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April 23, 2018

The Honorable Scott Pruitt, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Attention: Docket ID Number EPA-OAR-2015-0216
Submitted to the Federal eRulemaking Portal (www.regulations.gov)

Re: Notice of Proposed Withdrawal of the Control Techniques Guidelines for the Oil and Natural Gas Industry at 83 FR 10478 (March 9, 2018)

Dear Administrator Pruitt:

API respectfully submits the attached comments on the Environmental Protection Agency's (EPA's) "Notice of Proposed Withdrawal of the Control Techniques Guidelines for the Oil and Natural Gas Industry at 83 FR 10478 (March 9, 2018)."

API is the only national trade association representing all facets of the oil and natural gas industry, which supports 10.3 million U.S. jobs and nearly 8 percent of the U.S. economy. API's more than 625 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation's energy and are backed by a growing grassroots movement of more than 40 million Americans. Many of API's member companies would be directly impacted by the Control Techniques Guidelines (CTG).

As EPA notes in the proposed CTG withdrawal, "the EPA is currently looking broadly at the 2016 NSPS. In light of the fact that the EPA is reconsidering the 2016 NSPS and because the recommendations made in the CTG are fundamentally linked to the conclusions in the 2016 NSPS, the EPA believes it is prudent to withdraw the CTG in its entirety." Throughout the development of the 2012 oil and gas NSPS rule (Subpart OOOO) and its amendments in 2016, API has maintained a collaborative working relationship with Agency staff to provide input and data to inform the developments of these important rules. During this time, our objective has remained the identification of cost-effective emission control requirements that reduce VOC emissions from new and modified sources and, as a co-benefit, also reduce methane from those sources.

API agrees that the requirements in the 2016 NSPS and the language in the CTG are fundamentally linked. Given the ongoing reconsideration process that is expected to take several more months, API strongly supports EPA's proposed withdrawal of the CTG. The withdrawal will help avoid inconsistencies between the CTG and the 2016 NSPS; thereby eliminating confusion for both states and the regulated community.

The withdrawal of the CTG will have minimal environmental impact because of the number of state requirements already established in ozone non-attainment areas where existing oil and natural gas operations occur. As part of its *"Estimated Avoided Costs and Forgone Emission Reductions Associated with the Potential Withdrawal of the Control Technique Guidelines for the Oil and Natural Gas Industry,"* EPA included an assessment of the impact of regulations in California that limit emissions from existing oil and gas sources.[1] However, California is not the only state with programs in place that regulate emissions from existing oil and gas operations. Below is a summary of additional state programs in place that reduce potential emissions from the source types covered by the CTG. This summary is limited to states that have oil and natural gas activities and areas currently classified or treated as ozone nonattainment areas.

(1) Colorado –Regulation 7 in Colorado[2] was recently modified and includes provisions for both new and existing oil and gas emission sources located in non-attainment areas.
(2) Wyoming – Nonattainment Area Regulations (Chapter 8) include provisions[3] that address existing oil and gas sources in the Upper Green River Basin (UGRB) ozone nonattainment area.
(3) Pennsylvania – Non-major VOC sources in Pennsylvania are subject to control requirements through the states application of Best Available Technology requirements and its approach to permitting. A conditional exemption (Exemption 38) currently applies to production sites.[4]. This exemption has been in place since 2013 and requires operators to perform leak detection and repair (LDAR), control emissions from storage tanks per NSPS Subpart OOOO, and limit emissions from other sources to less than 2.7 tons per year of VOC emissions. Further, through its permitting of natural gas compression facilities, Pennsylvania requires controls to meet its Best Available Technology requirements. Notably, with respect to existing sources, Pennsylvania has also been including LDAR requirements as part of the permit renewal process over the last several years even if a facility has not been modified.
(4) Texas – Barnett Shale (Dallas-Ft. Worth Nonattainment Area) – Many non-major oil and gas sources within the Barnett Shale area are subject to permit by rule (PBR), standard permit, or non-rule standard permit requirements.[5] These permits contain emission control requirements and work practices that can become applicable to existing sources at a facility due to the addition or modification of a source at the facility.

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[1] https://www.arb.ca.gov/regact/2016/oilandgas2016/oilgasfro.pdf
[2] https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-9.pdf
[3] https://rules.wyo.gov/Default.aspx
[4] http://www.depgreenport.state.pa.us/elibrary/GetDocument?docId=7858&DocName=AIR%20QUALITY%20PERMIT%20EXEMPTIONS.PDF%20
[5] https://www.tceq.texas.gov/assistance/industry/oil-and-gas/oilgas_air.html

As part of its analysis of the impacts due to the proposed withdrawal of the CTG and any future analysis of the benefits of a future CTG, API recommends that EPA expand its assessment of the impacts from state regulations beyond California to ensure an accurate assessment of potential benefits.

Additionally, API recommends that EPA review our December 4, 2015 comments (Attachment B) on the draft CTG for refinements to the cost effectiveness analysis. For example, as described in our prior comments, EPA underestimated the costs associated with the control of existing storage vessels, the control of existing pneumatic pumps, as well as the costs of implementing LDAR programs at existing locations. Section 2 of our 2015 comments on the draft CTG also outlines important considerations regarding how the amount of volatile organic compounds present in material being handled can dramatically influence the potential emissions from a facility, thus impacting both the amount of emissions reductions and cost-effectiveness associated with implementation of the CTG.

Lastly, API outlined numerous technical considerations in our December 4, 2015 comments specific to the CTG. Building from these comments, API is providing a summary of key issues in Attachment A to this letter. These issues represent areas for potential improvement to ensure any future CTG are achieving the intended outcome of identifying cost-effective emission reductions that appropriately address emissions that contribute to ozone formation, including whether an area is VOC or NO_x limited.

Our organizations have collaborated well in the past and API remains committed to working with EPA and the Administration to identify emission control opportunities that are both cost-effective and, when implemented, do not impact safety or hinder our ability to provide the energy our nation will continue to demand for many years to come.

If you have any questions regarding the content of these comments, please contact Matthew Todd (toddm@api.org, 202-682-8319).

Sincerely,

Howard J. Feldman

Cc: Peter Tsirigotis, EPA
David Cozzie, EPA

Attachments

ATTACHMENT A

Attachment A - Considerations for Possible Future Revisions to Oil and Gas CTG

Ensure a Robust Cost Analysis - In developing the current CTG, EPA did not adequately include all the cost impacts required by the Clean Air Act, which include retrofit costs, operational costs, energy requirements, environmental impacts, and fuel costs. See API's December 4, 2015 comment letter on the draft CTG for specific details.

Establish Applicability Thresholds Based On VOC Content in Natural Gas

- CTG are not cost effective for many oil and gas facilities **-** EPA supported the CTG requirements using economic studies based on "average model facilities" without determining whether the resulting control requirements are appropriate for the entire range of sources included in the source category.
- The CTG go well beyond RACT for oil and gas operations handling natural gas with low VOC content – CTG controlling natural gas emissions should have minimum VOC applicability thresholds for any controls to be economic in low VOC natural gas areas. As part of our review of the original CTG proposal and using EPA's costs and cost effectiveness criteria, API calculated the lower limit of VOC thresholds as follows:
    - Fugitive emission monitoring at oil sites is never cost effective.
    - Reciprocating compressor controls are only cost effective if gas is greater than 1% VOC by weight.
    - Pneumatic controllers at gas plants, pneumatic piston pumps and fugitive emission monitoring at production facilities are only cost effective if gas is greater than 6-7 % VOC by weight.
    - The VOC emission threshold for storage vessels should be higher than the 6 tpy threshold for new storage vessels (~ 10-15 tpy VOC) due to the increased cost of controlling existing tanks (i.e. tanks may need early replacement because of back pressure caused by the addition of a closed vent system (CVS) and control device).

Consider Appropriate Timeframes for Phase-in of Requirements – EPA should clarify that any CTG requirements imposed by the states are to be implemented over the maximum period allowable. Consistent with the provisions provided in Subparts OOOO and OOOOa, EPA should ensure adequate timeframes are provided for implementation of new requirements. Specifically, leak monitoring (due to limited monitoring equipment and qualified personnel), storage vessels (due to design requirements and number of controls potentially required), and pneumatic pumps (due to design requirements and compliance of existing CVS) are particularly subject to practical limitations on implementation schedule.

Provide Additional Clarity and Appropriate Flexibility for States

- Ozone and NO_x Impacts – EPA should allow states to determine which emissions controls are appropriate for their nonattainment area from any future CTG. The rationale being that ozone drivers vary by nonattainment area (i.e., NO_x verses VOC limited and summer verses winter ozone). VOC reductions may increase NO_x emissions, and thus could be detrimental to the ozone control strategy for some areas.

- Status as Guidelines - CTG are guidelines for states on appropriate and economic controls not standards like the NSPS. Any future model rules should include language allowing use of equivalent state rule requirements and compliance assurance procedures and guidance. Preamble should include a discussion encouraging this flexibility for consistency with other State rules and programs.
    - EPA should reiterate that each state is able to adopt other existing regulations in lieu of CTG to satisfy RACT.
    - States should be allowed to determine what CTG provisions should be applied.
- Voluntary Programs - Any future CTG should include a federal framework for encouraging voluntary methane reductions from existing oil and natural gas sources.

Leak Detection and Repair

- Ensure consistency with the resolution of NSPS Subpart OOOOa issues, including appropriate inspection frequency, "Delay of Repair" provisions, and simplification of the monitoring plan, record keeping and reporting requirements.
- Exemptions – EPA should exempt sites subject to state, local, or other federally enforceable leak detection programs
- Low production well exemption – EPA should clarify that the exemption for LDAR at wells less than 15 boe/day should apply to all the equipment at the well site and apply throughout the life of the well. In other words, whenever the production of a well falls below 15 boe/day, it should no longer be subject to RACT.

Remove PE certification requirements for closed vent systems (CVS) and pneumatic pumps

- Requirements in current CTG are excessive for Reasonably Available Control Technology. EPA should remove PE certification provisions entirely from a future CTG to relieve the redundancy created relative to each company's existing general duty obligations. In establishing the current CTG, EPA did not justify the extra expense and burden of Professional Engineer certifications.

Storage Vessels

- VOC emission threshold - The VOC emission threshold for storage vessels should be higher than the 6 tpy threshold for new storage vessels (~ 10-15 tpy VOC) due to the increased cost of controlling existing tanks (i.e., tanks may need early replacement because of back pressure caused by CVS and control device).

Pneumatic Pumps

- Ensure consistency with resolution of NSPS Subpart OOOOa issues, including CVS inspection requirements and treatment of heaters and boilers. EPA should clarify in the CTG that the presence of a heater or boiler should not be considered to be equivalent to presence of control device.

- Remove ongoing requirement to revisit presence of a control device **-** EPA should only require an initial assessment of presence (and technical feasibility of any control devices present). Operators should not be required to continuously monitor status relative to presence of a control device.

ATTACHMENT B

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December 4, 2015

The Honorable Gina McCarthy, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Attention: Docket ID Number EPA-OAR-2015-0216
Submitted to the Federal eRulemaking Portal (www.regulations.gov)

Re: Environmental Protection Agency's (EPA's) "Release of Draft Control Techniques Guidelines for the Oil and Natural Gas Industry" at 80 FR 56577 (September 18, 2015)

Dear Administrator McCarthy:

American Petroleum Institute (API) respectfully submits the attached comments on the Environmental Protection Agency's (EPA's) "Release of Draft Control Techniques Guidelines for the Oil and Natural Gas Industry" at 80 FR 56577 (September 18, 2015).

API represents over 625 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. Collectively, they provide most of the nation's energy and many will be directly impacted by the proposed regulations.

The proposed rule is part of the President's "Methane Strategy," which includes multiple regulations and programs from several different agencies, intended to further reduce greenhouse gas emissions from oil and natural gas operations. However, it's important to take into account the recent methane emission trends associated with our industry. Even as U.S. oil and natural gas production has surged, methane emissions have declined significantly. For example, EPA's GHG inventory shows methane emissions from hydraulically-fractured natural gas wells have fallen nearly 79 percent since 2005 and total methane emissions from natural gas systems are down 11 percent over the same period. According to the Energy Information Agency, these reductions have occurred during a time when total U.S. gas production has increased 44% and, as a result of the increased use of natural gas, carbon dioxide (CO_2) emissions from the energy sector are now near 20-year lows. These trends are indicative of what our industry, when given the freedom to innovate, can achieve to improve the environment as we bolster our nation's energy security.

Each of the proposals (NSPS Subpart OOOOa, Source Determination, Minor Source Tribal NSR), including this one, has potentially significant impacts on our industry's operations and, collectively, they have the potential to hinder our ability to continue providing the energy our nation demands. These cumulative impacts must be considered in conjunction with the impacts of the lowered ozone standards and the pending Bureau of Land Management (BLM) methane rule, which has not yet been proposed and will likely require costly methane controls for some of the very same emission sources. Our organizations have collaborated well in the past and API remains committed to working with EPA and the Administration to identify emission control opportunities that are both cost-effective and, when implemented, don't impact safety or hinder our ability to provide the energy our nation will continue to demand for many years to come. Attached are our comments on the "Release of Draft Control Techniques Guidelines for the Oil and Natural Gas Industry" as well as an executive summary.

As we noted in our comment extension request, we again request that EPA officially re-open the docket for all three rulemakings when the proposed BLM methane rule is published in the Federal Register, to allow additional time for public comment once its interrelationship with the EPA proposed regulations can be fully analyzed. Also, given the limited comment period and minimal extension for these complex proposals, API will continue its review and, if warranted, provide supplemental comments to the agency that we request be included in the appropriate docket to protect the record and considered before finalizing the rules.

We look forward to working with you and your staff as these rules are developed. If you have any questions regarding the content of these comments, please contact Matthew Todd (toddm@api.org, 202-682-8319).

Sincerely,

Howard J. Feldman

Howard J. Feldman

Cc: Janet McCabe, EPA
Joe Goffman, EPA
Peter Tsirigotis, EPA
David Cozzie, EPA
Bruce Moore, EPA
Cheryl Vetter, EPA
Chris Stoneman, EPA
Charlene Spells, EPA

Attachment

API Comments on the Draft Control Techniques Guidelines for the Oil and Natural Gas Industry

December 4, 2015

Docket ID No. EPA-HQ-OAR-2015-0216

Executive Summary

As detailed in our comments, API has numerous concerns with EPA's draft Control Techniques Guideline (CTG) for the Oil and natural gas (O&G) sector. EPA has indicated the desire to finalize the draft CTG in early 2016. We are concerned that this artificial deadline will hinder the agency's ability to adequately address stakeholder comments. This is an unrealistic schedule for issuing a complex guidelines with the concerns identified that cover oil and natural gas industry segments as large and diverse as the onshore production, processing, and transmission and storage segments. EPA has only a few months to review and analyze all the submitted comments, make appropriate revisions, and complete the necessary internal and interagency reviews. As such, EPA should take sufficient time between the close of the comment period and promulgation of the final guidance to adequately consider and address public comments.

Many of API's concerns stem from the broad applicability of EPA's draft Reasonably Available Control Technology (RACT) recommendations and the associated model regulatory text. The one-size-fits-all approach is not appropriate for an industry that varies greatly in the type, size and complexity of operations. EPA has supported its RACT recommendations using economic studies based on "average model facilities" without determining whether the resulting control requirements are appropriate for the entire range of sources included in the source category. The notification, monitoring, recordkeeping, performance testing and reporting requirements are significantly more burdensome than justified for the small and/or temporarily affected facilities.

Listed below are API's primary concerns with the proposed rule. To facilitate review of our comments, API has summarized the concern and provided a recommendation with a reference to the detailed comments where additional supporting discussion has been included.

EPA Must Develop Applicability Thresholds Based On VOC Content To Avoid Requiring Controls That Are Clearly Not Cost Effective And Not RACT For Areas With Low-VOC Gas

Issue – By performing all RACT analyses using a single representative gas composition, EPA has recommended RACT for several fugitive sources that will result in cost effectiveness values considerably higher than EPA considers acceptable in many areas of the U.S. The volatile organic compound (VOC) content of the gas at a site is directly related to the VOC emissions, and thus, the VOC emission reduction when controls are applied. By using a single gas composition for all RACT analyses, EPA did not properly evaluate the VOC cost effectiveness for dry gas, coal bed methane, and other areas that have low-VOC gas. API has performed an analysis that provides recommendations for these thresholds that are technically sound.

Recommendation – Include VOC content applicability thresholds that ensure that areas with low VOC gas are not subject to controls that are not cost effective.

Refer to Section 2.0 for detailed comments on this matter.

Storage Vessel Monitoring Requirements

Issue – The CTG model rule includes onerous continuous parameter monitoring requirements for storage vessels that are considerably more stringent than EPA has proposed for NSPS. The RACT monitoring requirements for storage vessels should not be more stringent than the Best System of

Emission Reduction (BSER) monitoring requirements in the NSPS. Further, EPA did not include the costs of this more stringent monitoring in the impacts assessment for storage vessels.

Recommendation – Make the continuous compliance requirements in the CTG consistent with the proposed requirements in NSPS subpart OOOOa.

Refer to Section 13.8 for detailed comments on this matter.

<u>Fugitives At Well Sites And Compressor Stations</u>

Issue – The draft CTG has a process that requires significant, unnecessary recordkeeping and reporting, and requires surveys of sites that are proven to have little to no detectable leaks. Associated proposed definitions unnecessarily complicate compliance. Additionally, the initial semi-annual frequency is not warranted, and the complex process for determining frequency introduces a burdensome paperwork exercise with no emissions reduction benefit. Closed vent systems (CVS) should not be subject to duplicative requirements. As well, leak detection should not be duplicative with other state or federal enforceable leak detection requirements.

Recommendation – Streamline program to require annual inspections at sites with a compressor or storage vessel. Eliminate the requirement for a site-specific monitoring plan. Existing programs demonstrate that monitoring with an annual frequency results in very low emissions. A companywide monitoring plan will cover all the relevant material; there is no added benefit and significant added cost of developing thousands of site-specific monitoring plans. Revise definitions according to our recommendations. CVS monitoring requirements should be the same as those for fugitive emission components. Finally, exempt sites subject to state, local, or other federally enforceable leak detection programs.

Refer to Section 17.0 for detailed comments on this matter.

<u>EPA Should Delay Finalizing the CTGs Until Six Months After NSPS OOOOa is Finalized</u>

Issue – The CTGs and NSPS OOOO/OOOOa regulate the same type of equipment. Proposing these two actions at the same time resulted with significant inconsistences that appear to be unintentional and would be illogical if the inconsistences were intended. Finalizing these two actions at the same time is like to result in inconsistences in the final actions, as well as duplication of technical errors.

Recommendation – The CTG actions can be delayed without significant impacts. EPA should delay finalizing the CTGs until six months after NSPS OOOOa is finalized.

Refer to Section 1.0 for detailed comments on this matter.

<u>The Emissions Threshold For Controlling Existing Storage Vessels Should Be Higher Than 6 Tpy VOC</u>

Issue – The proposed rule applies the same 6 TPY VOC applicability for new storage vessels to existing storage vessels. Cost of control is higher for existing storage vessels than new storage vessels. EPA's cost estimate underestimates the retrofit costs for an existing storage vessel by ignoring other costs such as purchasing additional land to meet safety buffers for combustion devices. Some existing storage vessels would need to be replaced since they could not handle the additional pressure required for a closed vent system to a control device. These additional considerations make a 6 TPY VOC applicability threshold economically unreasonable for existing tanks.

Solution – Increase the applicability threshold to 10 – 15 TPY VOC to assure that controls are economically feasible.

Refer to Section 13.2 for detailed comments on this matter.

<u>EPA Should Exempt Natural Gas Pneumatic Pumps That Emit At A Rate Lower Than A High Bleed Controller</u>

Issue – EPA is proposing to regulate low emitting sources which would add considerable expense and burden while providing very limited environmental benefit.

Recommendation – EPA should exempt low emitting pumps, i.e. pumps that emit at a rate lower than a high bleed controller. This should include low usage equipment as well. This is consistent with the position taken in subpart OOOO and reinforced under the subpart OOOOa proposal for pneumatic controllers.

Refer to Section 15.4.1 for detailed comments on this matter.

<u>Pneumatic Pump Control Technical Feasibility</u>

Issue – EPA has ignored major technical and safety issues in assuming that pneumatic pumps can be readily connected to existing closed vent systems. There are numerous potential issues with connecting the discharge from a pneumatic pump to an existing control device and closed vent system. These issues can impact both the performance of the pump and result in back pressure on the other sources being controlled.

Recommendation – EPA should provide an exemption from the requirements to control pump emissions where it has been determined to not be technically feasible.

Refer to Sections 15.0 for detailed comments on this matter.

<u>Common Sense Voluntary Reductions And Incentives Will Lead To Increased Early Emission Reductions</u>

Issue – The CTGs should work in concert with the Methane Challenge Voluntary Initiative to seek common sense voluntary reductions and incentives, which will lead to increased early emission reductions. If the Administration wishes to seek additional reductions through a federal framework, the best approach would be a voluntary program without duplicative mandatory regulation. The industry is interested in participating in a well-constructed voluntary program, and has shared options for achieving substantial methane emissions reductions more rapidly than regulations would allow. Industry and EPA's incentives are aligned in desiring to keep methane in the pipeline, to reduce losses and improve product recovery. Industry members strive to evaluate options for cost effective measures to reduce emissions and implement them where they can achieve the greatest reductions. For example, EPA recently reported that total methane emissions from natural gas systems are down 11 percent since 2005 despite significant growth in production. To continue this progress and maximize the results, the industry requires flexible voluntary programs with appropriate incentives, not inflexible regulatory mandates.

Solution – Eliminate duplicative regulation of emissions.

Refer to all sections for detailed comments on this matter.

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GENERAL COMMENTS

1.0 GENERAL PROCEDURAL AND LEGAL COMMENTS

EPA has requirements in the proposed Control Technique Guidelines (CTG) on the same sources regulated in NSPS, Subpart OOOO, including currently proposed amendments, and the proposed NSPS Subpart OOOOa. Writing two separate rules on the same equipment at the same time inevitably cause inconsistences between the rules, as has been the case in these proposed rules. For instance, continuous parameter monitoring systems (CPMS) are required in the proposed CTGs for control devices, regardless of what type of affected source the emissions are coming from. However, NSPS Subpart OOOOa requires CPMS for emissions coming from centrifugal compressors or pneumatic pumps, but only sensory monitoring and inspection requirements for storage vessels. Discussions with EPA indicate they intended to propose the same compliance assurance in both NSPS Subpart OOOOa and the CTGs.

An existing storage vessel regulated by the CTG may be located right next to a new storage vessel regulated by NSPS, Subpart OOOOa. Requiring stringent CPMS monitoring for the existing storage vessel and visual inspections for the new storage vessel will be very confusing to both the agency inspectors and to the oil & gas industry personnel in trying to comply with the two different sets of requirements. Retrofitting existing equipment is more expensive than the respective increased cost for new equipment, thus you would expected existing equipment to have less stringent requirements than those for new equipment. The opposite occurred in the proposal. EPA widely utilized Best System of Emissions Reduction (BSER) as Reasonably Available Control Technology (RACT), which is not always supportable. However, in all cases BSER should be considered a cap to RACT (see Section 4.1).

For this reason, API requests that EPA delay finalizing the CTGs for at least six months after the NSPS, Subpart OOOOa rule has been finalized. Finalizing the NSPS first allows the requirements to be implemented during the initial equipment construction when it is most effective. Additionally, the existing CTGs are expected to have the most impact on existing equipment in new nonattainment areas designated due to the lowering of the Ozone NAAQS in October 2015. These new nonattainment areas are not expected to be finalized until October 2017. Further, the CTGs require state regulatory actions before these requirements can be implemented. Thus, delaying the finalized CTG until early in 2017 will cause no delays in implementation for these areas . The CTGs are not expected to have significant impact in existing ozone nonattainment areas, since RACT requirements are already in place (i.e in Denver, CO; Houston, Dallas, and Beaumont, TX; etc .). Where states feel that regulatory changes are needed promptly, they can proceed with those actions based on the NSPS OOOO/OOOOa final rule.

2.0 EPA MUST DEVELOP APPLICABILITY THRESHOLDS BASED ON VOC CONTENT TO AVOID REQUIRING CONTROLS THAT ARE CLEARLY NOT COST EFFECTIVE AND NOT RACT FOR AREAS WITH LOW-VOC GAS

CTGs are required by the CAA to help an area obtain the NAAQS. As such, CTGs cannot consider the benefits of methane reductions in the economic analysis of control options. As proposed, the CTG would require controls in production fields (i.e. coalbed methane or dry gas fields) where little to no VOC reductions would occur. EPA should adopt minimum VOC thresholds for fugitive monitoring, pneumatic pumps, pneumatic controllers and centrifugal compressors, below which no controls would be required to maintain the cost effectiveness of controls where little or no benefits to NAAQS attainment would occur.

2.1 Cost Effectiveness Is Key Element Of RACT

As stated in Chapter 1 of the draft CTG, EPA defines RACT as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." 44 FR 53761 (September 17, 1979). Historically, the primary measure that EPA has relied upon to assess economic feasibility is the cost of the emission reduction in relation to the level of emission reduction. This "cost-effectiveness" is calculated by dividing the annual costs of the control (including capital recovery along with operating and maintenance costs) by the annual emission reduction.

EPA calculated and showed the cost effectiveness for every option considered. The cost effectiveness values for the fugitive emission sources that EPA recommended as RACT are summarized in Table 2-1.

Table 2-1 EPA VOC Cost Effectiveness Values from CTG

Source	Cost Effectiveness ($/ton VOC reduced)	
	without savings	with savings
Reciprocating Compressor (Gathering and Boosting Station)	$1,132	$298
Reciprocating Compressor (Processing Plant)	$334	($500)
Pneumatic Controller (Well Site)	$210	($627)
Pneumatic Controller (Processing Plant)	$2,807	$1,970
Pneumatic Pump (Diaphragm) – Existing Control Device	$312	$312
Pneumatic Pump (Piston) – Existing Control Device	$2,840	$2,840
Equipment Leaks (Processing Plant)	$2,844	$2,010
Fugitive Emissions (Natural Gas Well Site)	$2,945	$2,111
Fugitive Emissions (Oil Well Site)	$12,294	$11,460
Fugitive Emissions (Gathering and Boosting Station)	$2,710	$1,876

It is evident that EPA relied on the cost effectiveness in determining the economic feasibility of controls for the oil and natural gas industry, as every section of the document that discusses the recommended RACT level of control includes a discussion of cost effectiveness. For example, on pages 7-17 and 7-18 of the CTG, EPA states:

> *"Our rationale for selecting 95 percent control when there is an existing control device is that, as presented in Table 7-4 in section 7.3.1.4 of this chapter, the VOC cost of control when an existing combustion device is available on-site was estimated to be $312/ton for diaphragm pumps and $2,850/ton for piston pumps. As presented in Table 7-6 in section 7.3.1.5 of this chapter, the VOC cost of control when an existing VRU is available on-site was estimated to be a cost savings for diaphragm pumps and $2,007/ton for piston pumps. We consider these costs to be reasonable. Requiring control where there is not an existing control device on-site was not considered to be reasonable available technology, and the costs per ton of VOC reduced are estimated at greater than $20,000 per ton of VOC reduced for diaphragm pumps and over $200,000 per ton of VOC reduced for piston pumps."*

This citation also shows that there are levels at which EPA considers the cost effectiveness for VOC to be reasonable, as well as levels that EPA considers to be unreasonable. Historically, EPA has avoided establishing a bright line that separates reasonable versus unreasonable, but past EPA decisions do provide insight into what constitutes reasonable.

The best and most relevant example of EPA's view of a reasonable cost effectiveness level for VOC for the oil and natural gas industry was provided in EPA's final decision related to the 4 tpy alternative emission limitation for storage vessel affected facilities under NSPS subpart OOOO, which was published on September 23, 2013. Following are quotes from the preamble for these final amendments (78 FR 58429.

> *". . . . our analysis indicates that the cost of controls for each storage vessel affected facility at a VOC emission rate of 4 tpy is approximately $5,100 per ton. This cost increases to approximately $6,900 per ton at an emission rate of 3 tpy, and to approximately $10,000 per ton at 2 tpy. For comparison, we note that, in a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], we had concluded that a VOC control option was not cost effective at a cost of $5,700/ton, which calls into question the cost effectiveness of continuing control of storage vessel affected facilities at an emission rate below 4 tpy."*
>
> *"In light of the cost-effectiveness, the secondary environmental impacts and the energy impacts, we have concluded that the BSER for reducing VOC emissions from storage vessel affected facilities is not represented by continued control when their sustained uncontrolled emission rates fall below 4 tpy."*

There are several key facts worthy of note regarding these statements related to establishing a reasonable cost effectiveness level for RACT for fugitive sources from this industry.

1) This decision was specific to the exact industry that is covered by the oil and natural gas CTG.
2) The 2007 rulemaking cited as precedent was for fugitive sources analogous to most of the sources covered in the CTG. Specifically, this rulemaking was for "Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry; Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries; Final Rule."
3) This threshold was used by EPA to establish a cost effectiveness level considered unreasonable for BSER, which is by definition, more stringent that RACT. Therefore, based on clear precedent summarized above, EPA must consider any cost effectiveness value greater than $5,700 per ton of VOC reduction to be unreasonable for the purpose of recommending RACT for fugitive source the oil and natural gas industry.

2.2 Cost Effectiveness Of Recommended Fugitive RACT For Oil Wells Is Unreasonable

Given this fact, an obvious first observation is that the cost effectiveness for EPA's recommended RACT for fugitive emissions at oil wells is well above this reasonableness threshold. EPA provided a vague and unsupportable rationale for ignoring the results of their own analysis and recommending level of control estimated to have a cost effectiveness of $11,460 (considering savings), which is more than double the level previously determined to be unreasonable (see pages 9-32 and 9-33 of the CTG). Without any consideration of any other factors discussed below, EPA must not finalize a recommendation of any fugitive leak monitoring program as RACT for fugitive emissions at well site. This is discussed in more detail in section 17.0.

2.3 Variation In VOC Content Of Gas Directly Impacts Emission Reductions And Cost Effectiveness

A lower VOC content would reduce the emission reduction achieved by a technology, thus increasing the cost effectiveness. For instance, consider a fugitive emission source where the cost of reducing the emissions is $10,000 per year. If the VOC emissions reduction for this measure at a site with a gas stream consisting of 20% VOC by weight is 5 tons per year, the cost effectiveness would be $2,000 per ton. However, applying the same reduction measure to a site where the gas content of the stream is 5% VOC by weight, the VOC emission reduction would be reduced to 1.25 tons per year and the cost effectiveness would increase to $8,000. Therefore, this difference in VOC content causes the cost effectiveness to be reasonable (by EPA's previous determination) at one site and unreasonable at another.

All the analyses in the CTG were conducted using a single representative gas composition.[1] For oil and natural gas production, this gas composition included 6.8% VOC by volume and 18.3% VOC by weight.

API notes that the documentation for the selection of this representative composition is lacking. In Table 1 of the 2011 EC/R memorandum, gas composition information from a variety of sources was presented. After a review of the available data, the outcome was that only data provided by the Gas Research Institute (GRI) data during the 1995 MACT development was used to calculate the representative gas compositions. Part of the rationale for relying on this GRI data was that a comparison of the GRI data to the other information showed that the GRI data was representative. However, Table 1 and the paragraph that describes this conclusion are severely flawed. For example, the memo states "For production, the 1995 GRI data is well within the ranges of the other data sources, which range from 1.19 to 11.6 percent for VOC by volume." However, the maximum VOC content shown in Table 1 for the other data sources is 5.7 volume percent. Also, Table 1 presents the average VOC content of the other data sources as 3.5 volume percent, as compared to an average of 3.66 volume percent for the GRI data. However, in Table 5 of the EC/R memorandum (which summarizes the GRI data) the sum of the volume percentages of the VOC components is 6.8 percent. Not only does this not match the 3.66 percent provided as the average in Table 1, it is also higher than the maximum VOC content of all the other data sources evaluated. This raises questions about the overall credibility of the analysis leading to EPA's representative composition. It also indicates that EPA may have significantly overestimated VOC emissions when this representative composition was used. In order for the public to have confidence in EPA's overall impacts assessment, EPA must explain these discrepancies in the documentation of the representative analysis and make corrections as necessary.

Despite the significant errors discussed above in EPA's documentation, API believes that the resulting representative gas composition (containing 6.8 percent VOC by volume and

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[1] Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. *Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking*. July 2011.

18.3 percent VOC by weight) is a reasonable portrayal of an "average" gas composition across the U.S. However, API strongly disagrees with the use of this representative composition to establish a universal RACT recommendation. It is inappropriate to use these general averages for determining whether particular existing oil and natural gas sources should be subject to VOC regulation and what is a cost-effective level of RACT control. The gas compositions in oil and natural gas fields in ozone nonattainment areas and the transport region where these RACT regulations will apply vary widely. In many areas, the VOC content is considerably lower than level in EPA's representative composition.

2.4 Evaluation Of Cost Effectiveness For Sites In EPA's Dataset

As noted above, the average VOC content for the GRI data set chosen by EPA to establish the representative composition was 6.8% by volume. The cost effectiveness calculated by EPA for the recommended RACT level of control for fugitive emissions from gas wells, using this representative composition, was $2,111 (considering savings). EPA considers this level to be reasonable. However, the VOC content of the gas compositions for the individual sites in the GRI data set ranged from 0.59% to over 28% by volume. This significant difference in gas composition would have a tremendous impact on the emission reductions, and thus, the associated cost effectiveness. Table 2-2 estimates the cost effectiveness values for each of the sites in EPA's GRI data set.

Table 2-2 Estimated Cost Effectiveness for Recommended RACT for Fugitive Emissions at Gas Well Sites at Sites in EPA's Gas Composition Data Set

Site	VOC Content (vol %)	Estimated Cost Effectiveness
Representative Composition	6.82%	$2,111
GRI1	0.59%	$24,414
GRI2	2.20%	$6,547
GRI3	3.93%	$3,665
GRI4	28.13%	$512
GRI5	7.15%	$2,015
GRI6	8.64%	$1,667
GRI7	7.01%	$2,055
GRI8	10.09%	$1,428
GRI9	6.22%	$2,316
GRI10	2.41%	$5,977
GRI11	3.21%	$4,487
GRI12	2.30%	$6,263

Considering the actual compositions from EPA's own dataset shows that the recommended RACT level for fugitive emissions as gas well sites would result in many gas well sites being subject to controls that have cost effectiveness values above the $5,700 level which EPA has previously determined to be unreasonable for this industry. In fact, four of the twelve sites in EPA's data set, or 25%, would incur what EPA itself has determined are unreasonable costs when considering the VOC emission reduction. This includes one site that would be required to install controls at a cost effectiveness of over $24,000 per ton of VOC reduction.

2.5 Evaluation Of Cost Effectiveness With Varying VOC Composition In Gas

In order to demonstrate the overall impact of varying VOC content on cost effectiveness, API conducted a succinct analysis for the fugitive emission sources at oil and natural gas sites covered by the CTG. This analysis was conducted using two different costs. The first analysis was conducted using EPA's estimated annual costs as provided in the CTG without adjustment. However, as discussed throughout this document, API believes EPA's costs in the CTG underestimated the actual impact that will occur in several instances. Therefore, the second analysis uses API's updated cost estimates.

2.5.1 Analysis Using EPA Costs

As noted above, EPA's representative gas composition consisted of 6.8% VOC by volume and 18.3% VOC by weight. The cost effectiveness values that were provided in Table 2-1 were based on emissions calculated using these weight percentages. Cost effectiveness values were calculated at varying concentrations of VOC by assuming a linear relationship between VOC emission reductions and the VOC content. Figure 2-1 through Figure 2-4 show the results of this analysis. For reciprocating compressors at processing plants and pneumatic controllers at well sites, EPA estimated that there would be net savings due to the recovery of natural gas. These sources were not included in this analysis.

Figure 2-1 CTG Cost of Control – Reciprocating compressors at Gathering and Boosting Stations

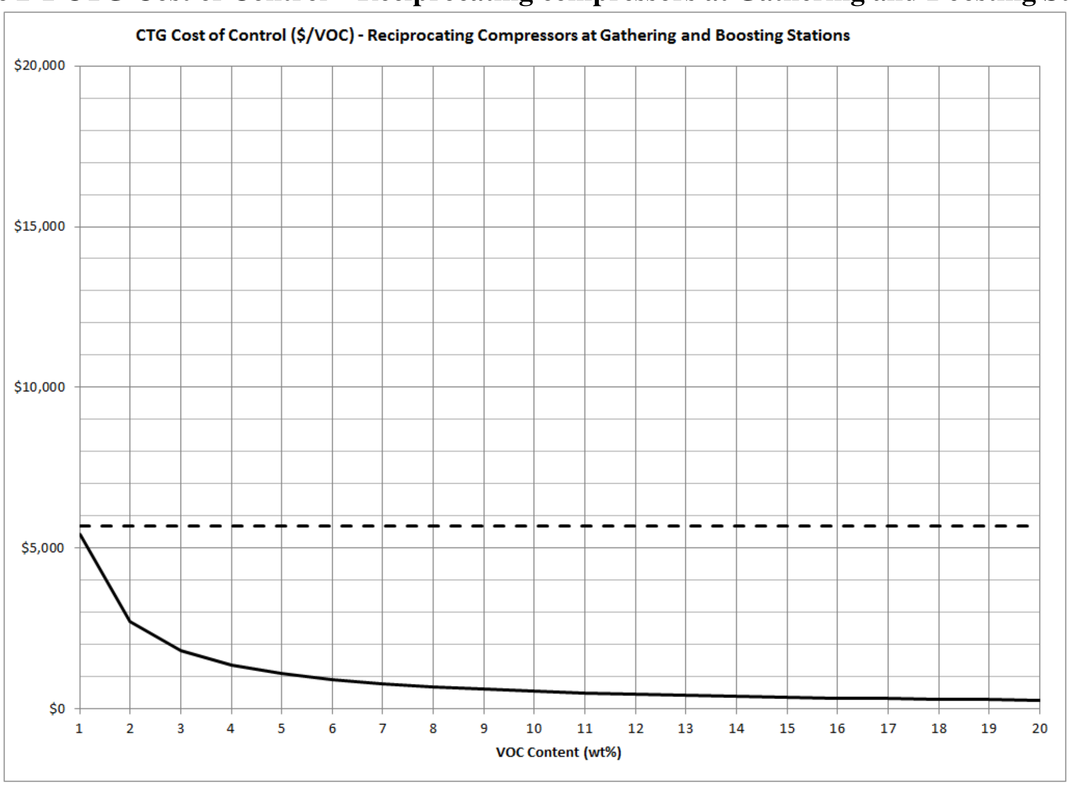


Figure 2-2. CTG Cost of Control – Pneumatic Controllers at Processing Plants

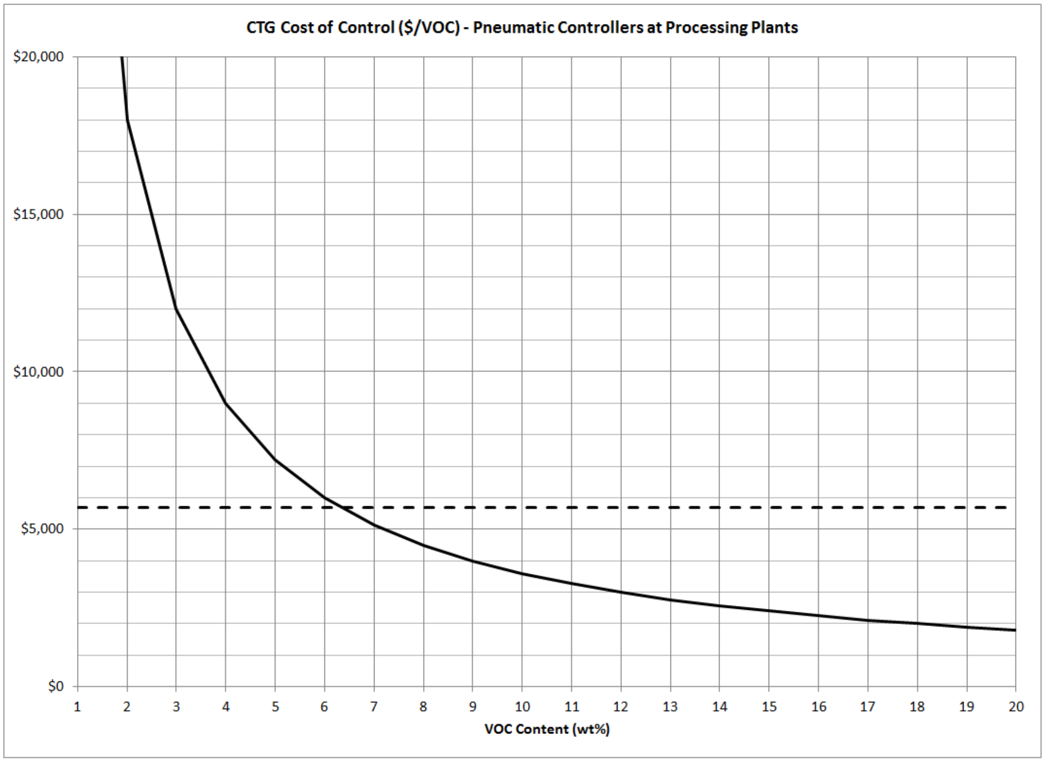


Figure 2-3. CTG Cost of Control – Pneumatic Pumps

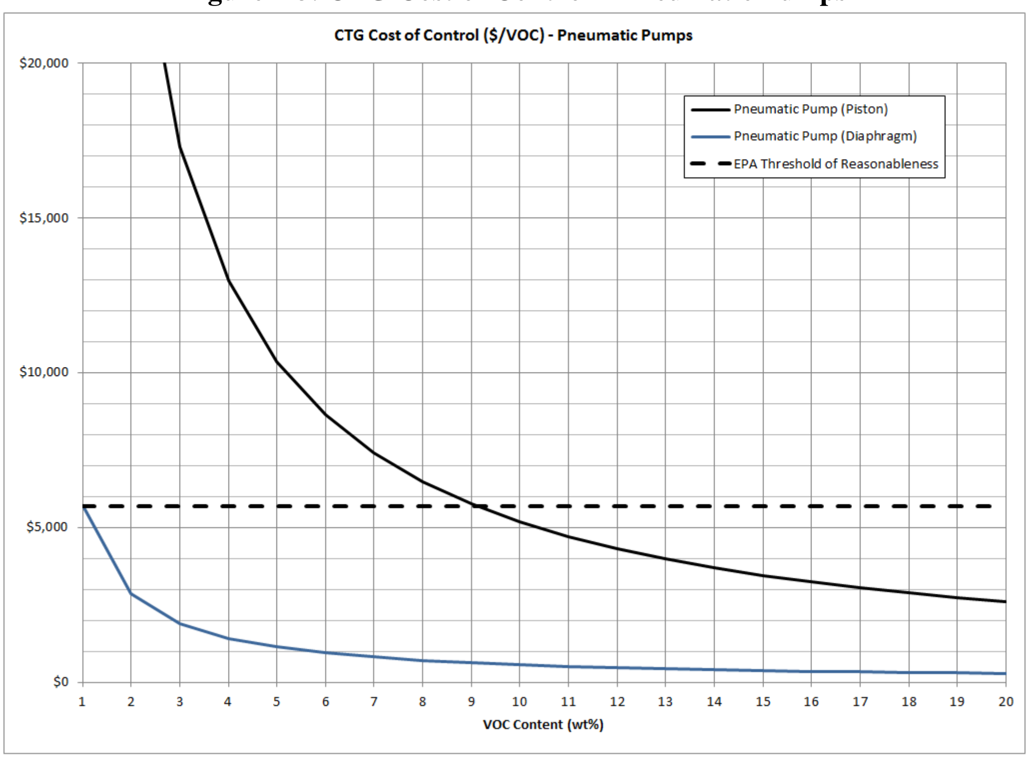
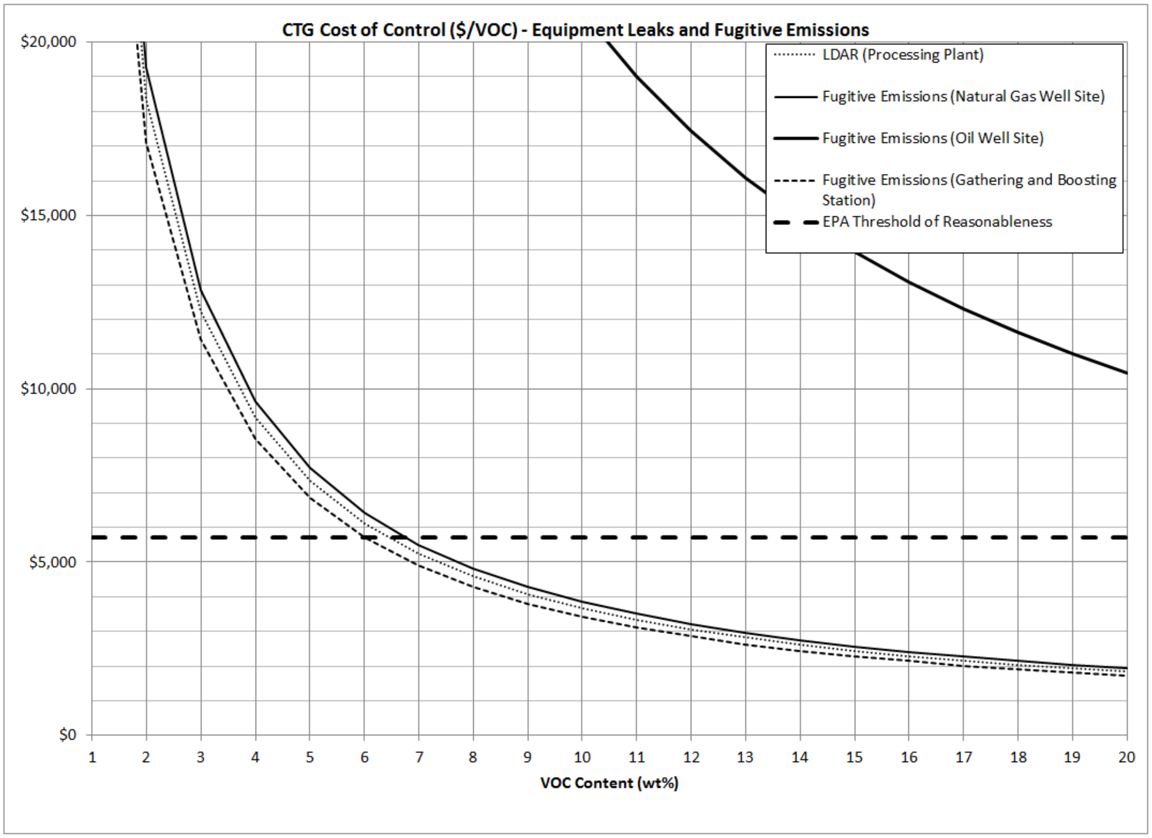


Figure 2-4. CTG Cost of Control – Equipment leaks and Fugitive Emissions



The conclusion of this analysis based on the EPA costs, are as follows:

- For reciprocating compressors at gas processing plants, the cost effectiveness is below $5,700 for VOC concentrations down to 1% by weight.
- The cost effectiveness for fugitive emissions control at oil well sites is greater than $5,700 and thus unreasonable at all VOC concentrations.
- For pneumatic controllers and LDAR at gas processing plants, pneumatic piston pumps, and fugitive emissions at natural gas well sites and gathering and boosting stations, the cost effectiveness rises above $5,700 at VOC concentrations about 6 and 7% by weight.

2.5.2 Analysis Using Updated API Costs

For pneumatic pumps and fugitive emissions from well sites, EPA significantly underestimated the cost of control. API provides detailed analyses of these costs in sections 15.0 and 17.3 for pneumatic pumps and fugitives, respectively. Table 2-3 shows the difference in the annual costs estimated by EPA and the corrected costs based on API members' extensive experience installing and implementing these controls.

Table 2-3. Comparison of EPA and Updated API Cost Estimates

Source	Annual Costs (including savings)	
	EPA	API
Pneumatic Pump (Diaphragm)	net savings	$4,359
Pneumatic Pump (Piston)	$201	$5,024
Fugitive Emissions (Gas Well Sites)	$1,599	$7,712
Fugitive Emissions (Oil Well Sites)	$2,079[a]	$8,192[a]

[a] EPA cost is for semi-annual OGI program. API cost is for annual program.

Table 2-4 shows the cost effectiveness calculations using API's updated annual costs. Note that these are based on the VOC emission reductions estimated by EPA using the representative gas composition.

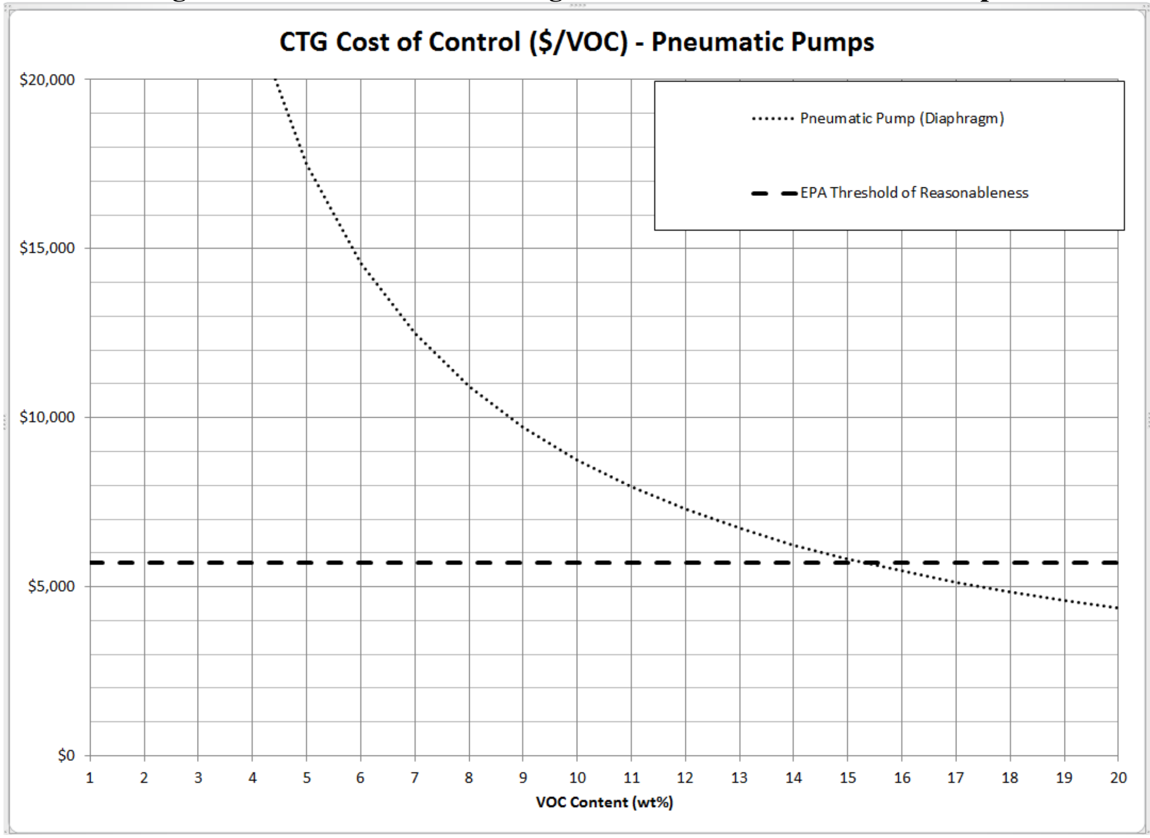
Table 2-4. Comparison of EPA and Updated API Cost Effectiveness Calculations

Source	Cost Effectiveness ($/ton VOC reduction)	
	EPA	API
Pneumatic Pump (Diaphragm)	net savings	$4,790
Pneumatic Pump (Piston)	$2,007	$50,240
Fugitive Emissions (Natural Gas Well Site)	$2,111	$10,147
Fugitive Emissions (Oil Well Site)	$11,460[a]	$45,511[a]

[a] EPA cost is for semi-annual OGI program. API cost is for annual program.

As seen in Table 2-4, the cost effectiveness values for EPA's draft RACT recommendations for fugitive emissions programs at well sites and for pneumatic piston pumps are well above EPA's reasonableness threshold of $5,700/ton. The diaphragm pneumatic pumps are below this threshold. However, this cost effectiveness is based on the 18.3% by weight VOC content in EPA's representative composition. As discussed above, many areas have gas compositions much lower than this level. Figure 2-5 illustrates the cost effectiveness at different VOC composition levels. As can be seen, the cost effectiveness crosses the $5,700 reasonableness threshold at around 15% VOC by weight.

Figure 2-5 Cost of Control Using API Estimates – Pneumatic Pumps



2.6 Many Areas That Will Be Impacted By The CTG And Model Rule Are Low VOC Gas Areas

The oil and natural gas produced in the US varies considerably. This can range from very heavy, thick crude oil (a.k.a. black oil or dead oil) that has no associated natural gas, to light hydrocarbon liquids (a.k.a. condensate) that co-produce VOC-laden gas, to gas that is almost 100% methane with no associated liquids. Each type of formation may have some similarities, but still can have wide variation. Some tight sands behave like sand stone and can produce significant amounts of heavier hydrocarbons. Shale fields run the gamut from wells that produce nearly 100% methane to wells that produce significant quantities of hydrocarbons that are liquid at stock tank conditions. The definitions of the various types of reservoirs are very broad and the defining characteristics have little to do with the reservoir's potential to emit VOC or HAP.

As evidenced by the brief discussion above, areas that produce low VOC gases are likely to be adversely and unfairly impacted by high costs with little VOC emission reduction. However, this is not just a theoretical exercise, as there are numerous areas that will be impacted by EPA's RACT recommendation and model rule and the resulting SIPs where low-VOC gases are prevalent.

There are several active oil and natural gas production areas that are in the ozone transport region or ozone nonattainment areas (or in areas likely to be nonattainment under the new 70 ppbv ozone NAAQS) where the VOC content is very low. These include, but are not limited to the Marcellus, New Albany, Barnett, and Mancos areas. It is estimate that there are over 23,000 wells in these low-VOC areas.[2] While not all of these areas will be in moderate or above ozone nonattainment areas where RACT is required, States may choose to voluntarily implement these recommended RACT requirements to address the VOC from oil and natural gas operations.

In addition, coal bed methane (CBM) typically is produced at low pressures and contains very high percentage of methane (often as high as 97% by volume) and almost no hydrocarbons heavier than ethane. Coal has classically been thought of as a "cap rock", not a reservoir rock. This means that the pore volume (i.e., porosity) is on the order of 0.25%. This very low porosity demonstrates that the only gases that can be stored in the coalbed must be of a size that allows them to be adsorbed to the surface of the coal. Coal has a high affinity to accept CO_2 onto its absorption sites, and a slightly smaller affinity for methane. Heavier hydrocarbons do not "fit" on the adsorption sites (the traces of heavier hydrocarbons that are sometimes reported in CBM fields have come from the very small pore volume, not desorption). Consequently, CBM fields tend to have zero or near zero VOC emissions. There are also several CBM areas that are in the transport region or potential ozone nonattainment areas including, but not limited to, the Black Water, Appalachian, and Uinta areas. It is estimated that there are over 10,000 CBM wells in these areas.[3]

Therefore, a large number of low-VOC sites could be impacted by the RACT rules resulting from this CTG. These sites will be subject to requirements that clearly have costs at a level that EPA has considered unreasonable in relation to the associated VOC emission reductions. Therefore, EPA must include VOC applicability thresholds in the RACT recommendations and model RACT rules to avoid these high cost impacts with very minimal environmental benefit.

2.7 There Is Precedent For VOC Applicability Thresholds In Ctgs And Federal Regulations

There are precedents in many NSPS and other federal regulations where EPA has recognized that the composition of the gas impacts the level of emissions, and thus has included applicability thresholds. This is particularly prevalent for regulations that focus on fugitive emissions, such as the 1983 CTG for fugitive monitoring in Gas Processing[4] (which stated 1% VOC by weight; see section 16.2.8), and multiple NSPS subparts. For example, NSPS subparts VV and VVa only cover equipment "in VOC service," which is defined as equipment that "contains or contacts a process fluid that is at least 10 percent VOC by weight." In other words, equipment components that contact a process fluid with less than 10 weight percent VOC are exempt from the leak detection and repair requirements.

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[2] Marcellus - http://stateimpact.npr.org/pennsylvania/drilling/
New Albany - http://www.in.gov/dnr/dnroil/files/og-NASWellsByStatus1990to2013.pdf
Barnett - http://www.tceq.state.tx.us/assets/public/implementation/barnett_shale/bs_images/bsOilGasWells.png
Mancos - https://www.env.nm.gov/aqb/4C/Documents/Mancosshale_May30_2012.pdf

[3] Black Warrior - http://www.gsa.state.al.us/gsa/cbm/Coalbed%20Methane%20Research.htm
Appalachian – http://www.dcnr.state.pa.us/cs/groups/public/documents/document/dcnr_007916.pdf
Uinta - http://www.blm.gov/style/medialib/blm/ut/vernal_fo.Par.57849.File.dat/GCW%20Cums%20TSD%2003-22-12%20final.pdf

[4] http://www3.epa.gov/ozonepollution/SIPToolkit/ctg_act/198312_voc_epa450_3-83-007_leaks_naturalgas_processing.pdf

2.8 Conclusion: EPA Must Include Applicability Thresholds Based On VOC Content In The Gas

The discussion above clearly proves the need for EPA to include applicability thresholds based on VOC content in the gas for the RACT recommendations and model rule for several fugitive emission sources where it is proven that the cost effectiveness levels are at unacceptable levels as VOC content decreases.

Specifically, API recommends that EPA exempt the following emission sources from RACT requirements in the CTG if the gas composition at the site exceeds an appropriate threshold. Using EPA's proposed cost estimates that threshold is 7.0 % VOC by weight or less:

- Pneumatic controllers at gas processing plants,
- LDAR at gas processing plants,
- Pneumatic piston pumps, and
- Fugitive emissions at natural gas well sites and gathering and boosting stations.

Considering API's more accurate cost estimates, requirements for fugitive VOC emissions at all well sites and pneumatic piston pumps are not cost effective even using EPA's representative composition. Further, the cost effectiveness for the requirements for pneumatic diaphragm pumps becomes reasonable at 15 % VOC by weight.

3.0 EPA SHOULD APPLY LOW PRODUCTION EXEMPTION TO ALL EMISSION SOURCES AND THIS EXEMPTION SHOULD APPLY WHENEVER THE AVERAGE PRODUCTION OF A WELL SITE FALLS BELOW THE 15 BOE/DAY LEVEL

In Section 9.1 of the CTG, EPA states: "For purposes of this guideline, the emissions and programs to control emissions discussed herein would apply to the collection of fugitive emissions components at a well site with an average production of greater than 15 barrels of oil equivalent per well per day (15 boe/day), and the collection of fugitive emissions components at compressor stations in the production segment. It is our understanding that fugitive emissions at a well site with low production wells are inherently low and that many well sites are owned and operated by small businesses. We are concerned about the burden of the fugitive emissions recommendation on small businesses, in particular where there is little emission reduction to be achieved."

This exemption is specific to the fugitive emission requirements at well sites. However, the reasons stated by EPA are applicable to all emission sources at low-production well sites. Therefore EPA should universally apply this exemption and totally exempt all sources at well sites with average production of less than 15 boe/day from all requirements.

Furthermore, this exemption should apply throughout the life of the well site. In other words, whenever the average production of a well site falls below 15 barrel equivalents it should no longer be subject to any RACT requirements.

4.0 THE CTG DOCUMENT DOES NOT ADEQUATELY COVER ALL THE DATA REQUIRED BY THE CLEAN AIR ACT, WHICH INCLUDE RETROFIT COSTS, OPERATIONAL COSTS, ENERGY REQUIREMENTS, ENVIRONMENTAL IMPACTS, AND FUEL COSTS.

Clean Air Act Section 108(b)(1) outlines the information that EPA is required to provide to states and other air pollution agencies related to air pollution control techniques for criteria pollutants associated with NAAQS. Specifically, this paragraph states that EPA "shall include data relating to the cost of installation and operation, energy requirements, emission reduction benefits, and environmental impact of the emission control technology. Such information shall include such data as are available on available technology and alternative methods of prevention and control of air pollution. Such information shall also include data on alternative fuels, processes, and operating methods which will result in elimination or significant reduction of emissions." In this CTG, EPA failed to comply with this requirement. Not only did lead to insufficient information being provided for states, it led EPA to recommend RACT requirements (which are reflected in the model rule) that are not based on accurate information. Throughout these comments, API points out examples of the inadequacies in EPA's cost estimates.

4.1 The CTGS Must Take Into Consideration The Impacts And Costs Of Retrofitting Existing Sources

EPA is not taking into account the significant cost differences between applying a control in a new and existing operations. Applying BSER controls to existing source controls are more expensive (not RACT) for several reasons. As economically feasible is part of the definition of RACT, these costs must be considered.

- Existing controls may not be adequate for CTG compliance. There will be situations where the control device itself is not designed adequately or does not have the necessary uptime and efficiency, or is designed for testing and monitoring. Furthermore the existing control device may not have the monitoring systems required by the CTG. The control device may have been installed for state permitting or regulatory compliance, or maintaining emissions below a threshold, In these situations the existing control device and monitoring systems would need upgrade, potentially significant upgrade. Those costs must be considered by USEPA in their evaluation.
- There may be permitting implications if a flare is the chosen control device.
- New land may be required to add control devices to existing sites.
- Existing vapor recover units, compressors, and storage vessels may require early retirement.
- Existing controls may have remaining useful life and will require early retirement.

4.2 EPA Should Consider The Cost Of Disturbance Of Land To Install New Controls

One of the elements that EPA did not consider in estimating the impacts of these RACT requirements on existing sources is the cost of disturbance of land to install new controls. Industry standards and insurance typically require that combustion devices must be placed 50-150 feet from equipment containing hydrocarbon to avoid explosions from thermal radiation. Due to the spacing requirement for control devices, adding a control device may require additional surface disturbance beyond the existing pad location. There are numerous repercussions of additional land disturbance including:

- Additional land may have to be purchased. EPA has not included in the cost estimate for the control devices the cost of the additional land that would be required.

- Wetlands may be further impacted requiring additional wetland mitigation and/or a Corps 404 Permit under the Clean Water Act. EPA has not considered the additional cost for wetland mitigation and permitting.
- The additional land needed may encroach on endangered species habitat and may not be allowed to be developed or require additional mitigation. EPA has not considered the impacts of this situation.
- Federal land will potentially require NEPA analysis for the additional disturbance. EPA has not considered the great cost and effort of a NEPA analysis for additional disturbance on Federal land.
- National Historic Preservation Act review may be required for the additional disturbance. EPA has not considered the impact under the NHPA.

4.3 EPA Should Not Require The Same Controls As In The NSPS, Which Is For New Sources

On September 18, 2015, EPA proposed NSPS Subpart OOOOa, which covers all the same emission sources addressed in the draft CTG but for new sources. The Clean Air Act has requirements for evaluating the stringency of controls for the different programs.

Control Technique Guidelines define Reasonably Available Control Technologies (RACT) as the following:

- "RACT emissions limitations are the lowest emissions limitations that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility."[5]
- While EPA has not set a financial threshold for RACT, per a 2006 EPA memo[6], generally the VOC cost threshold has been approximately $2000 per ton in 1980 dollars ($5,784.37 in 2015 dollars[7]).

New Source Performance Standards outline the Best System of Emissions Reduction (BSER)

- "For purposes of this section, if in the judgment of the Administrator, it is not feasible to prescribe or enforce a standard of performance, he may instead promulgate a design, equipment, work practice, or operational standard, or combination thereof, which reflects the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. (CAA – U.S. Code Title 42 Chapter 85 Subchapter I Part A 7411 (h)(1)."

Despite this difference in statutory authority, in this package of rulemakings, EPA has determined in almost every case that the exact same controls are appropriate for new sources and existing

[5] http://www3.epa.gov/ttn/atw/ctg_act.html
[6] http://www3.epa.gov/ttn/caaa/t1/memoranda/ractqanda.pdf
[7] http://www.bls.gov/data/inflation_calculator.htm

sources in non-attainment areas. In other words, EPA determined that BSER and RACT are equal. In a few cases (alternative emission limitation for storage vessels, continuous monitoring provisions for storage vessels), the RACT requirements in the model rule in the appendix to the CTG are more stringent than the NSPS. EPA cannot propose the same requirements for BSER and RACT without an explanation. EPA must re-evaluate RACT based on the appropriate criteria and re-issue the draft CTG based on these appropriately conducted analyses.

5.0 EPA SHOULD REITERATE THAT EACH STATE IS ABLE TO ADOPT OTHER EXISTING REGULATIONS IN LIEU OF CTGS AS RACT.

EPA has defined RACT as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility" (44 FR 53762; September 17, 1979). Since the cost effectiveness tabulations are based upon a nationwide average, economic feasibility[8] may vary from state to state. Thus, while EPA considers CTGs to constitute "presumptive" RACT, states are not required to adopt the control measures specified in CTGS as RACT. CTGs may not meet the definition of RACT[9] in terms of being reasonably available for a specific source or source category for a particular area.

Additionally a RACT analysis might conclude different control measures should include the application of a VOC threshold for the implementation within a particular area based upon the sources in that particular area.

According to 2006 Guidance from Harnett[10], in response to a question regarding how to address requirements as part of the SIP where a State determination that sources subject to Federal rules meet RACT by compliance with those requirements:

> To rely on federal rules to meet the RACT requirement, the State must incorporate these requirements into the SIP. For example, a State could incorporate by reference the Federal requirement or could submit a permit that includes this provision as a SIP revision.

The same guidance points out that "a State may rely on control obligations required by federally enforceable permits by submitting the relevant portions of these permits (i.e., the portions establishing the VOC and NOx obligations) as SIP revisions along with a demonstration that such controls are RACT." And "a RACT analysis needs to be done for all CTG sources and all major non-CTG sources. While the CTGs and ACTs provide a starting point for such an analysis, RACT can change over time as new technology becomes available or the cost of existing technology adjusts. States are encouraged to use the latest information available in making RACT determinations, whether that information is in CTGs, ACTs, other guidance that is available or through information submitted during the public review process."

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[8] 1994 guidance indicates that cost effectiveness should be within \$160 to \$1300 per ton.
[9] Note that API does not agree with this presumption, as there is no basis under the law for the suggestion that EPA's recommendations carry any greater weight than individual state determinations.
[10] http://www3.epa.gov/ttn/caaa/t1/memoranda/ractqanda.pdf

While a CTG is the starting point for a RACT analysis for a source category covered by a CTG, the analysis must still be conducted to identify "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." EPA should reiterate this obligation and that it is wholly acceptable that such an analysis may conclude that existing regulations satisfy the RACT obligations for a source category and the CTG need not be adopted as written.

An example of where this is especially true relates to monitoring, inspection and performance testing requirements. States typically have their own policies and procedures on these requirements. It is less burdensome for state agency personnel and the regulated community to use the state compliance assurance requirements in lieu of the EPA style requirements included in the model rule. If EPA includes compliance assurance requirements in the model rule, EPA should specifically state in the preamble that state may utilize their own compliance assurance provisions in lieu of those in the model rule.

6.0 API REQUESTS THAT THE CONTROL TECHNIQUE GUIDELINES FOR THE OIL AND NATURAL GAS INDUSTRY AND EPA'S SIP PLANNING GUIDANCE ENCOURAGE STATES NOT TO REQUIRE EMISSIONS OFFSETS FOR MINOR OIL AND NATURAL GAS EMISSIONS SOURCES.

States with marginal non-attainment areas and above are subject to the non-attainment new source review requirements including offsets for increases of emissions for new or modified major stationary sources. While the Clean Air Act only requires emissions offsets in the Non-attainment New Source Review (NNSR) program for major sources in non-attainment areas, some States additionally require offsets for minor sources (Wyoming – WYDEQ). Additionally, some State statutes do not distinguish between major sources and minor sources in their Prevention of Significant Deterioration (PSD) programs applicable to attainment areas with respect to the requirement that new or modified facility does *"not cause or contribute to an exceedance of a NAAQS."* (e.g. Wyoming WAQSR Chapter 6, Section 2(c)(ii)), which can result in air quality offset requirements for minor sources. In rural areas of the US, where most oil and natural gas development occurs, there are limited opportunities to acquire emission or air quality offsets. In the event emissions offsets are required, new oil and natural gas production could be significantly restricted.

With Control Technique Guidelines and NSPS OOOO/OOOOa, the value of additional VOC offsets through beyond-the-requirements control of minor sources is even further diminished. Additionally, virtually no offset opportunities exist for oil and natural gas in rural areas. Thus, API requests that the CTGs and EPA's SIP planning guidance specifically encourage states not to require emissions or air quality offsets for minor oil and natural gas emissions sources.

7.0 STATES SHOULD BE ALLOWED TO DETERMINE WHAT CTGS SHOULD BE APPLIED

The precursors to ozone formation are both VOCs and NO_X. The net impact of ozone formation depends on the NO_X, VOCs, and meteorology for a particular location. As noted in EPA's

Integrated Science Assessment for Ozone[1] , "Duncan et. al 2010[2] found that O3 [ozone] formation over most of the U.S. became more sensitive to NO_X over most of the U.S. from 2005 to 2007 largely because of decreases in NO_X emissions." Further control of VOC in many areas may result in no discernible ozone reduction. Moreover, control of emissions with combustion devices results in increases of NO_x. The ozone formation for most of the U.S. is NO_X limited; therefore, in most areas of the country adding more NO_X could result in increased ozone formation and implementing a CTG RACT rule would be counterproductive. Analysis for particular areas could find that there was no benefit to ozone reductions with application of CTGs, or in the worst case, such an analysis may find that the net result of controlling VOC emissions with combustion creates *more* ozone since it would add NO_X emissions. EPA should allow the states to determine whether incorporation of the CTGs into RACT SIPs is beneficial through analysis of the air quality for the particular area.

8.0 THE FINAL CTG SHOULD INCLUDE A FEDERAL FRAMEWORK FOR ENCOURAGING VOLUNTARY METHANE REDUCTIONS FROM EXISTING OIL AND NATURAL GAS SOURCES

The incentive to generate voluntary methane reductions from existing oil and natural gas sources will be significantly undercut if EPA adopts CTGs that apply to all existing oil and natural gas sources, including those highly-controlled sources that have voluntarily implemented "best management practices" (BMP) under the Methane Challenge Program. In particular, the adoption of CTGs applicable to the entire source category will trigger a requirement for states to establish RACT standards for all sources, including the BMP-controlled sources, which are located in ozone nonattainment areas and ozone transport areas classified as moderate or higher. The imposition having to change from the BMPs to the RACT requirements once they are finalized will deter many companies from trying to implement the BMPs. Furthermore, once the RACT requirements for the CTGs are included in a state's regulations and State Implementation Plan (SIP), companies will be unable to get offset credits from reduction implemented under a BMP that they make legally and practically enforceable.[11]

To correct this problem, EPA should establish in the final CTGs a federal framework that encourages, to the maximum extent permissible under the CAA, voluntary methane reductions from existing oil and natural gas sources. Such methane reductions are necessary to help ensure

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[1] US EPA. 2013a. "Integrated Science Assessment for Ozone and Related Photochemical Oxidants (Final)." EPA/600/R–10/076F.

[2] Duncan, BN; Yoshida, Y; Olson, JR; Sillman, S; Martin, RV; Lamsal, L; Hu, Y; Pickering, KE; Retscher, C; Allen, DJ. (2010). Application of OMI observations to a space-based indicator of NOx and VOC controls on surface ozone formation. Atmos Environ 44: 2213-2223. http://dx.doi.org/10.1016/j.atmosenv.2010.03.010

[11] The CAA establishes specific rules for the generation of offsets. One key requirement is that the emission reductions must not otherwise be required by some other CAA program or regulation. *See* Section 173 (c)(2) of the CAA (providing that "Emission reductions otherwise required by this chapter shall not be creditable as emissions reductions for purposes of any such offset requirement"). EPA has also established federal guidance providing that to the extent that the emission reductions are in fact required by CAA, those reductions are not "surplus" and consequently may not be used to generate offsets. *See* Emissions Trading Policy Statement; General Principles for Creation, Banking and Use of Emission Reduction Credits, 51 Fed. Reg. 43,814, (December 4, 1986).

the achievement of the Administration's goal to cut methane emissions from the oil and natural gas sector by 40-45 percent from 2012 levels by 2025.

This important policy objective can easily be accomplished by narrowing the scope of the oil and natural gas sector subject to the CTGs as well as setting the control thresholds for sources such as storage vessels at a higher level than the NSPS OOOOa levels. Also the final CTGs should include language that excludes sources that have established legally and practically enforceable limits for already implemented BMPs under the Methane Challenge Program from implementing the CTG requirements. Sources that are controlled and following the BMPs for the Methane Challenge that have made them legally and practically enforceable could use the reductions as offsets since they are not under the CTGs. Allowing companies to be exempt from the CTGs that implement the BMPs and make them legally and practically enforceable to get offsets will encourage companies to make reductions earlier than when the would be required for newly designated ozone nonattainment areas under the 2015 ozone NAAQS. Final designations will be issued by October 26, 2017 and the RACT SIPs will be due by October 26, 2019 that would need to include the CTGs. Any reductions made after the designations years of 2013-2015 or 2014-2016 could still be used for Reasonable Further Progress demonstrations and used as offsets as long as they are done before the RACT regulations are put in place. If the CTG fails to provide a source category exclusion for those sources that have voluntarily implemented BMPs for reducing their methane and VOC emissions, the only option available to generate offsets will be for existing sources to achieve VOC reductions that exceed the RACT control levels specified in the CTGs. Under this "RACT-Plus" approach, sources could generate offsets for only a small increment of the total VOC reductions that the company could achieve by the implementation of BMPs under the Methane Challenge Program. This small increment would be those VOC reductions that are in excess of the VOC reduction levels mandated by the state in the VOC RACT standards applicable to affected oil and natural gas sources.

Only a small increment of the total VOC reductions achieved by companies under the Methane Challenge Program would be available to generate a correspondingly small amount of offsets once the CTGs are incorporated into the state regulations. This small amount of offsets may not be a sufficient incentive to encourage robust participation by many companies to achieve substantial methane emission reductions under the Methane Challenge Program above any VOC RACT standard. Furthermore, the states could impose stricter requirements for RACT in their regulations and RACT SIPS beyond the CTGs leaving no further reductions available. The window to do reductions that would still be creditable by making the BMPs legally and practically enforceable but before CTGs are incorporated in the regulations and the RACT SIPs will only be from 2017-2019 giving companies a very small window to acquire offsets.

9.0 THE CONTROL DEVICE TESTING AND MONITORING COMPLIANCE ASSURANCE REQUIREMENTS ARE NOT APPROPRIATE

9.1 Oil and Natural Gas Production Sites Are Unique From Traditional Stationary Sources

The sources that will be subject to RACT rules based on the recommendations in the CTG are unique from typical stationary sources in that they are small sites, located in remote areas, dispersed from each other (often requiring an hour or more travel time between regulated sites), and typically unmanned. These sites lack the infrastructure of power, communication or even a simply found geographic address that are required to make many of the historic compliance assurance measures function. Because EPA has "force fit" the testing, monitoring, and other compliance assurance requirements designed for traditional stationary sources to the oil and natural gas industry, the proposed testing and monitoring requirements result in unnecessary burden without a commensurate benefit. Sections 9.1.1 through 9.1.3 briefly describe some of the unique aspects of the oil and natural gas industry. Sections 9.2 and 9.3 provide specific examples of the inappropriateness of these requirements and provide recommendations that will ensure compliance and environmental benefit without creating unnecessary and costly burdens on the industry.

9.1.1 Oil and natural gas Production Operating Conditions Are Not Steady State

Oil and natural gas operations are unique due to the dependence on the naturally occurring underground nature of the resource being harvested. This section summarizes some of those unique characteristics and their impact on emission control devices (primarily combustion control devices).

Unlike other industrial sectors where operating conditions are defined in the engineering stage, the oil and natural gas production sector does not operate at steady state conditions. Equipment design must be tailored to the conditions and fluid compositions supplied by the reservoir. Oil and natural gas is located thousands of feet below the surface and must flow in two or three phases to the surface. Ideally, this flow would occur at a relatively steady rate at a velocity fast enough to suspend small droplets of produced water and liquid hydrocarbons during the vertical ascent to the surface. The mixture is then separated in the two or three phase separator with steady pulses of produced water sent from the bottom of the separator to its storage vessel, hydrocarbon liquids off the middle to its storage vessel, and natural gas off the top of the separator to the gathering system. This may occur at times, but it is not typical.

As production declines and velocity in a vertical pipe decrease, the small droplets start to move slower than the gas combine into larger and larger droplets. These eventually form slugs of liquid that must be pushed up the pipe. The increasing back-pressure on the reservoir reduces in-flow, production, and hence velocity. As backpressure on the reservoir increases and the velocity continues to decrease, the liquid column in the wellbore can stop the gas flow until the gas pressure below the slug increases sufficiently to push the liquid to the surface. The management of these wellbore liquids is a major concern throughout the life of a well that mandates changes in both down hole and surface equipment. The impact to environmental emissions controls is that flow to the control device varies from essentially zero to high flow rates and quickly back to zero rapidly and often. This highly variable, non-steady state flow mandates equipment to be sized much larger than ideal steady state conditions would dictate and makes flow measurement infeasible.

9.1.2 Production Separator Operation

The purpose of the two or three-phase production separator is to separate the two or three-phase flow from the well to make sure that only natural gas goes to the gathering system and only liquid hydrocarbons and produced water are sent to their respective storage vessels. Separators are sized to give sufficient "residence time" to allow the separation of phases to take place. Since the actual mix of gas, oil (or condensate), and produced water varies randomly with time, it is impossible to predict when or how often a given control-action will occur.

The flow into the separator is made up of the fluids that the reservoir produces at any given moment, as modified by the transport of those fluids to the surface. The liquid levels in the separator are maintained by valves (often called dump valves) on the separator outlets to the oil/condensate storage vessel and the produced water storage vessel (although liquid collection systems are sometimes used in lieu of a storage vessel). The dump valves are sized to handle the highest flow rate of liquid that the separator can be expected to receive. Because of the highly variable flow conditions, separators normally provide flow to storage vessels in short spurts, typically lasting only seconds, to maintain the required liquid levels and dump cycles may be separated by many minutes, hours, or even days.

9.1.3 Closed Vent System Flow Rate

Gas flow from the storage vessel into the closed vent system (CVS) predominantly results from flashing vapors (resulting from the spurts of liquids from the separator) and dwarfs the working and standing/breathing emissions typical from storage vessels (that occur between spurts). However, the CVS and control device must be sized sufficiently to handle the peak vapor volumes expected. Measuring the flow in CVS causes two distinct problematic issues. The normal volumes from working and standing losses and the flashing of separator liquids are at very low velocities that are hard to measure with current measurement technology (see "Technical Review of Western Climate Initiative Proposals to Meter Fuel and Control Gas", Attachment A). Measuring the flow of flash vapors and peak flow rates would require a device that can go from zero flow to maximum flow in milliseconds, and be able to go back to zero just as quickly. The hysteresis (i.e., the amount that the previous state impacts the future state) and the latency (i.e., the time required to return to steady flow after a transient) of the very best commercial measurement devices available today are both inadequate for millisecond-scale transients. Currently for minerals accounting purposes the Federal government and states do not require flow measurement for liquids but only gaging or strapping of the tank because of the lack of adequate measurement technology.

9.2 The Proposed Testing, Monitoring, And Other Compliance Assurance Requirements Are Inappropriate For The Oil and natural gas Industry

9.2.1 The NESHAP-Level Approach For Compliance Assurance Is Inappropriate And Unrealistic For Oil and natural gas Production Sites

For the most part, EPA has copied the full MACT control device and compliance assurance requirements in NESHAP HH (40 CFR 63, Subpart HH) for the CTG model rule, rather than craft cost-effective requirements tailored to address the unique situations related to RACT for oil and natural gas operations. The capital cost of the control device is trivial in comparison to the cost of the performance tests, monitoring, recordkeeping, etc. for complying with NESHAP HH. These ongoing operating and maintenance costs were not adequately considered by EPA in the cost effectiveness determination for the RACT recommendations. Furthermore, these RACT regulations will apply to dispersed that do not have electricity, may not have automation and may have limited space for existing automation to accept additional inputs into their programmable logic controller (PLC) and remote transmitting unit (RTU). Although it may be appropriate to evaluate control devices similar to those found in NESHAP HH major sources, it is not appropriate to arbitrarily invoke compliance assurance requirements intended for the maximum control of hazardous air pollutants (HAPs) as the standard for RACT guidelines for the control of volatile organic compounds (VOCs).

Examples of the inappropriateness of invoking MACT compliance assurance requirements for RACT guidelines include but are not limited to:

- E.2(a) of the model rule requires Continuous Parameter Monitoring System (CPMS) for control devices. EPA did not include the cost for installing, maintaining, and operating a CPMS in any of the impact assessments for this rulemaking. Most affected facilities in the production segment of the industry will be located in remote areas without available electricity or limited remote transmitting unit (RTU) space. In addition, a programmable logic controller (PLC) is often needed to record, average, and analyze the large amounts of data to determine if a parameter is exceeded, resulting in activation of a control system or signal for site visit evaluation. The calibration, maintenance, and repair of a CPMS requires specialized crafts knowledgeable in instrumentation and controllers. This work cannot be performed by lease operators during normal inspection visits.

- E.2(f)(1) of the model rule requires the operator to establish minimum and/or maximum values for the operation parameter and operate the control device within the range. As explained in section 9.3.4, this requirement is impractical to meet for either manufacturer certified combustors or combustion controls where the performance test is performed in the field, but for different reasons. This requirement is the same as the NESHAP HH requirement located in §63.773(d)(5)(i)(a) & (c).

- Similar to above, E.2.(d)(1)(iii) of the model rule requires that a flare pilot be assured by a heat detection sensor and continuous controller. Section E.2(a) of the model rule makes this appear to be a CPMS requiring all of the assurance provisions of (c), (f) and (g). This requirement is essentially identical to the one in §63.773(d)(3)(i)(C) with the CPMS general provisions located §63.773(d)(1) requiring to meet (4), (6), & (7). Requiring a pilot monitoring device to meet the requirements for a CPMS is extremely burdensome for any rule but is unprecedented for RACT regulations.

- Compliance Demonstrations (E) and Test Methods (F). EPA reference methods that determine percent reduction on a mass basis, as is specified in Subpart HH major source control requirements where the CTG model rule does not specify percent reduction of a pollutant on a mass basis. This causes the measurement of volume that is not practical or in many cases possible with the types of operations and fluid flows typical for these facilities.

9.2.2 Compliance Assurance Requirements Are Unnecessarily Complex

The use of extensive cross referencing both between sections concerning control devices (i.e., E.1 for initial compliance requirements, F for performance testing, and E.2 for continuous monitoring requirements) and various test methodologies renders the requirements confusing and nearly impossible to follow. These segmented requirements unnecessarily add to the compliance burden, and likely to lead to errors and misunderstanding. Companies that operate stationary sources subject to EPA's NSPS and NESHAP regulations may have personnel whose sole job is to understand EPA's complex requirements. However, many companies regulated by these RACT rules are primarily small businesses that do not have this luxury. API members along with the consultants they have hired have had difficulty in interpreting the requirements for control devices as proposed. There is still not agreement of interpretation within API with many of the provisions.

9.2.3 The Compliance Assurance Requirements For Centrifugal Compressors Are Not Justified

During discussions with EPA, API was told that the control device monitoring and testing requirements of the 2012 rule were retained since few centrifugal compressors were expected to require control and that most of these affected sources would be located at more developed facilities, such as Natural Gas Processing Plants. While this statement may sufficiently explain the retention of some of the monitoring provisions, it does not address the practical considerations in complying with the performance test provisions and the identifying parameter ranges required for the continuous monitoring. Although there are few centrifugal compressors that require control, almost all of the control devices they are connected to also fed with gases from other sources, such as storage vessels, that bring in the impracticality of flow measurement discussed in Section 9.1.3.

9.2.4 The Proposed Compliance Assurance Requirements For Pneumatic Pumps Have Numerous Problems

There are many issues with the proposed compliance assurance provisions for pneumatic pumps. Following are two major issues associated with the compliance assurance requirements. These are discussed at length in Section 15.0

Compliance Assurance Requirements of an Existing CVS/Control Device Should Not Change

EPA determined that the benefit of controlling the discharge of a pneumatic pump was insufficient to justify the installation of a control device, thus the requirement to only connect new pneumatic pumps to existing CVS/control device. Further, EPA only considered the cost of piping the pump discharge to the CVS but did not include costs for additional compliance assurance (see Section 15.3). Most control devices are expected to be installed due to state minor source NSR permits. These permits have their own compliance assurance requirements which are significantly different those in the CTG model rule, resulting in significant additional cost. These additional costs have not been included in EPA's cost analysis, cannot be justified with the low emission benefits achieved, and add no additional environmental benefit. Thus, API recommends that EPA should not require additional compliance assurance requirements in the CTG model rule for a CVS or control device when a pneumatic pump is connected to it (see Section 15.0).

Clarification is Needed When a Pneumatic Pump Must be Connected to a CVS/Control Device

There is significant uncertainty on when a pneumatic pump must be connected to a control device. Control device is an undefined term and defining it is a necessary first step to resolve this issue (see Sections 10.0 and 15.4.5). Another great source of uncertainty is when a boiler or process heater is considered a control device and when it is part of a process (see Section 10.0). API believes that pneumatic pumps should not be required to be routed to a boiler or heater.

Further, the control device and the pneumatic pump may be owned/operated by two different companies (i.e. chemical injection for gathering system corrosion control at a well site). In this case, even though a control device is at the location, it is not available to the owner/operator of the pneumatic pump (see Section 15.4.6). Finally, instances occur where it is not technically feasible to connect the pneumatic pump to the control device (see 15.3.3).

9.3 Compliance Assurance Requirements For Combustion Control Devices

9.3.1 The Proposed Compliance Assurance Requirements May Discourage The Use Of Enclosed Combustors

The design of enclosed combustors intrinsically yields higher destruction efficiencies than flares because of the heater style of burner and protection from cross wind. The enclosure also creates an induced draft of air that aids complete combustion of heavier (higher molecular weight) hydrocarbon streams. Additionally, the enclosure isolates the flame from sight that may cause concern to some members of the public. These benefits sometimes encourage industry to install the high cost internal (i.e., "enclosed") combustor instead of the commonly used open flame flare. Enclosed combustors do have the ability to be performance tested where the open nature of flares do not. It is ironic that EPA is requiring substantially more burdensome monitoring and performance testing requirements for enclosed combustors in the proposed rule, even though these combustors have greater environmental benefit than flares. It is counterproductive for the environment to disadvantage enclosed combustors with compliance assurance requirements, just because they are technically feasible. EPA should encourage the use of enclosed combustors by using the same visual inspection requirements as with flares for opacity.

9.3.2 The Continuous Parameter Monitoring System (CPMS) Provisions Are Inappropriate

In section A.4(c) of the model rule, continuous parameter monitoring and the comparison of daily average parameter monitoring results against site-specific maximum or minimum values established during the performance test are required for storage vessels. For the reasons stated below, EPA has not justified these requirements and must not include them in the final CTG model rule.

First, these RACT requirements are considerably more stringent than the BSER requirements proposed for NSPS subparts OOOO and OOOOa. For those NSPS, EPA did not propose any parameter monitoring for storage vessel control devices. RACT-level requirements should, by definition, generally be less stringent than BSER. In this case, EPA has included RACT monitoring requirements for storage vessel control device monitoring that are orders of magnitude more stringent than the BSER requirements in the NSPS.

Second, EPA did not justify the significant additional cost of this continuous monitoring. In fact, EPA did not include costs of monitoring equipment in their capital cost estimates, nor did they include any annual costs associated with the maintenance of this system or for the collection and maintenance of this monitoring data.

9.3.3 The Determination Of CPMS Range Determinations In Field Performance Test Is Technically Impractical

Section E.2(f)(1) of the model rule requires that for any parameter that requires CPMS monitoring, the operator must determine the minimum or maximum value of the parameter that continuously achieves the performance requirements in E.1(a). E.2(f)(1)(i) requires a performance test performed by the operator to determine the minimum or the maximum operating parameter based values measured during the performance test. However, the operator has limited ability to adjust the conditions of the process to test the control device. The performance test must be run at the conditions available when the test is scheduled. The operator is unable to vary the operating conditions to determine the limit of the operating parameter as a manufacturer does when conducting a shop test on an enclosed combustor. Section E.2(f)(1)(i) cannot practically be complied with, because the performance test cannot be completed at the full range of conditions for which the control device will be operated. Furthermore, this goes far beyond what EPA requires for testing control devices for NESHAP HH for area sources that apply to nearly all oil and natural gas production sites and approaches the NESHAP HH requirements for major sources like natural gas processing facilities. For a RACT rule at a remote, unmanned site, it is more reasonable to test the device during the current operating conditions.

9.3.4 It Is Not Technically Feasible To Meet The CPMS Flow Measurement Requirements For Manufacturer Certified Combustion Control Devices

Paragraph E.2(f)(1)(iii) requires that for manufacturer certified enclosed combustors, an operator must install CPMS measurement on the inlet flow to assure that the flow is not greater than the maximum or less than the minimum that the manufacture specifies. As explained in section 9.1.3, the measurement of flow from storage vessels is very difficult, even when only the normal emissions must be measured. With both the minimum and maximum range to be measured, it is doubtful if a single instrument can measure both values. The pump flow as well is intermittent low pressure, low velocity/flow and difficult to measure as discussed in Section 15.0.

9.4 Compliance Options For Combustion Control Devices

Section E.1(a)(1) specifies four compliance options that can be used to assure compliance with the combustion control device requirements. These options include (1) percent reduction of the pollutant, (2) limiting the concentration in the exhaust, (3) maintaining a minimum combustion zone temperature, and (4) inject the stream into the flames zone of a boiler or process heater. Comments are provided below on options 1 and 2. As explained in Section 10.0 below, option 4 is a direct conflict with the definition of "route to a process", and therefore, API recommends that EPA remove E.1(a)(1)(iv) and (d)(4)(iv).

9.4.1 Percent Reduction Of Pollutant Should Be Based On Volume Not Mass And Should Not Require Measurement of Flow to the Control

The standards for centrifugal compressors, pneumatic pumps, and storage vessels each require a percent reduction.

- For centrifugal compressors, C.2(a) requires that VOC emissions be reduced by 95.0 percent or greater
- For pneumatic pumps located between the wellhead and point of custody transfer, H.2(b)(1) requires that natural gas emissions by 95.0 percent, and
- For storage vessels, A.2(a) requires that VOC emissions be reduced by 95.0 percent

Note that in none of these standards specify the basis for the 95.0 percent reduction. However the initial compliance demonstration requirements in E.1 add the requirement that this percent reduction in emissions be determined on a mass basis. The associated performance test requirements for calculating percent reduction by weight of pollutants requires the measurement of flow to the control device. These requirements were predominantly adopted from the major source NESHAP requirements in Subpart HH that specify control requirements of 95 percent reduction by weight. While mass reduction requirements may be appropriate and specified by Subpart HH, they are burdensome and impractical for RACT requirements for small, remote, dispersed and unmanned production facilities.

Section 9.1.3 above describes the many difficulties encountered when attempting to measure the flow of vapors to a control device at oil and natural gas production sites. EPA has not explained the reason for prescribing the reduction of pollutants to be determined by weight in the compliance demonstration and performance testing requirements when a mass destruction was not specified as part of the control requirements. Conditions of intermittent high/low flow conditions, variable and turbulent flow, and variable temperature and pressure make it infeasible to perform the test methods in the production field that are typically used in refineries or chemical plants. Coupled with the dispersed and remote nature of the small sources regulated under this rule, the proposed requirements are not appropriate and are unnecessarily burdensome. API requests EPA to determine percent of TOC reduction through a carbon balance methodology similar to that described in EPA's Flare Efficiency Study Report.[12]

The requirement in E.1(a)(1)(i), E.1(d)(1), and E.1(d)(2) should be modified to require reduction of TOC emissions by 95% on a volumetric concentration basis using a "carbon balance" methodology for analysis of the exhaust stack effluent from an "enclosed combustion device" being used as a control device to demonstrate reduction efficiency.

Methodologies 25A for TOC (calibrated to propane), 3A for CO_2 and O_2, and 10 for CO should be specified for testing of the stack effluent gas. The CO_2 measured using Method 3A should be adjusted downward by the latest published atmospheric CO_2 concentration, as reported from the Mauna Loa monitoring site by NOAA's Earth System Research Laboratory, multiplied by the ratio of O_2 measured in the stack effluent as compared to the ambient O_2 content of 20.8 volume %. (3A measured CO_2 (ppmv) – (Mauna Loa Concentration (ppmv) X (3A measured O_2 (ppmv)/208,000 (ppmv) ambient O_2 concentration).

The percent pollutant reduction or destruction efficiency of 95% would be demonstrated when the following equation yields a value of 95% or greater:

$$(CO_{2c} + CO)/(CO_{2c} + CO + (3*TOC))$$

Where:

CO_{2c} = CO_2 ppmv concentration measured in the stack via method 3A minus the ambient CO_2 ppmv concentration present in the stack determined as described above.

CO = CO concentration measured in the stack via method 10

TOC = Total Organic Carbon, expressed as propane, measured in the stack via method 25A

The following table shows this calculation and outcome for an assumed stack effluent composition:

Table 9-1 Assumed Stack Affluent Composiiton

Outlet CO_2	30,000	Measured Value
Outlet CO	100	
Outlet TOC	30	
Outlet O2	150,000	
Ambient O2	208,000	
Ambient CO_2	388	

[12] . Technical Report "EPA-600/2-83-052" "FLARE EFFICIENCY STUDY" by Marc McDaniel, July 1983 (see http://www3.epa.gov/ttn/chief/ap42/ch13/related/ref_01c13s05_jan1995.pdf).

Outlet CO_{2c} from combustion	29,720	Outlet CO_2 - ((Ambient CO_2 X (Outlet O2/Ambient O2))
Destruction Efficiency	99.70%	(CO_{2c} +CO)/(CO_2c +CO+(3*TOC))

9.5 EPA Must Revise The Provisions Related To Flares Subject To §60.18

9.5.1 There Are Technical Challenges In Meeting The §60.18 For Flares In Oil and natural gas Production And Gas Processing That Must Be Addressed

Flares are an attractive control device choice for the oil and natural gas industry due to their simplicity, reliability, lower maintenance requirements, and effectiveness in reducing organic compound emissions. The requirements in §60.18 of the 40 CFR part 60 General Provisions were developed by EPA to generally apply to flares. However, these requirements were developed and refined based on industrial flares primarily used at large petroleum refineries and petrochemical plants. As discussed above in section 9.1, there are unique aspects of the oil and natural gas industry that require accommodations in the control device requirements. The following sections suggest changes related to the application of the §60.18 provisions to Subpart OOOO and OOOOa affected facilities that will allow the compliant use of flares in the oil and natural gas industry without compromising their effectiveness in reducing VOC and methane emissions.

9.5.2 The Use Of Electronic Ignition Systems Should Be Allowed

§60.18(c)(2) requires that flares shall be operated with a flame present at all times, as determined by monitoring using a thermocouple or any other equivalent device to detect the presence of a flame.

API continues to believe that an option to use electronic ignition systems should be allowed for the oil and natural gas sector. Since oil and natural gas operations are not always steady state, flares with continuously lit pilots (24/7) can unnecessarily burn and waste fuel gas for the pilot while causing unnecessary emissions when there is otherwise no emissions stream being burned. An attractive and effective alternative is to allow the use of electronic ignition systems that ensure a flame is present whenever emissions are being routed to the flare.

In addition, many oil and natural gas production sites are remote and unmanned. In these situations, an electronic ignition system has proven to be a more reliable means of ensuring there is always a flame when emissions are routed to the flare than attempting to maintain a continuous pilot.

In the Natural Gas STAR program, EPA published a Partner Recognized Opportunity (PRO) in PRO Fact Sheet No. 903.[13] Presumably this was published because EPA approves of the design, recognizes its benefits and wanted to promote its use in industry. EPA should not forfeit the benefits of this control technology enhancement by disallowing its use. As an established and

[13] http://www3.epa.gov/gasstar/documents/installelectronicflareignitiondevices.pdf

preferred technology by EPA in the Natural Gas STAR program, operators should not have to petition EPA for approval.

API recognizes the need to ensure that the electronic ignition system is working and that a flame is present at all times when emissions are being routed to the flare. API believes that the existing requirements in §60.18(f)(2) already provides an appropriate requirement: Paragraph (e) states that "Flares used to comply with provisions of this Subpart shall be operated at all times when emissions may be vented to them" and (f)(2) states "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." With the simple amendments to F(a)(1) and E.2(d)(1)(iii) shown below, EPA can allow the use of auto-ignition devices while also ensuring compliance.

Specific recommendations for these amendments are provided in section 9.5.5.

9.5.3 Testing Should Not Be Required To Demonstrate Compliance With §60.18(f)(4)

Paragraph 60.18(f)(4) requires that the volumetric flow rate be "*determined by Reference Methods 2, 2A, 2C, or 2D as appropriate*". As a result, a test will be required for every flare used to comply with the CTG model rule. As discussed in section 9.1, the measurement of flow is impractical and potentially impossible at oil and natural gas production sites. In addition, even if these technical challenges were ignored, EPA's estimate of impacts did not include significant costs that would be incurred by the industry.

While not specifically referenced in this paragraph, the provisions in §60.8(c) require that performance tests be conducted on conditions that reflect "*representative performance of the affected facility*." During representative conditions, the exit velocities of the flare at oil and natural gas sites will never approach 400 feet per second. This can be easily demonstrated through the use of engineering calculations rather than testing or direct measurements. Specific changes must be made to F(a) to correct this situation. The recommendations for these amendments are provided in section 9.5.5

The technical challenges related to volumetric flow rate are not unique to storage vessels in the production segment. At many gas processing plants, pressure release devices are often routed to flares along with the emissions from other equipment. While there are typically no emissions from these pressure release devices, they can develop leaks. Under subparts OOOO and OOOOa, these pressure relief devices are subject to §60.482-4a(a) of NSPS subpart VVa. Since these pressure release devices are routed to a "closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device", they are exempt from the LDAR requirements in §60.482-4a(a) and (b), but are subject to the closed vent system and control device requirements of §60.482-10a. Paragraph §60.482-10a(d) requires flares to comply with §60.18. The leaks that would occur from these pressure release devices would be very low, meaning that the difficulties in measuring the flow to these flares results in costly test programs that are entirely unnecessary given the extremely low flow rates. Therefore, API also recommends that the volumetric flow rate for these flares also be allowed to be determined using engineering calculations. API suggests that paragraphs be added to G.3 to address this technical infeasibility situation. These recommendations for these amendments are provided in section 9.5.5.

9.5.4 Sonic And Other Flares Operated During Maintenance, Startup, Shutdown, And Malfunction Situations Should Not Be Required To Comply With The Exit Velocity Requirements In §60.18(c)(4)

In EPA's September 18, 2015 Federal Register Notice (80 FR 56646), EPA specifically requested comment on the use of pressure-assisted flares in the oil and natural gas industry.

As EPA notes, pressure-assisted, or sonic, flares are designed to exceed §60.18's maximum exit velocity of 400 feet per second. As a result, they do not meet §60.18. Some facilities with potential large volume flows may utilize sonic flares, such as those included at onshore natural gas processing facilities, to control emissions in times of emergency, upsets, or maintenance. Sonic flares offer advantages over traditional low-pressure flares in some applications. For example, some designs allow smokeless operation over the entire operating range without any assist medium. This is a clear benefit for remote areas. Additionally, with no assist medium, energy usage and its related emissions are minimized and there remains no potential for steam/air over-assist. Some designs also offer less low frequency noise and less flame visibility in low profile designs. Sonic flares operate with destruction efficiencies that are at least as equivalent to, and generally greater, than low pressure flares.

Pressure-assisted (sonic) flares are not designed for continuous use, but instead operate in emergency, upset or maintenance situations where high volumes and pressures are sent to the flare. In some scenarios, pressure relief valves subject to LDAR monitoring are routed to sonic flares for the purpose of emergencies or upsets. Maintenance events are also routed to these flares in some cases.

However, a conflict with the velocity limits in §60.18(c)(3) is not limited to the case of pressure-assisted flares. Velocity limits for commonly used low-pressure flares (ground or elevated steam-assisted, air-assisted or unassisted flares) are achievable under representative day-to-day conditions. However, velocity limits for even low-pressure flares can be exceeded under conditions that approach the hydraulic capacity of flares. General application of §60.18(b) to a Subpart without the inclusion of §60.11 or an alternative exemption for periods of emergency, upset or maintenance is problematic.

Flares designed under §60.18(b) may exceed velocity limits during periods of emergency, upset or maintenance. In order to remain in compliance with the velocity limits, flare operators would need to install additional flare capacity for SSM events either by replacing an existing flare or adding additional flares. Therefore, the exemption from the §60.18 maximum velocity requirements should not be limited to pressure-assisted flares, but rather to all flares during periods of emergency, upset, or maintenance. As discussed in section 9.5.6 below, there is substantial evidence that indicates that the performance of flares will be maintained at these higher velocities.

Therefore, in order to allow the use of sonic flares and traditional flares designed under §60.18(b) for the oil and natural gas industry, EPA should exempt flares from the maximum velocity requirements in §60.18(c)(4).

Revisions are needed to F(a) and to G to allow the use of flares in these situations. The recommendations for these amendments are provided in section 9.5.5.

9.5.5 Recommended Model Rule Changes To Address Issues With Flare Requirements

Following are the recommended rule changes related to the issues discussed above that are related to the requirement that flares used for compliance with the CTG model rule comply with the requirements of §60.18.

G.3

(h) For a flare that is subject to §60.18 via §60.482-10a(d), the volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the process unit. In addition, the velocity limits in §60.18(c)(3) do not apply during periods of emergency, upset, or maintenance.

E.1

(d) Each control device used to meet the emission reduction standard in section A.2 for a storage vessel must be installed according to paragraphs (d)(1) through (45) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a control device model tested under section F(d), which meets the criteria in section F(d)(11) and F(e).

* * * * *

(3) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes from working or flash losses are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

* * * * *

(5) You must design and operate a flare in accordance with the requirements of section F.

F(a)(1)

(1) A flare that is designed and operated in accordance with §60.18(b), with the exceptions noted in paragraphs (a)(1)(i) through (iii) of this section. You must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(i) A flare that is equipped with an electronic ignition system will satisfy the requirements in §60.18(c)(2) and (e),

(ii) The volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the centrifugal compressor, pneumatic pump, or storage vessel affected facility, and

(iii) During periods of emergency, upset, or maintenance, the velocity limits in §60.18(c)(3) do not apply.

E,2(d)(1)

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the ~~continuous ignition of the pilot flame~~ presence of a flame as required in E.1(d)(3).

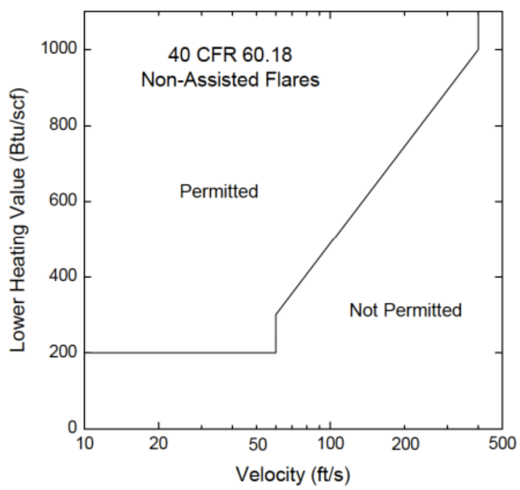
9.5.6 Velocity Limits in §60.18(c)(3) Are Unnecessary To Ensure High Destruction Efficiency in Flares

There is substantial evidence that flares operating with higher exit velocities are effective in reducing emissions. Following is a discussion of this evidence. [14]

Origins of Existing Flare Velocity Limits

The velocity limits in 40 CFR 60.18 were originally promulgated on January 21, 1986 and are graphically depicted below. The figure shows flame exit velocities in feet-per-second (fps) along the x-axis and lower heating value of the waste gas in Btu per standard cubic feet (scf) along the y-axis. A minimum heat content is required of 200 Btu/scf for unassisted flares or 300 Btu/scf for assisted flares up to 60 fps, where the required heat content increases as a function of exit velocity until a maximum allowable velocity of 400 fps is reached.

Figure 9-1 Current EPA Flare Velocity Limits



This relationship was developed following a series of EPA sponsored tests conducted in the 1980's that examined how various flare operating parameters, including velocity, affect flare performance. The tests with relevance to the current velocity requirements are the 1983 McDaniel[15] test and the 1984 Pohl[16] test. The focus of the 1985 Pohl[17] and 1986 Pohl[18] studies was not on high velocity, but any test runs from these studies where the exit velocity of the flare was greater than 60 feet per second (fps) have been included in this analysis.

The 1986 limits appear to originate with only four data points from these tests – the average value at the upper limits of each study. The 60 fps, 300 Btu/scf limit for steam-assisted flares was set

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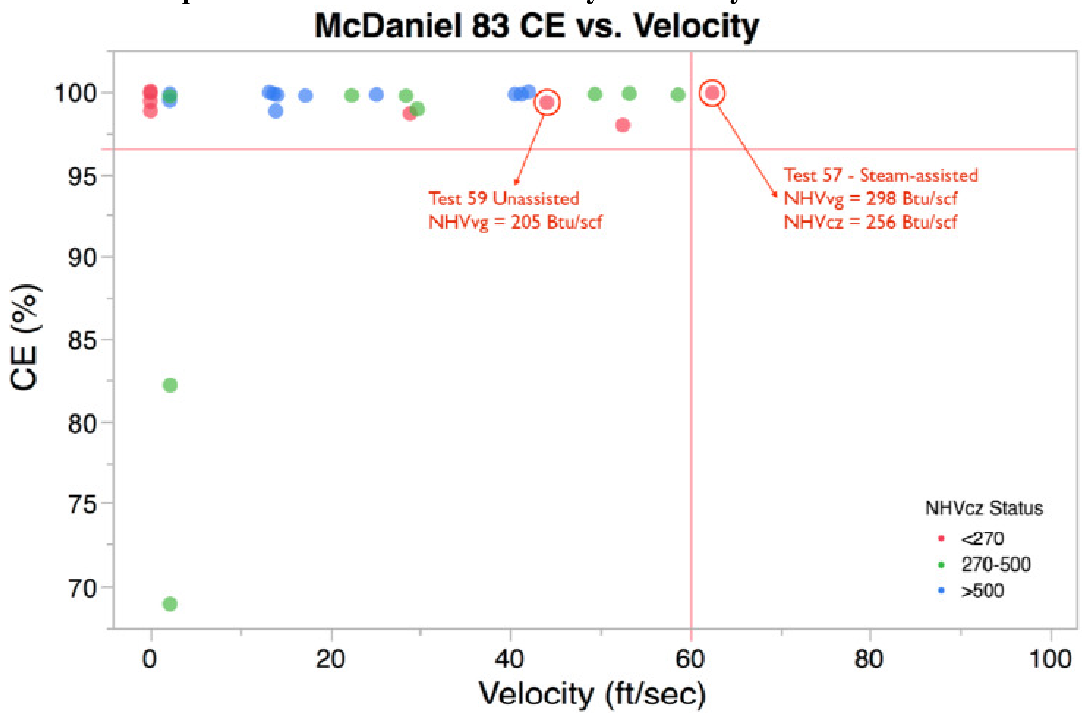
[14] Adapted from "A Review of Flare Velocity Limits in 40 CFR 60.18 and 63.11." Prepared for American Petroleum Institute October 26, 2014 by Scott Evans.
[15] McDaniel, M.; "Flare Efficiency Study," EPA-600/2-83-052, July 1983
[16] Pohl, J., et. Al.; "Evaluation of the Efficiency of Industrial Flares: Test Results," EPA-600/2-84-095
[17] Pohl, J, and Soelberg, N.; "Evaluation of the Efficiency of Industrial Flares: Flare Head Design and Gas Compostion," EPA-600/2-85-106, September 1986
[18] Pohl, J, and Soelberg, N.; "Evaluation of the Efficiency of Industrial Flares: H2S Gas Mixtures and Pilot Assisted Flares," EPA-600/2-86-080; September 1986

based on a single data point -- McDaniel 1983[15] test 57. The 200 Btu/scf limit for unassisted flares was also set based on a single data point – McDaniel test 59. These tests were performed on an 8.6-inch steam-assisted flare fueled with a propylene/nitrogen mix. The data are shown in

Figure 9-3. The data are binned by heat content, where red dots indicate test runs whose combustion zone net heating value (NHVVG) is less than 270 Btu/scf, green dots indicate test runs with NHVVG between 270 and 500 Btu/scf, and blue indicate test runs with NHVVG greater than 500 Btu/scf.

Figure 9-2 A Comparison of Combustion Efficiency vs Velocity for McDaniel 1983

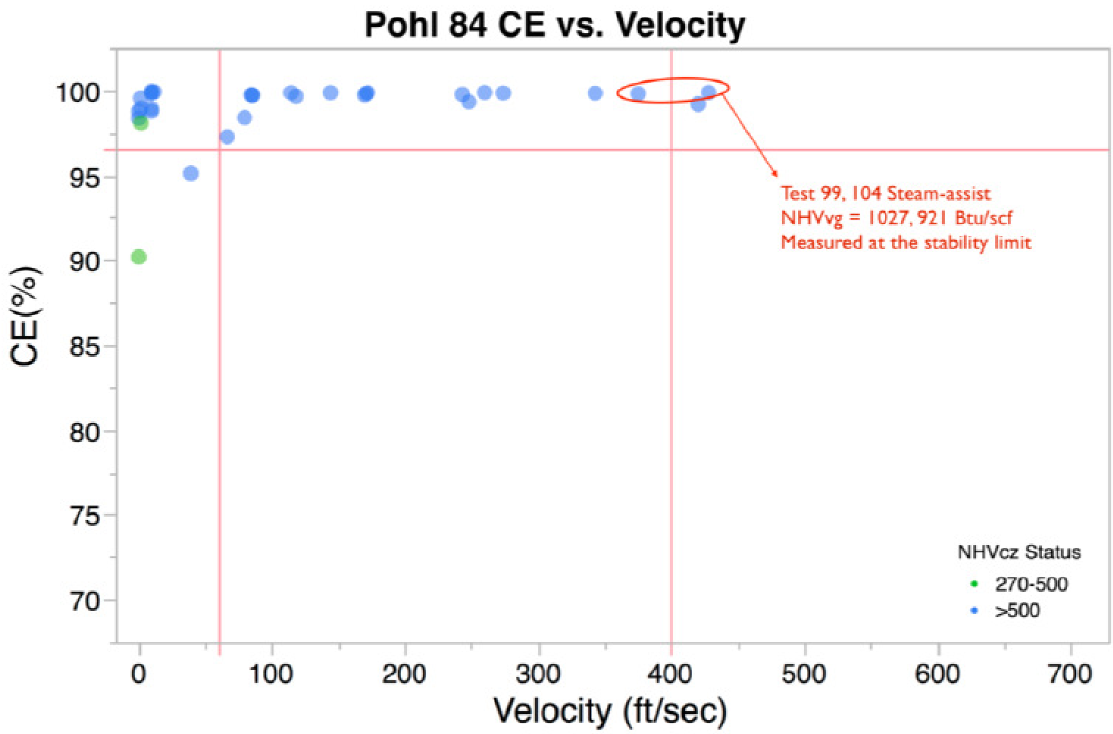


McDaniel did not collect data at velocities higher than 60 fps. At the 60 fps upper limit of the data, combustion efficiency remained very high and with no evidence of a trend toward lower combustion efficiency. These data were used to establish the 60 fps velocity limit although there is no evidence that operating at higher velocities results in degraded combustion efficiency.

The 400 fps, 1,000 Btu/scf limit appears to be set based on two data points from flame stability test runs 99 and 104 from Pohl 1984.[16] That study was performed on a 3-inch steam assisted flare fueled with a propane/nitrogen mix. These data are shown in

Figure 9-3. The data are binned by heat content, where green dots indicate test runs with NHVCZ between 270 and 500 Btu/scf and blue indicate test runs with NHVCZ greater than 500 Btu/scf.

Figure 9-3 A Comparison of Combustion Efficiency vs Velocity for Pohl 1984



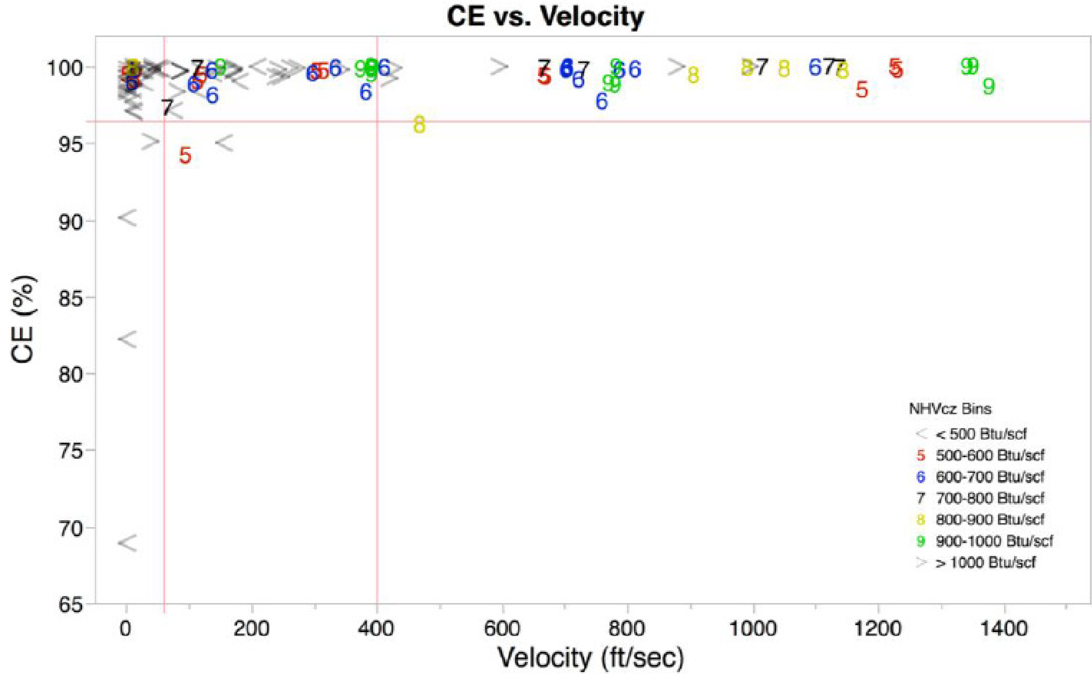
Similarly to the data used to establish the 60 fps limit, data collected in this study were not collected at velocities higher than the upper limit of 400 fps. As in McDaniel 83, Pohl 84 showed no evidence of a trend towards lower combustion efficiency at the upper velocity limit measured. These data were used to establish the 400 fps limit although there is no evidence that operating at higher velocities results in degraded combustion efficiency.

High Velocity Flare Test Data

Figure 9-4 shows all data from publically available high velocity flare tests as of October 2014. Some low velocity data are also included to the extent that they were measured during a test series including high velocity data. Data includes the 1980's flare studies referenced above as well as more recent studies (Marathon Garyville[19] and Dow[20]). This data is similarly displayed based upon combustion efficiency (CE) as a function of exit velocity in fps. The data is binned by combustion zone net heating value (NHVCZ) in groups of 500 Btu/scf. Only data with NHVcz > 270 are included.

[19] Clean Air Engineering, "Performance Test of Steam-Assisted and Pressure-Assisted Ground Flare Burners with Passive FTIR – Garyville," March 21, 2013
[20] Varner, V., Kodesh, Z.; "Emission Testing of Pressure Assisted Flare Burners," Presented at the American Flame Research Committee 2014 Industrial Combustion Symposium, September 2014

Figure 9-4 A Comparison of Combustion Efficiency vs Velocity for All Publically Available High Velocity Flare Tests binned by NHVcz Range



Almost all of the low velocity data that also have low CE have NHVcz values less than 500 Btu/scf. Additionally, virtually all of the test runs with velocity greater than the current limit of 400 fps, were conducted at NHVcz values less than the current 1,000 Btu/scf limit. This graph clearly shows that high combustion efficiency above the current limits is not only possible, but that it is assured based upon available test data.

Flame Stability

The claim is often made that the reason velocity limits are necessary is to ensure "flame stability." However, flame stability has been defined differently in different studies. McDaniel did not address flame stability. Pohl defines flame stability as:

The term "flame stability" simply means that a flame is maintained; flame instability occurs when the jet velocity exceeds the flame velocity and the flame goes out. [Pohl 84, p2-3]

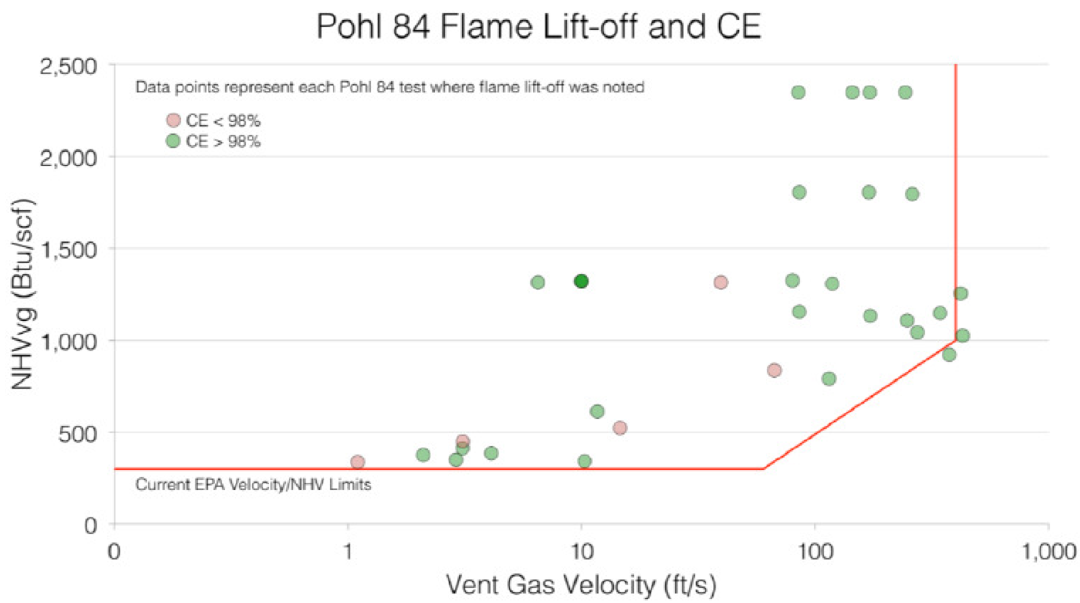
Others[21] have defined flame stability in terms of "lift-off", a conditions that occurs when the base of the flame detaches from the flare tip.

While there is no doubt that Pohl's definition results in unacceptable flare performance, there is little evidence that flame lift-off has any correlation either positive or negative to combustion

[21] Shore, D., "Improving Flare Design: A Transition From Art-Form to Engineering Science," Presented at AFRC-JFRC October, 2007.

efficiency. Figure 5 shows every data point from Pohl 84 where flame lift-off was noted in the report.

Figure 9-5 A Comparison of Flame Lift-Off and Combustion Efficiency from Pohl 84



27 of the 32 lifted flames showed high combustion efficiency. None of the remaining five points had measured combustion efficiency below 91%. Figure 9-5 clearly shows that flame lift-off does not affect combustion efficiency over a wide range of velocities and net heating values.

Concern over flame lift-off affecting combustion efficiency is not supported by the data. The only definition of flame stability with relevance to velocity limits is Pohl's definition… a high velocity flame is stable until it goes out.

There is also no evidence of a gradual decline of combustion efficiency when approaching the point where the flame is extinguished or the "snuff point." Both the Pohl 84 data and the Marathon Garyville data were collected as near as possible to the snuff point while still maintaining a flame. No evidence of degraded combustion efficiency was noted.

Conclusion

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 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.

9.6 While EPA Has Been Testing Various Manufacturer Devices, The Process Has Been Slow

The CTG model rule allows for the use of combustion devices that are tested by the manufacturer which eliminates the need for source testing at the site. This has been allowed under NSPS Subpart OOOO (40 CFR 60, Subpart OOOO) and MACT HH and HHH (40 CFR 63, Subparts HH and HHH), for several years. EPA maintains a list of approved Combustion Control Devices[22] on their website. EPA has also stated that the current "approved list" will be adopted for OOOOa. API requests confirmation of this in the response to comments to reflect EPA's intent.

However, there are several issues with the approval process. First, more than half of the devices listed on the website are characterized as "under review", and they have maintained this status for a long period of time (one or more years). According to one manufacturer, the approval process should be less than a month. The CTG will result in the need for many more combustion devices to control existing sources, which increases the need to shorten the approval process. Closer inspection revealed that incomplete test reports may be a possible cause for achieving "under review" status, and therefore it may not be a fault of EPA's process. However, EPA needs to investigate the cause for these long delays in this approval process and correct them.

Second, manufacturers report that relief from propene testing would decrease the testing costs considerably. The requirement for propene testing for combustion devices that will be used at oil and natural gas production facilities seems illogical as there are insignificant amounts of double bond hydrocarbon compounds in natural gas. API requests that F(d)(2)be modified as follows to allow the use of propane to expedite the approval process.

> (2) Performance testing must consist of three 1-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. ~~Propene (propylene)~~ Propane gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

10.0 EPA MUST ELIMINATE THE CONFUSION AND CONFLICT ASSOCIATED WITH "CONTROL DEVICE" AND "ROUTED TO A PROCESS"

It is clear from the model rule control requirements for centrifugal compressors at C.2(b), pneumatic pumps at H.2(b)(4), and storage vessels at A.2(b)(1) that "route to a process" was intended as an alternative to a control device. For example:

A.2(b)(1): Except as required by paragraph (b)(2) of this section, if you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of Section D.1(a), that is connected through a closed vent system that meets the requirements of section D.1(b), and routed to a control device that meets the conditions specified in paragraph (b)(3)(i) and (ii) of this section. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

[22] http://www3.epa.gov/airquality/oilandgas/pdfs/mantesteddevices.pdf

However, the definitions and provisions related to "control device" and "routed to a process" are inconsistent and confusing, and in some instances, conflicting. This is particularly the case with regard to boilers and process heaters. The following sections highlight these issues and suggest a recommendation that will eliminate the confusion and conflicts without any reduction in the effectiveness of the rule.

10.1 Definition Of "Routed To A Process" Should Be Clarified

The CTG model rule includes the following definition:

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered. Salable quality gas means natural gas that meets the flow line or collection system specifications, regardless of whether such gas is sold.

The use of "routed to a process" is clear as used in connection to a VRU, as these emissions are recycled and incorporated into a product.

This definition also unmistakably applies to situations where the emissions are combusted in a boiler or process heater. There are three different ways in which hydrocarbon vapors can be fed into a boiler or process heater for destruction – 1) vapors routed to the flame zone, 2) vapors routed to the fuel system as a primary fuel, and 3) vapors routed to the combustion air supply as a secondary fuel. For all three of these methods of introducing hydrocarbon emissions into a boiler or process heater the emissions are clearly "consumed in the same manner as the material that fulfills the same function in the process" Further, the emissions are "transformed by chemical reaction into materials that are not regulated materials". However, the CTG model rule is not as clear how this definition applies for boilers and process heaters. EPA must clarify this linkage between "routed to a process" and boilers and process heaters throughout the model rule.

Despite the fact that EPA defined routed to a process/route to a process in a manner that would include all situations when emissions are routed to a boiler or process heater, there are instances throughout the model rule where EPA appears to consider boilers and process heaters as control devices. For example, in E.1(a)(1), EPA includes boilers and process heaters in a parenthetical describing a combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater). Similarly, this same parenthetical description of enclosed combustion device in in E.1(d)(1). Further, in the list of "control devices" exempted from performance testing in F(a), there are several specific boiler and process heater examples that are exempted.

One of these exemptions, specifically F(a)(3), exempts boilers or process heater "into which the vent stream is introduced with the primary fuel or is used as the primary fuel." These seems to indicate that EPA draws a distinction between the three situations described above where emissions are routed to a boiler or process heater (even though they are all three clearly covered by the definition of "routed to a process").

The recommended changes discussed below resolve this conflict.

10.1.1 NSPS Subparts VV And VVa Include The Concept Of "Fuel Gas"

In the rulemakings for NSPS Subparts VV and VVa, EPA has addressed this same basic situation in a clear and reasonable manner. For example, §60.482-4a(c) states that:

> "Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in §60.482-10a is exempted from the requirements of paragraphs (a) and (b) of this section."

Further, Subpart VVa includes the following related definitions.

> *Fuel gas* means gases that are combusted to derive useful work or heat.
>
> *Fuel gas system* means the offsite and onsite piping and flow and pressure control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices or in-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.

API believes that this precedent can be utilized to improve the clarity in Subparts OOOO and OOOOa. This recommendation is provided below.

10.1.2 Recommended Change to Definition Of "Routed To A Process Or Route To A Process"

API recommends that the following changes be made to the definition of routed to a process or route to a process" in the CTG model rule.

> *Routed to a process or route to a process* means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered. Salable quality gas means natural gas that meets the flow line or collection system specifications, regardless of whether such gas is sold. Emissions used as fuel gas in a boiler, process heater, or other combustion device are considered to be routed to a process.

API further recommends that the following definition of fuel gas be added.

> *Fuel gas* means gases that are combusted to derive useful work or heat.

10.2 Definitions Of "Control Device", "Combustion Device", And "Combustion Control Device"

The confusion discussed above related to boilers and process heaters and routed to a process is acerbated by the fact that the CTG model rule does not define control device. In addition to this situation that needs to be corrected, the model rule requirements for pneumatic pumps make defining "control device" critical. This is discussed later in Section 15.4.5,

As discussed in Section 10.1.2, the definition of "routed to a process" clearly includes routing emissions to a boiler or process heater to be consumed, yet the CTG model rule discusses boilers and process heaters as control devices in other places.

In addition, the situation is further confused as EPA uses the terms "combustion device", "combustion control device", and "enclosed combustion control device" in an arbitrary manner that further confuses the situation. None of these terms are defined in the CTG model rule.

In conjunction with the recommended definitions in Section 10.1.2**API offers the following definitions to be added to the CTG model rule.**

> *Control device* means any equipment used for recovering or oxidizing volatile organic compound (VOC) or methane emissions. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, and combustion devices. Recovery devices that recycle the emissions back to the process, and combustion devices that use the emissions as fuel gas, are not considered control devices under this rule.
>
> *Combustion control device means* a thermal vapor incinerator, catalytic vapor incinerator, flare, or other combustion device that do not burn emissions as a fuel gas.
>
> *Enclosed combustion control device* means a combustion control device with an enclosure such that the flame is not an open flame.

This definition of control device, along with the definition of "routed to a process or route to a process" recognizes that routing to a process is not emissions control but rather a beneficial use or reuse of exhaust gases and vapors. Thus, routing pneumatic pump exhaust or compressor blowdown gas to be used as a fuel gas would not make heaters and boilers using these streams part of a control device.

In addition, the following changes are needed throughout the model rule to rectify the inconsistent usage of these terms throughout. These changes also address the changes related to boilers and process heaters and "routed to a process."

> **E.1**
>
> (a) Each control device used to meet the VOC emission reduction requirements must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a combustion control device model tested under section F(d), which meets the criteria in section F(d)(11) and section F(e).
> (1) Each combustion control device ~~(e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater)~~, except for a flare, must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (~~iv~~iii) of this section.
> * * * * *
> ~~(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.~~
> * * * * *
> (d) Each control device used to meet the emission reduction standard in section A.2 for a storage vessel must be installed according to paragraphs (d)(1) through (4) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a combustion control device model tested under F(d), which meets the criteria in F(d)(11) and F(e).
> (1) For each enclosed combustion control device ~~(e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater)~~ you must meet the requirements in paragraphs (d)(1)(i) through (iv) of this section.
> * * * * *
> (iv) Each combustion control device ~~(e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater)~~ must be designed and operated in accordance with

one of the performance requirements specified in paragraphs (i) through (iii) of this section.
~~(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.~~

F
(a) Performance test exemptions. You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (~~7~~5) of this section.
~~(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.~~
~~(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.~~
(~~4~~2) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, Subpart H; or you have certified compliance with the interim status requirements of 40 CFR part 266, Subpart H.
(~~5~~3) A hazardous waste incinerator for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 264, Subpart O; or you have certified compliance with the interim status requirements of 40 CFR part 265, Subpart O.
(~~6~~4) A performance test is waived in accordance with §60.8(b).
(~~7~~5) A combustion control device whose model can be demonstrated to meet the performance requirements of E.1(a) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.
* * * * *
(b)(3)(iv) Reserved ~~If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC (minus methane and ethane) across the device by comparing the TOC (minus methane and ethane) in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) exiting the device, respectively.~~

E.2
(b) Reserved ~~You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.~~
~~(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel.~~
~~(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.~~
* * * * *
(d)(1)(iv) Reserved ~~For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5°C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.~~
* * * * *
(d)(1)(viii) (A) The continuous monitoring system must measure gas flow rate at the inlet to the combustion control device. The monitoring instrument must have an accuracy of ±2 percent or better. The flow rate at the inlet to the combustion control device must not

exceed the maximum or be less than the minimum flow rate determined by the manufacturer.
(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the combustion control device.

11.0 THE PROPOSED BY-PASS DEVICE REQUIREMENTS ARE NOT REASONABLE AND WERE NOT JUSTIFIED BY EPA

EPA failed to consider the cost and technical feasibility of the audible alarm and notification via remote alarm at the nearest field office for non-secured by-pass device requirements. A remote alarm at a field office does not add any additional environmental benefit, where an onsite device meets the intent of the alarm requirements. There are several considerations for a field office to receive data from field locations including onsite equipment, programming, and installation and maintenance. Adding an alarm will require installation of new equipment requiring potentially a facility to be shut down and the equipment purged so that "hot work" can be performed to install the equipment which will result in additional emissions. Furthermore, a company would need a remote transmitter unit (RTU) installed or have an existing RTU with sufficient capacity to transmit a signal from the device to an operations center to notify the operations center. There are also cost from programming, installation, and maintenance of the alarm. Equipment and installation costs are several thousands of dollars for each data point, per site, routed into a system, even if existing monitoring equipment is located onsite. Ongoing support and maintenance of the monitored parameter is required to sustain operation

For bypass devices secured with a car-seal or lock-and-key type configuration, the requirement is for visual verification that the device is secured. The requirements for non-secured devices should be similar and only require verification if the alarm - whether audio or visual - has been triggered. Since there is a flow indicator present, the amount vented would be known. Following are recommended changes to the CTG model rule language:

D.1(b)(3)(i)(A)
(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and/or visible alarm~~, and initiate notification via remote alarm to the nearest field office,~~ when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere.

D.2(d)(1)
(d) For each bypass device, except as provided for in section D.1, you must meet the requirements of paragraphs (d)(1) or (2) of this section.
(1) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere. You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and/ot visible alarm when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere.

12.0 THERE IS UNNECESSARY OVERLAP AND REDUNDANCY BETWEEN THE COVER AND CLOSED VENT SYSEM AND FUGITIVE EMISSION REQUIREMENTS

EPA proposes fugitive monitoring like requirements for closed vent systems, but also includes closed vent systems in the definition of Fugitive Emission Components. This results in CVS being subject to both closed vent system requirements in Section D and the fugitive emission component monitoring requirements in Section I. This creates a situation which is unnecessarily duplicative and redundant. Specifically, EPA has required both optical gas imaging monitoring for the tank cover and the closed vent systems under Section I, as well as annual Method 21 (M21) monitoring and visual inspections for closed vent systems under Section D. This could result in as many as three different leak detection programs at a single facility.

To avoid this conflict, API provides recommendations that will eliminate this overlap while still ensuring that emissions from leaks from closed vent system components are minimized. The problem and API's recommendations are discussed in detail in Section 16.0.

TECHNICAL COMMENTS

13.0 STORAGE VESSELS

13.1 The Cost Analysis For Retrofitting Existing Storage Tanks With Controls Is Inadequate

In section 4.3.1.2 of the Draft CTG, EPA describes the control option of routing emissions to a combustion device. API agrees that a combustor is one of the technically feasible options to reduce VOC emissions from storage vessels. In this section, EPA estimates the cost impacts of a combustor. These costs are summarized in Table 4-5 of the CTG. However, this cost analysis is inadequate in several respects, ranging from simple mathematical errors to the omission of cost elements that EPA includes in their own guidance. Section 10.1.1 summarizes the background for EPA's cost estimate. This is followed by section 10.1.2, which discusses the numerical errors and section 10.1.3, which shows how EPA omitted costs identified in the EPA OAQPS Control Cost Manual from the analysis.

Note that these corrections do not account for the testing, monitoring, and other compliance costs that are included in the CTG model rule, as discussed in section 9.0. If EPA maintains these onerous requirements in the final CTG, they must update the cost analysis further to include these costs.

13.1.1 *Basis For Draft CTG Cost Estimate For Combustors For Storage Vessels*

EPA evaluated costs for control of vapors from storage vessels as described in the 2012 Technical Support Document (2012 TSD) for NSPS OOOO.[23] As stated in section 7.3 of the 2012 TSD, cost data for a combustor were obtained from an Initial Economic Impact Analysis prepared for the proposed State-only revisions to a Colorado regulation (2008 Colorado EIA),[24] which were assumed to be in 2007 dollars. EPA escalated the costs to 2008 dollars using the Chemical Engineering (CE) Indices for 2007 (525.4) and 2008 (575.4),[25] or a factor of 1.0952. EPA also added estimated costs for operating and maintenance labor. These cost data are summarized below in Table 13-1.

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[23] U.S. EPA, "Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution," Background Supplemental Technical Support Document for the Final New Source Performance Standards, April 2012.

[24] Initial Economic Impact Analysis for Proposed State-Only Revisions to the Colorado Air Quality Control Commission's Regulation Number 7, "Emissions of Volatile Organic Compounds." September 18, 2008.

[25] Economic Indicators: Chemical Engineering Plant Cost Index. Chemical Engineering Magazine.

Table 13-1 NSPS Subpart OOOO Cost Analyses for Combustor for Storage Vessels

			NSPS 2012 TSD Table 7-5		NSPS 2012 TSD Table 7-5
Cost Item		Basis Year:	2007	(x 1.0952)	2008
Capital Costs Items					
	Combustor		$16,540		$18,114
	Freight and Design		$1,500		$1,643
	Auto Ignitor		$1,500		$1,643
	Surveillance System Instrumentation Auxiliary Equipment		$3,600		$3,943
	Combustor Installation Indirect Installation Sales Tax		$6,354		$6,959
	Storage Vessel Retrofit				
	Subtotal				
	Contingency				
Total Capital Investment			**$29,494**		**$32,302**
Annual Costs Items					
Operating Labor		*labor hours*	130		130
		labor rate	$33.51		$36.70
		supervisory hours	19.5		19.5
		supervisory rate	$52.85		$57.88
	Operating Labor		$5,387		$5,900
Maintenance Labor		*labor hours*	130		130
		labor rate	$33.51		$36.70
		supervisory hours	0		0
		supervisory rate	$52.85		$57.88
	Maintenance Labor		$4,356		$4,771
	Subtotal Labor		**$9,743**		**$10,671**
	Maintenance		$2,000		$2,190
	Pilot Fuel		$1,897		$2,078
	Make-up gas				
	Data Management		$1,000		$1,095
		interest rate (%)	7%		7%
		equipment life (years)	15		15
		CRF	0.1098		0.1098
	Capital Recovery ($/yr)		$3,238		$3,547
	Overhead				
	Administrative Charges				
	Property Taxes				
	Insurance				
Total Annual Costs ($/yr)			**$17,878**		**$19,580**
Control Threshold (tpy)			**6**		**6**
		control efficiency (%)	95%		95%
		emission reductions (tpy)	5.7		5.7
Cost Effectiveness ($/ton)			**$3,136**		**$3,435**

EPA evaluated costs in the draft CTG for control of vapors from storage vessels in a similar manner as for NSPS OOOO, with the costs adjusted to a 2012 basis. EPA referenced a more recent version of the Colorado Initial Economic Impact Analysis (2013 Colorado EIA)[26] for most of the costs, but relied on the cost given in the 2012 TSD for the surveillance system, with an adjustment of 5.69% to account for changes in cost from 2008 to 2012. In that the draft CTG is applicable to existing storage vessels, and these storage vessels would require certain alterations to accommodate the routing of vapors to a control device, EPA added a cost item in the draft CTG for "Storage Vessel Retrofit." The costs in the draft CTG are summarized in Table 13-2, with a comparison to the costs in the 2012 TSD.

13.1.2 Numerical Errors In The Draft CTG Cost Evaluation

There appear to be two numerical errors in the draft CTG cost data. One is an omission of the non-labor component of maintenance and the other is an understatement of the cost of fuel to maintain the pilot flame. The impacts on cost-effectiveness of these two numerical errors are shown in Table 13-3.

Omission of the Non-Labor Component of Maintenance.

Table 1 of the 2013 Colorado EIA includes a cost of $2,197 for Maintenance. This should have been understood as maintenance materials, corresponding to the $2,000 in the 2008 Colorado EIA. As in the 2012 TSD, the Maintenance line item from the Colorado EIA should have been included as a maintenance cost in addition to the cost of maintenance labor.

Miscalculation of the Cost of Pilot Fuel.

The cost of Pilot Fuel is given in Table 1 of the 2013 Colorado EIA as $768, which is substantially lower than the value of $2,078 from the 2012 TSD. A footnote to Table 1 of the 2013 Colorado EIA indicates that the cost was based on a fuel cost of $3.41/ million Btu (MMBtu). A typical high heat value (HHV) for natural gas is 1,028 MMBtu/ million scf (MMscf), or 1.028 MMBtu/ thousand scf. The cost per thousand scf would then be 3.41*1.028 = $3.51/ thousand scf. Various sources give values of pilot fuel consumption ranging from 50 scf/hr[27] to 70 scf/hr.[28] At the lower consumption rate of 50 scf/hr, this would correspond to 3.51*50*8760/1000 = $1,537/year, or twice the cost given in the 2013 Colorado EIA.

Further, this pilot fuel cost (said to be based on the Henry Hub Spot Price in August 2013) of $3.41/MMBtu does not match the assumed VRU cost offset of recovered gas that is priced at $4/Mcf (equivalent to $3.89/MMBtu). While this would not result in a significant increase in the cost of control for a single storage vessel, it could when amplified to include the cost of controls for the entire industry.

[26] Initial Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7, "Emissions of Volatile Organic Compounds," submitted with Request for Hearing Documents on November 15, 2013.

[27] Wyoming Department of Environmental Quality, Division of Air Quality, Proposed Revisions to the Chapter 6, Section 2, Oil and Gas Production Facilities Permitting Guidance, Technical Support Document, September 2013.

[28] U.S. Environmental Protection Agency, "EPA Air Pollution Control Cost Manual," EPA/452/B-02-001, Sixth Edition, January 2002. http://www.epa.gov/ttn/catc/dir1/cs3-2ch1.pdf

Table 13-2. NSPS Subpart OOOO versus Draft CTG Cost Analyses for Combustor for Storage Vessels

			NSPS 2012 TSD Table 7-5	Draft CTG Table 4-5
Cost Item		Basis Year:	2008	2012
Capital Costs Items				
	Combustor		$18,114	$18,169
	Freight and Design		$1,643	$1,648
	Auto Ignitor		$1,643	$1,648
	Surveillance System		$3,943	$3,805
	Instrumentation			
	Auxiliary Equipment			
	Combustor Installation		$6,959	$6,980
	Indirect Installation			
	Sales Tax			
	Storage Vessel Retrofit			$68,736
	Subtotal			
	Contingency			
Total Capital Investment			**$32,302**	**$100,986**
Annual Costs Items				
Operating Labor		*labor hours*	130	130
		labor rate	$36.70	$32.00
		supervisory hours	19.5	19.5
		supervisory rate	$57.88	$51.03
	Operating Labor		$5,900	$5,155
Maintenance Labor		*labor hours*	130	130
		labor rate	$36.70	$32.00
		supervisory hours	0	0
		supervisory rate	$57.88	$51.03
	Maintenance Labor		$4,771	$4,160
	Subtotal Labor		**$10,671**	**$9,315**
	Maintenance		$2,190	
	Pilot Fuel		$2,078	$768
	Make-up gas			
	Data Management		$1,095	$1,057
		interest rate (%)	7%	7%
		equipment life (years)	15	15
		CRF	0.1098	0.1098
	Capital Recovery ($/yr)		$3,547	$11,088
	Overhead			
	Administrative Charges			
	Property Taxes			
	Insurance			
Total Annual Costs ($/yr)			**$19,580**	**$22,228**
Control Threshold (tpy)			**6**	**6**
		control efficiency (%)	95%	95%
		emission reductions (tpy)	5.7	5.7
Cost Effectiveness ($/ton)			**$3,435**	**$3,900**

Table 13-3. Draft CTG Cost Analyses for Combustor for Storage Vessels –Corrected for Numerical Errors

Cost Item		Basis Year:	Draft CTG Table 4-5 2012	Draft CTG *corrected* Table 4-5 2012
Capital Costs Items				
	Combustor		$18,169	$18,169
	Freight and Design		$1,648	$1,648
	Auto Ignitor		$1,648	$1,648
	Surveillance System		$3,805	$3,805
	Instrumentation			
	Auxiliary Equipment			
	Combustor Installation		$6,980	$6,980
	Indirect Installation			
	Sales Tax			
	Storage Vessel Retrofit		$68,736	$68,736
	Subtotal			
	Contingency			
Total Capital Investment			**$100,986**	**$100,986**
Annual Costs Items				
Operating Labor		*labor hours*	130	130
		labor rate	$32.00	$32.00
		supervisory hours	19.5	19.5
		supervisory rate	$51.03	$51.03
	Operating Labor		$5,155	$5,155
Maintenance Labor		*labor hours*	130	130
		labor rate	$32.00	$32.00
		supervisory hours	0	0
		supervisory rate	$51.03	$51.03
	Maintenance Labor		$4,160	$4,160
	Subtotal Labor		**$9,315**	**$9,315**
	Maintenance			$2,197
	Pilot Fuel		$768	$1,537
	Make-up gas			
	Data Management		$1,057	$1,057
		interest rate (%)	7%	7%
		equipment life (years)	15	15
		CRF	0.1098	0.1098
	Capital Recovery ($/yr)		$11,088	$11,088
	Overhead			
	Administrative Charges			
	Property Taxes			
	Insurance			
Total Annual Costs ($/yr)			**$22,228**	**$25,194**
Control Threshold (tpy)			**6**	**6**
		control efficiency (%)	95%	95%
		emission reductions (tpy)	5.7	5.7
Cost Effectiveness ($/ton)			**$3,900**	**$4,420**

13.1.3 Omission Of Costs Identified In The EPA OAQPS Control Cost Manual

EPA maintains a Control Cost Manual which has the following stated purpose:

> *The objectives of this Manual are two-fold: (1) to provide guidance to industry and regulatory authorities for the development of accurate and consistent costs (capital costs, operating and maintenance expenses, and other costs) for air pollution control devices, and (2) to establish a standardized and peer reviewed costing methodology by which all air pollution control costing analyses can be performed.*[29]

The EPA Control Cost Manual, then, is expressly intended to provide guidance in the evaluation of the cost of control devices. The costs to be included in the evaluation of a flare as a control device are addressed in Section 3.2, Chapter 1 of the EPA Control Cost Manual. These costs include the following line items for Indirect Annual Costs:

- Overhead	60% of total labor and material costs
- Administrative charges	2% of Total Capital Investment
- Property tax	1% of Total Capital Investment
- Insurance	1% of Total Capital Investment

EPA neglected these costs in both the 2012 TSD and the draft CTG, but has offered no rationale for doing so. The omission of these costs, then, appears to be arbitrary and capricious. The impact of these Indirect Annual Costs is shown below in Table 13-4.

13.1.4 Understatement Of Operating And Maintenance Hours

The EPA Control Cost Manual indicates an allowance of 630 hours per year for operation of a flare, and 0.5 hours per shift for maintenance of a flare. Assuming one shift per day, the estimated maintenance labor would be 182 hours. EPA, however, allowed just 130 hours per year for operating the device and another 130 hours per year for maintenance. In the 2012 TSD, EPA acknowledged the higher level of hours in the EPA Control Cost Manual, but reasoned that operating labor would be lower for these devices when used in the oil and natural gas production sector due to most of the sites being unmanned.[30] However, operating and maintenance hours would be increased for unmanned sites due to the travel time involved in getting personnel to the sites. It is, then, inappropriate to arbitrarily reduce estimated operating and maintenance hours for these facilities. The impacts of increasing the operating and maintenance hours to the levels indicated by the EPA Control Cost Manual are shown below in Table 13-5.

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[29] U.S. Environmental Protection Agency, "EPA Air Pollution Control Cost Manual," EPA/452/B-02-001, Sixth Edition, January 2002. http://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf

[30] U.S. EPA, "Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution," Background Supplemental Technical Support Document for the Final New Source Performance Standards, April 2012; page 7-4.

Table 13-4. Draft CTG Cost Analyses for Combustor for Storage Vessels – Corrected Plus Indirect Annual Costs

Cost Item	Basis Year:	Draft CTG *corrected* Table 4-5 2012	Draft CTG *corrected, plus Indirect Annual Costs* Table 4-5 2012
Capital Costs Items			
	Combustor	$18,169	$18,169
	Freight and Design	$1,648	$1,648
	Auto Ignitor	$1,648	$1,648
	Surveillance System	$3,805	$3,805
	Instrumentation		
	Auxiliary Equipment		
	Combustor Installation	$6,980	$6,980
	Indirect Installation		
	Sales Tax		
	Storage Vessel Retrofit	$68,736	$68,736
	Subtotal		
	Contingency		
Total Capital Investment		**$100,986**	**$100,986**
Annual Costs Items			
Operating Labor	*labor hours*	130	130
	labor rate	$32.00	$32.00
	supervisory hours	19.5	19.5
	supervisory rate	$51.03	$51.03
	Operating Labor	$5,155	$5,155
Maintenance Labor	*labor hours*	130	130
	labor rate	$32.00	$32.00
	supervisory hours	0	0
	supervisory rate	$51.03	$51.03
	Maintenance Labor	$4,160	$4,160
	Subtotal Labor	**$9,315**	**$9,315**
	Maintenance	$2,197	$2,197
	Pilot Fuel	$1,537	$1,537
	Make-up gas		
	Data Management	$1,057	$1,057
	interest rate (%)	7%	7%
	equipment life (years)	15	15
	CRF	0.1098	0.1098
	Capital Recovery ($/yr)	$11,088	$11,088
	Overhead		$6,907
	Administrative Charges		$2,020
	Property Taxes		$1,010
	Insurance		$1,010
Total Annual Costs ($/yr)		**$25,194**	**$36,141**
Control Threshold (tpy)		**6**	**6**
	control efficiency (%)	95%	95%
	emission reductions (tpy)	5.7	5.7
Cost Benefit ($/ton)		**$4,420**	**$6,340**

Table 13-5. Draft CTG Cost Analyses for Combustor for Storage Vessels – Corrected Plus Indirect Annual Costs and Full Labor Hours

Cost Item		Basis Year:	Draft CTG *corrected, plus Indirect Annual Costs* Table 4-5 2012	Draft CTG *corrected, plus Indirect Annual Costs and Full Labor Hours* Table 4-5 2012
Capital Costs Items				
	Combustor		$18,169	$18,169
	Freight and Design		$1,648	$1,648
	Auto Ignitor		$1,648	$1,648
	Surveillance System		$3,805	$3,805
	Instrumentation			
	Auxiliary Equipment			
	Combustor Installation		$6,980	$6,980
	Indirect Installation			
	Sales Tax			
	Storage Vessel Retrofit		$68,736	$68,736
	Subtotal			
	Contingency			
Total Capital Investment			**$100,986**	**$100,986**
Annual Costs Items				
Operating Labor		*labor hours*	130	630
		labor rate	$32.00	$32.00
		supervisory hours	19.5	94.5
		supervisory rate	$51.03	$51.03
	Operating Labor		$5,155	$24,982
Maintenance Labor		*labor hours*	130	182
		labor rate	$32.00	$32.00
		supervisory hours	0	0
		supervisory rate	$51.03	$51.03
	Maintenance Labor		$4,160	$5,824
	Subtotal Labor		**$9,315**	**$30,806**
	Maintenance		$2,197	$2,197
	Pilot Fuel		$1,537	$1,537
	Make-up gas			
	Data Management		$1,057	$1,057
		interest rate (%)	7%	7%
		equipment life (years)	15	15
		CRF	0.1098	0.1098
	Capital Recovery ($/yr)		$11,088	$11,088
	Overhead		$6,907	$19,802
	Administrative Charges		$2,020	$2,020
	Property Taxes		$1,010	$1,010
	Insurance		$1,010	$1,010
Total Annual Costs ($/yr)			**$36,141**	**$70,527**
Control Threshold (tpy)			**6**	**6**
		control efficiency (%)	95%	95%
		emission reductions (tpy)	5.7	5.7
Cost Benefit ($/ton)			**$6,340**	**$12,373**

13.2 The Emissions Threshold For Controlling Existing Storage Vessels Should Be Higher Than 6 TPY VOC

In section 4.4 of the draft CTG, EPA explains that 6 tpy of VOC was selected as the applicability threshold because this level was found to be "a cost effective applicability threshold for requiring 95 percent control of VOC emissions from existing storage vessels". Table 13-2 through Table 13-4 showed the cost effectiveness calculation at an emissions level of 6 tpy of VOC.

However, as was demonstrated in section 13.1, EPA's cost estimate for combustors for storage vessels was flawed. After adjusting for these flaws, the cost effectiveness values change accordingly for storage vessel emitting 6 tpy VOC.

As was shown in Table 13-4, the cost effectiveness for a 6 tpy VOC storage vessel is estimated to be $6,340 when the Indirect Annual Costs from the EPA Control Cost Manual are taken into account. This is greater than the value of $5,700/ton that EPA deemed to be unacceptably high in related rulemaking.[31] When the Indirect Annual Costs from the EPA Control Cost Manual are taken into account, it appears that a control threshold of 8 tpy would be more appropriate than a threshold of 6 tpy. This is shown in Table 13-6.

Table 13-6 Cost Effectiveness Evaluation for Combustor for Storage Vessels – Corrected Plus Indirect Annual Costs

Total Annual Costs ($/yr)	**$36,141**	**$36,141**
Control Threshold (tpy)	**6**	**8**
control efficiency (%)	95%	95%
emission reductions (tpy)	5.7	7.6
Cost Effectiveness ($/ton)	**$6,340**	**$4,755**

Further, as was shown in Table 13-5, the cost per ton of emission reductions is shown to be $12,373 for a 6 tpy VOC storage vessel when the full labor hours from the EPA Control Cost Manual. This is also greater than the value of $5,700/ton that EPA deemed to be unacceptably high in a related rulemaking.[32] When the full labor hours from the EPA Control Cost Manual are taken into account, it appears that a control threshold of 15 tpy would be more appropriate than a threshold of 6 tpy. This is summarized in Table 13-7.

Table 13-7. Cost Effectiveness Evaluation for Combustor for Storage Vessels – Corrected Plus Indirect Annual Costs and Full Labor Hours

Total Annual Costs ($/yr)	**$70,527**	**$70,527**
Control Threshold (tpy)	**6**	**15**
control efficiency (%)	95%	95%
emission reductions (tpy)	5.7	14.25
Cost Benefit ($/ton)	**$12,373**	**$4,949**

[31] 78 FR 58429 (September 23, 2013).

[32] 78 FR 58429 (September 23, 2013).

13.3 Adding Control To An Existing Storage Vessel To A Control Device Can Present A Safety Issue

Many existing storage vessels were not initially designed to route emissions to a control device. For these existing tanks, the integrity may not be able to withstand the back pressure from the closed vent system and control device. The high back pressure could result in tank damage or even rupture. Therefore, they will require changes to the tank, or full replacement of the tank, in order to handle the back pressure from the control device and closed vent system without damaging the tank. Most of the storage vessels in the oil and natural gas industry last only 10-15 years maximum and would eventually be subject to NSPS OOOOa due to routine replacement.

13.4 Adding Combustion Control To An Existing Storage Vessel May Cause Negative Environmental Impacts That Are More Significant Than The VOC Reductions

Combustion of gas from storage vessels not only destroys VOCs, it creates NO_X, CO, and CO_2 emissions. EPA acknowledges this on page 4-6 of the draft CTG, as they state that "Combustion and partial combustion of organic pollutants also created secondary pollutant including nitrogen oxides, carbon monoxide, sulfur oxides, carbon dioxide, and smoke/particulates." However, EPA did not attempt to quantify these impacts.

The precursors to ozone formation are both VOCs and NO_X. The net impact of ozone formation depends on the NO_X, VOCs, and sunlight for a particular location. As noted in EPA's Integrated Science Assessment for Ozone[33] , "Duncan et. al 2010[34] found that O3 [ozone] formation over most of the U.S. became more sensitive to NO_X over most of the U.S. from 2005 to 2007 largely because of decreases in NO_X emissions." The ozone formation or most of the U.S. is NO_X limited; therefore, in most areas of the country adding more NO_X could result in increased ozone formation would be counterproductive to the point of CTGs to help reduce ozone formation. Analysis for particular areas could find that the net result of controlling storage vessels actually creates more ozone. EPA should allow the states to determine whether controlling storage vessels creates or reduces ozone prior to having to incorporate the RACT recommendations in this CTG into their SIPs through analysis of the air quality for the particular area.

13.5 EPA's Does Not Define "Maximum Daily Average Throughput"

Paragraph (a) of section A.1 of the model rule states that "The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline established by your regulatory authority". API agrees with this approach, except that the term "maximum daily throughput" is contradictory from both a plain text and mathematical point of view. **API suggests that the following definition be added to section A.6 of the model rule.**

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[33] US EPA. 2013a. "Integrated Science Assessment for Ozone and Related Photochemical Oxidants (Final)." EPA/600/R–10/076F.

[34] Duncan, BN; Yoshida, Y; Olson, JR; Sillman, S; Martin, RV; Lamsal, L; Hu, Y; Pickering, KE; Retscher, C; Allen, DJ. (2010). Application of OMI observations to a space-based indicator of NOx and VOC controls on surface ozone formation. Atmos Environ 44: 2213-2223. http://dx.doi.org/10.1016/j.atmosenv.2010.03.010

Maximum average daily throughput means the daily average throughput during the 30-day PTE evaluation period that represents steady-state conditions.

13.6 The Lack Of An Alternate Uncontrolled VOC Emission Standard In The CTG Model Rule Leads To Existing Storage Vessels Being Controlled Although Emissions Have Declined Below The Applicability Threshold

Under NSPS subpart OOOO and proposed subpart OOOOa, EPA has allowed for the removal of storage vessel control devices once emissions are below 4 TPY (§60.5395(d)(2) and proposed §60.5395a(a)(3)). In the proposed amendments to subpart OOOO published on April 12, 2013 (78 FR 22126), EPA provided extensive rationale for why it was justified to include this alternative limit for storage vessels.

However, the draft CTG model rule does not include this alternative. API believes that if BSER, as required for NSPS, includes this alternative, then certainly the less stringent RACT should also include it. EPA must either include this alternative 4 TPY limit in the CTG RACT recommendation and model rule, or justify why it is not included.

From a cost effectiveness standpoint, EPA stated that below 4 tpy of VOCs controlling storage vessels was not cost effective under NSPS subpart OOOO, which was published on September 23, 2013. Following are quotes from the preamble for these final amendments (78 FR 58429).

> *". . . . our analysis indicates that the cost of controls for each storage vessel affected facility at a VOC emission rate of 4 tpy is approximately $5,100 per ton. This cost increases to approximately $6,900 per ton at an emission rate of 3 tpy, and to approximately $10,000 per ton at 2 tpy. For comparison, we note that, in a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], we had concluded that a VOC control option was not cost effective at a cost of $5,700/ton, which calls into question the cost effectiveness of continuing control of storage vessel affected facilities at an emission rate below 4 tpy."*

> *"In light of the cost-effectiveness, the secondary environmental impacts and the energy impacts, we have concluded that the BSER for reducing VOC emissions from storage vessel affected facilities is not represented by continued control when their sustained uncontrolled emission rates fall below 4 tpy."*

For RACT, it would definitely not be cost effective below 4 tpy.

13.7 "Well Completion Vessel" Is Not Defined In The CTG Model Rule, Which Could Lead To Confusion

In section A.6 of the model rule, the definition of "storage vessel" includes the following sentence, "A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this rule." This sentence contains the following terms, which are not defined in section A.6,

- "well completion vessel",
- "recovered liquids",
- "well",

- "startup of production", and
- "flowback".

The omission of these related definitions makes the applicability of RACT toward well completion vessels unclear.

Since the CTG model rule will apply to existing sources only, API believes that well completion vessels would not be subject, as they would be associated with new wells and regulated under the existing NSPS subpart OOOO and proposed OOOOa as potential new, modified, or reconstructed storage vessel affected facilities.

However, in order to avoid confusion, API recommends that the following definitions be added to section A.6 of the model rule. These definitions are consistent with the existing NSPS subpart OOOO and proposed subpart OOOOa (§60.5430 and §60.5430a).

> *Flowback* means the process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage.
>
> *Recovered liquids* means any crude oil, condensate or produced water recovered through the separation process during flowback.
>
> *Startup of production* means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water.
>
> *Well* means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.
>
> *Well completion vessel* means a vessel that contains flowback during a well completion operation following hydraulic fracturing or refracturing. A well completion vessel may be a lined earthen pit, a tank or other vessel that is skid-mounted or portable. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this rule.

13.8 EPA Has Not Justified The Continuous Parameter Monitoring Requirements In The CTG

In section A.4(c) of the model rule, continuous parameter monitoring and the comparison of daily average parameter monitoring results against site-specific maximum or minimum values established during the performance test are required for storage vessels. As discussed earlier in Section 9.2.1, these NESHAP-level monitoring requirements are not appropriate for RACT. EPA has not justified these requirements and must not include them in the final CTG model rule.

However, for storage vessels the monitoring requirements in the RACT model rule are even more egregious as these RACT requirements are considerably more stringent than the BSER requirements proposed for NSPS subparts OOOO and OOOOa. For those NSPS, EPA did not propose any parameter monitoring for storage vessel control devices. RACT-level requirements should, by definition, generally be less stringent than BSER. In this case, EPA has included RACT monitoring requirements for storage vessel control device monitoring that are orders of magnitude more stringent than the BSER requirements in the NSPS. They must be removed from the model rule. **API recommends the monitoring requirements for storage vessels be consistent with those for NSPS subpart OOOOa**.

14.0 PNEUMATIC CONTROLLERS

14.1 EPA Must Clarify That Continuous Bleed Pneumatic Controllers With Bleed Rates Less Than 6 Standard Cubic Feet Per Hour Are Not Subject To Any Requirements Under The RACT Recommendation And Model Rule For Pneumatic Controllers From The Wellhead To The Natural Gas Processing Plant Or Point Of Custody Transfer To An Oil Pipeline

The CTG in section 6 proposes that each continuous bleed natural gas-driven pneumatic controllers is the affected facility for RACT by stating the following:

> "RACT for Each Single Continuous Bleed Natural Gas-Driven Pneumatic Controller Located from the Wellhead to the Natural Gas Processing Plant or Point of Custody Transfer to an Oil Pipeline: Each pneumatic controller, which is a single continuous bleed natural gas-driven pneumatic controller must have a natural gas bleed rate less than or equal to 6 scfh (unless there are functional needs, including but not limited to responsetime, safety and positive actuation, requiring a bleed rate greater than 6 scfh)."

Furthermore, the CTG states on page 6-3:"It is assumed intermittent, or no-bleed, controllers meet the definition of a low-bleed."

While API appreciates EPA recognizing the inherent low emissions of intermittent vent controllers, this statement could also be interpreted that for the purpose of this CTG that intermittent vent controllers should be considered continuous low bleed controllers.

Section B.1 provides the applicability requirements of the model rule to pneumatic controllers. Specifically for pneumatic controllers located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline, paragraph B.1(b) says that the VOC control requirements apply to each "single continuous bleed natural gas-driven controller operating at a natural gas bleed rate greater than 6 standard cubic feet per hour."
Paragraph B.2(c) then requires the following:

> *(c)(1) Each pneumatic controller subject to VOC emissions control requirements at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must have a bleed rate less than or equal to 6 standard cubic feet per hour.*
>
> *(2) Each pneumatic controller subject to VOC emission control requirements at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must be tagged with the date that the pneumatic controller is required to comply with the model rule (as established by your regulatory authority) that allows traceability to the records for that controller as required in section B.5(a)(3).*

Section B.1(b) is very clear that the rule only applies to pneumatic continuous bleed natural gas-driven controller operating at a natural gas bleed rate greater than 6 standard cubic feet per hour. Given the above citations from section 6, it can be interpreted to mean that all existing pneumatic controllers are subject to RACT in the CTG. However, the model rule for pneumatic controllers in Appendix B states that continuous high bleed controllers are the affected facility which is consistent with NSPS but inconsistent with the stated RACT in section 6. API recommends correcting its RACT statement in section 6 to clearly indicate that RACT applies only to continuous high bleed gas-driven pneumatic controllers and that RACT applies only to controllers constructed before August 12, 2011, the proposal date for NSPS which defines new sources.

If instead it is EPA's intent to apply RACT to all pneumatic controllers, this will setup the potential for an operator choosing to delay action until after a RACT rule becomes effective rather than take early action. While RACT is mainly for lowering emissions using emissions control, emission reduction from high bleed pneumatic controllers often requires replacement or when feasible a pilot valve retrofit to make them low bleed or intermittent vent. The cost of retrofit may also be considered a reconstruction of the controller as well in many instances. Replacing a controller with a new one or reconstructing it, will make the controller a new source and no longer an existing source, so would then be subject to NSPS not RACT. If this new replacement or reconstruction occurs before the RACT rule is effective, it could become an existing source subject to all the RACT requirements. Even where existing low bleeds and intermittent vents are already used, an operator may replace them anyway just to ensure being considered a new source rather than an existing source if this CTG doesn't clearly define the dates that separate new sources from existing sources. However, these issues are resolved if RACT applies as we recommend; only high bleed controllers are affected facilities, and existing sources are defined as construction prior to the proposal dates of Subpart OOOO or OOOOa as appropriate.

API disagrees with the CTG recommendation that all controllers should be replaced as described in section 6.5 of the RACT.

The CTG should only stipulate high bleed natural gas pneumatic controllers must be replaced, unless justifiable as consistent with the NSPS. Replacing an existing high bleed controller with a new low bleed controller or intermittent controller would cause the new controller be covered under NSPS and would not be subject to an existing source RACT rule.

API requests that EPA acknowledge this fact and provide a clear statement that continuous bleed pneumatic controllers with bleed rates less than 6 standard cubic feet per hour are not subject to any requirements under the RACT recommendation and Model Rule for pneumatic controllers from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline.

15.0 PNEUMATIC PUMPS

15.1 Introduction

API appreciates EPA's efforts to simplify the guidelines for pneumatic pump control requirements as well as EPA's recognition that there are limited scenarios for which control of pneumatic pumps will be cost effective. However, from review of proposal and supporting documents, it is clear that EPA did not appreciate some key technical issues as well as some key costs that would be incurred if the rule were finalized as proposed.

Each of these points is expanded upon in this section, but API recommends that the following exemptions should be added to the proposed CTGs for pneumatic pumps:

- Technical Feasibility – If it is not technically feasible to connect a pump to an existing on site control device, there should be an exemption.
- Small or limited use emission pumps (< 53 thousand scf per year emission rate, which is equivalent to a continuous 6 scf/hour emission rate) rate or any pump operating less than 90 days per year).

Additionally, EPA has proposed overly burdensome and costly testing and monitoring requirements for control systems used to control pumps. If control requirements are retained for any types of pneumatic pumps, the model rule should eliminate testing, monitoring, and recordkeeping requirements for the control device that are triggered solely due to the connection of a pneumatic pump exhaust to the closed vent system or control device. Alternatively, EPA should only require control of pumps when an existing NSPS OOOO/OOOOa control device which is already subject to the same requirements as in the proposed rule is present.

Finally, for many technical reasons, API believes it is important that EPA should clarify in the CTGs that the presence of a heater or boiler should not be considered to be equivalent to presence of control device.

Given that the CTGs mirror the requirements under the proposed NSPS OOOOa, API also appreciates EPA's discussion in the NSPS preamble that recognizes the limitations of solar powered pumps, the typical unavailability of electricity at well sites and other remote sites, and the fact that gas-assist lean-glycol recirculation pumps on glycol dehydration units are not pneumatic pumps. API agrees with EPA's approach of defining the affected source as only pumps using natural gas as the pneumatic power source and located at a site with an existing control device. API also agrees with EPA's approach of only requiring control of new, modified or reconstructed pneumatic pumps on sites with existing control devices (combustion control or vapor recovery). However, API has several important issues with the details of the CTG as proposed.

- EPA inappropriately requires an existing control device/system to meet the closed-vent-system, performance testing, monitoring, and recordkeeping requirements of NSPS OOOOa. This is exacerbated by the proposal to require the same measures as for wet-seal centrifugal compressor affected source control devices.
- API believes the capital cost estimate EPA made is low and that several significant cost items are left out of the cost analysis.
- API believes the estimated emissions per pump for diaphragm type pumps is overestimated and the equal proportional split between piston type chemical pumps and diaphragm pumps is incorrect. Due to the limited time available for comment, API did not have time survey members adequately, but there are many more piston pumps installed than diaphragm pumps.
- Because the cost is underestimated and the emissions overestimated, the control actions required by the regulation are not cost effective in many instances.

- EPA failed to recognize important design and process factors that could render routing a pneumatic pump to an existing control device technically infeasible or unsafe.
- Some details of the model rule language are unclear or not defined fully.

Each of these issues is discussed in more detail in the following sections.

15.2 Control Device And Closed Vent System Requirements

As written, control devices not subject to Subpart OOOO or OOOOa would be required to be used to control emissions from pneumatic pumps. It is not clear if this was EPA's intent in writing the model rule. From the lack of consideration for performance requirements, performance testing, closed vent system monitoring, recordkeeping, and reporting compliance costs in the economic analysis, it appears that EPA did not intend for control devices not subject to Subpart OOOO or Subpart OOOOa to be pulled into the monitoring, reporting, and recordkeeping requirements under the CTGs. If EPA maintains a requirement to route higher emitting pneumatic pumps to existing control devices, this should not trigger the performance specifications, performance testing, monitoring, closed vent system monitoring, recordkeeping, and reporting requirements for the control device if it is not already subject to regulation under Subpart OOOO or Subpart OOOOa. This change from the proposed approach would address one of the two critical cost elements ignored by EPA when assessing the cost of control; specifically, the costs of testing, monitoring, reporting, and recordkeeping requirements.

EPA should also provide for routing of pump exhaust from glycol heat medium pumps (typically diaphragm type pumps) to a controlled tank or knock-out drum prior to the control device to provide for buffering the intermittent flow when the pump exhaust stroke occurs. This would provide for more stable flow to the control device and piping system and simplify connecting a pneumatic pump exhaust to an existing control system.

The draft CTG unnecessarily and inappropriately requires existing control devices and closed vent systems to comply with the full suite of requirements identical to those specified for control devices and systems on centrifugal compressor affected facilities degassing tank vents if a new, modified, or reconstructed pneumatic pump affected source is routed to the control device. EPA failed to recognize that the majority of the existing control devices and closed vent systems installed on sites where pneumatic pumps are likely to be used will not already be subject to Subpart OOOO requirements let alone those for centrifugal compressor affected facilities. Since centrifugal compressors are rarely used in the production segment and new, modified, or reconstructed centrifugal compressors in the gathering & collection, processing, and transportation & storage segments are almost certainly dry seal equipped, the probability is near zero that an existing control device on well sites or remote facilities would already be subject to the centrifugal compressor affected source requirements for closed vent systems and control devices. Most already installed or newly installed control devices/systems and closed vent systems will predate the requirements of Subpart OOOO or be installed pursuant to State regulations or enforceable permit conditions that limit emissions below the thresholds for applicability of Subpart OOOO. Even where an existing control device and closed vent system has applicable requirements under Subpart OOOO, these are almost certainly those requirements for control devices and closed vent systems installed on storage tank affected sources rather than centrifugal compressor affected sources and thus would have new requirements under the proposed rule. This could subject an individual control device and closed vent system to a dual set of requirements if the proposed rule is finalized as proposed. Note that this discussion focuses on enclosed combustion control devices as sites with VRU's are likely to have electricity and hence no pneumatic pump affected sources.

By requiring existing closed vent systems and control devices to comply with the specified requirements listed in sections D.1, D.2, E.1, and E.2 of the draft CTG retroactively applies unnecessary, burdensome, and costly requirements to existing control devices and systems that were not designed, installed, or intended to comply with these requirements. Note also that none of the additional costs are included in EPA's analysis of the reasonableness of controlling pneumatic pump affected sources and the additional costs are likely to render such control not reasonable - cost analysis details are presented in a separate section of these comments.

- Section D.1 and D.2: An existing closed vent system may not be designed or constructed to meet the standard of "no detectable emissions" specified. Again, this may force retrofit or replacement of the existing piping system to enable meeting the "no detectable emissions" requirement.
- Section E.1: Existing control devices and the piping to them are not likely to have the necessary ports installed to enable performance testing as specified and would have to be taken offline in order to retrofit them if retrofit is even possible.
- Section E.2: Existing control devices are unlikely to have all of the monitoring instruments and capabilities required for continuous compliance demonstration as required and these would have to be retrofitted to the control device. Again, retrofit may not be possible which would leave an operator with no avenue to comply without installing a new control device which EPA already found to be not reasonable from a control cost standpoint. Additionally, the data monitoring, logging and averaging required under E.2.c would require either installation of an entirely new monitoring system or tying the monitoring devices into an existing automation system programmable logic controller (PLC) which may not have the number of input ports necessary nor have the memory and computing power necessary. Due to the typical lack of electrical power, the installation of a monitoring system would also require installation of a solar power system with the necessary power to operate the system and the necessary battery back-up to assure adequate data recovery.

Requiring control devices and covered vent systems, where a pneumatic pump affected source is routed to them, to comply with the performance testing, continuous monitoring, and associated requirements of the draft CTG is not necessary. The exhaust from a pneumatic pump affected source is the same natural gas used for the pilot flame in a combustion control device and as fuel for a boiler or heater. It is not difficult to combust and should not require the same rigor of demonstration for more difficult to combust compounds. In general, the low molecular weight straight chain aliphatic hydrocarbons that characterize the natural gas industry, including associated gas, are easy to combust.

To address the issues regarding retroactive application of the requirements in sections D and E of the CTGs to existing control devices and closed vent systems not already subject to the requirements proposed, API recommends EPA take one of the following approaches.

- Maintain the current definition of pneumatic pump affected source and require that the existing control device and closed vent system comply with whatever existing requirements for testing, monitoring, and reporting exist for the particular site/control device and closed vent system.

-or-

- Redefine the pneumatic pump affected source as only those new, modified, or reconstructed natural gas powered pneumatic pumps installed at a site with an existing control device that is already subject to the requirements contained in §60.5410a, §60.5411a, §60.5412a, §60.5413a, §60.5415a, §60.5416a, and §60.5417a proposed in the rule.
- To assure the integrity of the newly installed piping routing a new, modified, or reconstructed pneumatic pump affected source to an existing closed vent system or directly to the control device EPA could require an annual leak inspection with an Optical Gas Imaging camera for the newly installed piping to an existing control device or closed vent system.

15.3 Technical Basis For RACT Recommendation

15.3.1 EPA Underestimated The Cost Of The Proposed Control Strategy Which Renders Is Not Cost Effective In Many Situations

In the cost analysis for the proposed control strategy for pneumatic pumps, EPA incorrectly only listed a one-time capital cost impact of $2,000 for the design and installation of piping to route vapors from the exhaust of a pneumatic pump to an existing control device. This value was based upon Natural Gas Star program data.[35] Using a 7% interest rate, EPA estimated the annualized cost of controlling a pneumatic pump at $285/year. This value is too low and does not include significant cost items required by the rule. As an example, EPA assumed a cost of $23,252 for tying a wet-seal centrifugal compressor seal-oil degassing tank into an existing control device. (See Section 8.4.4.3 of Technical Support Document for NSPS Subpart OOOOa and Table 5-8 in the draft CTG document.) The low pressure nature of both pneumatic pump exhaust and a seal-oil degassing tank are similar. Unfortunately, the discussion of pneumatic pump control and seal-oil degassing control is not detailed enough to understand the difference in EPA's cost estimates.

API believes the average capital cost (inclusive of engineering) that would be incurred for design evaluation, designing, and construction of the piping to tie a pneumatic pump into an existing control device/system would be closer to $5,800 and would vary considerably from site to site.

Following are the details of API's initial capital cost estimate.

- Collecting the site specific information on an existing control device/system and performing an engineering evaluation of the ability to safely and technically add pump exhaust gas to the control device/system. 8 hours of engineering time at $185 per hour = $1480.
- Evaluating the specific pump's ability to tolerate the exhaust backpressure necessary to route to the existing control device/system; designing the piping necessary to route a pump exhaust to the control device/system; specifying materials, connection points, and connection types for routing a pump exhaust to the control device/system; and writing a work-order and procedure for connecting. Eight (8) hours of engineering time @ $185 per hour = $1480.

[35] http://www.epa.gov/gasstar/documents/pipeglycoldehydratortovru.pdf.

- Ordering and collecting materials for installing the piping, commissioning a contractor to perform the work, and overseeing the work. Six (6) hours of construction specialist time at $140 per hour = $840.
- Travel to the site, installation of the piping for tie-in, verification of the proper functioning of the tie-in and travel from the site. One day of a contract construction crew time at $2,000 per day = $2,000.

Utilizing EPA's assumed 7% interest rate, this equates to an annualized initial capital cost of $826 rather than EPA's value of $285.

In addition to underestimating the capital costs of routing the emissions to a control device, EPA did not consider other significant initial and reoccurring costs that would be incurred. The draft CTG requires an existing control device and closed vent system with a pneumatic pump routed to them to comply with the same performance testing, closed vent system, continuous monitoring, and recordkeeping and reporting requirements applicable to closed vent systems and control devices specified for centrifugal compressor affected facilities. The majority of the existing control devices and closed vent systems installed on sites where pneumatic pumps are likely to be used will not already be subject to Subpart OOOO requirements let alone those for centrifugal compressor affected facilities. The probability is near zero that an existing control device subject to the centrifugal compressor affected source requirements for closed vent systems and control devices will be on a site where a pneumatic pump source is located.

Most already installed or newly installed control devices/systems and closed vent systems will predate the requirements of Subpart OOOO or be installed pursuant to State regulations or enforceable permit conditions that limit emissions below the thresholds for applicability of Subpart OOOO. As such, costs not included in EPA's analysis are:

- The costs for an initial M21 demonstration that the closed vent system, at a site not already subject to the requirements under Subpart OOOO, is operating with no detectable emissions.
- The costs for initial and periodic performance testing of a control device that is not already subject to the required performance testing.
- The costs for monthly smoke inspections, including travel to and from the site for a trained visual smoke inspector.
- The costs for design, installation and maintenance of a parametric monitoring system.
- The recordkeeping and reporting cost.

The table below provides a more complete estimate of the costs associated with implementing the proposed rule requirements for pneumatic pumps. This table reflects the true cost of compliance with the CTG, including potential source testing, the need to install monitoring equipment, and the costs of conducting recurring inspection and equipment maintenance that would all be triggered by the proposed compliance requirements. Note that none of the performance testing exemptions listed in E.2(b) are considered. It should be noted that:

- Heaters with a design capacity of 44 MW (150 million BTU/hr) will not occur in the types of sites where pneumatic pump affected sources will be used

- Heaters used at well sites and other remote sites are likely to be seasonally used, or have intermittent firing dependent on heat demand and hence will not be able to accept the exhaust gas from a pneumatic pump as part or all of the fuel at all times
- As discussed previously, an existing control device is almost certainly not already subject to the performance testing requirements of the CTGs and hence not manufacture certified.
- Hazardous waste incinerators or hazardous waste fueled heaters will not occur at the type of sites where pneumatic pump affected sources will be used.

Table 15-1 Pneumatic Pump Control Cost Table

Cost Item	***Initial Cost***	***Annualized Cost***
Capital Costs (including engineering)	$5,800	$826
Option 1 Combustor Testing (repeat each 5 years)	$6,000	$1,200
Option 2 Process Heater Testing (repeat each 5 years)	$6,000	$1,200
Annual M21 & Visual CVS Inspection *(Contractor or Trained Technician - ½ day with vehicle)*	$600	$600
Monthly 15 min Smoke Check (trained operator inspection - $160/month)		$1,800
Flow Monitor, Thermal Dispersion Meter	$5,000	$712
CPMS - install measurement device and solar panel	$9,000	$1,282
CPMS - Annual Maintenance (contractor 1/2 day)		$600
Annual CPMS Auditing (trained instrument technician complete with equipment and vehicle - 1/2 day)		$600
Scenario		***Annualized Total***
Sites with Affected Pneumatic Pumps & Combustor field performance test		$6,908
Sites with Manufacturer Certified Combustor (no performance test)		$6,420
Sites with Affected Pneumatic Pumps (& Process Heater performance test)		$6,908
Sites with existing Subpart OOOO or OOOOa affected storage tank with control device		$3,308
Sites with existing Subpart OOOO or OOOOa affected compressor with control device		$826

Table 15-2 Retrofit Costs for Control Devices

Cost Item	*Initial Cost*	*Annualized Cost*
Retrofit control device with new or relocated ports to enable performance testing per Section F. (likely to occur)	$3,000	$427
Retrofit closed vent system to meet "no detectable emission" requirement per Section D.1(b) (less likely to occur)	$3,000	$427

Table 15-3 Average Pneumatic Pump Emission Rate (Reproduced from TSD)

	Tons/year Methane	Tons/year VOC
Piston Pump	0.38	0.11
Diaphragm Pump	3.46	0.96

Combining the complete estimate of actual costs for routing a pneumatic pump affected source to an existing control device with the emission estimates for piston pumps and diaphragm pumps from the CTGs and Technical Support Document (repeated in proposed NSPS OOOOa rule preamble) yields the following tables of control cost per ton for VOC.

Table 15-4 Piston Pump Control Cost Effectiveness (assuming 8760 hours of annual pump operation)

		Single Pollutant Approach
Production Piston Pumps	***Scenario***	**VOC Only**
	Sites with Affected Pneumatic Pumps & Combustor field performance test[1]	$62,797
	Sites with Manufacturer Certified Combustor (no performance test)	$58,362
	Sites with Affected Pneumatic Pumps (& Process Heater performance test)[1]	$62,797
	Sites with existing subpart OOOO or OOOOa affected storage tank with control device	$30,070
	Sites with existing subpart OOOO or OOOOa affected compressor with control device	$7,509

1. Note – These costs do not include the additional costs of retrofitting the control device (sampling ports, etc.) and the closed vent system per Table 14-2. Inclusion of these costs would only further increase the cost effectiveness ratios.

Table 15-5 Diaphragm Pump Control Cost Effectiveness (assuming 8760 hours of annual pump operation)

	Scenario	Single Pollutant Approach VOC Only
Production Diaphragm Pump	***Sites with Affected Pneumatic Pumps & Combustor field performance test***[1]	$7,196
	Sites with Manufacturer Certified Combustor (no performance test)	$6,687
	Sites with Affected Pneumatic Pumps (& Process Heater performance test)[1]	$7,196
	Sites with existing subpart OOOO or OOOOa affected storage tank with control device	$3.446
	Sites with existing subpart OOOO or OOOOa affected compressor with control device	$860

1. Note – These costs do not include the additional costs of retrofitting the control device (sampling ports, etc.) and the closed vent system per Table 14-2. Inclusion of these costs would only further increase the cost effectiveness ratios.

While EPA does not establish a bright line that separates what they consider to be reasonable and unreasonable with regard cost effectiveness, the proposal provides indications of levels that EPA clearly considers to be unreasonable. On page 56636 of the September 18, 2015 Federal Register notice proposal, EPA indicates: "In a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], **we had concluded that a VOC control option was not cost-effective at a cost of $5,700 per ton**."

As illustrated above, for piston pumps, the control costs exceed the reasonable cost of control per ton for all possible scenarios.

For diaphragm pumps, the cost effectiveness values shown above are lower due to the higher emissions. However, as discussed further in 15.3.4, diaphragm pumps are generally used for heat tracing and as such are not used everywhere and, when they are used do not operate year round. Using a more realistic estimate of 4 months of operation per year, the emissions from these pumps are actually 1/3rd the level assumed by EPA. The table below reflects the cost effectiveness of controlling diaphragm pumps after accounting for their non-year round operation.

Table 15-6 Diaphragm Pump Control Cost Effectiveness (assuming 4 months of annual pump operation)

		Single Pollutant Approach
	Scenario	VOC Only
Production Diaphragm Pump	***Sites with Affected Pneumatic Pumps & Combustor field performance test***[1]	$21,587
	Sites with Manufacturer Certified Combustor (no performance test)	$20,062
	Sites with Affected Pneumatic Pumps (& Process Heater performance test)[1]	$21,587

	Sites with existing subpart OOOO or OOOOa affected storage tank with control device	$10,377
	Sites with existing subpart OOOO or OOOOa affected compressor with control device	$2,581

1. Note – These costs do not include the additional costs of retrofitting the control device (sampling ports, etc.) and the closed vent system per Table 15-2. Inclusion of these costs would only further increase the cost effectiveness ratios.

After accounting for the non-year round operation of pneumatic pumps, the only reasonable control costs found were for an existing control device and closed vent system that is already subject to the performance testing and monitoring requirements specified in the CTGs. As explained in more detail earlier in these comments, the probability of this occurring is near zero.

This illustrates the need for EPA to revise the draft CTG approach to performance testing and monitoring for control devices and closed vent systems used for pneumatic pump affected sources as previously explained earlier in these comments.

It is important to note that the above costs assume that the control device and closed vent system existing on site has enough design margin to accommodate the tie-in of a pneumatic pump and that such a change to site configuration does not trigger the need for a revision to the site's air permit.

15.3.2 EPA Did Not Consider or Provide For Instances Where Routing A Pneumatic Pump Affected Source To An Existing Control Device Is Not Technically Feasible Or Where The Control Device Belongs To Another Party

Whether considering a VRU, flare, enclosed combustion device, or any other control technique, control devices are designed for a specific set of conditions with a number of key assumptions. For example, a flare header might be designed to allow enough flow to permit two pressure safety valves (PSV) to open simultaneously without creating so much back pressure as to take either PSV out of critical flow. The design is sensitive to other flow streams in the pipe and putting a pump exhaust into that header could result in too much backpressure for the safety devices to function as intended. Conversely, but equally important, a pneumatic pump is chosen for a specific backpressure and the backpressure imposed by a PSV could stop the pump from functioning at a critical moment, exacerbating the already unstable situation that resulted in the opening of the PSVs.

Additionally, enclosed combustion devices are designed for a maximum BTU load and may not be able to accommodate the exhaust gas from a pneumatic pump affected source without replacing the control device.

The design process for VRUs are even more sensitive to changes than other control devices. The VRU equipment is designed to recover vapors and raise their pressure enough to be useful, is expensive, and has a limited range of possible flow rates. Adding vapor loads to a VRU must be carefully evaluated on a case-by-case basis.

In some instances an existing control device on a particular site may be owned and operated by a third party, such as a control device owned and operated by a gathering and collection system operator with a glycol dehydration unit on a well site. In these instances, the well site operator does not have the right to route a pneumatic pump affected source exhaust to the control device.

EPA should provide exclusion in the CTGs such that routing a pneumatic pump affected source to an existing control device or closed vent system is not required if it is not technically feasible or if the control device is not owned and operated by the site operator. Proposed updated rule language is included in 15.4.1.

If needed, EPA could provide provisions in the rule for an operator to make an engineering determination that an existing control device cannot technically handle the additional gas from a pneumatic pump affected source exhaust, document this determination, and make such a determination available for inspection by EPA or other competent authority.

15.3.3 EPA Did Not Consider How CTG Requirements to Route Pneumatic Pumps To Control Devices Can Potentially Trigger Permitting Requirements.

Under draft CTG, EPA is requiring that the exhaust from pneumatic pumps be controlled by control devices if those devices are present on site.

EPA's analysis of the proposed approach to pneumatic pumps has ignored the fact that such an action may require amending the air permit for a facility simply due connecting a pump to a control device. In many cases, the act of tying a new stream into a combustion control device will result in a change in emissions from a site due to the rerouting, which can trigger permitting. Local permitting requirements are very sensitive to the reality that control devices are subtle and complex engineering structures that have very real physical limits. As discussed above, EPA's proposal for natural gas pneumatic pumps seems to ignore these physical realities.

EPA has not accounted for any time or expense associated with this permitting action, nor have they considered any of the additional burden on permitting authorities. These impacts should be quantified and considered prior to finalizing the CTG requirements that may trigger state permitting requirements. One alternative to this concern is to revise the affected source criteria so that a pneumatic pump would not be an affected source, if it was connected to a control device on site. This could be accomplished by revising the text of H.1 as follows:

> Each pneumatic pump, which is a natural gas-driven chemical/methanol or natural gas-driven diaphragm pump located at a natural gas processing plant or located from the wellhead and point of custody transfer to the natural gas transmission and storage segment ~~for~~ which has not been connected to a control device when one is located on site.

An additional advantage of this approach is that it clearly removes the addition of monitoring and performance testing currently in the proposed rule. As discussed in Section 15.3.1, these costs were not included in EPA's cost effectiveness analysis, nor should compliance assurance requirements from OOOOa be required for a control device that was installed for another purpose.

15.3.4 EPA Overstated The Emissions, And Therefore The Benefits, Of The Proposed Requirements For Pneumatic Pumps

EPA has overestimated the emissions from diaphragm pumps. As EPA notes in Section 7.2.1 of the CTGs: "Diaphragm pumps are commonly used to circulate hot glycol or other heat-transfer fluids in tubing covered with insulation to prevent freezing in pipelines, vessels and tanks." As such, these pumps only during the winter season which represents a fraction of the year on average. Yet, EPA has assumed these pumps operate 8,760 hours per year when estimating emissions. This assumption grossly inflates the actual emissions from these sources. A more realistic estimate would be that these sources would operate 3-4 months during the course of the year and rarely more than 8 months per year. See discussion of cost effectiveness values in Section 15.3.1, including consideration of operation of diaphragm pumps for 4 months/year.

Diaphragm pumps are also used intermittently to transfer bulk fluids such as engine oil or emptying a sump. When used for these types of service they do not run for long periods, are not large emission sources and should not be covered by the CTGs.

API recognizes the need for EPA to simplify analysis for assessing cost benefits for the development of the CTGs. EPA presents values in Section 7 of the CTGs which are based on a number of assumptions. It should be noted that the exhaust rates from pneumatic pumps are, in reality, based on assumed pump rate, a gas-supply pressure, and a pump model. All of these values vary considerably from site to site and even from pump to pump on a given site. When one reviews several manufacturer's pumps, it is readily apparent that they all have a multiplier factor for calculating required supply pressure and allowable exhaust pressure and these factors vary by over two orders of magnitude from one pump model to the next.

15.4 Applicability/Definitions

15.4.1 The CTG Should Have An Exemption For Limited Use/Low Emission Pumps Such As Chemical Injection Pumps

API believes EPA's intent to regulate pneumatic pumps that have lower emission rates than continuous low bleed pneumatic controllers is inappropriate. EPA has previously determined that continuous bleed pneumatic controller devices emitting less than 6 scf/hour did not require control and EPA continues to support that position in the NSPS OOOOa rule proposal. EPA's Technical support document shows the assumed emission rate from pneumatic piston (chemical and methanol) pumps to be 2.48 scf/hour, which is less than half the 6 scf/hour threshold for continuous bleed pneumatic controllers. The cost effectiveness of controlling such low emitting pumps is substantially above EPA's assumed $285/ton as described Section 15.3.1. Piston pumps in services with emissions below 52,000 scf/year (equivalent to 6 scf/hour annualized) should be exempt due to the low volume of gas exhausted. Demonstration of emissions below this threshold should be a one-time engineering calculation for individual pumps or a class of pumps in similar service - for example chemical/methanol pumps below a pressure & volume combination which would yield exhausted volumes above the threshold.

There are also natural gas-driven pneumatic pumps, typically diaphragm pumps, that are used intermittently to transfer bulk liquids. These are generally either manually operated as needed or are triggered by a level controller. For instance, there are engine skid sump pumps, pipeline sump pumps, tank bottom pumps, flare knockout drum pumps, separator knockout drum pumps, etc. that are used to pump liquids from one place to another. These pumps do not run continuously or even seasonally for long periods, but only run periodically as needed. Thus, these pumps do not exhaust large volumes of gas in the aggregate. For this reason, there should be an annual venting limit and an exemption for intermittently operated pumps.

EPA should provide an exemption under the rule for any pump emitting at a rate less than the rate of a continuous low bleed pneumatic controller. Specifically, any pneumatic pump which emits less than 53,000 scf/year (i.e. 6 scf/hour for an entire year) should be exempted. This would provide a reasonable exemption for intermittent use pneumatic pumps which do not have large aggregate emissions, including diaphragm pumps that are operated manually, triggered by a level controller, or operated temporarily or seasonally.

Alternatively, EPA could use the operating time of a pump with exhaust rate of 22.45 scf/hour (equivalent to assume emission rate of a diaphragm pump from the technical support document) that would result in 53,000 scf/year of emissions, which is 96.5 days. This could be rounded down to 90 days of operation, or 2,160 hours. This approach would simplify the exemption, as companies would track the hours of operation instead of calculating the exact exhaust rate.

API proposes the following updates to the applicability text under H.1 of the model rule:

> Each pneumatic pump, which is a natural gas-driven chemical/methanol or natural gas-driven diaphragm pump located at a natural gas processing plant or located from the wellhead and point of custody transfer to the natural gas transmission and storage segment with an exhaust rate greater than 53,000 scf/year and operates more than 2,160 hours per year and for which a control device owned and operated by the owner and operator of the pump is located on site and not demonstrated to be technically infeasible to control.

15.4.2 The Rule Text Should Exempt Portable Pneumatic Pumps

There are many scenarios where portable pneumatic pumps are used by industry for infrequent and temporary operations, such as pumping out a tank or a sump. Since these pumps will, by their very nature, result in very low emissions, portable pumps should be exempt from the rule. Such as exemption would be analogous to that provided to portable or transportable (has wheels, skids, carrying handles, dolly, trailer or platform) engines relative to the NSPS RICE rules.

API recommends that EPA update the definition of pneumatic pump under the rule to exclude temporary and portable pumps.

EPA should amend the definitions in the draft rule language under Section H to address these temporary and portable sources, i.e. "A temporary or portable pump is considered a pump subject to the CTGs if the pump stays in one location for more than 12 months (or full annual operating period of a seasonal source)." (See revised definition under 15.4.3)

15.4.3 The CTG Text Should Be Clearer On Exclusion Of Lean Glycol Circulation Pumps (Often Referred To As Kimray Pumps) On Dehydration Units (As Intended By The NSPS OOOOa Preamble Language)

EPA's intent is clear in the Preamble (FR 56627) to NSPS Subpart OOOOa that EPA is not proposing to regulate glycol dehydrator pumps under that rule, but the draft CTG text is not as clear on this point.

EPA can improve this by editing the definitions in the CTGs draft rule language. The two definitions below are inconsistent; however, it is noted that neither defined term is used in the CTG text itself. EPA should remove the two definitions below.

> ~~"Chemical/methanol or diaphragm pump means a gas-driven positive displacement pump typically used to inject precise amounts of chemicals into process streams or circulate glycol compounds for freeze protection."~~
>
> ~~"Natural gas-driven chemical/ methanol or diaphragm pump means a chemical or methanol injection or circulation pump or a diaphragm pump powered by pressurized natural gas."~~

These definitions should be replaced with the following definition:

> "Natural gas-driven chemical/methanol pump or natural gas-driven diaphragm pump means a gas-driven positive displacement pump used to inject chemicals into process streams or circulate glycol compounds for freeze protection. A glycol circulation pump on a glycol dehydration unit is not a chemical/methanol or diaphragm pump. A temporary or portable pump is considered a pump subject to the CTGs if the pump stays in one location for more than 12 months (or full annual operating period of a seasonal source)."

15.4.4 The Rule Should Allow For Removal Of Control Device – I.E. Pneumatic Pump No Longer Has To Be Controlled If Control No Longer Present

If a control device is no longer needed for the purpose for which it was originally installed, EPA should clarify that any pneumatic pumps that were routed to the device should no longer require control. A control device should not be required to remain in service only for the purpose of controlling one or more pneumatic pumps.

For example, NSPS subpart OOOO allows for removal of control device from a storage vessel if emissions fall below a certain level. Specifically, under the NSPS, EPA has allowed for the removal of control devices once emissions are below 4 TPY (40 CFR 60.5395(d)(2) and 60.5395a(a)(3)). In the preamble to the NSPS OOOO revisions dated April 12, 2013 (Federal Register Vol. 78, No. 71, 22133-22134) EPA also noted that removal of control at 4 TPY will help relieve the control device shortage issue as well as reduce emissions from burning more pilot gas than the waste gas being burned. If a control device is removed, the requirement to route pneumatic pump exhaust to the control device should no longer be applicable.

15.4.5 EPA Must Define "Control Device" In The Context Of Its Use In The Requirements For Pneumatic Pumps

H.2(b)(1) states:

> *Each natural gas-driven pneumatic pump located between the wellhead and point of custody transfer to the natural gas transmission and storage segment, for which a control device is located on site, must reduce natural gas emissions by 95 percent, except as provided in paragraph (b)(2) of this section.*

Control device is not a defined term and should be specifically defined to clarify EPA's intent which, from review of the complete NSPS OOOOa proposal and TSD, appears to be to utilize combustion control devices and/or VRUs if available. This issue is discussed in Section 10.0, and a definition recommended that will eliminate the issues related to the uncertainty of when the pneumatic pump requirements apply.

However, if EPA does not elect to incorporate API's suggested changes in section 10.0, then EPA must made revisions within section H of the CTG model rule to clarify this situation. Specifically, API recommends the following change:

> **H.2(b)(1)** Each natural gas-driven pneumatic pump located between the wellhead and point of custody transfer to the natural gas transmission and storage segment, for which a control device is located on site, must reduce natural gas emissions by 95 percent, except as provided in paragraph (b)(2) of this section. For the purpose of this section, boilers,

process heaters, and other combustion devices that burn natural gas to derive useful work or heat are not considered control devices.

15.4.6 The Control Device Must Be Owned and Operated By The Pump Owner and Operator

EPA must be clear that a control device on site must be owned and operated by the same company that owns and operates the pumps. For instance, the dehydration unit located on a production site may be owned and operated by the gathering company, not the producer. If there is a dehydration unit on site with a control device that is owned and operated by the gathering company, the producer has no right to route pump exhaust to the control device and should not be required to route the pump exhaust to the dehydration control device owned and operated by a separate entity.

15.4.7 Heaters Should Not Be Considered As Existing Control Devices (i.e. Pneumatic Pump Exhaust Should Not Be Required To Be Routed To A Heater Simply Because One Is Present)

The language in section E.1 of the model rule describes requirements that each control device must meet and this list includes process heaters. This language could be misinterpreted to mean that any process heater should be considered a control device and thus, its presence would require routing of a pump exhaust to the heater. It is not believed that this was EPA's intent.

EPA should clarify that routing emissions to a process heater should be considered "routing to a process" and the heater should not be considered as a control device. More discussion on this topic is provided in section 10.0. However, if EPA does not elect to incorporate API's suggested changes in section 10.0, then EPA must made revisions within section H of the CTG model rule to clarify this situation. The recommended changes are shown above in section 15.4.5.

15.4.8 Non-Affected Facilities (e.g., Pumps Not Requiring Controls Under The CTGs Should Not Have Obligations Under The Rule)

H.3(c) states

(c) You own or operate a natural gas-driven pneumatic pump located between the wellhead and point of custody transfer to the natural gas transmission and storage segment and your pneumatic pump is not controlled by at least 95 percent because a control device is not available at the site, you must submit the certification in section H.5(a)(1)(i).

EPA should remove the requirements requiring certification for pumps located at sites without control devices. Specifically, H.3(c) should be removed from the draft CTGs.

15.4.9 The CTGs Should Not Include An Ongoing Requirement To Review The Status Of The Addition Of A Control Device

Section H.2 of the draft CTGs states:

(b)(2) You are not required to install a control device solely for the purposes of complying with the 95 percent reduction of paragraph (b)(1) of this section. If you do not have a control device installed on site by the compliance date specified by your regulatory authority, then you must comply instead with the provisions of paragraph (b)(2)(i) and (ii) of this section.

> *(i) Submit a certification in accordance with H.5(b)(1)(i).*
> *(ii) If you subsequently install a control device, you are no longer required to submit the certification in H.5(b)(1)(i) and must be in compliance with the requirements of paragraph (b)(1) of this section within 30 days of installation of the control device. Compliance with this requirement should be reported in the next annual report in accordance with H.5(a)(1)(iii).*

Companies typically do not track serial numbers on pumps, particularly small piston pumps for chemical injection. The pumps are often swapped out and moved around as needed for chemical injection. Typically pumps are purchased in bulk and maintained in a warehouse to install as needed. Trying to keep track of where these pumps are located and a control device is later added will be very difficult.

The applicability of control requirements in the CTGs should be based on an effective date of the CTG and not the construction, modification, or installation of a control device.

15.5 Reporting And Recordkeeping

15.5.1 Remove The Tagging Requirement.

It is unclear what EPA's intent is for requiring tagging of affected natural gas driven pneumatic pumps under H.2(a)(2), H.2(b)(3), and H.3(d). The applicability is clearly stated. The tagging appears to add little value.

API requests that EPA remove the following paragraphs related to tagging:

> ~~H.2(a)(2) Each natural gas-driven pneumatic pump at a natural gas processing plant must be tagged with the date the natural gas-driven pneumatic pump is required to comply with the model rule (as established by the regulatory authority) that allows traceability to the records for that gas-driven pneumatic pump as required in section H.5(a)(1)(i).~~
>
> ~~H.2(b)(3) Each natural gas-driven pneumatic pump located between the wellhead and point of custody transfer to the natural gas transmission and storage segment for which a control device is located on site must be tagged with the date that the pneumatic pump must comply with the model rule (as established by the regulatory authority) that allows traceability to the records for that natural gas-driven pneumatic pump as required in section H.5(a)(1)(ii).~~
>
> ~~H.3(d) You must tag each natural gas-driven pneumatic pump subject to VOC emission requirements according to the requirements of section (a)(2) or (b)(3), as applicable.~~

Building on section 15.4.9, if any tagging is retained, it should be to document that (a) no control device was not onsite as of the CTG effective date and therefore no further action would be needed at any time under the CTG or (b) that a pump is located with a control device on site, but the control has been determined to be technically infeasible.

15.5.2 EPA Should Remove The Recordkeeping Requirements For Control Devices And Closed Vent Systems

As discussed in Section 15.3.1, EPA's costs for controlling pneumatic pumps did not include the cost of the recordkeeping and reporting requirements in the cost estimate. The recordkeeping and reporting requirements that EPA has included are burdensome in some cases and expand requirements to non-affected sources.

- H.3(c) requires certification of non-affected sources (Section 15.4.8).
- H.4 requires testing data to be submitted that is not accounted for in the cost analysis, not cost effective when included, and not needed based on the exhaust gas being natural gas, which is the same as the pilot of the combustion device (Section 15.2). EPA should remove the combustion control device testing, monitoring, reporting, and recordkeeping requirements.
- H.5(a)(1)(i) – It is not clear what EPA means by records of "the manufacturer specifications". EPA should clearly specify what they want here. It is assumed this refers to the make model of the pump.
- H.5(a)(1)(ii) – Having to continue to track the data of a pump being constructed, reconstructed, or modified at a non-natural gas processing plant location that did not have a control device that later has one installed. Pumps should only be triggered at the time the pump is installed. With the movement and replacement of pumps, keeping track of such information will be extremely difficult. (See Section 15.4.9)

In many instances, these controls have been installed under a state permit (or other regulatory requirement) and have compliance assurance requirements associated with those requirements. It is inappropriate to add new compliance assurance requirements that may conflict to the original requirements the control device was installed to meet. Additionally, the control device may not be able to meet or be retrofitted to meet (i.e. install sample ports) to meet the compliance assurance requirements of the CTG model rule.

API recommends the amendments to the draft rule language as outlined for pumps in these rule comments and those below.

> H.5(b)(1) For each natural gas-driven pneumatic pump subject to VOC emission control requirements, annual reports are required to include the information specified in paragraphs (b)(1)(i) through (iv) of this section.
> ~~(i) In the initial annual report, a certification that there is no control device on site, if applicable.~~
> (ii) An identification of each natural gas-driven pneumatic pump, including the identification information specified in section H.2(a)(2) or (b)(3).
> (iii) An identification of any sites which contain natural pneumatic pumps and which installed a control device during the reporting period, where there was no control device previously at the site.
> (iv) Records of deviations specified in paragraph (c)(16)(ii) of this section that occurred during the reporting period.
> ~~(v) If complying with H.2(b)(1) with a control device tested under section F(d), which meets the criteria in section F(d)(11) and section F(e), records specified in paragraphs (a)(1)(iv)(A) through (G) of this section for each pneumatic pump constructed, modified or reconstructed during the reporting period.~~

H.5(a)(1) For each applicable natural gas-driven pneumatic pump subject to VOC emission control requirements, you must maintain the records identified in paragraphs (a)(1)(i) through (iii) of this section onsite or at the nearest local field office for at least five years.

> (i) Records of the date that an individual natural gas-driven pneumatic pump is required to comply with the model rule (as specified by the regulatory authority), location and

~~manufacturer specifications~~ make and model for each natural gas-driven pneumatic pump.

(ii) Records of deviations in cases where the pneumatic pump was not operated in compliance with the requirements specified in section H.2.

(iii) ~~Records of the control device installation date and the location of sites containing pneumatic pumps at which a control device was installed, where previously there was no control device at the site.~~

(iv) ~~Except as specified in paragraph (a)(iv)(G) of this section, records for each control device tested under section F(d) which meets the criteria in section F(d)(11) and section F(e) and used to comply with H.2(b)(1) for each pneumatic pump.~~

~~(A) Make, model and serial number of purchased device.~~

~~(B) Date of purchase.~~

~~(C) Copy of purchase order.~~

~~(D) Location of the pneumatic pump and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.~~

~~(E) Inlet gas flow rate.~~

~~(F) Records of continuous compliance requirements in F(e) as specified in paragraphs (a)(1)(iv)(F)(1) through (4) of this section.~~

~~(1) Records that the pilot flame is present at all times of operation.~~

~~(2) Records that the device was operated with no visible emissions except for periods not to exceed a total of 2 minutes during any hour.~~

~~(3) Records of the maintenance and repair log.~~

~~(4) Records of the visible emissions test following return to operation from a maintenance or repair activity.~~

(G) As an alternative to the requirements of paragraph (a)(1)(i~~v~~)(D) of this part, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the pneumatic pump and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the pneumatic pump and control device with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

16.0 EPA MUST RESOLVE THE OVERLAP AND REDUNDANCY BETWEEN THE COVER AND CLOSED VENT SYSTEM AND FUGITIVE EMISSION REQUIREMENTS

In D.2(b) of the CTG model rule, EPA included initial and continuous inspection and monitoring requirements for covers and closed vent systems. These requirements consist of a program to identify leaks on covers and closed vent systems and repair them. In addition, the model rule includes a fugitive emissions program in Section I that is also based on identifying and repairing leaks. Section I will also apply to covers and closed vent systems, as the definition of "fugitive emissions component" includes "closed vent systems," and "thief hatches or other openings on storage vessels." This results in covers and CVS being subject to both the leak detection and repair requirements in Section I and the leak detection and repair requirements in Section D. This creates a situation which is unnecessarily duplicative and redundant.

Table 16-1 provides a summary of these overlapping requirements.

Table 16-1 Summary of the Overlapping Closed Vent System and Cover Requirements in NSPS Subpart OOOO

<table>
<tr><th rowspan="2">Affected Equipment/Components</th><th colspan="2">D.2</th><th colspan="2">I</th></tr>
<tr><th>Inspections</th><th>M21</th><th>OGI</th><th>M21</th></tr>
<tr><td>closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (e.g., a welded joint between two sections of hard piping or a bolted and gasketed ducting flange)</td><td>(a)(2)
annual visual inspections for defects</td><td>(a)(1)
Initial, annual, and
after repairs/ replacements</td><td rowspan="3">Initially, semiannually (could move to quarterly or annual depending on % leakers), and after repair/ replacement</td><td rowspan="3">Option for use after repair/ replacement</td></tr>
<tr><td>Closed vent system components other than a joint, seam, or other connection that is permanently or semi-permanently sealed</td><td>(b)(3)
annual visual inspections for defects</td><td>(b)(1) and (2)
Initial, annual, and
after repairs/ replacements</td></tr>
<tr><td>Covers</td><td>(c)
annual visual inspections for defects</td><td>n/a</td></tr>
</table>

API does not believe that this was EPA's intention, as EPA did not include component counts and cost estimates for monitoring the storage vessel cover or the closed vent system with the LDAR cost estimates. EPA only included counts in the model plant for components for a wellhead, separator, heater, and dehydration unit according to the CTG (Table 9-4 and Table 9-5).

API believes that the appropriate and most effective solution is to require the same methodology to monitor the cover and CVS and other fugitive leaks, and that OGI is the most effective methodology. OGI can see the leaks regardless of the type of system. There is no need for additional monitoring on top of the OGI monitoring.

To avoid duplicative monitoring requirements, API recommends clearly defining "closed vent system" consistent with NSPS Subpart definitions, that is entirely separate from "fugitive emission component". By having a separate definition for closed vent system, a subset of fugitive components is created for affected facilities with closed vent systems that are subject to fugitive monitoring requirements even if the rest of an existing site, for example, is not subject to fugitive monitoring requirements in Section D. The net result is one consistent set of fugitive monitoring requirements that allows for use of OGI whether fugitive components are part of a closed vent system or part of another process.

Following are descriptions of these recommended improvements.

16.1 Define "Closed Vent System"

As noted above, API recommends that EPA add a definition of a closed vent system in the CTG model rule. The components of a closed vent system may have fugitive components included but also has additional components outside of fugitives that ensure the emissions are being routed to the control device. Under NESHAP Subpart HH, EPA defined closed vent system as

> *"Closed-vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and if necessary, flow inducing devices that transport gas or vapor from an emission point to one or more control devices. If gas or vapor from*

> *regulated equipment is routed to a process (e.g., to a fuel gas system), the conveyance system shall not be considered a closed-vent system and is not subject to closed-vent system standards."*

API recommends the same definition of closed vent system be added to the CTG model rule with an additional clarification **(bold)** that would include covers in the definition. This would ensure that all of the leak detection and repair requirements would also apply to components and openings on covers.

> *Closed-vent system* means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and if necessary, flow inducing devices that transport gas or vapor from an emission point to one or more control devices. If gas or vapor from regulated equipment is routed to a process (e.g., to a fuel gas system), the conveyance system **except for components and other openings on the cover of the equipment** shall not be considered a closed-vent system and is not subject to closed-vent system standards.

API recognizes that there are a number of interrelated aspects of this definition and the requirements related to the definitions of "routed to a process or route to a process" and "fugitive emissions component", as well as the associated requirements. Due to the insufficient length of the comment period, API is not offering a comprehensive recommendation in these comments. However, API will provide supplementary information with such a recommendation following the end of the comment period.

16.2 Remove Cover and Closed Vent Systems Components From Definition Of Fugitive Emissions Component

In order to totally resolve the redundancy in the cover and closed vent system and fugitive component requirements, the definition of "fugitive emissions component" in I.6 needs to be modified.

> Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, ~~closed vent systems, thief hatches or other openings on a storage vessels,~~ agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.

API has several other suggestions related to this definition. While they are not shown here since they are not related to closed vent systems and covers, they are provided and discussed in Section 17.2.1.

16.3 Remove Section D.2

API recommends that all paragraphs of Section D.2 be removed. As shown in Table 16-2 every relevant requirement of D.2 will be addressed by referring to a requirement in Section I, or in the case of the bypass requirements, requirements in D.1. In many cases, moving to the OGI-based requirements will result in a more robust program to identify and repair leaks from closed vent systems and cover components.

Table 16-2 Side-by-Side Comparison of CTG Model Rule Section D.2 and Section I Closed Vent System and Cover Requirements

D.2	Section D.2 Requirement	I	Section I Requirement
(a)	CVS Joints, seams and other connectors - Initial M21 and annual visual inspections.	I.2 – I.4	All components – OGI monitoring initial and semi-annual
(b)	Other CVS components - Annual M21 and annual visual inspections		
(c)	Covers - Annual visual inspection		
(d)	Bypass	n/a	Not addressed in section I, but completely addressed in D.1(b)(3)
(e)	M21	not needed	Not needed
(e)(1)-(8)	M21 requirements		
(e)(9)	Repairs - First attempt within 5 days, repair within 15 days.	I.2(f)(1)	Repairs - Repair within 15 days.
(a)(2)	For CVS Joints, seams and other connectors only – monitor using M21 after repair/replacement	I.2(f)(2)	Resurvey (all components) using OGI or M21 within 15 days of repair
(e)(10)	Delay of repair - If technically infeasible without shutdown – do at next shutdown	I.2(j)(1)	If technically infeasible during operation of the unit, do at next shutdown or within 6 months, whichever is earlier
(e)(11)	Unsafe to inspect	n/a	Not necessary for OGI monitoring
(e)(12)	Difficult to inspect		
(e)(13)	Records	I.5(a)	Records

The related recommended rule changes throughout the CTG model rule to refer to the analogous sections of Section I rather than Section D.2 are provided in section 16.5.

16.4 The Requirements Do Not Need To Address Covers On Unconcontrolled Storage Vessels And Covers And Closed Vent Systems On Storage Vessels Subject To Legally And Practically Enforceable Requirements

The changes recommended by API above will eliminate the redundancy in requirements for covers and closed vent systems on centrifugal compressor, pneumatic pump, and storage vessel affected facilities under the CTG model rule.

Under the draft model rule scenario, covers on uncontrolled storage vessels would have been subject to the fugitive emissions requirements. These covers will not be subject to any leak monitoring and repair requirements under the changes recommended by API above. However, as discussed in the following, requiring these covers to be monitored would add no value. If a tank is uncontrolled (i.e. <6 tpy VOC uncontrolled) then leaks would be accounted for as part of the allowable emissions for the uncontrolled storage vessel. Thief hatches and pressure relief devices have an inherent leak rate since they are not welded shut. However, emissions from the thief hatch and pressure relief device are accounted for in the emission determined using EPA's AP-42 7.1 with TANKS 4.09 and when flash emissions are estimated.

Thief hatches that are weighted or spring tensioned serve as emergency overpressure relief devices in addition to providing a point of access for obtaining a sample of the material stored in the storage vessel or for gauging the liquid level. Thief hatches act in combination with the pressure/vacuum (P/V) relief devices to prevent overpressure and bursting of a tank. During normal operations, neither the P/V devices nor the thief hatch will open. In the rare occurrence of overpressure conditions, the P/V devices will open to vent tank vapors. If the P/V devices flow capacity is not sufficient to prevent further overpressure of the tank, then the thief hatch will open to provide additional venting capacity. Such an overpressure incident may be due to a rapid inflow of produced fluid/gas into the storage vessel if, for example, a separator "dump valve" sticks open or fails. The functionality of P/V devices and thief hatches as overpressure relief devices must be preserved to enable safe operation. If the storage vessel is not controlled, these devices are not acting as part of a closed vent system, but rather overpressure relief.

If the tank is controlled under another legally and practically enforceable mechanism like a state permit, the closed vent monitoring requirements for the storage system would be covered by the state, and thus would also be legally and practically enforceable.

16.5 Recommended Changes To NSPS Subpart OOOOa Related To Closed Vent System And Cover Fugitive Monitoring

As noted above, API's recommendation is to have the covers and closed vent requirements throughout the CTG model rule refer to the fugitive monitoring and repair requirements in Section I rather than the cover and closed vent system requirements in Section D. Following are the specific suggested regulatory changes.

I.1 (f) ~~For fugitive emissions components also subject to the repair provisions of sections D.2(e)(9) through (12) and (f)(4) through (7), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (f)(1) and (2) of this section do not apply to those closed vent systems and covers~~. You must comply with the requirements of paragraphs (f)(1) and (2) of this section.

A.3(e) You conduct the initial cover and closed vent system inspections required in section ~~D.2~~ I within 180 days after the effective date of this rule as established by your regulatory authority.

A.5(a)

(1) If required to reduce emissions by complying with section A.2(a), the records specified in paragraphs (a)(6) through (8) of this section and section ~~D.2~~ I.5(a), as applicable.

(6) Records of each closed vent system inspection required under section ~~D.2(a) and (b)~~I.

(7) A record of each cover inspection required under section ~~D.2(c)~~I.

(8) If you are subject to the bypass requirements of section ~~D.2(d)~~D.1(b)(3), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

C.4(a)(4) You conduct the initial cover and closed vent system inspections required in section ~~D.2~~I within 180 days after the effective date specified by your regulatory authority.

C.6(a)(1)

(iii) Records of each closed vent system inspection required under section ~~D.2(a) and (b)~~I.
(iv) A record of each cover inspection required under section ~~D.2(c)~~I.
(v) If you are subject to the bypass requirements of section ~~D.2(d)~~D.1(b)(3), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.
(vi) If you are subject to the closed vent system no detectable emissions requirements of section ~~D.2(a) and (b)~~I, a record of the monitoring in accordance with section ~~D.2(e).~~ I.5(a).

17.0 FUGITIVE EMISSIONS AT WELL SITES AND COMPRESSOR STATIONS

17.1 General

The following section addresses comments on EPA's proposed requirements for fugitive component emissions. Comments are organized around the following topics:

- Applicability
- Impacts, Emissions and Costs
- Work Practices and Inspections
- Testing and Monitoring
- Reporting and Recordkeeping.

17.2 Applicability

17.2.1 The Definition Of Fugitives Emissions Component Is Confusing, Which Leads To Duplicative Facility Applicability Requirements For Leak Detection And Closed Vent Systems

The definition of *fugitive emission component* is inconsistent with historical definitions for other leak detection programs. In those programs, including the one in Subpart OOOO and OOOOa for gas processing plants, fugitives emission components are defined as *Equipment*. While it may be appropriate to have a separate definition apart from that used in gas processing plants, it should be reflective of the Equipment definition and not be more expansive to include equipment that is neither a fugitive component nor part of another system. Our recommended text changes to the definition can be found at the end of this section (see Section 17.2.11).

The definition is also not consistent with the TSD for the rulemaking (Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Facilities, Background Technical Support Document for the Proposed New Source Performance Standards. 40 CFR Part 60, subpart OOOOa, August, 2015). The TSD cites the white paper for the monitoring methods evaluated (Section 5.1 on page 47) and does not include blowdown lines in the description of "potential sources of fugitive emissions", but includes them in the definition of "fugitive emissions component". The white paper clearly states that emissions from blowdown lines/vents are "considered to be vented emissions and not leaks" for the purposes of the paper (page 13).

Furthermore, the types of fugitive emissions components that EPA has proposed is inconsistent with the types of components in Subpart W, which varies by reporting sector, but generally includes: valves, connectors, flanges, open-ended lines, pressure relief valves, control valves, block valves, orifice meters, regulators, pumps, and other (Tables W-1A through W-7 to Subpart W of Part 98). This will cause confusion between the two programs. Also, this definition is inconsistent with the definition used in NSPS Subparts VVa, KKK, and GGGa. Subpart VVa defines Equipment as "*each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart*" (§60.481a). Under Subpart KKK, EPA defined Equipment as *"each pump, pressure relief device, open-ended valve or line, valve, compressor, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by this subpart"* (§60.631). GGGa defines Equipment as "*each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment*" (§60.591a).

Since these CTGs includes separate closed vent system monitoring requirements for what is essentially a collection of fugitive emission components, *closed vent system* requires its own definition so that closed vent system requirements can stand alone and are not subject to duplicative compliance requirements as currently proposed when also included in this definition. More detailed comments that address this issue for closed vent systems are found in Section 12.0. Other equipment inappropriately included in this definition includes:

"access doors, …, thief hatches or other openings on storage vessel, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters."

The equipment list above that should be excluded from the definition are not fugitive components, but rather parts of systems or equipment such as the separators, pressure vessels, dehydrators, and heaters that may have fugitive components, and fugitive component monitoring would be applicable when required. Thief hatches , which are part of closed vent systems, have complexities of operation and design, as discussed in section 16.0, thief hatch monitoring is NOT needed for storage vessels with no closed vent system since thief hatch design and operation is not important with low emission tank that already vents to atmosphere. Including thief hatches with CVS eliminates unnecessary monitoring under Section I of the model rule.

Vents are not fugitive components because they are designed to vent. Compressors are covered in their own section of this rule. Instruments and meters are not defined and some are designed to vent.

The following section in the definition also needs to be deleted as it is confusing and sets conditions upon which it may or may not be a fugitive component which creates a circular conundrum for a monitoring plan:

> ~~*"Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions."*~~

With the section above in the definition, devices described are not fugitive components if it is not leaking as described. But if it is leaking, it is a fugitive component. Since it cannot be known ahead of time if it is leaking as described, there is no monitoring requirement because it is not a fugitive component until it is determined that it is leaking. These equipment types are not fugitive components, and other directed maintenance programs ensure that this equipment operates as designed.

API's requested revisions to the definition of Fugitive Emissions Component are provided at the end of this section (see Section 0).

17.2.2 States Should Have The Ability To Utilize Existing LDAR Regulations In Their SIPs Rather Than The EPA Model Rule

EPA did not consider the inconsistencies with state LDAR programs (CO, PA, WY, TX, CA, etc.). This creates duplicative and potentially conflicting requirements with no little environmental benefit. If a state has a leak program in place, the CTG should not impact or disrupt the existing state program. If the EPA has approved a SIP, then the state should be allowed to utilize their existing LDAR regulations rather than following the EPA CTG model rule since the EPA has already approved of the state's LDAR program as part of the SIP. This would eliminate duplicity and redundancy in the state and federal rules.

17.2.3 The 15 BOE Exemption In I.1(a) Recognizes Low Volume Production Being Lower Emission And Sensitive To Additional Cost Burden

Fugitive emissions do not correlate to production. A production rate gives no indication of the type or number of equipment that are located at the site. In addition, this exemption is irrelevant for new well sites which would not be economical to produce at 15 boe/day. This exemption might only be useful in the rare event of a modification to a stripper well.

API believes it more appropriate and would prefer that the CTG be based on the process equipment located at the site rather than a low production rate since fugitive emissions are based simply on the number of components associated with the process equipment.

API would prefer that the rule be based on the equipment located at the site rather than some arbitrary production rate. As indicated in Section 17.2.7, API believes that sites with equipment configurations or component counts less that the model plants should be exempt from the LDAR requirements, as based on EPA's analysis, LDAR is not cost effective at sites with fewer equipment/components.

17.2.4 The 15 BOE Exemption Is Not The Only Exemption To Consider

The 15 BOE/day exemption will generally not be useful for new sites since this level of production is consistent with a stripper well. Stripper wells represent wells near the end of their productive life not the beginning. Consequently, it would be rare for operators planning to construct well sites with initial production at this low level. The usefulness of this provision is at the end of a well's productive life as an off ramp to exempt being an affected facility much like being able to remove a control device at less than 4 tpy of storage vessel emissions. However, it would be useful for modified or reconstructed sources.

Another exemption is based on GOR. EPA recognizes that oil wells with little to no gas volumes should be exempt from REC requirements based on a low GOR of 300; this same GOR should also be another threshold to exempt well sites from leak detection. If gas volumes are so low that gas gathering is uneconomic, it is not cost effective to have leak detection requirements for little to no methane or natural gas reductions. Since VOC reduction alone is not cost effective, the lack of natural gas production should be a factor in affected facility exemptions.

Text change recommendation to reflect these comments are provided in Section 0.

17.2.5 The Definition Of Well Site For Fugitives Is Problematic And A New Definition For "Central Production Site" Is Needed

EPA has expanded the definition of a well site to include tank batteries not at a well site, as follows:

Well site means one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, natural gas well, or injection well and its associated well site. For the purposes of the fugitive emissions standards at section I.1, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water condensate from wells not located at the well site (e.g., centralized tank batteries). For the purposes of the fugitive emission requirements, a well site that only contains one or more wellheads is not subject to these requirements. (CTG I-8)

The proposed definition of "well site" includes both a well pad and other sites with process equipment that receives produced fluids from wells. The definition is problematic in that it can be interpreted to mean that all well pads connected to a tank battery or other centralized station can be aggregated as part of a single well site. This is unprecedented and appears to be an attempt to aggregate sites that are not otherwise contiguous or adjacent but instead functionally interrelated. This could lead to conflict with the Source Determination rule leading to potential permitting questions subject to variable interpretations. In Source Determination, courts have ruled against functional interrelatedness. In effect, EPA is applying Option 2 from the Source Determination proposal to define a source in NSPS. **It is inappropriate to aggregate sites.**

This erroneous definition change is being made to support the misconception that hydraulic fracturing increases fugitive emissions and constitutes a modification. The practical result of this error is that EPA's proposed definition of "well site" dissociates from the common sense and generally accepted and practically understood use of the term within industry. As well, tank batteries may or may not be tank batteries because of a false construct based on the activity at a distinctly separate surface site that has one or more wells. Additionally, the wellhead only exemption is rendered meaningless since aggregating separate surface sites into one means there will be no wellhead only well sites since wellhead only sites can produce to centralized tank batteries which would now be considered part of the wellhead only well site. EPA should instead consider a well site to be a distinct and separate surface site from a central processing site with no wellheads. API's recommended definition is provided in Section 0.

Another outfall of trying to define a well site other than in its generally accepted and common sense definition is that EPA assumes that any wellsite such as a wellhead only site produces to a central tank battery. This is not always true, there are other possibilities. A well could produce to a tank battery, a compressor station, or a tank battery combined with a compressor station, any of which may also happen to have one or more wells on the same surface site, making them well sites. Consequently, the collection of well sites that go to a central tank battery with no wells make the battery and the collection of well sites an aggregated single well site. But, if the central tank battery happens to include an onsite well, it is a separate well site, not an aggregated well site. These various operating scenarios complicate determinations of well site as proposed when a definition includes sites with no wells. This argues for each separate surface site to be evaluated independently for modifications without attempted aggregation.

As described in the previous paragraph, there are multiple centralized site configurations which complicate the applicability requirements. While the previous paragraphs discussed the issues with the definition of a "well site", a new definition is needed to more accurately account for centralized sites. API recommends the terms "central production site" and "transmission compressor station" replace the use of the single term "compressor station". A central production site properly defined encompasses central gathering and boosting compressor stations, tank batteries, and combination tank batteries and compressor stations that have no wellheads located on the same surface site. Central production sites are located between a well site and natural gas processing plant or transmission pipeline. The recommended definition is found below at the end of this section.

17.2.6 EPA Must Exclude Co-Located Midstream Assets From Well Sites

In the final rule, EPA must clearly exclude co-located midstream assets from the fugitive emission monitoring program for well sites. As proposed, EPA's broad definition of "well site" and "fugitive emission component" could be interpreted to subject midstream assets to fugitive emission monitoring requirements simply because they are located in geographic proximity to a production facility. Such an approach is inconsistent both with the way that the oil and natural gas sector operates and with the CAA. Upstream natural gas production and midstream gas gathering and processing are fully distinct and sequential portions of the natural gas sector supply chain. Appropriate clarifications and changes to the proposed rule need to be addressed so that co-located midstream assets are not inadvertently included in fugitive emission monitoring requirements designed for well sites.

Including co-located midstream assets in the fugitive emissions monitoring program for well sites is inappropriate for a number of reasons. First, equipment owned, operated, or leased by midstream operators is legally distinct from equipment owned, operated, or leased by upstream producers. Given their separate and distinct legal status EPA must establish separate requirements for upstream and midstream equipment. It is arbitrary and capricious to include some midstream assets in the fugitive emissions monitoring program simply because they are co-located within the footprint of a well pad site while excluding other midstream equipment that is located on a separate parcel of land.

API believes that the recommended definition changes discussed above in section 17.2.5 will partially help alleviate this problem. However, API recommends that EPA should also limit well site requirements to the equipment owned or operator by the well operator. API notes that more detail on this issue is provided in comments submitted by the Gas Processors Association (GPA), along with recommended regulatory text.

17.2.7 Only Sites With Major Equipment (Such As Separator, Heater, Or Glycol Dehydrator) Should Be Subject. The Proposed Requirement To Exempt Sites With Only Wellheads Is Not Adequate

"For the purposes of this guideline, fugitive emissions recommendations would not apply to well sites that only contain wellheads." (CTG 9.1)

API agrees that a well site consisting only of wellheads should be exempt due to the small number of fugitive components. It would be overly burdensome, with little gain in emission reductions to broadly require LDAR programs at sites without process equipment located at the well site.

Similarly, API believes that additional exemptions should apply. EPA's Model Plants used in the Technical Support Document (TSD) for NSPS Subpart OOOOa are based on the following assumed equipment and component counts.

Table 17-1 EPA Model Well Site Equipment and Compressor Counts

	Assumed Equipment Counts		***Assumed Component Counts***	
Gas Well Sites	Wellheads	2	Valves	114
	Separators	2	Connectors	414
	In-line Heaters	1	OELs	14
	Dehydrators	1	PRVs	6
Oil Well Sites	Oil Wellheads	2	Valves	29
	Separators	1	Connectors	104
	Headers	1	OELs	1
	Heater/Treaters	1	PRVs	1

EPA uses these model well sites to establish the cost effective basis for the rule. Implementing LDAR is not cost effective at sites with component counts less than the model well sites. It is overly burdensome with little gain in emission reductions to broadly require LDAR programs at sites without process equipment located at the well site. API believes that any well site with equipment configurations or component counts less than the model well sites should be exempt from the LDAR requirements. This would exclude well sites with just wellheads, meter runs, pipeline risers, etc. and no production equipment, such as separators, heaters, and dehydrators.

There is a related inconsistency in the CTG text. Section 9.1 (Applicability) says that "for the purposes of this guideline, the emissions and programs to control emissions discussed herein would apply to the collection of fugitive emissions components at a well site … and compressor stations in the production segment". However, Section 9.4 (Recommended RACT Level of Control) refers to "RACT for the collection of fugitive emission components at well sites … and gathering and boosting stations".

17.2.8 Based On EPA's Estimates, LDAR Requirements For Oil Well Sites Are Not Cost Effective. Therefore, Oil Wells Should Be Exempt From The CTG LDAR Requirements

Similar to the proposed low producing well site exemption for fugitives, oil well sites should be exempt from the LDAR requirements as discussed earlier (Section 2.2). This is based on the costs, cost effectiveness, and benefits estimated for oil wells.

17.2.9 EPA Should Establish An Applicability Criteria Based On VOC Content Of The Gas Stream.

Unlike other equipment leak regulations, EPA neglected to include any kind of de minimis threshold concentration for VOC. For the CTG, since it is only related to VOC reduction guidance, it should provide a VOC threshold for LDAR as it does for tanks. API believes that the cost effectiveness calculation (see section 2.7 & 8) supports a VOC Threshold of 7% VOC by weight. API does not believe that even the 1% threshold used in the 1983 fugitive monitoring CTG for Natural Gas Processing Plants is supportable.

17.2.10 Components At Enhanced Oil Recovery Fields Must Be Exempted From The Fugitive Emissions Standards In Subpart OOOOa

Background on Enhance Oil Recovery

Crude oil development and production in U.S. oil reservoirs can include up to three distinct phases of recovery: primary, secondary, and tertiary recovery. During primary recovery, the natural pressure of the reservoir or gravity drive oil into the wellbore, combined with artificial lift techniques (such as pumps) which bring the oil to the surface. Secondary and tertiary recovery techniques, which are often referred to as Enhanced Oil Recovery, or EOR, extend a field's productive life generally by injecting water, gas, heat, or chemicals to displace oil and drive it to a production wellbore.

Examples of secondary EOR techniques includes water floods, and tertiary EOR techniques includes thermal recovery floods (e.g., steam), and gas injection floods (e.g., CO_2). These EOR oil recovery techniques are used in oil fields to improve oil recovery after reservoir gas has been produced, and reservoir pressure and primary oil production are very low (e.g., no reservoir energy). In addition, the reservoir gas is artificially or mechanically changed with inert gases. Inert gases include nitrogen, hydrogen sulfide (H_2S), and CO_2. These inert gases may be required to be gathered and process through specialty gas plants prior to sale. EOR is commonly found in older oil fields.

Water flooding is used to increase oil production by injecting a substantial amount of water into the oil reservoir rock voidage and increasing reservoir pressure. The injected water displaces the oil and carries the fluids to production wells. Water to oil ratios can be greater than 90%. In some EOR water floods, H_2S and other inert gases are generated in the reservoir. As a result, surface production equipment (i.e., plant) must be designed to handle high volumes of water and 3-phase fluids, and contain the potential "sour" and inert/contaminated gases for personnel safety reasons.

Thermal flooding is used to improve heavy oil recovery by injecting steam into the oil reservoir. Heavy oil has low viscosity, gas to oil ratio (GOR), and typically an API Gravity <18. The steam increases the heavy oil temperature reducing the viscosity allowing the oil to be produced from the well via artificial lift. The thermal surface equipment is designed to manage high volumes of water, heat the water, inject the steam, produce the hot oil, generally 2-phase separation of the fluids, and contain the low volumes of potential "sour" and contaminated gases for personnel safety reasons. Steam floods can generate substantial concentrations of hydrogen sulfide.

Gas injection (CO_2) flooding is used to improve oil recovery by injecting a miscible gas and water into the oil reservoir. The miscible gas, water, and increased reservoir pressure improves oil recovery and fluid sweep. Gas and water are injected into wells and the oil, water, and contaminated inert gas is recovered from production wells. The surface equipment is designed to manage high volumes of water, high pressure gas (e.g., CO_2 as a liquid), injection system, production/gathering system for the multi-phase liquids, high and low pressure separation of the fluids, and greater than 30% inert and potential "sour" gases. Due to the displacement characteristics of CO_2 and Immediately Dangerous to Life or Health (IDLH) for H_2S, the surface equipment is designed for personnel and public safety reasons.

EOR Gas Gathering Systems and Plants are designed to transport and process the volumes and EOR recovered gases that include CO_2, nitrogen (N_2) and H_2S.

EPA Did Not Consider EOR Operations

Oil production fields that utilize EOR have very different gas stream compositions and characteristics from the types of operations that EPA evaluated in the development of the proposed NSPS Subpart OOOOa and the CTGs. These differences have a significant impact on the VOC emissions. EPA's model plants and representative gas compositions used to evaluate the impacts that drove the regulatory decisions are derived from natural gas fields and natural gas processing plants, and these operations do not represent EOR operations. For example, EPA used a single nationwide gas composition to estimate fugitive emissions from all sources.[36] This gas composition includes 3.2% inerts by volume. In the limited time available during the public comment period, API did a very brief survey of member companies and found that the inert content of the gas streams in EOR fields ranged from 14% to over 64% by volume, depending on the type of EOR technique used. Obviously this significant difference in gas composition will have a tremendous impact on the baseline VOC and methane emissions and the emission reductions achieved by the fugitive emission requirements. And without a doubt, the decisions made by EPA regarding the reasonableness of the cost in relation to the VOC and methane emission reductions would not be applicable to EOR fields.

From a careful review of the background information for proposed NSPS Subpart OOOOa after which the CTGs are modeled, it appears that EPA did not consider EOR fields in any manner. A search of the September 18, 2015 preamble, the Background Technical Support Document, and the Regulatory Impact Assessment did not find a single mention of "enhanced oil recovery."

However, while EPA did not consider EOR operations in this rulemaking, clearly they are aware of these operations and the emissions. Subpart W of the GHG reporting program requires the reporting of GHG emissions from EOR operations and defines *enhanced oil recovery as follows:*

> *Enhanced oil recovery* (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this subpart, EOR applies to injection of critical phase or immiscible carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

Further, subpart W requires reporting of GHG emissions from two specific EOR operations - EOR injection pump blowdown and EOR hydrocarbon liquids dissolved CO_2. Note that in both instances EPA only requires the reporting of CO_2, indicating EPA's expectation that little or no methane would be emitted. Therefore, not only was EPA aware of these EOR operations, EPA had available GHG data from the GHG reporting program that they could have utilized. But they chose to totally ignore this segment in the industry in all technical evaluations.

Conclusions and Recommendation

Following are the conclusions regarding EOR.

- EOR fields are very different from the types of operations EPA evaluated in the development of the proposed NSPS Subpart OOOOa requirements.

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[36] Memorandum. Brown, Heather P, EC/R Incorporated to Moore, Bruce, EPA/OAQPS/SPPD. Composition of Natural Gas for use in the Oil and Gas Sector Rulemaking. July 28, 2011.

- The gas streams at EOR fields have an inert gas content radically higher than the representative gas composition used by EPA in the evaluation of control options for Subpart OOOOa and the CTGs.
- These differences will have a significant impact on the VOC baseline emissions, emission reductions, and cost effectiveness.
- Based on the fact that EPA did not once mention EOR in the CTGs or background documents, it is clear that there was no evaluation conducted for this segment of the oil and natural gas industry.

Given these facts, EPA must include an exemption for EOR operations from the fugitive leak requirements in the CTGs. Recommended CTG changes are provided in Section 0.

If EPA elects not to incorporate the changes suggested by API above, EPA cannot require EOR fields to comply with the fugitive leak requirements in the CTGs without a full evaluation of emissions, controls, costs, and impacts specific to these unique operations in the oil and natural gas industry and a separate proposal that provides the rationale for any rulemaking for EOR operations. If EPA chooses to follow the path, API will work with EPA to gather accurate information for their analysis.

17.2.11 Produced Water Injection Facilities Should be Exempt from the Requirements

Injection well facilities receive produced water that has been physically treated to remove liquid hydrocarbons and natural gas before arriving at the facility. For the following reasons these facilities should not be included in the fugitive monitoring program:

- They contain operations and activities associated with produced water delivery, storage, and injection.
- These facilities are constructed to manage a producing field's water production.
- Natural gas is not typically associated with these facilities.
- There are limited liquid hydrocarbons present at these facilities. Thus, there are very limited emissions from the storage vessels therefore storage vessels vent to atmosphere and are not controlled.
- Hydrocarbons are removed from the water prior to arriving at the injection well facility to avoid loss of revenue.

There is little to no environmental benefit in subjecting these injection well facilities to LDAR requirements and requiring additional resources which could be used for a better purpose. If EPA had considered the cost effectiveness of LDAR on injection well facilities, the results would show a net negative benefit. Therefore, injection well facilities should be excluded from the LDAR requirements. The recommended regulatory change for this exemption is provided in Section 17.2.12.

17.2.12 Recommended Text And Definition Changes Based On Comments In This Section

I.1 Applicability

(a) The collection of fugitive emission components at a well site with wells that produce, on average, greater than 15 barrel equivalents per day.

(1)The fugitive emissions requirements of this section do not apply to well sites that only contain wellheads.

(2) The fugitive emissions requirements of this section do not apply to any well site or process unit with a GOR less than 300.

(3) The fugitive emissions requirements of this section do not apply to any oil well site requiring mechanical artificial lift such as a rod pump or submersible pump with no associated gas gathering system.

(4) The fugitive emissions requirements of this section do not apply to a well site with one or more wellheads that does not include installation of at least one of the following: a separator, heater, or glycol dehydrator.

(6) The fugitive emissions requirements of this section do not apply to a well site that produces oil with either an API gravity less than 18˚or a GOR less than 300 scf.

(7) The fugitive emissions requirements of this section do not apply to an EOR .

(8) The fugitive emissions requirements of this section do not apply to a water injection well.

(b) The collection of fugitive emission components at a central production site or a transmission compressor station~~located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or to an oil pipeline~~.

Central production site means one or more contiguous surface sites with no wellheads and with a collection of either one or more gathering or boosting natural gas compressors, one or more crude oil or condensate storage vessels, or both that process crude oil or natural gas and located between a well site and natural gas processing plant or natural gas transmission line, but is not co-located with a well head.

Fugitive emissions component means each pump, pressure relief device, open-ended valve or line, valve, flange or other connector that is in VOC or natural gas service at a well site, central production site, or transmission compressor station but not including a natural gas processing plant process unit. ~~any component that has the potential to emit fugitive emissions of VOC at a well site or compressor station, , including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar~~

~~as the gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.~~

Well site means one or more contiguous surface sites~~areas~~ that are constructed for~~directly disturbed during~~ the drilling and subsequent operation of an oil or natural gas well, and any~~, or affected by,~~ production facilities directly associated with any oil well, natural gas well, or injection well. ~~and its associated well site. For the purposes of the fugitive emissions standards at section I.1, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water condensate from wells not located at the well site (e.g., centralized tank batteries). For the purposes of the fugitive emission requirements, a well site that only contains one or more wellheads is not subject to these requirements.~~

17.3 Impacts, Emissions, and Costs

17.3.1 EPA Did Not Consider Key Costs To Industry In Assessing The Cost Effectiveness Of Leak Detection Requirements Proposed.

In its cost analysis for the proposed control strategy for fugitives emissions, EPA did not adequately capture all of the costs associated with implementation of such a program. Specifically, in the cost-effectiveness evaluation, EPA underestimated the costs associated with:

- Conducting leak surveys
- Completing repairs, and
- Maintaining the required recordkeeping, including the costs of developing and maintaining the corporate and site-specific monitoring plans.

Further, EPA did not include several aspects beyond the cost of the actual survey work in its cost analysis, including:

- Training of personnel
- Travel time and costs
- Equipment maintenance (e.g. monitoring device calibration)

The following sections expand on each of these topics in more detail and API provides revised costs that are more representative of actual costs anticipated to comply with the proposed rule. Utilizing the more representative costs along with EPA's current estimates of emission reductions expected from the rule, the cost effectiveness of the proposed semi-annual OGI monitoring increases from EPA's estimate of $2,230 per well site to over $6,400 per site. As such, the Well Site Program Weighted Average cost effectiveness values (under a Multi-pollutant Method) would increase significantly beyond the already marginal value of $4,979 per ton of VOC.

When the full costs of monitoring are considered, the leak detection program proposed is not cost effective for either methane or VOC. This finding is based solely on corrected costs and does not reflect any changes to the assumed emission reductions, which API believes have been overstated as well.

At a minimum, API recommends OGI-based surveys be no more frequent than an annual frequency for any affected sources.

The exception to this is oil wells. As discussed above in section 17.2.8 there is no scenario where oil wells are cost effective. EPA should totally abandon the regulation of fugitive emissions at oil wells.

17.3.2 EPA Underestimated The Costs Of The Leak Survey And Leak Repairs In The Cost-Effectiveness Evaluation.

In the cost estimation for implementing the LDAR requirements, EPA underestimated the cost of conducting a leak survey at the model well site. Although EPA estimated the model plant to consist of 2 wells per well site, they used cost data representing an OGI leak survey conducted by a contractor for a single well per well site ($600/single well battery37) as the basis of the leak survey costs. The cost of the survey based on the reference document would be higher than the value used in the analysis that represents a single well site ($600/single well battery) and lower than the value provided for a multiple well site ($1,200/multiple well battery) that represents on average 5 wells per site. A better estimate based on the reference document used would be a linear scaling between the given cost range which would result in an estimate of $720/model well site, representing 2 wells per well site. EPA also did not include any administrative costs for managing leak surveys conducted by contractors, as indicated in the reference document.

17.3.3 Many Additional Aspects Beyond The Cost Of The Actual Survey Not Considered By EPA Should Be Included In Cost-Effectiveness Evaluation (E.G., Training, Monitoring Device Calibration, Travel Costs, Etc.)

The start-up cost of a major monitoring program involves many costs not associated with the routine recurring costs of the regular survey, such as program design and set up. EPA's cost analysis also failed to consider costs associated with training, monitoring device calibration, data management, and transportation. These are significant costs and should be part of EPA's assessment of the costs of the proposed requirements.

API surveyed companies conducting voluntary LDAR programs and compared these costs to EPA's model well site costs for annual LDAR. EPA's well pad model plant costs for semi-annual OGI LDAR surveys. Using EPA's cost spreadsheet for OGI well pad costs posted to the docket,[38] API added or updated costs based on company information. API's cost estimate used the same assumptions as EPA's where company data were not available.Key differences in the costs include the following:

- EPA included the cost of a M21 monitoring device ($10,800), but excluded the cost of the data collection system. EPA's separate cost estimate for conducting M21 LDAR includes a cost of $14,500 for a data system in conjunction with the M21 monitoring device. It is not clear why EPA excluded this cost from the OGI LDAR estimate. EPA's estimate for developing monitoring plans does not indicate if it is

[37] Carbon Limits. *Quantifying cost-effectiveness of systematic LDAR Programs using IR cameras.* December 24, 2013. Available at http://www.catf.us/resources/publications/files/CATFCarbon_Limits_Leaks_Interim_Report.pdf.
[38] CTG_Section_9_OGI_Well_Pad_Model_Plant_Costs_7-7--2015.xlsx

for the corporate level plan, site level plans, or both. EPA's estimate is approximately one-half the cost provided by companies with voluntary programs.

- EPA's estimate of recordkeeping costs does not account for the need to purchase or expand a data collection system to store all the information associated with an ongoing LDAR program. EPA also does not consider the need for a data analyst to manage the information.
- EPA's costs do not consider the purchase of OGI equipment (~$100,000 per unit), annual calibration of each OGI unit, or the training required to operate each unit.
- EPA's costs do not consider travel to and from each site to conduct the semi-annual surveys and for additional travel to repair and resurvey components when the repair cannot be completed immediately following the survey.
- EPA assumed a cost of $2.00 to resurvey repaired components. This cost implies the use of soap bubbles under Section 8.3.3 of M21 to determine if the leak has been repaired. However, as written under §60.5397a (j)(2)(ii)(A), the proposed rule does not specify that soap bubbles can be used to determine if a leak is repaired [§60.5397a (j)(2)(ii)(A) - A fugitive emissions component is repaired when the M21 instrument indicates a concentration of less than 500 ppm above background.]. API's cost estimate for resurveying to determine if a leak is repaired is based on determining if the concentration is less than 500 ppm above background.

The following table compares cost information for semi-annual LDAR surveys and a 10,000 ppm leak definition based on data from companies conducting voluntary LDAR versus EPA's cost assumptions. Yellow highlighted cells indicate where costs are different and costs that EPA did not include in their analysis. Overall, API cost data indicate slightly lower well site costs ($1,590 based on API estimates compared to $2,096 from EPA's estimate shown in Table 17-2 Corrected Estimate of Monitoring Costs). However API's estimate includes recurring annual costs that were neglected in EPA's estimate and significantly higher company level costs. The resulting total annual cost estimate from API member companies is more than twice EPA's estimate.

Table 17-2 Corrected Estimate of Monitoring Costs

Item	API Annual Total Cost ($)	EPA Annual Cost ($)	Comment
One-Time Company Level Costs			
Read rule and instructions	$231.20	$231.20	Cost based on hours from PES Memorandum
Development of Equipment Leaks Monitoring Plan - Corporate Plan	$7,200.00	$3,468.00	API members estimate $7,200 to develop the initial corporate monitoring plan. EPA estimated cost based on average number of people and hours from PES Memorandum
Initial Activities Planning	$1,849.60	$1,849.60	EPA cost based on hours from PES Memorandum
Notification of Initial Compliance Status	$1,271.60	$1,271.60	Assumes that 1 hour is spent to prepare the notification for each well site for 22 well sites
FLIR Monitoring - Cost of OGI Equipment	$95,000	Excluded from EPA's analysis	API survey responses ranged from $90K-100K. API estimate conservatively assumes just 1 device is purchased.
FLIR Monitoring - Cost of Data Management System	$225,000.00		API survey responses ranged from $200K-250K

Item	API Annual Total Cost ($)	EPA Annual Cost ($)	Comment
FLIR certification Training	$2,000.00		API estimate conservatively assumes only one person is trained
M21 Monitoring and Data Collection System	$10,800	$10,800	EPA estimate includes cost of M21 monitoring device ($10,800) but excludes the cost of the data collection system ($14,500) that was assumed for M21
First Year Total Hours and Cost per Company	*$343,352*	*$17,620*	Sum of total company costs above
First Year Total Hours and Cost per Well Site	*$15,607*	*$801*	Assumes company owns 22 well sites

Table 17-3 Comparison of Monitoring Costs – Annual Costs

Item	API Annual Total Cost ($/yr)	EPA Annual Cost ($/yr)	Comment
RECURRING ANNUAL COSTS			
Annual Training	$2,000.00	Not included	API estimates for annual training ranged from $1,000 to $5,000. Conservatively assumed $2,000/yr
Data Analyst	$24,000.00	Not included	API estimate based on 10% resources of existing data analyst duties
Annual FLIR Device Calibration	$4,000.00	Not included	API estimates ranged from $3,000 - $5,000/camera. Conservatively assumed just one device is needed.
Annual transportation costs	$20,000.00	Not included	Per basin cost. API estimate assumes one basin requires 15,000 miles travel annually. Includes fuel and maintenance. Does not include the cost of purchasing a vehicle.
Recurring Annual Costs per Company	*$50,000.00*	*Not Included*	Sum of recurring annual costs above
Recurring Annual Costs per Well Site	*$2,272.73*	*Not Included*	Assumes company owns 22 well sites
Well Site Level Costs			
Subsequent Activities Planning	$63.05	$63.05	Based on hours from PES Memorandum. Total cost of planning divided by total number of well sites per company
Development of Site-specific Monitoring Plan	$120.00	Not Included	API estimate assumes 2 hours per site to develop the proposed site-specific monitoring plans
FLIR Survey cost	$462.40	$1,200.00	EPA cost from CL Report (outside contractor, well pad, $600 per survey). API estimate assumes 1 person and 4 hours to survey a well site using FLIR. Includes travel time.

Item	API Annual Total Cost ($/yr)	EPA Annual Cost ($/yr)	Comment
Repair Cost	$597.48	$597.48	Assumes 1.18% or 4 total leaks found per survey, 3 fixed online (3 * 0.17 hours *$66.24/hr) and 1 fixed offline (1 * 4.0 hours * $66.24/hr)
M21 Resurvey Costs	$115.60	$4.00	EPA's resurvey costs assume cost of $2.00 per component for offline component repair. API's resurvey cost assumes 2 hours are required to travel to/from the site and resurvey the fixed component.
Annual Report	$231.20	$231.20	Assumes that 4 hours are spent to prepare the annual report for each well site and includes storing/filing of records
Cost per Well Site (Well site level costs only)	*$1,590*	*$2,096*	Sum of well site level annual costs
Annual Cost per well site with Amortized Capital Cost	***$6,476***	***$2,230***	**Includes first year costs per company site from table above, cost amortized over 8 years at 7% interest**

17.3.4 EPA Did Not Account For The Limited Availability Of Trained Personnel And Equipment To Complete Monitoring

Section 9.4 of the draft CTG discusses the burden on the operators from the need to hire qualified contractors to perform the monitoring. Most API companies that have implemented voluntary LDAR programs for their upstream operations have performed their work internally with their own personnel. These companies took considerable time to train their initial core staff, and required in many cases, more than a year to have such a program fully operational.

Based on discussions with both OGI Instrument manufacturers and trainers, there is likely to be an initial delay in providing OGI instruments and training to meet demand. EPA should provide an initial compliance period of 1 year to allow LDAR detection equipment manufacturers and training organizations to meet the initial demand for equipment and training. In addition, API requests a one-year phase in be provided for the LDAR requirements to allow operators time to purchase monitoring devices, conduct training, and establish protocols.

17.3.5 EPA Did Not Consider Impacts Of Travel To/From Sites By Trained Personnel (Costs And Environmental Impacts)

Oil and natural gas production operations, gathering and boosting facilities, as well as transmission and storage compressor stations are geographically dispersed. Costs and impacts need to consider the time associated with traveling to and from sites, vehicle and fuel costs, and resulting vehicle emissions to conduct recurring LDAR. A company may have a third party contractor or specific in-house person doing the OGI monitoring that is different from the person doing the repairs. Although the majority of leaks are repaired when detected, there would be additional driving costs and impacts for leaks that cannot be repaired immediately and for conducting the resurvey after leaks are repaired.

According to survey data provided by 9 companies subject to Colorado Regulation 7, the average annual number of miles driven per basin for leak detection monitoring is 28,000, and the average annual transportation cost per basin is $34,785. API members conducting voluntary LDAR programs indicated an average of 15,000 miles traveled per basin, with an average annual cost of $20,000 per basin. These costs do not include purchasing additional vehicles to accommodate the required travel. Neither transportation costs nor costs for purchasing additional vehicles were included in EPA's evaluation of cost effectiveness.

17.3.6 Recordkeeping Costs Are Significantly Underestimated

The Colorado Regulation 7 record keeping requirements are not as stringent as the proposed model rule requirements. Based on survey data provided by 9 companies subject to Colorado Regulation 7, the average record keeping cost per basin is $188,125 with a reccurring average annual cost of $39,444. That represents 41% of the average annual survey cost per basin.

Companies conducting voluntary LDAR surveys estimate their recording keeping costs at $60,000. Additionally companies that maintain a copy of OGI records estimate the data storage burden to be approximately 102 MB per survey per well. These costs represent approximately 26% of the average annual recurring LDAR costs per basin. These costs were not included in EPA's evaluation of cost effectiveness.

17.3.7 EPA Significantly Underestimated The Costs Of Developing And Maintaining The Corporate And Site-Specific Monitoring Plans

CTG I.2 and I.5 list the reporting, and recordkeeping requirements. Section I.2 describes companies developing both corporate-wide and site specific fugitives emissions monitoring plans with the alternative of doing a site specific plan with elements of both the corporate-wide and site specific fugitives emissions monitoring plan requirements. EPA did not fully evaluate the complexities or the costs for developing and maintaining the proposed requirements.

EPA has not included in the cost effective analysis for leak detection and repair any of the significant costs for developing and maintaining both a corporate-wide and site specific plans, particularly with respect to EPA's expectation that component counts are to be included in the monitoring plan. The cost estimate of $3,468 for the monitoring plan is greatly underestimated considering the great amount of detail required for the 2 different plans.

API member companies estimate the cost for developing a corporate monitoring plan to be $7,200, and the cost to develop each site-specific monitoring plans to be $120. Annual recurring costs to keep the plans up to date are estimated to range from $1,000 to $3,000.

To count and tag components at a compressor station, costs approximately $10,000. In a study performed by an API member company which compared three basic leak detection methods: Audio, Visual, and Olfactory (AVO), OGI, and M21. M21 was already being conducted, the additional cost of component counts was $15 to $58 per site. However, if done in conjunction with an OGI survey, the cost would be substantially higher. API members estimate a cost of $120 per well site to develop an initial component count (excluding travel costs), and a recurring annual cost of $60/site.

In addition, EPA provided no provision for an area-wide monitoring plan. Section I.2 recommends that companies either have a corporate-wide fugitive monitoring plan or a site specific monitoring plan. EPA provides no other options such as area wide plans for an operations area or basin. However, the information required in each plan is so detailed and specific, it will make it very difficult to write a plan that covers the various pieces of information for each separate area such as:

- Technique for determining fugitive emissions.
- The manufacturer and model number of the fugitive emissions detection equipment to be used. – Different equipment may be used in each area and over time depending if done internally or by a contractor.
- Procedures and timeframes for identifying and repairing fugitive equipment components from which fugitive emissions are detected. This will vary based on whether leak detection is done internally or by a contractor and by area.
- Procedures and timeframes for verifying fugitive emission component repairs. This will vary based on whether leak detection is done internally or by a contractor and by area
- Verification of the optical gas imaging equipment - Different equipment may be used in each area and over time depending if done internally or by a contractor.
- Procedures for determining the maximum view distance from the equipment – Each area may have different facility designs such as enclosed portions of the facility due to cold weather and physical locations such as on sides of cliffs that could limit or constrain the viewing distances.
- Procedures for conducting surveys – May vary by area or whether it is being done by contractors or internally.
- Training and experience needed prior to performing surveys – May depend on the equipment being used or whether the surveys in the area are being done internally or by contractors.
- Procedures for calibration and maintenance – Will vary based on the various equipment used by the area or contractors.

In some locations a company may choose to use contract services and other areas the same company may choose to conduct the surveys with internal staff. In addition, the variations in the development plans for different production areas may dictate different monitoring approaches. For example, an old declining field in one part of the country may have no sites or only a few sites subject to NSPS OOOOa which may require a company to handle the program differently than in another part of the country where they are drilling 30 wells or more a year that would be subject to NSPS OOOOa.

In some locations a company may choose to use contract services and other areas the same company may choose to conduct the surveys with internal staff. In addition, the variations in the development plans for different production areas may dictate different monitoring approaches. For example, an old declining field in one part of the country may require a company to handle the program differently than in another part of the country where active drilling is taking place.

The proposed requirement for site-specific monitoring plans, including the requirement to specify a walking path for each site, is unnecessary and the requirements are onerous. Many times production areas do not have site maps developed for each site. Development of a sitemap would be solely for this rule. The cost of developing site maps for every site was not included in the cost evaluation for LDAR. Furthermore, the requirement to specify a walking path for each site is unnecessary for oil and natural gas well sites and compressor stations. The person conducting the survey must be trained and have the knowledge and ability to use the monitoring device.

The elements required in both plans are extensive, requiring a great amount of detail with no added benefit. EPA should not require both plans. Furthermore, it is unnecessary for the plan to require many of the detailed information EPA is requesting for the site specific plans since these are small, dispersed, unmanned well sites and compressor stations. EPA should allow companies to create area monitoring plans in place of site-specific plans or as an option for corporate wide plans. Proposed rule revisions to address these issues are provided in (refer to Section 17.3.9).

17.3.8 Fugitive Emissions Program for Gross Emitters

In the preamble for proposed NSPS Subpart OOOO and OOOOa (80 FR 56637), EPA indicated that commenters on the white papers agreed that emissions from equipment leaks exhibit a skewed distribution, and pointed to other examples of data sets in which the majority of fugitive methane and VOC emissions come from a minority of components (e.g., gross emitters). Based on this information, EPA solicited comment on whether the fugitive emissions monitoring program should be limited to "gross emitters".

"Notably, we further identified that many studies have shown a skewed distribution for emissions related to leaks, where a majority of emissions come from a minority of sources. Commenters on the white papers agreed that emissions from equipment leaks exhibit a skewed distribution, and pointed to other examples of data sets in which the majority of VOC emissions from leaks come from a minority of components. Commenters noted that emitters are likely due to random occurrences of low-probability but high-emissions conditions." (CTG 9.4)

As EPA acknowledges, a growing body of research indicates a skewed emissions distribution for fugitive emission sources, where a small number of sources are responsible for a high percentage of emissions. The fugitive emission monitoring program under OOOOa should be targeted towards identifying and correcting these high emitting sources which results in the greatest cost-effective reductions, and produces significant reductions in emissions more quickly. API data on the leaks identified from recurring LDAR surveys indicates that annual LDAR is sufficient for identifying and correcting the relatively few fugitive sources with very high emission rates.

17.3.9 Recommended Rule Text Revisions Based On Comments In This Section.

(CTG I.2)

For fugitive emissions, VOC emission control requirements apply to the collection of fugitive emission components at a well site, central production site, and transmission compressor station (that is located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or to an oil pipeline), as specified in paragraphs (a) through (e) of this section for monitoring the collection of fugitive emission components. These requirements are independent of the closed vent system and control requirements in section D.

(b) You must develop corporate-wide or area-wide fugitive emissions monitoring plan that covers the collection of fugitive emission components at well sites and compressor stations in accordance with paragraph (c) of this section, ~~and you must develop a site-specific fugitive emissions monitoring plan specific to each collection of fugitive emission components at a well site and each collection of fugitive emission components at a compressor station in accordance with paragraph (d) of this section. Alternatively, you may develop a site-specific plan for each collection of fugitive emission components at a well site and each collection of fugitive emission components at a compressor station that covers the elements of both the corporate-wide and site specific plans.~~

(c) Your corporate-wide or area-wide monitoring plan must include the elements specified in paragraphs (c)(1) through (c)(8) of this section, as a minimum.

(1) Frequency for conducting surveys. Monitoring surveys must be conducted at least as frequently as required by sections I.3 and section I.4 of this section.
(2) Technique for determining fugitive emissions.
(3) Manufacturer and model number of fugitive emission detection equipment to be used.
(4) Procedures and timeframes for identifying and fixing fugitive emission components from which fugitives are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (e) of this section at a minimum.
(5) Procedures and timeframes for verifying fugitive emission component repairs.
(6) Records that will be kept and the length of time records will be kept.
(7) Your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii).

~~(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification and may either be performed by the facility, by the manufacturer, or by a third party. For purposes of complying with the fugitive emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.~~

~~(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.~~
~~(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of ≤10,000 ppm at a flow rate of ≥60 g/hr from a quarter inch diameter orifice.~~

~~(ii) Procedure for a daily verification check.~~
~~(iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.~~
(i~~v~~) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.
(ii~~v~~) Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.
(B) How the operator will deal with adverse monitoring conditions, such as wind.
(C) How the operator will deal with interferences (e.g., steam).

(iii~~vi~~) Training and experience needed prior to performing surveys.
(iv~~ii~~) Procedures for calibration and maintenance. Procedures must comply with those recommended by the manufacturer.

~~(d) Your site-specific monitoring plan must include the elements specified in paragraphs (d)(1) through (d)(3) of this section, as a minimum.~~

~~(1) Deviations from your corporate-wide plan.~~
~~(2) Sitemap.~~
~~(3) Your plan must also include your defined walking path. The walking path must ensure that all fugitive emissions components are within sight of the path and must account for interferences~~.

Add to the definitions:

Optical gas imaging instrument means an instrument that makes visible emissions that may otherwise be invisible to the naked eye. Optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions imaging a gas that is half methane, half propane at a concentration of >10,000 ppm.

17.4 Work Practices/Inspections

17.4.1 Requiring An Initial Survey Requirement Within 30 Days Of Becoming Subject To The CTG Is Not Appropriate For A Number Of Reasons.

"(a) Each well site with a collection of fugitive emissions components must conduct an initial monitoring survey within 30 days of being subject to VOC emission control requirements of section I.
(b) Each compressor station site with a collection of fugitive emissions components must conduct an initial monitoring survey within 30 days of being subject to VOC emission control requirements of section I.2." (CTG Appendix I.3)

There are numerous problems with this requirement both in the language chosen to describe the requirement as well as the unique technical issues that arise as a result of trying to define a well site as something other than a surface site with a well. First, within 30 days of first well completion is inappropriate, as production doesn't always begin immediately after a well completion if for example gathering infrastructure is not yet available or construction of production facilities such as storage vessels, separators, heaters and control devices are not yet complete. There may also be use of temporary equipment because of well flow problems while trying to startup production or while permanent facility construction is being completed. Instead this requirement needs to be tied to the startup of production to be consistent with other requirements in the rule such as for storage vessels.

Within the first 30 days of startup of production, production rates for wells are evaluated to determine whether any storage vessels will be affected facilities. If so, control devices are required to be constructed and operational within 60 days from startup. As well, the first 30 days may exempt a wellsite altogether if production is less than 15 BOE/day. The point is that the first 30 days of production is an evaluation period for applicability of requirements, the second 30 days is allowed to complete construction of any required emissions control and closed vent system. And that is for true well sites with wells. The problem gets more complex by including central tank batteries in the definition of a wellsite rather than having its own definition as being part of a central production site that we recommended in Section 0.

Consider this realistic scenario. An operator wants to develop a new field of 20 wells that are planned to be drilled in succession, with potential plans to drill more. It is determined that it makes sense to construct a central tank battery that will become defined as a well site upon first production that will grow in size as each new well begins production and is aggregated to the central tank battery wellsite. The central tank battery is completed to enable startup of production of the first well with a capacity to eventually handle all 20 wells.. After startup of the battery, semi-annual leak monitoring is required within 30 days and is completed and leaks repaired. Shortly thereafter, the second well comes online and starts production to the central battery well site, and is a wellhead only site. Now, according to the CTG, the central battery must be surveyed again a month after the initial survey because of the new well. This time no leaks are found. This 30 day monitoring pattern continues until all 20 wells are completed and will continue if more wells are immediately added or first wells are refractured for any reason. The wellhead only sites are also monitored each time since they are part of the central battery well site.

The point of the scenario is that the wellsite definition is not workable in terms of the how the initial monitoring requirements have been designed in this proposal. Instead of monitoring a central tank battery initially, then semi-annually, to hopefully annually as currently conceived in the proposal, the central production site and all wells tied into it will have to undergo monitoring at an unpredictable frequency based on changes that don't occur at the battery but rather wells tied into it. The battery will always require initial well monitoring as will all the wells tied to it within 30 days each time a new well is added or refracture occurs at an existing well. This is overly burdensome and costly. Again, API recommends dissociating central batteries from the well site definition to avoid this situation.

Instead of 30 days, the time period for the initial survey should be within 180 days after startup of production to allow sufficient time for completion of construction and the startup period, and scheduling the new site into the area leak detection plan. After the initial 60 days to complete construction of the control device, an additional 120 days should be allowed to work monitoring of the well into the next scheduled monitoring period that would include all the wells in the area. Calling out a contract crew to monitor one remote well site, when in a matter of a few weeks or couple months they may already be scheduled to monitor an entire area is not a cost efficient use of manpower. Such inefficient use of resources could put undue pressure on availability of crews for all operators.

Suggested regulatory revisions are provided at the end of this section (see Section 17.4.13).

17.4.2 API Members Find That Recurring LDAR Has A Diminishing Return.

EPA solicited comments on requiring monitoring survey on a quarterly basis. API members find that recurring LDAR has a diminishing return [currently proposed as semiannually]. The first survey identifies and corrects most of the leaks, but significantly fewer leaks are identified in subsequent surveys. The Colorado Regulation 7 data reduction assumptions are based on an assumption that annual inspections will yield an annual leaking component rate of 1.18%, 1.77% for facilities with quarterly inspection and 2.26% for facilities with monthly inspection schedules. These assumptions were based on the chemical manufacturing industry (Subpart VV) and do not fit with the LDAR data observed in the upstream oil and natural gas industry. API companies conducting voluntary LDAR programs have observed much lower initial leak rates , ranging from 0.18% to 0.84% leaks per component for annual LDAR.

Quarterly monitoring may not be possible in all areas. For example in some areas, particularly in western mountainous areas, winter weather makes it difficult to visit well sites that can be remote and widely scattered. It also may not be possible to utilize OGI methods in winter conditions, since visual detection of leaks requires a temperature difference between the leak and ambient air. Test data presented in Table 4-13 of EPA's draft Technical Support Document (TSD) *Optical Gas Imaging Protocol (40 CFR Part 60, Appendix K)*[39] shows that 5,000 ppm leaks were detected

[39] Reference: *Draft Technical Support Document for Optical Gas Imaging Protocol (40 CFR 60, Appendix K)*, Revision No. 5, August 11, 2015, EPA Contract No. EP-D-11-006 by Eastern Research Group, Inc., available at

with delta temperatures between the gas leak and background of around 1.4 to 1.9°C (2.5 to 3.4°F). However, the delta temperature is highly dependent on other factors, such as the wind conditions, hydrocarbon concentration, and mass emission rate.

In addition, even EPA's cost analysis found that the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions. Per page 56636 of FR version, EPA indicates: "In a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], **we had concluded that a VOC control option was not cost-effective at a cost of $5,700 per ton**. In light of the above, we find that the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions under either approach."

17.4.3 API Advocates A Fixed Initial Annual Frequency, Regardless Of The Percent Of Leaking Components.

EPA solicited comment on the proposed metrics of one percent and three percent and whether these thresholds should be specific numbers of components rather than percentages of components for triggering change in survey frequency discussed in this action.

> *"We recommend that the monitoring frequency be increased to quarterly in the event that two consecutive semiannual monitoring surveys detect fugitive emissions at 1.0 percent or more of the fugitive emissions components at a well site or at 1.0 percent or more of the fugitive emissions components at a compressor station. We also recommend that the monitoring frequency be decreased to annual in the event that two consecutive semiannual surveys detect fugitive emissions at less than 1.0 percent of the fugitive emissions components at a well site, or at less than 1.0 percent of the fugitive emissions components at a compressor station. We also recommend that you require that the monitoring frequency return to semiannual if an annual survey detects fugitive emissions between one and three percent of the fugitive emissions components at the well site, or between one and three percent of the fugitive emissions components at the compressor station, and return to quarterly if a survey detects fugitive emissions at greater than three percent of the fugitive emissions components at the well site, or greater than three percent of the fugitive emissions components at the compressor station."* (CTG 9.5.1)

API does not support the proposed metrics of one percent and three percent of components, respectively, as these metrics require maintaining a count of all fugitive components. API advocates a fixed initial annual frequency, regardless of the percent of leaking components.

To count and tag components at a compressor station, costs ~$10K and requires continual ever-greening. In a study performed by an API member company which compared three basic leak detection methods: AVO, OGI, and M21, component counts were made by a manual observer while on site. Because M21 was already being conducted, the additional cost of component counts was $15 to $58 per site. However, if done in conjunction with an OGI method, the cost would be substantially higher because individual components need not be individually located for the purposes of OGI monitoring. API companies estimate a cost of $120 per well site to count

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http://www.regulations.gov/contentStreamer?documentId=EPA-HQ-OAR-2010-0505-4949&disposition=attachment&contentType=pdf

components initially, with a recurring cost of $60 per well site to validate and update the counts annually.

17.4.4 Having The Same Frequency Of Monitoring As EPA's NSPS OOOOa Will Be Far Too Burdensome With The Large Number Of Existing Sites Which Are Almost All Unmanned, Dispersed Locations.

The draft August 2015 CTG (EPA-453/P-15-001) proposes semiannual fugitives monitoring of well sites greater than 15 boe/day and gathering/booster stations as RACT (page 9-31). The cost data presented in Table 9-11 shows a cost of $8,069/ton of VOC reduction for annual OGI inspections, while Table 9-12 shows a cost of $9,124/ton of VOC reduction for semi-annual OGI inspections. Despite a cost difference of $1,055/ton of VOC reduction or only 12.3% difference, EPA proposes semiannual OGI inspections as RACT. The small cost difference (based on EPA's analysis) between annual and semi-annual inspections does not justify the semi-annual inspections.

Also, the cost data on page 9-19 of the August 2015 CTG shows an OGI contractor cost estimate of $600 for a well site and $2,300 for a gathering/booster station, and repair costs of $299 for well sites and $3,436 for gathering/booster stations assuming 1.18% of the components leak and 75% are repaired online and 25% are repaired offline. EPA estimated the cost for resurveying components after offline repair based on $2.00 per component resurveyed and the assumption that a company purchases M21 instrumentation for $10,800 and is able to perform the resurveying without needing contractors. EPA assumed annual reports would take one person a total of 4 hours to complete at a cost of $231.

For comparison purposes, the costs from the Colorado Regulation 7 survey data were the following: OGI survey by contractor - $200-400 per well site, $1,321 for gathering/booster stations; excludes equipment rental, which is approximately $250 per site; Repair costs - $200 for well sites; Annual reports - $4,370 average annual report for a company's basin (note that Regulation 7 reports are required on a basin basis).

EPA assumes companies will use a third party for monitoring at $600 per site and does not include estimated costs for a company to buy and maintain a camera of their own (higher capital cost) or supervisory costs. In the report "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries" (March 2014, Prepared for Environmental Defense Fund by ICF International) a more representative cost analysis includes the camera purchase costs as well as transportation and recordkeeping, resulting in an annual cost of $191,000 (compared to $4,031 in the EPA OOOOa TSD, assuming quarterly OGI inspections as presented in Table 5-19). This analysis was updated in 2014 in which the annual cost (including cost of repairs inadvertently omitted from the previous analysis) was $193,000.

17.4.5 Proposed Approach To Allow Reduction In Monitoring Frequency Forces The Need To Develop Component Counts For Each Well Site In Order To Properly Document The Percentage Of Leaking Components. This Is Inconsistent With Subpart W Monitoring Program For Transmission And Storage.

> *"We recommend a monitoring survey of each collection of fugitive emissions components at a well site and collection of fugitive emissions components at a compressor station be conducted at least semiannually after the initial survey and that consecutive semiannual monitoring surveys be conducted at least four months apart. We recommend that the monitoring frequency be increased to quarterly in the*

> *event that two consecutive semiannual monitoring surveys detect fugitive emissions at 1.0 percent or more of the fugitive emissions components at a well site or at 1.0 percent or more of the fugitive emissions components at a compressor station. We also recommend that the monitoring frequency be decreased to annual in the event that two consecutive semiannual surveys detect fugitive emissions at less than 1.0 percent of the fugitive emissions components at a well site, or at less than 1.0 percent of the fugitive emissions components at a compressor station. We also recommend that you require that the monitoring frequency return to semiannual if an annual survey detects fugitive emissions between one and three percent of the fugitive emissions components at the well site, or between one and three percent of the fugitive emissions components at the compressor station, and return to quarterly if a survey detects fugitive emissions at greater than three percent of the fugitive emissions components at the well site, or greater than three percent of the fugitive emissions components at the compressor station."* (CTG 9.5.1)

API does not support the proposed metrics based on a direct count of all fugitive components, which can be time consuming and costly. If EPA elects to use a component count, API recommends that a simplified approach, such as the 40 CFR98 Subpart W upstream component count approach would be used [specified in §98.233(r)]; that method only requires a count of major pieces of equipment, which are combined with EPA assumptions on component counts per equipment.

See Section 17.3.8 regarding API's preference for annual monitoring.

17.4.6 API Opposes Performance-Based Frequency

EPA solicited comment on whether a performance-based frequency or a fixed frequency is more appropriate. API does not support a performance based approach. Tracking sites based on performance criteria is unnecessary and complex. A fixed annual frequency is sufficient for detecting and repairing leaks, as indicated in the comment above, and simplifies compliance. API members find that recurring LDAR has a diminishing return. The first survey identifies and corrects most of the leaks, but significantly fewer leaks are identified in subsequent surveys. API advocates a fixed annual frequency, regardless of the percent of leaking components.

17.4.7 API Suggests 30 Days An Appropriate Amount Of Time For Repair Of Sources Of Fugitive Emissions At Well Sites

EPA solicited comment on whether 15 days is an appropriate amount of time for repair of sources of fugitive emissions at well sites. Many leaks detected can be repaired on site with simple tightening of screwed connections, or replacement of small components carried by the maintenance team, when authorized maintenance personnel are available around the time of the survey. Fifteen days is adequate in these circumstances. However a few leaks require more time to repair due to safety issues, availability of replacement parts, availability of maintenance personnel, weather conditions, or other issues related to the sites being remote, dispersed, and unmanned facilities. Recent data from Colorado's Regulation 7 indicate that about 5% of identified leaks required a delay of repair.[40] It is more reasonable to allow 30 days to do the repairs.

Proposed text revisions are provided in Section 17.4.13.

17.4.8 The current proposal does not allow for multiple attempts to repair identified leaks

In the proposed model rule, EPA requires discovered leaks to be repaired within 15 days. Multiple attempts to repair may be required to repair such that 15 days is not be adequate to make a successful repair. Provisions are needed to allow for occurrences where complex leaks cannot be fixed within 15 days. These may be situations where additional engineering and analysis is required to develop the safe and correct solution to repair the leak. There needs to be sufficient regulatory flexibility to address instances where several repair attempts are needed until the leak is repaired.

EPA should provide appropriate provisions to accommodate situations where multiple attempts are required to repair a leak. Proposed text revisions are provided in Section 17.4.13.

17.4.9 Forcing All Repairs Within 6 Months Is Unreasonable Due To True Cost Impacts

A minority of detected leaks require more time to be repaired because they require a full shutdown of the well in order to do the repair. For example, recent data from Colorado's Regulation 7 indicate that about 5% of identified leaks required a delay of repair.[41] Repairs on the well head itself require full shutdown of the well. Some repairs require a workover of the well. Also, many companies do not allow hot work to be performed on the well site due the risk of explosion or fire. The well must be shut in and the equipment purged in order to do any hot work such as welding for repairs. Many different issues must be assessed before a well is shut in and equipment purged for repairs. Shutting down the well could result in losing the well completely or damage to the formation that can reduce production. The emissions from shutting in the well and purging the equipment could result in more emissions than are being released from the leak. Also, EPA did not consider the cost of lost production during repairs in the cost analysis for fugitive leaks which can be significant.

Some repairs at compressor stations require the compressor station to be shut in which could require shutting in all the wells that feed into the compressor station as well. Most compressor stations in the gather system do not have a way to by-pass the compressor or parts of the system so work can be done. Bringing down the compressor station could result in shutting in parts of a field and losing the production from that portion of the field which is a huge cost.

The unreasonableness of the requirement to repair a leak within 6 months is even more apparent when applied to integrated production arrangements such as those on the North Slope of Alaska. Fields on the North Slope are arranged with multi-well pads feeding into a small number of centralized production stations where primary separation and some pre-treating and compression of gas occurs. Gas from these central production stations is routed to a gas processing facility, oil to the Trans-Alaska Pipeline, and produced water to reinjection. Dependent on where a leak occurs in this integrated production arrangement repairing a leak within 6 months may necessitate

[40] Colorado Air Quality Control Commission, Public meeting on October 15, 2015.
[41] Colorado Air Quality Control Commission, Public Meeting on October 15, 2015.

shutting down an entire section of a field feeding a particular central production station or perhaps a series of central production stations. Given the geographic and seasonal realities of the Alaskan North Slope, oil and gas operators schedule large separation facilities shutdowns during the summer months. With the litany of plausible scenarios that could result in a separation facility being required to shut down in order to fix a leak in late fall, winter, and early spring, such shutdowns will result in greater safety and integrity concerns. In addition, the flaring of between 250,000 MMscf and 500,000 MMscf of gas during shutdowns may be an unintended and unavoidable consequence of the proposed rule. Simply stated, the emissions release associated with shutting down a production facility; shutting in and freeze protecting wells; and depressuring and purging the necessary equipment will result in far greater emissions than are being released from the leak that could be repaired during the next scheduled process shutdown. In addition to the increased safety concerns and counter-productive flaring, implementing the repair requirements as currently drafted will also result in severe economic repercussions. Every day of a non-scheduled or non-summer shutdown will result in millions of dollars in lost revenue for the State of Alaska and the operators. Dependent on the length and extent of the shutdown required and difficulty restarting the wells and facilities, taking such an action may impact the domestic US supply of crude oil, particularly in the West Coast markets where most Alaska crude is shipped. It is clear that EPA did not contemplate such potential wide ranging and large impacts when considering the requirement for repair of a leak within 6 months. Although the North Slope is an extreme example due to the unique climate realities, similar impacts would occur on a smaller scale for other integrated production arrangements.

EPA should allow for delay of repair of fugitive components until the next shutdown. EPA has allowed for delay of repairs beyond 6 months and OOOOa should be less stringent that what is required under NSPS Subpart VVa. Subpart VVa under §60.482-9a allows for the following delay of repairs and NSPS OOOOa should allow for equivalent delay of repair:

§60.482-9a *(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.*

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves and connectors will be allowed if:

- *(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and*
- *(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §60.482-10a.*

(d) Delay of repair for pumps will be allowed if:

- *(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and*
- *(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.*

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(f) *When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition."*

API was unable to gather and provide the typical times between shutdowns of well sites and compressor stations due to the short comment period on this rule.

Proposed text revisions are provided in Section 17.4.13.

17.4.10 Thresholds for M21 Leak Definition and Repair.

EPA requested comment on whether the fugitive emissions repair threshold for M21 monitoring surveys should be set at 10,000 ppm or whether a different threshold is more appropriate (including information to support such threshold). EPA also solicits comment on whether 500 ppm above background is the appropriate repair resurvey threshold when M21 instruments are used or if not, what the appropriate repair resurvey threshold is for M21.

Tables 9-14, 9-15, and 9-16 of the CTG draft show the summaries of the cost of control for VOC at each of the repair thresholds (i.e., 10,000, 2,500, and 500 ppm) for the three monitoring frequency options (i.e., annual, semiannual, and quarterly).

If M21 is used to repair the leak, then the leak definition should instead be 10,000 ppm instead of 500 ppm. A leak definition of 10,000 ppm is consistent with the leak definition used in NSPS Subpart KKK for valves at natural gas processing plants, which references NSPS Subpart VV. Also, OGI monitors detect leaks at approximately 10,000 ppm. In addition, API demonstrated in comments provided to Docket ID Number EPA–HQ–OAR–2010–0505 (Proposed Rulemaking – Oil and Natural Gas Sector Regulations Standards of Performance for New Stationary Sources: Oil and Natural Gas Production and Natural Gas Transmission and Distribution, November 30, 2011) that there is only a small incremental difference in emission reductions between a leak definition of 500 ppm and 10,000 ppm.

Based on data in a leak detection study that compared M21 to FLIR, approximately 85% of FLIR-found-leaks were over 0.1 scfh, as quantified by HiFlow. Using the correlation equation from the 1995 Protocol for Equipment Leak Emission Estimates and the average density of the field gas in the corresponding asset areas, 10,000 ppm corresponds to a leak rate range of 0.07 to 0.15 scfh depending on the component type leaking. Based on this, the study found that approximately 70% of FLIR-found-leaks were over 10,000 ppm.

Therefore, consistent with the valve leak detection provided in NSPS Subparts KKK and VV, and given that OGIs typically detect leaks over 10,000 ppm, the repair leak threshold should be set at 10,000 ppm.

Proposed text revisions are provided in Section 17.4.13.

17.4.11 API Supports Flexibility In The Methods Allowed For Resurveying Repaired Components.

"We recommend the implementation of a monitoring plan that includes semiannual monitoring using OGI and repair of components that are found to be leaking at well sites and compressor stations." (CTG 9.4)

EPA solicited comments on whether either optical gas imaging or M21 should be allowed for the resurvey of the repaired components when fugitive emissions are detected with OGI. API supports flexibility in the methods allowed for resurveying repaired components. EPA should allow for the use of M21, OGI, or infrared laser beam illuminated instruments. In particular, M21 is preferred, as Section 8.3.3 of M21 allows the use of soap bubbles.

17.4.12 Monitoring Each Fugitive Component for Emissions

CTG I.2(e) – EPA is requiring that "*Each monitoring survey shall observe each fugitive emissions component for fugitive emissions*." Having to look at each component with an OGI system is extremely time consuming. Furthermore, it is not necessary to look at each component for leaks with the OGI equipment. From a scan around the facility you should be able to easily see if there are any leaks, and then if there are, move in to identify the exact location of the leak. OGI does not work like M21 where you have to sniff each component to determine if it is leaking.

Also, it is not always feasible to look at each component. Several locations in the North have equipment inside buildings with components next to the wall making getting to each component with OGI equipment impossible. . Here is an example of what the sites look like:

Figure 17-1 Picture of Equipment Building

API recommends making this requirement more in line with how OGI equipment works and the fact that each component does not need to be scanned to require that each piece of equipment with fugitive monitoring components be observed. For instance, observe the separator or well head for leaking components.

Proposed text revisions are provided in Section 17.4.13.

17.4.13 Recommended Text Revisions Related To Work Practices/Inspections:

> I.2(e) Each monitoring survey shall observe each piece of equipment with fugitive emissions components for fugitive emissions.
>
> I.2(f)(1) Each identified source is required to monitor fugitive emission components as specified in section I.3 and I.4. Identified fugitive emissions shall be repaired or replaced as soon as practicable, ~~but~~ no later than ~~15~~30 calendar days after detection of the fugitive emissions. Where delays in acquiring replacement parts prevent completion of repairs

within 30 days, repairs must be completed within 30 days of acquiring parts. If the repair or replacement is technically infeasible or unsafe , or shutdown emissions are larger than what would be reduced~~ to repair during operation of the unit~~,~~ to repair during operation of the unit~~, the repair or replacement must be completed during the next scheduled shutdown ~~or within 6 months, whichever is earlier~~.

(2) Each repaired or replaced fugitive emissions component must be resurveyed as soon as practical, but no later than ~~15~~30 days after completion of the repair or replacement, to ensure that there is no leak.

(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using M21 or optical gas imaging no later than ~~15~~30 days of finding such fugitive emissions.

(ii)(A) A fugitive emissions component is repaired when the M21 instrument indicates a concentration of less than ~~500~~10,000 ppm above background.

I.3(a) Each well site with a collection of fugitive emissions components must conduct an initial monitoring survey within ~~30~~180 days of being subject to VOC emission control requirements of section I.
(b) Each compressor station site or central production site with a collection of fugitive emissions components must conduct an initial monitoring survey within ~~30~~180 days of being subject to VOC emission control requirements of section I.2.

(a) A monitoring survey of each collection of fugitive emissions components at a well site, a central production site, and a compressor station site subject to VOC emission control requirements under section I shall be conducted at least ~~semi~~annually after the initial survey. Consecutive ~~semi~~annual monitoring surveys shall be conducted at least nine~~ four~~ months apart.
~~(b) The monitoring frequency specified in paragraph (a) of this section shall be increased to quarterly in the event that two consecutive semiannual monitoring surveys detect fugitive emissions at greater than three percent of the fugitive emissions components at a well site or at greater than three percent of the fugitive emission components at a compressor station subject to VOC emission control requirements under section I.~~
~~(c) The monitoring frequency specified in paragraph (a) of this section may be decreased to annual in the event that two consecutive semiannual surveys detect no fugitive emissions at less than one percent of the fugitive emissions components at the well site, or less than one percent of the fugitive emissions components at a compressor station subject to VOC emission control requirements under section I. The monitoring frequency shall return to semiannual if a annual survey detects fugitive emissions between one and three percent of the fugitive emissions components at the well site, or between one and three percent of the fugitive emissions components at the compressor station, and shall return to quarterly if a survey detects fugitive emissions at greater than three percent of the fugitive emissions components at the well site, or greater than three percent of the fugitive emissions components at the compressor station.~~

17.5 Testing And Monitoring

17.5.1 EPA Should Provide Flexibility And Allowance For Technology Development.

Ongoing Research and Development Activities

The scale up of LDAR activities under the draft rule provides a strong incentive to bring down costs while enhancing leak detection effectiveness, and is already stimulating a substantial increase in R&D investment, as EPA notes in its proposal. We call to the Agency's attention two ongoing initiatives that aim to develop improved LDAR technologies for use by companies as they seek to comply with federal and state methane emissions reduction requirements: a public-private initiative and a partnership between a number of corporate actors and an environmental non-governmental organization. These initiatives may well demonstrate within the next several years, the commercial availability of substitute technologies, equipment and approaches that are more efficient and cost-effective than the continued use of M21 or OGI.

Department of Energy (DOE)/ Advanced Research Projects Agency – Energy (ARPA-E)

As of December 16, 2014, ARPA-E had selected eleven private sector projects involving methane observation networks with innovative technologies to obtain methane emissions reductions that would receive awards totalling some $35,000,000, (MONITOR Program). The objective is to catalyze and support the development of transformational, high impact energy technologies that can effectively promote methane emissions reduction. DOE's aim is to lower the cost of compliance through the development of low cost detection systems coupled with advanced modelling capabilities to pinpoint and quantify - major leaks and engage in mitigation prioritization with a focus on larger emitters. The proposed rule's approach, consistent with current technology, relies on detection alone as the criteria to define the need for repair without any prioritization based on the size of the leak. Generally the thrust of the work being supported by ARPA-E does not look at leaks from individual components, but will lead to examination of larger areas to identify significant leaks which can then be specifically identified and repaired.

ARPA-E is planning within 6-7 months to set up a testing facility intended to serve as a site for field tests to ensure that technologies are tested in a standardized, realistic environment outside of the laboratory. This would be followed by a second round of testing to assess previously undemonstrated capabilities and further technical gains. ARPA-E believes some of these technologies could become commercially available in from 2-3 years. The goal within 18 months to 2 years is to develop a methodology to demonstrate the superiority of one or more of these technologies to OGI that do not require the manpower, the fleets of trucks and other equipment and surveys that are time-consuming to undertake and dwarf the cost to the regulated community even of an expensive FLIR camera ($90,000). Each of ARPA-E's partners will need to demonstrate it can bring the costs down to $3,000 per site per year (many of which have multiple wells). The hope and expectation is that costs will be significantly lower, going down as to as little as $1,000 per site.

EDF Methane "Detectors Challenge" (MDC)

In June 2014, the Environmental Defense Fund (EDF) along with five private sector partners issued a request for a proposal intended to target innovators from universities, start-up companies, instrumentation firms, and diversified technology companies among others to develop continuous methane leak detection monitoring for the oil and natural gas industry. They also sought expressions of interest in becoming part of the lab and field tests that would lead to pilot purchases and testing at oil and natural gas facilities. The initiative is intended to catalyze and expedite development and commercialization of low-cost, methane detection technologies that will help minimize emissions in the oil and natural gas industry. MDC is based upon the belief that shifting the methane emission detection paradigm from periodic to continuous will allow leaks to be found and fixed, more readily decreasing methane emissions significantly. The ideal system would serve as a "smart" alarm sending an alert to an operator when an increase in ambient methane is detected that reflects emissions beyond what one would normally expect to see. The "MDC program refers to cost as a critically important factor and EDF and its partners sought out technologies that could reasonably be expected to be sold for roughly $1,000 or less per well pad (or compressor site) when produced at scale over the following 2-5 years.

The MDC commenced with a set of laboratory tests of five different sensor technologies in 2014, called "Phase 1." Four of these five technologies were selected for further development and assessment in a follow-up effort referred to as "Phase 2" which tested each technology developer's entire system in controlled laboratory and outdoor settings in order to ensure that the systems performed as required prior to moving into industry pilots, which is the immediate next step.

We urge EPA to stay abreast of technological developments and closely track the results of research and testing through an open dialogue with experts in the private sector and government.

Recommendations

An optical gas imaging (OGI) instrument is defined in 40 CFR 60.18(g)(4) as "… an instrument that makes visible emissions that may otherwise be invisible to the naked eye." EPA's Technical Support Document (TSD) for Optical Gas Imaging Protocol (40 CFR Part 60, Appendix K)[42] provides a summary of the current state of the technology for two commercially available OGI cameras, the FLIR GF320 and Opgal EyeCGas, to detect equipment fugitive leaks by infrared thermographic imaging.

EPA should allow any new technology to be used that is equivalent to OGI or M21 in detecting fugitive leaks. Such new technologies should not be limited to meeting EPA's current definition of OGI (i.e. "… an instrument that makes visible emissions that may otherwise be invisible to the naked eye."). In addition, since OOOOa is not a quantification rule, such new technologies need only demonstrate that they can detect leaks; they do not need to quantify leaks.

17.5.2 The Regulation Should Allow Flexibility In The Methods Used To Detect Fugitive Emissions

The Agency has asked for comment on "criteria we can use to determine whether and under what conditions well sites operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well site fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining."

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[42] Reference: *Draft Technical Support Document for Optical Gas Imaging Protocol (40 CFR 60, Appendix K)*, Revision No. 5, August 11, 2015, EPA Contract No. EP-D-11-006 by Eastern Research Group, Inc., available at http://www.regulations.gov/contentStreamer?documentId=EPA-HQ-OAR-2010-0505-4949&disposition=attachment&contentType=pdf

A study performed by an API member company compared three basic leak detection methods: AVO, OGI, and M21. In general, the M21 approach was the most labor and time intensive, and, therefore, the most costly. FLIR methods could be implemented for less than 20% of the cost of M21 approaches. The results showed that AVO, while the least costly method, was not generally effective when compared to M21. On average, AVO found only 9% of the well pad leaks found by M21, and only 12% of the well pad site emissions calculated from M21 leaks. At the compressor station, because of the high ambient noise and close proximity of equipment, AVO method was not effective at all, and found 0% of the leaks found by M21 methods. The FLIR technique, on the other hand, was more effective.

- At well pads, FLIR finds 41% of leaks found by any method, but FLIR finds 89% of the total well pad emissions identified by any method (i.e. FLIR finds more of the larger leaks). It is also important to note that FLIR finds additional leaks not found by M21. Conversely, M21 finds 89% of the leaks, but only 31% of the total emissions (i.e. M21 finds more of the smaller leaks).
- At compressor stations, FLIR finds 46% of all leaks found by any method, but FLIR finds 96% of the total compressor station emissions identified by any method. It is also important to note that FLIR finds additional leaks not found by M21. Conversely, M21 finds 75% of the leaks, but only 15% of the total emissions.

Although AVO was not effective in this particular study, there are locations with high H_2S concentrations where AVO is more effective than M21. Sites with high levels H_2S should be allowed to use AVO or H_2S monitoring systems to identify leaks at well pads.

17.5.3 Characterizing Performance Using Laser Technology

Subpart W allows the use of an infrared laser beam illuminated instrument for equipment leak detection [§98.234(a)(3)]. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with M21 monitoring, in which case 10,000 ppm or greater is designated a leak. However, since the CTGs do not require quantification, API does not advocate establishing a specific ppm threshold for determining a leak.

17.5.4 A Streamlined Approval Process Is Needed For Alternative Technologies As These Technologies Become More Prevalent.

EPA should build into its final rule an "on-ramp" that provides an alternative path for rapid substitution of new detection equipment and monitoring strategies once they are validated and shown to be effective. This should include a fast-track review process, with firm deadlines for decision-making so that alternatives to the current LDAR requirements can be approved without time-consuming amendments to the NSPS.

As a general matter, the rule should seek to establish a more streamlined "fast-track" process for approving new detection technology that can be substituted in lieu of OGI equipment whether its use does not require modification of the LDAR protocol, or is an entirely new approach (continuous monitoring).

Where a new technology has been adequately field tested and validated through the ARPA-E MONITOR or another program and meets performance specifications outlined by EPA, the rule should authorize its deployment following a review by the Agency. The review should be completed within 180-days following submission of a complete data package by the technology developer or an oil or gas company the Agency, and the technology should be deemed approved for use unless it is disapproved by the Agency within that period. This deadline should be included in the rule itself to assure expedited action.

Detection level "equivalency" should not be required as EPA has required for using OGI versus M21. Because new detection equipment may have very different capabilities from existing technologies, it is critical to avoid a narrow "equivalence test for approving alternative methods. Moreover, the stringency of the process and "equivalency" testing has made it impossible to get other technologies approved. The excessive requirements EPA has put under the Alternative Leak Detection Program in §60.18(g) has made it so that no company is utilizing OGI.

Colorado Regulation 7[43] provides a process for approving new alternative Approved Instrument Monitoring Methods (AIMM) that could serve as a basis for OOOOa:

At a minimum, the technology must be able to pinpoint the general location of leaking or venting emissions. For non-quantifying devices, the device must be capable of detecting all hydrocarbons, and testing and certification must be repeatable. Colorado Regulation 7 also requires an indication of limitations, other applications, how the device works, how it will be used, the process for recordkeeping, and training required. Colorado Regulation 7 may also require comparative monitoring with either an IR Camera or M21.

API recommends that EPA allow for the use of alternative monitoring that detects leaks based on the following criteria:

- Occurs at least annually
- Pinpoints the general location of the leak
- Detects the hydrocarbons found at the sites
- Testing and certification must be repeatable
- Indication of limitations, other applications, how the device works, how it will be used, the process for recordkeeping, and training required.

17.5.5 Comment On Whether To Allow EPA M21 As An Alternative To OGI For Monitoring, Including The Appropriate EPA M21 Level Repair Threshold

The draft CTG implies that the initial leak surveys must be taken using an OGI. We recommend revising the requirements to specifically state that OGI, M21, or an equivalent method may be used for both the initial survey and repair leak surveys.

In addition, EPA should allow the use of soap bubbles for leak detection, since EPA approves M21 for repair confirmation and emissions quantification is not required. According to Section 8.3.3 of M21, leaks may be screened using the presence of soap bubbles. If bubbles are not observed, then the source is assumed to have no detectable emissions under M21. EPA allows the use of 8.3.3 for other industries including chemicals and refining. It should be allowed here too. The leaks may not be repaired by the same person doing the leak survey. Allowing the soap

[43] https://www.colorado.gov/pacific/sites/default/files/AP-BusIndGuidance-AIMMprocessmemo.pdf

bubble test would allow the person doing the repair to check the repair without requiring the leak survey person to have to go out to the site for a second time. This would reduce the time and expense required for doing repairs.

17.6 Reporting And Recordkeeping

17.6.1 The CTG Should Not Require A Separate Report For Each Well Site.

CTG I.5 (b) Annual reports shall be submitted for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station subject to VOC emission control requirements under section I that include the information specified in paragraph (a) of this section for each monitoring survey conducted during the year. Multiple collection of fugitive emissions components at a well site or collection of fugitive emissions as a compressor station subject to VOC emission control requirements under section I may be included in a single annual report.

API interprets "each collection of fugitive emissions components" to refer to a single LDAR survey at a well site or compressor station. The requirement to provide a separate report for each well site, even where the report can combine multiple emission surveys at a well site, is onerous. API requests the option to combine reports for multiple wells sites or compressor stations submit the combined reports in one annual report.

17.6.2 The Requirement For Capturing Photo / Image Of Leaker Is Onerous And Of Limited/No Value.

CTG I.5(a)(6)(ii) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the well site or compressor station subject to VOC emission control requirements under section I imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

EPA is building on their alternative compliance requirement to submit photos of REC equipment for green completions by proposing to require a photograph of each affected well site or compressor station for each monitoring survey performed. Under the well completions portion of the rule, a photograph is offered as an alternative to the records required. However, for the CTG it does not appear to be offered as an alternative but just additional recordkeeping.

The photo must include the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file and must identify the affected facility. It is not clear what purpose photos of the affected well site or compressor station would serve. Photos of the well site or compressor are not going to show all of the surveyed components, does not show that a survey was done, and will not provide any indication that a leak was repaired.

A photo of a survey being performed does not provide any additional compliance assurance that the survey requirements were met. Relying on the operator's certification, procedure, and documentation of repairs provides the greatest amount of compliance assurance for an OGI survey. In addition, keeping records of all the photographs will require of the great amount of storage which EPA did not account for in the cost estimate.

In addition, photographs create a security risk such as terrorist activities, retaliation, and anti-competitive activities. Oil and natural gas production and gathering operations are generally un-manned and may not have security measures such as cameras, fences, or gates. The proposed photos of fugitive monitoring activities will inherently capture details that would otherwise not be available. If EPA chooses to require photographs in electronic reporting, these detailed photos will be centralized in the public domain. Individuals with no interest in fugitive monitoring activities will have interest in viewing the photographs. EPA and states will inevitably receive Freedom of Information Act (FOIA) requests for reasons unrelated to fugitive monitoring.

Finally, keeping records of all the photographs will require of the great amount of storage which EPA did not account for in the cost estimate. API members estimate the data storage requirement for these photos is approximately 100 MB per well site survey.

Photographs do not provide any additional environmental benefit and should not be required under Subpart OOOOa for fugitive emissions monitoring. API requests that EPA remove the requirement to take a photograph.

17.6.3 API Strongly Opposes Sending Digital Photographs And Logs To The Permitting Agencies.

EPA solicited comments on whether these [digital photographs and logs] records also should be sent directly to the permitting agency electronically to facilitate review remotely; and how to minimize recordkeeping and reporting burdens API strongly opposes sending digital photographs and logs to the permitting agencies. EPA's cost estimate did not account for the burden of data storage requirements and management of data that would be place on the states. There is no apparent benefit to requiring the state to manage and maintain copies of this information. And, as indicated previously, there is a real security risk putting photographs in the public domain that includes geo data for exact location of sites that are unmanned with little to no security.

17.6.4 EPA Needs To Greatly Reduce The Recordkeeping And Reporting Burden For Leaks

The recordkeeping and reporting requirements of Colorado Regulation 7 are significant, although the requirements are far less than EPA has proposed in this rule. Furthermore, they add burden to the operator without any environmental benefit. The recordkeeping and reporting requirements NSPS OOOO should be greatly reduced. Colorado Regulation 7 only requires that the following records be maintained:

> *"XVII.F.8.Recordkeeping: The owner or operator of each facility subject to the leak detection and repair requirements in Section XVII.F. must maintain the following records for a period of two (2) years and make them available to the Division upon request.*
> *XVII.F.8.a. Documentation of the initial approved instrument monitoring method inspection for new well production facilities;*
> *XVII.F.8.b. The date and site information for each inspection;*
> *XVII.F.8.c. A list of the leaking components and the monitoring method(s) used to determine the presence of the leak;*
> *XVII.F.8.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;*
> *XVII.F.8.e. The date the leak was repaired;*
> *XVII.F.8.f. The delayed repair list, including the basis for placing leaks on the list;*

> *XVII.F.8.g. The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring; and*
> *XVII.F.8.h. A list of components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section XVII.F.5., an explanation stating why the component is so designated, and the plan for monitoring such component(s)."*

API requests that minimal records be required to reduce the cost and burden of this rule similar to what Colorado Regulation 7 requires. Further information is not needed to ensure compliance with the leak detection and repair requirements.

Also, API requests that minimal reporting of the leaks be required. Colorado Regulation 7 simply requires that the following information be reported:

> *"XVII.F.9. Reporting: The owner or operator of each facility subject to the leak detection and repair requirements in Section XVII.F. must submit a single annual report on or before May 31st of each year that includes, at a minimum, the following information regarding leak detection and repair activities at their subject facilities conducted the previous calendar year:*
> *XVII.F.9.a. The number of facilities inspected;*
> *XVII.F.9.b. The total number of inspections;*
> *XVII.F.9.c. The total number of leaks identified, broken out by component type;*
> *XVII.F.9.d. The total number of leaks repaired;*
> *XVII.F.9.e. The number of leaks on the delayed repair list as of December 31st; and"*

17.6.5 Proposed Text Revisions Associated With Reporting and Recordkeeping Requirements.

I.5(a) Records for each monitoring survey shall be maintained as specified in paragraphs (a)(1) through (6) and must contain, at a minimum, the information specified in paragraphs (a)(1) through (a)(6). Records are required to be maintained onsite or at the nearest local field office for at least five years.

(1) Date of the survey.
(2) Location of the survey
(3) A list of leaking components
(4) The date of the first attempt to repair and additional attempts to repair
(5) The date the leak was repaired
(6) The delay of repair list including the basis for placing leaks on the list
(7)The date the leak was remonitored to verify the effectiveness of the repair

~~(2) Beginning and end time of the survey.~~

~~(3) Name of operator(s) performing survey. You must note the training and experience of the operator.~~

~~(4) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.~~

~~(5) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.~~

~~(6) Documentation of each source of fugitive emissions (e.g. fugitive emissions component), including the information specified in paragraphs (a)(6)(i) through (iv) of this section.~~

~~(i) Location.~~

~~(ii) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the well site or compressor station subject to VOC emission control requirements under section I imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photo graph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.~~

~~(iii) The date of the successful repair of the fugitive emission component.~~

~~(iv) The instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.~~

(b) Annual reports shall be submitted for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a central production site or transmission compressor station subject to VOC emission control requirements under section I that include the information specified in paragraph (a) of this section for each monitoring survey conducted during the year. Multiple collection of fugitive emissions components at a well site or collection of fugitive emissions as a central production site or transmission compressor station subject to VOC emission control requirements under section I may be included in a single annual report.

Attachment A

Technical Review of Western Climate Initiative Proposals to Meter Fuel and Control Gas

Technical Review of Western Climate Initiative Proposals to Meter Fuel and Control Gas

Prepared by: David A. Simpson, P.E.
MuleShoe Engineering

Prepared: February 16, 2010

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Technical Review of WCI Proposals to Meter Fuel and Control Gas

I. Executive Summary

The Western Climate Initiative (WCI) makes the assumption that Operators would be reporting the "most accurate" volumes if the gas was metered as a "fuel" stream and a "control" stream instead of applying theoretical factors and Engineering approaches to estimate these volumes. The reports make this assertion without discussing the technology that would be deployed to measure these streams to "provide the rigor required for either cap-and-trade or offset programs". The review below categorically rejects their basic assumption and asserts that the act of installing meters on the streams considered will provide a **false sense of security** and a **net deterioration in the quality of data reported**.

There is no gas measurement technology currently existing that would provide better data in the field than is currently being reported using manufacturer's numbers and theoretical calculations. In addition to making the data less representative of reality, the costs that would be imposed are staggering—industry would be required to spend billions of dollars to report gas emissions data that is demonstrably worse than the data they are reporting today.

A. Summary Expenditures

The "Per Company" column below assumes 2,000 wells per company, "Total WCI" column assumes 100,000 wells affected in the WCI States and Provinces (breakdown is included under "Cost of Implementation" below). Many wells cannot sustain either the increased operating cost or the capital expenditure so they would be plugged instead of spending this money—there is no way to predict this mix of expenditure vs. plugging.

	Per well ($k)	Per Company ($million)	Total WCI ($million)
RTU Replacement	$3.5	$7	$350
Host/Database		$15	$750
Site Modifications	$30.0	$60	$3.000
Total Capital	$33.5	$82	$4,100
Annual Operating Costs	$1.5	$3	$150

B. Author Biography

David Simpson has 30 years experience in Oil & Gas and is currently the Proprietor and Principal Engineer of MuleShoe Engineering. Based in the San Juan Basin of Northern New Mexico, MuleShoe Engineering addresses issues in Coalbed Methane, Low Pressure Operations, Gas Compression, Gas

Measurement, Field Construction, Gas Well Deliquification, and Produced Water Management.

A Professional Engineer with his Master's degree, David has had numerous articles published in professional journals, has contributed a chapter on CBM to the 2nd edition of Gas Well Deliquification, by Dr. James Lea, et al, and has spoken at various conferences, including the 2003 SPE *Annual Technical Conference and Exposition* in Denver. He has been a featured speaker at the bi-annual *Four Corners Oil & Gas* Conference for the last 6 years and is a regular instructor at short courses at the annual ALRDC *Gas Well Deliquification Workshop* in Denver. David was Program Chair for the highly successful SPE Advanced Technology Workshop titled "Managing the Performance of Low Pressure Gas Wells and Associated Facilities" held in Ft Worth, TX in October, 2008. His consulting practice includes clients in 10 countries.

II. Discussion

The Western Climate Initiative has developed at least two documents that each reach the conclusion that gas consumed on wellsites must be measured to achieve adequate "accuracy" in accounting for emissions. The documents further require that gas used for pneumatic controls must be measured separately from gas burned because vented gas has a different "emissions factor" on the environment than burned gas has.

The industry has long said and demonstrated that measuring either fuel gas or control gas represents a very large cost for a very small return. The discussion below supports that position.

A. Magnitude of Gas Consumed

1. *Engine Fuel*

   The industry has an excellent understanding of engine fuel. Where engine fuel is measured, the theoretical correlations match very well with measured data. The added value of measuring this fuel-gas stream is not clear to most wellhead compressor operators; consequently it is rare to see a fuel meter on a wellhead compressor or pump jack. The various stakeholders in the gas production process (including regulatory agencies and mineral owners) have accepted that these volumes are both small and adequately represented by the theoretical usage factors.

   Engines utilized in field locations range from a single-cylinder Arrow running a pump jack (smallest is the Arrow C-46 which is rated at 6 hp at 500 rpm at sea level with 70,000 BTU/hp-hr fuel consumption) to a nominal 1,000 hp compressor (such as the Waukesha P48 GLD which is rated at 1,200 hp at 1,400 rpm at sea level with 7,720 BTU/hp-hr fuel consumption). This equates to a required measurement range of 5 MCF/day to 220 MCF/day (3.5 to 153 SCFM) assuming a pump jack at ½ load and a GLD at full load.

2. *Separator/Tank Heaters*

   I recently did a review of 536 tank and separator burners in the San Juan Basin. Burner nameplate capacity ranged from 50,000 BTU/hr to 500,000 BTU/hr. The average capacity was 340,000 BTU/hr. Since these burners only operate 5-6 months out of the year, this number equates to less than 170,000 BTU/hour on an annual basis. For some perspective, the on-demand hot water heater in my house is rated at 185,000 BTU/hour. This is a fair comparison since both devices are classed as "on demand" in that they will each turn off when conditions warrant—while in service, tank heaters only run a fraction of the time to maintain the tank at the set temperature.

   The current method of reporting fuel consumed in burners is to determine if the heater had gas to it during the month, if it did then most operators take the nameplate energy consumption times 24 hours per day for every day of the month. For a 340,000 BTU/hour burner this equates to 253 MMBTU in a 31 day month. I have worked with several operators who would report this number even if the burner only had gas to it for a single day.

In reality, the water or condensate entering a tank is usually substantially warmer than the burner set point so the burner will tend to run less than 15 minutes out of an hour on the coldest night. This means that if you shut your heater down at noon on April 1 you would have burned 1 MMBTU for the month and reported 253 MMBTU. Even if the burner has gas to it for an entire month, you burn the gas in the pilot for 744 hours in a 31 day month (typical pilot lights burn approximately 1,700 BTU/hr), but you only run the main burner for something like 186 hours—for a 340,000 BTU/hr burner you consume less than 70 MMBTU and report 253 MMBTU.

The main challenge of measuring the gas consumed in a burner is that the device must measure the pilot flow with the same level of uncertainty as you apply to the main burner flow. For a common 500,000 BTU/hr burner this means that you have to have a 294:1 "turndown ratio". Turndown ratio is a measure of ability of a measurement device to provide similar "accuracy" over the expected operating range. According to Wikipedia, a Square Edged Orifice meter has a turndown ratio of 3:1. Even a Diaphragm Meter (similar to residential gas meters) only has a turndown ratio on the order of 80:1. A meter that can measure full burner flow would register zero with pilot flow.

With burner on/off control, there is a rapid transient in the flow as the line fills upstream of the burner followed by steady flow. A device that could successfully capture both the transient and the steady flow would have to be able to go from "off " to the top end of its range in less than 1 second, and then hold steady for up to 15 minutes, then go to zero in a fraction of a second. There is so much uncertainty in this transient flow that any available gas measurement technology would yield a worse result than manufacturer's estimates and Engineering calculations.

Required measurement range 0.04 to 12 MSCF/day (0.02 to 8.3 SCFM).

3. *Dehydrator Reboilers, Heater/Treaters, and Line Heaters*

These devices are similar in specific energy-use to the tank/separator heaters, but they tend to run continuously.

Dehydrators are used to remove water-vapor from a gas stream. This water vapor is adsorbed to a liquid that must then be regenerated. Regeneration takes place in a reboiler that is used to add enough heat to the liquid to cook the water out (about 8,000 BTU/lbm of water on average). Since "rich" liquid (i.e., liquid containing high levels of water) is continuously entering the reboiler, the heater is always on.

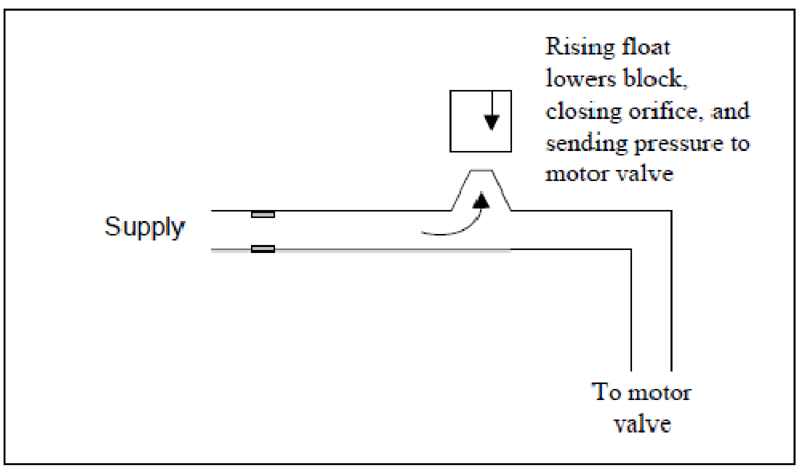
Both Heater/Treaters and Line heaters are designed to add heat to a process stream to control a process variable. For example, Line Heaters are often used in waxy crude to prevent precipitation of paraffin in the pipe causing a clogged line. A Heater/Treater is used to flash light hydrocarbons for further processing into Natural Gas and Natural Gas Liquids streams. Both of these classes of equipment have burners on the high end of the expected range for tank/separator heaters, and both operate around the clock, year-round.

Many technologies could be used to meter any of these streams with adequate repeatability and uncertainty. Whether you meter this stream or use engineering calculations, you will get very similar volumes burned.

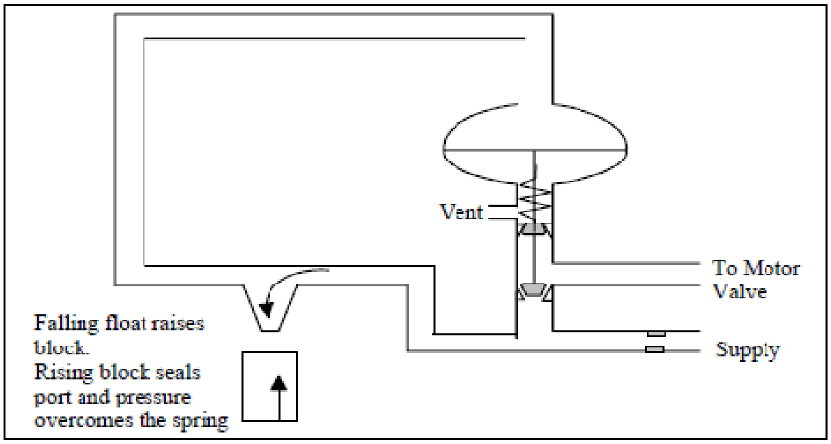
4. *Pneumatic devices*

I did a study in the year 2000 (see SPE 61030) that quantified the gas used in high-bleed pneumatic devices. The project described in that paper was an economic success because we were able to replace high-bleed CEMCO throttling level-controllers with no-bleed, snap acting level controllers. The replacement controllers were markedly less effective, but they were marginally good enough and we were able to sell the gas that would have been vented in the CEMCO.

When talking about controllers (level, temperature, etc.), there are two parameters that have to be clarified: (1) Signal Type and (2) Bleed characteristics. Signal type is either “Throttling” or “Snap Acting”. Bleed characteristic is either “continuous bleed” or “no bleed” An example of a Continuous Bleed, Throttling controller is shown below

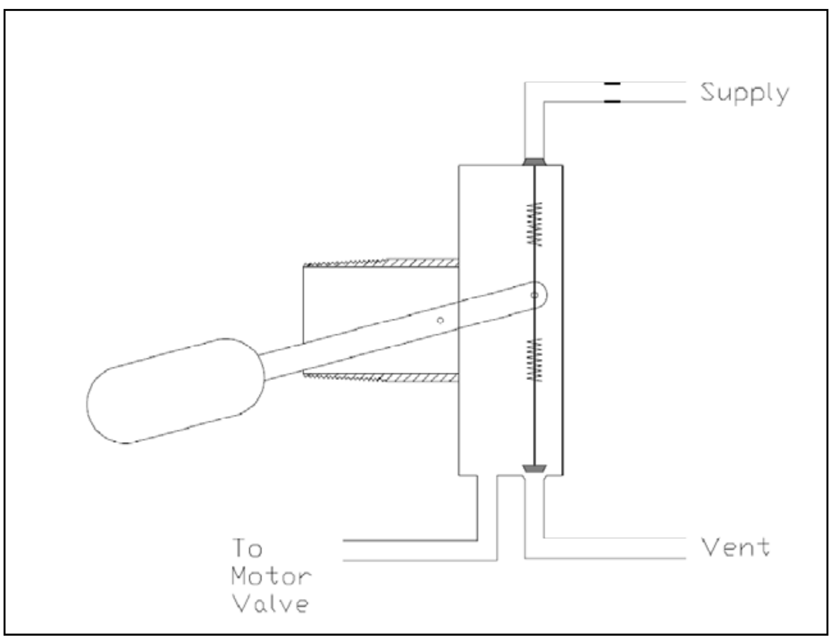


In this device, supply gas is provided through a restrictive orifice to the vent. As the block (attached to a level float for example) descends, it begins restricting the flow through the vent and sends pressure to the controlled device (a motor valve in this case). The beauty of this device is that it operates the controlled device very gently and tends to produce very stable performance. The downside is that you are venting gas anytime that the controlled device is other than fully open. Since many controlled devices are shut most of the time (e.g. in the referenced study, we determined from a sample of over 4,000 wells that the average well cycled the separator dump valve 5 times per hour for 3 minutes each cycle) some operators have tried to reduce the amount of vented gas by turning the process over like:



In this case, the block closes the vent most of the time. When the fluid level increases, the vent opens some. When the vent is opened far enough to drop the pressure on top of the pilot below the spring setting, the pilot snaps open and sends gas to the motor valve very rapidly. At the end of the cycle, the pilot goes shut and vents the motor valve through the top valve seat. Instead of venting for 45 minutes each hour, it vents about 15 minutes per hour at the cost of throttling the flow.

A "No Bleed" controller would look something like:



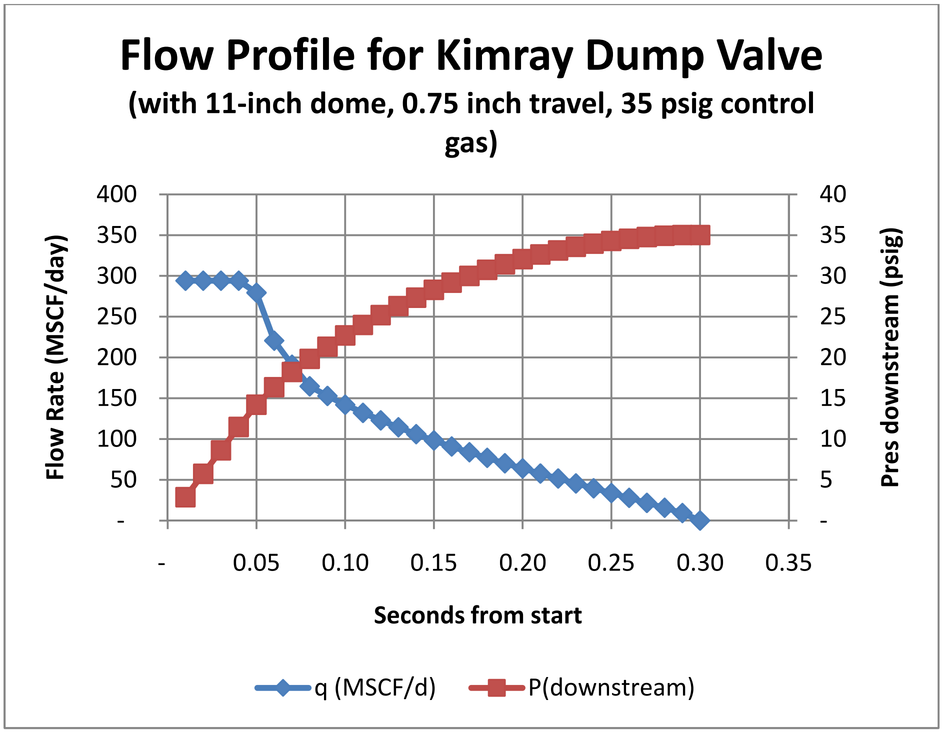
This simplified example shows that when the float is down, the supply valve is shut tight and the vent valve is open. As the float starts rising, the vent is closed. As it continues to rise it reaches a point where the spring tension is inadequate to hold the supply valve shut and it "snaps" open. At the end of the cycle the falling float reaches the point where it can close the supply. As it continues to fall it eventually reaches the point where the vent opens and the motor valve shuts. Most snap acting controllers are applied in service this simple and it is rare to require a pilot in this on/off service.

Notice in the description of the action of the no-bleed controller, the supply gas us used to operate the valve against a dead-end. At the end of the process the supply is shut off before the vent opens. The only gas that is vented in a no-bleed controller is the volume of the piping and the motor-valve bonnet. The supply system is never directly exposed to an open vent, so there is no ongoing "bleeding" of gas.

It is possible to throttle a controlled device with a no-bleed controller with an external pilot, but the control tends to be poor and can't be controlled very long (i.e., the devices used to sense an intermediate position are cumbersome and tend to have a "jerky" action). For practical purposes, when you decide to go to no-bleed you are locking the device into snap acting.

Continuous-bleed controllers are reasonably easy to meter the gas (a CEMCO continuous bleed, throttling level controller vents about 800 SCF/day at 35 psig supply pressure assuming that it is not venting or is venting at a reduced rate for 15 minutes per hour).

For a no-bleed controller, each time the dump valve cycles, control pressure is applied to a diaphragm to counteract spring tension and open the dump valve. At the end of the cycle, the line from the controller to the diaphragm and the diaphragm dome are vented to atmosphere. If we assume that the two devices are connected by 12 ft of 3/8 tubing (0.0092 ft^3) and the diaphragm dome is 0.04 ft^3 (assuming 11-inch diameter, and 0.75 inches of travel) then the volume vented each dump is 0.049 ft^3. At 35 psig and 60°F then this volume is 0.157 SCF/dump. At 5 dumps per hour this equates to 19 SCF/day (2% of a high-bleed device). The flow and pressure profile will look like:



Notice that the entire cycle takes something on the order of 0.3 seconds. This flow is made up of a period of sonic velocity (Reynolds Number 996,000) followed by a period of a significant fraction of sonic velocity (Reynolds Number ends up at 648,000 for 0.65 Mach), and finally a period of flow in a normal turbulent flow regime ending with a Reynolds Number of 10,000 just before the level control is closed. A measurement device would have to be able to go from offline to 294 MSCF/d within 5 ms, and be able to do a 100:1 turndown ratio. No meter ever made has that kind of latency or turndown ratio. Some meter technologies would give you numbers (most would never register), but none will give you measurement.

B. Gas Measurement Technologies

When I talked about “meter accuracy” above I always said “accuracy”. “Accuracy” is an amazingly imprecise term that is never used by competent gas measurement professionals. The layman/advertising concept of “accuracy” is encompassed in the terms “repeatability” and “uncertainty” which have precise definitions that can be measured and used to compare the performance of a device relative to a standard or to another device.

“Repeatability” is a measure of a device’s ability to report the same output for a given set of inputs. Many things can impact a device’s repeatability. For example, turbine meters have the worst repeatability of all industrial gas measurement devices because gear lash is a random parameter that can change the speed of the turbine rotor by several percentage points independent of the magnitude of the change in measured input parameters. Acceptable repeatability occurs when the standard deviation of the sample data is within ±0.05% of the mean value.

“Uncertainty” is the “dead band” of the instruments. Each component of a gas-measurement station has a defined uncertainty, usually expressed in a range around the device’s calibrated span. For example, a digital pressure transducer may have a stated uncertainty of ±0.5% which means that if the device has a calibrated span of 0-10,000 psig and reads 450 psig then the reading represents a value between 400 and 500 psig. Recalibrating the same device to 0-500 psig would change the meaning of 450 psig to 447.5-452.5 psig. Uncertainty is just that—you do not know where the actual number resides within the uncertainty range. A gas-measurement device is generally considered acceptable if the cumulative effect of each end-devices’ uncertainty is less than ±2.0% (this is based on government requirements which were set before digital instruments, about 1% of the total uncertainty is uncertainty in manual chart integration, 0.5% is from using average temperatures). Electronic Flow Measurement (EFM) devices and digital temperature/pressure instruments make normal uncertainty less than 0.5% in most square-edged orifice (AGA 3) stations today.

Another important gas-measurement concept is “latency”. Latency is a measure of the time lag between a change in flow and that change being reliably represented in the measurement device output. Every technology has some amount of latency. For example, a stopped turbine meter requires flow to overcome static friction before it starts spinning, and once it starts spinning it will tend to spool up to a high angular velocity before coming back down to report the actual flow rate. Consequently, turbine meters perform best in very steady flows—putting a turbine on the gas line to a separator dump valve would result in the meter not registering most dump events and over ranging on the few that it does register.

All gas measurement technologies are “inferential” technologies. This means that the equations infer a flow rate from some unrelated, but measurable, parameter. For example, Square Edged Orifice Measurement uses the *Bernoulli Equation* published by Daniel Bernoulli in 1738 to relate the pressure drop across a known flow restriction to a velocity, and then uses specific correlations developed for gas measurement to convert the velocity into a volume flow rate at standard conditions. The first assumption in Mr. Bernoulli’s development of his famous equation is that the fluid is both incompressible and inviscid. Neither of these assumptions is literally true in a gas flow, but the industry has proven that both assumptions are close enough to being true to allow meaningful flow rates to be estimated. At commercial velocities, highly compressible natural gas does indeed act like an incompressible fluid unaffected by fluid friction over short distances. As velocity increases toward the speed of sound or decreases to result in a Reynolds Number under 4,000 the incompressible assumption becomes progressively less valid and the uncertainty in a measurement device increases dramatically.

1. *Gas Analysis*

   Many states and the federal government have agreed that small wells (typically wells making less than 100 MCF/day) would be exempt from requirements for semi-annual analysis of the gas. This decision has not caused wholesale inaccuracies and I get the impression that all the stakeholders are satisfied with annual or even less frequent gas analysis.

   For the Western Climate Initiative to re-introduce semi-annual analysis requirements and to propose quarterly analysis on small streams is not a reasonable imposition.

2. *Square Edged Orifice Meters*

   The operating principle is to infer a flow rate from the differential pressure across a known restriction based on measured pressure and temperature. For a clean, well conditioned flow stream the uncertainty of the reported volume is on the order of 0.5-2%. Both uncertainty and repeatability are adversely affected by 2 phase flow, dirt, and changes in flow profile and in small-volume and/or intermittent service the uncertainty can exceed ±25%.

   These meters are the most common type of gas measurement in upstream gas operations. One of the reasons for their popularity is the extensive body of research that has gone into defining the meter configuration and operating limits. This research is documented in the series of reports collected into API 14.3 (also published as AGA 3).

   The standards indicate that Square Edged Orifice measurement is only appropriate in meter tubes equal to or greater than 2.000 inches internal diameter (ID) and for Reynolds Numbers above 4,000. This means that the smallest volume that can be reliably measured with this technology at 35 psig is 5 SCFM (7.2 MSCF/day).

   Latency in this technology is caused by the chaos in the flow as it moves to establish a pseudo-steady-state condition. I have evaluated carefully-controlled flows at the Colorado Engineering Experiment Station (CEESI) during start-up using instruments that record pressures 100 times per second and have found that reaching repeatable flow in a Square Edged Orifice Meter can take as much as 5 minutes from a dead stop.

3. *V-Cone Meters*

   The operating principle is to infer a flow rate from the differential pressure across a known restriction based on measured pressure and temperature. These meters are self-conditioning and tolerant of solids. The total uncertainty is on the order of 0.5-1%. Turndown is 10:1, and it is advertised to work down to Reynolds Numbers of 6,000 or greater.

   This device has potential, but the smallest meter (1/2” ID) would register zero during pilot flow and would have a dP less than 7 inH_2O (0.25 psi) while supplying gas to a 500,000 BTU/hr burner which would increase the uncertainty to several percent.

Latency of these meters is similar to Square Edged Orifice Meters.

4. *Turbine Meters*

The operating principle is to relate a rotor's angular velocity to a volume flow rate. Turbine meters assume reasonably steady flow with respect to time. Changes in rate take considerable time to steady out. Latency for a change to a flowing stream can be up to a minute, for a start/stop flow it can be many minutes.

Turbine meters rely on considerable mass to spin the rotors and they rarely provide adequate results in gas flows below 50 psig.

5. *Coriolis Meters*

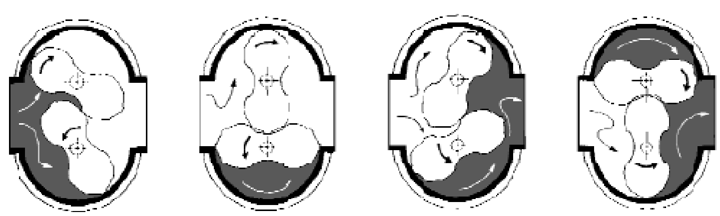
The operating principle is that the momentum of a flowing fluid will vibrate a piping loop, and that the frequency of the vibration is a function of the mass flow rate and density of the fluid. Low velocities and low pressures have a serious negative impact on uncertainty and repeatability. The MicroMotion division of Emerson has some fairly new instruments that can handle quite low flows, but the latency is similar to a turbine meter.

6. *Ultrasonic Meters*

The operating principle of Ultrasonic Meters is that there will be a Doppler Shift in the speed of sound as fluid moves away from a fixed sound-pickup point. The magnitude of this shift is a function of fluid density and fluid velocity. Low velocities and low pressures have a serious negative impact on uncertainty and repeatability.

7. *Roots Rotary Meters*

The operating principle of these positive displacement meters is to trap a fixed volume of gas within each revolution of a pair of lobes. Counting revolutions yields a volume.



This device is quite close to "measuring" gas volumes instead of "inferring" a volume from a tenuous mathematical relationship, but it is still counting revolutions instead of gas molecules.

Latency in Rotary Meters is very high due to having to start the rotors spinning again and leakage past the rotors before they start spinning.

8. *Diaphragm Meters*

   The operating principle of these positive displacement meters is to fill a resilient chamber to line pressure, then that chamber is shifted to the demand side while a second chamber is filled. Each time the meter shifts chambers it records a pulse that represents a known volume.

   The uncertainty, repeatability, and latency of these devices is excellent. Turndown ratio is on the order of 80:1. “Household quality” meters would handle the low flows, but materials of construction are generally inappropriate for field gas (e.g., they have considerable brass that is rapidly deteriorated by any H_2S in the flow; all of the Household meters have aluminum casings which have not stood up well to condensate service). “Industrial quality” meters are considerably more expensive and many of them still have inappropriate materials. A meter with no aluminum or “yellow metal” is difficult to find and is very expensive.

9. *Exotic/Laboratory instruments*

   The volume of gas discussed in this application kept leading me to devices like “Thermal Dispersion Meters” (this meter has two probes, one is heated and one is a temperature sensor, the dT can be correlated to a mass flow rate, very long latency); and laboratory quality devices that are absolutely intolerant of free liquids and/or solids. None of these devices has a published standard for construction, installation, and operation and none has a reasonable chance of success.

10. *Conclusion*

    In conclusion, the act of installing meters on the streams considered will provide a false sense of security and a net deterioration in the quality of data reported. Specifically:

    a) Engine fuel can be measured by dP inferential devices (either Square-Edged Orifice Meters or V-Cone meters), but the resulting metered volume will be very close to the theoretical data that is being collected today. Where the two numbers are significantly different I would expect that there is a measurement device error (such as an incorrect meter parameter or a backwards orifice plate) before I would expect the theoretical calculation is incorrect.

    b) No meter exists that can reliably measure both pilot flow and burner flow on a tank or separator heater if the burner is the only load on the system. If measuring these volumes becomes mandatory, then a diaphragm meter could be used to measure the pilot flow and either a Roots Meter or another diaphragm meter could be used for the burner flow. A fuel gas system with multiple engines and multiple burners could be metered with a V-Cone or Square-Edged orifice meter, but the burner volumes would only be able to be measured while the engine was consuming fuel—when the engine is not running, the burner is unlikely to register as an increment from zero.

The theoretical values for burners could be improved by putting a "valve open" clock on the supply line, which (in conjunction with manufacturer's data and Engineering analysis) would result in a better volume than attempting to meter the gas.

c) Heater/Treaters, Dehy Reboilers, and Line heaters are reasonably constant loads that could be metered by several of the technologies above (the diaphragm meter would be preferred, but the small V-cone and the smallest Corriolis meter would work), but again the data would be of a similar magnitude of the data being reported today.

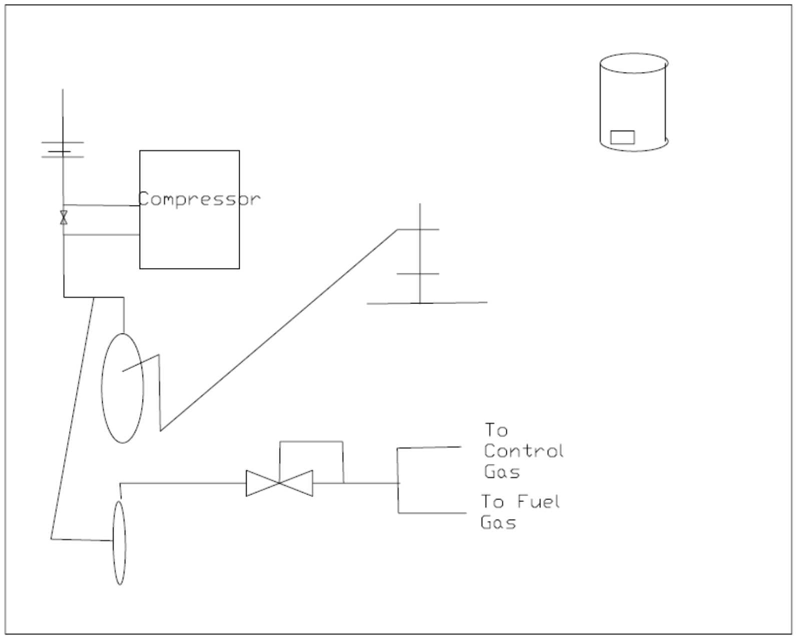
d) No meter exists that can reliably measure the flow to a single dump valve or even a dozen dump valves off the same no-bleed controller. Even if a group of dump valves (three or more) were controlled off the same controller, the flow and pressure traverse would be similar to the one above and the meter would have to go from zero to 900 MCF/d in a few milliseconds then back to zero within about 1/3 second. It can't be done.

The diaphragm meter comes the closest, but it will tend to either be over ranged for most of the flow period or will fail to register a significant portion of the tail. I would guess that the total uncertainty would be on the order of 20-30%.

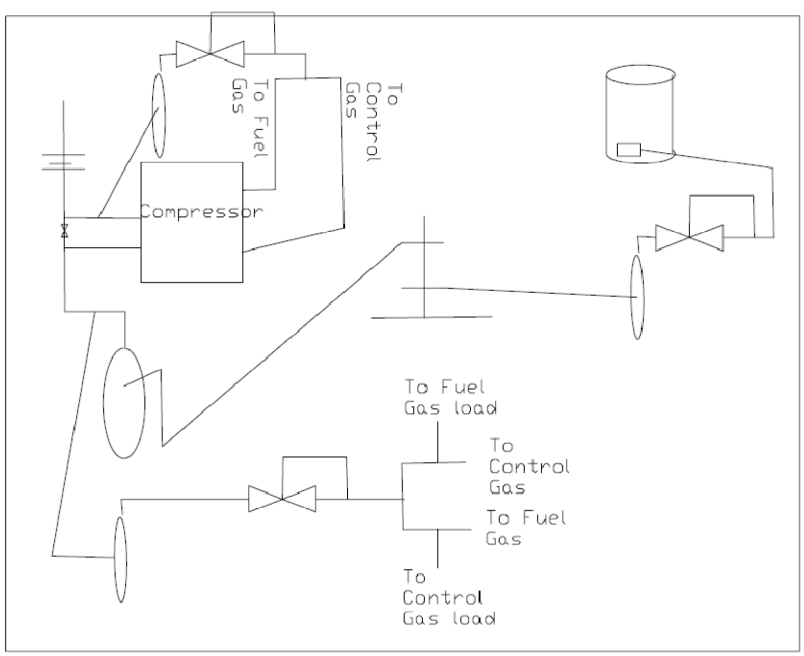
On the other hand, the flow to a continuous-bleed controller could be measured successfully with either a Roots meter or a diaphragm meter.

C. Wellsite Configurations

The reports from the Western Climate Initiative start with an assumption that there is something that can be reasonably termed a "standard" wellsite where fuel-gas measurement equipment can be "relatively easily" installed. This is patently false. The implication is that every site looks something like:



This layout brings gas from the wellbore tubing to a single separator, and then takes fuel gas off the separator outlet to supply both control requirements and fuel requirements. While there are wells that are configured like this, they are rare. A layout that would be equally as likely to occur would look like:



This layout did not suffer the expense of running a fuel gas line across the location to supply gas to the tank heater from the separator; it pulled that fuel stream from the casing valve and put a second fuel pot as a less expensive alternative to laying a line. Also, the compressor takes its fuel and control gas from an on-skid fuel-gas system. This is the normal configuration since compressor-discharge gas is far better suited to both fuel gas and control gas applications than suction gas is.

This distributed fuel-gas supply scenario has evolved over the decades because the regulations in place at the time of site facilities-construction did not presume to tell operators how to build their sites.

III. Costs of Implementation

It is difficult to develop costs for a “typical” wellsite, “typical” automation system, or “typical” host/database modification because there is no such thing. There are companies within the WCI area of operation that don’t have any automation or measurement on their wellsites today and use Excel spreadsheets to allocate sales volumes back to wells. There are companies with home-grown automation systems that have zero flexibility and cannot be retrofit for two additional volume calculations and would have to be discarded and replaced. There are companies with purchased systems that they do not have the license to modify. There are wellsites that will be trivial to retrofit. There are wellsites that will require laying new lines and replacing production equipment.

My approach to cost estimates is to try to address the wellsites, field automation equipment, and host/database systems that I’ve worked with at my clients operations over the years. I am certain that this technique will be representative of a large number of wellsites and a number of operators, but it will not be all encompassing because it is impossible to assess all of the permutations.

Accessing EIA data at http://www.eia.doe.gov/pub/oil_gas/petrosystem/petrosysog.html and CAPP data at http://www.capp.ca/GetDoc.aspx?DocID=146286 for 2006 (the last year that has both US and Canadian well counts) I get the following counts of wells (after deducting 31,000 wells from California to account for Kern County):

	Gas	Oil	Total
New Mexico	36,202	15,456	51,658
California	3,692	16,197	19,889
Utah	5,259	2,574	7,833
Montana	6,207	4,199	10,406
BC	6,608	1,122	7,730
Manitoba	0	2,692	2,692
			100,208

For the economic analysis I’ll use 100,000 wells.

A. RTU costs

Looking at the specifications on a number of RTU's, there are high-end RTU's like the Fisher FloBoss 107/107E that can accept multiple gas-measurement inputs. These devices are not the norm for wellsite use. More common are units like the Kimray DACC 500 RTU that can only accept one flow calculation. At least 75% of the RTU's currently installed will need to be upgraded at a per-unit cost of $4,000-5,000. Assuming that 25% of the locations do not need RTU replacement then the average for the wells is approximately $3,500/site.

B. Host/Database costs

Host databases are very difficult to modify. Changing the Host requires that you: (1) have a place to put the new data; (2) change the data poling logic to pull the new data off the RTU to populate the new database fields; (3) add the new data to EFM editing programs; and (4) modify reporting systems to show the new data. I spent 12 years managing projects similar to this for Amoco and was involved when Amoco was making some significant changes to their host database. Amoco's changes were far less extensive than adding two measurement points that have to be reported to regulatory agencies and those changes cost $15 million and took almost 2 years. If the average impacted user has 2,000 wells then for 100,000 wells in WCI you could expect to spend $750 million.

C. Installation costs

After interviewing several operators and several roust-about service providers, modifying control and fuel gas systems to allow measurement and installing measurement equipment should be budgeted at 10 days of work per site. At $1,200/day that is $12,000/well labor. Jobs like this one are typically 60% materials (including the cost of a meter run of undecided technology) and 40% labor so total budgetary cost should be $30,000/well—100,000 wells would cost $3 billion.

This does not address the gas volume vented during the site blowdown and purge or the vented gas during semi-annual meter calibrations. To put that volume in perspective, for a small location without a compressor operating at 150 psig, the volume vented and later purged would be on the order of 2.5 MSCF—the same volume that would be vented in 131 days of operating a single no-bleed dump valve at 35 psig and 5 cycles/hour. The amount vented and purged during meter calibrations will depend on meter technology selected, but it is far from zero for any technology.

These costs also do not address the 2 weeks of lost production (call it 12 days at an average production rate of 100 MSCF/d) of something like 1,200 MSCF that was either deferred or more likely in competitive reservoirs was allowed to migrate to offset wells. At a $5/MMBTU sales price the cost of this lost production is $600 million across 100,000 wells.

D. Operating costs

Operating costs are the easiest to assess. A measurement tech can handle approximately 200 meter stations. The cost of a measurement tech with vehicle and benefits is $150,000/year which works out to about $750/meter/year or $1,500/site/year.

IV. Conclusion

The idea that there would be any benefit to society from requiring gas measurement of control gas and fuel gas is patently false regardless of your position on the risk to society of gases being released to the atmosphere. A project to put this measurement in place would result in considerable vented gas, excessive capital expenditures, and excessive increases in operating costs. On the other hand the data from this expensive equipment would actually be less representative of the gases released than the current methods. In short, you would be implementing a very large cost to develop less precise data.