occurrence and duration of any flare smoking event..

2.7.4.6 Flare Operators Are Required to be in Compliance With the Proposed Emergency Release Flare Tip Velocity and Visible Emission Limits Within Three Years, Though The Large number of New Flares Required will Take a Decade to Install.

[210] Per the definition in NSPS Ja - Process upset gas means any gas generated by a petroleum refinery process unit or by ancillary equipment as a result of startup, shutdown, upset or malfunction.
[211] This language comes from NSPS Ja 60.103a(h) i.e. the exemption from the 162 ppm H2S fuel gas standard.

Because the rule provides significantly inadequate compliance time for this change, it will force operators to be in violation of these limits in order to maintain the safety of the operation, during every emergency after the 3 year compliance deadline, until new flares can be installed (about a decade). Putting operators in this position is unreasonable and arbitrary and thus at least a decade should be provided for compliance if this proposed prohibition is finalized.

2.7.5 Proposed §63.670(h) Should Not Be Finalized.

Proposed §63.670(h) is as follows.

> (h) *Visible emissions monitoring*. The owner or operator shall monitor visible emissions while regulated materials are vented to the flare. An initial visible emissions demonstration must be conducted using an observation period of 2 hours using Method 22 at 40 CFR part 60, Appendix A-7. Subsequent visible emissions observations must be conducted at a minimum of once per day using an observation period of 5 minutes using Method 22 at 40 CFR part 60, Appendix A-7. If at any time the owner or operator sees visible emissions, even if the minimum required daily visible emission monitoring has already been performed, the owner or operator shall immediately begin an observation period of 5 minutes using Method 22 at 40 CFR part 60, Appendix A-7. If visible emissions are observed for more than one continuous minute during any 5-minute observation period, the observation period using Method 22 at 40 CFR part 60, Appendix A-7 must be extended to 2 hours.

No information is presented in the record to support the cost-effectiveness of these requirements or to demonstrate they are necessary for compliance assurance purposes. No cost and burden estimates are provided, as required by the CAA and the PRA, associated with the additional personnel that will be required and no data provided to support the need for these observations. There is no added value from this proposed additional monitoring versus the use of video observation to identify smoking occurrences.

2.7.5.1 The Proposed Visible Emission Monitoring in §63.670(h) is Not Needed to Control HAPs and is Unreasonable and Costly.

As discussed in Section 2.7.4.1, smoke from a flare does not imply reduced combustion efficiency. In fact, based on the results from the recent flare studies, it is widely accepted that high levels of combustion efficiency occur at the incipient smoke point. In the preamble[212], EPA agrees with this point, but goes on to say

> Smoking flares can contribute significantly to emissions of particulate matter 2.5 micrometers in diameter and smaller ($PM_{2.5}$) emissions, and we are concerned that increasing the allowable period of visible emissions from 5 minutes to 10 minutes for every 2-hour period could result in an increase in the $PM_{2.5}$ emissions from flares.

$PM_{2.5}$ is not a regulated pollutant under Section 112 of the CAA and EPA has not provided any cost or HAP emissions information to justify the costs and burdens associated with the proposed requirement to require daily visual emissions monitoring of flares and additional monitoring of flares whenever visible emissions are observed. Nor is this requirement consistent with §63.11 and EPA's intention in promulgating this requirement. In 1994, in response to a comment, EPA stated in promulgating §63.11:

> Section 63.11(b)(4) states that "Flares shall be designed for and operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours." This requirement was intended to provide a practical method for occasional observation. While this paragraph does not state the frequency that Method 22 must be applied, the <u>EPA certainly did not intend for facilities to continuously, or even daily, monitor the flare to comply with the no visible emissions requirement</u>. [213] [Emphasis Added]

Since recent test data indicates that smoking is not an indicator of poor combustion efficiency, imposing a visible emissions limit on flares is not required or needed as a control device compliance assurance measure. Thus, compliance assure provides no authorization for imposition of this requirement, even though it has historically been imposed by §60.18 and 63.11. Thus, this requirement must be justified on its own merits. As indicated above EPA claims the requirement is justified as a $PM_{2.5}$ control. However, $PM_{2.5}$ is not a regulated pollutant under CAA section 112 and EPA has not presented any data to suggest that particulate matter emitted from flares contains HAPs regulated by RMACT 1.

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[212] 79 Fed. Reg. 36906 (June 30, 2014)

[213] US EPA, *General Provisions for 40 CFR Part 63: National Emission Standards for Hazardous Air Pollutants for Source Categories, Background Information for Promulgated Regulation*, EPA-450/3-91-019b, February 1994, Page 2-170.

Performing daily visible emissions observations using EPA Method 22 provides an unnecessary burden on refiners and is an unwise use of manpower and financial resources for the following reasons:

- Since smoking events are rare and unscheduled, the probability that a smoking event will occur during a routine check is low.
- Since most flares do not receive regulated material continuously, it will be inefficient and difficult to schedule routine checks when regulated material is present. Furthermore, for a great many flares, there is no way to predict if regulated material will be sent to that flare on any particular day, so there is no way to know until after-the-fact if a daily observation was needed or even possible (no observation is possible if there is no flare gas flow to the flare for that day).
- Flare test data clearly demonstrates that visible emissions do not suggest poor destruction efficiency. In fact, EPA's combustion efficiency operating limits will result in many flares being operated at such low levels of steam that some level of visible emissions will be inevitably be present some of the time.
- Due to increased regulation of flaring, particularly through CDs and NSPS Ja, most flares are now equipped with flare gas recovery units and/or procedures that minimize routine flaring of everything except pilot and purge gas.
- Non-routine flaring would normally be checked as part of plant operating procedures.
- Most plants utilize video cameras to help the operators to keep the flares in compliance with the visible emissions standard. No information has been presented to indicate that this current monitoring is inadequate to identify flare smoking occurrences.
- If we assume a modest 15 minutes per flare to meet the daily 5 minute observation requirement (setup, reading, associated recordkeeping) and that all 510 flares are subject to this requirement each day, since you cannot know which flares might receive regulated material on a particular day) we estimate a base cost for this requirement of at \$3 million[214]. This cost greatly escalates, if extended observations are required, when the doubling or tripling of the number of refinery flares, as required by this rule, occurs, and when the Method 22 observations required when there is a visible emission observed are considered.

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[214] Based on EPA's \$84.95 per hour cost for a technical hour of effort.

2.7.5.2 Video and Visual Monitoring Should be Specified Instead of the Daily and Event Method 22 Observations in Proposed §63.670(h).

The vast majority of refinery flares are equipped with video cameras. These cameras alert the flare operator of anything unusual that might be occurring at the flare tip, and in particular, smoking. In addition, experience demonstrates that any flare smoking will be quickly apparent to operators and, in the case of most refineries, the public. Smoking event normally quickly result in communications from operators and the public. As discussed above, API/AFPM believes the available data shows that smoking does not represent a reduction in HAP destruction and that the current limitation is therefore not justified. None-the-less, if the visible emissions limit is maintained, there is no basis for adding burdensome and costly Method 22 monitoring, when video surveillance has been demonstrated to be more than adequate to identify smoking occurrences and their duration.

API/AFPM therefore recommends that video surveillance of each flare tip be required and that a record (e.g. notation in the flare operator's log) be required when visible emissions are observed, that the duration of any such smoking occurrence be recorded, and that any >5 minute occurrence in 2 hours be reported in the next periodic report. While video monitors are very reliable, they occasionally fail. In that case, the source should be required to use an alternative video camera or make hourly visual observations during the outage, when flare gas is being routed to the flare. Requiring Method 22 observations, when flare smoking is so unusual, is wasteful and unnecessary and a simple visual check is all that is justified during a video outage.

2.7.5.3 If Maintained in The Rule, §63.670(h) Should be Revised and Clarified.

The video monitoring discussed in the previous comment provides adequate information on the occurrence and duration of smoking incidents and thus there is no justification for proposed §63.660(h). However, should it be maintained many clarifications are needed and they are discussed here.

1. §63.670(h) requires an "initial visible emissions determination" using an observation period of 2 hours. It is unclear what purpose this requirement serves in the face of the requirement for daily observations. Observing flares when they are not smoking is a waste of resources and of no environmental value and adding an extra observation to the useless daily observations is even more wasteful. Thus, we recommend this "initial determination" be deleted.

2. If the “initial demonstration” requirement is maintained, the meaning of initial must be clarified. API/AFPM assumes “initial” refers to the first time a flare becomes subject to §60.670, but “initial” could be read to apply to every introduction of regulated material. For most refinery flares regulated materials go to the flare at irregular, unpredictable times, perhaps several times in a day. There is no reasonable way to know when these events occur or how long they will continue. It is unreasonable and illogical to require repeated initial demonstrations. We ask that, if this initial demonstration is maintained, that it be clarified to only be required when a particular flare becomes subject to §63.670 for the first time.

3. Proposed §63.670(h) requires “If at any time the owner or operator sees visible emissions, … the owner or operator shall immediately begin an observation period of 5 minutes using Method 22 at 40 CFR part 60, Appendix A-7.” Since these visible emission events cannot be predicted and could happen at any time, it is infeasible to begin Method 22 monitoring “immediately.” To begin Method 22 monitoring, trained personnel must be available and dedicated to the observation (per Method 22 requirements). If multiple flares are smoking, multiple trained personnel must be available. Such personnel cannot be operators, because the operators must address the conditions causing the flaring and/or the smoking. Even in the best of circumstances, it would take a minimum of 30 minutes to begin Method 22 observations and if trained personnel were not on-site it could take several hours. Thus, in most cases, the monitoring could not begin before the visible emissions end. This wording should be revised to change “immediately” to “as soon as reasonable” if this requirement is maintained. Even with that change large burdens for training large numbers of additional potential observers must be ascribed to this requirement and additional personnel must be assumed necessary.

More significantly, there does not seem to be any reason to require Method 22 monitoring for these situations. The proposal uses simple observation (visible or video) to determine that visible emissions have occurred as the trigger for this requirement. There is no reason simple observation should not be the basis for determining the duration of those visible emissions. This visible emissions requirement has been in place for flares for decades, with no indication that violations of the 5 minute criterion have gone unreported. It is arbitrary and unreasonable to impose this extremely burdensome and possibly infeasible new monitoring requirement. API/AFPM recommends this proposed requirement not be finalized, but a simple requirement to maintain a record of the time and duration of any visible flare emissions be maintained and any >5 minute occurrence in 2 hours be reported in the next periodic report.

4. EPA Method 22 requires rest periods in the 2-hour period unless two observers are used. It should be clarified that two observers are not required.

5. Finally, in lieu of two or more hours of monitoring, sources should be allowed to stipulate that the 5 minute period has been exceeded. Similarly, the daily monitoring requirement is not necessary if monitoring in response to a visible emission occurrence has been performed before daily monitoring has been carried out that day and the rule language should provide for this situation.

2.7.6 The Proposed Requirement To Install An Automatic Pilot Ignition System Is Ill-Conceived and Should Not Be Finalized.

On page 36905 of the preamble EPA states

> We are also proposing to amend Refinery MACT 1 and 2 to add a new operational requirement to use automatic reignition systems for all flare pilot flames. An automatic reignition system provides a quicker response time to relighting a snuffed-out flare compared to manual methods and thereby results in improved flare flame stability. In comparison, manual relighting is much more likely to result in a longer period where the pilot remains unlit. Because of safety issues with manual relighting, we anticipate that nearly all refinery flares are already equipped with an automated device to reignition the pilot flame in the event it is extinguished. Also, due to the possibility that a delay in relighting the pilot could result in a flare not meeting the 98-percent destruction efficiency for the period when the pilot flame is out, we are proposing to amend Refinery MACT 1 and 2 to add this requirement to ensure that the pilot operates at all times.

This is another example of EPA proposing costly and wasteful requirements based on an unreal, theoretical concern. EPA provides no information to support their concern that flare pilot outages are a problem; much less that slow reignition is a problem, despite the fact that such outages have been reported to EPA and States for decades and, thus, they would have extensive data to support their concern if it were valid. Current pilot flame technology is now to the point that it's very difficult for them to extinguish.

EPA's assertion in this paragraph that "nearly all refinery flares are already equipped with an automated device to reignition the pilot flame in the event it is extinguished" is incorrect. Quite the opposite is true; most refinery flares are equipped with manual and not automatic ignition systems.

The reasons that automatic pilot ignition systems are not widely utilized in refineries are many:

- Flares are equipped with multiple pilots and multiple thermocouples, infra-red cameras, and other devices to monitor for the presence of the pilot flames and a flare flame. It is very uncommon for a flare to lose all of its pilots and/or all pilot monitors (though it is not unusual for some pilot monitors to fail before the next repair opportunity). Members report a typical incident rate of <0.1 occurrence per year per flare of all pilots and the pilot flame being extinguished. There is adequate redundancy such that if a pilot goes out, the operator is quickly alerted and reignition is quickly instituted.

- There are two types of systems that are used to reignition pilots. These are Flame Front Generators (FFG) and electronic spark ignition systems. Automation of these systems is not considered better than manual reignition for use in continuously manned operations, such as in refineries.

- These systems are expensive and require an outage of the flare to install and maintain. As shown below in Table 2.7.15, typical refinery flare auto-reignition system installation cost is on the order of $3-4 million per flare. In general, such activities are coincided with a flare tip replacement, so these costs are incremental to the costs for taking the flare out-of-service, crane rental, etc. Not knowing how these installations would be coordinated with other flare outages leads to considerable upward uncertainty, but we estimate that the cost to install automatic pilot ignition systems across the 500+ flares in the refining industry would therefore be at least $1 to 2 billion. The cost to the industry to shut down process units in order to isolate the flare systems to install the equipment would be even larger than this.

Table 2.7.15 – Cost Information for Automatic Pilot Ignition Systems.

	Ref A 12 Flares	**Ref B 18 Flares**	**Ref C 8 Flares**	**Ref D 2 Flares**	**Ref E 3 Flares**	**Ref F 2 Flares**	**Ref G 3 Flares**
Auto-ignition Facilities Costs	41 M$	61 M$	27 M$	7 M$	10 M$	7 M$	4 M$

Furthermore, flare gas recovery and flare minimization efforts are to the point that even if there were an outage, it is unlikely that there would be much impact. As discussed in comment 2.7.3.3, EPA estimates 3810 TPY HAP emissions from flares API/AFPM estimates 1280 TPY). Thus, the 510 refinery flares average 1.7 lb/hr of HAP emissions by EPA's estimate and .57 lb/hr for our estimate. Thus, on average an unreasonably long outage of an hour would result in 87 lb of HAP emissions by EPA's estimate and 28 lb by API's estimate. To protect against this unlikely event, EPA proposes to require $1.5-2.0 billion in investment ($3-4 million per flare). Even if it were unrealistically assumed that there is an hour per year of flare outage for every refinery flare, this represents a cost effectiveness of over $5,000,000 per ton of HAP.

Consequently, it makes no sense on a safety, environmental, or cost basis to require installation of automatic ignition systems. These systems are costly, require flare outages to install and repair, and provide little improvement in compliance assurance versus manual reignition in a refinery setting. Given the low frequency of pilot outages and the requirement to continuously monitor for a pilot flame, manual ignition systems are protective of the environment.

Lastly, EPA has not identified what CAA provision authorizes this change or included any cost or associated emission reduction information in the rule record or the PRA Information Request Supporting Statement to support this costly proposal.

While we do not support the proposal for mandatory installation of auto-igniters in the refinery sector, our position does not extend to the O&G production sector, where we are aware EPA is considering allowing the optional use of auto igniters through NSPS, Subpart OOOO. In upstream, auto igniters may make sense since availability of pilot gas is dependent on a producing well where production may occasionally be interrupted for various reasons and flares are typically not of the large, elevated steam-assisted variety typical in refineries. In the refinery sector, operations are more steady state, there is generally no issue with an intermittent supply of pilot fuel, and personnel are readily available to rapidly reignition pilots if necessary.

2.7.7 Proposed Language Must Be Clarified to Require The Presence of Only One Flare Pilot Flame.

The proposed language associated with flare pilot monitoring appears to require all pilots to be lit, while the existing requirement is to have at least one lit. Such a change would have major cost and fuel supply implications that have not been addressed or justified. As recommended in Comment 1.5.2.2, all proposed language associated with flare pilot requirements and monitoring in RMACT 1 and 2 needs to be revised.

2.7.8 Comments on Proposed Flare Monitoring Instrumentation Requirements.

New and revised requirements for flare instrumentation is proposed in §63.671 and in Table 13. Because of the interaction of these requirements with other proposed new monitoring requirements for RMACT 1 and 2 and NSPS Ja, we have consolidated our discussion of the flare monitoring issues into Comments 1.5.1 and 1.5.2.

Relative to flares, our comments in that consolidated section are based on the following themes:

Per NSPS Ja flare minimization requirements, excess flaring should not be required in order to perform marginal or unnecessary instrument testing.

The special situations associated with flare instruments must be addressed (e.g., inaccessible pilot monitors, sonic and optical flow meters, optical composition monitors).

Flare instrumentation requirements must be consistent with the requirements in NSPS Ja, State Rules (e.g., Texas HGVOC monitoring, SCAQMD and BAAQMD monitoring), and applicable refining CDs, so that wasteful duplication or replacement of existing instrumentation due to minor differences is avoided.

Flare instrument requirements must be technically feasible using, as much as reasonable, industry standard equipment.

Flare instrument requirements should impose no more instrumentation outage than is absolutely necessary and periods of instrument outage and maintenance must be excused from compliance demonstration requirements.

2.7.9 Periods Where No Data is Available Because of Required Instrument Outages Cannot Be Emission Limitation Deviations.

The proposed flare combustion zone emission limitations and velocity limits have 15-minute averaging time. The proposal requires QA/QC and maintenance activities for the monitors that take more than 15 minutes to perform. This will result in several averaging periods every day for which no data is available, since daily calibrations of the GC, heat content and/or hydrocarbon analyzers are required and daily checks of pressure taps for pluggage are required. As we discuss in Comment 1.5.2.7, proposed §63.671(a)(4), provides that it is not a monitoring deviation to have the monitor off-line for some, though not all, of these activities and we request in that comment that all such required QA/QC and maintenance activates be allowed. However, that allowance does not provide relief from the emission limitations during these allowed monitor outages. API/AFPM requests that EPA include specific language in the rule providing that lack of compliance data for entire averaging periods is not a deviation from the combustion or velocity emission limitations.

2.7.10 Comments on Flare Performance Testing Requirements.

2.7.10.1 It Should Be Clarified That Initial Flare Performance Testing for the Combustion Limitations is Not Required.

The rule preamble contains the following on page 36908.

> A summary of the [combustion] operating limits specified in this proposed rule is provided in Table 3 of this preamble. We are proposing that owners or operators of flares used as APCD would conduct an initial performance test to determine the values of the parameters to be monitored (*e.g.*, the flow rate and heat content of the incoming flare vent gas, the assist media flow rate, and premix air flow rate, if applicable) in order to demonstrate continuous compliance with the operational limits in Table 3.

There does not appear to be any rule language that implements a general performance test requirement for flares. The discussion quoted above does not support a general performance test requirement since the combustion zone limits are specified in the rule and while the parenthetical indicates the parameters to be monitored, there is no limitation of them individually, only on the combustion zone limit calculated from those continuously measured values. Further, a performance test requirement would require purposely flaring large quantities of gas, probably more gas than most flares normally combust in a year, a clearly undesirable situation.

Since this preamble discussion has led some of our members to believe an initial performance test is required for all flares, not just those developing a flare specific alternative or an alternative emission limitation, API/AFPM requests EPA make clear in the final rule preamble that there is no general flare performance test requirement.

2.7.10.2 The Testing Required for Development of an Alternative Emission Limitation Should Not Be Identified As A Performance Test.

Proposed §63.670(r) provides for development of an alternative emission limitation for flares using flare specific testing. That testing is referred to as a “performance test” throughout that section. Use of that terminology is problematic, because there are many requirements imposed for performance tests that are not needed or apropos for this testing, for instance the requirement to operate at maximum representative conditions (rather than allowing operation over a range of conditions as is appropriate for establishing an alternative) and the requirement to submit the test results through the ERT (which isn’t set-up for receiving this type of testing).

We believe all of the requirements needed to assure a good test are included in §63.670(r) and thus it would be better to refer to this as a flare specific test, rather than as a flare performance test and we recommend EPA make that change.

2.7.11 API/AFPM Concurs With the Conclusion That Wind Effects Are Not a Significant Issue for Refinery Flares.

A recent article by Scott Evans and James Seebold discusses data on full-scale industrial flares and observations with respect to wind, in particular, the application of the momentum flux ratio and wake dominated flow. The full-scale industrial flare data was compared to conclusions drawn from model flare (typically < 3" simple pipe flares).

The Momentum Flux Ratio (MFR) has been used to describe flare plume and ambient wind interactions, taking into account both the momentum of the ambient wind, particularly the perpendicular component, as well as the upward momentum of the flare gas. It is defined as the ratio of vent gas momentum to wind momentum. For MFR less than one, the plume begins to bend.

The article concluded that there is no evidence of combustion efficiency degradation due to wind effects in full-scale industrial flares despite references to previous observations of wind effects on model-scale flares. Furthermore, testing confirmed that CE of industrial-scale flares is high, even at low MFR's.

Thus, we concur with EPA's conclusion that available data does not demonstrate that poor combustion is correlated with low MFR's for refinery flares.

2.7.12 Typographical and Clarity Suggestions for Proposed §63.670.

1. The reference in §63.670(b) to paragraph (h), should be to paragraph (g).

2. The reference in §63.660(i) to (c)(1)-(3) should be to (i)(1)-(3).

2.8 The Proposed Prohibition on Using a Flare to Control Halogenated Vent Streams Cannot Be Finalized Since No Required Supporting Analyses or Justifications are Provided. If EPA Believes This Is an Issue, It Should Withdraw This Proposal, Gather Information, and Address It In the Next Technology Review.

2.8.1 Statutory Authority, Emission Estimates, Standard Basis and Justification, Negative Environmental Impacts, and Cost Estimates Must Be Provided for Comment. All of the Safety Implications with Banning the Use of Flares as Controls for The Organic HAP in Halogenated Streams Must Be Addressed.

Proposed §63.670(a) states that "The owner or operator shall not use a flare to control halogenated vent streams as defined in §63.641." No discussion of this provision is included in the preamble to the proposal, nor is it even mentioned. There is no demonstration that it is justified or authorized, and even less support for the level of the standard, its applicability, and negative impacts. Nor is there any demonstration that such a provision is "achievable" for fluorinated compounds, such as those present in the HF alkylation process. Thus, there is no legal basis for imposing this requirement and the potentially significant costs and emission impacts it engenders.

Several chemical industry rules contain prohibitions on the flaring of halogenated process vent streams during normal operation, but only organic halogen compounds are considered in determining if the stream is "halogenated" and the significant costs and emission impacts were fully vetted in those rulemakings. Under this proposal, organic halogen compounds, hydrogen halides, and elemental halogens are all included in the proposed definition of "halogenated" and the prohibition applies to any stream, not just process vents, and to startup, shutdown, and emergency operations. No analysis is provided or referenced to demonstrate such a prohibition is justified or that the proposed standard was set using the procedures required under section 112. No analyses are provided to support applying the prohibition and no information is provided on the affected streams. We know that some halogenated materials are present in Isomerization Units, in Reformers, and in HF Alkylation and thus these operations may be impacted, though no definite information is available given the surprising inclusion of this requirement in the proposal. Presuming the intent is not to just have these streams rerouted to other types of combustion control devices, caustic scrubbers or thermal oxidizer/caustic scrubber combinations will be required to reduce the halogen contents to less than the proposed 0.45kg/hr, where that level is exceeded. These units are costly to install, particularly since special alloy systems are needed, and costly to operate, and generate additional by-product air pollutants (e.g., GHGs, NOx) and significant quantities of wastewater that requires processing.

While 0.45kg/hr halogen from halogenated organics was concluded to be justified to control process vents under the chemical rules, new analyses are required to explain the legal authority for this requirement, describe how the proposed standard comports with the asserted authority (e.g., if based on section 112(d)(6), whether this represents a development that might warrant revising the existing MACT standards), and to determine if such costs and emission impacts are justified for total halogen and, if so, for what type of streams and at what rate of halogen release for the refining source category. Since the definition of MPV is very different under this proposal (includes all periodic, intermittent and SSM streams) than the definition of process vent under the chemical rules, and since it is proposed to also apply this prohibition to vent types not subject to such a requirement in the chemical rules, it is evident that a new, complete analysis is needed for the refining industry before such a standard can be proposed. Lack of these analyses and their presentation for comment violates the obligation under section 307(d)(3) to set forth the basis and purpose for this requirement (including identification of the legal basis, explanation as to how this standard meets the asserted standard-setting authority, and such facts/data as are necessary to justify and support the proposed standard) and the Administrative Procedure Act and thus this portion of the proposal cannot be finalized. If EPA believes this is an issue it should withdraw this proposal, gather information, and address in a new proposed rule or the next technology review.

Furthermore, there are significant safety concerns associated with routing unusual, emergency, or infrequent halogen-containing streams to non-flare dispositions since these systems may be more prone to generation the of aqueous halogen acid, whereas, since elevated flares provide the best dispersion typically available. Banning the use of flares for halogenated streams coupled with the proposed ban on atmospheric RV releases, could result in very large thermal oxidizer/halogen scrubber systems having to be built and operated continuously with no vent gas being processed except during emergencies, resulting in very high costs and significant continuous emissions from these “standby” systems.” The potential for a catastrophic event is greatly increased if a safety valve must release to process equipment (i.e., a halogen scrubber) before being discharged and such a requirement is likely a violation of safe design practices as required by OSHA’s PSM and EPA’s RMP requirements and thus is likely to be infeasible.

2.8.2 If Promulgated, The Halogen Ban Should Exclude SSM Releases and They Should Be Addressed Through RCA/CA Work Practice Alternative Standards.

The proposed prohibition on routing vents containing >1 lb/hr of halogen to a flare would apply to episodic and periodic events that occur during startup, shutdown and emergency operations under the proposed elimination of the existing SSM exception. It is unclear that the control of emergency releases is even feasible without interfering with the operation of the RVs required to prevent catastrophic failures due to the back pressures imposed on those safety release systems, but even handling MSS episodic releases that are amenable to halogen removal, would require large investments in standby facilities that may never or will be infrequently used but which continuously produce combustion emissions. Our members report it is unclear there are even feasible ways of handling some of these streams without flaring, without introducing additional other process safety risks.

Routing episodic releases to a flare is often the best way to protect personnel since the release is moved away from work areas and is highly dispersed. Additionally, a flare provides an unobstructed relief path as well as control of any contained organics versus other control options or releasing the event emissions directly to the atmosphere. Thus, use of the flare for these type situations should be encouraged. As an initial thought, a RCA/CA work practice approach similar to what we have recommended for all atmospheric gas vapor RVs in organic HAP service might be able to be extended to emergency flaring of halogenated Group 1 RMACT 1 streams, if the required administrative record and regulatory language was developed and proposed for comment.

2.8.3 Controlling Halogenated Streams Generates Pollution and the Costs and Pollution Impacts Must be Justified.

In addition to the costs of the alloy thermal oxidizer/caustic scrubber systems required to control organic halides, these systems generate combustion emissions that must be justified and caustic wastewater that must be treated. Handling caustic wastes generally requires facilities and incurs additional costs and environmental concerns that must be addressed when considering imposing additional caustic treatment requirements. These costs and waste issues have not been addressed in this proposal.

2.8.4 If Promulgated, The Definition of “Halogenated Vent Stream” Should Be Clarified, If This Requirement is Finalized.

A definition of halogenated vent stream is proposed as follows.

> Halogenated vent stream or halogenated stream means a stream determined to have a mass rate of halogen atoms of 0.45 kilograms per hour or greater, determined by the procedures presented in §63.115(d)(2)(v). The following procedures may be used as alternatives to the procedures in §63.115(d)(2)(v)(A):
>
> (1) Process knowledge that halogen or hydrogen halides are present in a vent stream and that the vent stream is halogenated, or

(2) Concentration of compounds containing halogen and hydrogen halides measured by Method 26 or 26A of part 60, Appendix A–8 of this chapter, or

(3) Concentration of compounds containing hydrogen halides measured by Method 320 of Appendix A of this part.

The analytical methodologies in §63.115(d)(2)(v)(A) all deal with determining the halogen content of streams containing organic halogens. The "alternative methods" listed in this proposed definition all deal with determining the halogen halide and elemental halogen content of streams. Thus, not all of the allowed methods determine all of the potential halogenated materials covered by the definition and the proposed methods are therefore not really "alternatives." Generally, owners and operators have adequate knowledge of their process to identify what halogenated materials might be present in a particular stream. Thus, it is not necessary to test for them all. To that end we recommend the following.

1. Change "alternative" to "additional" in the second sentence of the proposed definition.

2. Add a sentence to the definition as follows: "Process knowledge may be used to identify the most appropriate procedure(s) for determining if a particular stream is halogenated."

3.0 Comments on Proposed Subpart UUU (RMACT 2) Amendments

3.1 Alternative Standards are Needed in RMACT 2 for Certain Startup and Shutdown Situations Because the Normal Limits Cannot Be Met in All Situations and Attempting to Meet Them In Some Situations Imposes an Unacceptable Process Safety or Operating Risk.

Many FCCUs and SRPs cannot meet the proposed standards during startup and shutdown (S&S) periods. Extended averaging times would help in some cases, but this proposal shortens averaging times instead, making the inclusion of alternatives even more critical.

3.1.1 FCCU MSS Issues

3.1.1.1 Compliance With The Proposed Alternative Metal HAP Standard for Startup of FCCUs Controlled With an Electrostatic Precipitator (ESP) is Not Feasible. An Alternative Standard Based on Maintaining a Minimum Regenerator Primary Cyclone Inlet Velocity of 20 ft./sec (hourly average) Is Recommended. This Alternative Should Be Available to all FCCUs During All Periods of S&S, Including Hot Standby[215].

EPA has proposed a specific alternative metal HAP/PM standard for startup of an FCCU controlled with an ESP. No alternative PM limits have been proposed for startups of FCCUs equipped with other types of PM controls, or for any FCCUs during periods of shutdown or hot standby.

During startup, when torch oil is in use, EPA proposes to allow an FCCU that uses an ESP to control PM (as a surrogate for metal HAP) to meet a 30% opacity limit (on a 6-minute rolling average basis) as an alternative demonstrating compliance with the 1.0 lb. PM/1000 lb coke burn limit. However, serious process safety concerns prevent most FCCU ESPs from being operated when torch oil is in the regenerator, that is, during periods of startup, shutdown, and hot standby. To avoid the possibility of a fire and explosion, ESPs are usually de-energized and

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[215] Hot standby refers to a period where feed has been removed from the unit, usually as a result of a process upset. Torch oil is introduced into the regenerator to keep the catalyst hot and in a mode where the unit can quickly be brought back on line once the upset has been resolved. In so doing, emissions, production loss, and the significant risk of equipment damage due to thermal cycling are minimized as compared with a full shutdown and subsequent cold restart.

bypassed during these periods, and consequently these FCCUs are generally unable to meet the proposed 30% opacity limit.

Although some FCCUs with wet gas scrubbers (WGS) are designed to be able to safely keep those controls on-line during periods of S&S, including hot standby, there are situations where some sites are unable to meet their WGS operating parameter requirements during these periods. For example, the WGS gas/liquid ration and delta P requirements may not be able to be met during the startup and shutdown due to low regenerator gas flow. Experience has also shown that the current 30% opacity limit is unachievable during these periods for FCCUs controlled with tertiary cyclones, when regenerator gas flow is below cyclone minimum design flow.[216]

Consequently, a feasible alternative metal HAP standard for periods of startup, shut down, and hot standby is needed for all FCCU control types.

All FCCU catalyst regenerators have internal (primary and secondary) cyclones that function to retain the catalyst in the regenerator and thereby minimize catalyst and metal HAP emissions from the regenerator. Additional control to meet the RMACT 2 emission limit of not more than 1.0 lb. PM/1000 lb. of coke burn is provided by a bag house, wet gas scrubber, ESP, or tertiary (external) cyclone. Assuring adequate velocity to the internal cyclones ensures that the catalyst sent to these additional controls is minimized and ensures that they are operating as effectively as possible. Similarly, even if the FCCU cannot meet the normal opacity limits during startup, shutdown or hot-standby (e.g. due to the ESP being off-line for safety reasons or the tertiary cyclones or WGS operating at non-routine conditions), assuring adequate velocity to the internal regenerator cyclones will control and minimize particulate emissions.

The efficiency of a cyclone is a function of the inlet gas velocity. The discussion below provides a technical explanation in support of API's recommendation to allow all FCCUs the option of complying with a 20 fps minimum inlet velocity to the primary regenerator cyclones during periods of S&S, including hot standby.

PSRI Background

Particulate Solid Research Inc. (PSRI) is an international consortium of companies that funds applied research in the fluidization, solids transport, and other fluid-particle areas. Since 1971, PSRI has amassed a prolific amount of design data on all aspects of fluidization, entrainment,

[216] API discussed these performance issues in a meeting with Brenda Shine and staff on August 7, 2014.

pneumatic conveying, attrition, distributor design, standpipes, solids transfer, and circulating fluidized beds. From the data produced, PSRI has developed design correlations and techniques which are among the best and most useful in the field.

Cold Flow Model Cyclone Research

Cyclones have been used to separate solids from gas streams since the middle of the nineteenth century. These devices are used in a variety of industry applications covering a wide range of operating parameters. Early researchers conducted experiments to understand the operation of cyclones and develop design correlations. Zenz[217] developed an empirical procedure which has become a common basis for most cyclone applications. Others including Muschelknautz[218] have developed theoretical models to describe and predict cyclone operation. Cyclone manufacturers have used the results from this early research along with field experience, inspection history, and troubleshooting to develop their own design guidelines to improve performance and equipment reliability. However, industry continues to demand improved FCCU cyclone performance based upon process improvement, government regulations, environmental emissions, and overall profitability. As such, this technical area has remained an area of focus and research.

Historically, cyclones were tested in a batch configuration with an ideal inlet velocity and at relatively low solids loadings (< 0.1 lb/ft3). However, years of experience running FCCU circulating fluidized beds and high velocity fluidized beds led PSRI to test in a continuous circulating mode after the solids have reached an equilibrium size distribution in that particular circulating system. Cyclones are part of the FCCU system (fluid bed, riser, conveying line, etc.) and therefore need to be tested as part of a given system. As such, PSRI has published several reports for membership on cyclone efficiency. One program conducted testing on a 2-feet-diameter fluidized bed containing two cyclones in series. The primary cyclone had a diameter of 14-in. The gas velocity was increased gradually from 0.25 fps all the way up to 2.5 fps. This translates into FCCU primary cyclone inlet gas velocities as low as 5 fps and as high as 42 fps. Entrainment or solids loading increased with increasing gas velocity. The following figure (Figure 3.1) shows the performance of the test primary cyclone as the gas velocity was increased. The data clearly shows the cyclone achieves near full efficiency when the inlet velocity reaches 20 fps.

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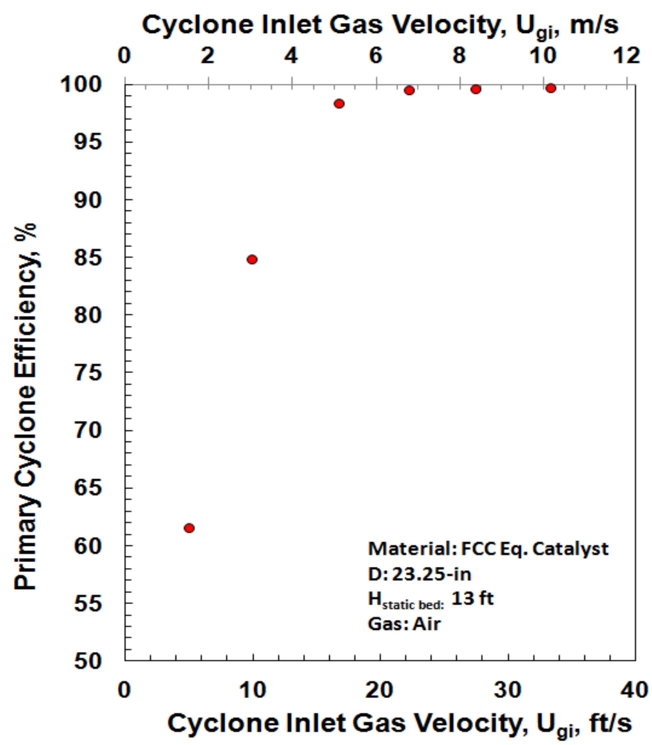
[217] Zenz, F.A., Cyclone Separators, in Manual on Disposal of Refinery Wastes Volume on Atmospheric Emissions, Chapter 11, American Petroleum Institute, Pub. No. 931, Washington, D.C. (1975)
[218] Muschelknautz, E. (1970) Design of Cyclone Separators in the Engineering Practice, Staub-Reinhalt. Luft, 30 (5)

Figure 3.1. PSRI FCCU Primary Cyclone Inlet Velocity Gas Test Results
Inlet Gas Velocity vs. Removal Efficiency



PSRI Cyclone Evaluation Tool

PSRI's Fluidized Bed System Simulator is a Microsoft Excel-based tool that simulates an entire fluidized bed system. This tool was developed using correlations derived for PSRI's cyclone testing database. For the purposes of these comments, the tool was used to simulate catalyst entrainment rates and cyclone collection efficiencies at different cyclone inlet velocities for two different commercial cyclone systems. These systems are actual refinery FCC configurations and represent different cyclone licensor technologies.

The conditions chosen (350 °F air, 1350 °F air with 5% CO2) represent a range of expected environments inside a FCC regenerator during a unit startup – from after the air blower is started to the point where torch oil is in use and feed is ready to be introduced. All results are similar in that they show the cyclone achieves near full efficiency when the inlet velocity reaches 20 fps. Results are shown in Figures 3.2 and 3.3.

Figure 3.2. Commercial Unit #1 - Inlet Gas Velocity vs. Removal Efficiency

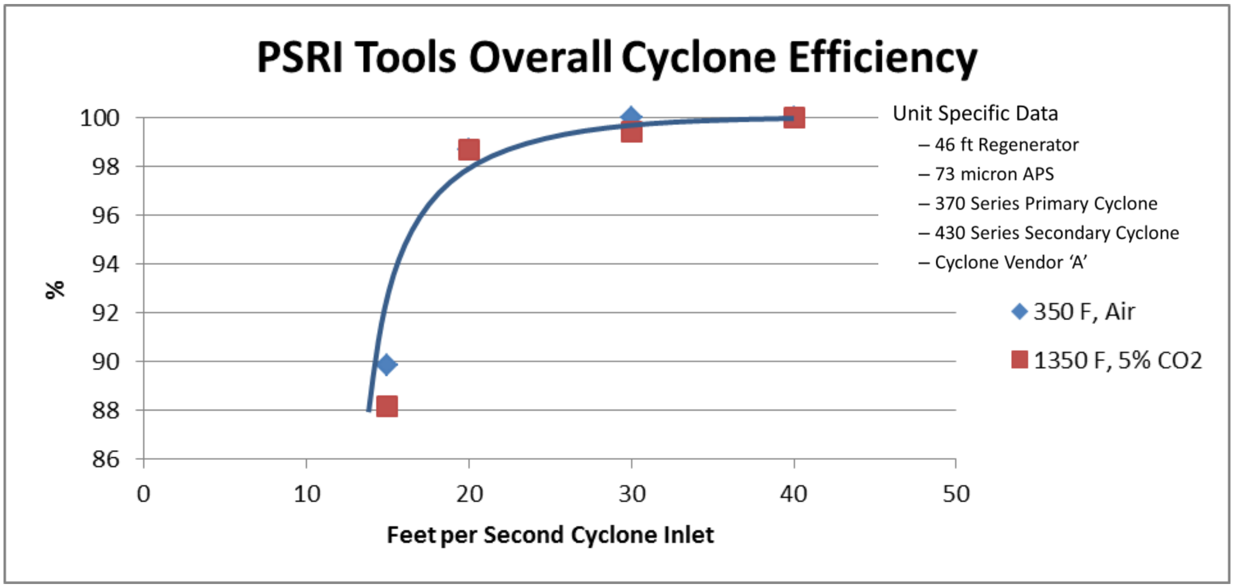
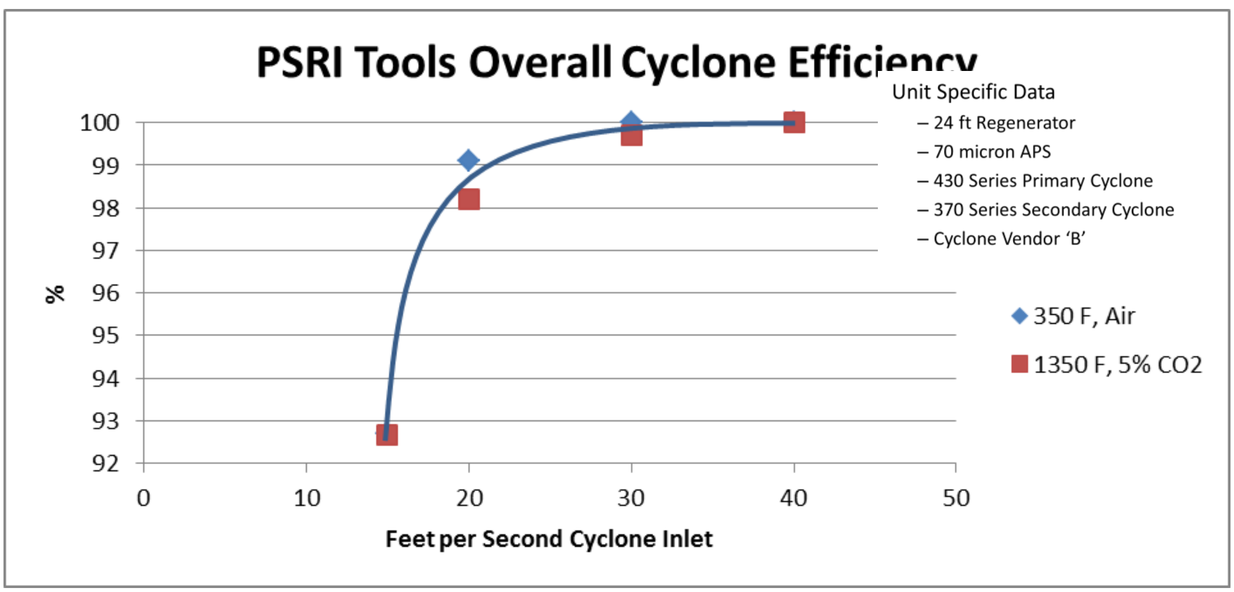


Figure 3.3. Commercial Unit #2 - Inlet Gas Velocity vs. Removal Efficiency



The data provided above support the position that the primary cyclone inlet velocity is an important parameter for minimizing PM emissions from the FCCU regenerator and therefore appropriate to use as an alternative limit for metal HAPs during periods when the external control devices are unable to operate as designed. Maintaining a minimum primary cyclone inlet velocity of 20 fps after introducing catalyst to the unit would minimizing PM and metal HAP emissions during S&S, including hot standby.

This alternative limit should be provided as an option for all FCCUs that cannot comply with the normal operating limit or meet their existing AMP requirements. For example, the WGS gas/liquid ratio and delta P requirements may not be able to be met during the startup and shutdown due to low regenerator gas flow. And for units with tertiary cyclones, the limits may not be able to be met during periods when regenerator gas flow is below cyclone minimum design flow.

Recommended language (Shown as revisions to the proposed new §63.1564(a)(5)):

> §63.1564 What are my requirements for metal HAP emissions from catalytic cracking units?
>
> (a) * * *
>
> (5) During periods of startup, shutdown, and hot standby, when catalyst is in the regenerator ~~only~~, ~~if your catalytic cracking unit is followed by an electrostatic precipitator~~, you can choose from the two options in paragraphs (a)(5)(i) and (ii) of this section:
>
> (i) You can elect to comply with the requirements paragraphs (a)(1) and (2) of this section; or
>
> (ii) You can elect to maintain a minimum regenerator primary cyclone average inlet velocity of 20 feet per second on an hourly average basis ~~the opacity in the exhaust gas from your catalyst regenerator at or below 30 percent opacity on a 6-minute average basis~~.
>
> The regenerator primary cyclone hourly average inlet velocity shall be calculated as follows:

$$V_c = [R_a/3600] * [14.7 / (P_r + P_a)] * [(T_r + 460) / 520] * [1/A_c]$$

Where:

Vc = calculated regenerator primary cyclone inlet velocity, feet per second

Ra = total air and purges to the regenerator, SCFH (at standard conditions of 60 °F and 14.7 psia)

Pa = local atmospheric pressure, psia

Pr = regenerator pressure, psig

Tr = regenerator temperature, °F

Ac = regenerator primary cyclones total inlet area, ft^2

3.1.1.2 API/AFPM Recommends That All FCCUs, Including Units With Fired Boilers, Be Allowed to Use EPA's Proposed Alternate CO Standard of Maintaining a >1% Hourly Average Excess Regenerator O_2 Concentration. This Alternative Should Be Allowed During All Periods of S&S, Including Hot Standby and Apply to All Compliance Options.

EPA has proposed an alternate standard for organic HAPs that would apply during startup of those FCCUs that are not equipped with fired boilers on their regenerator flue gas. Specifically, EPA proposes that FCCUs without fired boilers meet a work practice standard of greater than 1% percent hourly average excess regenerator O_2. No alternate standards have been proposed for startups of FCCUs equipped with fired boilers or for any FCCUs during periods of shutdown and hot standby.

EPA's assumption that refiners are able to safely and reliably startup their FCCUs with flue gas boilers in service and meet the normal operating limit of 500 ppm CO is incorrect. There are many reasons for this, including the design of the boiler (i.e., flue gas boilers were not designed to handle all CO from a FCC during a startup or shutdown) and the fact that many boilers are not able to safely and reliably handle the impact of transient FCCU operations on the flue gas. For example, CO boilers are typically brought on-line separately from the regenerator to avoid temperature excursions and damage to the boiler internals. Reliable boiler operation is critical to the overall refinery steam system and care must be taken to avoid jeopardizing boiler operation to prevent major upsets of the entire refinery's process operations. A major upset or site wide shutdown could result in flaring and emissions of HAPs far in excess of that emitted while bypassing the CO boiler. Even those refiners who do start up with a boiler in service cannot routinely meet normal CO limits during this period because of the flue gas flow and composition variability.[219]

Combustion of torch oil in the FCCU regenerator needed to heat the catalyst and vessel up during startup is the primary reason the CO limit cannot be met during these operations. Torch oil is also used during shutdown to control the cooling rate (and potential equipment damage) and during hot standby and thus the normal CO standard cannot be met at these times either. Hot standby is used to hold an FCCU regenerator at operating temperature for outages where a regenerator shutdown is not needed. There are a number of reasons that a FCCU could end up in hot stand-by. An upstream or downstream unit could have an operational issue that requires the FCCU to be placed on hot stand-by. Preparing for a hurricane would place the unit in hot stand-by, or a malfunction at a FCCU that may require the feed to be removed from the unit. While hot standby is not common, it does occur occasionally.

Hot standby is used to avoid full FCCU shutdowns. To fully shut down a FCCU will take 3 to 4 days, and then to startup the unit it will take another 3 or 4 days. Such a "cold" shutdown requires the unit to go through a thermal cycle (from hot to cold, then cold to hot). Thermal cycling has the potential to cause equipment problems (e.g. slide valve failures, hot spots, tower issues, scrubber issues, refractory failures, etc.). Cold shutdown also increases personnel exposures associated with removing catalyst and securing equipment. Additionally, this can produce additional emissions over maintaining the unit in hot standby.

Finally, it is unclear that the alternative standard applies to FCCUs subject to NSPS J (and Ja – See Comment 3.2.3). The NSPS rules do not apply during startup and shutdown, while after these amendments RMACT 2 will apply during such periods. The current wording of the proposed alternative limit is unclear that it may be used by FCCUs subject to NSPS J or Ja. Additionally, API/AFPM requests that the alternative standard be referenced from Table 8 Option 1 and any new NSPS Ja option, for the same reasons. We suggest language below based on the existing language in §63.1565(b)(1)(i)

[219] API discussed these performance issues in a meeting with Brenda Shine and staff on August 7, 2014.

In order to minimize organic HAP during periods of S&S and hot standby, API/AFPM recommends expanding the proposed work practice to encompass all FCCUs, including those with fired boilers and extending the alternative to shutdown and hot standby operations. Maintaining an adequate level of excess oxygen for the combustion of fuel in the regenerator will minimize CO and organic HAP emissions from FCCUs during these periods.

Recommended language (Shown as revisions to the proposed new §63.1565(a)(5)):

> §63.1565 What are my requirements for organic HAP emissions from catalytic cracking units?
>
> (a) * * *
>
> (5) Whether or not your catalytic cracking unit is subject to the NSPS for CO in §60.103 or §60.102a of this chapter, d~~D~~uring periods of startup, shutdown, and hot standby ~~only~~, ~~if your catalytic cracking unit is not followed by a CO boiler, thermal oxidizer, incinerator, flare or similar combustion device,~~ you can choose from the two options in paragraphs (a)(5)(i) and (ii) of this section:
>
> (i) You can elect to comply with the requirements in paragraphs (a)(1) and (2) of this section; or
>
> (ii) You can elect to maintain the oxygen (O_2) concentration in the exhaust gas from your catalyst regenerator at or above 1 volume percent (dry basis).

3.1.1.3 API/AFPM Recommend a Minimum of 18 months be Provided to Update Procedures and Permits to Reflect the Revised FCCU Standards and the Alternative Standards.

As proposed, the rule requires compliance with the revised standards (except for PM) and the alternate FCCU standards upon promulgation. As discussed in Comment 1.1.2.3, facilities will need a minimum of 18 months to revise their procedures, permits, and possible AMPs, including obtaining the required Management of Change approvals, and to provide training on the new and revised requirements. For any changes that require a project, including monitoring changes, sites will need at least three years to install the new equipment. For example, if FCCUs are required to upgrade from a standard oxygen monitor to a CPMS or CEMS, 3 years will be required.

3.1.1.4 The Alternative Standards for FCCU Startups, Shutdowns and Periods of Hot Standby Should be Included in Tables 1 and 8.

Table 1 of RMACT 2 tabulates the applicable Metal HAP emission limits and Table 8 the applicable Organic HAP emission limits. The proposed tables only include the normal operating limits. For clarity, the alternative limits applicable during other time periods should be included in these tables.

3.1.2 Sulfur Recovery Plant (SRP) MSS Issues

3.1.2.1 The Proposed Alternative Limit for SRP Shutdowns Needs to Be Extended to SRP Startups.

Proposed §63.1568(a)(4) provides alternative standards for SRP shutdowns. The normal SRP emission limitation cannot always be achieved during SRP startups and thus §63.1568(a)(4) should be extended to startups as well.

There are three specific examples of startup activities where this relief is needed, though others may occur. Extending the proposed §63.1568(a)(4) alternatives to startup as well as shutdown will address these issues.

- The first example is during startup of some SRP configurations. During startups of these SRPs the gas from the Claus System must bypass the tail gas unit and vent directly to the incinerator. The sulfur in the line can solidify and cause a high temperature flash which can send excess sulfur to the incinerator and cause the normal SO_2 limit to be exceeded.

- The second example is during catalyst presulfiding. During startup the Claus System (and "SCOT" unit, if present) must be warmed up and the tail gas catalyst must be activated (i.e., sulfided) before full H_2S removal can occur. Sulfiding must be done at low temperatures to avoid catalyst damage. During these low temperature periods there can be incremental slip of reduced sulfur from the unit or to the tail gas incinerator, resulting in high SO_2 or TRS until the reactors are activated and on temperature. While presulfided catalyst has been used in some situations, this is not always possible and has been identified as introducing significant safety concerns. Startup of pre-sulfided catalysts requires special attention because of the potential for overheating and resulting equipment damage. Presulfided catalysts self-heat in air and therefore also require handling and loading in an inert atmosphere (vs. loading in air for the oxide form of the catalyst). This introduces additional safety risk from asphyxiation with nitrogen. Multiple fatalities have occurred in the industry when using inert atmospheres.

- The third example is during a startup, following an unplanned or short notice shutdown, such as can happen after a shutdown due to a process upset, due to freeze conditions, or in preparation for a hurricane or other weather event. In a normal SRP shutdown, a "sulfur sweep" is performed. This sweep involves firing the unit with natural gas at stoichiometric conditions so there is very little excess O2. By doing this a large flow rate of inert gas can be passed through the unit to remove sulfur and sulfur compounds from the equipment. It normally takes several days of sweeping to get to the point where there is no sulfur dripping from the seal legs. There is not enough time to do this when a hurricane decides to come ashore, a cold snap leads to SRP shutdown, or during some unplanned shutdowns due to process upsets. When an SRP that has not been swept of sulfur is restarted from a cold condition the normal rolling average emission limitation often cannot be met while the residual sulfur in the unit is being vaporized and removed. This occurs as the SRP is being heated up with air and may continue into the initial acid gas feed operation, depending on the specifics of the situation.

3.1.2.2 The Proposed Alternative Limit for SRP Shutdowns Needs to Be Clarified.

Proposed §63.1568(a)(4) provides that you can elect to send any shutdown purge gases to a flare or a thermal incinerator or oxidizer. However, the flare may not be a viable option because the resulting emissions might exceed the 500 lb/day total sulfur RCA action level. Language needs to be added to allow temporary MSS purges from SRPs to be flared without including the contained sulfur in the NSPS Ja RCA sulfur trigger calculation.

It also should be clarified in (a)(4)(iii) that the minimum temperature specified is the firebox temperature, rather than the stack temperature.

3.1.3 A Simplified Mechanism for Obtaining Approval for Alternative SSM Limits is Needed.

API/AFPM is concerned about the lack of a mechanism to obtain case-by-case review and approval of separate alternative SSM limits. While we have recommended some alternative limits in our discussions above on FCCUs and SRPs, we recognize that other alternative will likely be needed because of 1) advancements in technology, 2) process improvements, and 3) the possibility that not all situations may be readily foreseen at this time. We urge EPA to allow a process for companies to submit an application for case-by-case alternative SSM limits to be approved by the agency, either EPA or as delegated to States. This would be similar to the case-by-case alternate NOx limits for process heaters operated under certain conditions as provided in Ja.

3.2 Fluid Catalytic Cracker Emission Limit Issues

3.2.1 EPA's Proposal to Revise the FCCU Emission Limitations by Changing the Operating Limits to 3-hour Averages and Changing the 30% Opacity Limits to Unit-Specific Limit Rather Than Maintaining the Floor Limits Established in 2002 is Unlawful, Unjustified and Problematic. The Current Daily Average Emission Limitations and 30% Opacity Limits Should Be Maintained.

EPA bases the changes in FCCU limit averaging times from a daily to a 3-hour averages on its desire for consistency with NSPS Ja[220], alleging that a daily average could allow FCCUs to exceed the PM (or Ni) limits for short periods during the day while still complying with the daily average[221]. EPA has also justified this change under the assumption that performance tests are conducted in three hour time periods (three one-hour stack tests) and therefore this should establish the minimum operating period by which compliance should be demonstrated.[222]

EPA has not provided any data to support its allegation that units might be exceeding the emission limit during periods during the day. This is completely hypothetical and reflects EPA's trend throughout this rulemaking to use a hypothetical compliance assurance argument to change emission limits without having to justify the change under or follow section 112 procedures. A change in emission limits is not authorized by section 112 of the CAA for the purposes of improving compliance assurance. Compliance assurance relates to how an emission limit is monitored, not the level of the emission limit. The performance of FCCU control devices are predictable and not prone to wild swings, provided that the equipment is operated in a responsible manner and in accordance with the requirements established in the performance test. Furthermore, even if there were short periods of operation above the emission limit, such an occurrence would be compliant, as long as the daily average is met. That is inherent in the definition of "average" (i.e., some values above and some values below) and is the basis on which the current RMACT 2 standards were established. Any change in averaging time or in how the level of the standard is set (e.g., going form a fixed opacity to one

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[220] Ibid., middle column.
[221] 79 Fed. Reg. 36929 (June 30, 2014), right column..
[222] 79 Fed. Reg. 36929 (June 30, 2014)

determined through performance testing) is a change in the standard and can only be made as provided in section 112.

The stringency of a numerical emission limitation is set by the numerical value and the averaging time over which that limit is applied. The emission limitations in RMACT 2 for FCCUs were established as daily averages in the original rulemaking, following the floor and ample margin of safety requirements in section 112(d)(2) of the CAA. Without providing any justification other than general, unsupported verbiage about the duration of performance tests, an irrelevant issue, and a desire for consistency with NSPS Ja, a legally deficient argument, it is proposed to revise many of those requirements to rolling three hour averages, significantly changing the stringency of those limits. The CAA requires that such a change in stringency be justified pursuant to the conditions established in sections 112(d)(6) or (f)(2). But increasing stringency and consistency with NSPS rules is not a criterion for a section 112(d)(6) action. Rather that section requires a change to be due to "developments in practices, processes, and control technologies." The only change in technology since the 2002 promulgation of RMACT 2 is the availability of PM CEMS, which is unproven, and has not been successfully demonstrated to accurately reflect PM emissions on FCCU stacks. Further, the monitoring option used to demonstrate compliance is unrelated to whether an averaging time is hourly, three hour, daily or even longer.

Furthermore, the NSPS and MACT rules have different objectives and different legal bases and while consistency may be desirable, it is only possible if the requirements of sections §111 and 112 are both met. NSPS rules apply to new, reconstructed, and modified sources and require installation of best technology when it is most economical to do so. They address criteria pollutants and are driven by short term effects, such as ambient ozone and PM daily levels. The MACT rules are designed to prevent adverse effects to the community from HAPs-based on exposures of 24 hours a day for 70 years. A short-term blip in the emission rate that does not result in an exceedance of the daily limit will not adversely impact the chronic or acute health of the community. MACT standards apply to existing facilities, where best available technologies such as required by NSPS rules may not be justified. Thus, under section 112, emission limitations are based on an assessment of technologies at existing units and their risk impact, as detailed in section 112(d)(2) and (3). That assessment and evaluation was finalized for FCCU regenerators in RMACT 2 in 2002 and is different from the emission limit established in the NSPS Ja rulemaking. Section 112(d)(6) specifies the criteria EPA must meet to change that initial standard. Consistency with NSPS requirements is not a section 112(d)(6) criterion and we do not believe the proposed revision meets the statutory criterion, nor has EPA provided a statutorily acceptable rationale or emission and cost analysis for comment to justify such a change. EPA has not provided any analysis of the potential cost-effectiveness to comply with this change in averaging period. This reduction in the averaging period will certainly decrease the flexibility that sites currently have to adjust to changes in operating conditions. The additional burden associated with this loss in flexibility has not been quantified.

Finally, EPA's assumption that stack testing is performed in three hours is incorrect and, again, the performance test time is not a criterion allowed by the CAA for changing a section 112(d)(2) standard. The stack testing methodology requires three tests to be performed for a minimum of one hour each. Many FCCU stack tests are performed at run lengths greater than one hour in order to make sure that the results are an accurate reflection of the emissions, e.g. to include periods of soot blowing and to assure adequate detection limits. Even if the site limits the three runs to one-hour each, the actual time spent in the field with set-up, individual test sample change-out, take-down, etc. is often typically over several hours. Therefore, the testing results are representative of an operating period well in excess of three hours.

Consequently, EPA has no justifiable basis for making this change in the averaging period. API recommends that EPA retain the current daily averaging basis as applicable throughout the rule.

EPA also proposes to change the current 30% opacity limit for FCCUs controlled with tertiary cyclones, bag houses and ESPs from the 30% limit established as the floor in the original 2002 rulemaking to a new limit established through performance testing. As discussed above, such a change in an emission limit must meet the criteria specified in section 112(d)(6) and various analyses and explanations must be provided for comment. Since the section 112(d)(6) criteria are not met by this proposed change and no analysis is provided for comment, this change cannot be finalized. Although this change in the opacity limit is a concern for all FCCUs regardless of the type of back end PM control, the application of this change to FCCUs that use a cyclone as their final PM control is a particular concern. We address this concern specifically in our next comment.

3.2.2 Particulate/Metal HAP Emission Limit Issues

3.2.2.1 The 30% Opacity Limit Emission Limitation Should Be Retained for Normal Operation of FCCUs with Third Stage Separator (TSS)[223] PM[224] Controls.

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[223] FCCUs typically contain two stages of cyclone separation within the regenerator to minimize catalyst losses and emissions. Further control, external to the regenerator, is typically required to meet the 1 lb PM/1000 lb of coke burn limit. Ten FCCUs in the US obtain this additional control with a cyclone which provides a third stage of PM separation.

[224] In the RMACT 2 rulemaking, PM was established as a surrogate for metal HAPs and PM control and monitoring is the focus

When RMACT 2 was promulgated, complying with NSPS J was established as the section 112(d)(2) requirement for metal HAPs, and compliance with NSPS J was established as one way of demonstrating compliance with RMACT 2 for FCCU PM. Thus, FCCU's subject to NSPS J must meet a PM limit of 1.0 lb PM/1000 lb coke burn-off and an opacity limit of 30%, except for one 6-minute average opacity reading in any 1-hour period. FCCUs that were not subject to NSPS J were given the option of 1) meeting the NSPS Ja PM and opacity limits, 2) meeting just the PM limit from NSPS J, or 3) meeting a lb/hr or lb/1000 lb coke burn-off Nickel limit.

When NSPS Ja was promulgated in 2008[225], the PM emission limitations in NSPS J were changed by eliminating the 30% opacity limit and making opacity monitoring a compliance monitoring technique for FCCUs using cyclones, fabric filters, or ESPs to control PM. Alternative parameter monitoring approaches were provided for FCCUs using ESPs and fabric filters. As a compliance monitoring technique, the opacity limit that would demonstrate compliance was changed from the 30% limit in NSPS J to a unit specific limit established through a performance test. EPA explained their reasoning for this change in the proposal preamble as follows:

> Unlike the existing standards, the proposed standards include no opacity limit because the opacity limit was intended to ensure compliance with the PM limit and because we are now proposing that sources use direct PM monitoring or parameter monitoring to ensure compliance with the PM limit.[226]

As discussed in Comment 3.2.2.1.2 below, EPA was incorrect in assuming that the opacity limit was intended to ensure compliance with the PM limit. While direct PM monitoring was, and still is, unproven, this change in the NSPS requirements was manageable because other parameter monitoring approaches are allowed for ESPs and fabric filters and because NSPS Ja would only be triggered for an existing TSS FCCU if major changes were being made, where replacing the PM controls would likely be needed to accommodate the changes that caused NSPS Ja to become applicable, in the first place.

In this proposal, the PM requirements for FCCUs subject to NSPS J or opting to comply with those limits would change to the limits in NSPS Ja. That is, opacity would change under the two NSPS J-based compliance options in RMACT 2 from a 30% opacity limit to use of opacity as a compliance monitoring approach where the limit would be established based on a performance

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of several of the compliance options available for addressing metal HAPs.

[225] 73 Fed. Reg. 35838 (June 24, 2008)

[226] 72 Fed. Reg. 27180 (May 14, 2007)

test and no allowance for soot blowing would be provided. EPA has explained this change based on providing consistency with NSPS Ja and on improved compliance assurance that the 1 lb PM/1000 lb coke burn emission limit is being met. Neither reason is valid or authorized. The 10 existing FCCUs that use TSS for PM compliance have no viable alternative monitoring approach, since PM CEMS are not usable in this service and no other parameter monitoring is proposed or viable.

This is an unauthorized change in the stringency of the existing source standard, and is unachievable on a continuous basis for FCCUs using TSS for PM control, and will result in tens of millions of dollars in new controls for each of these FCCUs. EPA has not provided any analysis of the statutory basis, environmental impacts, costs, or operational and compliance feasibilities and impacts associated with this change. API/AFPM strongly urges EPA to maintain the current RMACT 2 opacity limit for these FCCUs. As a practicable and cost-effective alternative to address EPA's apparent concern as to whether the PM standard is being achieved, API/AFPM suggests annual PM performance tests for FCCUs using this compliance option, rather than the every 5 year performance tests that would otherwise be required under this proposal.

3.2.2.1.1 A Performance Test-Based Opacity Limit Cannot Always Be Met by Existing FCCUs That Use TSS for PM Control.

Experience from 10 FCCUs in the US that use tertiary cyclones to meet the RMACT2 PM emission limitation indicates that these units cannot at all times meet the proposed new opacity limitations, because performance tests are not representative of opacity variability for these operations.[227] The available data shows that a performance test based limit would likely result in an opacity limit in the range of 10% and such a limit cannot be maintained under normal operating conditions. Additional or replacement PM controls (e.g., ESP or wet gas scrubber) would have to be installed on these units at costs in the tens of millions of dollars per FCCU[228] and would require at least three years of compliance time, which is not provided in this proposal. Since the underlying PM standard is unchanged, there is no emission reduction justification for this proposed change and the change would not meet the section 112(d)(6) requirement of being cost effective. Additionally, processes or practices have not changed as required for a section 112(d)(6) revision for existing FCCUs that would justify this investment and a forced FCCU outage to install the new facilities.

[227] API discussed these performance issues in a meeting with Brenda Shine and staff on August 7, 2014.
[228] One API member has estimated a cost of approximately $50 million to add a wet gas scrubber to an existing FCCU.

Parameter monitor limits established through performance testing are appropriate if there is a reasonably direct correlation between control device operating parameters and emissions. Because FCCU regenerator opacity measurements are less precise than other parameter measures and are strongly influenced by particle size (which is inversely related to mass), opacity is only a qualitative indicator for PM emission rate or mass in this service.

The following figures show PM emissions (lb/1000 lb coke burn-off or lb/hr) versus opacity for individual FCCU that use TSS for PM control.

Figure 3.4 PM emissions (lb/1000 lb coke burn-off) versus opacity for one FCCU.

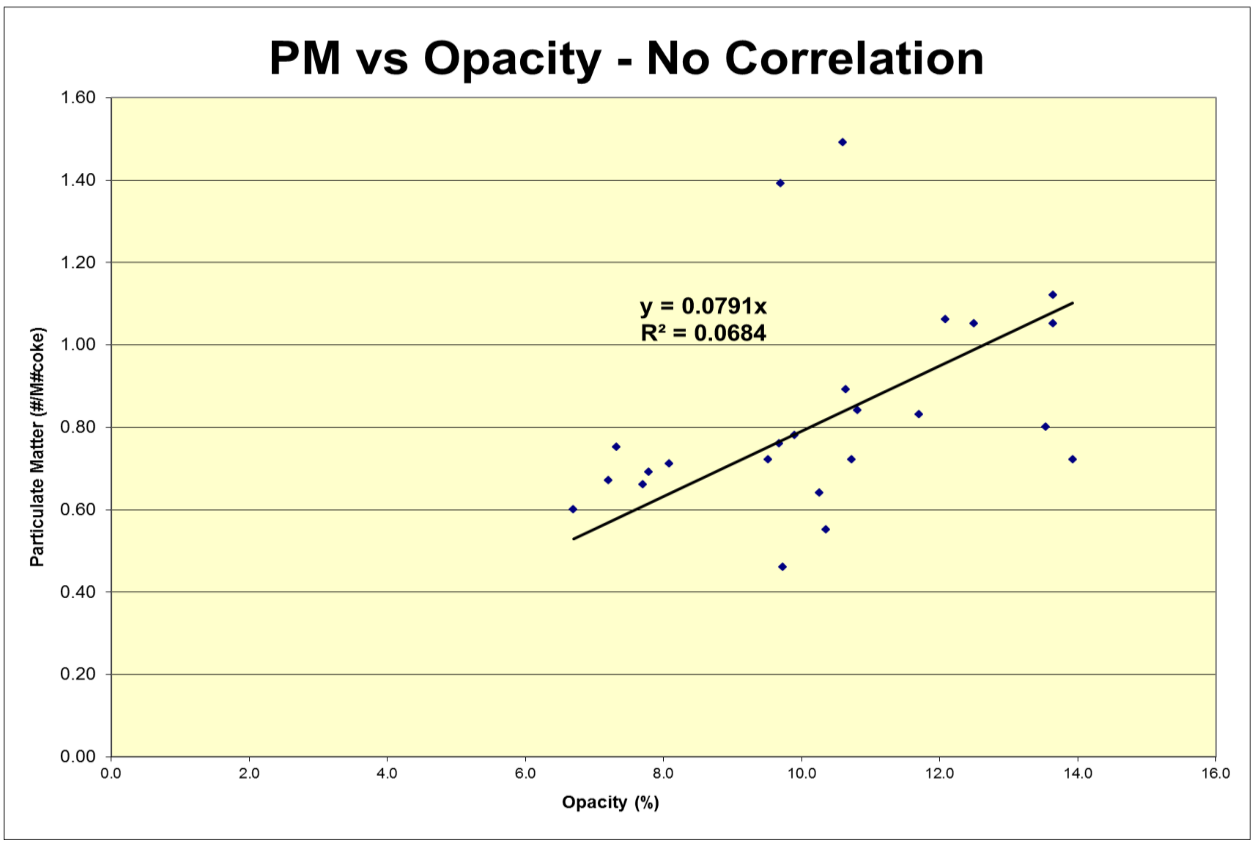
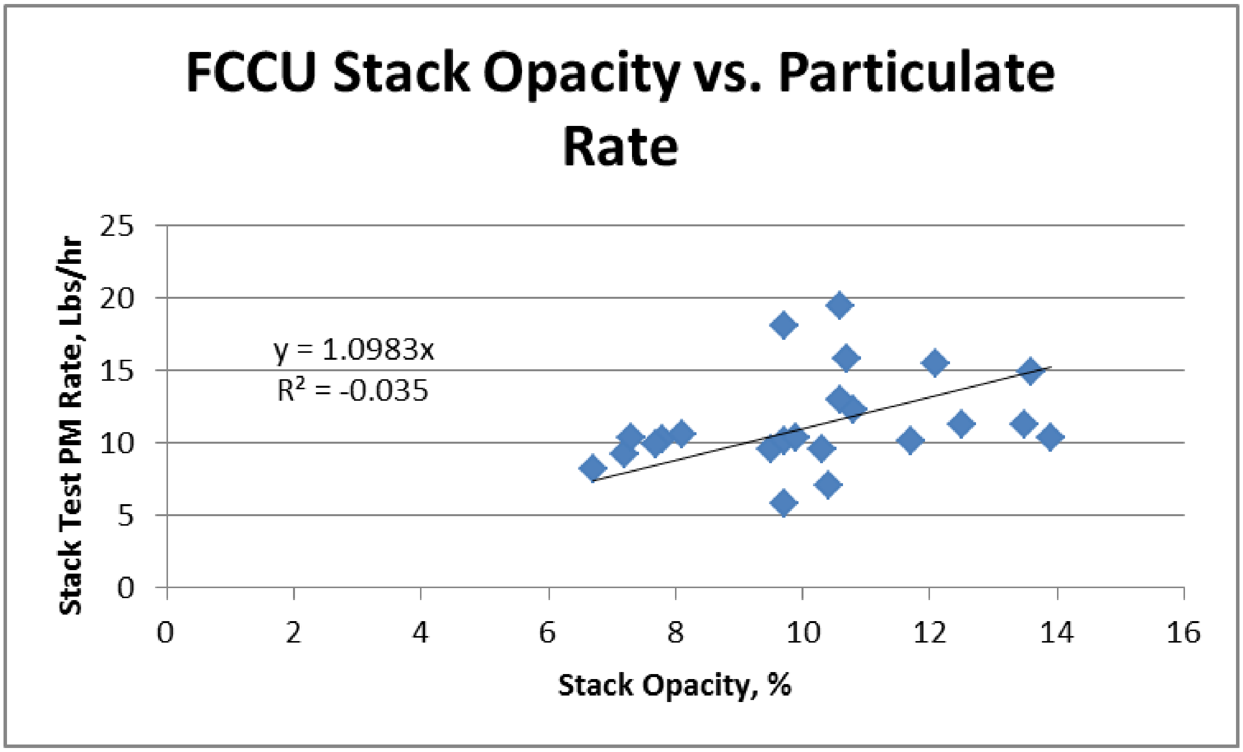


Figure 3.5 PM emissions (lb/hr) versus opacity for one FCCU.



Data from **Site Specific Correlation Study – Optical Density Readings and Particulate Matter Emissions from Canton, OH FCCU**
Marathon Petroleum Company and USEPA First Revised Consent Decree Appendix Q Study Requirement 07/31/2006

Figure 3.6 PM emissions (lb/1000 lb coke burn-off) versus opacity for one FCCU.

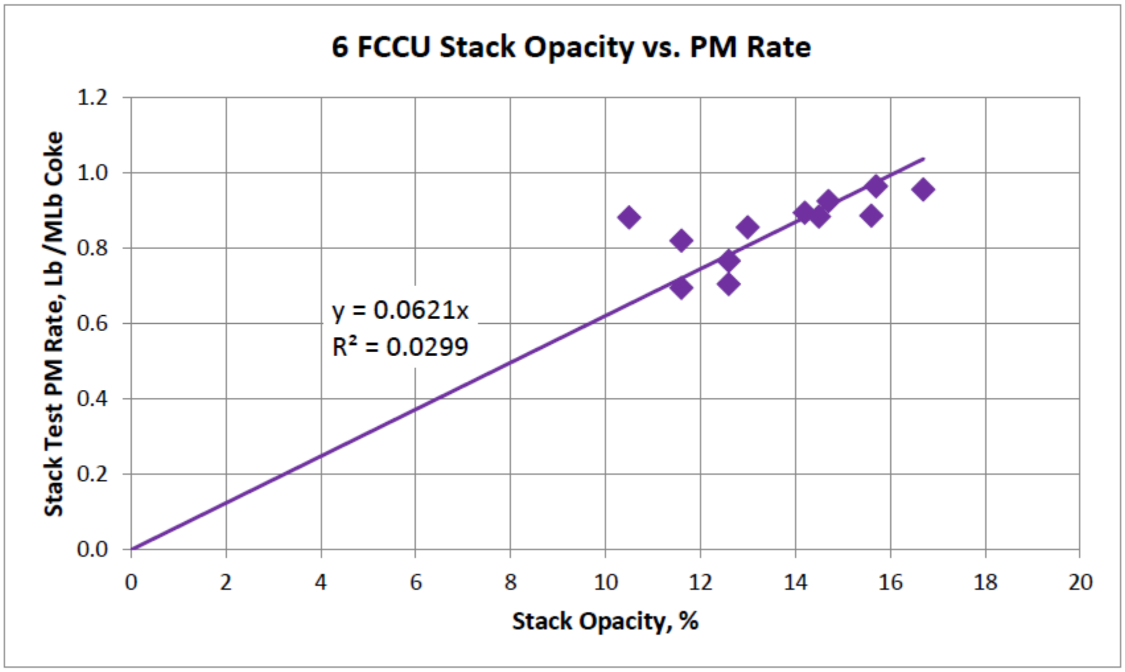
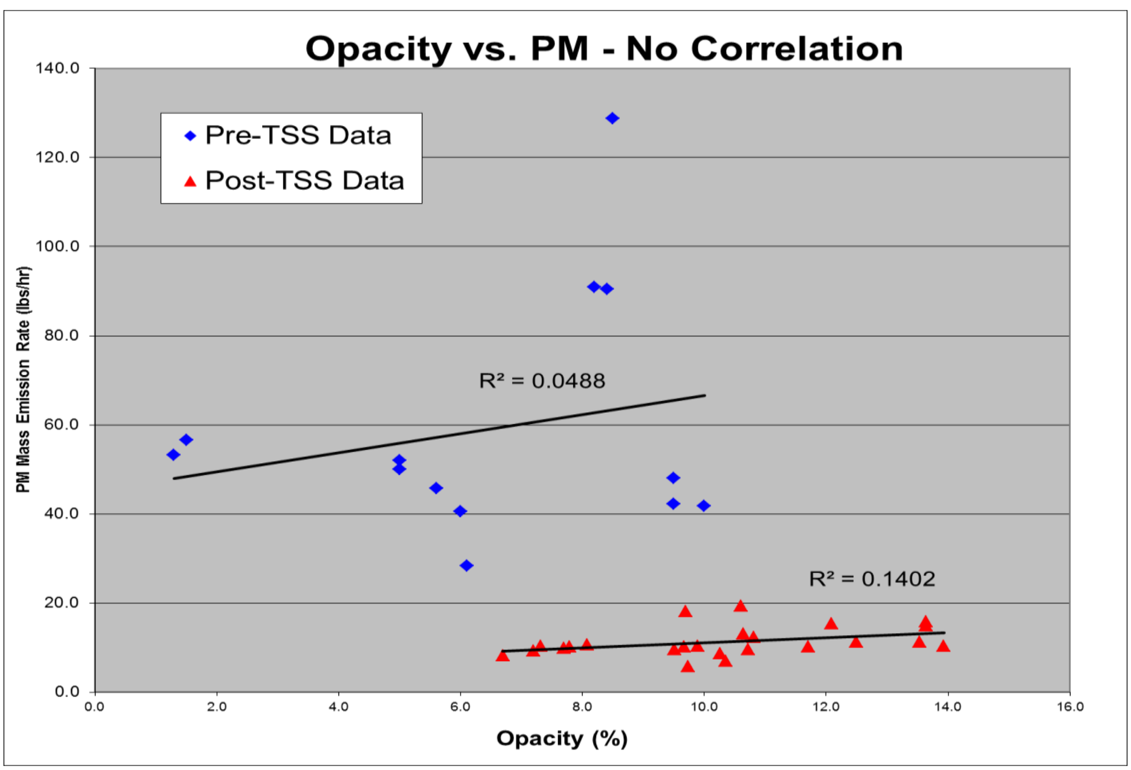


Figure 3.7 PM emissions (lb/hr) versus opacity for one FCCU.



R^2 is a statistic that will give some information about the goodness of fit of a model. In regression, the R^2 coefficient of determination is a statistical measure of how well the regression line approximates the real data points. An R^2 of 1 indicates that the regression line perfectly fits the data. A value such as $R^2 = 0.7$ may be interpreted as follows: "Seventy percent of the variance in the response variable can be explained by the explanatory variables. The remaining thirty percent can be attributed to unknown, lurking variables or inherent variability." In the case of this specific data, the R^2 values indicate a poor correlation.

This data shows the large variability in FCCU opacity readings for any given PM emission rate and thus the difficulty that would be encountered in trying to establish an opacity limit via performance testing.

3.2.2.1.2 The NSPS J Opacity Limit Was Not Intended as A Compliance Demonstration for the PM Emission Limit. The Purpose of the Opacity Limit Was To Assure the PM Control is Operating Properly. If EPA Believes Additional Compliance Assurance with the PM Mass Limit is Needed API/AFPM Recommends Annual PM Performance Tests.

In 1974[229], EPA imposed the NSPS J opacity limit for FCCUs for the first time. It was part of a number of rulemakings, where opacity limits were imposed. EPA explained its philosophy in making the opacity an emission limit, rather than a compliance monitor in the rulemaking Background Information Document (BID)[230] as follows:

[229] 39 FR 9315, Mar. 8, 1974

[230] US EPA, *Background Information for Promulgated Standards, Vol. 3*, EPA 450/2-74-003 (APTD-1352c), February 1974, pages 5 and 6.

1. Several commentators felt that opacity limits should be only guidelines for determining when to conduct the stack tests needed to determine compliance with concentration/mass standards. Several other commentators expressed the opinion that the opacity standard was more stringent than the concentration/mass standard.

As promulgated, the opacity standards are regulatory requirements, just like the concentration/mass standards. It is not necessary to show that the concentration/mass standard is being violated in order to support enforcement of the opacity standard. Where opacity and concentration/mass standards are applicable to the same source, the opacity standard is not more restrictive than the concentration/mass standard. The concentration/mass standard is established at a level which will result in the design, installation and operation of the best adequately demonstrated system of emission reduction (taking costs into account) for each source. The opacity standard is established at a level which will require proper operation and maintenance of such control systems on a day-to-day basis, but not require the design and installation of a control system more efficient or expensive than that required by the concentration/mass standard.

Opacity standards are a necessary supplement to concentration/mass standards. Opacity standards help ensure that sources and emission control systems continue to be properly maintained and operated so as to comply with concentration/mass standards. Particulate testing by EPA method 5 and most other techniques requires an expenditure of $3,000 to $10,000 per test including about 300 man-hours of technical and semi-technical personnel. Furthermore, scheduling and preparation are required such that it is seldom possible to conduct a test with less than 2 weeks notice. Therefore, method 5 particulate tests can be conducted only on an infrequent basis.

If there were no standards other than concentration/mass standards, it would be possible to inadequately operate or maintain pollution control equipment at all times except during periods of performance testing. It takes 2 weeks or longer to schedule a typical stack test. If only small repairs were required, e.g., pump or fan repair or replacement of fabric filter bags, such remedial action could be delayed until shortly before the test was conducted. For some types of equipment such as scrubbers, the energy input (the pressure drop through the system) could be reduced when stack tests weren't being conducted, and this could result in the release of significantly more particulate matter than normal. Therefore, EPA has required that operators properly maintain air pollution control equipment at all times (40 CFR 60.11(d)) and meet opacity standards at all times except during periods of startup, shutdown, and malfunction (40 CFR 60.11(c)), and during other periods of exemption as specified in individual regulations.

> Opacity of emissions is indicative of whether control equipment is properly maintained and operated. However, it is established as an independent enforceable standard, rather than an indicator of maintenance and operating conditions because information concerning the latter is peculiarly within the control of the plant operator. Furthermore, the time and expense required to prove that proper procedures have not been followed are so great that the provisions of 40 CFR 60.11(d) by themselves (without opacity standards) would not provide an economically sensible means of ensuring on a day-to-day basis that emissions of pollutants are within allowable limits. Opacity standards require nothing more than a trained observer and can be performed with no prior notice. Normally, it is not even necessary for the observer to be admitted to the plant to determine properly the opacity of stack emissions. Where observed opacities are within allowable limits, it is not normally necessary for enforcement personnel to enter the plant or contact plant personnel. However, in some cases, including times when opacity standards may not be violated, a full investigation of operating and maintenance conditions will be desirable. Accordingly, EPA has requirements for both opacity limits and proper operating and maintenance procedures.
>
> 2. Some commentators suggested that the regulatory opacity limits should be lowered to be consistent with the opacity observed at existing plants; others felt that the opacity limits were too stringent. The regulatory opacity limits are sufficiently close to observed opacity to ensure proper operation and maintenance of control systems on a continuing basis but still allow some room for minor variations from the conditions existing at the time opacity readings were made.

EPA also explained the need for a window for special operations in the 1974 BID document.[231] (The 3-minute period mentioned in this quote has since been changed to 6 minutes.)

> The 3-minute period in any one hour during which the opacity of the gases discharged to the atmosphere may be 30 percent or more is to permit "blowing" of the boiler tubes in the carbon monoxide boiler to remove soot."

Changing from the existing 30% opacity with a soot blowing[232] allowance to a unit specific opacity limit with no allowance is unachievable without adding (or replacing the TSS with) an ESP, or wet gas scrubber (WGS), or similar very costly control, and similarly, even FCCUs with additional downstream PM controls would not be able to achieve a site specific limit at all times. This again is related to the main issue that opacity does not directly correlate with PM emissions and variability in operations of both the FCCU and/or PM control equipment may be reflected in opacity changes with no impact on emitted PM. Thus this change is in direct conflict with EPA statement in the second paragraph of the above quote that:

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[231] Op. Cit., page 18

[232] Soot blowing is required in a boiler to maintain good combustion efficiency, thereby minimizing fuel use and emissions. It is also required with Selective Catalytic Reduction NOx controls to maintain their NOx control efficiency.

> The opacity standard is established…, but not require the design and installation of a control system more efficient or expensive than that required by the concentration/mass standard.

EPA has not provided any cost-effectiveness analysis supporting this change in stringency. While EPA indicates a concern that the 30% opacity limit may not be sufficiently stringent to ensure compliance with the underlying PM limit, that conclusion is based on a false premise as to the purpose of the opacity standard. As indicated in the above quote "Opacity of emissions is indicative of whether control equipment is properly maintained and operated."

Available FCCU PM technologies or processes have not changed since RMACT 2 was promulgated, and no emission reduction will result from this proposed change in the section 112(d)(2) opacity limit. Thus, this change in the opacity limit cannot be justified under CAA section 112(d)(6) and thus is not authorized by the CAA.

API/AFPM strongly urges EPA to maintain the current 30% opacity limit and soot blowing allowance. As a practicable and cost-effective alternative to address EPA's concern as to whether the underlying standard is being achieved, API/AFPM suggests annual PM performance tests be required for FCCUs using this compliance option, rather than the every 5 year performance tests that would otherwise be required under this proposal.

Suggested Regulatory language (Shown as revisions to the proposed new §63.1571(a)(5) and to Table 2):

Revise proposed §63.1571 as follows:

> §63.1571 How and when do I conduct a performance test or other initial compliance demonstration?
>
> (a) * * *
>
> (5) Except as specified in paragraph (i), c~~C~~onduct a performance test for PM or Ni, as applicable, from catalytic cracking units at least once every 5 years for those units monitored with CPMS, BLD, or COMS…..
>
> (i) For catalytic cracking units using a cyclone to control PM, conduct a performance test for PM or Ni, as applicable, at least once every year. You must conduct the first periodic performance test no later than [THE DATE 18 MONTHS AFTER THE DATE OF PUBLICATION OF THE FINAL RULE AMENDMENTS IN THE FEDERAL REGISTER]. Those units monitoring PM concentration with a PM CEMS are not required to conduct a periodic PM performance test.

Revise Proposed Table 2 – as applicable

1. b. and 2.b Continuous opacity monitoring system ~~used to comply with a site-specific opacity limit.~~ /

~~Cyclone, f~~Fabric filter, or electrostatic precipitator. /

Maintain the 3-hour rolling average opacity of emissions from your catalyst regenerator vent no higher than the site-specific opacity limit established during the performance test. /

Cyclone. /

Maintain the ~~3-hour~~ly ~~rolling~~ average opacity of emissions from your catalyst regenerator vent no higher than 30% (except for one 6-minute average per hour) ~~the site-specific opacity limit established during the performance test~~.

Revise §63.1564(b)(4)(i) to remove the reference to a site-specific opacity limit.

3.2.2.2 Table 2 of RMACT 2 Should be Revised to Clarify that Units Equipped with Fabric Filters or ESPs have the Option of Demonstrating Compliance Using Either the Specified Parametric Monitoring or Opacity Monitoring.

Table 2, as proposed for revision, has led to confusion regarding the types of controls that are subject to site-specific opacity limits. We believe EPA's intent is that units equipped with fabric filters or ESPs would have the option of demonstrating compliance using either the specified parametric monitoring approach or the site specific opacity monitoring approach, until such time as the site triggered NSPS Ja for that unit. Table 2 should be clear on this point. For example, the Table needs to be clear that units equipped with ESPs can choose to demonstrate compliance by coke burn-off or flow rate limit and total power limit[233] and secondary current, without also the need to demonstrate compliance with the site-specific opacity limit.

3.2.2.3 The Proposed Change in Monitoring Parameter For ESPs Need to Be Corrected.

EPA should revise the monitoring requirements for ESPs in Table 2 4(b)(i) as follows, to be consistent with existing regulations and Table 2, 1(c), and 2(c), as follows.

[233] As we discuss in Comment 3.2.2.3, below that the proposed requirement to monitor both power and current is duplicative and only power needs to be monitored.

Maintain the daily average ~~gas~~ coke burn-off rate or daily average flow rate no higher than the limit established in the performance test; and maintain the ~~daily~~3-hour rolling average ~~voltage~~total power and secondary current ~~(or total power input)~~ above the limit established in the performance test.

3.2.2.4 The PM CPMS Emission Limitation and Compliance Options Should be Made Available To FCCUs Complying with the NSPS J Compliance Option.

EPA has proposed to amend §63.1564 and Tables 1 through Table 7 to provide for the use of PM CPMS as the compliance demonstration for FCCUs that are also subject to NSPS Ja, by incorporating the 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air (the equivalent standard for the 1.0 g PM/kg coke burn standard) and the associated PM CPMS requirements from NSPS Ja. The option to use this compliance approach should be made available to all FCCUs whether or not they are subject to NSPS Ja, particularly since it may be a preferable alternative for some unit configurations to demonstrate compliance during periods of startup and shutdown. Since it has already been demonstrated in the NSPS Ja rulemaking to be an equivalent compliance assurance approach for FCCUs, API requests that this option be provided in §63.1564 and Tables 1 through Table 7 for all FCCUs, including those required to comply with NSPS J as their PM compliance option.

3.2.3 A Compliance Option for CO For FCCUs Subject to NSPS Ja Should Be Added and the §63.1565 and Tables 8-14 Modified Accordingly.

Paragraph 63.1565 and Tables 8-14 specify the compliance options for CO emissions (as a surrogate for organic HAP) from FCCU regenerators. Two options are provided. FCCUs subject to NSPS J must comply with that standard, with some adjustments specified in §63.1565. FCCUs that are not subject to NSPS J may opt to comply with the NSPS J option or with requirements spelled out in this paragraph and these tables that are similar to NSPS J, but not identical. However, some FCCUs will become subject to NSPS Ja over time and it is unclear what their compliance obligations are. Thus, API/AFPM requests that a "comply with NSPS Ja" option be added in this paragraph and Tables. While NSPS J includes language that allows for compliance with Ja as a NSPS J compliance option, it is confusing not to have it spelled out in RMACT 2, particularly relative to changes in NSPS J requirements spelled out in RMACT 2.

As we have indicated above relative to PM, replacing existing requirements in CO options 1 and 2 cannot be done without proper justification and analysis being provided for comment and such changes should be strenuously avoided. However, referencing NSPS Ja 60.102a everywhere §60.103 is referenced in this paragraph and these tables would provide a clear compliance option for FCCUs subject to NSPS Ja, without changing the requirements for other FCCUs.

3.2.4 API/AFPM Concur With EPA's Conclusion that The Current CO limit Provides for Adequate Control of Hydrogen Cyanide.

On page 36931 and 2, EPA explains their conclusion that the establishment of a separate FCCU HCN limit is not supported by the very limited HCN emission data and the inadequate understanding of the HCN/NOx interaction. Further, they concluded that there have been no changes in processes or technology that would provide a basis for going beyond the current CO limit. API/AFPM concur with these conclusions.

3.2.5 API/AFPM recommends that EPA remove the OMMP approval requirements.

With the proposed new rule requirements (e.g. stack testing requirements, new monitoring requirements, etc.) the Operating, Monitoring, and Maintenance Plan (OMMP) required by RMACT 2 will need to be updated. Currently any changes to an approved OMMP must be submitted and cannot be followed until the EPA approves the new version of the OMMP. This approval process puts the refiner at great risk of not being able to comply with the rule by the compliance date (in many cases in this proposal the publication date). API/AFPM recommends that EPA remove the OMMP approval requirements.

Recommended language revision:

> *§63.1574(f)(1):* You must submit the plan to your permitting authority for review ~~and approval~~ along with your notification of compliance status. While you do not have to include the entire plan in your part 70 or 71 permit, you must include the duty to prepare and implement the plan as an applicable requirement in your part 70 or 71 operating permit. You must submit any changes to your permitting authority for review and begin complying with the revised plan once submitted. ~~and approval and comply with the plan until the change is approved.~~

3.2.6 A Delay-of-Repair Provision is Needed With The New Proposed 12 Hour Repair Requirement in §60.105a of NSPS Ja and §63.1573(b)(3) for Faulty Atomizing Spray Wet Scrubber Air and Water Lines.

EPA has proposed an alternative to a CPMS for measuring pressure drop for units controlled by a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles. However, the requirement to repair or replace faulty air or water lines within 12 hours of identification of an abnormal pressure reading is not feasible.

It takes time to evaluate, plan, design, and install a replacement spool piece or a clamp on a leaking line. Experience has shown that while evaluation of the problem and identification of possible fixes can be initiated within 12 hours, depending on the severity and location of the leak it may take a few days before the repair can be completed. API recommends that EPA require the site to initiate the evaluation of the repair or replacement within 12 hours, with the repair to be completed as soon as practicable but not later than 15 days.

Recommended language revisions:

§63.1573 What are my monitoring alternatives?

* * * * *

(b) What is the approved alternative for monitoring pressure drop? You may use this alternative to a continuous parameter monitoring system for pressure drop if you operate a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles. You shall:

(1) Conduct a daily check of the air or water pressure to the spray nozzles;

(2) Maintain records of the results of each daily check; and

(3) Initiate evaluation of the repair or replacement of ~~Repair or replace~~ faulty (e.g., leaking or plugged) air or water lines within 12 hours of identification of an abnormal pressure reading. The repair or replacement shall be completed as soon as practicable but not later than 15 days after identification of the abnormal pressure reading. As an alternative, the owner or operator may demonstrate via stack testing that the inorganic HAP limit is being met at these new conditions.

3.2.7 The RMACT 2 (and NSPS J/Ja) CO Limit Oxygen Adjustment Should Be Corrected For FCCUs That Use Oxygen Enrichment.

RMACT 2 sets the FCCU CO limit as 500 ppm (dry basis). Per Table 8, for FCCUs subject to NSPS J, compliance is demonstrated by meeting the NSPS requirements. NSPS J specifies that the measured CO value be adjusted to 0% O2. The equation used for correcting measured FCCU regenerator CO values to 0% O_2, as required by the NSPS J, does not work properly for FCCUs that use oxygen enrichment, a common practice, and API/AFPM request the equation in NSPS J be adjusted for that situation. Because the issue applies to NSPS Ja as well as NSPS J and to other pollutants under those rules, we address the specifics in Comment 4.3.5.

3.3 Sulfur Recovery Plant Subject to NSPS Ja Should Only Have to Comply With NSPS Ja.

Since this proposal incorporates the requirements from NSPS J and Ja compliance with either this rule would be equivalent to compliance with one of the NSPS rules. It would be duplicative and wasteful for an SRP to have to demonstrate compliance and separately report under both this rule and the NSPS rule. Therefore, API/AFPM requests language be added to make compliance with this rule compliance with NSPS J or Ja, as applicable.

3.4 Catalytic Reforming Unit (CRU) Issues.

3.4.1 The Proposed Limitation on the Application of the <5 psig CRU Purge Vent Criterion for Release to the Atmosphere is Not Authorized by CAA section 112(d)(2) or (d)(6), Significantly Impacts Fuel Production, Increases Net Hydrocarbon Emissions (Particularly Methane) and Should not Be Finalized.

It is proposed to revise the CRU <5 psig purge vent atmospheric release criterion in §63.1566(a)(4) under the authority of CAA section 112(d)(2) and (3) on the purported basis[234] that revision is needed to meet the intent of the original floor determination. This proposed change would limit the <5 psig exemption from the control requirements to only passive vessel depressurization (i.e., pressure/depressure). EPA believes units utilizing active purging techniques (i.e., flow through) are capable of directing the purge gas to a control system, regardless of the CRU vessel pressure. If a CRU owner or operator uses active purging

[234] See 79 Fed. Reg. 36904 (June 30, 2014), bottom right column.

techniques (e.g., a continual nitrogen purge) or active vessel depressurization (e.g., vacuum pump), then the change would require that the low pressure purge gas meet the 98-percent organic HAP reduction or 20 ppmv TOC emission limit.

EPA reported in the RMACT 2 final rule preamble that this release criterion was based on rules in the States where CRUs were most prevalent[235]. Thus, this criterion represents the control floor for this vent and any revision requires a CAA section 112(f)(2) or (d)(6) evaluation and determination, neither of which was made in this proposal. Furthermore, the record for the original rulemaking identifies this exception as applying to purging and depressuring the reactor, but does not indicate that the depressuring and purging cannot be active. In fact, it is clear that the purpose of this provision was to allow release to the atmosphere when there was inadequate pressure to reach control, a situation that can occur regardless of whether the purging is passive or active.

The original rule could have gone beyond the floor and required compression to provide adequate pressure to reach control but did not do that. Since compression was an available technology originally, adding compression, as this change would require, does not meet the CAA 112(d)(6) requirement of representing "developments in practices, processes, and control technologies." Thus, we do not believe this change is authorized under CAA section 112(d)(2) or (d)(6) and it should not be finalized.

Inadequate pressure is not the only reason low pressure CRU purges are not sent to control. These purges are primarily nitrogen with only small amounts of VOC and HAP and they are typically high volume. Thus, they cannot be sent to normal combustion controls, and can only be sent to flares with large supplemental natural gas addition. Because of the very low hydrocarbon content of these streams (typically <1000 ppm VOC) the impact is significantly increased net hydrocarbon emissions, and particularly methane emissions, from the flare. Even then, regeneration times will be extended significantly in order to avoid overwhelming the flare with low BTU gas[236]. Thus, the impact of this proposal is 1) to extend purge times and thereby significantly reducing fuels production, or 2) forcing sources to install facilities to compress these streams and then supplement them with natural gas to allow sending them to combustion controls, a wasteful action that increases net emissions and incurs substantial costs.

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[235] See 67 Fed. Reg. 17764 (April 11, 2002), top right column.

[236] Estimates from two CRUs suggest regeneration cycle time increases (and associated lost production) of from 6 hours to 48 hours per regeneration.

EPA needs to recognize that a ban on “active venting” to atmosphere would severely impact the industry’s ability to implement routine catalyst changes, maintenance/turnaround work, and other activities that would necessitate taking a catalyst-filled reactor vessel out of service for reformers and isomerization units. Typically, after a reactor has been cleared of hydrocarbons and depressured, the reactor would be put under a nitrogen purge and vented to atmosphere. This assures a safe environment during these activities since any oxygen influx could result in pyrophoric combustion and damage equipment or harm personnel. Should this ban be promulgated, additional flare considerations will be needed for nitrogen streams and/or redesign and new construction of the entire reformer reactor system may be required. EPA did not consider the overwhelming impacts of this ban on refinery process safety, and the costs of new equipment that may be needed.

Finally, if this change is made, API/AFPM requests EPA make clear that these gas flows and the flow of supplemental gas needed to make them combustible, are part of the base flare flow for purposes of the NSPS Ja flow RCA/CAA trigger (i.e., these flows do not count towards the RCA/CAA flare flow trigger).

3.4.2 Three Years is Required If the Proposed Revisions to §63.1566(a)(4) Are Finalized and Facility Costs and Burdens Must be Added to the Rule Cost Analyses and Information Collection Supporting Statement Burden Estimates.

If this change is finalized, three years is needed to allow addition of compression, natural gas addition facilities, and other facilities to allow these purge streams to be controlled. The costs of these facilities, the ongoing costs for natural gas, and the net emission increases associated with this approach need to be addressed in the rule analyses. Additionally, the Agency should specifically allow these purge streams to be flared, despite the flare gas minimization requirements of NSPS Ja, since even with natural gas addition, these streams are often too variable and too low in heating value to send to the CRU process heater or to refinery fuel systems.

3.4.3 Impact of Ban on Flaring Halogenated Streams on CRUs.

The ban on flaring gases containing more than 1 lb/hr halogen will have a significant impact on CRUs, where HCl is present in process and many periodic streams. Section 2.8 of these comments discusses these issues in more detail.

3.4.4 CRU Startup, Shutdown and Equipment Standby Issues

There are several Maintenance, Startup and Shutdown situations besides regenerator purging, where nitrogen purges are used in CRU operations. For instance, for safety reasons, a nitrogen purge is kept on the reformer catalyst to keep out air and moisture during unit turnarounds, including when the regenerator vent caustic scrubber is being maintained, during catalyst dumping operations. These high nitrogen purges are vented to the atmosphere for several reasons: they are low pressure, they have inadequate heating value to be routed to fuel or to the flare, there is little hydrocarbon and control devices may be also shutdown. The rule needs to clarify that such Maintenance, Startup and Shutdown nitrogen purges can be routed to the atmosphere without all of the burdens associated with MPVs being imposed.

3.5 Other RMACT 2 Issues.

3.5.1 EPA Should Carefully Review The RMACT 2 Tables for Accuracy and Clarity.

API/AFPM have not had the time prior to the close of the comment period to comprehensively and systematically review the subpart UUU revised tables in detail. These tables are complicated and detailed, and, as we have indicted in a few comments difficult to interpret, we respectfully request that EPA ensure that they are accurate, clear, and consistent with the rule text in the promulgated rule.

3.5.2 Proposed §63.1570(d) should not be finalized.

Proposed §63.1570(d) requires “During the period between the compliance date specified for your affected source and the date upon which continuous monitoring systems have been installed and validated and any applicable operating limits have been set, you must maintain a log detailing the operation and maintenance of the process and emissions control equipment.”

This requirement is unclear, ambiguous, and unnecessary and should be deleted. Continuous monitoring systems must be installed and validated and any applicable operating limits met no later than the compliance date. Thus, there can be no gap between the compliance date and the availability of these systems. Even if that time period is clarified, what information and how much detail is required to be maintained in a log and what is the justification for having a log if there is no applicable emission limit or the existing emission limit and applicable compliance provisions apply?

4.0 Comments on Proposed Part 60 Subpart Ja Amendments

4.1 General Comments on NSPS Ja.

API/AFPM is disappointed EPA has not taken this opportunity to address critical NSPS Ja corrections and clarifications. In Comment 4.2, we address the NSPS Ja amendments proposed in this notice and in Comment 4.3 we summarize some of the NSPS Ja critical issues remaining to be addressed by EPA.

4.2 Comments on NSPS Ja Provisions and Issues.

4.2.1 A Delay-of-Repair Provision is Needed With The New Proposed 12 Hour Repair Requirement in §60.105a of NSPS Ja and §63.1573(b)(3) for Faulty Atomizing Spray Wet Scrubber Air and Water Lines.

See discussion in Comment 3.2.6 relative this same proposal in RMACT 2.

4.2.2 Exclusions are Needed in NSPS Ja From The Flare Modification Provisions For Connections Required to Meet the Requirements of this Proposal.

If finalized as proposed, many atmospheric RVs will be routed to flares. While those flares will have to meet the new §63.670 flare requirements, making the additional connections to the flare header for RVs will also trigger NSPS Ja requirements for that flare and any interconnected flares because of the unique modification definition in NSPS Ja for flares. It is unreasonable to force flares into NSPS Ja sulfur and other requirements, through this rulemaking, which deals with organic HAPs and assures their destruction and the destruction of any associated VOC. We recommend EPA add language to NSPS Ja to exclude the tie-in of atmospheric RVs to an existing flare header as an NSPS Ja modification.

4.2.3 The Proposed New Requirement For a Flare H_2S Performance Test Is Unnecessary, Since a CEMS is Required, and Should Not Be Finalized.

It is proposed to amend §60.104a(a) to require a flare performance test to demonstrate initial compliance with the H_2S limit on flare gas. This requirement was purposely not included in the NSPS Ja rule, since it is unnecessary and wasteful in light of the requirement for continuous H_2S monitoring. Nor is it reasonable to require such testing since H_2S levels in flare gas vary substantially and a representative sample is not likely for many flares during the short three hour performance test period. In fact, for most flares, there is no continuous flow to test, and it would be environmentally imprudent to require flare flows just to test.

4.3 Outstanding NSPS Ja Issue That Should Be Addressed in This Rulemaking.

4.3.1 The Flow Meter Specifications in the Proposal and in NSPS Ja Should be Made Consistent with the Instrumentation in General Use.

While refineries have already developed plans and purchased equipment to meet the flow monitor requirements in NSPS Ja, there is still vulnerability to enforcement and citizen suits, since the specifications for the flow monitors in NSPS Ja do not coincide clearly with the specifications of available instrumentation. That risk is compounded by the proposed requirements in Table 13 of RMACT 1, which perpetuates that disconnect between rule requirements and the specification of ultrasonic flow meters, which are the bulk of the new and existing flow instrument in this service. In Comment 1.5.2.5, API/AFPM address this issue and recommend the flow meter specification from the Shell Deer Park Flare CD replace the specification in both NSPS Ja and in RMACT 1 for flare gas flow meters.

Similar issues occur in the specifications in this proposal for FCCU Regenerator flow meters and for SRP flow meters, through the proposed specifications in RMACT 2 Table 41 and for SRPs through proposed additions of §60.106a(a)(6) and (7) to NSPS Ja. We address these concerns in Comments 1.5.4.1 and 1.5.5, respectively.

API/AFPM requests that EPA clarify all NSPS Ja flow monitor specifications per our comments and provide clear specifications that are consistent with available instrumentation specifications and capabilities and that avoid wasteful and unjustified replacement of existing instruments in order to try to meet an unrealistic and unnecessary instrument specification.

4.3.2 EPA Should Use This Opportunity to Address the API NSPS Ja Reconsideration Petition Item Relative to the Applicability of Fuel Gas Combustion Device Requirements to Flares that Only Handle Wastewater Treatment Unit Offgas.

By removing the "fuel gas combustion device" description from the definition of flares when finalizing the 2012 NSPS Ja reconsideration amendments there is no longer a tie to the definition of fuel gas which specifically says that "Fuel gas does not include vapors that are collected and combusted in a thermal oxidizer or flare installed to control emissions from wastewater treatment units ..." As a result flares that are used to comply with NSPS QQQ and/or part 61 subpart FF, and flares that combust other gases that are not considered fuel gases under subpart Ja are no longer excluded from subpart Ja fuel gas combustion deice requirements.

This change was not proposed and is presumably inadvertent. The needed rule revisions to make NSPS Ja consistent with NSPS J flare applicability should be included in the Refining Sector Rule final rule. We recommend adding a paragraph (2) to §60.103a(g) as follows (based from the definition of fuel gas in §60.101a) and renumbering the existing §60.103a(g) as §60.103a(g)(1):

> (2) Flares that are only used to control emissions from wastewater treatment units other than those processing sour water, marine tank vessel loading operations or asphalt processing units (i.e., asphalt blowing stills) are excluded from the requirements of §60.103a.

4.3.3 EPA Should Address the Issue of Measuring H_2S in the Wet Flare Gas at This Time

The NSPS Ja imposes H_2S and Total Reduced Sulfur (TRS) concentration limits for flare gas. These limits are specified on a dry basis, but flare gas is wet and any sample system that removes water will also remove at least some H_2S and TRS, making the values measured using such a sample system questionable at best. API/AFPM recommends NSPS Ja be amended to address this outstanding item from our reconsideration petitions.

API/AFPM recommends that the NSPS Ja specify alternatives to measurement of moisture content for adjusting the wet readings for flare gas measurements, as follows.

Option 1: Monitor the temperature of the waste gas exiting the knock out drum and assume the waste gas is saturated with moisture at that temperature. Use that volume % moisture to correct the wet gas concentration to a dry gas concentration, or

Option 2: Determine the moisture content of the waste gas (under typical flaring conditions), through bomb samples, wet and dry bulb temperatures, or similar means, to determine the moisture content of the flare gas and use that to correct the wet basis correction factor, or

Option 3: Develop a flare gas moisture content correction (based on typical to conservatively high waste gas temperature from the knock out drum and saturated conditions) for applicable scenarios (e.g., flare gas recovery compressor outage, steaming equipment to the flare, individual safety valve release). This would be a conservative moisture correction factor, but would not require any additional monitoring or calculations) by the facility.

Providing these alternatives in NSPS Ja would clarify how these corrections are to be made, rather than leaving a source, its permitting authority, and inspectors in limbo as to whether a particular approach is acceptable. Incorporating these alternatives would also clarify that measurement of moisture contents is not required.

4.3.4 Consistent With the Removal of the SSM Provisions From RMACT 1, EPA Should Use This Opportunity to Address the Handling of Tank Vents During Tank Shutdown in Both RMACT 1 and in NSPS Ja.

§60.102a(g)(iii) of NSPS Ja states "The combustion in a portable generator of fuel gas released as a result of tank degassing and/or cleaning is exempt from the emissions limits in paragraphs (g)(l)(i) and (ii)." Thus, the sulfur limits in NSPS Ja for combustion of fuel gas do not apply to portable generators combusting gas from tank degassing and/or cleaning. "Portable generator" is not defined, however, and is an entirely new term and the explanation for this exception in Section 2.1 of the Response to Comments is unclear whether thermal incinerators and diesel engines, the commonly used controls, are considered portable generators. For these short term control situations, portable engines, thermal oxidizers, and flares are typically used, depending on availability, gas composition, utility availability and other factors. Additionally, portable flares are sometimes used.

EPA should address flares used for this purpose as discussed in Comment 2.7.3.7 and revise NSPS Ja to allow temporary use of flares, thermal oxidizers, and engines for tank degassing with spot sulfur sampling. Given the small amount of gas generated from this type of activity, the typical low concentration of H_2S in these gases, and their infrequent occurrence there is no justification for limiting the types of VOC controls by imposing extensive compliance assurance requirements. Use of portable thermal oxidizers should be encouraged, since these are the most energy and environmentally efficient choice. While some Alternative Monitoring Plans (AMPs) have been approved for these situations[237], the burdens of obtaining AMPs on owners/operators and regulators are excessive and can introduce delays in tank maintenance or lead to the use of less than optimum controls.

We suggest the following revision to §60.102a(g)(iii):

> (iii) The combustion in a portable generator of fuel gas released as a result of tank degassing and/or cleaning is exempt from the emissions limits in paragraphs (g)(1)(i) and (ii) of this section. The combustion of fuel gas in a portable engine or thermal oxidizer released as a result of tank degassing and/or cleaning is exempt from the requirements of §60.107a. Compliance with the emissions limits in paragraphs (g)(1)(i) and (ii) of this section shall be demonstrated through an initial sample analysis or the average of three hourly sample analyses using either an H_2S colorimetric tube or a portable H_2S meter to determine the concentration of H_2S in gases entering the portable unit. A record of the date and time of each sample and the sample results shall be maintained.

4.3.5 The Oxygen Correction Equations in NSPS J, Ja and RMACT 2 Need to be Adjusted for FCCUs that Use Oxygen Enrichment.

Many emission limits in NSPS J, and Ja are specified as applying at 0 percent excess air. CO, an RMACT 2 limit in particular, is subject to that criterion if the FCCU is subject to NSPS J and thus must, per RMACT 2 Table 8, comply with NSPS J CO requirements in order to be in compliance with RMACT 2.

[237] See for instance, Jones, J., EPA, to C. Longo, GEM Mobile Treatment Serves, Request for Approval of an Alternative Monitoring Plan for Tank Degassing and Vapor Control Projects at Petroleum Refineries, April 11, 2013 and Jones, J., EPA to S. Sellinger, Envent Corporation, Approval of an Alternative Monitoring Plan for Tank Degassing and Vapor Control Projects at Petroleum Refineries, April 11, 2013.

NSPS J and Ja provide equations for correcting measured CO (and other FCCU pollutants – SO_2, NOx, PM[238]) to 0% O_2[239] as follows.

$$C_{adj} = C_{meas}\left[20.9_c \big/ (20.9 - \%O_2)\right]$$

Where:

C_{adj} = pollutant concentration adjusted to 0-percent excess air or O_2, parts per million (ppm) or g/dscm;

C_{meas} = pollutant concentration measured on a dry basis, ppm or g/dscm;

20.9_c = 20.9 percent O_2 –0.0 percent O_2 (defined O_2 correction basis), percent;

20.9 = O_2 concentration in air, percent; and

$\%O_2$ = O_2 concentration measured on a dry basis, percent.

This adjustment equation fails if the O_2 concentration in the regenerator off-gas is near or above 20.9, which occurs as FCCUs transition from normal operation to startup and shutdown or into and out of hot standby, where O_2 enrichment is in use by the FCCU. In fact, with O_2 enrichment the O_2 concentration will exceed the normal air concentration during these transitions and result in large negative CO concentrations being calculated.

API/AFPM recommends that this issue be addressed by providing an "air-only" alternative correction equation for FCCUs that use O_2 enrichment, as follows.

$$\text{Air Only Pollutant} = \text{x(Poll)} * \text{C(air)} * \left(\frac{20.9}{20.9 - \text{O2} * \text{C(air)}}\right)$$

Where:

Air Only Pollutant = pollutant concentration adjusted to 0-percent excess air or O2, parts per million (ppm) or g/dscm

$\text{C(air)} = \frac{\text{F(stack)}}{\text{F(stack)}+3.785*\text{F(O2)}}$, ppm or g/dscm

[238] PM only has this issue when a PM CEMS is used to meet the concentration compliance alternative limit in NSPS Ja and RMACT 2.

[239] See, for instance, §§60.106(h)(6) and 60.104a(d)(8).

$\mathrm{x(Poll)} = \text{Measured Pollutant concentration in stack}$

and

$3.785 = \frac{1-0.209}{0.209}$ = Equivalent N_2 flow, based on enrichment oxygen rate.

$\mathrm{F(stack)} = \text{Stack flow rate}$

$\mathrm{F(O2)}$ = Enrichment O_2 flow rate

5.0 Comments on Proposed Amendments to Other Parts 60, 61 and 63 Subparts

5.1 EPA Should Only Finalize Its Proposal to Apply The New Refinery Flare Requirements to Flares at Subpart R and Y Facilities For Flares That Also Receive Refinery Flare Gas.

It is proposed to add §63.650(d) and 63.651(e) to RMACT 1. These paragraphs would impose the new refinery flare requirements on flares that are dedicated to gasoline distribution and marine facilities that are part of the RMACT 1 affected facility, but that do not also receive refinery gas. Flares for these dedicated uses are different from general refinery flares, in that they are typically smaller, more likely to be air-assisted, burn known compositions of gas, and in some cases have different designs. As discussed in Comment 2.7.2, the rule analyses supporting this proposal do not reflect the technical, cost, or other issues associated with these flare types. Nor is it clear that these sources were reported in the ICR data collection effort and included in the risk modelling, since many of these operations are independently managed, often permitted separately, and sometimes not even physically abutting the refinery.

Furthermore, EPA has done separate risk and technology reviews for subpart R and Y facilities and concluded there was no technology improvement that should be applied to such facilities under section 112(d)(6)[240]. There is no reasonable basis for overturning that conclusion and having different requirements for flares in this service just because they happen to be located adjoining or near a refinery. The proposed §63.670 flare requirements should not apply to flares that are dedicated to subpart R and/or Y operations and these two proposed new paragraphs should not be finalized.

Gases sent to a dedicated flare at these facilities are different than the gases sent to refinery flares. The gases sent to these flares are primarily vapors from transfer operations (from the vessel being loaded or from the storage tank into which a vessel is being unloaded) and to a lesser extent small storage tank and/or equipment leak flows and occasionally flows from equipment clearing operations. The transfer operation flows are intermittent flows of well characterized, high BTU materials and are not subject to the composition and BTU content variability of many refinery flares. Because these operations handle a limited number and type

[240] 71 Fed. Reg. 17352 (April 6, 2006) and 76 Fed. Reg. 22566 (April 21, 2011)

of materials, even equipment leak and storage vessel flows are typically well characterized and high BTU materials. By the nature of these types of facilities, the flares do not have to be sized for extremely large emergency flows and thus flares at these facilities usually have smaller design capacities than typical refinery flares and operate at less turndown than do refinery flares. For these reasons, flare destruction efficiency concerns are minimal and it is unlikely that any significant emission reductions would accrue to justify this proposed change.

Neither the ICR or API/AFPM survey specified that co-located marine loading and gasoline terminaling operations that are not operated by the refinery management, should be included in the survey responses. Inspection of the ICR database indicates that only a few such operations were included in the responses, confirming that most such facilities are separately managed or are not considered part of the refinery.

Because steam is often not available at these locations, the majority of these flares are air-assisted. Overall, then, refinery flare information is not representative of dedicated gasoline distribution and marine flares and thus EPA's refinery flare database is an unacceptable basis for establishing flare regulations for these facilities.

Similarly, in many cases, there are significant facilities and staffing differences between refineries and these facilities. Co-located gasoline distribution and marine operations often have operators present only when loading or unloading operations are underway. For gasoline terminals, loading, particularly off-hour loading, can be automated and unmanned. Many of these facilities also are not connected to large digital data systems and thus are not easily able to accommodate the continuous monitoring specified in the proposed new flare requirements.

5.2 API/AFPM Supports EPA's Conclusion that "It Is Not Necessary to Revise Refinery MACT 1 Requirements for Gasoline Loading."

API/AFPM agrees with EPA's conclusion during the risk and technology review of subpart R[241] that there have been no "developments in practices, processes, and control technologies" that would justify revising the requirements for gasoline loading at refinery subpart R facilities. Furthermore, as we indicated in Comment 5.1, that conclusion also applies to flares dedicated to subpart R facilities.

[241] 71 Fed. Reg. 17352 (April 6, 2006)

5.3 API/AFPM Questions The Need to Duplicate The Existing Coast Guard Requirement.

EPA proposes to revise §63.560(a) of subpart Y by adding a paragraph (4) as follows.

> (4) Existing sources with emissions less than 10 and 25 tons must meet the submerged fill standards of 46 CFR 153.282.

While the subpart Y risk and technology review for this source category[242] already completed the CAA review requirements for subpart Y marine facilities at refineries, it is proposed to add this additional requirement for refinery subpart Y facilities, even though it is already imposed through Coast Guard regulations. We question the need for this change since it has no risk impact. Having identical requirements imposed through two different rules and regulatory agencies will result in duplicative recordkeeping and reporting burdens (e.g., any deviations would have to be reported to both the Coast Guard and the EPA) and duplicative enforcement burdens (i.e., both EPA and Coast Guard will inspect for compliance.)

[242] 76 Fed. Reg. 22566 (April 21, 2011)

Attachment A-1

ENVIRON Comments on Risk Modelling

At the request of the American Petroleum Institute (API), ENVIRON has provided technical assistance in support of API's preparation of comments on the U.S. Environmental Protection Agency's (EPA) proposed rule, "Petroleum Refinery Sector Risk and Technology Review and NSPS" (Refinery Sector Rule). As part of that assistance, ENVIRON has reviewed and evaluated residual risk modeling conducted by EPA in support of its Refinery Sector Rule. Risk modeling of the 33 refineries reported by EPA to have the highest cancer and chronic noncancer risk was conducted to assist API in verifying EPA's risk estimates and to identify key risk-drivers at those facilities for further review by API and member companies and correction if warranted.

Below is a summary of key findings:

- While modeled results are consistent with EPA's judgment in its proposed rule that refinery risks are "acceptable," certain potential data issues were identified that, once corrected, will lower risk estimates for the highest-risk refineries and others.
- For certain refineries, EPA modeled emission-outlier sources that overestimated actual emissions, sources that were mislocated or incorrectly extended offsite, or calculated maximum risks at nonresidential locations, causing risks to be misstated.
- For certain refineries, EPA's risk modeling does not reflect corrected emission inventory data, causing risks to be overstated.
- Correction of data errors, if present, and re-modeling of risk by EPA using corrected data is warranted. For example, using corrected data from companies, the hEM-3 model was used to re-calculate risk for the two refineries with the highest EPA-reported facility-wide cancer risk, correcting modeled cancer risk from 67 in a million to 15 in a million for one refinery, and from 67 in a million to 13 in a million for the other.

ENVIRON's complete report is attached separately.

October 27, 2014

MEMORANDUM

To: Matt Todd, API

From: Stan Hayes, ENVIRON
Ted Bowie, ENVIRON
Idania Zamora, ENVIRON

Re: Review and Evaluation of Residual Risk Modeling Associated with EPA's Proposed Refinery Sector Rule

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At the request of the American Petroleum Institute (API), ENVIRON has provided technical assistance in support of API's preparation of comments on the U.S. Environmental Protection Agency's (EPA) proposed rule, "Petroleum Refinery Sector Risk and Technology Review and NSPS" (Refinery Sector Rule). As part of that assistance, ENVIRON has reviewed and evaluated residual risk modeling conducted by EPA in support of its Refinery Sector Rule.

Risk modeling of the 33 refineries reported by EPA to have the highest facility-wide cancer and chronic noncancer risk was conducted to assist API in verifying EPA's risk estimates and to identify key risk-drivers at those refineries for review and correction if warranted. This memorandum describes the results of ENVIRON's review and evaluation.

Key Points

Below is a summary of key points:

- While modeled results are consistent with EPA's judgment in its proposed rule that refinery risks are "acceptable," certain potential data issues were identified that, once corrected, will lower risk estimates for the highest-risk refineries and others.
- For certain refineries, EPA modeled emission-outlier sources that overestimated actual emissions, sources that were mislocated or incorrectly extended offsite, or calculated maximum risks at nonresidential locations, causing risks to be misstated.
- For certain refineries, EPA's risk modeling does not reflect corrected emission inventory data, causing risks to be overstated.
- Correction of data errors, if present, and re-modeling of risk by EPA using corrected data is warranted. For example, using corrected data from companies, the HEM-3 model was used to re-calculate risk for the two refineries with the highest EPA-reported facility-wide cancer risk, correcting modeled cancer risk from 67 in a million to 15 in a million for one refinery, and from 67 in a million to 13 in a million for the other.

Background

On May 15, 2014, the proposed Refinery Sector Rule was signed by EPA Administrator McCarthy and published in Federal Register on June 30th. EPA extended the original 60-day public comment period by an additional 60 days until October 28th.

As part of its development of the Refinery Sector Rule, EPA conducted residual risk modeling of 142 U.S. petroleum refineries. EPA developed emission inventories for that modeling using emission inventory data submitted by refineries in response to EPA's 2011 Refinery Information Collection Request (ICR),[1] with certain modifications to those data. As stated by EPA, data sets were refined by quality assurance checks, updated based on additional information received from refineries, and supplemented by results from ICR stack testing.

With those modified emission inventories, EPA estimated residual risks for refineries using the risk-based Human Exposure Model (HEM-3). Results of EPA's risk analyses are available on its website.[2]

Methodology

Using the most recent version of EPA's HEM-3 risk model[3,4] and the meteorological,[5] census,[5] refinery emission inventory database,[6] and risk assessment methodology[7,8] used by EPA, risk modeling was conducted of the 33 refineries for which EPA reported a modeled facility-wide cancer maximum individual risk (MIR) of 20 in a million or greater or a chronic noncancer maximum target organ specific hazard index (TOSHI) greater than 1.

Key features of the HEM-3 model include:

- AERMOD dispersion model (version 13350);
- An extensive library of toxicity values used to calculate risk;
- A library of over 800 meteorological datasets;
- A library of census databases that includes both 2010 and 2000 Census data;

[1] Information on EPA's Refinery ICR is available at www.epa.gov/ttn/atw/petref/petrefpg.html
[2] EPA residual risk assessment results are available at www.epa.gov/ttn/atw/petref.html
[3] EPA. 2014a. "The HEM-3 User's Guide." U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina. April. Available at www2.epa.gov/sites/production/files/2014-04/documents/hem3_users_guide.pdf
[4] EPA. 2014b. "Multi HEM-3 and RTR Summary Programs User's Guide." U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina. April. Available at www2.epa.gov/sites/production/files/2014-04/documents/multi_hem-3_users_guide.pdf
[5] Meteorological and census files available at www2.epa.gov/fera/download-human-exposure-model-hem
[6] EPA emission inventory information accessed on June 3, 2014; available at www.epa.gov/ttn/atw/petref/petrefpg.html
[7] EPA risk assessment methodology discussed at www2.epa.gov/fera/risk-assessment-and-modeling-human-exposure-model-hem
[8] Methods used are intended to match EPA's residual risk assessment methodology, and do not necessarily reflect ENVIRON's independent risk assessment judgment and practice.

- Ability to model point, area, volume, and polygon sources; and
- Automatic calculation of rural or urban land use type based on population density determined using census data.

HEM-3 calculates both cancer and noncancer risk. EPA measures noncancer risk using a "target organ specific hazard index," or TOSHI. The TOSHI is calculated as the ratio of the modeled concentration for each emitted HAP having a noncancer toxicity to a health benchmark concentration for that HAP, and then summing the ratios over all the HAPs affecting the same target organ. Both types of risk were calculated at a number of different locations near each refinery, including the centroids of 2010 U.S. Census blocks and additional locations specified by EPA.

Risk modeling was conducted using EPA's estimated facility-wide actual emissions, with source parameter data (e.g., stack height, exit temperature, exit velocity, stack diameter, length, width) from EPA's refinery emission inventory database. Surface and upper air meteorological data, which were downloaded from EPA's HEM-3 website, were selected for use for each refinery by HEM-3 from its library of model-ready files.

For each refinery, detailed risk attribution analyses were performed to identify risk-driver sources and hazardous air pollutants (HAPs) for both the modeled cancer MIR and chronic noncancer maximum TOSHI.

Modeling results were analyzed to identify potential data issues if present. Those issues were flagged for further review and data correction if warranted.

Examples were identified illustrating the presence of data issues that have the potential to materially affect EPA's reported risk estimates.

Results

Refinery Selection

Refineries were selected for modeling using risk results reported[9] by EPA for what EPA termed "actual" emissions. The thirty refineries for which EPA reported a facility-wide cancer MIR of 20 in a million or greater were selected for HEM-3 modeling. Four of these refineries also had an EPA-reported noncancer maximum TOSHI greater than 1. Three additional refineries also were selected because EPA reported a facility-wide noncancer maximum TOSHI greater than 1. The 33 refineries modeled are indicated in Figure 1.

HEM-3 Risk Modeling

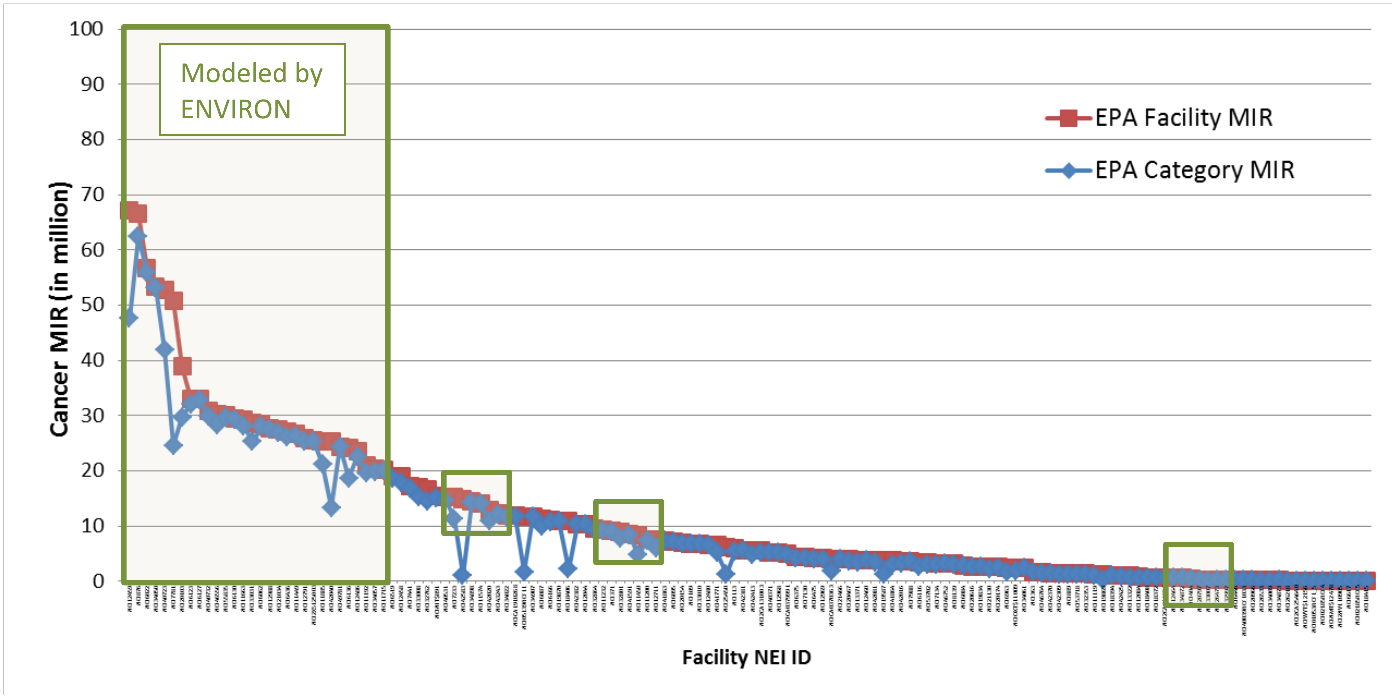
Modeled refineries are listed in Table 1. The first thirty refineries are in descending order of EPA-reported facility-wide cancer MIR; the last three are in descending order of EPA-reported facility-wide noncancer maximum TOSHI.

Figure 2 compares ENVIRON modeled results with those reported by EPA. Agreement was generally close. For cancer MIR, the two estimates were within 10% for 28 of 33 refineries, within 5% for 26 refineries, and 1% or less for 18 refineries. For noncancer maximum TOSHI, the two estimates were within 10% for 26 refineries, 5% or less for 24 refineries, and 1% or less for 10 refineries. Estimated cancer MIR differed by more than 10% for 4 refineries. Estimated noncancer maximum TOSHI differed by 10% or more for 7 refineries.

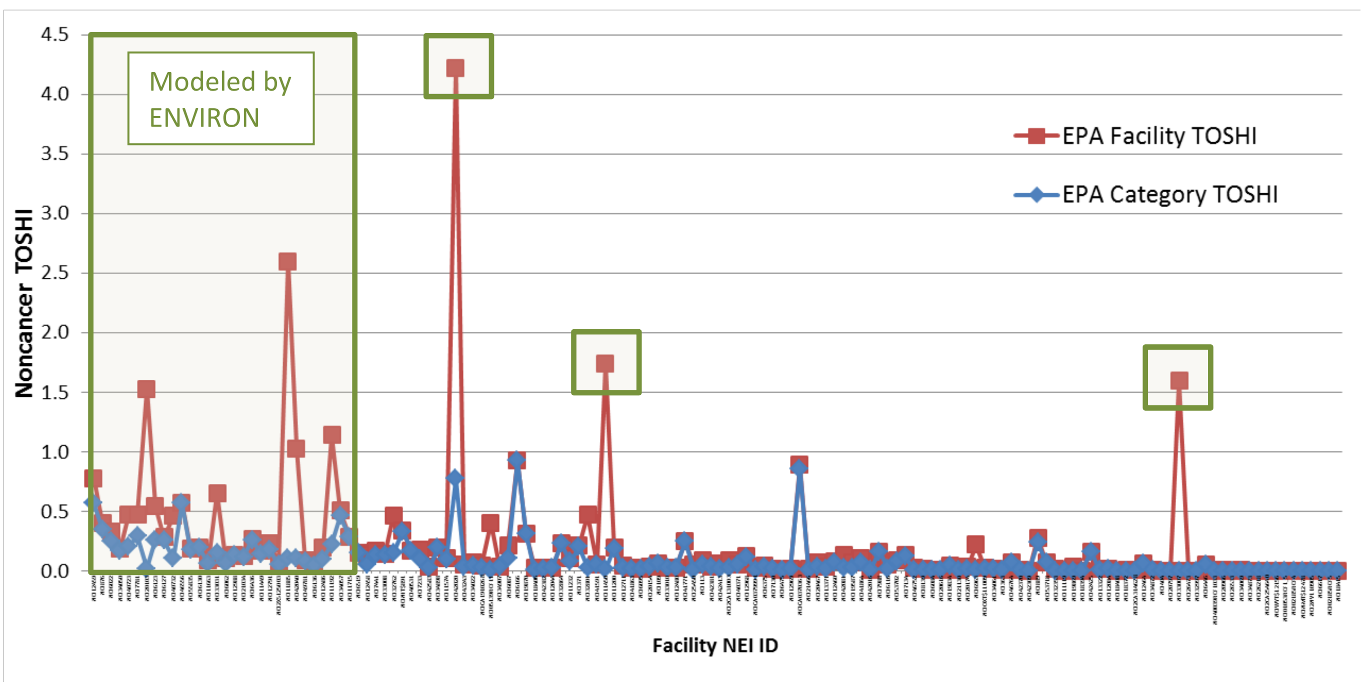
Results were most different for EPA's highest-reported risk refinery (NEI12459), for which the facility-wide cancer MIR calculated by ENVIRON was 47 in a million (29% lower than the 67 in a million cancer MIR reported by EPA) and the facility-wide noncancer maximum TOSHI was 0.59 (24% lower than the 0.78 reported by EPA).

The emission inventory and associated HEM-3 input files used by EPA to calculate the reported facility-wide 67 in a million cancer MIR may have been updated subsequent to that calculation to include additional data corrections. If so and if that updated emission inventory was posted on EPA's website, replacing the original inventory, that updated inventory information would have been downloaded and used in ENVIRON HEM-3 modeling. Assuming that this is the case, the facility-wide cancer MIR and maximum TOSHI calculated by ENVIRON would supersede values originally reported by EPA for this refinery.

[9] EPA. 2014c. "Draft Residual Risk Assessment for the Petroleum Refining Source Sector." U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina. May. Available at www.epa.gov/ttn/atw/petrefine/rtrassessment2014.pdf.



(a) Cancer MIR



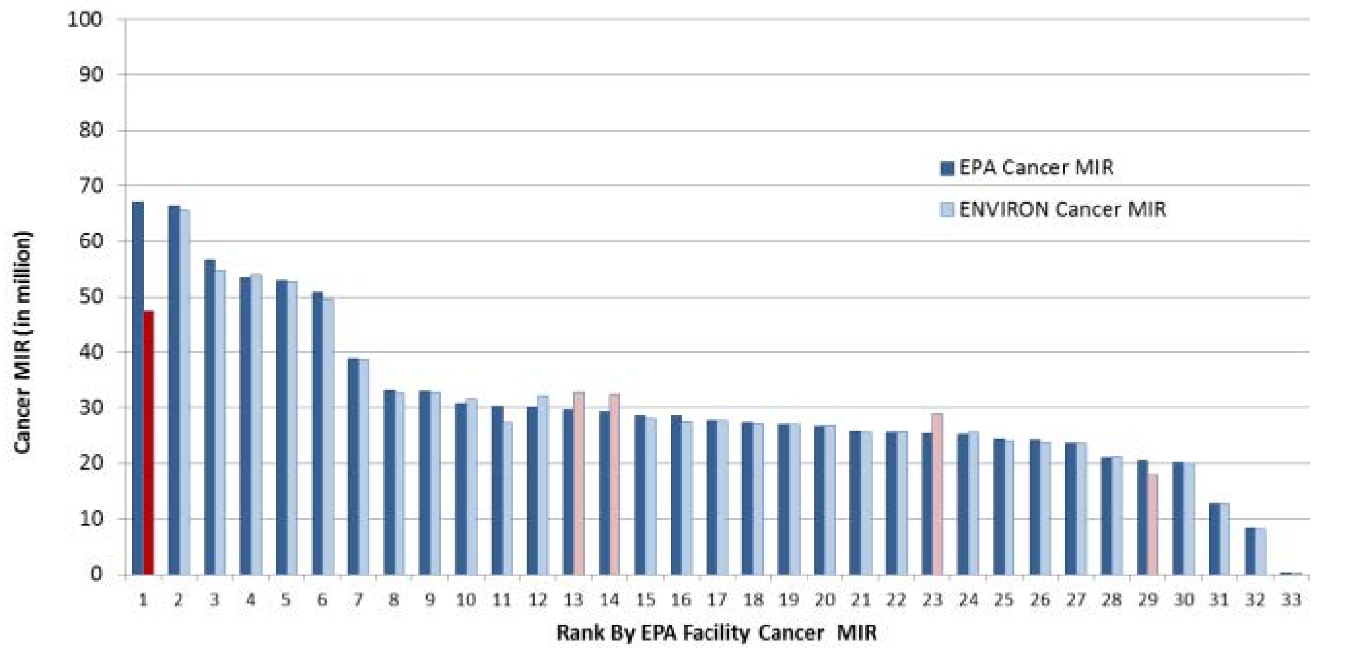
(b) Chronic noncancer maximum TOSHI

Figure 1. Refineries modeled by ENVIRON, with reported EPA facility and category risks

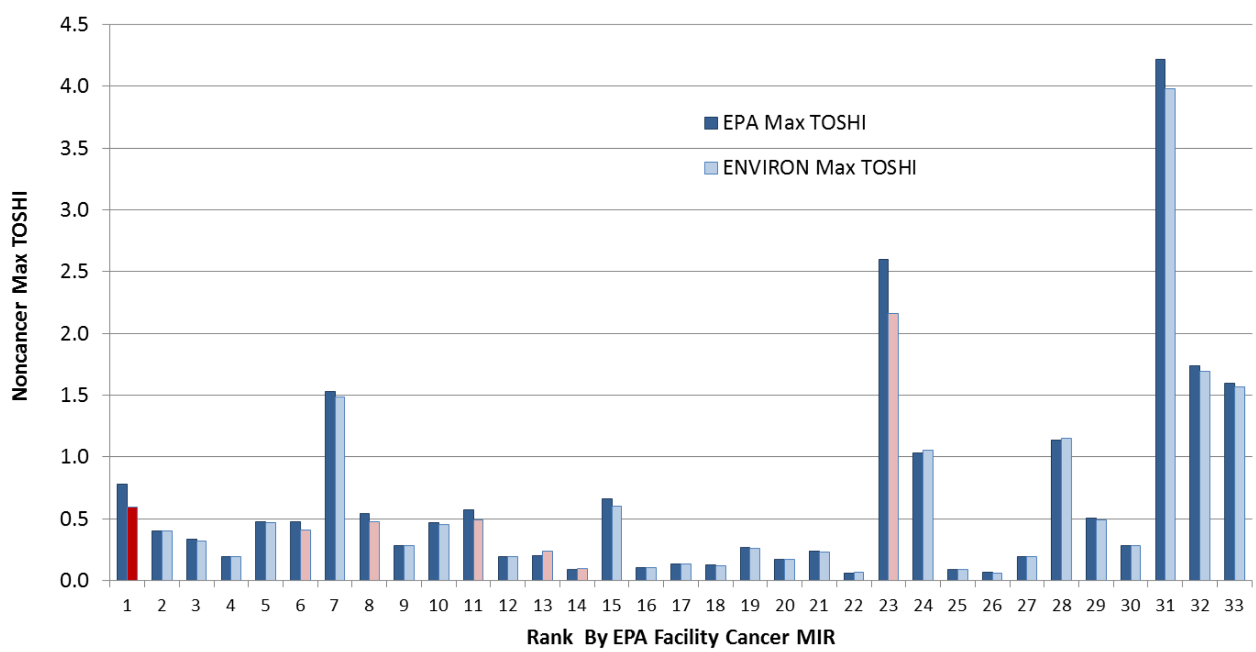
Table 1. Facility-wide cancer and noncancer risk, as modeled by EPA and ENVIRON using EPA methodology (table includes all refineries with EPA-reported cancer MIR > 20 in million or chronic noncancer maximum TOSHI > 1.

EPA Rank	Facility NEI ID	Cancer MIR			Noncancer Max TOSHI		
		EPA	ENVIRON	% Diff	EPA	ENVIRON	% Diff
1	NEI12459	67.1	47.5	**-29%**	0.78	0.59	**-24%**
2	NEI876	66.5	65.5	-1%	0.41	0.40	-1%
3	NEI6022	56.6	54.7	-3%	0.33	0.32	-5%
4	NEI34050	53.4	53.8	1%	0.19	0.19	1%
5	NEI40723	52.8	52.6	0%	0.48	0.47	-2%
6	NEI7781	50.8	49.6	-2%	0.48	0.41	**-14%**
7	NEI20103	38.9	38.6	-1%	1.53	1.49	-3%
8	NEI6123	33.1	32.6	-2%	0.55	0.48	**-13%**
9	NEI6127	33.0	32.9	0%	0.29	0.28	-1%
10	NEI40732	30.8	31.6	3%	0.47	0.45	-3%
11	NEI46556	30.2	27.4	-9%	0.57	0.49	**-14%**
12	NEI55835	30.0	32.1	7%	0.19	0.19	1%
13	NEI6130	29.5	32.9	**11%**	0.20	0.24	**17%**
14	NEI11663	29.3	32.4	**11%**	0.09	0.10	**10%**
15	NEI33031	28.6	28.0	-2%	0.66	0.60	-9%
16	NEI6062	28.5	27.6	-3%	0.11	0.11	-2%
17	NEI12988	27.6	27.7	0%	0.13	0.14	1%
18	NEI21034	27.4	27.1	-1%	0.13	0.12	-4%
19	NEI6436	27.0	26.9	0%	0.27	0.26	-2%
20	NEI11449	26.6	26.8	1%	0.17	0.17	1%
21	NEI12791	25.8	25.6	-1%	0.24	0.23	-1%
22	NEI2KS125003	25.6	25.8	1%	0.06	0.07	2%
23	NEI11885	25.4	28.8	**14%**	2.60	2.16	**-17%**
24	NEI42040	25.3	25.7	1%	1.03	1.05	2%
25	NEI49781	24.4	24.0	-2%	0.09	0.09	-2%
26	NEI6136	24.2	23.7	-2%	0.07	0.06	-2%
27	NEI12486	23.6	23.6	0%	0.20	0.19	-1%
28	NEI11192	21.0	21.2	1%	1.14	1.15	1%
29	NEI34057	20.4	18.0	**-12%**	0.51	0.49	-3%
30	NEI11715	20.1	20.0	0%	0.28	0.29	1%
31	NEI42020	12.8	12.8	0%	4.22	3.98	-6%
32	NEI11450	8.3	8.2	-2%	1.74	1.69	-3%
33	NEI33007	0.3	0.3	-1%	1.60	1.57	-2%

X%	Difference **> 20%**
Y%	Difference **10-20%**



(a) Cancer MIR



(b) Noncancer maximum TOSHI

Figure 2. Comparison of EPA and ENVIRON HEM-3 modeled facility-wide risk estimates (all refineries with EPA cancer risk > 20 in million or maximum TOSHI > 1, dark red shading indicates differences greater than 20%, light red shading 10-20%)

Risk Attribution

Having determined that EPA and ENVIRON modeling results matched acceptably well, a detailed analysis of HEM-3 risk modeling output was conducted for each refinery to determine the contribution of individual sources and HAPs to facility-wide risk.

For each refinery, the highest ten sources and HAPs (not necessarily from the highest ten sources) contributing to modeled facility-wide risk were identified as risk-drivers for cancer MIR and noncancer maximum TOSHI. Sources and HAPs contributing the largest risk percentages were highlighted as key risk-drivers.

Figure 3 summarizes facility-wide cancer risk-driver source types and HAPs. For source types, the total number of occurrences of a given source type among the top ten cancer MIR contributors is plotted in the top chart, with that total subdivided according to their percentage contribution. For example, there were 84 process equipment leak sources among the top ten risk-driver sources at the top 33 refineries. Of these, 62 sources contributed less than 10% of the cancer MIR, 14 sources contributed between 10% and 20%, 6 sources contributed between 20% and 30%, 1 source contributed between 30% and 40%, and 1 source contributed between 40% and 50%.

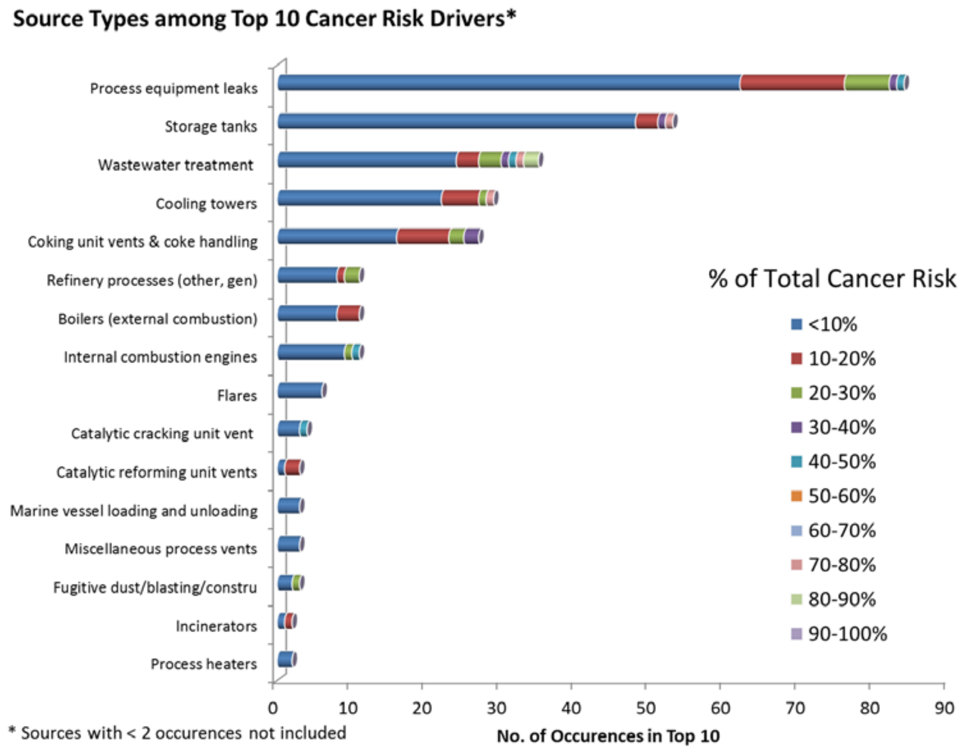
For HAPs, the number of occurrences in the top ten is subdivided according to their rank among top ten HAPs. For example, naphthalene was among the top ten risk-driver HAPs at 29 of 33 refineries. Among these, naphthalene was the highest-ranked facility-wide risk driver HAP at 10 refineries, the 2nd highest at 10 refineries, and the 3rd highest at 5 refineries.

The figure shows that the source types occurring most frequently among the top ten contributors to the facility-wide cancer MIR are process equipment leaks, storage tanks, and wastewater treatment. The most frequently occurring HAPs are naphthalene, benzene, ethyl benzene, and 1,3-butadiene.

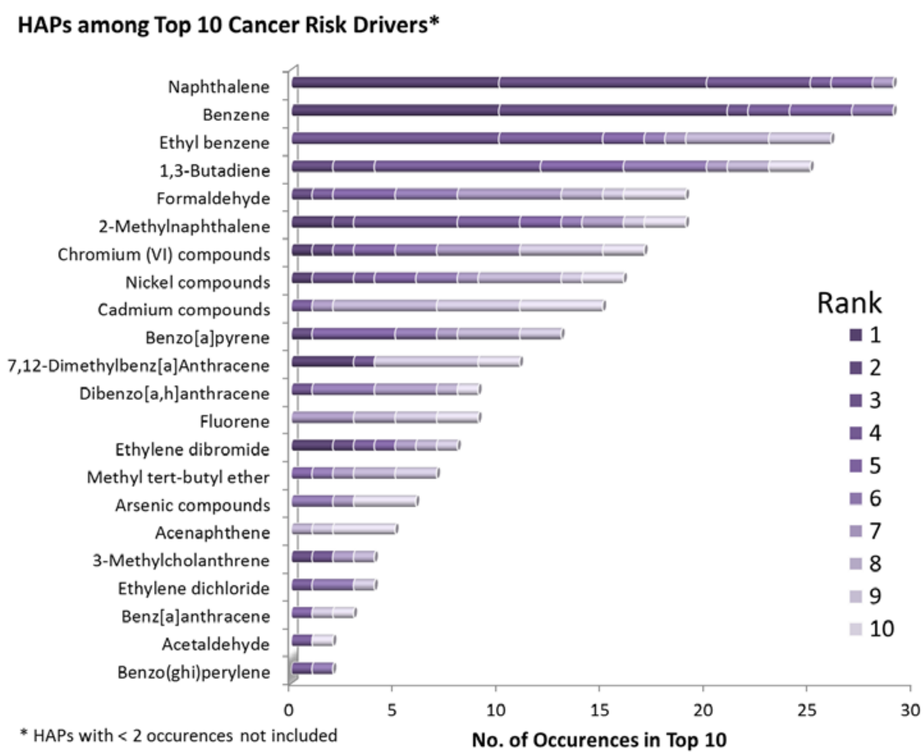
Figure 4 summarizes facility-wide noncancer risk-driver source types and HAPs at the seven refineries having a maximum TOSHI greater than 1. For source types, the total number of occurrences of a given source type among the top ten contributors to the maximum TOSHI is plotted in the top chart, with that total subdivided according to their percentage contribution. For example, there were 23 internal combustion engine sources among the top ten risk-driver sources at the seven refineries. Of these, 6 sources contributed less than 10% of the maximum TOSHI, 6 sources contributed between 10% and 20%, 9 sources contributed between 20% and 30%, and 2 sources contributed between 40% and 50%.

For HAPs, the number of occurrences in the top ten at the seven refineries is subdivided according to their rank among top ten HAPs. For example, acrolein was among the top ten risk-driver HAPs at all seven refineries. Of these, acrolein was the highest risk-driver HAP at 5 refineries and the 2nd highest at the other 2 refineries.

The figure shows that the source types occurring most frequently among the top ten contributors to the noncancer maximum TOSHI are internal combustion engines, process heaters, and cooling towers. The most frequently occurring HAPs are acrolein, nickel compounds, naphthalene, and formaldehyde.

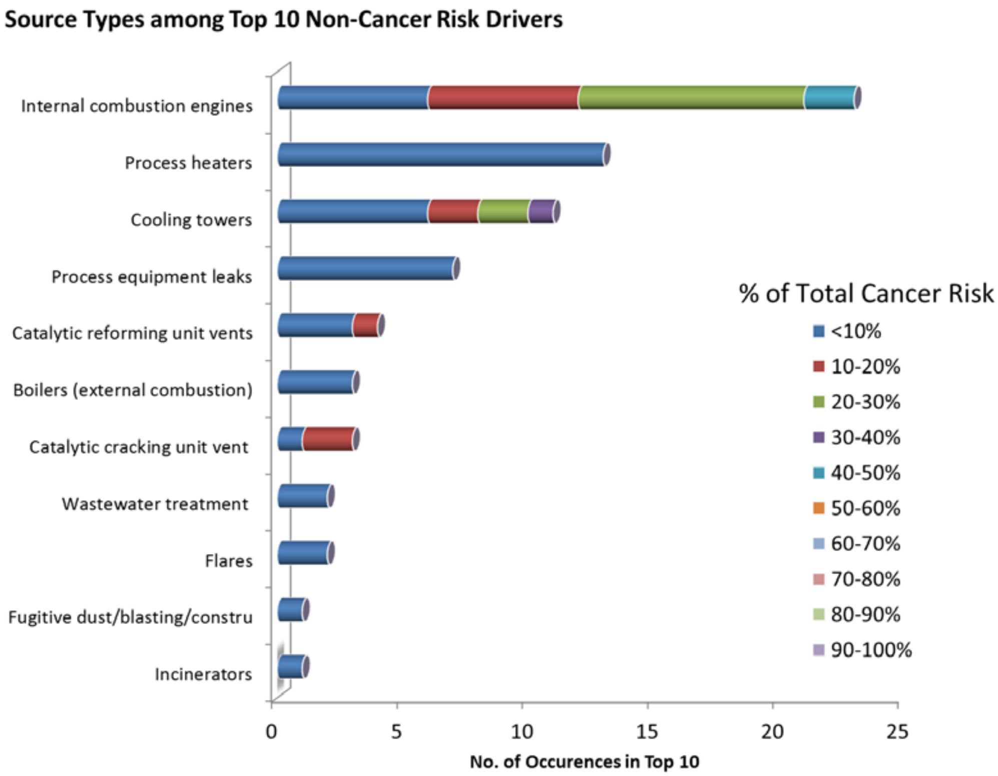


(a) Risk-driver source types

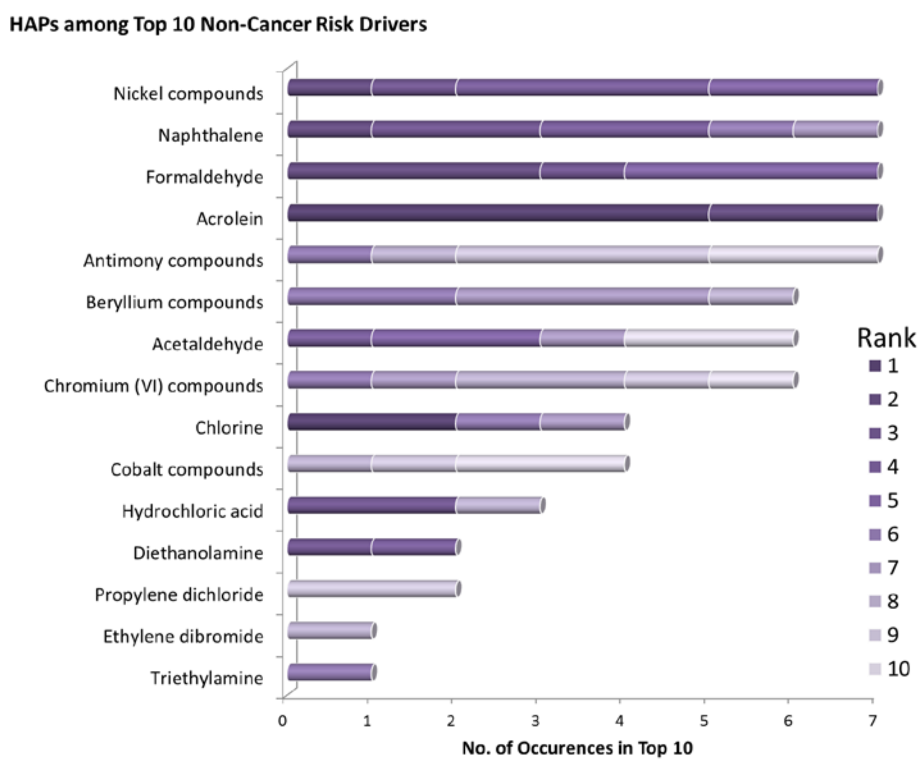


(b) Risk-driver HAPs

Figure 3. Facility-wide cancer MIR risk-driver source types and HAPs



(a) Risk-driver source types



(b) Risk-driver HAPs

Figure 4. Facility-wide noncancer maximum TOSHI risk-driver source types and HAPs

Error Analyses

Risk modeling results were analyzed to identify potential data issues if present, including the following:

- Mislocated sources (e.g., offsite or materially misplaced)
- Possible emission outliers (e.g., unusually high compared to other similar sources)
- Emissions needing verification (e.g., key emissions or sources needing further verification)
- Nonrepresentative risk receptors (e.g., risk evaluation locations onsite or offsite where extended exposure could not occur)
- Non-census block risk receptors (e.g., addition by EPA of new, non-census block risk evaluation locations close to the refinery, such as individual residences at locations materially different than census data)
- Updated emission inventory needed (e.g., data not reflecting the most recent company corrections)

Table 2 tabulates the potential data issues found for each of the 33 refineries modeled. As noted in a number of cases, further analyses are needed to verify or rule out the presence of a data error. Not all potential data issues would have the same effect on EPA's risk estimates. Some could have a larger and more material impact on risk estimates, while others could have a smaller and less material effect.

Correction of data errors, if present, and re-modeling of risk using corrected data are warranted.

Table 2. Error analysis results: Potential data issues in EPA residual risk modeling

EPA Rank[1]	Facility NEI ID	Potential Data Issues
1	NEI12459	1. Possible emission outlier: Naphthalene estimated to account for 38 of 48 in million modeled facility-wide cancer MIR; tank farm source MEST0035 listed in EPA refinery emission inventory database as largest individual source of naphthalene (16.5 tpy, compared to 2nd largest at 7.3 tpy); emissions need verification 2. Updated emission inventory needed: Apparent mismatch between EPA-reported cancer MIR (67 in million) and modeled risk using emission inventory posted on EPA website (47 in million); needs resolution; also, data corrections made by refinery not used in EPA modeling (refinery calculates MEST0035 naphthalene emissions to be 0.3 tpy, not 16.5 tpy); update needed
2	NEI876	1. Mislocated sources: Incorrect source locations and emission inventory data, including collocated stack and area sources 2. Updated emission inventory needed: Corrections developed by refinery; corrected data not used; update needed
3	NEI6022	1. Possible emission outliers: Ethylene dibromide estimated to account for 27 of 55 in million modeled facility-wide cancer MIR; refinery listed in EPA refinery emission inventory database as having 2nd, 4th, 5th, and 6th largest individual sources of ethylene dibromide (0.99, 0.19, 0.15, 0.13 = 1.49 tpy); presumed used in leaded fuel (avgas); emissions need verification 2. Nonrepresentative receptor: Modeled cancer MIR (55 in million) is at census block on commercial building; modeled risk at highest residential census block is 48 in million
4	NEI34050	1. Possible emission outliers: Process equipment leak sources MEPE0028 and MEPE0063 estimated to account for 25 of 54 in million modeled facility-wide cancer MIR; emissions need verification 2. Nonrepresentative risk receptor: Modeled cancer MIR (54 in million) is at census block on commercial building; modeled risk at highest residential census block is 40 in million
5	NEI40723	1. Possible emission outlier: MEPE0060 listed in EPA refinery emission inventory database as 6th highest individual source of naphthalene (4.13 tpy); also, refinery listed by EPA as having 1st, 4th, 11th, 13th (MEP0060), and 14th largest benzene process equipment leak sources; emissions need verification 2. Mislocated sources: Process equipment leak source MEPE0060 estimated to account for 21 of 53 in million modeled facility-wide cancer MIR; extends offsite toward cancer MIR, causing higher modeled risk; other area sources offsite as well; locations need verification
6	NEI7781	1. Possible emission outlier: Coker source MECU0046 estimated to account for 17 of 50 in million modeled facility-wide cancer MIR; listed in EPA refinery emission inventory database as 3rd largest individual source of ethylene dibromide (2nd largest after closure of refinery NEI46556); emissions need verification 2. Emissions verification needed: MECU0046 listed in EPA refinery emission inventory database as "Coking Unit Vents & Coke Handling" emission process group; however, it is only coking unit source of ethylene dibromide listed in database; also, EPA refinery emission estimation protocol does not list ethylene dibromide as emitted by cokers; emissions need verification

Table 2. Error analysis results: Potential data issues in EPA residual risk modeling

EPA Rank[1]	Facility NEI ID	Potential Data Issues
7	NEI20103	1. Emissions verification needed: 7,12-dimethylbenz[a]anthracene emissions from multiple sources estimated to account for 28 of 39 in million modeled cancer MIR; acrolein emissions from IC engines estimated to account for 1.38 of 1.49 modeled facility-wide maximum TOSHI; emissions need verification
8	NEI6123	1. Mislocated sources: Refinery process MERP0031 area source extends offsite, overlapping an offsite census block; may be slight rotation angle error 2. Nonrepresentative risk receptor: Nearest census block (overlapped by mislocated area source) is local jail; cannot have 70-year exposures; not valid for 70-year cancer risk (note that this census block was excluded by HEM-3 because of overlap)
9	NEI6127	1. Mislocated sources: Large area sources extend offsite, nearly reaching adjacent highest risk location; area sources also extend offsite to southeast; some modeled area source dimensions, stack locations and parameters do not match actual values 2. Non-census block risk receptors: EPA added non-census block receptor close to refinery and almost on top of offsite area sources; need to verify receptor is inhabited residence 3. Updated emission inventory needed: Corrected data not used; update needed
10	NEI40732	1. Emissions verification needed: Cooling tower source MECT0035 estimated to account for 25 of 32 in million modeled facility-wide cancer MIR; emissions need verification 2. Mislocated sources: Some sources do not map well to refinery; source locations need verification
11	NEI46556	1. Possible emission outlier: Source listed in EPA refinery emission inventory database as largest individual source of ethylene dibromide; nearly 25 times larger than next largest source (24.8 tpy, compared with 2nd high=0.99 tpy); REFINERY NOW CLOSED
12	NEI55835	1. Mislocated sources: Some area sources extend offsite; appear to be slight rotation angle errors; tanks offset closer to MIR than actual locations 2. Nonrepresentative risk receptor: Modeled facility-wide cancer MIR (32 in million) at census block in parking lot, possibly onsite, not residential location; also listed as "Empty Block;" modeled risk at highest residential census block is 30 in million
13	NEI6130	1. Nonrepresentative risk receptor: Modeled facility-wide cancer MIR (33 in million) at census block in largely vacant area with only one house, may be in transition area for purchase by refinery; need to verify still occupied as residence; modeled risk at next highest census block is 11 in million

Table 2. Error analysis results: Potential data issues in EPA residual risk modeling

EPA Rank[1]	Facility NEI ID	Potential Data Issues
14	NEI11663	1. Emissions verification needed: Wastewater treatment source MEWW0113 estimated to account for 23 of 28 in million modeled facility-wide cancer MIR; emissions need verification
15	NEI33031	1. Nonrepresentative risk receptor: Modeled facility-wide cancer MIR (28 in million) is at census block in open area (park?), not residential location; modeled risk at highest residential census block is 24 in million 2. Non-census block risk receptor: EPA added non-census block risk receptors close to refinery, one of which has modeled risk of 24 in million, same as highest census block; needs verification
16	NEI6062	1. Emissions verification needed: Coker sources MECU0007 and MECU0008 estimated to account for 13 of 28 in million modeled facility-wide cancer MIR; emissions need verification 2. Mislocated sources: Some sources offsite, area source extends toward nearby census block (not modeled MIR, however)
17	NEI12988	1. Mislocated sources: Area sources extend offsite in some places, but not into residential areas; not expected to have major impact on modeled cancer MIR
18	NEI21034	1. Emissions verification needed: Coker sources estimated to account for 25 of 27 in million modeled facility-wide cancer MIR; emissions need verification, particularly 7,12-dimethylbenz[a]anthracene, which is estimated to account for 22 in million
19	NEI6436	1. Emissions verification needed: Coker sources estimated to account for 7 of 27 in million modeled facility-wide cancer MIR; emissions need verification, particularly naphthalene and 2-methylnaphthalene, which are estimated to account for 6 in million of coker risk; also, wastewater treatment source MEWW0203 estimated to account for 6 in million; emissions need verification 2. Mislocated sources: Area source MEPE0038 is offsite in some places, extending toward location of modeled cancer MIR; however, source not major risk contributor, and thus is not expected to have major impact on MIR 3. Multiple refineries: Several adjoining refineries, some now owned by same company, may impact same/similar residential area, although individual refinery MIRs do not appear to be at same location, and thus are not additive
20	NEI11449	1. Updated emission inventory needed: Wastewater treatment (WWT) source MEWW0151 estimated to account for 23 of 26 in million modeled facility-wide cancer MIR; directly across street from MIR; EPA assumed in previous modeling that WWT emissions occurring facility-wide throughout the refinery were emitted entirely from MEWW0151, which is much smaller and closer to modeled cancer MIR; need to determine if outdated data still being used, and correct if necessary
21	NEI12791	1. Multiple refineries: Several adjoining refineries, some now owned by same company, may impact same/similar residential area, although individual refinery MIRs do not appear to be at same location, and thus are not additive

Table 2. Error analysis results: Potential data issues in EPA residual risk modeling

EPA Rank[1]	Facility NEI ID	Potential Data Issues
22	NEI2KS125003	1. Emissions verification needed: Coker sources estimated to account for 15 of 26 in million modeled facility-wide cancer MIR; emissions need verification, particularly 2-methylnaphthalene, which is estimated to account for 9 in million from coker sources 2. Mislocated sources: Source locations do not match refinery layout; modeled sources are collocated, not at actual locations; source information verification needed 3. Nonrepresentative risk receptor: Modeled facility-wide cancer MIR (26 in million) is at census block in open area, not residential location; modeled risk at highest residential census block (apartment building) is 22 in million; need to verify apartment building will remain occupied
23	NEI11885	1. Emission verification needed: Acrolein emissions from IC engines estimated to account for 2.05 of 2.16 modeled facility-wide maximum TOSHI; also, wastewater treatment source MEWW0025 estimated to account for 8 of 29 in million modeled cancer MIR; emissions need verification 2. Mislocated sources: Some sources are mislocated (e.g., area source in parking lot), may affect MIR, but extent uncertain
24	NEI42040	1. Nonrepresentative risk receptor: EPA modeled facility-wide cancer MIR (26 in million) is at census block in truck stop/gas station, not residential location; modeled risk at highest residential census block is 16 in million; EPA modeled maximum TOSHI (1.05) is at census block located in same truck stop/gas station; modeled TOSHI at highest residential census block is 0.34 2. Emissions verification needed: Two turbines estimated to account for 16 of 26 in million modeled cancer MIR and 0.4 of 1.05 modeled maximum TOSHI; emissions need verification
25	NEI49781	1. Mislocated sources: Some sources appear to be offsite, but not sure; effect on modeled cancer MIR uncertain 2. Non-census block risk receptors: EPA added non-census block risk receptos near refinery, but they are located in agricultural field, not cancer MIR or maximum TOSHI locations; need verification
26	NEI6136	1. Emissions verification needed: Benzene estimated to account for 15 of 24 in million modeled facility-wide cancer MIR, 98% of modeled max TOSHI; emissions need verification
27	NEI12486	1. Nonrepresentative risk receptor: Modeled facility-wide cancer MIR (24 in million) is in commercial lot, not residential location; risk at highest residential census block is 21 in million
28	NEI11192	1. Emissions verification needed: Acrolein emissions from IC engines WEIC0043, -44, -45, -46 estimated to account for 1.10 of 1.15 modeled facility-wide maximum TOSHI; emissions need verification
29	NEI34057	1. Nonrepresentative risk receptor: Modeled facility-wide cancer MIR (18 in million) is at census block in forested area near junkyard, not residential location; modeled risk at next highest residential census block is 16 in million

Table 2. Error analysis results: Potential data issues in EPA residual risk modeling

EPA Rank[1]	Facility NEI ID	Potential Data Issues
30	NEI11715	1. Emissions verification needed: Wastewater treatment plant area source estimated to account for 16 of 20 in million modeled cancer MIR; emissions need verification
31	NEI42020	1. Emissions verification needed: Chlorine estimated to account for 2.55 of 3.98 modeled facility-wide maximum TOSHI, 1.94 of 2.55 from cooling towers; emissions need verification 2. Possible emission outlier: Cooling towers are listed in EPA refinery emission inventory database as 5th, 8th, 11th, 13th, and 14th largest chlorine emitters among nearly one hundred cooling towers emitting chlorine; emissions need verification 3. Mislocated sources: Process equipment leak area source MEPE0043 mislocated offsite in southeast corner
32	NEI11450	1. Emissions verification needed: Acrolein estimated to account for 1.64 of 1.69 modeled facility-wide maximum TOSHI; emissions need verification 2. Possible emission outlier: WEIC0040 and WEIC0041 listed in EPA refinery emission inventory database as 2nd and 3rd largest acrolein-emitting IC engines; emissions need verification
33	NEI33007	1. Mislocated sources: Incorrect source location/other data; incorrect collocated sources 2. Emissions verification needed: Chlorine from cooling towers estimated to account for 1.55 of 1.57 modeled facility-wide maximum TOSHI; emissions need verification 3. Possible emission outlier: Cooling towers listed in EPA refinery emission inventory database as 3rd, 6th, 7th, 16th, and 24th largest chlorine-emitting cooling towers and 2nd largest refinery cooling tower total; emissions need verification 4. Updated emission inventory needed: Corrected refinery data not used in EPA modeling

Note 1: Refineries ranked by reported EPA cancer MIR (calculated by EPA using facility-wide, actual emissions)

Examples of Potential Data Issues

Several examples illustrate the presence of suspect data that have the potential to affect modeled EPA risk estimates materially.

Example 1 – Possible Emission Outlier and Updated Emission Inventory Needed (NEI12459)

The highest modeled facility-wide cancer MIR was reported by EPA to be 67 in a million for refinery NEI12459. However, using the emission inventory for this refinery posted by EPA on its website, ENVIRON found the modeled cancer MIR calculated using HEM-3 to be 47 in a million at the census block location shown in Figure 5.

As discussed earlier, prior to being posted on EPA's website, the emission inventory used by EPA to calculate the reported 67 in a million cancer MIR may have been updated subsequently to include additional data corrections. The updated emission inventory version was downloaded by ENVIRON from EPA's website and used in risk modeling. Thus, modeled risk estimates calculated for this refinery are believed to supersede the risk estimates reported by EPA.

Detailed analysis of ENVIRON's HEM-3 modeling results calculated that 38 of the 47 in a million modeled cancer risk at the highest-risk census block was attributed by HEM-3 to emissions of naphthalene from a tank farm located on the northern portion of the refinery.

Comparison of naphthalene emissions from that tank farm with other refinery naphthalene sources elsewhere caused that source to be flagged as a possible emission outlier. As shown in Figure 6, the tank farm (designated by EPA as MEST0035) is listed in the EPA emission inventory database as the largest source of calculated naphthalene emissions of the nearly 12,000 naphthalene sources in the database. At 16.5 tpy, this tank farm source is listed as more than a factor of two larger than the second largest source at 7.3 tpy.

In addition to corrections reflected in the updated emission inventory posted by EPA on its website, refinery staff re-calculated naphthalene emissions for MEST0035 and attempted to submit those revised calculations to EPA in August 2011, correcting their estimate of emissions for that source from 16.5 tpy to 0.3 tpy, or about 1/50th of the amount listed in EPA's refinery emission inventory database. Those corrections are not reflected in the EPA refinery emission inventory database or in EPA's risk modeling.

Based on information from refinery staff, most naphthalene emissions were from a vacuum residual tank for which the liquid weight percent of naphthalene assumed in the 2011 ICR submittal was incorrect. Corrected emissions were calculated using a liquid speciation profile determined by refinery staff to be more accurate and consistent with other regulatory reporting.

Incorporating corrected naphthalene emissions from tank MEST0035, ENVIRON conducted HEM-3 re-modeling of refinery emissions. The corrected cancer MIR was calculated to be 13 in a million, down from EPA's reported estimate of 67 in a million and ENVIRON's initial recalculation using the database posted by EPA of 47 in a million. Similarly, the corrected maximum TOSHI was re-calculated to be 0.26, down from EPA's reported estimate of 0.78 and ENVIRON's initial recalculation of 0.59.

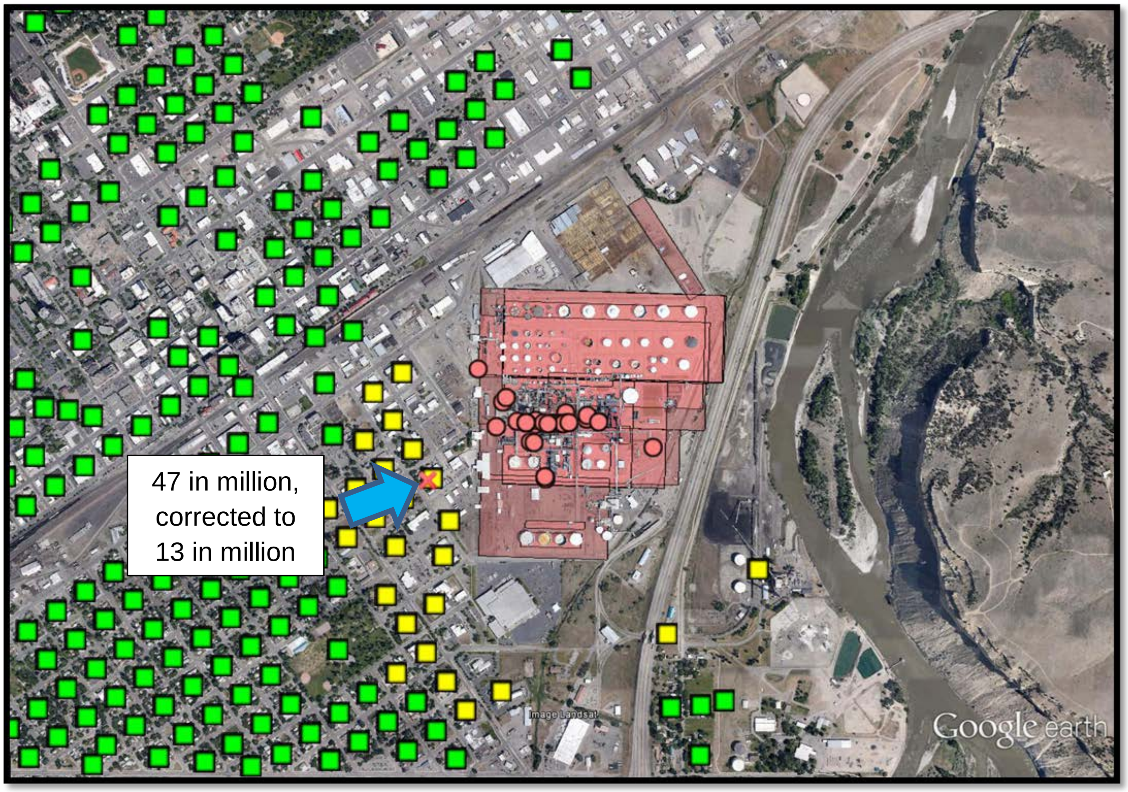


Figure 5. Location of HEM-3 facility-wide cancer MIR, as calculated using HEM-3

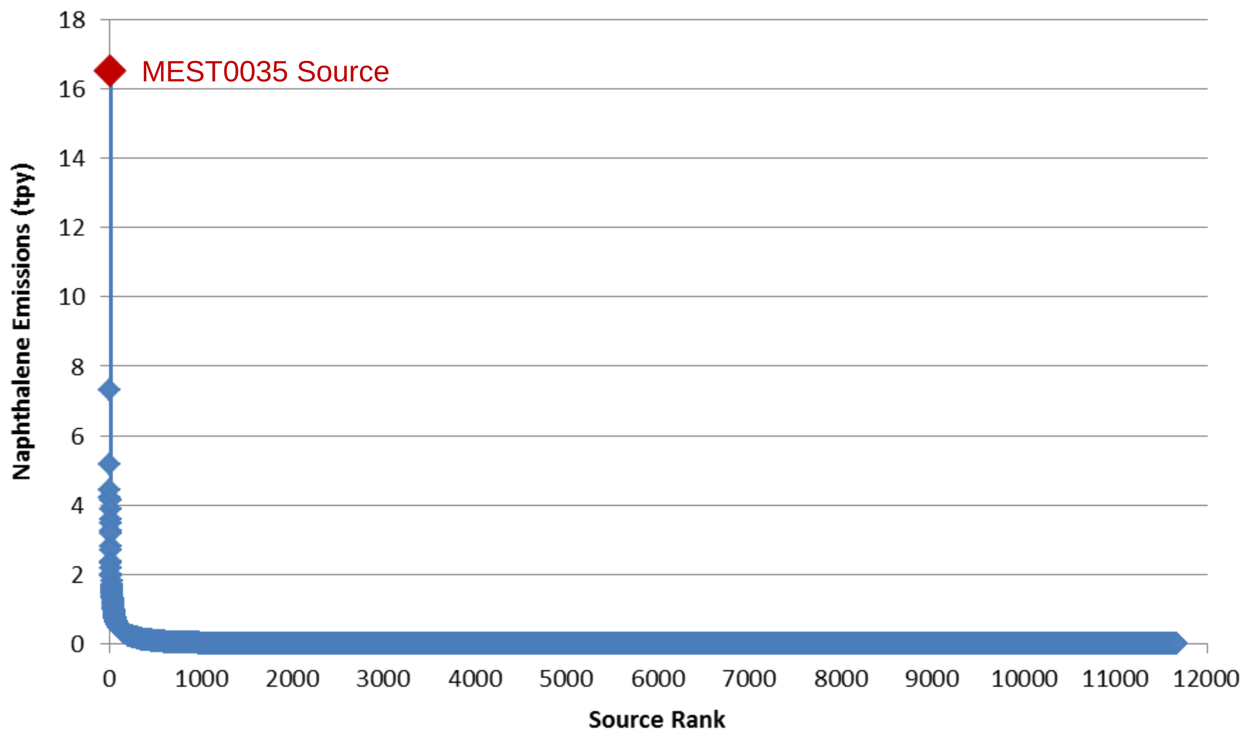


Figure 6. Ranked distribution of naphthalene sources listed in EPA refinery emission inventory database, showing MEST0035 tank farm source

Example 2 – Mislocated Sources and Updated Emission Inventory Needed (NEI876)

The second highest modeled facility-wide cancer MIR was reported by EPA to be 67 in a million for refinery NEI876, marginally lower than EPA's reported cancer MIR for refinery NEI12459 (which HEM-3 risk modeling using corrected emissions data calculates is actually 13 in a million, as discussed earlier). Figure 7 shows the location of the EPA-modeled cancer MIR calculated using HEM-3 (67 in million), just north of the refinery.

Figure 8 plots the source locations modeled by EPA, many of which are incorrectly collocated and modeled as closer to the EPA cancer MIR location than is actually the case.

Corrected emission and source location data have been developed by refinery staff, including the following:

- Use of measurement data from refinery leak monitoring conducted in 2011, instead of default non-monitored emission factors to estimate ICR-baseline year 2010 emissions

- Correction of an error discovered in the TANKS run used to estimate emissions for tank T062

- Removal of sources that no longer exist

- Specification of latitude and longitude coordinates for a number of sources with missing location data in the refinery's ICR submittal.

Incorporating data corrections, ENVIRON conducted HEM-3 re-modeling of refinery emissions (see Figure 9). The corrected cancer MIR was calculated to be 15 in a million, down from EPA's reported estimate of 67 in a million. Similarly, the corrected maximum TOSHI was re-calculated to be 0.15, down from EPA's reported estimate of 0.41.

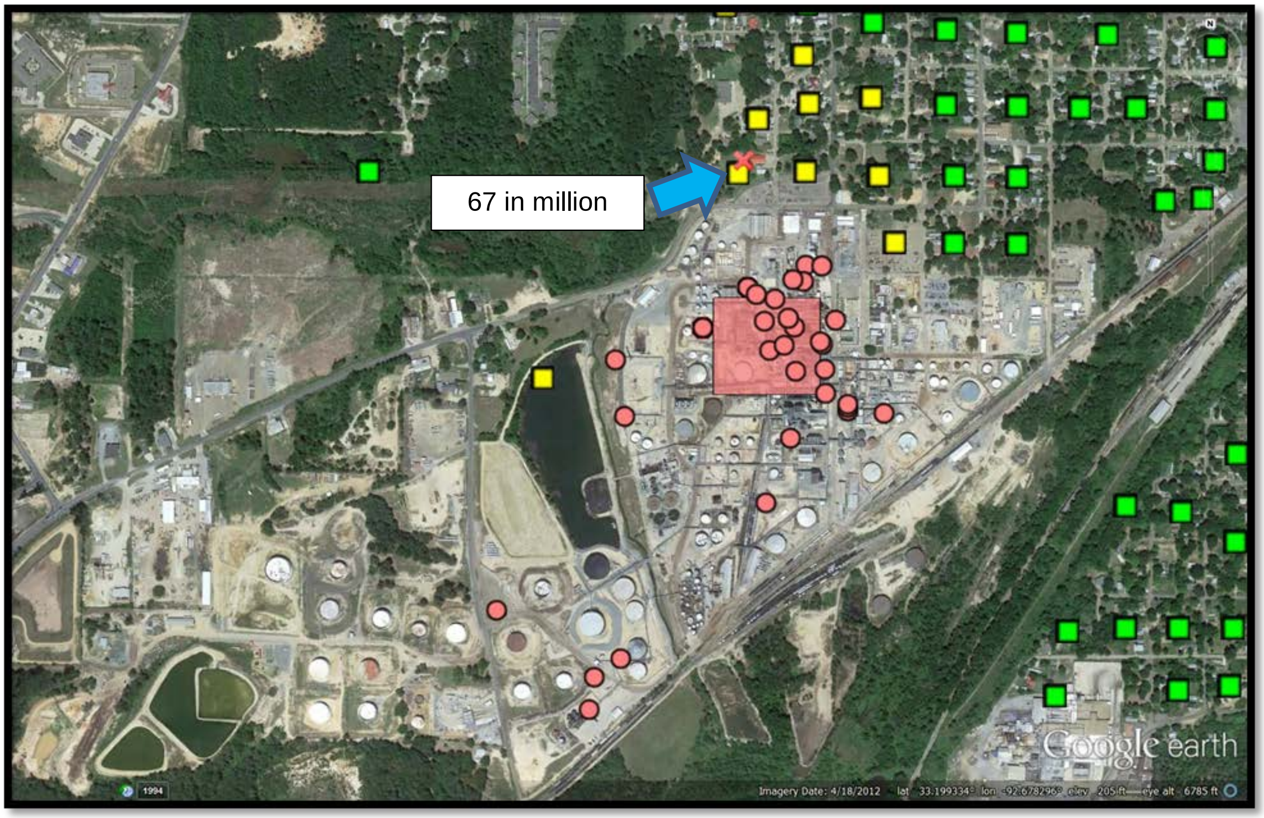


Figure 7. Modeled facility-wide cancer MIR, as calculated using EPA emission inventory data

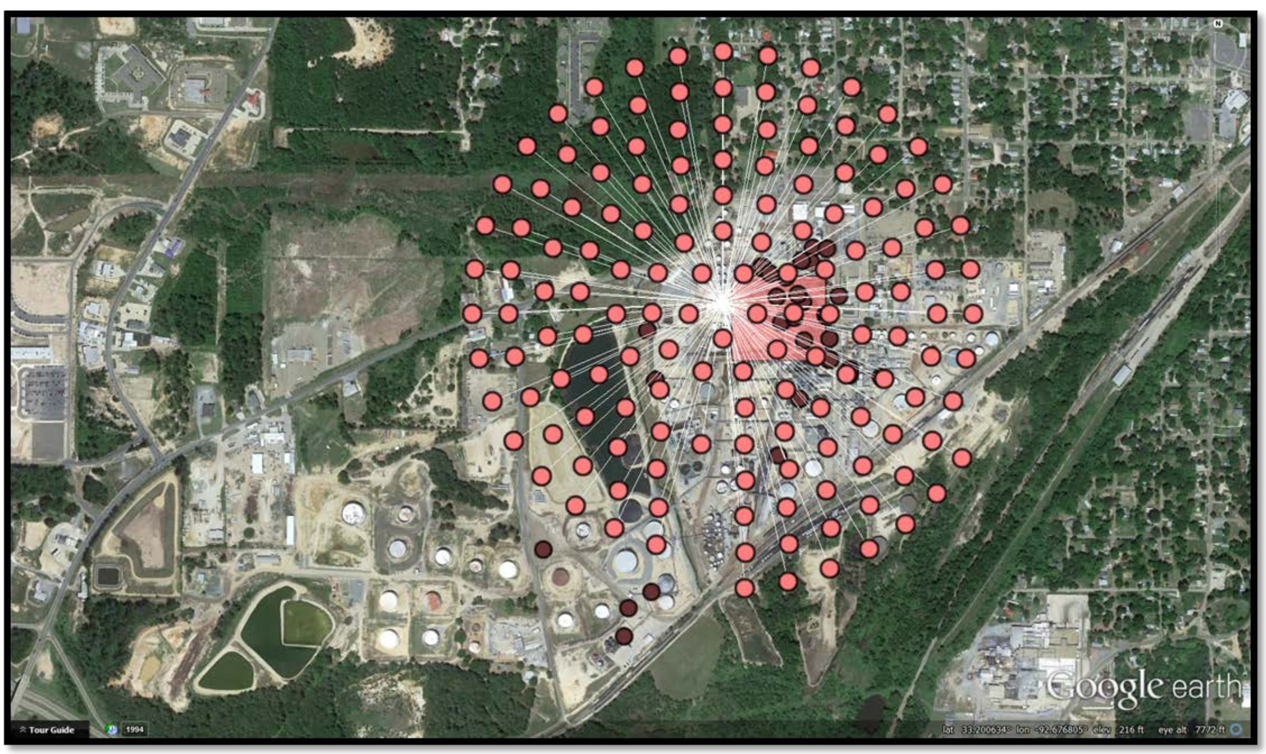


Figure 8. Incorrect collocated sources in EPA refinery emission inventory database

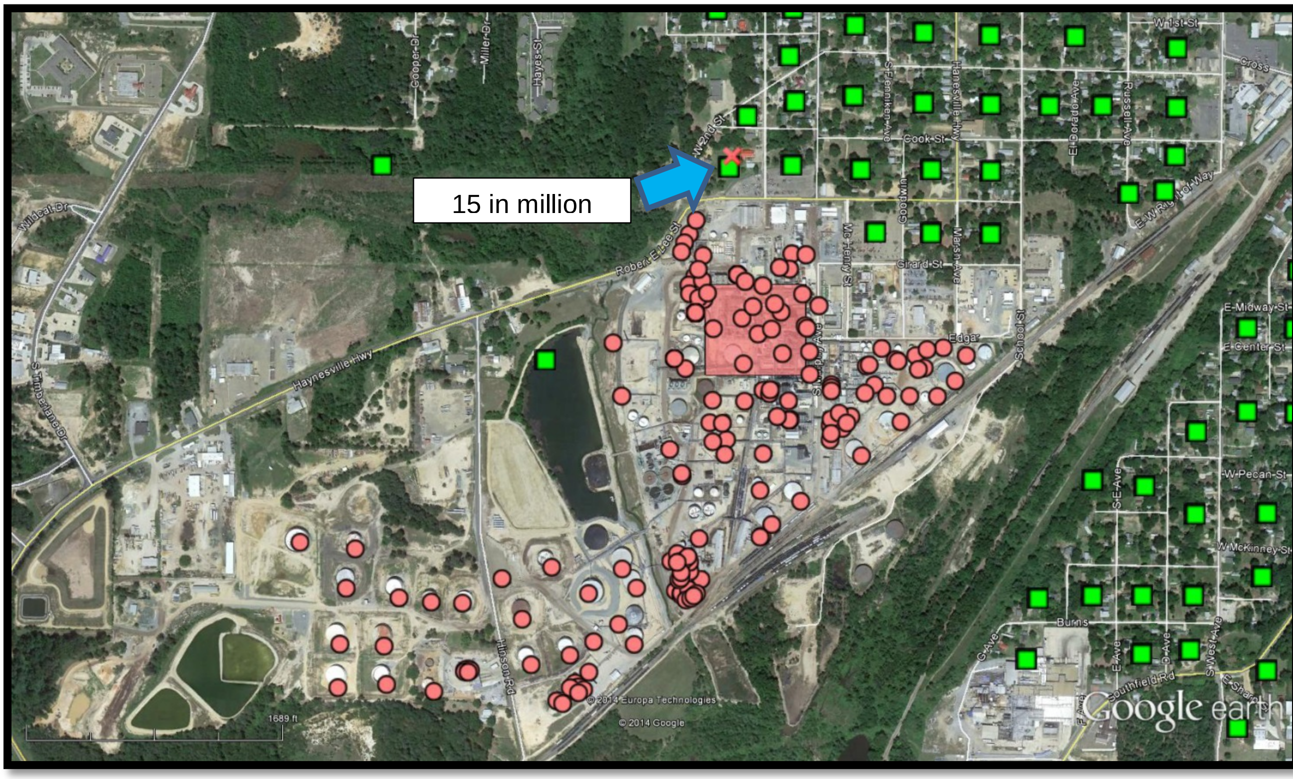


Figure 9. Modeled facility-wide cancer MIR, as calculated using corrected data, and showing corrected source locations

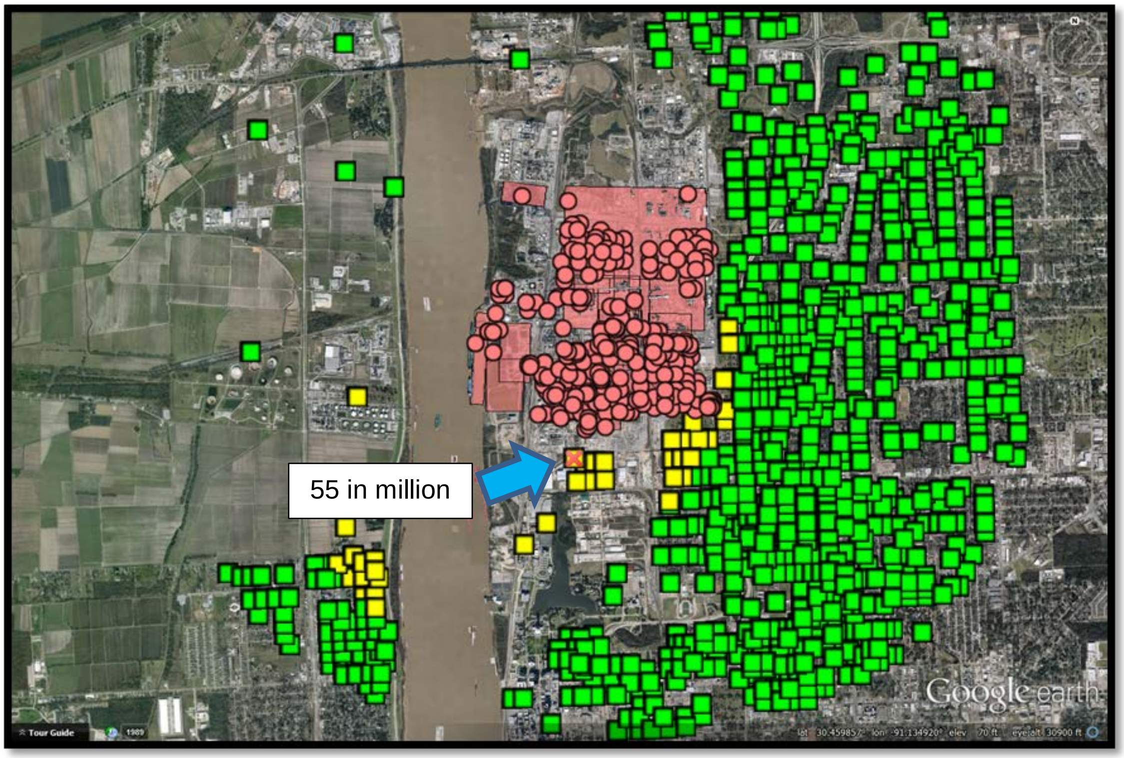
Example 3 – Possible Emission Outlier and Non-Representative Risk Receptor (NEI6022)

The third highest modeled facility-wide cancer MIR was reported by EPA to be 57 in a million for refinery NEI6022, which HEM-3 modeling by ENVIRON calculated to be 55 in a million. Figure 10(a) shows the location of the modeled cancer MIR. That location, however, is a commercial building that is not representative of a location where continuous 70-year exposures could occur, as assumed in EPA's cancer risk calculation. Cancer risk at the modeled highest-risk residential census block location, which is shown in Figure 10(b), is calculated by HEM-3 to be 48 in a million.

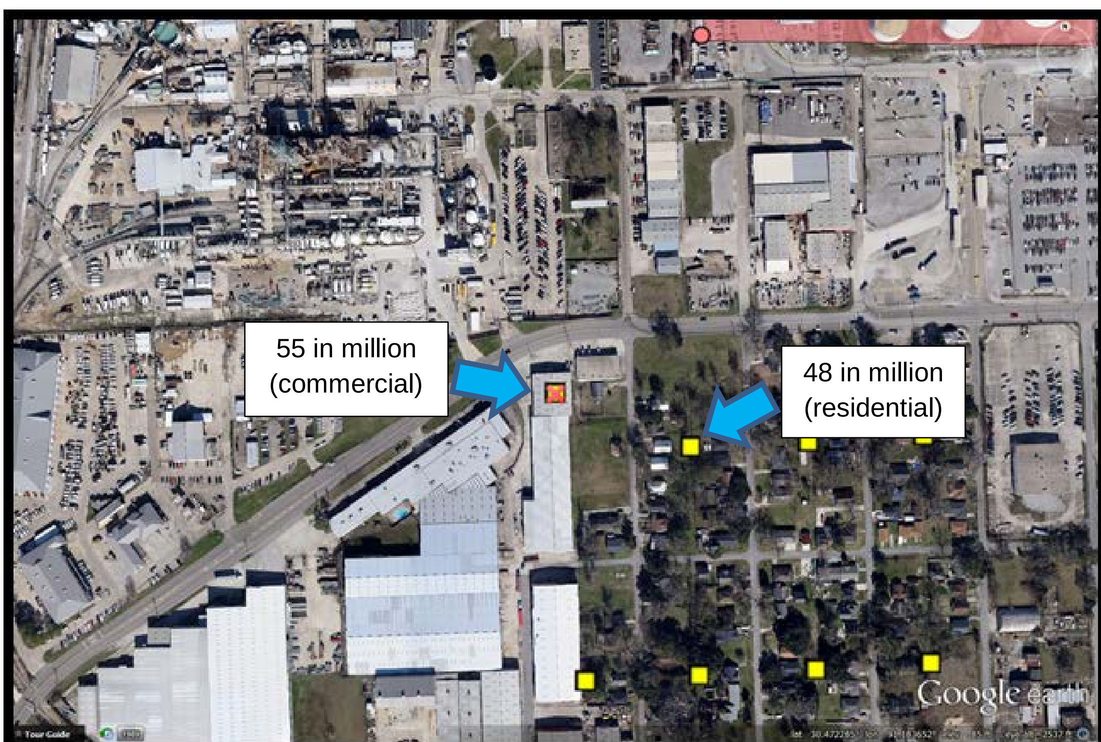
Detailed analysis of HEM-3 modeling results calculated that 29 of the 55 in a million modeled cancer MIR was attributed by HEM-3 to wastewater treatment sources, with 23 of that 29 in a million attributed to source MEWW0418. HEM-3 attributed 27 of that 29 in a million to emissions of ethylene dibromide.

Comparison of ethylene dibromide emissions from that source with ethylene dibromide sources elsewhere caused that source to be flagged as a potential emission outlier . As shown in Figure 11, refinery NEI6022 is listed in the EPA refinery emission inventory database as having the 2nd, 4th, 5th, and 6th largest individual sources of ethylene dibromide emissions. Note that the single largest source listed in the data is excluded from Figure 11 because it was located at refinery NEI46556, which is now closed.

We understand that company staff plans to submit corrections to the ICR emissions inventory data for this refinery, revising their estimate of ethylene dibromide emissions from wastewater sources. HEM-3 risk re-modeling with corrected values is expected to lower refinery risk estimates.



(a) Modeled facility-wide EPA cancer MIR



(b) Modeled highest residential census block

Figure 10. Non-representative modeled EPA cancer MIR location and highest residential census block, as calculated using HEM-3

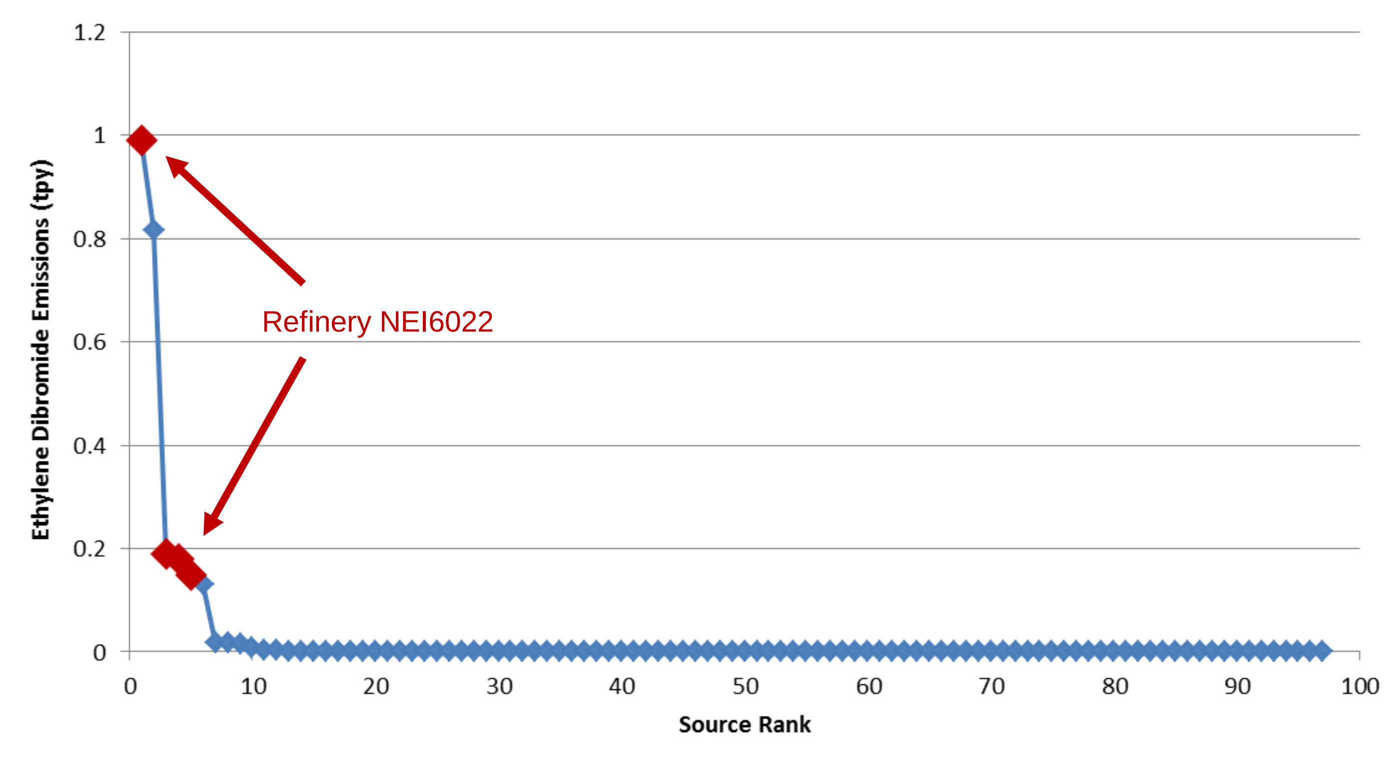


Figure 11. Ranked distribution of ethylene dibromide sources listed in EPA refinery emission inventory database, refinery NEI6022 sources listed as 2nd, 4th, 5th, and 6th largest sources shown (single largest source at refinery NEI46556 excluded, now closed)

Example 4 – Possible Emission Outliers and Mislocated Sources (NEI40723)

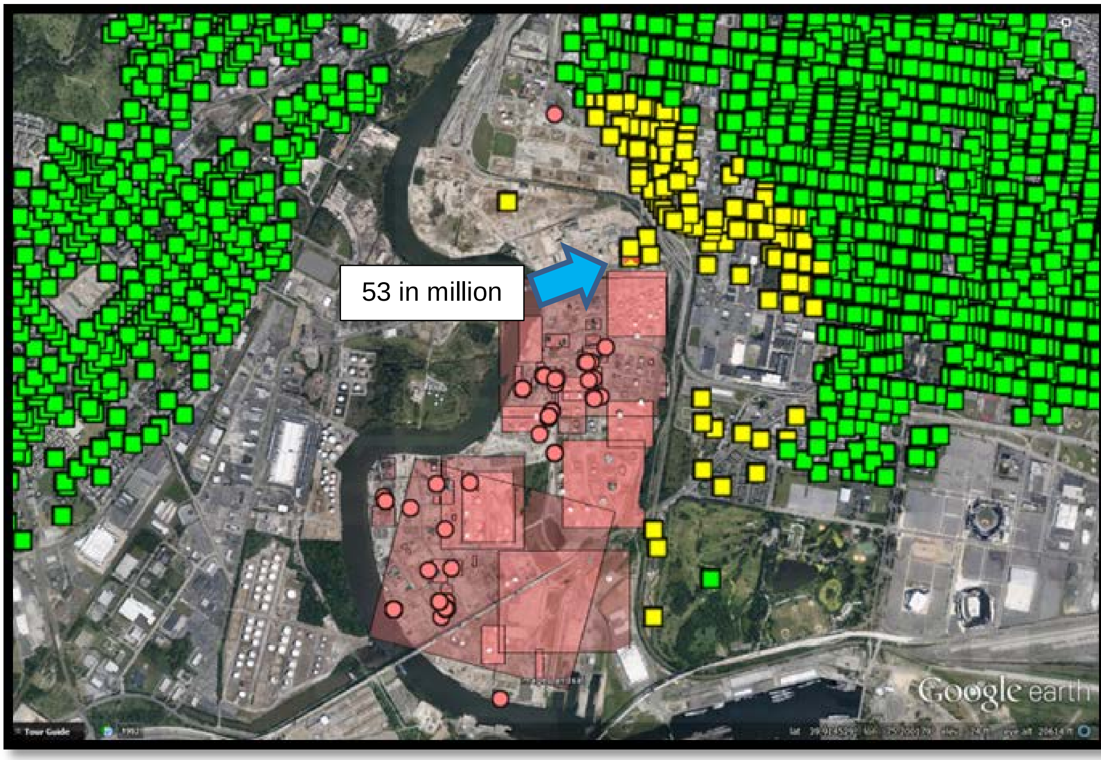
The fifth highest modeled facility-wide cancer MIR was reported by EPA to be 53 in a million for refinery NEI40723. Figure 12(a) shows the location of the modeled cancer MIR calculated by HEM-3. Figure 12(b) shows several area sources that extend nearer to the modeled cancer MIR location than actual refinery units. Another view of the extension is shown in Figure 13. To the extent that this extension causes modeled emissions to be released closer to the cancer MIR location than is actually the case, that risk would be calculated as higher than it otherwise would be.

Detailed analysis of HEM-3 modeling results calculated that 15 of the 53 in a million risk at the modeled cancer MIR was attributed by HEM-3 to emissions of naphthalene from an area source designated by EPA as MEPE0060.

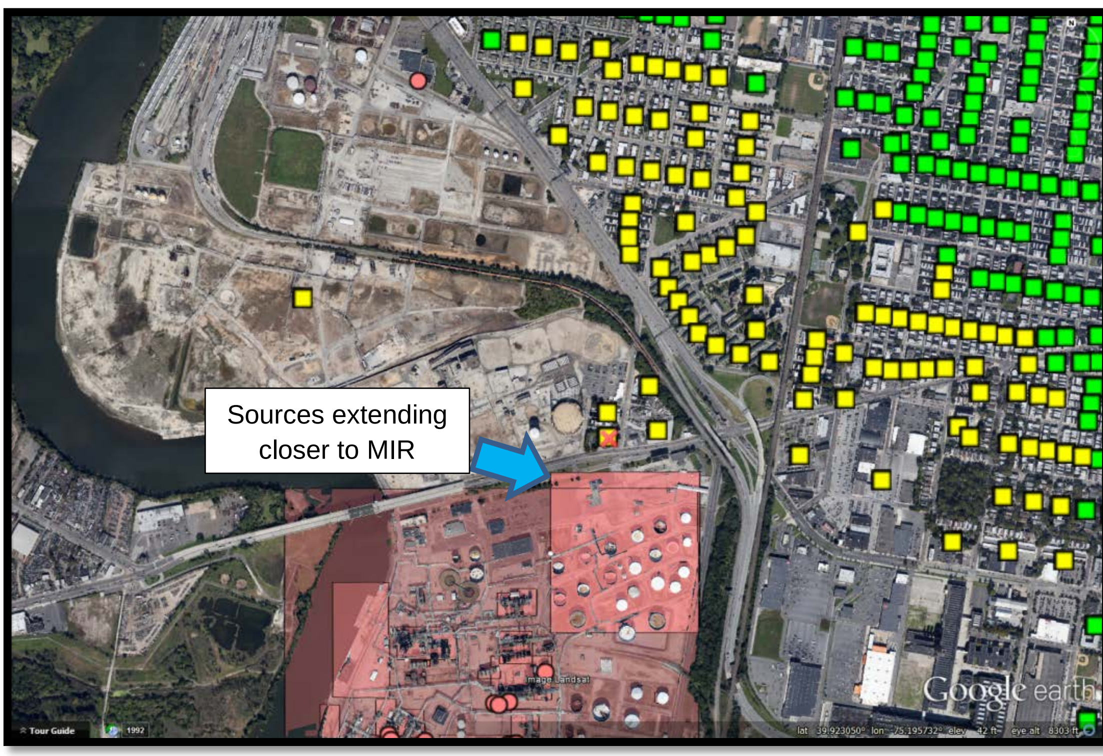
Comparison of naphthalene emissions from that source with refinery naphthalene sources elsewhere caused that source to be flagged as a possible emission outlier. As shown in Figure 14, that source is listed in the EPA refinery emission inventory database as the 6th largest source of naphthalene emissions of the nearly 12,000 naphthalene sources in the database.

Similarly, comparison of benzene emissions from that source with refinery benzene sources elsewhere caused that source also to be flagged as a possible benzene emission outlier. Figure 15 shows that the EPA refinery emission inventory database lists refinery NEI40723 as having the 1st, 4th, 11th, 13th (MEP0060), and 14th largest calculated benzene process equipment leak sources of the more than 2,000 such sources in the database.

Further verification of the emissions from these key risk-driver sources is warranted. If corrections are appropriate, re-modeling of corrected source emissions and locations using HEM-3 is warranted.



(a) Modeled facility-wide cancer MIR



(b) Area sources extending closer to modeled cancer MIR

Figure 12. Mislocated sources extending closer to cancer MIR than refinery equipment, as calculated using HEM-3

Figure 13. 3-dimensional view of sources extending closer to modeled facility-wide cancer MIR than refinery equipment

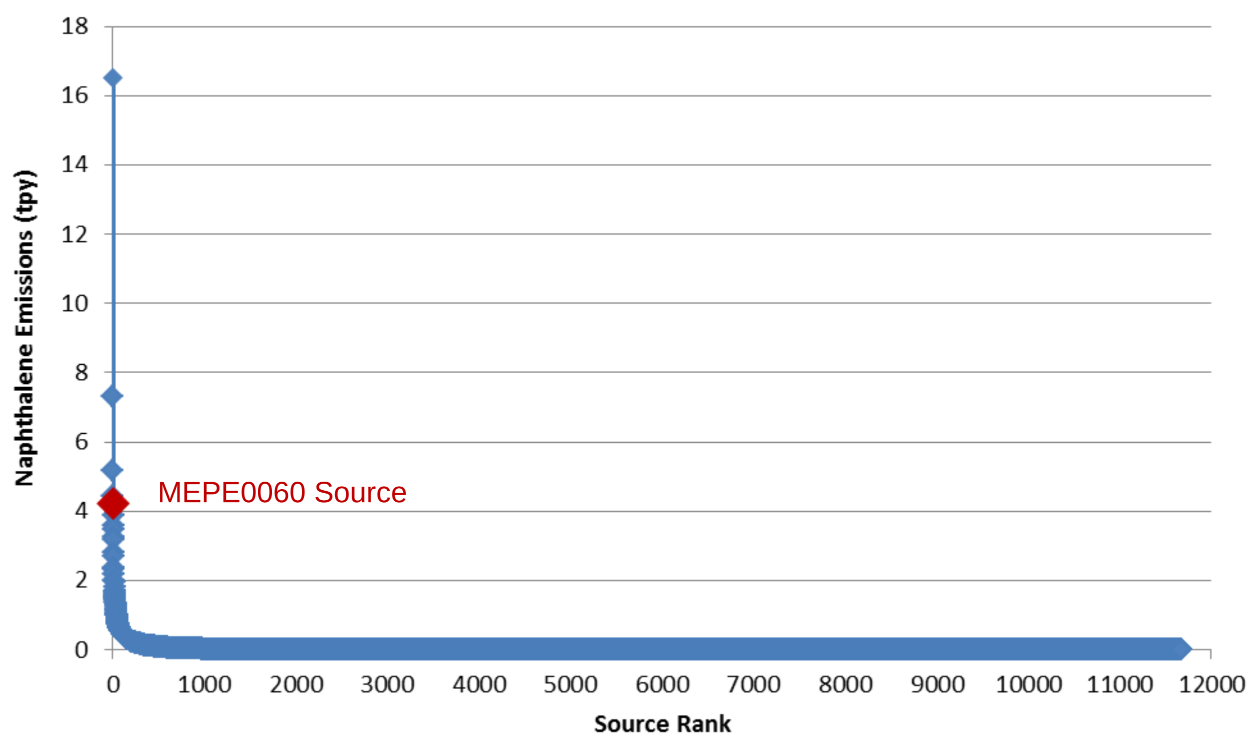


Figure 14. Ranked distribution of sources of naphthalene emissions listed in EPA refinery emission inventory database, showing MEPE0060 process equipment leak source

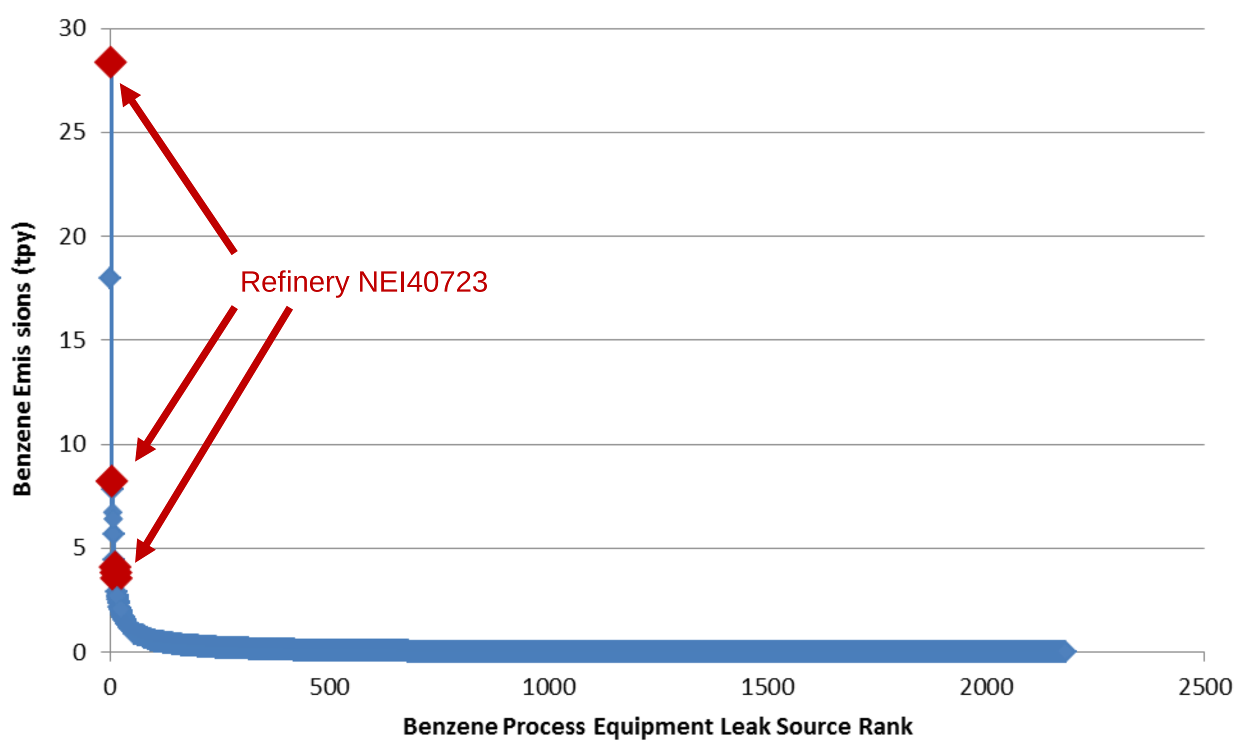


Figure 15. Ranked distribution of benzene process equipment leak sources listed in EPA refinery emission inventory database, showing sources at refinery NEI40723

Example 5 – Possible Emission Outlier and Mislocated Sources (NEI33007)

The fourth highest modeled facility-wide noncancer maximum TOSHI was reported by EPA to be 1.60 for refinery NEI33007, which HEM-3 modeling by ENVIRON calculated to be 1.57.

Detailed analysis of HEM-3 modeling results calculated that 1.55 (99%) of the 1.57 modeled maximum TOSHI was due to emissions of chlorine from five cooling towers.

Comparison of chlorine emissions from those cooling towers with other chlorine-emitting cooling tower sources elsewhere caused that source to be flagged as a possible outlier for which chlorine emissions were overestimated. As shown in Figure 16, cooling towers sources (designated by EPA as WECT0010, -0021, -0006, -0005, and -0016) are listed in the EPA refinery emission inventory database as the 3rd, 6th, 7th, 16th, and 24th largest sources of chlorine emissions among the nearly one hundred chlorine-emitting cooling towers in the database.

Figure 17 plots the emission source locations modeled by EPA, many of which are incorrectly collocated, including all of the risk-driver cooling towers, causing their combined impact to be overestimated.

Corrected emission and source location data have been developed by refinery staff as follows:

- Correction of estimated cooling tower chlorine emissions using chlorine (Cl_2) measurement data from weekly 2013–2014 cooling tower recirculating water tests

- Correction of cooling tower locations using actual latitude and longitude locations as determined from facility plot plans and GPS measurements. Figure 18 plots actual cooling tower locations compared to their EPA-modeled collocation point.

Incorporating these data corrections, ENVIRON conducted HEM-3 re-modeling of refinery emissions. The modeled facility-wide maximum TOSHI decreased from 1.60, as modeled by EPA and above EPA's health benchmark of 1, down to 0.02, well below that benchmark.

Figure 19 shows the location of the modeled maximum TOSHI, both modeled using EPA data and as corrected.

Since chlorine is not a carcinogen, the cancer MIR remained the same as calculated by EPA at 0.3 in a million.

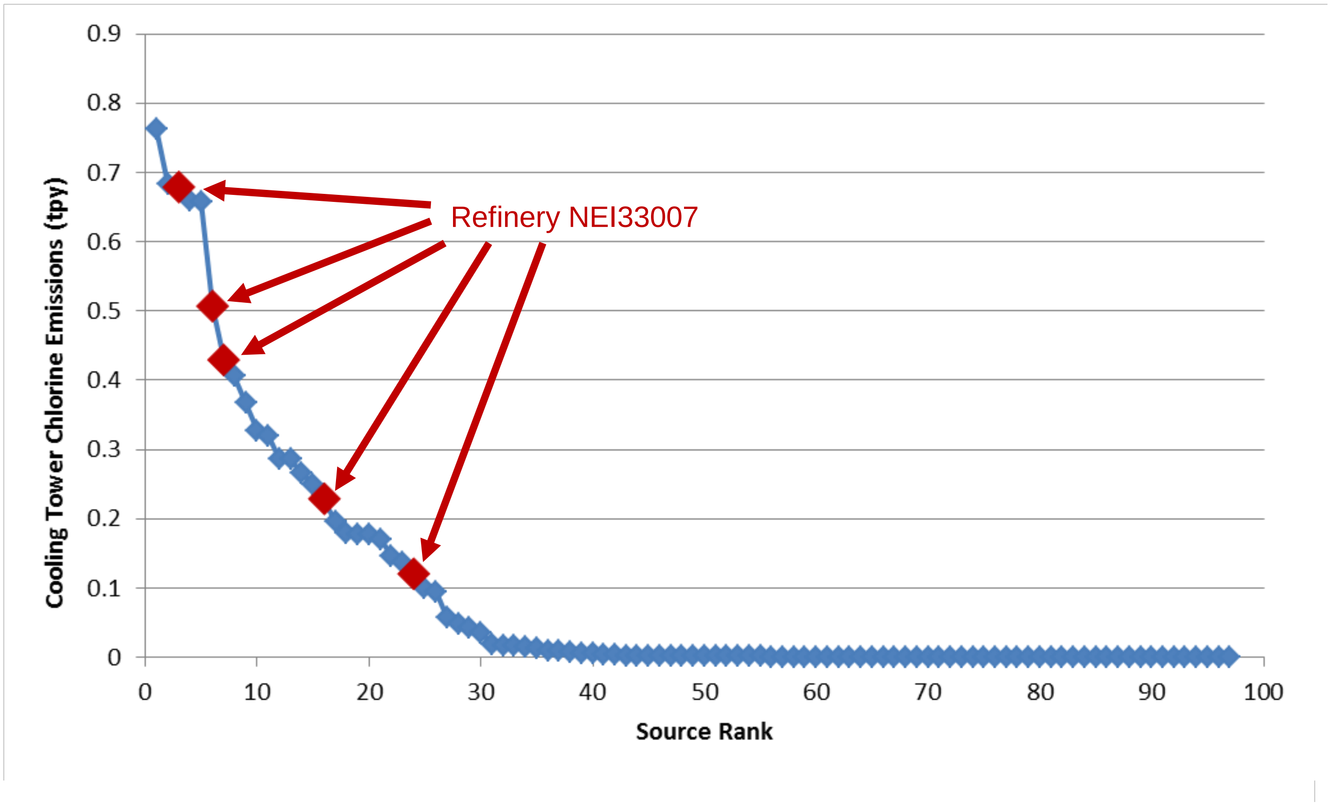


Figure 16. Ranked distribution of cooling tower sources emitting chlorine listed in EPA refinery emission inventory database, showing NEI33007 cooling tower sources

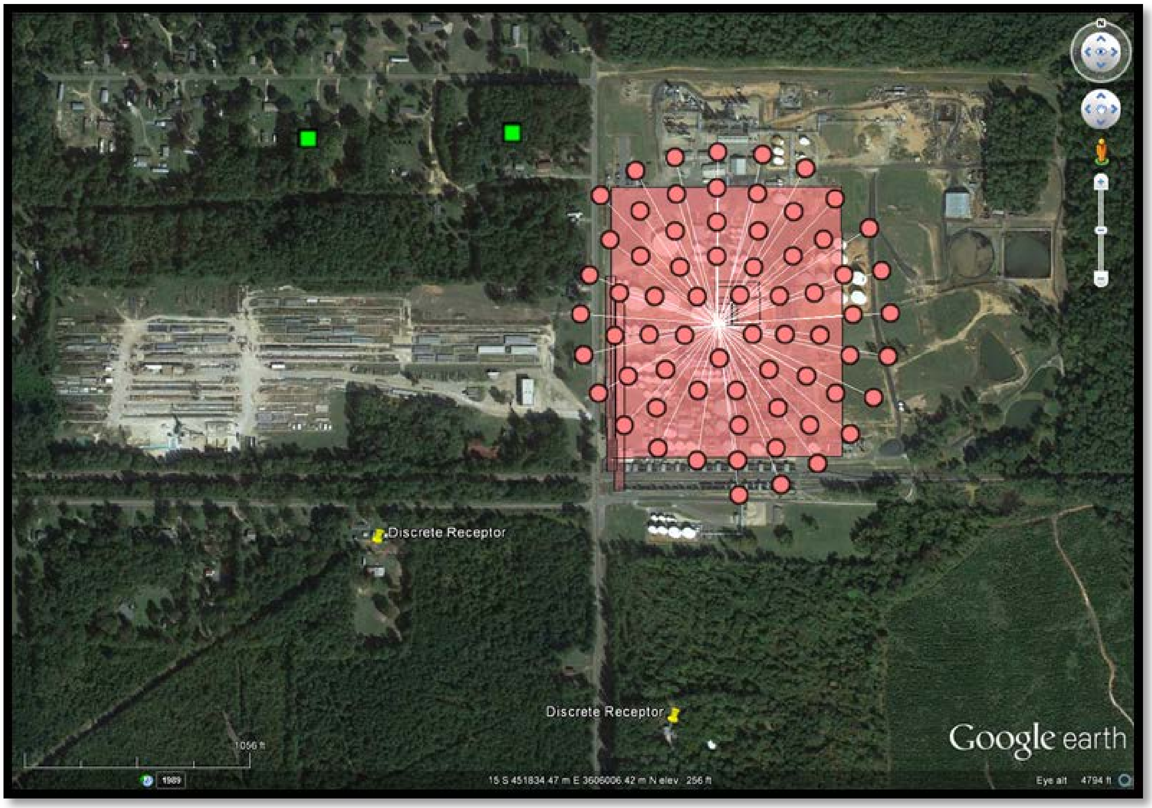


Figure 17. Mislocated sources in EPA refinery emission inventory database

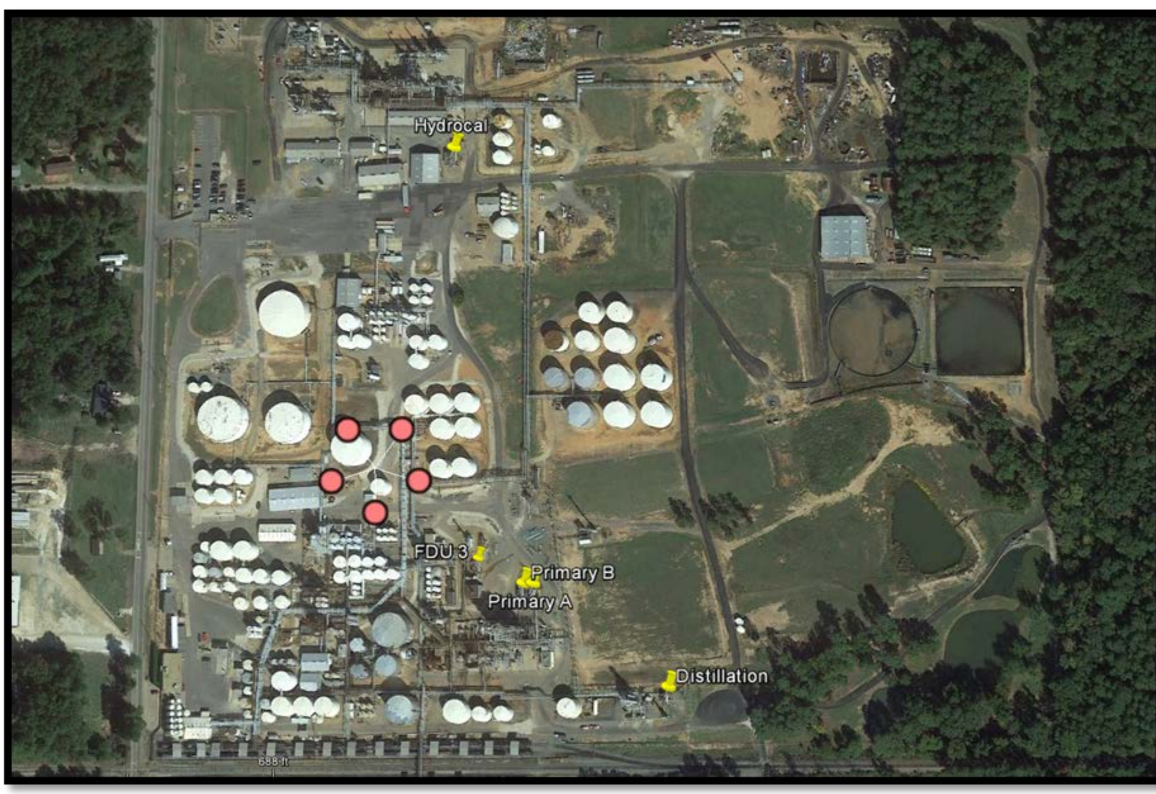


Figure 18. Actual cooling tower locations compared to EPA-modeled collocation point

Figure 19. Location of modeled facility-wide maximum TOSHI, as calculated using HEM-3

Summary

Using the most recent version of EPA's HEM-3 risk model and the meteorological, census, refinery emission inventory information, and risk assessment methodology used by EPA, facility-wide risk modeling was conducted of the 33 refineries for which EPA reported a facility-wide cancer maximum individual risk (MIR) of 20 in a million or greater or a chronic noncancer maximum target organ specific hazard index (TOSHI) greater than 1. Selection of refineries was based on modeled facility-wide risks reported by EPA.

Risk modeling results were compared to EPA's reported risks for each refinery to verify that results were acceptably close to those reported by EPA.

For each refinery, detailed risk attribution analyses were performed to identify the top ten risk-driver sources and HAPs for modeled cancer MIR and noncancer maximum TOSHI.

Modeling results were analyzed to test for and identify if present a number of potentially important data issues, including mislocated sources, possible emission outliers, nonrepresentative risk receptors, and emission inventories that did not reflect the most recent company corrections. Possible data issues were flagged for further review and data correction, if appropriate.

Examples are presented that illustrate possible data issues that have the potential to materially affect EPA's reported risk estimates. Such data issues are also present for other refineries, as summarized in this report.

ENVIRON conducted HEM-3 re-modeling using corrected source and emission data provided by company staff for several of these examples, including the two refineries for which EPA reported the highest estimated facility-wide cancer MIRs. In both cases, corrected cancer risks were significantly lower than reported by EPA (from 67 in a million to 15 in a million for one refinery, and from 67 in a million to 13 in a million for the other refinery).

Though beyond the scope of ENVIRON's review and evaluation here, further correction of data and risk modeling by EPA to re-calculate corrected risk estimates for affected refineries is warranted.

Attachment B–1

ERM Report on API/AFPM Fenceline Monitoring Pilot Study

(Note: Attachments B-1 and B-2 are submitted separately to the Docket)

In late 2013, the American Petroleum Institute (API) and the American Fuel and Petrochemical Manufacturers (AFPM) initiated a Pilot Project to evaluate the draft fenceline monitoring methods that were expected to be incorporated by the U.S. Environmental Protection Agency into proposed revisions to federal air toxics standards that address air emissions from petroleum refineries.

For this Pilot Project, 12 major source petroleum refineries volunteered to collect data for six (6) two-week periods. Results of the program are reported in the ERM report. The refinery from a similar 2009 EPA study is also included in the report for comparison.

The ERM report is provided separately.

Attachment B–2

ERM Pilot Study Report Appendices

Appendices to Attachment B-1 (ERM Report on API/AFPM Fenceline Monitoring Pilot Study) are submitted separately.

Attachment B–3

ERM Method 325B Uncertainty Analysis

(Note: Attachments B-3 and B-4 are submitted separately to the Docket)

API/AFPM requested ERM, the pilot study contractor, to assess the overall uncertainty of results generated through the analysis of passive sampling tubes under proposed EPA Method 325B. In summary they concluded:

> Several parameters can affect the results determined using proposed Method 325B, including: analyzer bias, analyzer precision, field precision, audit accuracy, and calibration. Proposed Method 325B provides the maximum acceptable uncertainty for each of these components of the analytical laboratory approach to ensure consistent results when using the method. The application of propagation of error principles, along with the maximum acceptable uncertainty values for each individual parameter provided by the EPA, yields an estimate of the overall uncertainty in the result. This analysis results in a calculated overall uncertainty from application of proposed Method 325B of approximately 63 percent.

The ERM report is provided separately.

Attachment B–4

ERM Lab QC Report

As the result of anomalies in the sample observed between laboratories on check side-by-side duplicate samples collected during the pilot study, API/AAFPM requested that ERM conduct a laboratory proficiency test (PT) conducted on the two laboratories used in the API/AFPM pilot fenceline monitoring study in order to confirm whether systematic biases are observed between the two laboratories. Any such bias is not an issue in the pilot study itself, because all of the sample results were obtained using the same laboratory. However, systemic bias is an issue in estimating the laboratory variability that will occur if this program is finalized and the 142 refineries impacted are sending samples to different laboratories.

This evaluation was conducted in July 2014. The results show that one laboratory consistently obtained results 20% lower than the spiked standard, while the other laboratory consistently obtained results 5% higher than the standard. It should be noted that all results fall within the QC Performance Acceptance Limits (PALs) of 39.1 ng to 59.6 ng for the certified standard, but the results for the one laboratory are very close to the lower limit.

ERM's report is submitted separately.

Attachment C-1

Delayed Coking Unit (DCU) Detailed Calculations

(Note: Attachments C-1 and C-2 are submitted separately to the Docket)

This Attachment provides additional information and details used in developing the API/AFPM DCU emissions, cost and cost effectiveness estimates reported in Comment 2.2.3.

This Attachment consists of:

C.1 – Unit Configuration Considerations

C.2 – DCU Distribution

C.3 – Emissions Estimates

C.4 – Project Costs

C.5 – Cost Effectiveness Calculations

This information has been submitted separately.

Attachment C–2

Report on API/AFPM Coke Vent Release Pressure Study

Introduction

Individual vent data from 41 coke drums at 11 delayed coking units (DCUs) were collected to evaluate current release pressures, the variability in release pressures, the impact of that variability on potential Refining Sector Rule atmospheric release limits and the impacts of establishing a not-to-be-exceeded limit versus an average limit.

Attachment report has been submitted separately.

Attachment D-1

Details of the Analysis of 2010 API/AFPM Refinery Flare Data

(Note: Attachments D-1 through D-5 are submitted separately to the Docket)

As discussed and summarized in Section 2.7.3.4 of these comments, an analysis of potential VOC[243], HAP and CO_2e emissions and cost-effectiveness (cost/ton VOC and HAP reduced) of possible steam-assisted flare emission limitations was performed. These analyses used the CZ-NHV as the metric for assuring high Combustion Efficiency (CE)[244]. This Attachment describes in additional detail how the analyses were performed.

Attachment analysis has been submitted separately.

[243] VOCs included all non-methane, non-ethane hydrocarbon constituents reported in the flare gas.
[244] For the purposes of this study, VOC destruction efficiency was assumed equal to the CE, though destruction efficiency may actually be somewhat higher than the CE.

Attachment D-2

EPA PFTIR Data Analysis Critique

Scott Evans, Clean Air Engineering
Robert Spellicy, PhD, IMACC

This report is submitted separately.

Attachment D-3

The Relationship Between Olefin and Hydrogen Vent Gas Content and Flare Combustion Efficiency

Scott Evans, Clean Air Engineering

This report is submitted separately.

Attachment D-4

A Review of Flare Velocity Limits in

40 CFR 60.18 and 63.11

Scott Evans, Clean Air Engineering

This report is submitted separately.

Attachment D-5

A Review of Flare Visible Emission from Refinery Flares

Scott Evans, Clean Air Engineering

This report is submitted separately.