NOT YET SCHEDULED FOR ORAL ARGUMENT

No. 17-1145

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

CLEAN AIR COUNCIL, et al.,

Petitioners

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, et al.,

Respondents.

EPA'S OPPOSITION TO PETITIONERS' EMERGENCY MOTION FOR A STAY OR, IN THE ALTERNATIVE, SUMMARY VACATUR

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CERTIFICATE AS TO PARTIES, RULINGS AND RELATED CASES

A. PARTIES AND AMICI

Except for the following, all parties, intervenors, and amici appearing in this court are listed in the Brief for Petitioners. Texas Oil & Gas Association, GPA Midstream Association, Independent Petroleum Association of America, American Exploration & Production Council, Domestic Energy Producers Alliance, Eastern Kansas Oil & Gas Association, Illinois Oil & Gas Association, Independent Oil and Gas Association of West Virginia, Inc., Interstate Natural Gas Association of America, and American Petroleum Institute have moved to intervene.

B. RULINGS UNDER REVIEW

Reference to the agency decision under review appears in the Brief for Petitioners.

C. STATEMENT OF RELATED CASES

Respondents are aware of the following consolidated case related to this matter, which may involve the same or similar issues: *American Petroleum Institute v. EPA*, D.C. Cir. No. 13-1108. This case, and the cases consolidated with it, are presently held in abeyance and challenge the 2016 Rule that is subject to partial reconsideration and partially stayed by EPA's July 5, 2017, decision that is the subject of challenge in this case.

DATED: June 15, 2017

/s/ *Benjamin R. Carlisle*
Benjamin R. Carlisle

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GLOSSARY

2016 Rule	"Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule." 81 Fed. Reg. 35,824 (June 3, 3016).
AMEL	Alternative means of emission limitation
CAA	Clean Air Act
EPA	The United States Environmental Protection Agency
LDAR	Leak detection and repair
NAAQS	National Ambient Air Quality Standard
NSPS	New source performance standards
Proposed Rule	Proposed rule, Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593 (Sept. 18, 2015).

STATUTORY BACKGROUND

The Clean Air Act ("CAA"), 42 U.S.C. §§ 7401-7671q, creates a comprehensive program for control of air pollution through a system of shared federal and state responsibility. Under Section 111 of the CAA, 42 U.S.C. § 7411, EPA must establish a list of stationary source categories that the Administrator has determined "cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." *Id.* § 7411(b)(1)(A). For each category, EPA must set federal "standards of performance" for constructed, modified, and reconstructed sources. *Id.* §§ 7411(a)(2), (b)(1)(B); 40 C.F.R. § 60.15. The standards are referred to as "new source performance standards," or "NSPS."

NSPS help states achieve and maintain clean air by setting emission standards for new sources that reflect the degree of emission limitation achieved through the application of the best system of emission reduction that has been adequately demonstrated.[1] *See* 42 U.S.C. § 7411(a)(1); *Essex Chem. Corp. v. Ruckelshaus,* 486 F.2d 427, 434 n.14 (D.C. Cir. 1973). Accordingly, NSPS promulgated under Section 111 apply to all new sources within a category across the United States. 42 U.S.C. § 7411(b)(4). The CAA defines "new source" to include any stationary source for which "construction or modification" of the source is commenced after the

[1] Emissions standards for existing sources are addressed in 42 U.S.C. § 7411(d).

publication of proposed regulations prescribing the particular NSPS applicable to that source. *Id.* § 7411(a)(2).

THE CHALLENGED ACTION

EPA issued a notice of proposed rulemaking to set NSPS for certain pollutants emitted from new and modified sources from oil and natural gas facilities on September 18, 2015. 80 Fed. Reg. 56,593 ("Proposed Rule").[2] On June 3, 2016, EPA finalized the rule, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule," 81 Fed. Reg. 35,824 (June 3, 2016) ("2016 Rule"). Among the new standards imposed by the 2016 Rule are the requirements to monitor and control well site and compressor station fugitive emissions, the pneumatic pump standards, as well as closed vent certification by a professional engineer that is required for demonstrating compliance with a number of emission standards. Recognizing that "[i]n recent years, certain states have developed programs to control various oil and gas emissions sources," EPA also set forth a previously unannounced process through which owners and operators could apply to EPA for approval to use "alternative means of emission limitation." 2016 Rule at 35,871; Pet. Attach. at 3; 40 C.F.R. § 60.5398a.

On August 2, 2016, EPA received petitions for administrative reconsideration that raised numerous objections to the 2016 Rule. Pet. Attach. at 85-151. In

[2] The 2015 proposal to establish new standards was a discretionary rulemaking and was not compelled by 42 U.S.C. § 7411(b)(1)(B).

response, on April 18, 2017, EPA alerted the administrative petitioners that it had concluded that certain issues merited reconsideration under 42 U.S.C. § 7607(d)(7)(B). *Id.* EPA further noted that it intended to issue a 90-day stay of the fugitive emission requirements under 42 U.S.C. § 7607(d)(7)(B). Pet. Attach at 154.

On June 5, 2017, EPA published a "notice of reconsideration and partial stay," 82 Fed. Reg. 25,730 (June 5, 2017), in which it convened a proceeding for reconsideration of four aspects of the 2016 Rule: (1) the applicability of the fugitive emissions requirements to low production well sites; (2) the process and criteria for requesting approval for the use of an alternative means of emission limitation; (3) the requirement that a professional engineer assess and certify "closed vent systems" used to comply with emission standards; and (4) conditions and limitations for a pneumatic pump at a well site to be exempt from the emission control requirement. Pet. Attach. at 3-4.[3] EPA issued a narrow, 90-day stay of the specific requirements associated with the issues under reconsideration: the fugitive emissions requirements, the standards for pneumatic pumps at well sites, and the professional engineer certification requirements. *Id.* at 4-5.

[3] EPA also noted its intent to "look broadly at the entire 2016 Rule." Pet. Attach. at 4. EPA has also proposed further stays of certain requirements of the 2016 Rule. https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-proposes-stay-oil-and-gas-standards-two

Petitioners filed a Petition for Review of EPA's decision to administratively stay these aspects of the 2016 Rule and the present motion for a stay or summary vacatur of EPA's decision on June 5, 2017.

STANDARD OF REVIEW

A judicial stay of an agency decision is a disfavored remedy. "On a motion for [a judicial] stay, it is the movant's obligation to justify the court's exercise of such an extraordinary remedy." *Cuomo v. United States Nuclear Regulatory Comm'n*, 772 F.2d 972, 978 (D.C. Cir. 1985). The factors for determining whether a judicial stay is warranted are: (1) the likelihood that the moving party will prevail on the merits; (2) the prospect of irreparable injury to the moving party; (3) the possibility of harm to other parties; and (4) the public interest. *Id.* at 974; *see also* Circuit Rule 18. This standard is applied stringently. *Aberdeen & Rockfish R.R. Co. v. Students Challenging Regulatory Agency Procedures*, 409 U.S. 1207, 1218 (1972); *Wisconsin Gas Co. v. F.E.R.C.*, 758 F.2d 669, 673-74 (D.C. Cir. 2015). Likewise, "[s]ummary reversal is rarely granted and is appropriate only where the merits are 'so clear, plenary briefing, oral argument, and the traditional collegiality of the decisional process would not affect [the Court's] decision.'" D.C. Cir. Handbook of Practice and Internal Proc. at 36 (quoting *Sills v. Federal Bureau of Prisons,* 761 F.2d 792, 793-94 (D.C. Cir. 1985); "Parties should avoid requesting summary disposition of issues of first impression for the Court.").

To demonstrate a likelihood of success on the merits, Petitioner must show that it is likely to persuade this Court that EPA's action is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 42 U.S.C. § 7607(d)(9). The "arbitrary or capricious" standard presumes the validity of agency actions, and a reviewing court is to uphold an agency action if it satisfies minimum standards of rationality. *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 520-21 (D.C. Cir. 1983); *Ethyl Corp. v. EPA*, 541 F.2d 1, 34 (D.C. Cir. 1976). Where EPA has considered the relevant factors and articulated a rational connection between the facts found and the choices made, its regulatory choices must be upheld. *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983). Particular deference is given by the Court to an agency with regard to matters within its area of technical expertise. *Baltimore Gas & Elec. Co. v. NRDC*, 462 U.S. 87, 103 (1983).

This deference extends to EPA's interpretation of a statute it administers. *United States v. Mead Corp.*, 533 U.S. 218, 227-31 (2001); *Chevron, U.S.A., Inc. v. NRDC*, 467 U.S. 837, 842-45 (1984). "The court need not conclude that the agency construction was the only one it permissibly could have adopted to uphold the construction, or even the reading the court would have reached." *Chevron*, 467 U.S. at 843 n.11.

SUMMARY OF ARGUMENT

Petitioners attempt to portray an EPA decision to stay limited portions of the NSPS applicable to the oil and gas industry as an emergency that requires the Court to mandate compliance with the very aspects of the 2016 Rule that may change following reconsideration. There is no emergency and Petitioners have failed to demonstrate the requirements necessary for a stay or summary vacatur of EPA's decision.

EPA has granted a temporary, three-month stay of discrete provisions of the NSPS articulated in the 2016 Rule. During the stay, EPA will reconsider aspects of the 2016 Rule that relate to the universe of sources that must implement the rule's well site and compressor station fugitive emission requirements ("fugitive emission requirements") and control requirements for well site pneumatic pumps. EPA will also reconsider the new professional engineer certification requirement for closed vent systems.

In reviewing EPA's decision to determine Petitioners' likelihood of success on the merits, the Court is to assess whether it was likely arbitrary and capricious for EPA to issue a stay under 42 U.S.C. § 7607(d)(7)(B) to avoid burdening stakeholders with compliance obligations while EPA allows further public comment and Agency consideration of these limited issues. This appears to be, in substantial part, an issue of first impression.

At the outset, the premise of Petitioners' motion is flawed. EPA has broad discretion to reconsider its rules. It also has broad authority to issue a brief stay under 42 U.S.C. § 7607(d)(7)(B), regardless of whether the statutory criteria for when EPA is *mandated* to reconsider its rules are met. Moreover, EPA's decision fell well within the range of reasonable outcomes that were available to it. Indeed, although Petitioners rely on cases in which EPA permissibly exercised its discretion to refrain from reconsidering an agency action, they wholly fail to carry their burden to show that it is arbitrary and capricious for EPA to allow additional public input into aspects of the 2016 Rule that EPA found were not practicable to raise during the notice-and-comment period.

Petitioners also have not met their burden to show irreparable harm. On the aspects of EPA's stay relating to the professional engineer and pneumatic pump requirements, they do not even attempt to argue this point. As to the stay of the fugitive emissions requirements, even if Petitioners' factual assertions are taken at face value, they establish only that EPA's stay will result in a small incremental difference in emissions—for example, the methane emission reduction that would result in the absence of the stay is just 0.046% of the annual methane emissions from the oil and gas industry. Nor do Petitioners account for other regulatory regimes that exist to reduce other emissions, such as ozone precursors.

Having failed to carry their burden on the requirements of a stay or summary vacatur of EPA's decision, Petitioners' motion should be denied.

ARGUMENT

I. Petitioners Have Not Established that They Are Likely to Succeed on the Merits.

A. Petitioners' Motion Amounts to a Collateral Attack on EPA's Decision to Allow Reconsideration.

42 U.S.C. § 7607(b)(1) authorizes judicial review over a discrete list of EPA rulemakings "or final action taken by the Administrator under this chapter." *See also*

id. at § 7607(e). An agency decision to convene reconsideration proceedings is not "final action" subject to judicial review. *See Bennett v. Spear*, 520 U.S. 154, 178 (1997) (agency action must mark the completion of the agency's decision-making process and have concrete legal consequences); *FTC v. Std. Oil Co.*, 449 U.S. 232, 242 (1980). Convening reconsideration reflects the commencement, not the consummation of an agency process and—standing alone—has no legal effect beyond the burdens of participation.

Nevertheless, Petitioners' challenge is a sideways effort to attack EPA's decision to convene reconsideration proceedings, *see* Pet. Br. at 10-13 (arguing that reconsideration was improperly convened), notwithstanding that they cannot (and, therefore, do not) challenge this action directly. Indeed, the practical effect of Petitioners' attempt to overturn the 90-day stay is to require a large number of facilities to comply with the very provisions of the 2016 Rule that may change following reconsideration. Looking just to the fugitive emissions requirements, by Petitioners' estimate more than 14,000 wells, *see* Pet. Br. at 26, not to mention compressor stations, will be required to complete a monitoring survey, repair or replace any source of fugitive emissions within 30 days, and resurvey such repairs again within 30 days. 40 C.F.R. § 60.5397a(f), (h)(1)-(3). These facilities will be substantially deprived of the potential benefits of reconsideration: if they are low-production wells, they will be required to comply notwithstanding that status; if they are among the thousands of wells that may be eligible for an alternative means of emission limitation, they will be subject to immediate compliance with the 2016 Rule and to the current application process on which they are seeking to comment.

B. Petitioners' Arguments Fail Because They Rely on an Inaccurate, Narrow View of EPA's Authority.

Petitioners' arguments hinge on the cramped view that EPA only has authority to convene a "reconsideration" proceeding under Section 7607(d)(7)(B) (and therefore stay the effectiveness of the 2016 Rule) and may only do so if, and only if, "two statutory conditions . . . are met." Pet. Br. at 10-11.[4] Section 7607(d)(7)(B) states:

> If the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule, the Administrator *shall convene a proceeding for reconsideration of the rule* . . .

42 U.S.C. § 7607(d)(7)(B) (emphasis added).

It is a basic principle of administrative law that EPA has "inherent authority to reconsider [its] own decisions." *Trujillo v. Gen. Elec. Co.*, 621 F.2d 1084, 1086 (10th Cir. 1980); *see also United Gas Improvement Co. v. Callery Properties, Inc.*, 382 U.S. 223, 229 (1965); *Mazaleski v. Treusdell*, 562 F.2d 701, 720 (D.C. Cir. 1977). This authority is not contingent on meeting any particular statutory conditions and nothing in the text of

[4] Petitioners concede that "EPA has authority to revisit existing regulations by initiating a new rulemaking," Pet. Br. at 10, but appear to imply that this is not "reconsideration" authority.

Section 7607(d)(7)(B) suggests that it is intended to eliminate or limit this fundamental regulatory authority to convene reconsideration proceedings. *Gonzales* v. *Oregon*, 546 U.S. 243, 267 (2006) ("Congress, we have held, does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions . . . .").

To the contrary, the statutory text specifies only when EPA "shall" exercise reconsideration authority to convene such a proceeding and does not purport to limit when EPA "may" convene such a proceeding to any set of statutorily defined circumstances. *See Sierra Club. v. Jackson*, 648 F.3d 848, 856 (D.C. Cir. 2011) ("shall" is usually interpreted as the language of command whereas "may" is usually construed as permissive); *Bennett v. Panama Canal Co.*, 475 F.2d 1280, 1282 (D.C. Cir. 1973). Moreover, Section 7607(d)(7)(B) contains no prohibitory language (*e.g.*, "shall not" or "may not") establishing that the situations in which EPA must convene a reconsideration proceeding are the only circumstances in which EPA may convene such proceedings. *See Ma v. Ashcroft*, 257 F.3d 1095, 1112 n.27 (9th Cir. 2001); *cf. Judge v. Quinn*, 612 F.3d 537, 555 (7th Cir. 2010) (contrasting a Connecticut statute which contained the prohibitory language "shall not" with an Illinois statute, which contained no such language). Words in a statute are construed according to their ordinary meaning, *Levin v. United States*, 133 S. Ct. 1224, 1231 (2013), and courts are not to read additional words or limitations into a statute that Congress did not see fit to include, *Kay v. FCC*, 525 F.3d 1277, 1279 (D.C. Cir. 2008).

The context surrounding this provision reinforces that EPA has broad authority to convene a reconsideration proceeding of rules issued under the CAA. *See King v. Burwell*, 135 S. Ct. 2480, 2492 (2015) (words of a statute must be read in context). 42 U.S.C. § 7607(d)(7)(B) provides that entities seeking judicial review must raise their objections during the public comment period, but provides an opportunity to raise objections "of central relevance" if they were "impracticable to raise . . . within such time" or "arose after the period for public comment." By mandating that EPA "shall convene a proceeding for reconsideration of the rule" if these criteria are met, Congress allowed interested parties to compel an open, public process to address such objections, obtain the EPA's considered judgement, and—if necessary—judicial review. At the same time, by limiting the circumstances in which EPA was mandated to convene reconsideration, Congress precluded parties from requiring that EPA re-open the public process to address all after-the-fact objections. Nothing in this context suggests that Congress intended to restrict EPA's authority to correct errors or improve its rulemaking on its own initiative.

The CAA provides that "[t]he effectiveness of the rule [*i.e.*, a rule governed by Section 7607] may be stayed during *such reconsideration* . . . for a period not to exceed three months." 42 U.S.C. § 7607(d)(7)(B) (emphasis added).[5] Although "such

[5] CAA Section 7607(d)(7)(B) is not EPA's only source of authority to stay a rule. Other authority includes that under 5 U.S.C. § 705 and through notice and comment rulemaking. *See, e.g.*, *Mexichem Specialty Resins, Inc. v. EPA*, 787 F.3d 544, 561-62 (2015) *Cont.*

reconsideration" may be subject to more than one interpretation, there is good reason to conclude that Section 7607(d)(7)(B) authorizes EPA to issue a short-term stay whether or not reconsideration was mandatory. To begin, the phrase "such reconsideration" is reasonably read to refer to the discrete corresponding clause "a proceeding for reconsideration of the rule." *Id.* "Such reconsideration" is subject to no straightforward limitation, notwithstanding that Congress easily could have provided, for example, that a stay is available only when "such reconsideration is required by law." *See City of Arlington, Tex. v. F.C.C.*, 133 S. Ct. 1863, 1868 (2013) ("Congress knows to speak in plain terms when it wishes to circumscribe, and in capacious terms when it wishes to enlarge, agency discretion.").

Moreover, the CAA specifies that "[t]his subsection [7607(d)] applies" broadly to the "promulgation *or revision*" of a wide variety of EPA actions under the CAA, including "any standard of performance under section 7411." 42 U.S.C. § 7607(d)(1) (emphasis added). EPA's authority to issue a three-month stay is a component of its authority under subsection 7607(d). By specifying that subsection 7607(d) applies broadly to the revision of NSPS, the statutory text suggests that Congress did not intend to cabin EPA's authority to issue a stay to only those circumstances where EPA is *mandated* to convene reconsideration proceedings to consider revising a rule.

(Kavanaugh, J., dissenting in part); *id.* at 558 (declining to reach EPA's authority under 5 U.S.C. § 705); *Natural Res. Def. Council, Inc. v. Reilly*, 976 F.2d 36, 39 (D.C. Cir. 1992) (declining to address EPA's authority to issue a stay through rulemaking under the APA). These other sources of authority are not at issue in this case.

This interpretation of Section 7607(d)(7)(B) provides EPA uniform authority to convene an open, public process to receive comments on and rectify issues in its CAA rulemakings before the burdens of any such errors are imposed on the regulated community. In contrast, the alternative reading of Section 7607(d)(7)(B) forecloses EPA's ability to issue this short-term stay—requiring immediate compliance with a rule that all parties, including EPA, may believe is defective—where the deficiencies were not "impracticable to raise" during the comment period. On Petitioners' view, if EPA mistakenly ignored or misinterpreted crucial information provided during the comment period, it has no authority to issue this three-month stay of compliance with the defective rule that resulted. This could force the regulated community to comply with the rule while engaged in litigation or wait for EPA to commence and complete a full rulemaking correcting the error, by which time it may be too late and reconsideration may effectively have been defeated. *See* Pet. Br. at 12-13; *see also supra* at 7-8. In contrast, if the same objection arose *after* the comment period closed, a stay of compliance would be available.

There is no reason to believe that Congress intended to create such disparate compliance regimes for the regulated community. The same rationale applies to allowing a stay under either circumstance: affording EPA an opportunity to solicit further comment on the perceived error while avoiding the burdens of compliance and while seeking to avert possible litigation.

Because EPA has broad authority to convene reconsideration proceedings and issue a stay, Petitioners have failed to show a likelihood of success on the merits. In this case, EPA looked to the statutory factors in concluding that reconsideration was appropriate and, as described below, reasonably concluded that it was. However, strict adherence to these factors is not a requirement for convening reconsideration or granting a short-term stay. Section 7607(d)(7)(B) prescribes a *minimum* public process that EPA must afford, not a *maximum*. Moreover, under section 7607(d)(7)(B), EPA has authority to stay a rule during reconsideration proceedings. The Supreme Court's seminal decision in *Vt. Yankee Nuclear Power Corp. v. NRDC*, 435 U.S. 519, 544-45 (1978), is in accord, explaining that courts should generally defer to agencies and allow them to fashion their own rules of procedure and methods of inquiry.

Natural Res. Def. Council, Inc. v. Reilly, 976 F.2d 36, 40 (D.C. Cir. 1992), is not to the contrary.[6] Although Petitioners latch onto the statement in that case that Congress permitted a stay under Section 7607(d)(7)(B) in "carefully defined circumstances," *id.*, that case did not specify or even have cause to consider the circumstances under which such a stay could issue. The question in *NRDC v. Reilly* was whether a separate provision of the CAA, Section 112(d)(9), 42 U.S.C. § 7412(d)(9), provided EPA authority to grant an *additional* stay, beyond the three

[6] Neither is the out-of-circuit decision in *Chevron U. S. A., Inc. v. EPA*, which simply discussed the circumstances under which that the Administrator was mandated, rather than permitted, to convene reconsideration. 658 F.2d 271, 274 (5th Cir. 1981).

months provided by Section 7607(d)(7)(B), in a situation where EPA had a nondiscretionary obligation to promulgate standards under a specific schedule. *See id.* at 37-41. The criteria for invoking Section 7607(d)(7)(B) itself were not at issue.

C. Even Adopting Petitioner's Narrow View of EPA's Authority, Reconsideration Was Appropriately Granted.

Petitioners also have not carried their burden of demonstrating that it was arbitrary and capricious for EPA to conclude that the petitions raised issues meeting the criteria articulated in CAA Section 7607(d)(7)(B). Instead, they attempt to evade that standard by arguing that the ordinary deference courts must afford to EPA does not apply. Pet. Br. at 14 n.9; *see also id.* at 14-22.

The standard of review is specified by statute: the Court may not set aside EPA's action unless it is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 42 U.S.C. § 7607(d)(9) (noting other bases to do so which are not at issue here). Although courts are at their "most deferential" when an agency evaluates scientific or technical matters, *see, e.g.*, *Baltimore Gas & Elec. Co. v. NRDC*, 462 U.S. 87, 103 (1983), the arbitrary and capricious standard applies broadly and generally requires only that the agency decision be "reasonable and reasonably explained." *Cmtys. for a Better Env't v. EPA*, 748 F.3d 333, 335 (D.C. Cir. 2014); *see also Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983). The questions presented here are factual in nature and fall with EPA's special expertise to assess the scientific and other issues in the comments it received and determine what issues were, could have, and could not have been raised.

The cases Petitioners cite with respect to the "logical outgrowth" test, Pet. Br. at 12, considered whether the final result of EPA's analysis was sufficiently tied to its proposed rule that the agency was not *required* to convene reconsideration (in other words, whether EPA reasonably denied reconsideration).[7] They did not involve judicial review of whether the agency reasonably decided to *allow* further public process based on the statutory criteria, an issue as to which the EPA has discretion to determine whether an adequate showing has been made. *See* 42 U.S.C. § 7607(d)(7)(B) (reconsideration mandated if "[i]f the person raising an objection can *demonstrate to the Administrator*" that the criteria are met (emphasis added)). This appears to be an issue of first impression.

Applying the arbitrary and capricious standard, there are generally a range of reasonable outcomes that an agency could permissibly reach. Indeed, in close cases EPA could reasonably decide to grant reconsideration or reasonably decide to deny it on the same set of facts. The Court is not to second-guess the agency as to the best outcome but merely to determine if the agency reached a permissible decision. *C&W*

[7] In fact, many of Petitioners' cases do not address at all whether reconsideration was allowable, mandated, or even requested, but rather consider the separate issue of whether EPA provided adequate notice-and-comment procedures. *See, e.g., City of Portland v. EPA*, 507 F.3d 706, 715 (D.C. Cir. 2007); *Husqvarna AB v. EPA*, 254 F.3d 195, 203 (D.C. Cir. 2001); *Ariz. Pub. Serv. Co. v. EPA*, 211 F.3d 1280, 1299 (D.C. Cir. 2000).

Fish Co. v. Fox, 931 F.2d 1556, 1565 (D.C. Cir. 1991). Here, EPA has determined to allow greater public process in light of the issues the administrative petitioners raised.

1. EPA Reasonably Granted Reconsideration With Respect to Its Newly Articulated Rationale Not to Exempt Low-Production Wells.

EPA proposed to exclude low production well sites from the standards for fugitive emissions from well sites because it believed that "lower production associated with these wells would generally result in lower fugitive emissions," and solicited comment on this proposal. Proposed Rule at 56,639. In the 2016 Rule, however, EPA took the opposite approach and subjected low-production wells to the emission standards it developed because "stakeholders indicated that well site fugitive emissions are not correlated with levels of production, but rather based on the number of pieces of equipment and components." 2016 Rule at 35,856.

In granting reconsideration, EPA noted that "the final rule differs significantly from what was proposed in that it requires these well sites to comply with the fugitive emissions requirements based on information and rationale not presented for public comment during the proposal stage. . . . It was therefore impracticable to object to this new rationale during the public comment period." Pet. Attach. at 3. In particular, the rationale for EPA's decision not to exempt low-production wells from the 2016 Rule is potentially in tension with EPA's rationale for specifying what constitutes a "modified" source subject to the 2016 Rule. The 2016 Rule provides that a "modification" of a well site that will render the site subject to the NSPS occurs when "(i) A new well is drilled at an existing well site; (ii) A well at an existing well site is hydraulically fractured; or (iii) A well at an existing well site is hydraulically refractured." 40 C.F.R. § 60.5365a(i)(3)(iii). In responding to comments on the definition of "modification," EPA justified this definition by explaining that fugitive emissions after drilling a new well, fracturing, or refracturing would be expected to increase *based on the increase in production*:

> These events are followed by production from these wells which generate additional emissions at the well sites. Some of these additional emissions will pass through leaking fugitive emission components at the well sites (in addition to the emissions already leaking from those components). Further, it is not uncommon that an increase in production would require additional equipment and, therefore, additional fugitive emission components at the well sites.

2016 Rule at 35,881. This potential inconsistency is precisely the issue that IPAA, one of the administrative petitioners, pointed out in its request for reconsideration. Pet. Attach. at 139.

Regardless of whether EPA solicited or received general comments on the proposed exemption for low-production wells or the relationship between production, equipment, and emissions, it was reasonable for EPA to conclude that the administrative petitioners would not have expected EPA to announce in the 2016 Rule a result that is arguably internally inconsistent. EPA's determination to convene reconsideration and allow public input on this issue exceeds the "minimal standards of rationality" applied in conducting arbitrary and capricious review. *Small Refiner Lead Phase-Down Task Force*, 705 F.2d at 520-21.

2. EPA Reasonably Granted Reconsideration to Solicit Public Involvement on its Alternative Means of Emission Limitation Application Process and Criteria.

The Proposed Rule indicated that certain owners and operators of oil and natural gas facilities may already be implementing fugitive emissions monitoring and repair programs that were equivalent to, or more stringent than, EPA's proposed standards. Proposed Rule at 56,638. As a result, EPA solicited comment on the "criteria" that EPA could "use to determine whether and under what conditions" fugitive emission sources meet the equivalent of the NSPS. *Id.* At no point in the Proposed Rule did EPA suggest that it was considering adopting a specific application process for determining whether a facility may employ certain work practices as an alternative means of emission limitation in lieu of the fugitive emissions requirement.

Rather than finalizing "criteria" for determining equivalency, in the 2016 Rule EPA disclosed for the first time a process by which owners and operators could apply to EPA for approval that their facilities may employ controls qualifying an alternative means of emission limitation in lieu of meeting the 2016 Rule's requirements. 2016 Rule at 35,871; *id.* at 35,906 (40 C.F.R. § 60.5398a). The process required the submission of 12 months of verified test data and a host of other information regarding the emissions limitation method, 40 C.F.R. § 60.5398a.

Petitioners argue that EPA cannot *sua sponte* grant reconsideration related to this previously unannounced application process. This assertion is wrong as a matter of law: EPA has inherent authority to convene reconsideration proceedings. *See supra* at 9-10. But even if Petitioners were correct on the law, they are wrong on the facts. Among the "issues for which TXOGA request[ed] reconsideration" was that EPA should provide a simpler process than that provided in the 2016 Rule for alternative means of emission limitations. Pet. Attach. at 148-49 (adopting API's petition with respect to the issues on which TXOGA sought reconsideration); *see also id.* at 89, 105-06 (API's petition).

The administrative petitioners provided comments on the previously undisclosed process reached by EPA suggesting that revisions may need to be made to establish its scope and legal effect. *See* Pet. Attach. at 3. Unaware that EPA was considering a process like the one it adopted in lieu of setting criteria for determining equivalency, that process was not subject to public discussion and leaves substantial questions unresolved. For example, "once an AMEL has been approved, can it be used by anyone operating in [the] state?" Pet. Attach. at 105-06. Similarly, the public was not on notice to provide input on who would be permitted to submit applications and the effects of a state modification of a state fugitive emissions program. It was not arbitrary and capricious for EPA to determine that it was not practicable to comment on an application process that no one had seen or knew EPA was considering. *Cf., e.g.*, *Envtl. Integrity Project v. EPA*, 425 F.3d 992, 996 (D.C. Cir. 2005) (commenters are not required to "divine the agency's unspoken thoughts"). Indeed, EPA's practice for establishing similar processes in the past has been to propose the process prior to rulemaking. *See, e.g.*, 49 Fed. Reg. 29,698, 29,717 (July 23, 1984); 46 Fed. Reg. 1,136, 1,156 (Jan. 5, 1981).

EPA's decision to allow further public process on the alternative means of emission limitation procedures is the only area in which Petitioners specifically and distinctly argue that the issues identified by the administrative petitioners are not of "central relevance" to the 2016 Rule. Pet. Br. at 20. But a party that can demonstrate that it is implementing an alternative means of emission limitation may be excused from multiple provisions of the NSPS, including the fugitive emissions requirements, *see* 40 C.F.R. § 60.5398a(a), such that the alternative means of emission limitation program in large part "determine[s] the universe of affected facilities." Pet. Attach. at 3. Administrative petitioners' comments, in turn, address how that program functions, including whether each well (of the thousands that Petitioners identify) must submit a separate application, supported by a year of verified test data, to be excused from these provisions. Moreover, the alternative means of emission limitation provisions were added to serve the important interest of ensuring that the NSPS complemented existing state programs and encouraged use of emerging technology. 2016 Rule at 35871.

It is no way arbitrary and capricious for EPA, before parties incur compliance costs or pursue litigation, to allow reconsideration and take public comment rather than set that process in stone without public input. *See* Pet. Attach. at 3. Doing so was squarely with the range of reasonable outcomes available to EPA.

3. EPA Reasonably Granted Reconsideration of the Professional Engineer Certification Requirements and Pneumatic Pump Requirements.

As noted below, Petitioners' failure to even attempt to show that EPA's stay of the professional engineer certification requirements or pneumatic pump requirements will result in irreparable harm is, in itself, adequate basis to deny their motion as to these aspects of EPA's stay. *See infra* at 26. Regardless, Petitioners have also failed to demonstrate a likelihood of success on these issues.

EPA articulated several well-supported reasons to convene reconsideration of the pneumatic pump standards. In the Proposed Rule, EPA proposed that owners and operators be required to route pneumatic pumps through a control device, Proposed Rule at 56,610, 56,666; *see also* Pet. Attach. at 4, but never suggested or solicited comment on any exemption to that requirement. Similarly, although API requested that a technical infeasibility exemption be added to the final rule, Pet. Attach. at 181, 188, the scope and parameters of this exemption were never subject to public notice or comment. As a result, the technical infeasibility exemption that EPA announced in the 2016 Rule adopted a different approach than previously applied to the oil and gas industry and created an unanticipated and unnoticed distinction between "greenfield" (new development) and "brownfield" sites. 2016 Rule at 35,844-45; Pet. Attach. at 4. Administrative petitioners sought, and EPA allowed, reconsideration to provide a public process to discuss and provide clarity on the appropriate parameters of the exemption. *See* Pet. Attach. at 91-93 (providing comments that API would have raised had EPA provided notice as to its intended scope of the exemption).

Similarly, although EPA solicited comment on the "criteria by which the PE verifies that the closed vent system is designed to accommodate all streams routed to the facility's control system," Proposed Rule at 56,649, it did not directly provide for review, propose to conduct, or conduct an assessment of the costs of this requirement, as opposed to the overall costs of the rule. Pet. Attach. at 4. Petitioners do not meaningfully dispute this point, offering only a generalized assertion regarding the "thoroughness of the agency's assessment of the 2016 Rule's overall costs." Pet Br. at 21. Administrative petitioners requested reconsideration based on EPA's alleged omission, Pet. Attach. at 91-92, 141-42, leading EPA to convene reconsideration on this issue in light of the requirement in CAA, 42 U.S.C. § 7411, that EPA consider costs in establishing NSPS.

If EPA had denied reconsideration of the professional engineer requirement and pneumatic pump standards, that denial likely would not have been arbitrary and capricious. The Court, however, is reviewing the mirror-image situation: whether EPA may rationally decide that the public comment process was hampered by its failure to propose or conduct a cost analysis and the differences between the proposed and final rule, and fix any such error while considering administrative petitioners' comments in a reconsideration proceeding. It was reasonable for EPA to determine that the administrative petitioners could not have predicted that EPA would have entirely failed to conduct a cost analysis of the professional engineer requirement and that their ability to object on this point was impaired.[8] It was likewise reasonable for EPA to conclude that further public input on the pneumatic pump standards was appropriate.

D. The Stay Was Appropriate in Scope and Adequately Justified

EPA has issued a stay limited in scope to the specific issues as to which it has granted reconsideration: the fugitive emissions requirement, the professional engineer requirements, and the standards for pneumatic pumps at well sites. Pet. Attach. at 4. As to the latter two elements of the stay, Petitioners do not argue that the stay is overbroad. Pet. Br. at 23-25. As to the stay of the fugitive emissions requirement, as already noted the matters under reconsideration "determine the universe of sources that must implement the fugitive emissions requirements." Pet. Attach. at 4. By Petitioners' estimate, there are thousands of wells (whether low or high production) in states with existing fugitive emissions programs that may be able to apply for alternative means of emission limitation, but the application process leaves it unclear whether each must apply to EPA separately. Moreover, the alternative means of emission limitation process applies not just to well sites, but also to compressor stations, rendering a stay of the fugitive emission requirements appropriate as to these

[8] Petitioners suggest that this error would not be a reasonable basis to revise the rule, but do not disagree that EPA is required to consider costs; neither do they argue that this requirement would remain a component of the NSPS if EPA concluded it was not cost-justified.

components as well. 40 C.F.R. § 60.5398a. That EPA has granted reconsideration as to whether it is appropriate to exempt low-production wells further renders indeterminable the breadth of facilities that will need to comply with any fugitive emissions requirements in the NSPS. The district court's decision in *Sierra Club v. Jackson*, 833 F. Supp. 2d 11, 33 (D.D.C. 2012), is thus inapposite because the stay is well-grounded in and proportionate to the issues under reconsideration.

Petitioners also attempt to import the requirements for a *judicial* stay into EPA's authority to issue a stay pending reconsideration in arguing that EPA's decision was not adequately explained. Pet. Br. at 24. But nothing in the text of CAA Section 7607(d)(7)(B) imposes any such requirements, and the relatively short (three-month) duration of a stay issued under this provision suggests that Congress left EPA greater discretion to issue a stay as it determines appropriate. The reasons for a stay here are self-evident—as discussed above, in the absence of a stay, thousands of wells would be required to comply with the very requirements that are subject to reconsideration and may be substantially altered. *See supra* at 8. These issues go to core elements of the 2016 Rule. Pet. Attach. at 4-5. And, as discussed below, the alleged harm resulting from the stay is, at most, incremental. *See infra* at 27-28.

II. Petitioners Have Not Demonstrated that They Will Suffer Irreparable Harm in the Absence of a Stay.

A. Petitioners Have Not Even Attempted to Demonstrate that EPA's Stay of the Pneumatic Pump Standards or Professional Engineer Requirements Will Cause Irreparable Harm.

The entirety of Petitioners' allegations of irreparable harm are focused on their contention that EPA's stay of the fugitive emissions requirements will result in greater emissions than would occur in the absence of a stay. Pet. Br. at 25-31. Having not even attempted to argue that irreparable harm will result from EPA's stay of the standards for pneumatic pumps or professional engineer certification requirements, Petitioners have waived their ability to do so. *Petit v. USDE*, 675 F.3d 769, 779 (D.C. Cir. 2012). This failure is sufficient basis, standing alone, for the Court to deny Petitioners' motion with respect to these aspects of EPA's stay of the 2016 Rule. *See Winter v. NRDC, Inc.*, 555 U.S. 7, 22 (2008); *Nken v. Holder*, 556 U.S. 418, 438 (2009) (Kennedy, J., concurring).

B. Petitioners Have Not Shown that EPA's Stay of the Fugitive Emissions Requirement Will Result in Irreparable Harm.

As to the fugitive emissions requirement, Petitioners do not demonstrate that any substantial irreparable harm is likely as a result of the three month stay. To establish irreparable harm, a petitioner must demonstrate an injury that is "both certain and great; it must be actual and not theoretical." *Wisconsin Gas Co*, 758 F.2d at 674. The petitioner must show that "[t]he injury complained of [is] of such imminence that there is a clear and present need for equitable relief to prevent irreparable harm." *Id.* (citation omitted). The movant must "substantiate the claim that irreparable injury is 'likely' to occur," and "show that the alleged harm will directly result from the action which the movant seeks to enjoin." *Id.*

At the outset, in purporting to calculate the emissions effects of EPA's stay, Dr. Lyon recognizes that he must adjust for emission controls associated with state leak detection and repair standards. Pet. Attach. at 38-39. In doing so, Dr. Lyon does not necessarily follow the methodology that EPA would adopt to determine which states might be excluded from an analysis of emission reductions. Regardless, even on the terms of his own analysis he makes no adjustment to account for the leak detection and repair program in the state that has, by far, the largest number of wells: Texas. Between 2011 and 2015, 48% of natural gas producing oil wells and 25% of producing natural gas wells in the United States were located in Texas. *See* Resp. Attach at 081, 083; *cf.* Pet. Attach at 42-43. Texas has mandated a leak detection and repair program to curb fugitive emissions. *See* Resp. Attach at 148-54 (Table 9; requirements for facilities in the Barnett Shale region); 30 Tex. Admin. Code §§ 116.601-615, 116.620 (requirements for facilities outside the Barnett Shale region). It is not clear why Dr. Lyon overlooked the emission reductions achieved by Texas's program, but as a result, his emissions analysis is internally inconsistent and, applying his own criteria, substantially inflated.

More fundamentally, although Petitioners attempt to paint the consequences of EPA's 90-day stay as a dire emergency, the brief stay of the 2016 Rule will result in only an incremental difference in emissions. For example, even accepting Dr. Lyon's inflated emissions calculations as accurate, he predicts that the stay will result in 4,301 tons[9] of methane emissions from wells in states with no leak detection and repair requirements. Pet. Attach. at 47-48. Natural gas and petroleum systems—standing alone—emitted 9,295,000 tons of methane in 2014. 2016 Rule at 35,838-39. Put in context, the 90-day stay will thus account for roughly 0.046% of annual methane emissions from this single subsector of United States industry. The same point holds for other sources or types of fugitive emissions, such as ozone precursors, that Petitioners' in-house scientists assess. As a result, Petitioners do not, and cannot, establish that EPA's three-month stay will have a meaningful impact on the environment generally, global climate change in particular, ambient ozone in a particular area, or human health.[10]

Petitioners also neglect to address other existing regulatory regimes to curb the emissions that they identify. For example, as to the emission of ozone precursors, there is a separate program pursuant to which EPA sets National Ambient Air Quality Standard ("NAAQS") for ozone, 40 C.F.R. § 50.19. NAAQS are set at a level requisite to protect public health with an adequate margin of safety. 42 U.S.C. §

[9] Petitioners' brief actually *quadruples* the emissions associated with the stay by citing Dr. Lyon's calculation of annual emissions as the amount that would be emitted during the 90-day stay. *Compare* Pet. Br. at 26 *with* Pet. Attach. at 47 (Table 3).

[10] The 2016 Rule did not suggest that fugitive emissions needed to be addressed on an emergency basis to avoid irreparable harm, allowing as it did for a year-long initial compliance period. 2016 Rule at 35,858-59.

7409(b)(1); *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 472 (2001). Under the CAA, States have primary responsibility for ensuring that ambient air quality meets the NAAQS in areas under their jurisdiction. 42 U.S.C. § 7407(a). For each pollutant, each State must draft and adopt a state implementation plan ("SIP") that provides for the implementation, maintenance, and enforcement of the NAAQS, and must submit the adopted SIP to EPA for review. 42 U.S.C. § 7410(a). As a result, States are already leading an effort to reduce the emissions of ozone precursors to ensure attainment and should ensure that a SIP is in place to address such issues. While the 2016 Rule may facilitate emission reductions on this point, it is not the only—or even the principal—method of achieving reduction of ambient ozone.

III. Petitioners' Stay Motion Will Cause Harm to Others and Will Not Serve the Public Interest.

The harm to others and the public interest, balanced against the incremental emissions increases Petitioners rely on, also militate in favor of denying Petitioners' motion. As already noted, *see supra* at 8, Petitioners essentially seek to require roughly 14,000 wells to immediately comply with the very provisions of the 2016 Rule that may be subject to change in reconsideration. Both EPA and the public—not to mention Petitioners, who are free to submit comments during reconsideration—have an interest in assuring that regulations are subject to meaningful public input and reflect EPA's best-considered judgment. *See, e.g., Yakus v. United States*, 321 U.S. 414, 437 & n.5, 440 (1944) (noting the public interest in a "centralized, unitary scheme of review" of the relevant regulations); *Hankins v. Norton*, 2005 U.S. Dist. LEXIS 37741, at *43-44 (D. Colo. Sept. 2, 2005) ("The public has a generalized interest in having administrative matters resolved in an orderly fashion, and by an agency having the expertise and discretion to deal competently and expeditiously with such matters.").

Petitioners claim that a stay of EPA's action would be in the public interest because of the alleged harm to the environment that they speculate would result from EPA's stay of the rule. However, the public has a wide range of interests. Congress recognized the competing public interests when it identified, as goals of the CAA, protecting the "productive capacity of [the nation's] population," 42 U.S.C. § 7401(b)(1), and "[insuring] that economic growth will occur . . . consistent with the preservation of existing clean air resources," 42 U.S.C. § 7470(3). EPA's short-term stay strikes a balance among these interests by allowing the Agency to consider whether to refine aspects of the 2016 Rule to better account for issues that the Agency did not consider and concerns among the regulated community that EPA did not foresee.

Attempting to minimize the burdens of compliance with the 2016 Rule, Petitioners imply that initial compliance costs are "$250 per well." Pet. Br. at 32. This low-end estimate is simply the cost for an initial survey of a well and, in assessing the 2016 Rule, EPA documented substantially higher compliance costs. *See* Resp. Attach. at 178-90 (describing the variety of costs that overall compliance with the fugitive emissions and repair requirements would impose). These costs are anything but trivial—running into the millions or tens of millions of dollars—when multiplied across the thousands of wells that may need to comply prematurely with a regulation that is potentially subject to significant change. The harm to others and balance of the equities favor denying Petitioners' motion.

CONCLUSION

For all of the foregoing reasons, Petitioners' motion for a stay or, in the alternative, summary vacatur should be denied.

Respectfully submitted,
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JUNE 15, 2017
90-5-2-3-21123

CERTIFICATE OF COMPLIANCE WITH FEDERAL RULE OF APPELLATE PROCEDURE 32(A)

I hereby certify that this brief complies with the requirements of Fed. R. App. P. 32(a)(5) and (6) because it has been prepared in 14-point Garamond, a proportionally spaced font.

I further certify that this brief complies with the type-volume limitation of Fed. R. App. P. 32(a)(7)(B) and District of Columbia Circuit Rule 18(b) because it contains 7,794 words, excluding the parts of the brief exempted under Rule 32(a)(7)(B)(iii), according to the count of Microsoft Word.

s/ *Benjamin R. Carlisle*
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CERTIFICATE OF SERVICE

I hereby certify that on June 15, 2017, I electronically filed the foregoing Brief for Respondents United States Environmental Protection Agency, et al., with the Clerk of the Court for the United States Court of Appeals for the District of Columbia Circuit by using the appellate CM/ECF system.

The participants in the case are registered CM/ECF users and service will be accomplished by the appellate CM/ECF system.

s/ *Benjamin R. Carlisle*
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NOT YET SCHEDULED FOR ORAL ARGUMENT

No. 17-1145

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

CLEAN AIR COUNCIL, et al.,

Petitioners

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, et al.,

Respondents.

ADDENDUM AND ATTACHMENTS TO EPA'S OPPOSITION TO PETITIONERS' EMERGENCY MOTION FOR A STAY OR, IN THE ALTERNATIVE, SUMMARY VACATUR

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Attachment 1

42 U.S.C. § 7607

42 U.S. CODE § 7607

Administrative proceedings and judicial review

(a) Administrative subpenas; confidentiality; witnesses. In connection with any determination under section 110(f) [42 USCS § 7410(f)], or for purposes of obtaining information under section 202(b)(4) or 211(c)(3) [42 USCS § 7521(b)(4) or 7545(c)(3)], any investigation, monitoring, reporting requirement, entry, compliance inspection, or administrative enforcement proceeding under the [this] Act (including but not limited to section 113, section 114, section 120, section 129, section 167, section 205, section 206, section 208, section 303, or section 306 [42 USCS § 7413, 7414, 7420, 7429, 7477, 7524, 7525, 7542, 7603, or 7606][,], the Administrator may issue subpenas for the attendance and testimony of witnesses and the production of relevant papers, books, and documents, and he may administer oaths. Except for emission data, upon a showing satisfactory to the Administrator by such owner or operator that such papers, books, documents, or information or particular part thereof, if made public, would divulge trade secrets or secret processes of such owner or operator, the Administrator shall consider such record, report, or information or particular portion thereof confidential in accordance with the purposes of section 1905 of title 18 of the United States Code, except that such paper, book, document, or information may be disclosed to other officers, employees, or authorized representatives of the United States concerned with carrying out this Act, to persons carrying out the National Academy of Sciences' study and investigation provided for in section 202(c) [42 USCS § 7521(c)], or when relevant in any proceeding under this Act. Witnesses summoned shall be paid the same fees and mileage that are paid witnesses in the courts of the United States. In case of contumacy or refusal to obey a subpena served upon any person under this subparagraph, the district court of the United States for any district in which such person is found or resides or transacts business, upon application by the United States and after notice to such person, shall have jurisdiction to issue an order requiring such person to appear and give testimony before the Administrator to appear and produce papers, books, and documents before the Administrator, or both, and any failure to obey such order of the court may be punished by such court as a contempt thereof.

(b) Judicial review.

> **(1)** A petition for review of action of the Administrator in promulgating any national primary or secondary ambient air quality standard, any emission standard or requirement under section 112 [42 USCS § 7412], any standard of performance or requirement under section 111 [42 USCS § 7411][,], any standard under section 202 [42 USCS § 7521] (other than a standard required to

be prescribed under section 202(b)(1) [42 USCS § 7521(b)(1)]), any determination under section 202(b)(5) [42 USCS § 7521(b)(5)], any control or prohibition under section 211 [42 USCS § 7545], any standard under section 231 [42 USCS § 7571] any rule issued under section 113, 119, or under section 120 [42 USCS § 7413, 7419, or 7420], or any other nationally applicable regulations promulgated, or final action taken, by the Administrator under this Act may be filed only in the United States Court of Appeals for the District of Columbia. A petition for review of the Administrator's action in approving or promulgating any implementation plan under section 110 or section 111(d) [42 USCS § 7410 or 7411(d)], any order under section 111(j) [42 USCS § 7411(j)], under section 112 [42 USCS § 7412],[,] under section 119 [42 USCS § 7419], or under section 120 [42 USCS § 7420], or his action under section 119(c)(2)(A), (B), or (C) (as in effect before the date of enactment of the Clean Air Act Amendments of 1977) or under regulations thereunder, or revising regulations for enhanced monitoring and compliance certification programs under section 114(a)(3) of this Act, or any other final action of the Administrator under this Act (including any denial or disapproval by the Administrator under title I [42 USCS §§ 7401 et seq.]) which is locally or regionally applicable may be filed only in the United States Court of Appeals for the appropriate circuit. Notwithstanding the preceding sentence a petition for review of any action referred to in such sentence may be filed only in the United States Court of Appeals for the District of Columbia if such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination. Any petition for review under this subsection shall be filed within sixty days from the date notice of such promulgation, approval, or action appears in the Federal Register, except that if such petition is based solely on grounds arising after such sixtieth day, then any petition for review under this subsection shall be filed within sixty days after such grounds arise. The filing of a petition for reconsideration by the Administrator of any otherwise final rule or action shall not affect the finality of such rule or action for purposes of judicial review nor extend the time within which a petition for judicial review of such rule or action under this section may be filed, and shall not postpone the effectiveness of such rule or action.

(2) Action of the Administrator with respect to which review could have been obtained under paragraph (1) shall not be subject to judicial review in civil or criminal proceedings for enforcement. Where a final decision by the Administrator defers performance of any nondiscretionary statutory action to a later time, any person may challenge the deferral pursuant to paragraph (1).

(c) Additional evidence. In any judicial proceeding in which review is sought of a determination under this Act required to be made on the record after notice and opportunity for hearing, if any party applies to the court for leave to adduce additional evidence, and shows to the satisfaction of the court that such additional evidence is material and that there were reasonable grounds for the failure to adduce such evidence in the proceeding before the Administrator, the court may order such additional evidence (and evidence in rebuttal thereof) to be taken before the Administrator, in such manner and upon such terms and conditions as [to] the court may deem proper. The Administrator may modify his findings as to the facts, or make new findings, by reason of the additional evidence so taken and he shall file such modified or new findings, and his recommendation, if any, for the modification or setting aside of his original determination, with the return of such additional evidence.

(d) Rulemaking.

(1) This subsection applies to--

(A) the promulgation or revision of any national ambient air quality standard under section 109 [42 USCS § 7409],

(B) the promulgation or revision of an implementation plan by the Administrator under section 110(c) [42 USCS § 7410(c)],

(C) the promulgation or revision of any standard of performance under section 111 [42 USCS § 7411], or emission standard or limitation under section 112(d) [42 USCS § 7412(d)], any standard under section 112(f) [42 USCS § 7412(f)], or any regulation under section 112(g)(1)(D) and (F) [42 USCS § 7412(g)(1)(D),(F)], or any regulation under section 112(m) or (n) [42 USCS § 7412(m) or (n)],

(D) the promulgation of any requirement for solid waste combustion under section 129 [42 USCS § 7429],

(E) the promulgation or revision of any regulation pertaining to any fuel or fuel additive under section 211 [42 USCS § 7545],

(F) the promulgation or revision of any aircraft emission standard under section 231 [42 USCS § 7571],

(G) the promulgation or revision of any regulation under title IV (relating to control of acid deposition),

(H) promulgation or revision of regulations pertaining to primary nonferrous smelter orders under section 119 [42 USCS § 7419] (but not including the granting or denying of any such order),

(I) promulgation or revision of regulations under title VI [42 USCS §§ 7671 et seq.] (relating to stratosphere and ozone protection),

(J) promulgation or revision of regulations under subtitle C of title I [42 USCS §§ 7470 et seq.] (relating to prevention of significant deterioration of air quality and protection of visibility),

(K) promulgation or revision of regulations under section 202 [42 USCS § 7521] and test procedures for new motor vehicles or engines under section 206 [42 USCS § 7525], and the revision of a standard under section 202(a)(3) [42 USCS § 7521(a)(3)],

(L) promulgation or revision of regulations for noncompliance penalties under section 120 [42 USCS § 7420],

(M) promulgation or revision of any regulations promulgated under section 207 [42 USCS § 7541] (relating to warranties and compliance by vehicles in actual use),

(N) action of the Administrator under section 126 [42 USCS § 7426] (relating to interstate pollution abatement),

(O) the promulgation or revision of any regulation pertaining to consumer and commercial products under section 183(e) [42 USCS § 7511b(e)],

(P) the promulgation or revision of any regulation pertaining to field citations under section 113(d)(3) [42 USCS § 7413(d)(3)],

(Q) the promulgation or revision of any regulation pertaining to urban buses or the clean-fuel vehicle, clean-fuel fleet, and clean fuel programs under part C of title II [42 USCS §§ 7581 et seq.],

(R) the promulgation or revision of any regulation pertaining to nonroad engines or nonroad vehicles under section 213 [42 USCS § 7547],

(S) the promulgation or revision of any regulation relating to motor vehicle compliance program fees under section 217 [42 USCS § 7552],

(T) the promulgation or revision of any regulation under title IV [42 USCS §§ 7641 et seq.] (relating to acid deposition),

(U) the promulgation or revision of any regulation under section 183(f) [42 USCS § 7511b(f)] pertaining to marine vessels, and

(V) such other actions as the Administrator may determine.
The provisions of section 553 through 557 and section 706 of title 5 of the United States Code shall not, except as expressly provided in this subsection, apply to actions to which this subsection applies. This subsection shall not apply in the case of any rule or circumstance referred to in subparagraphs (A) or (B) of subsection 553(b) of title 5 of the United States Code.

(2) Not later than the date of proposal of any action to which this subsection applies, the Administrator shall establish a rulemaking docket for such action (hereinafter in this subsection referred to as a "rule"). Whenever a rule applies only within a particular State, a second (identical) docket shall be simultaneously established in the appropriate regional office of the Environmental Protection Agency.

(3) In the case of any rule to which this subsection applies, notice of proposed rulemaking shall be published in the Federal Register, as provided under section 553(b) of title 5, United States Code, shall be accompanied by a statement of its basis and purpose and shall specify the period available for public comment (hereinafter referred to as the "comment period"). The notice of proposed rulemaking shall also state the docket number, the location or locations of the docket, and the times it will be open to public inspection. The statement of basis and purpose shall include a summary of--

(A) the factual data on which the proposed rule is based;

(B) the methodology used in obtaining the data and in analyzing the data; and

(C) the major legal interpretations and policy considerations underlying the proposed rule.
The statement shall also set forth or summarize and provide a reference to any pertinent findings, recommendations, and comments by

the Scientific Review Committee established under section 109(d) [42 USCS § 7409(d)] and the National Academy of Sciences, and, if the proposal differs in any important respect from any of these recommendations, an explanation of the reasons for such differences. All data, information, and documents referred to in this paragraph on which the proposed rule relies shall be included in the docket on the date of publication of the proposed rule.

(4) **(A)** The rulemaking docket required under paragraph (2) shall be open for inspection by the public at reasonable times specified in the notice of proposed rulemaking. Any person may copy documents contained in the docket. The Administrator shall provide copying facilities which may be used at the expense of the person seeking copies, but the Administrator may waive or reduce such expenses in such instances as the public interest requires. Any person may request copies by mail if the person pays the expenses, including personnel costs to do the copying.

(B)

(i) Promptly upon receipt by the agency, all written comments and documentary information on the proposed rule received from any person for inclusion in the docket during the comment period shall be placed in the docket. The transcript of public hearings, if any, on the proposed rule shall also be included in the docket promptly upon receipt from the person who transcribed such hearings. All documents which become available after the proposed rule has been published and which the Administrator determines are of central relevance to the rulemaking shall be placed in the docket as soon as possible after their availability.

(ii) The drafts of proposed rules submitted by the Administrator to the Office of Management and Budget for any interagency review process prior to proposal of any such rule, all documents accompanying such drafts, and all written comments thereon by other agencies and all written responses to such written comments by the Administrator shall be placed in the docket no later than the date of proposal of the rule. The drafts of the final rule submitted for such review process prior to promulgation and all such written comments thereon, all documents accompanying such drafts, and written responses thereto shall be placed in the docket no later than the date of promulgation.

(5) In promulgating a rule to which this subsection applies (i) the Administrator shall allow any person to submit written comments, data, or documentary information; (ii) the Administrator shall give interested persons an opportunity for the oral presentation of data, views, or arguments, in addition to an opportunity to make written submissions; (iii) a transcript shall be kept of any oral presentation; and (iv) the Administrator shall keep the record of such proceeding open for thirty days after completion of the proceeding to provide an opportunity for submission of rebuttal and supplementary information.

(6) **(A)** The promulgated rule shall be accompanied by (i) a statement of basis and purpose like that referred to in paragraph (3) with respect to a proposed rule and (ii) an explanation of the reasons for any major changes in the promulgated rule from the proposed rule.

(B) The promulgated rule shall also be accompanied by a response to each of the significant comments, criticisms, and new data submitted in written or oral presentations during the comment period.

(C) The promulgated rule may not be based (in part or whole) on any information or data which has not been placed in the docket as of the date of such promulgation.

(7) **(A)** The record for judicial review shall consist exclusively of the material referred to in paragraph (3), clause (i) of paragraph (4)(B), and subparagraphs (A) and (B) of paragraph (6).

(B) Only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. If the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule, the Administrator shall convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed. If the Administrator refuses to convene such a proceeding, such person may seek review of such refusal in the United States court of appeals for the appropriate circuit (as provided in subsection (b)). Such reconsideration shall not postpone the effectiveness of the rule. The effectiveness of the rule may be stayed during such reconsideration, however, by the Administrator or the court for a period not to exceed three months.

(8) The sole forum for challenging procedural determinations made by the Administrator under this subsection shall be in the United States court of appeals for the appropriate circuit (as provided in subsection (b)) at the time of the substantive review of the rule. No interlocutory appeals shall be permitted with respect to such procedural determinations. In reviewing alleged procedural errors, the court may invalidate the rule only if the errors were so serious and related to matters of such central relevance to the rule that there is a substantial likelihood that the rule would have been significantly changed if such errors had not been made.

(9) In the case of review of any action of the Administrator to which this subsection applies, the court may reverse any such action found to be--

(A) arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law;

(B) contrary to constitutional right, power, privilege, or immunity;

(C) in excess of statutory jurisdiction, authority, or limitations, or short of statutory right; or

(D) without observance of procedure required by law, if (i) such failure to observe such procedure is arbitrary or capricious, (ii) the requirement of paragraph (7)(B) has been met, and (iii) the condition of the last sentence of paragraph (8) is met.

(10) Each statutory deadline for promulgation of rules to which this subsection applies which requires promulgation less than six months after date of proposal may be extended to not more than six months after date of proposal by the Administrator upon a determination that such extension is necessary to afford the public, and the agency, adequate opportunity to carry out the purposes of this subsection.

(11) The requirements of this subsection shall take effect with respect to any rule the proposal of which occurs after ninety days after the date of enactment of the Clean Air Act Amendments of 1977 [enacted Aug. 7, 1977].

(e) Other methods of judicial review not authorized. Nothing in this Act shall be construed to authorize judicial review of regulations or orders of the Administrator under this Act, except as provided in this section.

(f) Costs. In any judicial proceeding under this section, the court may award costs of litigation (including reasonable attorney and expert witness fees) whenever it determines that such award is appropriate.

(g) Stay, injunction, or similar relief in proceedings relating to noncompliance penalties. In any action respecting the promulgation of regulations under section 120 [42 USCS § 7420] or the administration or enforcement of section 120 [42 USCS § 7420] no court shall grant any stay, injunctive, or similar relief before final judgment by such court in such action.

(h) Public Participation. It is the intent of Congress that, consistent with the policy of the Administrative Procedures Act [5 USCS §§ 551 et seq.], the Administrator in promulgating any regulation under this Act, including a regulation subject to a deadline, shall ensure a reasonable period for public participation of at least 30 days, except as otherwise expressly provided in section [sections] 107(d), 172(a), 181(a) and (b), and 186(a) and (b) [42 USCS §§ 7407(d), 7502(a), 7511(a) and (b), 7512(a) and (b)].

Attachment 2

Proposed rule, Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593 (Sept. 18, 2015) (excerpts).

Federal Register / Vol. 80, No. 181 / Friday, September 18, 2015 / Proposed Rules 56593

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2010–0505; FRL–9929–75–OAR]

RIN 2060–AS30

Oil and Natural Gas Sector: Emission Standards for New and Modified Sources

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: This action proposes to amend the new source performance standards (NSPS) for the oil and natural gas source category by setting standards for both methane and volatile organic compounds (VOC) for certain equipment, processes and activities across this source category. The Environmental Protection Agency (EPA) is including requirements for methane emissions in this proposal because methane is a greenhouse gas (GHG), and the oil and natural gas category is currently one of the country's largest emitters of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations. The EPA is proposing both methane and VOC standards for several emission sources not currently covered by the NSPS and proposing methane standards for certain emission sources that are currently regulated for VOC. The proposed amendents also extend the current VOC standards to the remaining unregulated equipment across the source category and additionally establish methane standards for this equipment. Lastly, amendments to improve implementation of the current NSPS are being proposed which result from reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator on the August 16, 2012, final NSPS for the oil and natural gas sector and related amendments. Except for the implementation improvements and the setting of standards for methane, these amendments do not change the requirements for operations already covered by the current standards.

DATES: Comments. Comments must be received on or before November 17, 2015. Under the Paperwork Reduction Act(PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your comments on or before November 17, 2015. The EPA will hold public hearings on the proposal. Details will be announced in a separate announcement.

ADDRESSES: Submit your comments, identified by Docket ID Number EPA–HQ–OAR–2010–0505, to the Federal eRulemaking Portal: *http://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or withdrawn. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (i.e. on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets.*

Instructions: All submissions must include agency name and respective docket number or Regulatory Information Number (RIN) for this rulemaking. Direct your comments to Docket ID Number EPA–HQ–OAR–2010–0505. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *www.regulations.gov* or email. (See section III.B below for instructions on submitting information claimed as CBI.) The *www.regulations.gov* Web site is an ''anonymous access'' system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you submit an electronic comment through *www.regulations.gov,* the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. If you send an email comment directly to the EPA without going through *www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. Electronic files should avoid the use of special characters, any form of encryption and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at: *www.epa.gov/epahome/dockets.htm.*

Docket: The EPA has established a docket for this rulemaking under Docket ID Number EPA–HQ–OAR–2010–0505. All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the EPA Docket Center, EPA WJC West Building, Room Number 3334, 1301 Constitution Avenue NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For information concerning this action, or for other information concerning the EPA's Oil and Natural Gas Sector regulatory program, contact Mr. Bruce Moore, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–5460; facsimile number: (919) 541–3470; email address: *moore.bruce@epa.gov.*

SUPPLEMENTARY INFORMATION: *Outline.* The information presented in this preamble is organized as follows:

I. Preamble Acronyms and Abbreviations

Several acronyms and terms are included in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined here:

ANGA America's Natural Gas Alliance
API American Petroleum Institute
bbl Barrel
BID Background Information Document
BOE Barrels of Oil Equivalent
bpd Barrels Per Day
BSER Best System of Emissions Reduction
BTEX Benzene, Toluene, Ethylbenzene and Xylenes
CAA Clean Air Act
CFR Code of Federal Regulations
CPMS Continuous Parametric Monitoring Systems
EIA Energy Information Administration
EPA Environmental Protection Agency
GOR Gas to Oil Ratio
HAP Hazardous Air Pollutants
HPD HPDI, LLC
LDAR Leak Detection and Repair
Mcf Thousand Cubic Feet
NEI National Emissions Inventory
NEMS National Energy Modeling System
NESHAP National Emissions Standards for Hazardous Air Pollutants
NSPS New Source Performance Standards
NTTAA National Technology Transfer and Advancement Act of 1995
OAQPS Office of Air Quality Planning and Standards
OGI Optical Gas Imaging
OMB Office of Management and Budget
OVA Olfactory, Visual and Auditory
PRA Paperwork Reduction Act
PTE Potential to Emit
REC Reduced Emissions Completion
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
scfh Standard Cubic Feet per Hour
scfm Standard Cubic Feet per Minute
SISNOSE Significant Economic Impact on a Substantial Number of Small Entities
tpy Tons per Year
TSD Technical Support Document
TTN Technology Transfer Network
UMRA Unfunded Mandates Reform Act
VCS Voluntary Consensus Standards
VOC Volatile Organic Compounds
VRU Vapor Recovery Unit

II. Executive Summary

A. Purpose of the Regulatory Action

The purpose of this action is to propose amendments to the NSPS for the oil and natural gas source category. To date the EPA has established standards for emissions of VOC and sulfur dioxide (SO_2) for several operations in the source category. In this action, the EPA is proposing to amend the NSPS to include standards for reducing methane as well as VOC emissions across the oil and natural gas source category (*i.e.,* production, processing, transmission and storage). The EPA is including requirements for methane emissions in this proposal because methane is a GHG and the oil and natural gas category is currently one of the country's largest emitters of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations.1 The proposed amendments would require reduction of methane as well as VOC across the source category.

In addition, the proposed amendments include improvements to several aspects of the existing standards related to implementation. These improvements and the setting of standards for methane are a result of reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator on the August 16, 2012, NSPS (77 FR 49490) and on the September 13, 2013, amendments (78 FR 58416). Except for these implementation improvements, these proposed amendments do not change the requirements for operations and equipment already covered by the current standards.

B. Summary of the Major Provisions of the Regulatory Action

The proposed amendments include standards for methane and VOC for certain new, modified and reconstructed equipment, processes and activities across the oil and natural gas source category. These emission sources include those that are currently unregulated under the current NSPS (hydraulically fractured oil well completions, pneumatic pumps and fugitive emissions from well sites and compressor stations); those that are currently regulated for VOC but not for methane (hydraulically fractured gas well completions, equipment leaks at natural gas processing plants); and certain equipment that are used across the source category, but which the current NSPS regulates VOC emissions from only a subset of these equipment (pneumatic controllers, centrifugal compressors, reciprocating compressors), with the exception of compressors located at well sites.

Based on the EPA's analysis (see section VIII), we believe it is important to regulate methane from the oil and gas sources already regulated for VOC emissions to provide more consistency across the category, and that the best system of emission reduction (BSER) for methane for all these sources is the same as the BSER for VOC. Accordingly, the current VOC standards also reflect the BSER for methane reduction for the same emission sources. In addition, with respect to equipment used category-wide of which only a subset of those equipment are covered under the NSPS VOC standards (i.e., pneumatic controllers, and compressors located other than at well sites), EPA's analysis shows that the BSER for reducing VOC from the remaining unregulated equipment to be the same as the BSER for those currently regulated. The EPA is therefore proposing to extend the current VOC standards for these equipment to the remaining unregulated equipment.

The additional sources for which we are proposing methane and VOC standards were evaluated in the 2014 white papers (EPA Docket Number EPA–HQ–OAR–2014–0557). The papers summarized the EPA's understanding of VOC and methane emissions from these sources and also presented the EPA's understanding of mitigation techniques (practices and equipment) available to reduce these emissions, including the efficacy and cost of the technologies and the prevalence of use in the industry. The EPA received 26 submissions of peer review comments on these papers, and more than 43,000 comments from the public. The information gained through this process has improved the EPA's understanding of the methane and VOC emissions from these sources and the mitigation techniques available to control them.

The EPA has also received extensive and helpful input from state, local and tribal governments experienced in these operations, industry organizations, individual companies and others with data and experience. This information has been immensely helpful in determining appropriate standards for the various sources we are proposing to regulate. It has also helped the EPA design this proposal so as to complement, not complicate, existing state requirements. EPA acknowledges that a state may have more stringent state requirements (*e.g.*, fugitives monitoring and repair program). We believe that affected sources already complying with more stringent state requirements may also be in compliance with this rule. We solicit comment on how to determine whether existing state requirements (*i.e.*, monitoring, record keeping, and reporting) would demonstrate compliance with this federal rule.

During development of these proposed requirements, we were mindful that some facilities that will be subject to the proposed EPA standards will also be subject to current or future requirements of the Department of Interior's Bureau of Land Management (BLM) rules covering production of natural gas on Federal lands. We believe, to minimize confusion and unnecessary burden on the part of owners and operators, it is important that the EPA requirements not conflict with BLM requirements. As a result, EPA and BLM have maintained an ongoing dialogue during development of this action to identify opportunities for alignment and ways to minimize potential conflicting requirements and will continue to coordinate through the agencies' respective proposals and final rulemakings.

Following are brief summaries of these sources and the proposed standards.

Compressors. The EPA is proposing a 95 percent reduction of methane and VOC emissions from wet seal centrifugal compressors across the source category (except for those located at well sites).[2] For reciprocating compressors across the source category (except for those located at well sites), the EPA is proposing to reduce methane and VOC emissions by requiring that owners and/or operators of these compressors replace the rod packing based on specified hours of operation or elapsed calendar months or route emissions from the rod packing to a process through a closed vent system under negative pressure. See sections VIII.B and C of this preamble for further discussion.

Pneumatic controllers. The EPA is proposing a natural gas bleed rate limit of 6 standard cubic feet per hour (scfh) to reduce methane and VOC emissions from individual, continuous bleed, natural gas-driven pneumatic controllers at locations across the source category other than natural gas processing plants. At natural gas processing plants, the proposed rule regulates methane and VOC emissions by requiring natural gas-operated pneumatic controllers to have a zero natural gas bleed rate, as in the current NSPS. See section VIII.D of this preamble for further discussion.

Pneumatic pumps. The proposed standards for pneumatic pumps would apply to certain types of pneumatic pumps across the entire source category. At locations other than natural gas processing plants, we are proposing that the methane and VOC emissions from natural gas-driven chemical/methanol pumps and diaphragm pumps be reduced by 95 percent if a control device is already available on site. At natural gas processing plants, the proposed standards would require the methane and VOC emissions from natural gas-driven chemical/methanol pumps and diaphragm pumps to be zero. See section VIII.E of this preamble for further discussion.

Hydraulically fractured oil well completions. For subcategory 1 wells (non-wildcat, non-delineation wells), we are proposing that for hydraulically fractured oil well completions, owners and/or operators use reduced emissions completions, also known as ''RECs'' or ''green completions,'' to reduce methane and VOC emissions and maximize natural gas recovery from well completions. To achieve these reductions, owners and operators of hydraulically fractured oil wells must use RECs in combination with a completion combustion device. As is specified in the rule for hydraulically fractured gas well completions, the rule proposed here does not require RECs where their use is not feasible (*e.g.*, if it technically infeasible for a separator to function). For subcategory 2 wells (wildcat and delineation wells), we are proposing that for hydraulically fractured oil well completions, owners and/or operators use a completion combustion device to reduce methane and VOC emissions. The proposed standards for hydraulically fractured oil well completions are the same as the requirements finalized for hydraulically fractured gas well completions in the 2012 NSPS and as amended in 2014 (see 79 FR 79018, December 31, 2014). See section VIII.F of this preamble for further discussion.

Fugitive emissions from well sites and compressor stations. We are proposing that new and modified well sites and compressor stations (which include the transmission and storage segment and the gathering and boosting segment) conduct fugitive emissions surveys

[2] During the development of the 2012 NSPS, our data indicatedd that there were no centrifugal compressors located at well sites. Since the 2012 NSPS, we have not received information that would change our understanding that there are no centrifugal compressors in use at well sites.

semiannually with optical gas imaging (OGI) technology and repair the sources of fugitive emissions within 15 days that are found during those surveys. We are also co-proposing OGI monitoring surveys on an annual basis for new and modified well sites, and requesting comment on OGI monitoring surveys on a quarterly basis for both well sites and compressor stations. Fugitive emissions can occur immediately on startup of a newly constructed facility as a result of improper makeup of connections and other installation issues. In addition, during ongoing operation and aging of the facility, fugitive emissions may occur. Under this proposal, the required survey frequency would decrease from semiannually to annually for sites that find fugitive emissions from fewer than one percent of their fugitive emission components during a survey, while the frequency would increase from semiannually to quarterly for sites that find fugitive emissions from three percent or more of their fugitive emission components during a survey. We recognize that subpart W already requires annual fugitives reporting for certain compressor stations that exceed the 25,000 Metric Ton CO_2e threshold, and request comments on the overlap of these reporting requirements.

Building on the 2012 NSPS, the EPA intends to continue to encourage corporate-wide voluntary efforts to achieve emission reductions through responsible, transparent and verifiable actions that would obviate the need to meet obligations associated with NSPS applicability, as well as avoid creating disruption for operators following advanced responsible corporate practices. Based on this concept, we solicit comment on criteria we can use to determine whether and under what conditions well sites and other emission sources operating under corporate fugitive monitoring plans 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. We also solicit comment on how to address enforceability of such alternative approaches (i.e., how to assure that these well sites are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards).

Other reconsideration issues being addressed. The EPA is granting reconsideration of a number of issues raised in the administrative reconsideration petitions and, where appropriate, is proposing amendments to address such issues. These issues are as follows: Storage vessel control device monitoring and testing provisions, initial compliance requirements in § 60.5411(c)(3)(i)(A) for a bypass device that could divert an emission stream away from a control device, recordkeeping requirements of § 60.5420(c) for repair logs for control devices failing a visible emissions test, clarification of the due date for the initial annual report under the 2012 NSPS, flare design and operation standards, leak detection and repair (LDAR) for open-ended valves or lines, compliance period for LDAR for newly affected units, exemption to notification requirement for reconstruction, disposal of carbon from control devices, the definition of capital expenditure and initial compliance clarification. We are proposing to address these issues to clarify the rule, improve implementation and update procedures, as fully detailed in section IX.

C. Costs and Benefits

The EPA has estimated emissions reductions, costs and benefits for two years of analysis: 2020 and 2025. Actions taken to comply with the proposed NSPS are anticipated to prevent significant new emissions, including 170,000 to 180,000 tons of methane, 120,000 tons of VOC and 310 to 400 tons of hazardous air pollutants (HAP) in 2020. The emission reductions are 340,000 to 400,000 tons of methane, 170,000 to 180,000 tons of VOC, and 1,900 to 2,500 tons of HAP in 2025. The methane-related monetized climate benefits are estimated to be $200 to $210 million in 2020 and $460 to $550 million in 2025 using a 3 percent discount rate (model average).[3]

In addition to the benefits of methane reductions, stakeholders and members of local communities across the country have reported to the EPA their significant concerns regarding potential adverse effects resulting from exposure to air toxics emitted from oil and natural gas operations. Importantly, this includes disadvantaged populations.

The measures proposed in this action achieve methane and VOC reductions through direct regulation. The hazardous air pollutant (HAP) reductions from these proposed standards will be meaningful in local communities. In addition, reduction of VOC emissions will be very beneficial in areas where ozone levels approach or exceed the National Ambient Air Quality Standards for ozone. There have been measurements of increasing ozone levels in areas with concentrated oil and natural gas activity, including Wyoming and Utah. Several VOCs that commonly are emitted in the oil and natural gas source category are HAPs listed under Clean Air Act (CAA) section 112(b), including benzene, toluene, ethylbenzene and xylenes (this group is commonly referred to as ''BTEX'') and n-hexane. These pollutants and any other HAP included in the VOC emissions controlled under the NSPS, including requirements for additional sources being proposed in this action, are controlled to the same degree. The co-benefit HAP reductions for the measures being proposed are discussed in the Regulatory Impact Analysis (RIA) and in the Background Technical Support Document (TSD) which are included in the public docket for this action.

The EPA estimates the total capital cost of the proposed NSPS will be $170 to $180 million in 2020 and $280 to $330 million in 2025. The estimate of total annualized engineering costs of the proposed NSPS is $180 to $200 million in 2020 and $370 to $500 million in 2025 when using a 7 percent discount rate. When estimated revenues from additional natural gas are included, the annualized engineering costs of the proposed NSPS are estimated to be $150 to $170 million in 2020 and $320 to $420 million in 2025, assuming a wellhead natural gas price of $4/thousand cubic feet (Mcf). These compliance cost estimates include revenues from recovered natural gas as the EPA estimates that about 8 billion cubic feet in 2020 and 16 to 19 billion cubic feet in 2025 of natural gas will be recovered by implementing the NSPS.

Considering all the costs and benefits of this proposed rule, including the resources from recovered natural gas that would otherwise be vented, this rule results in a net benefit. The quantified net benefits (the difference between monetized benefits and compliance costs) are estimated to be $35 to $42 million in 2020 using a 3 percent discount rate (model average) for climate benefits.[4] The quantified net benefits are estimated to be $120 to $150 million in 2025 using a 3 percent discount rate (model average) for climate benefits. All dollar amounts are in 2012 dollars.

[3] We estimate methane benefits associated with four different values of a one ton CH_4 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For the purposes of this summary, we present the benefits associated with the model average at 3 percent discount rate, however we emphasize the importance and value of considering the full range of social cost of methane values. We provide estimates based on additional discount rates in preamble section XI and in the RIA.

[4] Figures may not sum due to rounding.

The EPA was unable to monetize all of the benefits anticipated to result from this proposal. The only benefits monetized for this rule are methane-related climate benefits. However, there would be additional benefits from reducing VOC and HAP emissions, as well as additional benefits from reducing methane emissions because methane is a precursor to global background concentrations of ozone. A detailed discussion of these unquantified benefits are discussed in section XI of this document as well as in the RIA available in the docket.

III. General Information

A. Does this reconsideration notice apply to me?

Categories and entities potentially affected by today's notice include:

TABLE 1—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS ACTION

Category	NAICS code [1]	Examples of regulated entities
Industry	211111	Crude Petroleum and Natural Gas Extraction.
	211112	Natural Gas Liquid Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	Pipeline Transportation of Natural Gas.
Federal government		Not affected.
State/local/tribal government		Not affected.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather is meant to provide a guide for readers regarding entities likely to be affected by this action. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 or 40 CFR 63.13 (General Provisions).

B. What should I consider as I prepare my comments to the EPA?

We seek comment only on the aspects of the new source performance standards for the oil and natural gas source category for the equipment, processes and activities specifically identified in this document. We are not opening for reconsideration any other provisions of the new source performance standards at this time.

Do not submit information containing CBI to the EPA through www.regulations.gov or email. Send or deliver information identified as CBI only to the following address: OAQPS Document Control Officer (C404–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention: Docket ID Number EPA–HQ–OAR–2010–0505. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to the EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

C. How do I obtain a copy of this document and other related information?

In addition to being available in the docket, electronic copies of these proposed rules will be available on the Worldwide Web through the Technology Transfer Network (TTN). Following signature, a copy of each proposed rule will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: *http://www.epa.gov/ttn/oarpg/*. The TTN provides information and technology exchange in various areas of air pollution control.

IV. Background

A. Statutory Background

Section 111 of the CAA requires the EPA Administrator to list categories of stationary sources that, in his or her judgment, cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The EPA must then issue ''standards of performance'' for new sources in such source categories. The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, and identify within each source category the facilities for which standards of performance would be established.

CAA Section 111(a)(1) defines ''a standard of performance'' as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirement) the Administrator determines has been adequately demonstrated.'' This definition makes clear that the standard of performance must be based on controls that constitute ''the best system of emission reduction . . . adequately demonstrated''. The standard that the EPA develops, based on the BSER, is commonly a numerical emissions limit, expressed as a performance level (*e.g.*, a rate-based standard). Generally, the EPA does not prescribe a particular technological system that must be used to comply with a standard of performance. Rather, sources generally can select any measure or combination of measures that will achieve the emissions level of the standard.

Standards of performance under section 111 are issued for new, modified and reconstructed stationary sources. These standards are referred to as ''new source performance standards.'' The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, identify the facilities within each source category to be covered and set the emission level of the standards.

CAA section 111(b)(1)(B) requires the EPA to ''at least every 8 years review and, if appropriate, revise'' performance standards unless the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the standard. When conducting a review of an existing performance standard, the EPA has discretion to revise that standard to add emission limits for pollutants or emission sources not information and analyses detailing the public health and welfare impacts of GHG, VOC and SO_2 emissions and the amount of these emission from the oil and natural gas source category (in particular from the various segments of the natural gas industry). Although EPA does not believe the proposed revision to the category listing is required for the standards we are proposing in this action, even assuming it is, the proposal is well justified.

B. Stakeholder Input

1. White Papers

As a follow up to the 2013 Climate Action Plan, the Climate Action Plan: Strategy to Reduce Methane Emissions (the Methane Strategy) was released in March 2014. The Methane Strategy instructed the EPA to release a series of white papers on several potentially significant sources of methane in the oil and natural gas sector and solicit input from independent experts. The papers were released in April 2014, and focused on technical issues, covering emissions and control technologies that target both VOC and methane with particular focus on completions of hydraulically fractured oil wells, liquids unloading, leaks, pneumatic devices and compressors. The peer review process was completed on June 16, 2014.

The peer review and public comments on the white papers included additional technical information that provided further clarification of our understanding of the emission sources and emission control options. The comments also provided additional data on emissions and number of sources, and pointed out newly published studies that further informed our emission rate estimates. Where appropriate, we used the information and data provided to adjust the control options considered and the impacts estimates presented in the 2015 TSD.

The EPA used an ad hoc external peer review process, as outlined in the EPA's Peer Review Handbook, 3rd Edition. Under that process, the Agency submitted names recommended by industry and environmental groups, along with state, tribal, and academic organizations to an outside contractor. To avoid any conflict of interest, the contractor did not work on the white papers and is not working on the EPA's oil and natural gas regulations or voluntary programs. The contractor built a list of qualified reviewers from these names and their own research, reviewed appropriate credentials and selected reviewers from the list. A different set of reviewers was selected for each white paper, based on the reviewers' expertise. A total of 26 sets of comments from peer reviewers were submitted to the EPA. Additionally, the EPA solicited technical information and data from the public. The EPA received over 43,000 submissions from the public. The comments received from the peer reviewers are available on EPA's oil and natural gas white paper Web site (*http://www.epa.gov/airquality/oilandgas/methane.html*). Public comments on the white papers are available in EPA's nonregulatory docket at *www.regulations.gov*, docket ID # EPA–HQ–OAR–2014–0557.

2. Outreach to State, Local and Tribal Governments

The EPA spoke with state, local and tribal governments to hear how they have managed issues, and to get feedback that would help us as we develop the rule. In February 2015, the EPA asked states and tribes to nominate themselves to participate in discussions. Twelve states, three tribes and several local air districts participated. We conducted several teleconferences in March and April 2015 to discuss such questions as:

- Whether these governments are, or have considered, regulating the sources identified in the white papers
- Factors considered in determining whether to regulate them
- Use of innovative compliance options
- Experiences implementing control techniques guidelines (CTGs)[41]
- Information and features that would be helpful to include in a CTG
- Whether any sources of emissions are particularly suitable to voluntary rather than regulatory action

In addition to the outreach described above, the EPA consulted with tribal officials under the ''EPA Policy on Consultation and Coordination with Indian Tribes'' early in the process of developing this regulation to provide them with the opportunity to have meaningful and timely input into its development. Additionally, the EPA has conducted meaningful involvement with tribal stakeholders throughout the rulemaking process and provided an update on the methane strategy to the National Tribal Air Association. Consistent with previous actions affecting the oil and natural gas sector, there is significant tribal interest because of the growth of the oil and natural gas production in Indian country. The EPA specifically solicits additional comment on this proposed action from tribal officials.

[41] Control techniques guidelines are not part of this action.

VII. Summary of Proposed Standards

A. Control of Methane and VOC Emissions in the Oil and Natural Gas Source Category

In this action, we propose to set emission standards for methane and VOC for certain new, modified and reconstructed emission sources across the oil and natural gas source category. For some of these sources, there are VOC requirements currently in place that were established in the 2012 NSPS, that we are expanding to include methane. For others, for which there are no current requirements, we are proposing methane and VOC standards. We are also proposing improvements to enhance implementation of the current standards. For the reasons explained in section V, EPA believes that the proposed methane standards are warranted, even for those already subject to VOC standards under the 2012 NSPS. Further, as shown in the analyses in section VIII, there are cost effective controls that achieve simultaneous reductions of methane and VOC emission. Some stakeholders have advocated that is appropriate to rely on VOC standards, as established in 2012, for sources in the production and processing segment. For example, based on methane and VOC emissions from pneumatic controllers, this approach could result in just a VOC standard for pneumatic controllers in the production segment and a VOC and methane standard in the transmission and storage segment. Some stakeholders have also advocated for the importance of setting methane standards in the production segment that go beyond the 2012 NSPS standards. We anticipate that these stakeholders will express their views during the comment period.

Pursuant to CAA section 111(b), we are proposing to amend subpart OOOO and to create a new subpart OOOOa which will include the standards and requirements summarized in this section. Subpart OOOO would be amended to apply to facilities constructed, modified or reconstructed after August 23, 2011, (*i.e.*, the original proposal date of subpart OOOO) and before September 18, 2015 (*i.e.*, the proposal date of the new subpart OOOOa) and would be amended only to include the revisions reflecting implementation improvements in response to issues raised in petitions for reconsideration. Subpart OOOOa would apply to facilities constructed, modified or reconstructed after September 18, 2015 and would include current VOC requirements already provided in subpart OOOO as well as new provisions for methane and VOC across the oil and natural gas source category as highlighted below in this section. More details of the rationale for these proposed standards and requirements are provided in section VIII of this preamble.

We note that the terms ''emission source,'' ''source type'' and ''source,'' as used in this preamble, refer to equipment, processes and activities that emit VOC and/or methane. This term does not refer to specific facilities, in contrast to usage of the term ''source'' in the contexts of permitting and section 112 actions. As summarized below and discussed in more detail in section VIII, the BSER for methane is the same as that for VOC for all emission sources, including those currently subject to VOC standards and for which we are proposing to establish methane standards in this action. Accordingly, the current requirements reflect the BSER for both VOC and methane for these sources. We are, therefore, not proposing any change to the current requirements for emission sources addressed under the 2012 NSPS.

Both VOC and methane are hydrocarbon compounds and behave essentially the same when emitted together or separately. Accordingly, the available controls for methane are the same as those for VOC and achieve the same levels of reduction for both VOC and methane. For example, combustion-based control technologies (*e.g.*, flares and enclosed combustors) that reduce VOC emissions by 95 percent can be expected to also reduce methane emissions by 95 percent. Similarly, work practice and operational standards (*e.g.*, leak detection and reduced emission completion of wells) that reduce emissions of VOC can be expected to have the same effect on methane emissions. Because VOC control technologies perform the same when used to control methane emissions, the BSER for methane is the same as the BSER for VOC. Therefore, we are proposing performance and operational standards to control methane and VOC emissions for certain emission sources across the source category. These proposed methane standards would require no change to the requirements for currently regulated affected facilities.

Please note that there are minor differences in some values presented in various documents supporting this action. This is because some calculations have been performed independently (*e.g.*, TSD calculations focused on unit-level cost-effectiveness and RIA calculations focused on national impacts) and include slightly different rounding of intermediate values.

B. Centrifugal Compressors

We are proposing standards to reduce methane and VOC emissions from new, modified or reconstructed centrifugal compressors located across the oil and natural gas source category, except those located at well sites. As discussed in detail in section VIII.B, the proposed standards are the same as those currently required to control VOC from centrifugal compressors in the production segment. Specifically, we are proposing to require 95 percent reduction of the emissions from each wet seal centrifugal compressor affected facility. The standard can be achieved by capturing and routing the emissions utilizing a cover and closed vent system to a control device that achieves an emission reduction of 95 percent, or routing the captured emissions to a process. Consistent with the current VOC provisions for centrifugal compressors in the production segment, dry seal centrifugal compressors are inherently low-emitting and would not be affected facilities. These proposed standards are the same as for centrifugal compressors regulated in the 2012 final rule.

C. Reciprocating Compressors

For the reasons discussed in section VIII.C, we are proposing an operational standard for affected reciprocating compressors across the oil and natural gas source category, except those located at well sites, that requires either replacement of the rod packing based on usage or routing of rod packing emissions to a process via a closed vent system under negative pressure. The owner or operator of a reciprocating compressor affected facility would be required to monitor the duration (in hours) that the compressor is operated, beginning on the date of initial startup of the reciprocating compressor affected facility. When the hours of operation reach 26,000 hours, the owner or operator would be required to immediately change the rod packing. Owners or operators can elect to change the rod packing every 36 months in lieu of monitoring compressor operating hours. As an alternative to rod packing replacement, owners and operators may route the rod packing emissions to a process via a closed vent system operated at negative pressure. These proposed standards are the same as for reciprocating compressors regulated in the 2012 rule.

D. Pneumatic Controllers

For the reasons presented in section VIII.D, consistent with VOC standards in the 2012 NSPS for pneumatic controllers in the production segment, we are proposing to control methane and VOC emissions by requiring use of low-bleed controllers in place of high-bleed controllers (*i.e.*, natural gas bleed rate not to exceed 6 scfh) [42] at locations within the source category except for natural gas processing plants. For natural gas processing plants, consistent with the VOC emission standards in the 2012 NSPS, we are proposing to control methane and VOC emissions by requiring that pneumatic controllers have zero natural gas bleed rate (*i.e.*, they are operated by means other than natural gas, such as being driven by compressed instrument air). We are proposing that these standards apply to each newly installed, modified or reconstructed pneumatic controller (including replacement of an existing controller). Consistent with the current requirements under the 2012 NSPS for control of VOC emissions from pneumatic controllers in the production segment and at natural gas processing plants, the proposed standards provide exemptions for certain critical applications based on functional considerations. These proposed standards are the same as for pneumatic controllers regulated in the 2012 rule.

E. Pneumatic Pumps

For the reasons detailed in section VIII.E, we are proposing standards for natural gas-driven chemical/methanol pumps and diaphragm pumps. The proposed standards would require the methane and VOC emissions from new, modified and reconstructed natural gas-driven chemical/methanol pumps and diaphragm pumps located at any location (except for natural gas processing plants) throughout the source category to be reduced by 95 percent if a control device is already available on site. For pneumatic pumps located at a natural gas processing plant, the proposed standards would require the methane and VOC emissions from natural gas-driven chemical/methanol pumps and diaphragm pumps to be zero.

F. Well Completions

We are proposing operational standards for well completions at hydraulically fractured (or refractured) wells, including oil wells. The 2012 NSPS regulated well completions to

[42] Bleed rate can be documented through information provided by the controller manufacturer.

control VOC emissions from hydraulically fractured or refractured gas wells. These proposed standards are the same as for natural gas wells regulated in the 2012 rule. We identified two subcategories of hydraulically fractured wells for which well completions are conducted: (1) Non-wildcat and non-delineation wells; and (2) wildcat and delineation wells. A wildcat well, also referred to as an exploratory well, is a well drilled outside known fields or are the first well drilled in an oil or gas field where no other oil and gas production exists. A delineation well is a well drilled to determine the boundary of a field or producing reservoir.

As discussed in detail in section VIII.F, we are proposing operational standards for subcategory 1 (non-wildcat, non-delineation wells) requiring a combination of REC and combustion. Compared to combustion alone, we believe that the combination of REC and combustion will maximize gas recovery and minimize venting to the atmosphere. Furthermore, the use of traditional combustion control devices (*i.e.*, flares and enclosed combustion control devices), present local emissions impacts. The proposed standards for subcategory 2 wells (wildcat and delineation wells) require only combustion. For subcategory 1 wells, we are proposing to define the flowback period of an oil well completion as consisting of two distinct stages, the ''initial flowback stage'' and the ''separation flowback stage.'' The initial flowback stage begins with the onset of flowback and ends when the flow is routed to a separator. During the initial flowback stage, any gas in the flowback is not subject to control. However, the operator must route the flowback to a separator unless it is technically infeasible for a separator to function. The point at which the separator can function marks the beginning of the separation flowback stage. During this stage, the operator must route all salable quality gas from the separator to a flow line or collection system, re-inject the gas into the well or another well, use the gas as an on-site fuel source or use the gas for another useful purpose. If it is technically infeasible to route the gas as described above, or if the gas is not of salable quality, the operator must combust the gas unless combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways. No direct venting of gas is allowed during the separation flowback stage. The separation flowback stage ends either when the well is shut in and the flowback equipment is permanently disconnected from the well, or on startup of production. This also marks the end of the flowback period. The operator has a general duty to safely maximize resource recovery safely and minimize releases to the atmosphere over the duration of the flowback period. The operator is also required to document the stages of the completion operation by maintaining records of (1) the date and time of the onset of flowback; (2) the date and time of each attempt to route flowback to the separator; (3) the date and time of each occurrence in which the operator reverted to the initial flowback stage; (4) the date and time of well shut in; and (5) date and time that temporary flowback equipment is disconnected. In addition, the operator must document the total duration of venting, combustion and flaring over the flowback period. All flowback liquids during the initial flowback period and the separation flowback period must be routed to a well completion vessel, a storage vessel or a collection system.

For subcategory 2 wells, we are proposing an operational standard that requires routing of the flowback into well completion vessels and commencing operation of a separator unless it is technically infeasible for the separator to function. Once the separator can function, recovered gas must be captured and directed to a completion combustion device unless combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways. Operators would be required to maintain the same records described above for category 1 wells.

Consistent with the current VOC standards for hydraulically fractured gas wells, we are proposing that ''low pressure'' wells would remain affected facilities and would have the same requirements as subcategory 2 wells (wildcat and delineation wells). The term ''low pressure gas well'' is unchanged from the currently codified definition in the NSPS; however, we solicit comment on whether this definition appropriately indicates hydraulically fractured oil wells for which conducting an REC would be technologically infeasible and whether the term should be revised to address all wells rather than just gas wells.

We are also retaining the provision from the 2012 NSPS, now at § 60.5365a(a)(1), that a well that is refractured, and for which the well completion operation is conducted according to the requirements of § 60.5375a(a)(1) through (4), is not considered a modified well and therefore does not become an affected facility under the NSPS. We point out that such an exclusion of a ''well'' from applicability under the NSPS has no effect on the affected facility status of the ''well site'' for purposes of the proposed fugitive emissions standards at § 60.5397a.

Further, we are proposing that wells with a gas-to-oil ratio (GOR) of less than 300 scf of gas per barrel of oil produced would not be affected facilities subject to the well completion provisions of the NSPS. We solicit comment on whether a GOR of 300 is the appropriate applicability threshold. Rationale for this threshold is discussed in detail in section VIII.F.

G. Fugitive Emissions From Well Sites and Compressor Stations

1. Fugitive Emissions From Oil and Natural Gas Production Well Sites

We are proposing standards to reduce fugitive methane and VOC emissions from new and modified oil and natural gas production well sites. The proposed standards would require locating and repairing sources of fugitive emissions (*e.g.*, visible emissions from fugitive emissions components observed using OGI) at well sites. Under the proposed standards, the affected facility would be ''the collection of fugitive emissions components at a well site''; where ''well site'' is defined in subpart OOOO as ''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, gas well, or injection well and its associated well pad.'' This definition is intended to include all ancillary equipment in the immediate vicinity of the well that are necessary for or used in production, and may include such items as separators, storage vessels, heaters, dehydrators, or other equipment at the site.

Some well sites, especially in areas with very dry gas or where centralized gathering facilities are used, consist only of one or more wellheads, or ''Christmas trees,'' and have no ancillary equipment such as storage vessels, closed vent systems, control devices, compressors, separators and pneumatic controllers. Because the magnitude of fugitive emissions depends on how many of each type of component *(e.g.*, valves, connectors and pumps) are present, fugitive emissions from these well sites are extremely low. For that reason, we are proposing to exclude from the fugitive emissions requirements those well sites that contain only wellheads. Therefore, we are proposing to add the following sentence to the definition of ''well site'' above: ''For the purposes of the fugitive emissions standards at § 60.5397a, a well site that only contains one or more wellheads is not subject to these standards.''

Also, we are proposing to exclude low production well sites (*i.e.*, a low production site is defined by the average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production) from the standards for fugitives emissions from well sites. Please refer to section VIII.G. for further discussion.

We are proposing that owners or operators of well site-affected facilities conduct an initial survey of ''fugitive emissions components,'' which we are proposing to define in § 60.5430a to include, among other things, valves, connectors, open-ended lines, pressure relief devices, closed vent systems and thief hatches on tanks using either OGI technology. For new well sites, the initial survey would have to be conducted within 30 days of the end of the first well completion or upon the date the site begins production, whichever is later. For modified well sites, the initial survey would be required to be conducted within 30 days of the site modification. We solicit comment on whether 30 days is an appropriate period for the first survey following startup or modification. For the purposes of these fugitive emissions standards, a modification would occur when a new well is added to a well site (regardless of whether the well is fractured) or an existing well on a well site is fractured or refractured. See section VII.G.3 below for a discussion of modifications in the context of fugitive emission requirements for well sites and compressor stations. After the initial monitoring survey, monitoring surveys would be required to be conducted semiannually for all new and modified well sites. We are also co-proposing monitoring surveys on an annual basis for new and modified well sites.

The proposed standards would require replacement or repair of components if evidence of fugitive emissions is detected during the monitoring survey through visible confirmation from OGI. As discussed in section VIII.G, we solicit comment on whether to allow EPA Method 21 as an alternative to OGI for monitoring, including the appropriate EPA Method 21 level repair threshold.

We are proposing that the source of emissions be repaired or replaced, and resurveyed, as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. We expect that the majority of the repairs can be made at the time the initial monitoring survey is conducted. However, we understand that more time may be necessary to repair more complex components. We have historically allowed 15 days for repair/resurvey in the LDAR program, which has appeared to be sufficient time. We are proposing to allow the use of either Method 21 or OGI for resurveys that cannot be performed during the initial monitoring survey and repair. As explained above, there may be some components that cannot not be repaired right away and in some instances not until after the initial OGI personnel are no longer on site. In that event, resurvey with OGI would require rehiring OGI personnel, which would make the resurvey not cost effective. For those components that have been repaired, we believe that the no fugitive emissions would be detected above 500 ppm above background using Method 21. This has been historically used to ensure that there are no emissions from components that are required to operate with no detectable emissions. We solicit comments on whether either optical gas imaging or Method 21 should be allowed for the resurvey of the repaired components when fugitive emissions are detected with OGI. We estimate that the majority of operators will need to hire a contractor to come back to conduct the optical gas imaging resurvey. While there will also be costs associated with resurveying using Method 21, we estimate that many companies own Method 21 instruments (*e.g.,* OVA/TVA) and would be able to perform the resurvey at a minimal cost. To verify that the repair has been made using OGI, no evidence of visible emissions must be seen during the survey. For Method 21, we are proposing that the instrument show a reading of less than 500 ppm above background from any of the repaired components. We solicit comment whether 500 ppm above background is the appropriate repair resurvey threshold when Method 21 instruments are used or if not, what the appropriate repair resurvey threshold is for Method 21.

If the repair or replacement is technically infeasible or unsafe during unit operations, the repair or replacement must be completed during the next scheduled shutdown or within six months, whichever is earlier. Equipment is unsafe to repair or replace if personnel would be exposed to an immediate danger in conducting the repair or replacement. All sources of fugitive emissions that are repaired must be resurveyed within 15 days of repair completion to ensure the repair has been successful (*i.e.,* no fugitive emissions are imaged using OGI or less than 500 ppm above background when using Method 21).

The EPA is proposing that these fugitive emission requirements be carried out through the development and implementation of a monitoring plan, which would specify the measures for locating sources of fugitive emissions and the detection technology to be used. A company would be able to develop a corporate-wide monitoring plan, although there may be specific information needed that pertains to a single site, such as number and identification of fugitive emission components. The monitoring plan must also include a description of how the OGI survey will be conducted that ensures that fugitive emissions can be imaged effectively. In addition, we solicit comment on whether other techniques could be required elements of the monitoring plan in conjunction with OGI, such as visual inspections, to help identify signs such as staining of storage vessels or other indicators of potential leaks or improper operation.

If fugitive emissions are detected at less than one percent of the fugitive emission components at a well site during two consecutive semiannual monitoring surveys, then the monitoring survey frequency for that well site may be reduced to annually. If, during a subsequent monitoring survey, fugitive emissions are detected at between one percent and three percent of the fugitive emission components, then the monitoring survey frequency for that well site must be increased to semiannually.

If fugitive emissions are detected from three percent or more of the fugitive emission components at a well site during two consecutive semiannual monitoring, then the monitoring survey frequency for that well site must be increased to quarterly. If, during a subsequent monitoring survey, fugitive emissions are detected from one to three percent of the fugitive emission components, then the monitoring survey frequency for that well site may be reduced to semiannually. If fugitive emissions are detected from less than one percent of the fugitive emission components, then the monitoring survey frequency for that well site may be reduced to annually. We solicit 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 also solicit comment on whether a performance-based frequency or a fixed frequency is more appropriate.

As discussed in more detail in section VIII.G below and the TSD for this action available in the docket, we have identified OGI technology with semiannual survey monitoring as the BSER for detecting fugitive emissions from new and modified well sites.

The proposed standards would apply to new well sites and to modified well sites. As explained in more detail in section VIII.B below, for purposes of this proposed standard, a well site is modified when a new well is completed (regardless of whether it is fractured) or an existing well is fractured or refractured after [effective date of final rule]. The standards would not apply to existing well sites where additional drilling activities were conducted on an existing well but those activities did not include fracturing or refracturing (e.g., well workovers that do not include fracturing or refracturing).

2. Fugitive Emissions From Compressor Stations

We are proposing standards to reduce fugitive methane and VOC emissions from new and modified natural gas compressor stations throughout the oil and natural gas source category. The proposed standards would require affected facilities to locate sources of fugitive emissions and to repair those sources. We are proposing that owners or operators of the affected facilities conduct an initial survey of the collection of fugitive emissions components (*e.g.,* valves, connectors, open-ended lines, pressure relief devices, closed vent systems and thief hatches on tanks) using OGI technology. For new compressor stations, the initial survey would have to be conducted within 30 days of site startup. For modified compressor stations, the initial survey would be required within 30 days of the site modification. After the initial survey, surveys would be required semiannually. We solicit comment on whether 30 days is an appropriate period for the first survey following startup.

The proposed standards would require replacement or repair of any fugitive emissions component that has evidence of fugitive emissions detected during the survey through visible confirmation from OGI. As discussed in section VIII.G, we solicit comment on whether to allow EPA Method 21 as an alternative to OGI for monitoring, including the appropriate EPA Method 21 level repair threshold.

We are proposing that the source of emissions be repaired or replaced, and resurveyed, as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. We expect that the majority of the repairs can be made at the time the initial monitoring survey is conducted. However, we understand that more time may be necessary to repair more complex components. We have historically allowed 15 days for repair/resurvey in the LDAR program, which has appeared to be sufficient time. We are proposing to allow the use of either Method 21 or OGI for resurveys that cannot be performed during the initial monitoring survey and repair. As explained above, there may be some components that cannot not be repaired right away and in some instances not until after the initial OGI personnel are no longer on site. In that event, resurvey with OGI would require rehiring OGI personnel, which would make the resurvey not cost effective. For those components that have been repaired, we believe that the no fugitive emissions would be detected above 500 ppm above background using Method 21. This has been historically used to ensure that there are no emissions from components that are required to operate with no detectable emissions. We solicit comments on whether either optical gas imaging or Method 21 should be allowed for the resurvey of the repaired components when fugitive emissions are detected with OGI. We estimate that the majority of operators will need to hire a contractor to come back to conduct the optical gas imaging resurvey. While there will also be costs associated with resurveying using Method 21, we estimate that many companies own Method 21 instruments (*e.g.,* OVA/TVA) and would be able to perform the resurvey at a minimal cost. To verify that the repair has been made using OGI, no evidence of visible emissions must be seen during the survey. For Method 21, we are proposing that the instrument show a reading of less than 500 ppm above background from any of the repaired components. We solicit comment whether 500 ppm above background is the appropriate repair resurvey threshold when Method 21 instruments are used or if not, what the appropriate repair resurvey threshold is for Method 21.

The source of emissions must be repaired or replaced as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. If the repair or replacement is technically infeasible or unsafe during unit operations, the repair or replacement must be completed during the next scheduled shutdown or within six months, whichever is earlier. Equipment is unsafe to repair or replace if personnel would be exposed to an immediate danger in conducting monitoring. All sources of fugitive emissions that are repaired must be resurveyed to ensure the repair has been successful (*i.e.,* no fugitive emissions are imaged using OGI or less than 500 ppm above background when using Method 21).

The EPA is proposing that these fugitive emission requirements be carried out through the development and implementation of a monitoring plan, which would specify the measures for locating sources of fugitive emissions and the detection technology to be used. The monitoring plan must also include a description of how the OGI survey will be conducted that ensures that fugitive emissions can be imaged effectively. In addition, we solicit comment on whether other techniques could be required elements of the monitoring plan in conjunction with OGI, such as visual inspections, to help identify signs such as staining of storage vessels or other indicators of potential leaks or improper operation.

If fugitive emissions are detected during two consecutive semi-annual monitoring surveys at less than one percent of the fugitive emission components, then the monitoring survey frequency for that compressor station may be reduced to annually. If, during a subsequent monitoring survey, visible fugitive emissions are detected using OGI from one to three percent of the fugitive emission components, then the monitoring survey frequency for that compressor station must be increased to semiannually.

If fugitive emissions are detected from three percent or more of the fugitive emission components during two consecutive semiannual monitoring surveys with OGI technology, then the monitoring survey frequency for that compressor station must be increased to quarterly. If, during a subsequent monitoring survey, fugitive emissions are detected from one to three percent of the fugitive emission components using OGI technology, then the monitoring survey frequency for that compressor station may be reduced to semiannually. If fugitive emissions are detected from less than one percent of the fugitive emission components, then the monitoring survey frequency for that well site may be reduced to annually. We solicit 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 also solicit comment on whether a performance-based frequency or a fixed frequency is more appropriate.

As discussed in more detail in section VIII.G below and the TSD for this action available in the docket, we have identified OGI technology as the BSER for detecting fugitive emissions from new and modified compressor stations.

The proposed standards apply to new and modified compressor stations throughout the oil and natural gas source category. As explained in section VII.G.3 below, compressor stations are considered modified for the purposes of these fugitive emission standards when one or more compressors is added to the station after [effective date of final rule].

3. Modification of the Collection of Fugitive Emissions Components at Well Sites and Compressor Stations

For the purposes of the fugitive emission standards at well sites and compressor stations, we are proposing definitions of ''modification'' for those facilities that are specific to these provisions and for this purpose only. As provided in section 60.14(f), such provisions in the specific subparts would supersede any conflicting provisions in § 60.14 of the General Provisions. This definition does not affect other standards under this subpart for wells, other equipment at well sites or compressors.

For purposes of the proposed fugitive emissions standards at well sites, we propose that a modification to a well site occurs only when a new well is added to a well site (regardless of whether the well is fractured) or an existing well on a well site is fractured or refractured. When a new well is added or a well is fractured or refractured, there is an increase in emissions to the fugitive emissions components because of the addition of piping and ancillary equipment to support the well, along with potentially greater pressures and increased production brought about by the new or fractured well. Other than these events, we are not aware of any other physical change to a well site that would result in an increase in emissions from the collection of fugitive components at such well site. To clarify and ease implementation, we propose to define ''modification'' to include only these two events for purposes of the fugitive emissions provisions at well sites. We note that under § 60.5365a(a)(1) a well that is refractured, and for which the well completion operation is conducted according to the requirements of § 60.5375a(a)(1) through(4), is not considered a modified well and therefore does not become an affected facility under the NSPS. We would like to clarify that such an exclusion of a ''well'' from applicability under the NSPS would have no effect on the affected facility status of the ''well site'' for purposes of the proposed fugitive emissions standards. Accordingly, a well at an existing well site that is refractured constitutes a modification of the well site, which then would be an affected facility for purposes of the fugitive emission standards at § 60.5397a, regardless of whether the well itself is an affected facility.

In the 2012 NSPS, we provided that completion requirements do not apply to refracturing of an existing well that is completed responsibly (*i.e.* green completions). Building on the 2012 NSPS, the EPA intends to continue to encourage corporate-wide voluntary efforts to achieve emission reductions through responsible, transparent and verifiable actions that would obviate the need to meet obligations associated with NSPS applicability, as well as avoid creating disruption for operators following advanced responsible corporate practices. To encourage companies to continue such good corporate policies and encourage advancement in the technology and practices, we solicit 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. We also solicit comment on how to address enforceability of such alternative approaches (*i.e.,* how to assure that these well sites are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards).

For the reasons stated above, we are also soliciting comments on criteria we can use to determine whether and under what conditions all new or modified well sites or compressor stations operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well sites or compressor stations fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining. We also solicit comment on how to address enforceability of such alternative approaches (*i.e.*, how to assure that these well sites and compressor stations are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards).

For purposes of the proposed standards for fugitive emission at compressor stations, we propose that a modification occurs only when a compressor is added to the compressor station or when physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station. Since fugitive emissions at compressor stations are from compressors and their associated piping, connections and other ancillary equipment, expansion of compression capacity at a compressor station, either through addition of a compressor or physical change to the an existing compressor, would result in an increase in emissions to the fugitive emissions components. Other than these events, we are not aware of any other physical change to a compressor station that would result in an increase in emissions from the collection of fugitive components at such compressor station. To clarify and ease implementation, we define ''modification'' as the addition of a compressor for purposes of the fugitive emissions provisions at compressor stations.

H. Equipment Leaks at Natural Gas Processing Plants

We are proposing standards to control methane and VOC emissions from equipment leaks at natural gas processing plants. These requirements are the same as the VOC equipment leak requirements in the 2012 NSPS and would require NSPS part 60, subpart VVa level of control, including a detection level of 500 ppm as in the 2012 NSPS. As discussed further in section VIII.H, we propose that the subpart VVa level of control applied plant-wide is the BSER for controlling methane emissions from equipment leaks at onshore natural gas processing plants. We believe it provides the greatest emission reductions of the options we considered in our analysis in Section VIII.H, and that the costs are reasonable.

I. Liquids Unloading Operations

For the reasons discussed in section VIII.I, at this time the EPA does not have sufficient information to propose a standard for liquids unloading. However, we are requesting comment on nationally applicable technologies and techniques that reduce methane and VOC emissions from these events.

Specifically, we request comment on technologies and techniques that can be applied to new gas wells that can reduce emissions from liquids unloading in the future.

J. Recordkeeping and Reporting

We are proposing recordkeeping and reporting requirements that are consistent with those required in the current NSPS for natural gas well completions, compressors and pneumatic controllers. Owners or operators would be required to submit initial notifications (except for wells, pneumatic controllers, pneumatic pumps and compressors, as provided in § 60.5420(a)(1)) and annual reports, and to retain records to assist in documenting that they are complying with the provisions of the NSPS.

For new, modified or reconstructed pneumatic controllers, owners and operators would not be required to submit an initial notification; they would simply need to report the installation of these affected facilities in their facility's first annual report following the compliance period during which they were installed. Owners or operators of well-affected facilities (consistent with current requirements for gas well affected facilities) would be required to submit an initial notification no later than two days prior to the commencement of each well completion operation. This notification would include contact information for the owner or operator, the American Petroleum Institute (API) well number, the latitude and longitude coordinates for each well, and the planned date of the beginning of flowback.

In addition, an initial annual report would be due no later than 90 days after the end of the initial compliance period, which is established in the rule. Subsequent annual reports would be due no later than the same date each year as the initial annual report. The annual reports would include information on all affected facilities owned or operated of sources that were constructed, modified or reconstructed during the reporting period. A single report may be submitted covering multiple affected facilities, provided that the report contains all the information required by 40 CFR 60.5420(b). This information would include general information on the facility (*i.e.*, company name and address, etc.), as well as information specific to individual affected facilities.

For well affected facilities, the information required in the annual report would include the location of the well, the API well number, the date and time of the onset of flowback following hydraulic fracturing or refracturing, the date and time of each attempt to direct flowback to a separator, the date and time of each occurrence of returning to the initial flowback stage, and the date and time that the well was shut in and the flowback equipment was permanently disconnected or the startup of production, the duration of flowback, the duration of recovery to the flow line, duration of combustion, duration of venting, and specific reasons for venting in lieu of capture or combustion. For each oil well for which an exemption is claimed for conditions in which combustion may result in a fire hazard or explosion or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways, the report would include the location of the well, the API well number, the specific exception claimed, the starting date and ending date for the period the well operated under the exception, and an explanation of why the well meets the claimed exception. The annual report would also include records of deviations where well completions were not conducted according to the applicable standards.

For centrifugal compressor affected facilities, information in the annual report would include an identification of each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period, as well as records of deviations in cases where the centrifugal compressor was not operated in compliance with the applicable standards.

For reciprocating compressors, information in the annual report would include the cumulative number of hours of operation or the number of months since initial startup or the previous reciprocating compressor rod packing replacement, whichever is later, or a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

Information in the annual report for pneumatic controller affected facilities would include location and documentation of manufacturer specifications of the natural gas bleed rate of each pneumatic controller installed during the compliance period. For pneumatic controllers for which the owner is claiming an exemption to the standards, the annual report would include documentation that the use of a pneumatic controller with a natural gas bleed rate greater than 6 scfh is required and the reasons why. The annual report would also include records of deviations from the applicable standards.

For pneumatic pump affected facilities, information in the annual report would include an identification of each pneumatic pump constructed, modified or reconstructed during the compliance period, as well as records of deviations in cases where the pneumatic pump was not operated in compliance with the applicable standards.

The proposed rule includes new requirements for monitoring and repairing sources of fugitive emissions at well sites and compressor stations. The owner or operator would be required to keep one or more digital photographs of each affected well site or compressor station. A photograph of every component that is surveyed during the monitoring survey is not required. The photograph 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. This could include a ''still'' image taken using OGI technology or a digital photograph taken of the survey being performed. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the affected facility with a photograph of a separately operating Geographic Information Systems (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. The owner or operator would also be required to keep a log for each affected facility. The log must include the date monitoring surveys were performed, the technology used to perform the survey, the monitoring frequency required at the time of the survey, the number and types of equipment found to have fugitive emissions, the date or dates of first attempt to repair the source of fugitive emissions, the final repair of each source of fugitive emissions, any source of fugitive emissions found to be technically infeasible or unsafe to repair during unit operation and the date that source is scheduled to be repaired. These digital photographs and logs must be available at the affected facility or the field office. We solicit comment on whether these records also should be sent directly to the permitting agency electronically to facilitate review remotely. The owner or operator would also be required to develop and maintain a corporate-wide and site specific monitoring plan enabling the fugitive emissions monitoring program.

Annual reports for each fugitive emissions affected facility would have to be submitted that include the date monitoring surveys were performed, the technology used to perform the survey, the monitoring frequency required at the time of the survey, the number and types of component found to have fugitive emissions, the date of first attempt to repair the source of fugitive emissions, the date of final repair of each source of fugitive emissions, any source of fugitive emissions found to be technically infeasible or unsafe to repair during unit operation and the date that source is scheduled to be repaired.

Consistent with the current requirements of subpart OOOO, records must be retained for 5 years and generally consist of the same information required in the initial notification and annual reports. The records may be maintained either onsite or at the nearest field office. We solicit comment on whether these records also should be sent directly to the permitting agency electronically to facilitate review remotely.

Lastly, the EPA realizes that duplicative recordkeeping and reporting requirements may exist between the NSPS, Subpart W, and other state and local rules, and is trying to minimize overlapping requirements on operators. We solicit comment on ways to minimize recordkeeping and reporting burden.

VIII. Rationale for Proposed Action for NSPS

The following sections provide our BSER analyses and the resulting proposed new source performance standards to reduce methane and VOC emissions from across the oil and natural gas source category. Our general process for evaluating BSER for the emission sources discussed below included: (1) Identification of available control measures; (2) evaluation of these measures to determine emission reductions achieved, associated costs, nonair environmental impacts, energy impacts and any limitations to their application; and (3) selection of the control techniques that represent BSER.

As mentioned previously and discussed in more detail below, the control technologies available for reducing methane and VOC emissions are the same for the emissions sources in this source category. This observation was made in the 2014 white papers and confirmed by the comments received on the 2014 white papers, as well as state regulations, including those of Colorado, that require methane and VOC mitigation measures from these sources of emissions.

CAA Section 111 also requires that EPA considers cost in determining BSER. Section VIII.A below describes how EPA evaluates the cost of control for purposes of this rulemaking. Sections VIII.B through VIII.I provide the BSER analysis and the resulting proposed standards for individual emission sources contemplated in this action.

Please note that there are minor differences in some values presented in various documents supporting this action. This is because some calculations have been performed independently *(e.g.*, TSD calculations focused on unit-level cost-effectiveness and RIA calculations focused on national impacts) and include slightly different rounding of intermediate values.

A. How does EPA evaluate control costs in this action?

Section 111 requires that EPA consider a number of factors, including cost, in determining ''the best system of emission reduction . . . adequately demonstrated.'' While section 111 requires that EPA consider cost in determining such system (*i.e.*, ''BSER''), it does not prescribe any criteria for such consideration. However, in several cases, the D.C. Circuit has shed light on how EPA is to consider cost under CAA section 111(a)(1). For example, in *Essex Chemical Corp.* v. *Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), the D.C. Circuit stated that to be ''adequately demonstrated,'' the system must be ''reasonably reliable, reasonably efficient, and . . . reasonably expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.'' The Court has reiterated this limit in subsequent case law, including *Lignite Energy Council* v. *EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999), in which it stated: ''EPA's choice will be sustained unless the environmental or economic costs of using the technology are exorbitant.'' In *Portland Cement Ass'n* v. *EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975), the Court elaborated by explaining that the inquiry is whether the costs of the standard are ''greater than the industry could bear and survive.''[43] In *Sierra Club* v. *Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981), the Court provided a substantially similar formulation of the cost standard when it held: ''EPA concluded that the Electric Utilities' forecasted cost was not excessive and did not make the cost of compliance with the standard unreasonable. This is a judgment call with which we are not inclined to quarrel.'' We believe that these various formulations of the cost standard—''exorbitant,'' ''greater than the industry could bear and survive,'' ''excessive,'' and ''unreasonable''—are synonymous; the DC Circuit has made no attempt to distinguish among them. For convenience, in this rulemaking, we will use reasonable to describe our evaluation of costs well within the boundaries established by this case law.

In evaluating whether the cost of a control is reasonable, EPA considers various costs associated with such control, including capital costs and operating costs, and the emission reductions that the control can achieve. A cost-effectiveness analysis is one means of evaluating whether a given control achieves emission reduction at a reasonable cost. Cost-effectiveness analysis also allows comparisons of relative costs and outcomes (effects) of two or more options. In general, cost-effectiveness is a measure of the benefit produced by resources spent. In the context of air pollution control options, cost-effectiveness typically refers to the annualized cost of implementing an air pollution control option divided by the amount of pollutant reductions realized annually. A cost-effectiveness analysis is not intended to constitute or approximate a cost-benefits analysis but rather provides a metric of the relative cost to reduction ratios of various control options.

The estimation and interpretation of cost-effectiveness values is relatively straightforward when an abatement measure controls a single pollutant. Increasingly, however, air pollution reduction programs require reductions in emissions of multiple pollutants, and in such programs multipollutant controls may be employed. Consequently, there is a need for determining cost-effectiveness for a control option across multiple pollutants (or classes of multiple pollutants). This is the case for this proposal where, for the reasons explained in section V, we are proposing to directly regulate both methane and VOC. Further, as discussed

[43] The 1977 House Committee Report noted: In the [1970] Congress [sic: Congress's] view, it was only right that the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business. 1977 House Committee Report at 184. Similarly, the 1970 Senate Committee Report stated:

The implicit consideration of economic factors in determining whether technology is ''available'' should not affect the usefulness of this section. The overriding purpose of this section would be to prevent new air pollution problems, and toward that end, maximum feasible control of new sources at the time of their construction is seen by the committee as the most effective and, in the long run, the least expensive approach. S. Comm. Rep. No. 91–1196 at 16.

to provide for control of the highest emitting wells first, with other wells being included at a later date. We solicit comment on whether GOR of the well and production level of the well should be bases for the phasing of requirements for RECs. We also solicit suggestions for other ways to address a potential short-term REC equipment shortage that may hinder operators' compliance with the proposed NSPS. Additionally, we solicit comment on what an appropriate threshold should be for low production wells.

Finally, we solicit comment on criteria that could help clarify availability of gathering lines. Availability of a gathering line is one consideration affecting feasibility of recovery of natural gas during completion of hydraulically fractured wells. There are several factors that can affect availability of a gathering line including, but not limited to, the capacity of an existing gathering line to accept additional throughput, the ability of owners and operators to obtain rights of way to cross properties, and the distance from the well to an existing gathering line. We are aware that some states require collection of gas if a gathering line is present within a specific distance from the well. For example, Montana allows gas from wells to be flared only in cases where the well is farther than one-half mile from a gas pipeline.[94] We solicit comment on whether distance from a gathering line is a valid criterion on which to base requirements for gas recovery and, if so, what would an appropriate distance for such a threshold. In addition, we solicit comment on any other factors that could be specified in the NSPS for requiring recovery of gas from well completions.

3. Use of a Separator During Flowback

For subcategory 1, subcategory 2 and low pressure gas wells, the current NSPS at § 60.5375(a) and (f) requires routing of flowback to a separator unless it is technically infeasible for a separator to function. The NSPS also provides in § 60.5375(f) that subcategory 2 and low pressure wells are required to control emissions through combustion using a completion combustion device (which can include a pit flare) rather than being required to perform a REC. It was our understanding that a separator could be used at some point during the flowback period of every well completion. Recent information indicates that some wells, because of certain characteristics of the reservoir, do not need to employ a separator. In those cases, we understand that operators direct the flowback to a pit and can combust gas contained in the flowback as it emerges from the pipe. At some point, after the well has flowed sufficiently to clean up the wellbore and the gas is of salable quality, production begins or the well is temporarily shut in. As a result of this new information, our initial understanding may not apply.

We solicit comment on (1) the role of the separator in well completions and whether a separator can be employed for every well completion; and (2) the appropriate relationship of the separator in the context of our requirements that cover a very broad spectrum of wells. We solicit further information that would help inform our consideration of this issue as we seek to ensure we have adequately established appropriate requirements for all well completions subject to the NSPS.

G. Proposed Standards for Fugitive Emissions From Well Sites and Compressor Stations

In April 2014, the EPA published the white paper titled ''Oil and Natural Gas Sector Leaks'' [95] which summarized the EPA's current understanding of fugitive emissions of methane and VOC at onshore oil and natural gas production, processing, and transmission and storage facilities. The white paper also outlined our understanding of the mitigation techniques (practices and technology) available to reduce these emissions along with the cost and effectiveness of these practices and technologies.

The detection of fugitive emissions from oil and natural gas well sites and compressor stations, which are comprised of compressors at natural gas transmission, storage, gathering and boosting stations, can be determined using several technologies. Historically, fugitive emissions were detected using sensory monitoring (*e.g.,* visual, olfactory or sound) or EPA Method 21 to determine if a leak exceeded a set threshold (*e.g.,* the leak concentration was greater than the leak definition for the component). As described in the white paper, we found that many fugitive emission surveys are now conducted using OGI in the oil and natural gas source category, a technology that provides a visible image of gas emissions or leaks to the atmosphere. The OGI instrument works by using spectral wavelength filtering and an array of infrared detectors to visualize the infrared absorption of hydrocarbons and other gaseous compounds. As the gas absorbs radiant energy at the same waveband that the filter transmits to the detector, the gas and motion of the gas is imaged. The OGI instrument can be used for monitoring a large array of components at a facility and is an effective means of detecting fugitive emissions when the technology is used appropriately.

Several studies in the white paper estimated that OGI can monitor 1,875–2,100 components per hour. In comparison, the average screening rate using a Method 21 instrument (*e.g.,* organic vapor analyzer, flame ionization detector, flow measurement devices) is roughly 700 components per day. However, the EPA's recent work with OGI instruments suggests these studies underestimate the amount of time necessary to thoroughly monitor components for fugitive emissions using OGI instruments. Even though the amount of time may be underestimated, we believe the use of OGI can reduce the amount of time necessary to conduct fugitive emissions monitoring since multiple fugitive emissions components can be surveyed simultaneously, thus reducing the cost of identifying fugitive emissions in upstream oil and natural gas facilities when compared to using a handheld TVA or OVA, which requires a manual screening of each fugitive emissions component.

1. Fugitive Emissions From Well Sites

Fugitive emissions may occur for many reasons at well sites such as when connection points are not fitted properly, thief hatches are not properly weighted or sealed or when seals and gaskets start to deteriorate. Changes in pressure or mechanical stresses can also cause fugitive emissions. Potential sources of fugitive emissions, fugitive emissions components, include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines, pressure relief devices, pump seals, valves or open thief hatches or holes in storage vessels, pressure vessels, separators, heaters and meters. For purposes of this proposed rule, fugitive emissions do not include venting emissions from devices that vent as part of normal operations, such as gas-driven pneumatic controllers or gas-driven pneumatic pumps.

Based on our review of the public and peer review comments on the white paper and the Colorado and Wyoming state rules, we believe that there are two options for reducing methane and VOC fugitive emissions at well sites: (1) A

[94] Administrative Rules of Montana (ARM) Title 17 Chapter 8 Air Quality Subchapter 16—Emission Control Requirements for Oil and Gas Well Facilities Operating Prior to Issuance of a Montana Air Quality Permit. Emission Control Requirements, 17.8.1603 Available at: *http://www.deq.mt.gov/dir/legal/Chapters/Ch08-toc.mcpx.*

[95] Available at *http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf.*

fugitive emissions monitoring program based on individual component monitoring using EPA Method 21 for detection combined with repairs, or (2) a fugitive emissions monitoring program based on the use of OGI detection combined with repairs. Several public and peer reviewer comments on the white paper noted that these technologies are currently used by industry to reduce fugitive emissions from the production segment in the oil and natural gas industry.

Each of these control options are evaluated below based on varying the frequency of conducting the survey and fugitive emissions repair threshold (*e.g.,* the specified concentration when using Method 21 or visible identification of methane or VOC when an OGI instrument is used). For our analysis, we considered quarterly, semiannual and annual survey frequency. For Method 21 monitoring and repair, we considered 10,000 ppm, 2,500 ppm and 500 ppm fugitive repair thresholds. The leak definition concentrations for other NSPS referencing Method 21 range from 500–10,000 ppm. Therefore, we selected 500 ppm, 2,500 ppm and 10,000 ppm. For OGI, we considered visible emissions as the fugitive repair threshold (*i.e.,* emissions that can be seen using OGI instrumentation). EPA's recent work with OGI indicates that fugitive emissions at a concentration of 10,000 ppm are generally detectable using OGI instrumentation provided that the right operating conditions (*e.g.,* wind speed and background temperature) are present. Work is ongoing to determine the lowest concentration that can be reliably detected using OGI.[96]

In order to estimate fugitive methane and VOC emissions from well sites, we used fugitive emissions component counts from the GRI/EPA report[97] for natural gas production well sites, and fugitive emissions component counts from the GHG inventory and API for oil production well sites. The types of production equipment located at natural gas production well pads include: Gas wellheads, separators, meters/piping, heaters, and dehydrators. The types of oil well production equipment include: Oil well heads, separators, headers and heater/treaters. The types of fugitive emissions components that are associated with both oil and natural gas wells include but are not limited to: Valves, connectors, open-ended lines and valves (OEL), and pressure relief device (PRD). Fugitive emissions component counts for each piece of equipment in the gas production segment were calculated using the average fugitive emissions component counts in the Eastern U.S. and the Western U.S. from the EPA/GRI report. These data were used to develop a natural gas well site model plant. Fugitive emissions components counts for these equipment types in the oil production segment were obtained from an American Petroleum Institute (API) workbook.[98] These data were used to develop an oil production well site model plant.

Since we have emission factors for only a subset of the components which are possible sources for fugitive emissions, our emission estimates are believed to be lower than the emissions profile for the entire set of fugitive emissions components that would typically be found at a well site.

The fugitive emission factors from AP–42,[99] which provided a single source of total organic compounds (TOC) emission factors that include non-VOCs, such as methane and ethane, were used to estimate emissions and evaluate the cost of control of a fugitive emissions program for oil and natural gas production well sites. Using the AP–42 factors, the methane and VOC fugitive emissions from a natural gas well site are estimated to be 4.5 tpy and 1.3 tpy, respectively. For an oil production well site, the estimated fugitive methane and VOC emissions are 1.1 tpy and 0.3 tpy, respectively. The calculation of these emission estimates are explained in detail in the background TSD for this proposal available in the docket.

Information in the white paper related to the potential emission reductions from the implementation of an OGI monitoring program varied from 40 to 99 percent. The causes for this range in reduction efficiency were the frequency of monitoring surveys performed and different assumptions made by the study authors. According to the calculations, which are based on uncontrolled emission factors for well pads contained within the EPA Oil and Natural Gas Sector Technical Support Document (2011), the Colorado Air Quality Control Commission, *Initial Economic Impact Analysis for Proposed Revisions to Regulation Number 7 (5 CCR 1001–9)* and the *FINAL ECONOMIC IMPACT ANALYSIS For Industry's Proposed Revisions to Colorado Air Quality Control Commission Regulation Number 3, 6, and 7 (5 CCR 1001–9)* (January 30, 2014), a quarterly monitoring program in combination with a repair program can reasonably be expected to reduce fugitive methane and VOC emissions at well sites by 80 percent. Although information in the white paper indicated emission reductions as high as 99 percent may be achievable with OGI, we do not believe such levels can be consistently achieved for all of types of components that may be subject to a fugitive emissions monitoring program. Therefore, using engineering judgement and experience obtained through our existing programs for finding and repairing leaking components, we selected 80 percent as an emission reduction level that can reasonably be expected to be achieved with a quarterly monitoring program. Due to the increased amount of time between each monitoring survey and subsequent repair, we believe that the level of emissions reduction achieved by less frequent monitoring surveys will be reduced from this level. Therefore, we assigned an emission reduction of 60 percent to semiannual monitoring survey and repair frequency and 40 percent to annual frequency, consistent with the reduction levels used by the Colorado Air Quality Control Commission in their initial and final economic impacts analyses. We solicit comment on the appropriateness of the percentage of emission reduction level that can be reasonably expected to be achieved with quarterly, semiannual, and annual monitoring program frequencies.

For Method 21, we estimated emissions reductions using The EPA Equipment Leaks Protocol document, which provides emissions factor data based on leak definition and monitoring frequencies primarily for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) and Petroleum Refining Industry along with the emissions rates contained within the Technology Review for Equipment Leaks document.[100] We used these data along with the monitoring frequency (*e.g.,* annual, semiannual, and quarterly) at fugitive repair thresholds at 500, 2,500 and 10,000 ppm to determine uncontrolled emissions. Using this information we calculated an expected

[96] Draft Technical Support Document Appendices, Optical Gas Imaging Protocol (40 CFR part 60, Appendix K), August 11, 2015.

[97] Gas Research Institute/U.S. Environmental Protection Agency, Research and Development, Methane Emission Factors from the Natural Gas Industry, Volume 8, Equipment Leaks, June 1996 (EPA–600/R–96–080h).

[98] API Workbook 4638, 1996.

[99] U.S. Environmental Protection Agency, Protocol for Equipment Leak Emission Estimates, Table 2–4, November 1995 (EPA–453/R–95–017).

[100] Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA–HQ–OAR–2002–0037–0180.

emissions reduction percentage for each of the combinations of monitoring frequency and repair threshold.

We also looked at the costs of a monitoring and repair program under various monitoring frequencies and repair thresholds (for Method 21), including the cost of OGI monitoring survey, repair, monitoring plan development, and the cost-effectiveness of the various options.[101] For purposes of this action, we have identified in section VIII.A two approaches (single and multipollutant approaches) for evaluating the cost-effectiveness of a multipollutant control, such as the fugitive emissions monitoring and repair programs identified above for reducing both methane and VOC emissions. As explained in that section, we believe that both the single and multipollutant approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we find the cost of control to be warranted as long as it is such under either of these two approaches.

Under the first approach (single pollutant approach), we assign all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced. Under the second approach (multipollutant approach), we allocate the annualized cost across the pollutant reductions addressed by the control option in proportion to the relative percentage reduction of each pollutant controlled. In the multipollutant approach, since methane and VOC emissions are controlled proportionally equal, half the cost is apportioned to the methane emission reductions and half the cost is apportioned to the VOC emission reductions. In this evaluation, we evaluated both approaches across the range of identified monitoring survey options: OGI monitoring and repair performed quarterly, semiannually and annually; and Method 21 performed quarterly, semiannually and annually, with a fugitive emissions repair threshold of 500, 2,500 and 10,000 ppm at each frequency. The calculation of the costs, emission reductions, and cost of control for each option are explained in detail in the TSD. As shown in the TSD, while the costs for repairing components that are found to have fugitive emissions during a fugitive monitoring survey remain the same, the annual repair costs will differ based on monitoring frequency.

As shown in our TSD, both OGI and Method 21 monitoring survey methodologies costs generally increase with increasing monitoring frequency (i.e., quarterly monitoring has a higher cost of control than annual monitoring). For EPA Method 21 specifically, the cost also increases with decreasing fugitive emissions repair threshold (i.e., 500 ppm results in a higher cost of control than 10,000 ppm). However, as shown in the TSD, the cost of control based on the OGI methodology for annual, semiannual, and quarterly monitoring frequencies for a model well site are estimated to be more cost-effective than Method 21 for those same monitoring frequencies.[102] We therefore focus our BSER analysis based on the use of OGI.

For the reasons stated below, we find that the control cost based on quarterly monitoring using OGI may not be cost-effective based on the information available. As shown in the TSD, under the single pollutant approach, if all costs are assigned to methane and zero to VOC reduction, the cost is $3,753 per ton of methane reduced, and $3,521 per ton if savings of the natural gas recovered is taken into account. If all costs are assigned to VOC and zero to methane reduction, the cost is $13,502 per ton of VOC reduced, and $12,668 per ton if savings of the natural gas recovered is taken into account. Under the multipollutant approach, the cost of control for VOC based on quarterly monitoring is $6,751 per ton, and $6,334 per ton of VOC reduced if savings are considered. 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. Having found the control cost using OGI based on quarterly monitoring not to be cost-effective, we now evaluate the control cost based on annual and semi-annual monitoring using OGI. As shown in the TSD, the costs between annual and semi-annual monitoring are comparable. Because semi-annual monitoring achieves greater emissions reduction, we focus our analysis on the cost based on semi-annual monitoring.

While the cost appears high under the single pollutant approach, we find the costs to be reasonable under the multipollutant approach for the following reasons. As shown in the TSD, for VOC reduction, the cost is $4,979 per ton; when savings of the natural gas recovered are taken into account, the cost is reduced to $4,562 per ton. For methane reduction, the control cost is $1,384 per ton; when cost savings of the natural gas recovered is taken into account, the cost is reduced to $1,268 per ton. As explained above, we believe that we have underestimated the emissions from these well sites; therefore, we believe the use of OGI is more cost-effective than the amount presented here. Furthermore, while being used to survey fugitive components at a well site, the OGI may potentially help an owner and operator detect and repair other sources of visible emissions not covered by the NSPS. One example would be an intermittently acting pneumatic controller that is stuck open. The OGI could help the owner and operator detect and address and reduce such inadvertent emissions, resulting in more cost saving from more natural gas recovered.

We also identified in section VIII.A two additional approaches, based on new capital expenditures and annual revenues, for evaluating whether the costs are reasonable. For monitoring and repair of fugitive emissions at well sites, we believe that the total revenue analysis is more appropriate than the capital expenditure analysis and therefore we did not perform the capital expenditure analysis. For the total revenue analysis, we used the revenues for 2012 for NAICS 211111, 211112 and 213112, which we believe are representative of the production segment. The total annualized costs for complying with the proposed standards is 0.085 percent of the total revenues, which is very low.

For all types of affected facilities in the production, the total annualized costs for complying with the proposed standards is 0.13 percent of the total revenues, which is also very low.

For the reasons stated above, we find the cost of monitoring and repairing fugitive emissions at well sites based on semi-annual monitoring using OGI to be reasonable. To ensure that no fugitive emissions remain, a resurvey of the repaired components is necessary. We expect that most of the repair and resurveys are conducted at the same time as the initial monitoring survey while OGI personnel are still on-site. However, there may be some components that cannot not be repaired right away and in some instances not until after the initial OGI personnel are no longer on site. In that event, resurvey with OGI would require rehiring OGI personnel, which would make the resurvey not cost effective. On the other hand, as shown in TSD, the cost of conducting resurvey using Method 21 is $2 per component, which is reasonable.

[101] See pages 68–69 of the TSD.

[102] See the 2015 TSD for full comparison.

We did not find any nonair quality health and environmental impacts, or energy requirements associated with the use of OGI or Method 21 for monitoring, repairing and resurvey fugitive components at well sites. Based on the above analysis, we believe that the BSER for reducing fugitive methane and VOC emissions at well sites is a monitoring and repair standard based on semi-annual monitoring using OGI and resurvey using Method 21.

As mentioned above, OGI monitoring requires trained OGI personnel and OGI instruments. Many owners and operators, in particular small businesses, may not own OGI instruments or have staff who are trained and qualified to use such instruments; some may not have the capital to acquire the OGI instrument or provide training to their staff. While our cost analysis takes into account that owners and operators may need to hire contractors to perform the monitoring survey using OGI, we do not have information on the number of available contractors and OGI instruments. In light of our estimated 20,000 active wells in 2012 and that the number will increase annually, we are concerned that some owners and operators, in particular small businesses, may have difficulty securing the requisite OGI contractors and/or OGI instrumentation to perform monitoring surveys on a semi-annual basis. Larger companies, due to the economic clout they have by offering the contractors more work due to the higher number of wells they own, may preferentially retain the services of a large portion of the available contractors. This may result in small businesses experiencing a longer wait time to obtain contractor services. In light of the potential concern above, we are co-proposing monitoring survey on an annual basis at the same time soliciting comment and supporting information on the availability of trained OGI contractors and OGI instrumentation to help us evaluate whether owners and operators would have difficulty acquiring the necessary equipment and personnel to perform a semi-annual monitoring and, if so, whether annual monitoring would alleviate such problems.

Recognizing that additional data may be available, such as emissions from super emitters that may have higher emission factors than those considered in this analysis, we are also taking comment on requiring monitoring survey on a quarterly basis.

CAA section 111(h)(1) states that the Administrator may promulgate a work practice standard or other requirements, which reflects the best technological system of continuous emission reduction when it is not feasible to enforce an emission standard. CAA section 111(h)(2) defines the phrase ''not feasible to prescribe or enforce an emission standard'' as follows:

> [A]ny situation in which the Administrator determines that (A) a hazardous air pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or (B) the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.

The work practice standards for fugitive emissions from well sites are consistent with CAA section 111(h)(1)(A), because no conveyance to capture fugitive emissions exist for fugitive emissions components at a well site. In addition, OGI does not measure the extent the fugitive emissions from fugitive emissions components. For the reasons stated above, pursuant to CAA section 111(h)(1)(b), we are proposing work practice standards for fugitive emissions from the collection of fugitive emission components at well sites.

The proposed work practice standards include details for development of a fugitive emissions monitoring plan, repair requirements and recordkeeping and reporting requirements. The fugitive emissions monitoring plan includes operating parameters to ensure consistent and effective operation for OGI such as procedures for determining the maximum viewing distance and wind speed during monitoring. The proposed standards would require a source of fugitive emissions to be repaired or replaced as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. We have historically allowed 15 days for repair/resurvey in LDAR programs, which appears to be sufficient time. Further, in light of the number of components at a well site and the number that would need to be repaired, we believe that 15 days is also sufficient for conducting the required repairs under the proposed fugitive emission standards.[103] That said, we are also soliciting comment on whether 15 days is an appropriate amount of time for repair of sources of fugitive emissions at well sites.[104]

Many recent studies have shown a skewed distribution for emissions related to leaks, where a majority of emissions come from a minority of sources.[105] 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, we solicit comment on whether the fugitive emissions monitoring program should be limited to ''gross emitters.''

We believe that a properly maintained facility would likely detect very little to no fugitive emissions at each monitoring survey, while a poorly maintained facility would continue to detect fugitive emissions. As shown in our TSD, we estimate the number of fugitive emission components at a well site to be around 700. We believe that a facility with proper operation would likely find one to three percent of components to have fugitive emissions. To encourage proper maintenance, we are proposing that the owner or operator may go to annual monitoring if the initial two consecutive semiannual monitoring surveys show that less than one percent of the collection of fugitive emissions components at the well site has fugitive emissions. For the same reason, we are proposing that the owner or operator conduct quarterly monitoring if the initial two semi-annual monitoring surveys show that more than three percent of the collection of fugitive emissions components at the well site has fugitive emissions. We believe the first year to be the tune-up year to allow owners and operators the opportunity to refine the requirements of their monitoring/repair plan. After that initial year, the required monitoring frequency would be annual if a monitoring survey shows less than one percent of components to have fugitive emissions; semi-annual if one to three percent of total components have fugitive emissions; and quarterly if over three percent of total components have fugitive emissions. We solicit comment on this approach, including the percentage used to adjust the monitoring frequency. We also solicit comment on the appropriateness of performance based monitoring frequencies. We also solicit comment on the appropriateness of triggering different monitoring frequencies based on the percentage of components with fugitive emissions. Under the proposed standards, the affected facility would be

[103] In our TSD we estimate the number of fugitive emissions components to be around 700 and of those components we estimate that about 1 percent would need to be repaired.

[104] This timelines is consistent with the timeline originally established in 1983 under 40 CFR part 60 subpart VV.

[105]

defined as the collection of fugitive emissions components at a well site. To clarify which components are subject to the fugitive emissions monitoring provisions, we propose to add a definition to § 60.5430 for ''fugitive emissions component'' as follows:

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 a 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.

Thus, all fugitive emissions components at the affected facility would be monitored for fugitive emissions of methane and VOC.

For the reasons stated in section VII.G.1, for purposes of the proposed standards for fugitive emissions at well sites, modification of a well site is defined as when a new well is drilled or a well at the well site (where collection of fugitive emissions components are located) is hydraulically fractured or refractured. As explained in that section, other than these events, we are not aware of any other physical change to a well site that would result in an increase in emissions from the collection of fugitive components at such well site. To clarify and ease implementation, we propose to define ''modification'' to include only these two events for purposes of the fugitive emissions provisions at well sites.

In the 2012 NSPS, we provided that completion requirements do not apply to refracturing of an existing well that is completed responsibly (i.e. green completions). Building on the 2012 NSPS, the EPA intends to continue to encourage corporate-wide voluntary efforts to achieve emission reductions through responsible, transparent and verifiable actions that would obviate the need to meet obligations associated with NSPS applicability, as well as avoid creating disruption for operators following advanced responsible corporate practices. It has come to our attention that some owners and operators may already have in place, and are implementing, corporate-wide fugitive emissions monitoring and repair programs at their well sites that are equivalent to, or more stringent than our proposed standards. Such corporate efforts present the potential to further the development of LDAR technologies. To encourage companies to continue such good corporate policies and encourage advancement in the technology and practices, we solicit 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. We also solicit comment on how to address enforceability of such alternative approaches (i.e., how to assure that these well sites are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards). We recognize that meeting an NSPS performance level should not, standing alone, be a basis for a source not becoming an affected facility.

For the reasons stated above, we are also soliciting comments on criteria we can use to determine whether and under what conditions all new or modified well sites operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well sites fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining. We also solicit comment on how to address enforceability of such alternative approaches (i.e., how to assure that these well sites are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards).

We are requesting comment on whether the fugitive emissions requirements should apply to all fugitive emissions components at modified well sites or just to those components that are connected to the fractured, refractured or added well. For some modified well sites, the fractured or refractured or added well may only be connected to a subset of the fugitive emissions components on site. We are soliciting comment on whether the fugitive emission requirements should only apply to that subset. However, we are aware that the added complexity of distinguishing covered and non-covered sources may create difficulty in implementing these requirements. However, we note that it may be advantageous to the operator from an operational perspective to monitor all the components at a well site since the monitoring equipment is already onsite.

As explained above, Method 21 is not as cost-effective as OGI for monitoring. That said, there may be reasons why and owner and operator may prefer to use Method 21 over OGI. While we are confident with the ability of Method 21 to detect fugitive emissions and therefore consider it a viable alternative to OGI, we solicit comment on the appropriate fugitive emissions repair threshold for Method 21 monitoring surveys. As mentioned above, EPA's recent work with OGI indicates that fugitive emissions at a concentration of 10,000 ppm is generally detectable using OGI instrumentation provided that the right operating conditions (e.g., wind speed and background temperature) are present. Work is ongoing to determine the lowest concentration that can be reliably detected using OGI As mentioned above, we believe that OGI. In light of the above, we solicit comment on whether the fugitive emissions repair threshold for Method 21 monitoring surveys should be set at 10,000 ppm or whether a different threshold is more appropriate (including information to support such threshold).

While we did not identify OGI as the BSER for resurvey because of the potential cost associated with rehiring OGI personnel, there is no such additional cost for those who either own the OGI instrument or can perform repair/resurvey at the same time. Therefore, the proposed rule would allow the use either OGI or Method 21 for resurvey. When Method 21 is used to resurvey components, we are proposing that the component is repaired if the Method 21 instrument indicates a concentration less than 500 ppm above background. This has been historically used in other LDAR programs as an indicator of no detectable emissions.

The proposed standards would require that operators begin monitoring fugitive emissions components at a well site within 30 days of the initial startup of the first well completion for a new well or within 30 days of well site modification. We are proposing a 30 day period to allow owners and operators the opportunity to secure qualified contractors and equipment necessary for the initial monitoring survey. We are requesting comment on whether 30 days is an appropriate amount of time to begin conducting fugitive emissions monitoring.

We received new information indicating that some companies could experience logistical challenges with the availability of OGI instrumentation and qualified OGI technicians and operators to perform monitoring surveys and in some instances repairs. We solicit comment on both the availability of OGI instruments and the availability of qualified OGI technicians and operators to perform surveys and repairs.

We are proposing to exclude low production well sites (i.e., a low production site is defined by the average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production) [106] from the standards for fugitives emissions from well sites. We believe the lower production associated with these wells would generally result in lower fugitive emissions. It is our understanding that fugitive emissions at low production well sites are inherently low and that such well sites are mostly owned and operated by small businesses. We are concerned about the burden of the fugitive emission requirement on small businesses, in particular where there is little emission reduction to be achieved. To more fully evaluate the exclusion, we solicit comment on the air emissions associated with low production wells, and the relationship between production and fugitive emissions. Specifically, we solicit comment on the relationship between production and fugitive emissions over time. While we have learned that a daily average of 15 barrel per day is representative of low production wells, we solicit comment on the appropriateness of this threshold for applying the standards for fugitive emission at well sites. Further, we solicit comment on whether EPA should include low production well sites for fugitive emissions and if these types of well sites are not excluded, should they have a less frequent monitoring requirement.

We are also requesting comment on whether there are well sites that have inherently low fugitive emissions, even when a new well is drilled or a well site is fractured or refractured and, if so, descriptions of such type(s) of well sites. The proposed standards are not intended to cover well sites with no fugitive emissions of methane or VOC. We are aware that some sites may have inherently low fugitive emissions due to the characteristics of the site, such as the gas to oil ratio of the wells or the specific types of equipment located on the well site. We solicit comment on these characteristics and data that would demonstrate that these sites have low methane and VOC fugitive emissions.

We are requesting comment on whether there are other fugitive emission detection technologies for fugitive emissions monitoring, since this is a field of emerging technology and major advances are expected in the near future. We are aware of several types of technologies that may be appropriate for fugitive emissions monitoring such as Geospatial Measurement of Air Pollutants using OTM–33 approaches (*e.g.,* Picarro Surveyor), passive sorbent tubes using EPA Methods 325A and B, active sensors, gas cloud imaging (*e.g.,* Rebellion photonics), and Airborne Differential Absorption Lidar (DIAL). Therefore, we are specifically requesting comments on details related to these and other technologies such as the detection capability; an equivalent fugitive emission repair threshold to what is required in the proposed rule for OGI; the frequency at which the fugitive emissions monitoring surveys should be performed and how this frequency ensures appropriate levels of fugitive emissions detection; whether the technology can be used as a stand-alone technique or whether it must be used in conjunction with a less frequent (and how frequent) OGI monitoring survey; the type of restrictions necessary for optimal use; and the information that is important for inclusion in a monitoring plan for these technologies.

2. Fugitive Emissions From Compressor Stations

Fugitive emissions at compressor stations in the oil and natural gas source category may occur for many reasons (*e.g.,* when connection points are not fitted properly, or when seals and gaskets start to deteriorate). Changes in pressure and mechanical stresses can also cause fugitive emissions. Potential sources of fugitive emissions include agitator seals, distance pieces, crank case vents, blowdown vents, connectors, pump seals or diaphragms, flanges, instruments, meters, open-ended lines, pressure relief devices, valves, open thief hatches or holes in storage vessels, and similar items on glycol dehydrators (*e.g.,* pumps, valves, and pressure relief devices). Equipment that vents as part of normal operations, such as gas driven pneumatic controllers, gas driven pneumatic pumps or the normal operation of blowdown vents are not considered to be sources of fugitive emissions.

Based on our review of the public and peer review comments on the white paper and the Colorado and Wyoming state rules, we believe that there are two options for reducing methane and VOC fugitive emissions at compressor stations: (1) A fugitive emissions monitoring program based on individual component monitoring using EPA Method 21 for detection combined with repairs, or (2) a fugitive emissions monitoring program based on the use of OGI detection combined with repairs. Several public and peer reviewer comments on the white paper noted that these technologies are currently used by industry to reduce fugitive emissions from the production segment in the oil and natural gas industry.

Each of these control options are evaluated below based on varying the frequency of conducting the monitoring survey and fugitive emissions repair threshold (*e.g.,* the specified concentration when using Method 21 or visible identification of methane or VOC when an OGI instrument is used). For our analysis, we considered quarterly, semiannual and annual monitoring frequencies. For Method 21, we considered 10,000 ppm, 2,500 ppm and 500 ppm fugitive repair thresholds. The leak definitions for other NSPS referencing Method 21 range from 500–10,000 ppm. Therefore, we selected 500 ppm, 2,500 ppm and 10,000 ppm. For OGI, we considered visible emissions as the fugitive repair threshold (*i.e.,* emissions that can be seen using OGI). EPA's recent work with OGI indicate that fugitive emissions at a concentration of 10,000 ppm are generally detectable using OGI instrumentation, provided that the right operating conditions (*e.g.,* wind speed and background temperature) are present. Work is ongoing to determine the lowest concentration that can be reliably detected using OGI.[107]

In order to estimate fugitive emissions from compressor stations, we used component counts from the GRI/EPA report [108] for each of the compressor station segments. Fugitive emission factors from AP–42 [109] were used to estimate emissions from gathering and boosting stations in the production

[106] For the purposes of this discussion, we define 'low production well' as a well with an average daily production of 15 barrel equivalents or less. This reflects the definition of a stripper well property in IRC 613A(c)(6)(E).

[107] Draft Technical Support Document Appendices, Optical Gas Imaging Protocol (40 CFR part 60, Appendix K), August 11, 2015.

[108] Gas Research Institute/U.S. Environmental Protection Agency, Research and Development, Methane Emission Factors from the Natural Gas Industry, Volume 8, Equipment Leaks, June 1996 (EPA–600/R–96–080h).

[109] Environmental Protection Agency, Protocol for Equipment Leak Emission Estimates, Table 2–4, November 1995 (EPA–453/R–95–017).

segment and emission factors from the GRI/EPA report were used to estimate fugitive emission from transmission and storage compressor stations and evaluate the cost of control for these segments.

Since we have emission factors for only a subset of the components which are possible sources for fugitive emissions, our emission estimates are believed to be lower than the emissions profile for the entire set of components that would typically be found at a compressor station.

The fugitive emission factors from AP–42,[110] which provided a single source of TOC emission factors that include non-VOCs, such as methane and ethane, were used to estimate emissions and evaluate the cost of control of a fugitive emissions program for compressor stations. Using the GRI/EPA and AP–42 data, fugitive emissions from gathering and boosting stations were estimated to be 35.1 tpy of methane and 9.8 tpy of VOC. Fugitive emissions from natural gas transmission stations were estimated to be 62.4 tpy of methane and 1.7 tpy of VOC. Fugitive emissions from natural gas storage facilities were estimated to be 164.4 tpy of methane and 4.6 tpy of VOC. The calculation of these emission estimates are explained in detail in the TSD available in the docket.

Information in the white paper related to the potential emission reductions from the implementation of an OGI monitoring program varied from 40 to 99 percent. The causes for this range in reduction efficiency were the frequency of monitoring surveys performed and different assumptions made by the study authors. According to the calculations, which are based on uncontrolled emission factors for well pads contained within the EPA Oil and Natural Gas Sector Technical Support Document (2011), the Colorado Air Quality Control Commission, *Initial Economic Impact Analysis for Proposed Revisions to Regulation Number 7 (5 CCR 1001–9) and the FINAL ECONOMIC IMPACT ANALYSIS For Industry's Proposed Revisions to Colorado Air Quality Control Commission Regulation Number 3, 6, and 7 (5 CCR 1001–9)* (January 30, 2014), a -quarterly monitoring program in combination with a repair program can reasonably be expected to reduce fugitive methane and VOC emissions at well sites by 80 percent. Although information in the white paper indicated emission reductions as high as 99 percent may be achievable with OGI, we do not believe such levels can be consistently achieved for all of types of components that may be subject to a fugitive emissions monitoring program. Therefore, using engineering judgement and experience obtained through our existing programs for finding and repairing leaking components, we selected 80 percent as an emission reduction level that can reasonably be expected to be achieved with a quarterly monitoring program. Due to the increased amount of time between each monitoring survey and subsequent repair, we believe that the level of emissions reduction achieved by less frequent monitoring surveys will be reduced from this level. Therefore, we assigned an emission reduction of 60 percent to semiannual monitoring survey and repair frequency and 40 percent to annual frequency, consistent with the reduction levels used by the Colorado Air Quality Control Commission in their initial and final economic impacts analyses. We solicit comment on the appropriateness of the percentage of emission reduction level that can be reasonably expected to be achieved with quarterly, semiannual, and annual monitoring program frequencies.

For Method 21, we estimated emissions reductions using The EPA Equipment Leaks Protocol document, which provides emissions factor data based on leak definition and monitoring frequencies primarily for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) and Petroleum Refining Industry along with the emissions rates contained within the Technology Review for Equipment Leaks document.[111] We used these data along with the monitoring frequency (*e.g.*, annual, semiannual, and quarterly) at fugitive repair thresholds at 500, 2,500 and 10,000 ppm to determine uncontrolled emissions. Using this information we calculated an expected emissions reduction percentage for each of the combinations of monitoring frequency and repair threshold which range from.

We also looked at the costs of a monitoring and repair program under various monitoring frequencies and repair thresholds (for Method 21), including the cost of OGI monitoring survey, repair, monitoring plan development, and the cost-effectiveness of the various options.[112] For purposes of this action, we have identified in section VIII.A two approaches (single pollutant and multipollutant approaches) for evaluating whether the cost of a multipollutant control, such as the fugitive emissions monitoring and repair programs identified above, is reasonable. As explained in that section, we believe that both approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we find the cost of control to be reasonable as long as it is such under either of these two approaches.

Under the first approach (single pollutant approach), we assign all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced. Under the second approach (multipollutant approach), we apportion the annualized cost across the pollutant reductions addressed by the control option in proportion to the relative percentage reduction of each pollutant controlled. In the multipollutant approach, since methane and VOC are controlled equally, half the cost is apportioned to the methane emission reductions and half the cost is apportioned to the VOC emission reductions. In this evaluation, we evaluated both approaches across the range of identified monitoring survey options: OGI monitoring and repair performed quarterly, semiannually and annually; and Method 21 monitoring performed quarterly, semiannually and annually, with a fugitive emissions repair threshold of 500, 2,500 and 10,000 ppm at each frequency. The calculation of the costs, emission reductions, and cost of control for each option are explained in detail in the TSD. As shown in the TSD, while the costs for repairing components that are found to have fugitive emissions during a fugitive monitoring survey remain the same, the annual repair costs will differ based on monitoring frequency.

As shown in our TSD, both OGI and Method 21 monitoring survey methodologies costs generally increase with increasing monitoring frequency (*i.e.*, quarterly monitoring has a higher cost of control than annual monitoring). For EPA Method 21 specifically, the cost also increases with decreasing fugitive emissions repair threshold (*i.e.*, 500 ppm results in a higher cost of control than 10,000 ppm). However, as shown in the TSD, the cost of control based on the OGI methodology for annual, semiannual, and quarterly monitoring frequencies are estimated to be more cost-effective than Method 21 for those same monitoring

[110] U.S. Environmental Protection Agency, Protocol for Equipment Leak Emission Estimates, Table 2–4, November 1995 (EPA–453/R–95–017).

[111] Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA–HQ–OAR–2002–0037–0180

[112] See pages 68–69 of the TSD.

frequencies.[113] We therefore focus our BSER analysis based on the use of OGI.

As shown in the TSD, the costs are comparable for all three monitoring frequencies using OGI. For the reasons explained below, we find the monitoring/repair program using OGI at compressor stations to be cost-effective for all three monitoring frequencies. Under the single pollutant approach, if we assign all control costs to VOC and zero to methane reduction, the costs range from $3,110 to $4,273 per ton of VOC reduced ($2,338 to $3,502 with gas saving) and zero for methane, which indicate that the control is cost-effective. Even if we assign all of the costs to methane and zero to VOC reduction, the costs, which range from $686 to $930 per ton of methane reduced ($471 to $715 per ton with gas savings), are well below our cost-effectiveness estimates for the semi-annual monitoring and repair option for reducing fugitive emissions at compressor stations, which we find to be reasonable for the reasons stated above. Under the multipollutant approach, the costs for VOC reduction range from $1,555 to $2,136 ($1,169 to $1,751 with gas saving). The costs for methane reduction range from $343 to $465 per ton ($236 to $358 per ton with gas savings). Again these cost estimates for methane reductions are well below our estimates for the monitoring/repair program at compressor stations using OGI based on semiannual monitoring, which we find to be reasonable for the reasons stated above. Further, as previously explained, we believe the emission reduction values used in these calculations underestimate the actual emission reductions that would be achieved by a fugitives monitoring and repair program, so these cost of control values likely represent a high end cost assumption. Therefore, we believe the use of OGI is more cost-effective than the amounts presented here. The calculation of the costs, emission reductions, and cost of control calculations for each option are explained in detail in the TSD for this action available in the docket.

While the costs are comparable for all three monitoring frequencies using OGI, for the reasons stated below, we have concerns with the potential compliance burdens, in particular on small businesses, associated with quarterly monitoring, and we believe that semi-annual monitoring could achieve meaningful reduction without such potential issues.

Further practical aspects we considered for the methodology of each monitoring survey include the likeliness that many owners and operators will hire a contractor to conduct the monitoring survey due to the cost of the specialized equipment needed to perform the monitoring survey and the training necessary to properly operate the OGI equipment. We also believe that small businesses are most likely to hire such contractors because they are less likely to have excess capital to purchase monitoring equipment and train operators. We are concerned that the limited supply of qualified contractors to perform monitoring surveys may lead to disadvantages for small businesses. Larger businesses, due to the economic clout they have by offering the contractors more work due to the higher number of compressor stations they own, may preferentially retain the services of a large portion of the available contractors. This may result in small businesses experiencing a longer wait time to obtain contractor services.

Specifically for conducting OGI monitoring surveys, we believe that many operators will hire OGI contractors to conduct the OGI surveys. The proposed fugitive emissions monitoring plan requires that operators verify the capability of OGI instrumentation, determine viewing distance, and determine the maximum wind speed. Additionally, there are specific requirements for conducting the survey such as how to operate OGI in adverse monitoring conditions or how to deal with interferences such as steam. Each corporate-wide plan will need to include these requirements and will require OGI contractors and operators to be trained to meet these requirement. The monitoring plan requirements will also cause the surveys to take more time, thus affecting the availability of OGI equipment and contractors. Therefore, if we specify quarterly monitoring surveys, we are concerned that the available supply of qualified contractors and OGI instruments may not be sufficient for small businesses to obtain timely monitoring surveys. For the reasons stated above, we have concerns with the potential compliance burdens, in particular on small businesses, associated with quarterly monitoring, and we believe that semi-annual monitoring could achieve meaningful reduction without such potential issues.

We also identified in section VIII.A two additional approaches, based on new capital expenditures and annual revenues, for evaluating whether the costs are reasonable. For monitoring and repair of fugitive emissions at compressor stations, we believe that the total revenue analysis is more appropriate than the capital expenditure analysis and therefore we did not perform the capital expenditure analysis. For the total revenue analysis, we used the revenues for 2012 for NAICS 486210, which we believe is representative of the production segment. The total annualized costs for complying with the proposed standards is 0.103 percent of the total revenues, which is very low.

For all types of affected facilities in the transmission and storage segment, the total annualized costs for complying with the proposed standards is 0.13 percent of the total revenues, which is also very low.

For the reasons stated above, we find the cost of monitoring and repairing fugitive emissions at compressor stations based on semi-annual monitoring using OGI to be reasonable. To ensure that no fugitive emissions remain, a resurvey of the repaired components is necessary. We expect that most of the repair and resurveys are conducted at the same time as the initial monitoring survey while OGI personnel are still on-site. However, there may be some components that cannot be repaired right away and in some instances not until after the initial OGI personnel are no longer on site. In that event, resurvey with OGI would require rehiring OGI personnel, which would make the resurvey not cost effective. On the other hand, as shown in the TSD, the cost of conducting a resurvey using Method 21 is $2 per component, which is reasonable.

We did not find any nonair quality health and environmental impacts, or energy requirements associated with the use of OGI or Method 21 for monitoring, repairing and resurveying fugitive emissions components at compressor stations. Based on the above analysis, we believe that the BSER for reducing fugitive methane and VOC emissions at compressor stations is a monitoring and repair standard based on semi-annual monitoring using OGI and resurvey using Method 21.

Although we identified OGI with semiannual monitoring as the BSER, we acknowledge that some states have promulgated rules that allow for annual monitoring of fugitive emission sources. In addition, EPA regulates GHGs in 40 CFR part 98 subpart W and requires annual fugitive emissions surveys for emissions reporting. As previously discussed we believe that we have underestimated our baseline fugitive emissions estimate for well sites and compressors and the emission reductions may be greater than we have estimated. However, because we continue to support efforts by states to

[113] See the 2015 TSD for full comparison.

establish fugitive emissions monitoring programs and to establish efficiencies across programs, we solicit comment on an alternate option for the fugitive emission monitoring program based on setting the initial monitoring frequency to an annual or quarterly frequency.

CAA section 111(h)(1) states that the Administrator may promulgate a work practice standard or other requirements, which reflects the best technological system of continuous emission reduction when it is not feasible to enforce an emission standard. CAA section 111(h)(2) defines the phrase ''not feasible to prescribe or enforce an emission standard'' as follows:

> [A]ny situation in which the Administrator determines that (A) a hazardous air pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or (B) the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.

The work practice standards for fugitive emissions from compressor stations are consistent with CAA section 111(h)(1)(A), because no conveyance to capture fugitive emissions exist for fugitive emissions components. In addition, OGI does not measure the extent the fugitive emissions from fugitive emissions components. For the reasons stated above, pursuant to CAA section 111(h)(1)(b), we are proposing work practice standards for fugitive emissions from compressor stations.

The proposed work practice standards include details for development of a fugitive emissions monitoring plan, repair requirements and recordkeeping and reporting requirements. The fugitive emissions monitoring plan includes operating parameters to ensure consistent and effective operation for OGI such as procedures for determining the maximum viewing distance and wind speed during monitoring. The proposed standards would require a source of fugitive emissions to be repaired or replaced as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. We have historically allowed 15 days for repair/resurvey in LDAR programs, which appears to be sufficient time. Further, in light of the number of components at a compressor station and the number that would need to be repaired, we believe that 15 days is also sufficient for conducting the required repairs under the proposed fugitive emission standards. That said, we are also soliciting comment on whether 15 days is an appropriate amount of time for repair of sources of fugitive emissions at compressor stations.[114]

Many recent studies have shown a skewed distribution for emissions related to leaks, where a majority of emissions come from a minority of sources.[115] 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 methane and VOC fugitive emissions come from a minority of components (*e.g.*, gross emitters). Based on this information, we solicit comment on whether the fugitive emissions monitoring program should be limited to ''gross emitters.''

We believe that a properly maintained facility would likely detect very little to no fugitive emissions at each monitoring survey, while a poorly maintained facility would continue to detect fugitive emissions. We believe that a facility with proper operation would likely find one to three percent of components to have fugitive emissions. To encourage proper maintenance, we are proposing that the owner or operator may go to annual monitoring if the initial two consecutive semiannual monitoring surveys show that less than one percent of the collection of fugitive emissions components at the compressor station has fugitive emissions. For the same reason, we are proposing that the owner or operator conduct quarterly monitoring if the initial two semi-annual monitoring surveys show that more than three percent of the collection of fugitive emissions components at the compressor station has fugitive emissions. We believe the first year to be the tune-up year to allow owners and operators the opportunity to refine the requirements of their monitoring/repair plan. After that initial year, the required monitoring frequency would be annual if a monitoring survey shows less than one percent of components to have fugitive emissions; semi-annual if one to three percent of total components have fugitive emissions; and quarterly if over three percent of total components have fugitive emissions. We solicit comment on this approach, including the percentage used to adjust the monitoring frequency. We also solicit comment on the appropriateness of performance based monitoring frequencies. We also solicit comment on the appropriateness of triggering different monitoring frequencies based on the percentage of components with fugitive emissions.

Under the proposed standards, the affected facility would be defined as the collection of fugitive emissions components at a compressor station. To clarify which components are subject to the fugitive emissions monitoring provisions, we propose to add a definition to § 60.5430 for ''fugitive emissions component'' as follows:

> 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 a natural gas-driven pneumatic controller or a natural gas-driven pump, 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.

Thus, all fugitive emissions components at the affected facility would be monitored for fugitive emissions of methane and VOC.

For the reasons stated in section VII.G.2, for purposes of the proposed standards for fugitive emission at compressor stations, we propose that a modification occurs only when a compressor is added to the compressor station or when physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station. As explained in that section, since fugitive emissions at compressor stations are from compressors and their associated piping, connections and other ancillary equipment, expansion of compression capacity at a compressor station, either through addition of a compressor or physical change to the an existing compressor, would result in an increase in emissions to the fugitive emissions components. Other than these events, we are not aware of any other physical change to a compressor station that would result in an increase in emissions from the collection of fugitive components at such compressor station. To provide clarity and ease of implementation, for the purposes of the proposed standards for fugitive emissions at compressor stations, we are proposing to define modification as the

[114] This timeline is consistent with the timeline originally established in 1983 under 40 CFR part 60 subpart VV.

[115] See 2015 TSD.

addition of a compressor at an existing compressor station or when a physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station.

To encourage broadly applied fugitive emissions monitoring, we are also soliciting comments on criteria we can use to determine whether and under what conditions all new or modified compressor stations operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for compressor stations fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining. We also solicit comment on how to address enforceability of such alternative approaches (*i.e.*, how to assure that these compressor stations are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards).

We are requesting comment on whether the fugitive emissions requirements should apply to all of the fugitive emissions sources at the compressor station for modified compressor stations or just to fugitive sources that are connected to the added compressor. For some modified compressor stations, the added compressor may only be connected to a subset of the fugitive emissions sources on site. We are soliciting comment on whether the fugitive emission requirements should only apply to that subset. However, we are aware that the added complexity of distinguishing covered and non-covered sources may create difficulty in implementing these requirements. However, we note that it may be advantageous to the operator from an operational perspective to monitor all the components at a compressor station since the monitoring equipment is already onsite.

As explained above, Method 21 is not as cost-effective as OGI for monitoring. That said, there may be reasons why and owner and operator may prefer to use Method 21 over OGI. While we are confident with the ability of Method 21 to detect fugitive emissions and therefore consider it a viable alternative to OGI, we solicit comment on the appropriate fugitive emissions repair threshold for Method 21 monitoring surveys. As mentioned above, EPA's recent work with OGI indicates that fugitive emissions at a concentration of 10,000 ppm is generally detectable using OGI instrumentation provided that the right operating conditions (*e.g.*, wind speed and background temperature) are present. Work is ongoing to determine the lowest concentration that can be reliably detected using OGI As mentioned above, we believe that OGI. In light of the above, we solicit comment on whether the fugitive emissions repair threshold for Method 21 surveys should be set at 10,000 ppm or whether a different threshold is more appropriate (including information to support such threshold).

While we did not identify OGI as the BSER for resurvey because of the potential cost associated with rehiring OGI personnel, there is no such additional cost for those who either own the OGI instrument or can perform repair/resurvey at the same time. Therefore, the proposed rule would allow the use either OGI or Method 21 for resurvey. When Method 21 is used to resurvey components, we are proposing that the component is repaired if the Method 21 instrument indicates a concentration of less than 500 ppm above background. This has been historically used in other LDAR programs as an indicator of no detectable emissions.

The proposed standards would require that operators begin monitoring fugitive emissions components at compressor stations with 30 days of the initial startup of a new compressor station or within 30 days of a modification of a compressor station. We are proposing 30 day period to allow owners and operators the opportunity to secure qualified contractors and equipment necessary for the initial monitoring survey. We are requesting comment on whether 30 days is an appropriate amount of time to begin conducting fugitive emissions monitoring.

We received new information indicating that some companies could experience logistical challenges with the availability of OGI instrumentation and qualified OGI personnel to perform monitoring surveys and in some instances repairs. We solicit comment on both the availability of OGI instruments and the availability of qualified OGI personnel to perform monitoring surveys and repairs.

We are requesting comment on whether there are other fugitive emission detection technologies for fugitive emissions monitoring, since this is a field of emerging technology and major advances are expected in the near future. We are aware of several types of technologies that may be appropriate for fugitive emissions monitoring such as Geospatial Measurement of Air Pollutants using OTM–33 approaches (*e.g.,* Picarro Surveyor), passive sorbent tubes using EPA Methods 325A and B, active sensors, gas cloud imaging (*e.g.,* Rebellion photonics), and Airborne Differential Absorption Lidar (DIAL). Therefore, we are specifically requesting comments on details related to these and other technologies such as the detection capability; an equivalent fugitive emission repair threshold to what is required in the proposed rule for OGI; the frequency at which the fugitive emissions monitoring survey should be performed and how this frequency ensures appropriate levels of fugitive emissions detection; whether the technology can be used as a stand-alone technique or whether it must be used in conjunction with a less frequent (and how frequent) OGI monitoring survey; the type of restrictions necessary for optimal use; and the information that is important for inclusion in a monitoring plan for these technologies.

H. Proposed Standards for Equipment Leaks at Natural Gas Processing Plants

In the 2012 NSPS, we established VOC standards for equipment leaks at onshore natural gas processing plants in the oil and natural gas source category. In this action, we are proposing methane standards for onshore natural gas processing plants. Based on the analysis below, the proposed methane standards are the same as the VOC standards currently in the NSPS.

Natural gas is primarily made up of methane. However, whether natural gas is associated gas from oil wells or non-associated gas from gas or condensate wells, it commonly exists in mixtures with other hydrocarbons. These hydrocarbons are often referred to as natural gas liquids (NGL). They are sold separately and have a variety of different uses. The raw natural gas often contains water vapor, H_2S, CO_2, helium, nitrogen and other compounds. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produced ''pipeline quality'' dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover NGL or other nonmethane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: Oil and condensate separation, water removal, separation of NGL, sulfur and CO_2 removal, fractionation of natural gas liquid and other processes, such as the capture of CO_2 separated from natural gas streams for delivery outside the facility.

In the analysis for the 2012 NSPS, we estimated nationwide methane emissions from equipment leaks at onshore natural gas processing plants to be 51.4 tpy. We identified four control options for reducing methane emissions from these equipment leaks in the 2012 TSD: (1) Subpart VVa level of control; (2) monthly survey using optical gas imaging (OGI) and an annual Method 21 survey; (3) monthly OGI survey without the annual Method 21 survey; and (4) annual OGI survey.

In April 2014, the EPA published the white paper titled ''Oil and Natural Gas Sector Leaks''[116] which summarized the EPA's current understanding of fugitive emissions of methane and VOC at onshore oil and natural gas production, processing, and transmission and storage facilities. The white paper also outlined our understanding of the available mitigation techniques (practices and equipment) available to reduce these emissions along with the cost and effectiveness of these practices and technologies. Based on our review of the public and peer review comments on the white paper and our additional research, we did not identify any additional control options beyond those that we identified for the 2012 NSPS.

For purposes of this action, we have identified two approaches in section VIII.A for evaluating whether the cost of a multipollutant control, such as the leak detection and repair programs described above, is reasonable. As explained in that section above, we believe that both approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we find the cost of control to be reasonable as long as it is such under either of these two approaches.

Under the first approach (single pollutant approach), which assigns all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced, we find the cost of control reasonable if it is reasonable for reducing one pollutant alone. The annualized costs for option 1 (subpart VVa level of control) is $45,160 without considering the cost savings of the recovered natural gas, and $33,915 considering the cost savings. We estimate the cost of reducing methane emissions from equipment leaks at natural gas processing plants under this option to be $931 per ton. The annualized costs for option 2 (monthly survey using OGI and annual Method 21 survey) is $87,059 without considering the cost savings of the recovered natural gas, and $75,813 considering the cost savings. We estimate the cost of reducing methane emissions from equipment leaks at natural gas processing plants under this option to be $1,795 per ton. At the time of the analysis for the 2012 NSPS, we were unable to estimate the methane emission reduction of options 3 (monthly OGI survey) and 4 (annual OGI survey-only programs) since OGI currently does not have the capability to quantify emissions.

We find the costs for methane emission reductions for option 1 (subpart VVa level of control) to be reasonable for the amount of methane emissions it can achieve. Also, because all of the costs have been attributed to methane reduction, the cost of simultaneous VOC reduction is zero and therefore reasonable.[117]

Although we propose to find the cost of control to be reasonable because it is reasonable under the above approach, we also evaluated the cost of option 1 (subpart VVa level of control) under the second approach (multipollutant approach). Under the second approach, we apportion the annualized cost across the pollutant reductions addressed by the control option in proportion to the relative percentage reduction of each pollutant controlled. In this case, since methane and VOC are controlled equally, half the cost is apportioned to the methane emission reductions and half the cost is apportioned to the VOC emission reductions. Under this approach, the costs are allocated based on the percentage reduction expected for each pollutant. Because option 1 (subpart VVa level of control) reduces the fugitive emission of natural gas from equipment components, emissions of methane and VOC will be reduced equally. Therefore, we attribute 50 percent of the costs to methane reduction and 50 percent to VOC reduction. Based on this formulation, the costs for methane reduction are half of the estimated costs under the first approach above and are therefore reasonable.

With option 1 (subpart VVa level of control) there would be no secondary air impacts, therefore no impacts were assessed. Also, we did not identify any nonair quality or energy impacts associated with this control technique, therefore no impacts were assessed.

In light of the above, we find that the BSER for reducing methane emissions from equipment leaks at natural gas processing plants is a leak detection and repair program at the subpart VVa level of control, and we are proposing to require such a program at natural gas processing plants. As described above, the proposed methane standard would be the same as the current VOC standard for natural gas processing plants in the NSPS.

I. Liquids Unloading Operations

Liquids unloading is an operation that is conducted at natural gas wells to remove accumulated liquids that can impede or even halt production of natural gas due to insufficient gas flow within the wellbore. Fluid accumulation is a common problem in both aging and newer natural gas wells. The typical industry practices used to accomplish liquids unloading include using plunger lifts, beam pumps, remedial treatments, or venting the well to atmosphere (also referred to as blowing down the well). The emissions from liquids unloading result from the intentional venting of gas from the wellbore during activities conducted on or near equipment associated with the removal of accumulated fluids. The volume of gas vented is presumed to be the total volume of gas in the casing and tubing minus the volume of water accumulated in the well. Wells can require multiple unloading events per year; however, the number and frequency of unloading events and volume of emissions generated vary widely. Some wells conduct liquids unloading without venting, through use of closed-loop systems and other technologies.

Based on the information and data available to the EPA during development of the 2012 NSPS, the EPA conducted a preliminary screening of emissions sources with the goal of maximizing emission reductions for new sources. At the time, there was not sufficient data available to determine whether liquids unloading was an issue for hydraulically fractured wells, which represent the majority of projected future production and new sources. In petitions on the 2012 NSPS, some petitioners asserted that the EPA should have regulated the methane and VOC emissions from liquids unloading operations because these emissions are significant and there are data that demonstrate that cost-effective mitigation technologies are available to address the emissions.

Data on liquids unloading operations supplied to the EPA subsequent to the 2012 rule finalization provided significantly better insight into emissions from liquids unloading. Data were provided in a study conducted by members of the American Petroleum

[116] Available at *http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf.*

[117] In 2012 we already found that the cost of this control to be reasonable for reducing VOC emissions from natural gas processing plants. We are not reopening that decision in this action.

subpart OOOO a provision similar to subpart KKK, 40 CFR 60.632(a), which allows a compliance period of up to 180 days after initial start-up. The commenter was ''concerned that a modification at an existing facility or a subpart KKK regulated facility could subject the facility to Subpart OOOO LDAR requirements without adequate time to bring the whole process unit into compliance with the new regulation.'' [120]

We clarify that subpart OOOO, as promulgated in 2012, already includes a provision similar to subpart KKK, § 60.632(a), as requested in the comment. Specifically, § 60.5400(a) requires compliance with 40 CFR 60.482–1a(a), which provides that ''[e]ach owner or operator subject to the provisions of this subpart shall demonstrate compliance . . . within 180 days of initial startup.'' This provision applies to all new, modified, and reconstructed sources. With respect to modification, which was of specific concern to the commenter, a change to a unit sufficient to trigger a modification and thus application of the subpart OOOO LDAR requirements for on-shore natural gas processing plants would be followed by startup, which would mark the beginning of the 180 day compliance period provided in 40 CFR 60.482–1a(a) (incorporated by reference in subpart OOOO § 60.5400(a)).

9. Tanks Associated With Water Recycling Operations

In many cases, flowback water from well completions and water produced during ongoing production is collected, treated and recycled to reduce the volume of potable water withdrawn from wells or other sources. Large, non-earthen tanks are used to collect the water for recycling following separation to remove crude oil, condensate, intermediate hydrocarbon liquids and natural gas. These collection tanks used for water recycling are very large vessels having capacities of 25,000 barrels or more, with annual throughput of millions of barrels of water. In contrast, industry standard storage vessels commonly found in well site tank batteries and used to contain crude oil, condensate, intermediate hydrocarbon liquids and produced water typically have capacities in the 500 barrel range.

In the 2012 NSPS, we had envisioned the storage vessel provisions as regulating the vessels in well site tank batteries and not these large tanks primarily used for water recycling. It was never our intent to cover these large water recycling tanks. It recently came to our attention that these water recycling tanks could be inadvertently subject to the NSPS due to the extremely low VOC content combined with the millions of barrels of throughput each year, which could result in a potential to emit VOC exceeding the NSPS storage vessel threshold of 6 tpy.[121] The EPA encourages efforts on the part of owners and operators to maximize recycling of flowback and produced water. We are concerned that the inadvertent coverage of these tanks under the NSPS could discourage recycling. It is our understanding that, due to the size and throughput of these tanks, combined with the trace amounts of VOC emissions that are difficult to control, that operators may choose to discontinue recycling to avoid noncompliance with the NSPS.

As a result, we are considering changes in the final rule to remove tanks that are used for water recycling from potential NSPS applicability. We solicit comment on approaches that could be taken to amend the definition of ''storage vessel'' or other changes to the NSPS that would resolve this issue without excluding storage vessels appropriately covered by the NSPS. In addition, we solicit comment on location, capacity or other criteria that would be appropriate for such purpose.

X. Next Generation Compliance and Rule Effectiveness

A. Independent Third-Party Verification

The EPA is taking comment on establishing a third-party verification program as discussed below. Third-party verification is when an independent third-party verifies to a regulator that a regulated entity is meeting one or more of its compliance obligations. The regulator retains the ultimate responsibility to monitor and enforce compliance but, as a practical matter, gives significant weight to the third-party verification provided in the context of a regulatory program with effective standards, procedures, transparency and oversight. While requiring regulated entities to monitor and report should improve compliance by establishing minimum requirements for a regulated entity's employees and managers, well-structured third-party compliance monitoring and reporting may further improve compliance.

The third-party verification program would be designed to ensure that the third-party reviewers are competent, independent, and accredited, apply clear and objective criteria to their design plan reviews, and report appropriate information to regulators. Additionally, there would need to be mechanisms to ensure regular and effective oversight of third-party reviewers by the EPA and/or states which may include public disclosure of information concerning the third parties and their performance and determinations, such as licensing or registration.

The EPA is considering a broad range of possible design features for such a program under the following two scenarios: (A) Third-Party Verification of Closed Vent System Design and (B) Third-Party Verification of IR Camera Fugitives Monitoring Program. These include those discussed or included in the following articles, rules, and programs:

(1) Lesley K. McAllister, Regulation by Third-Party Verification, 53 B.C. L. REV. 1, 22–23 (2012);

(2) Lesley K. McAllister, THIRD–PARTY PROGRAMS FINAL REPORT (2012) (prepared for the Administrative Conference of the United States), available at *http://www.acus.gov/report/third-party-programs-final-report;*

(3) Esther Duflo *et al.,* Truth-Telling By Third-Party Auditors and the Response of Polluting Firms: Experimental Evidence From India, 128 Q. J. OF ECON. 4 at 1499–1545 (2013);

(4) EPA CAA Renewable Fuel Standard (RFS) program: The RFS regulations include requirements for obligated parties to, in relevant part, submit independent third-party engineering reviews to the EPA before generating Renewable Identification Numbers (RINs).[122]

(5) Massachusetts Underground Storage Tank (UST) third-party inspection program: The owners/operators of most underground storage tanks in Massachusetts are required to have their USTs inspected by third-party inspectors every three years. While the third-party inspectors are hired directly by the tank owners and operators, they report to the Massachusetts Department of Environmental Protection (MassDEP). The third parties conduct and document detailed inspections of USTs and piping systems, review facility recordkeeping to ensure it meets UST program requirements, and submit reports on their findings electronically to MassDEP.[123]

Pollutants Reviews, 76 FR 52738 (Aug. 23, 2011). Pp. 3, 32–33.

[120] Comments of the Gas Processors Association Regarding the Proposed Rule, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 76 FR 52738 (Aug. 23, 2011). Pp. 33.

[121] Letter from Obie O'Brien, Vice President—Government Affairs/Corporate Outreach, Apache Corporation, to EPA Docket, Docket ID Number EPA–HQ–OAR–2010–4755, April 20, 2015. Similar letters from Rockwater Energy Solutions (EPA–HQ–OAR–2010–4756) and Permian Basin Petroleum Association (EPA–HQ–OAR–2010–4757).

[122] EPA, Renewable Fuel Standards (RFS), *http://www.epa.gov/OTAQ/fuels/renewablefuels/.*

[123] MassDEP, Third-Party Underground Storage Tank (UST) Inspection Program, *http://*

(6) Massachusetts licensed Hazardous Waste Site Cleanup Professional program: Private parties who are financially responsible under Massachusetts law for assessing and cleaning up confirmed and suspected hazardous waste sites must retain a licensed Hazardous Waste Site Cleanup Professional (commonly called a ''Licensed Site Professional'' or simply an ''LSP'') to oversee the assessment and cleanup work.[124]

We have identified one potential area for third-party verification under this rule.

Professional Engineer Certification of Closed Vent System and Control Device Design and Installation

When produced liquids from oil and natural gas operations are routed from the separator to the condensate storage tank, a drop in pressure from operating pressure to atmospheric pressure occurs. This results in ''flash emissions'' as gases are liberated from the condensate stream due to the change in pressure. The magnitude of flash emissions can dwarf normal working and breathing losses of a storage tank. If the control system (closed vent system and control device, including pressure relief devices and thief hatches on storage vessels) cannot accommodate the peak instantaneous flow rate of flash emissions, working losses, breathing losses and any other additional vapors, this may cause pressure relief devices and thief hatches to ''pop'' and they may not properly reseat, resulting in immediate and potentially continuing excess emissions. Through our energy extraction enforcement initiative, we have seen this to be the case, due in large part to undersized control systems that may have been inadequately designed to accommodate only working and breathing losses of a storage tank. We have worked in conjunction with states, including Colorado, in conducting inspection campaigns associated with storage vessels. In two inspection campaigns, in two different regions, we recorded venting from thief hatches or other parts of the control system at over 60 percent of the tank batteries inspected. Another inspection campaign resulted in a much higher leak rate, with 23 of 25 tank batteries experiencing fugitive emissions.

One potential remedy for the inadequate design and sizing of the closed vent system would be to require an independent third-party (independent of the well site owner/operator and control device manufacturer), such as a professional engineer, to review the design and verify that it is designed to accommodate all emissions scenarios, including flash emissions episodes. Another element of the professional engineer verification could be that the professional engineer verifies that the control system is installed correctly and that the design criteria is properly utilized in the field.

Another approach to detecting overpressure in a closed vent system would be to require a continuous pressure monitoring device or system, located on the thief hatches, pressure relief devices and other bypasses from the closed vent system. Through our inspections, we have seen thief hatch pressure settings below the pressure settings of the storage tanks to which they are affixed. This results in emissions escaping from the thief hatch and not making it to the control device.

The EPA requests comment on these approaches. Specifically, we request comment as to whether we should specify criteria by which the PE verifies that the closed vent system is designed to accommodate all streams routed to the facility's control system, or whether we might cite to current engineering codes that produce the same outcome. We also request comment as to what types of cost-effective pressure monitoring systems can be utilized to ensure that the pressure settings on relief devices is not lower than the operating pressure in the closed vent to the control device and what types of reporting from such systems should be required, such as through a supervisory control and data acquisition (SCADA) system.

B. Fugitives Emissions Verification

As discussed in sections VII.G and VIII.G, the EPA is proposing the use of OGI as a low cost way to find leaks. While we believe we are proposing a robust method to ensure that OGI surveys are done correctly, we have ample experience from our enhanced leak detection and repair (LDAR) efforts under our Air Toxics Enforcement Initiative, that even when methods are in place, routine monitoring for fugitives may not be as effective in practice as in design. Similar to the audits included as part of consent decrees under the Initiative (*See U.S. et. Al.* v. *BP Products North America Inc.),* we are soliciting comment on an audit program of the collection of fugitive emissions components at well sites and compressor stations.

For this rule, we are anticipating a structure in which the facilities themselves are responsible for determining and documenting that their auditors are competent and independent pursuant to specified criteria. The Agency seeks comment as to whether this approach is appropriate for the type of auditing we describe below, or whether an alternative approach, such as requiring auditors to have accreditation from a recognized auditing body or EPA, or other potentially relevant and applicable consensus standards and protocols (*e.g.*, American National Standards Institute (ANSI), ASTM International (ASTM), European Committee for Standardization (CEM), International Organization for Standardization (ISO), and National Institute of Standards and Technology (NIST) standards), would be preferable.

In order to ensure the competence and independence of the auditor, certain criteria should be met. Competence of the auditor can include safeguards such as licensing as a Professional Engineer (PE), knowledge with the requirements of rule and the operation of monitoring equipment (*e.g.*, optical gas imaging), experience with the facility type and processes being audited and the applicable recognized and generally accepted good engineering practices, and training or certification in auditing techniques.

Independence of the auditor can be ensured by provisions and safeguards in the contracts and relationships between the owner and operator of the affected facility with auditors. These can include: The auditor and its personnel must not have conducted past research, development, design, construction services, or consulting for the owner or operator within the last 3 years; the auditor and its personnel must not provide other business or consulting services to the owner or operator, including advice or assistance to implement the findings or recommendations in the Audit report, for a period of at least 3 years following the Auditor's submittal of the final Audit report; and all auditor personnel who conduct or otherwise participate in the audit must sign and date a conflict of interest statement attesting the personnel have met and followed the auditors' policies and procedures for competence, impartiality, judgment, and operational integrity when auditing under this section; and must receive no financial benefit from the outcome of the Audit, apart from payment for the auditing services themselves. In addition, owners or operators cannot provide future employment to any of the auditor's personnel who conducted or otherwise participated in the Audit for a period of at least 3 years following the Auditor's submittal of its final Audit report and must be empowered to direct

www.mass.gov/eea/agencies/massdep/toxics/ust/third-party-ust-inspection-program.html.

[124] *http://www.mass.gov/eea/agencies/massdep/cleanup/licensed-site-professionals.html.*

their auditors to produce copies of any of the audit-related reports and records specified in those sections. Both the owners and operators and their auditors should sign supporting certifications statements. To further minimize audit bias, an audit structure might require that audit report drafts and final audit reports be submitted to EPA at the same time, or before, they are provided to the owners and operators. Furthermore, the audits conducted by the auditors under this rule should not be claimed as a confidential attorney work products even if the auditors are themselves, or managed by or report to, attorneys.

There may be other options, in addition to the approaches above, that may increase owner or operator flexibility, but these options also present risks of introducing bias into the program, resulting in less robust and effective audit reports. EPA invites comment on the structure above as well as alternative auditor/auditing approaches with less rigorous independence criteria. For example, EPA could, in the final rule, allow for audits to be performed by auditors with some potential conflicts of interest (*e.g.*, employees of parent company, affiliates, vendors/contractors that participated in developing source master plan(s) and/or site-specific plan(s), etc.) and/or allow a person at the facility itself who is a registered PE or who has the requisite training in conducting optical gas imaging monitoring to conduct the audit. If such approaches are adopted in the final rule, the Agency could seek to place appropriate restrictions on auditors and auditing with less than full independence from their client facilities in an effort to increase confidence that the auditors will act accurately when performing their activities under the rule. Such provisions could include ones addressed to ensuring that auditor personnel who assess a facility's compliance with the fugitives monitoring requirements do not receive any financial benefit from the outcome of their auditing decisions, apart from their basic salaries or remuneration for having conducted the audits.

Additional examples of the types of restrictions that could be placed on such self-auditing to potentially improve auditor impartiality and auditing outcomes appear in the U.S. and CARB v. Hyundai Motor Company, et al. Consent Decree (CD). Until the CDs corrective measures are fully implemented, the defendants must audit their fleets to ensure that vehicles sold to the public conform to the vehicles' certification. The CD provides that the audit team will be in the United States, will be independent from the group that performed the original certification work, and must perform their audits without access to or knowledge of the defendants' original certification test data which the CD-required audits are intended to backcheck. EPA seeks comment as to whether similar restrictions could be effective for any potential enhanced self-auditing conducted under the rule.

Finally, EPA seeks comment on whether, and to what extent, the public should have access to the compliance reports, portions or summaries of them and/or any other information or documentation produced pursuant to the auditing provisions. EPA is also considering the approach it should take to balance public access to the audits and the need to protect Confidential Business Information (CBI). To balance these potentially competing interests, EPA is reviewing a variety of approaches that may include limiting public access to portions of the audits and/or posting public audit grades or scores to inform the public of the auditing outcomes without compromising confidential or sensitive information. EPA seeks comment on these transparency and public access to information issues in the context of the proposed auditing provisions.

A suggested structure which incorporates concepts from the discussion above, and relevant to an audit of the fugitives monitoring program of the collection of fugitive emissions components at well sites and compressor stations could include the following structure:

Within the first year of applicability to the rule, an OGI trained auditor, experienced with the facility type and processes being audited and the applicable recognized and generally accepted good engineering practices, and trained or certified in auditing techniques, and who has not:

a. served as a fugitive emissions monitoring technician at the source,

b. conducted past research, development, design, construction services, or consulting for the owner or operator within the last 3 years or;

c. provided other business or consulting services to the owner or operator, including advice or assistance to implement the findings or recommendations in the Audit report, for a period of at least 3 years following the Auditor's submittal of the final Audit report;

shall:

a. Verify that the source has established a master and site specific monitoring plan;

b. Verify that the master and site specific monitoring plan includes the elements described in the rule;

c. Verify that the fugitive components were monitored in accordance with the master and site specific monitoring plan and at the appropriate frequency under the plan(s) and the rule;

d. Verify that proper documentation and sign offs have been recorded for all fugitive components placed on the delay of repair list;

e. Ensure that repairs have been performed in the required periods under the rule;

f. Review monitoring data for feasibility (*e.g.*, do the survey results reflect a feasible timeframe in which to conduct the monitoring survey) and unusual trends;

g. Verify that proper calibration records and monitoring instrument maintenance information are maintained;

h. Verify that other fugitives emissions monitoring records are maintained as required; and

i. Observe in the field each technician who is conducting fugitive emissions monitoring to ensure that monitoring is being conducted as described in the rule and the master and site specific plan;

j. Submit a report to the EPA and the facility outlining the findings of the audit with deficiencies and corrective actions provided.

k. Sign a certification statement that the report was prepared by the auditor conducting the audit (or under his/her direction or supervision), that the report is true, accurate, and complete, that the Audit was prepared pursuant to, and meets the requirements of, 40 CFR part 60 subpart OOOOa, and any other applicable auditing, competency, and independence/impartiality/conflict of interest standards and protocols.

Upon the receipt of the auditor's report, the source should correct any deficiencies detected or observed within four months. The source would be required to maintain a record that: (i) Records the auditor's report; and (ii) describes the nature and timing of any corrective actions taken. The source would be required to submit in their periodic compliance report, a summary of the findings of the auditor's report and a description and timing of any corrective actions taken. EPA envisions that the audit would be repeated with some frequency and requests comment on the appropriate frequency, and any actions, trends or compliance triggers which might require or allow deviation from the frequency.

C. Third-Party Information Reporting

Third-party information reporting occurs when a third-party reports information on a regulated source's performance, directly to the regulator. To promote improved compliance, third-party information reporting reduces information asymmetries between what the regulated entities know about themselves and the regulators' knowledge about the entities.

An example of third-party information reporting involves federal income tax law where certain income

(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section or you must comply with paragraph (a)(3) of this section.

(1) Before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

(3) Collect the methane and VOC emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure and route the rod packing emissions to a process through a closed vent system that meets the requirements of § 60.5411a(a).

(b) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5410a.

(c) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5415a.

(d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420a.

§ 60.5390a What methane and VOC standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the methane and VOC standards, based on natural gas as a surrogate for methane and VOC, in either paragraph (b)(1) or (c)(1) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from this requirement.

(a) The requirements of paragraph (b)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required based on functional needs, including but not limited to response time, safety and positive actuation. However, you must tag such pneumatic controller with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller, as required in § 60.5420a(c)(4)(ii).

(b)(1) Each pneumatic controller affected facility at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller as required in § 60.5420a(c)(4)(iv).

(c)(1) Each pneumatic controller affected facility at a location other than at a natural gas processing plant must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller affected facility constructed, modified or reconstructed on or after October 15, 2013, at a location other than at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that controller as required in § 60.5420a(c)(4)(iii).

(d) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5410a.

(e) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5415a.

(f) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420a, except that you are not required to submit the notifications specified in § 60.5420a(a).

§ 60.5393a What methane and VOC standards apply to pneumatic pump affected facilities?

For each pneumatic pump affected facility you must comply with the methane and VOC standards, based on natural gas as a surrogate for methane and VOC, in either paragraph (a)(1) or (b)(1) of this section, as applicable.

(a)(1) Each pneumatic pump affected facility at a natural gas processing plant must have a natural gas emission rate of zero.

(2) Each pneumatic pump affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic pump as required in § 60.5420a(c)(16)(i).

(b)(1) Each pneumatic pump affected facility at a location other than a natural gas processing plant must reduce natural gas emissions by 95.0 percent, except as provided in paragraph (b)(2) of this section.

(2) You are not required to install a control device solely for the purposes of complying with the 95.0 percent reduction of paragraph (b)(1) of this section. If you do not have a control device installed on-site by the compliance date, then you must comply instead with the provisions of paragraphs (b)(2)(i) and (ii) of this section.

(i) Submit a certification in accordance with § 60.5420(b)(8)(i).

(ii) If you subsequently install a control device, you are no longer required to submit the certification in § 60.5420(b)(8)(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 § 60.5420(b)(8)(iii).

(3) Each pneumatic pump affected facility at a location other than a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pump as required in § 60.5420a(c)(16)(i).

(4) If you use a control device to reduce emissions, you must connect the pneumatic pump affected facility through a closed vent system that meets the requirements of § 60.5411a(a) and route emissions to a control device that meets the conditions specified in § 60.5412a(a), (b) and (c) and performance tested in accordance with § 60.5413a. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(c) You must demonstrate initial compliance with standards that apply to pneumatic pump affected facilities as required by § 60.5410a.

(d) You must demonstrate continuous compliance with standards that apply to pneumatic pump affected facilities as required by § 60.5415a.

(e) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420a, except that you are not required to submit the notifications specified in § 60.5420a(a).

§ 60.5395a What VOC standards apply to storage vessel affected facilities?

Except as provided in paragraph (e) of this section, you must comply with the VOC standards in this section for each storage vessel affected facility.

(a) You must comply with either the requirements of paragraphs (a)(1) and

<u>Attachment 3</u>

"Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule," 81 Fed. Reg. 35,824 (June 3, 2016) ("2016 Rule")
(excerpts).

FEDERAL REGISTER

Vol. 81 Friday,
No. 107 June 3, 2016

Part II

Environmental Protection Agency

40 CFR Part 60
Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2010–0505; FRL–9944–75–OAR]

RIN 2060–AS30

Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes amendments to the current new source performance standards (NSPS) and establishes new standards. Amendments to the current standards will improve implementation of the current NSPS. The new standards for the oil and natural gas source category set standards for both greenhouse gases (GHGs) and volatile organic compounds (VOC). Except for the implementation improvements, and the new standards for GHGs, these requirements do not change the requirements for operations covered by the current standards.

DATES: This final rule is effective on August 2, 2016.

The incorporation by reference (IBR) of certain publications listed in the regulations is approved by the Director of the Federal Register as of August 2, 2016.

ADDRESSES: The Environmental Protection Agency (EPA) has established a docket for this action under Docket ID No. EPA–HQ–OAR–2010–0505. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: For further information concerning this action, contact Ms. Amy Hambrick, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–0964; facsimile number: (919) 541–3470; email address: *hambrick.amy@epa.gov* or Ms. Lisa Thompson, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–9775; facsimile number: (919) 541–3470; email address: *thompson.lisa@epa.gov.* For other information concerning the EPA's Oil and Natural Gas Sector regulatory program, contact Mr. Bruce Moore, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–5460; facsimile number: (919) 541–3470; email address: *moore.bruce@epa.gov.*

SUPPLEMENTARY INFORMATION: *Outline.* The information presented in this preamble is presented as follows:

K. Congressional Review Act (CRA)

I. Preamble Acronyms and Abbreviations

Several acronyms and terms are included in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined here:

API American Petroleum Institute
bbl Barrel
boe Barrels of Oil Equivalent
BSER Best System of Emissions Reduction
BTEX Benzene, Toluene, Ethylbenzene and Xylenes
CAA Clean Air Act
CBI Confidential Business Information
CFR Code of Federal Regulations
CO_2 Eq. Carbon dioxide equivalent
DCO Document Control Officer
EIA Energy Information Administration
EPA Environmental Protection Agency
GHG Greenhouse Gases
GHGRP Greenhouse Gas Reporting Program
GOR Gas to Oil Ratio
HAP Hazardous Air Pollutants
LDAR Leak Detection and Repair
Mcf Thousand Cubic Feet
NEI National Emissions Inventory
NEMS National Energy Modeling System
NESHAP National Emissions Standards for Hazardous Air Pollutants
NSPS New Source Performance Standards
NTTAA National Technology Transfer and Advancement Act of 1995
OAQPS Office of Air Quality Planning and Standards
OGI Optical Gas Imaging
OMB Office of Management and Budget
PRA Paperwork Reduction Act
PTE Potential to Emit
REC Reduced Emissions Completion
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
scf Standard Cubic Feet
scfh Standard Cubic Feet per Hour
scfm Standard Cubic Feet per Minute
SO_2 Sulfur Dioxide
tpy Tons per Year
TSD Technical Support Document
TTN Technology Transfer Network
UMRA Unfunded Mandates Reform Act
VCS Voluntary Consensus Standards
VOC Volatile Organic Compounds
VRU Vapor Recovery Unit

II. General Information

A. Executive Summary

1. Purpose of This Regulatory Action

The Environmental Protection Agency (EPA) proposed amendments to the New Source Performance Standards (NSPS) at subpart OOOO and proposed new standards at subpart OOOOa on September 18, 2015 (80 FR 56593). The purpose of this action is to finalize both the amendments and the new standards with appropriate adjustments after full consideration of the comments received on the proposal. Prior to proposal, we pursued a structured engagement process with states and stakeholders. Prior to that process, we issued draft white papers addressing a range of technical issues and then solicited comments on the white papers from expert reviewers and the public.

These rules are designed to complement other federal actions as well as state regulations. In particular, the EPA worked closely with the Department of Interior's Bureau of Land Management (BLM) during development of this rulemaking in order to avoid conflicts in requirements between the NSPS and BLM's proposed rulemaking.[1] Additionally, we evaluated existing state and local programs when developing these federal standards and attempted, where possible, to limit potential conflicts with existing state and local requirements.

As discussed at proposal, prior to this final rule, the EPA had established standards for emissions of VOC and sulfur dioxide (SO_2) for several sources in the source category. In this action, the EPA finalizes standards at subpart OOOOa, based on our determination of the best system of emissions reduction (BSER) for reducing emissions of greenhouse gases (GHGs), specifically methane, as well as VOC across a variety of additional emission sources in the oil and natural gas source category (*i.e.,* production, processing, transmission, and storage). The EPA includes requirements for methane emissions in this action because methane is one of the six well-mixed gases in the definition of GHGs and the oil and natural gas source category is one of the country's largest industrial emitters of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations.

[1] 81 FR 6616, February 8, 2016, *Waste Prevention, Production Subject to Royalties, and Resource Conservation, Proposed Rule.*

In addition to finalizing standards for VOC and GHGs, the EPA is finalizing amendments to improve several aspects of the existing standards at 40 CFR part 60, subpart OOOO related to implementation. These improvements and the setting of standards for GHGs in the form of limitations on methane result from reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator on the August 16, 2012, NSPS (77 FR 49490) and on the September 13, 2013, amendments (78 FR 58416). These implementation improvements do not change the requirements for operations and equipment covered by the current standards at subpart OOOO.

2. Summary of 40 CFR Part 60, Subpart OOOOa Major Provisions

The final requirements include standards for GHG emissions (in the form of methane emission limitations) and standards for VOC emissions. The NSPS includes both VOC and GHG emission standards for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas source category. These emission sources include the following:

- Sources that are unregulated under the current NSPS at subpart OOOO (hydraulically fractured oil well completions, pneumatic pumps, and fugitive emissions from well sites and compressor stations);
- Sources that are currently regulated at subpart OOOO for VOC, but not for GHGs (hydraulically fractured gas well completions and equipment leaks at natural gas processing plants);
- Certain equipment that is used across the source category, for which the current NSPS at subpart OOOO regulates emissions of VOC from only a subset (pneumatic controllers, centrifugal compressors, and reciprocating compressors), with the exception of compressors located at well sites.

Table 1 below summarizes these sources and the final standards for GHGs (in the form of methane limitations) and VOC emissions. See sections V and VI of this preamble for further discussion.

TABLE 1—SUMMARY OF BSER AND FINAL SUBPART OOOOa STANDARDS FOR EMISSION SOURCES

Source	BSER	Final standards of performance for GHGs and VOC
Wet seal centrifugal compressors (except for those located at well sites)[2].	Capture and route to a control device	95 percent reduction.
Reciprocating compressors (except for those located at well sites)[2].	Regular replacement of rod packing (*i.e.*, approximately every 3 years).	Replace the rod packing on or before 26,000 hours of operation or 36 calendar months or route emissions from the rod packing to a process through a closed vent system under negative pressure.
Pneumatic controllers at natural gas processing plants.	Instrument air systems	Zero natural gas bleed rate.
Pneumatic controllers at locations other than natural gas processing plants.	Installation of low-bleed pneumatic controllers	Natural gas bleed rate no greater than 6 standard cubic feet per hour (scfh).
Pneumatic pumps at natural gas processing plants.	Instrument air systems in place of natural gas driven pumps.	Zero natural gas emissions.
Pneumatic pumps at well sites	Route to existing control device or process	95 percent control if there is an existing control or process on site. 95 percent control not required if (1) routed to an existing control that achieves less than 95 percent or (2) it is technically infeasible to route to the existing control device or process (non-greenfield sites only).
Well completions (subcategory 1: Non-wildcat and non-delineation wells).	Combination of Reduced Emission Completion (REC) and the use of a completion combustion device.	REC in combination with a completion combustion device; venting in lieu of combustion where combustion would present safety hazards. Initial flowback stage: Route to a storage vessel or completion vessel (frac tank, lined pit, or other vessel) and separator. Separation flowback stage: Route all salable gas from the separator to a flow line or collection system, re-inject the gas into the well or another well, use the gas as an onsite fuel source or use for another useful purpose that a purchased fuel or raw material would serve. If technically infeasible to route recovered gas as specified above, recovered gas must be combusted. All liquids must be routed to a storage vessel or well completion vessel, collection system, or be re-injected into the well or another well. The operator is required to have a separator onsite during the entire flowback period.
Well completions (subcategory 2: Exploratory and delineation wells and low pressure wells).	Use of a completion combustion device	The operator is not required to have a separator onsite. Either: (1) Route all flowback to a completion combustion device with a continuous pilot flame; or (2) Route all flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the flowback before the separator can function is not subject to control under this section. Capture and direct recovered gas to a completion combustion device with a continuous pilot flame. For both options (1) and (2), combustion is not required in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways.
Fugitive emissions from well sites and compressor stations.	For well sites: Monitoring and repair based on semiannual monitoring using optical gas imaging (OGI)[3].	Monitoring and repair of fugitive emission components using OGI with Method 21 as an alternative at 500 parts per million (ppm).
	For compressor stations: Monitoring and repair based on quarterly monitoring using OGI.	A monitoring plan must be developed and implemented and repair of the sources of fugitive emissions must be completed within 30 days of finding fugitive emissions.

TABLE 1—SUMMARY OF BSER AND FINAL SUBPART OOOOa STANDARDS FOR EMISSION SOURCES—Continued

Source	BSER	Final standards of performance for GHGs and VOC
Equipment leaks at natural gas processing plants.	Leak detection and repair at 40 CFR part 60, subpart VVa level of control.	Follow requirements at NSPS part 60, subpart VVa level of control as in the 2012 NSPS.

Reconsiderationissues being addressed. As fully detailed in sections V and VI of this preamble and the Response to Comment (RTC) document, the EPA granted reconsideration of several issues raised in the administrative reconsideration petitions submitted on the 2012 NSPS and subsequent amendments (subpart OOOO). In this final rule, in addition to the new standards described above, the EPA includes certain amendments to the 2012 NSPS at subpart OOOO based on reconsideration of those issues. The amendments to the subpart OOOO requirements are effective on August 2, 2016 and, therefore, do not affect compliance activities completed prior to that date.

These provisions are: Requirements for storage vessel control device monitoring and testing; initial compliance requirements for a bypass device that could divert an emission stream away from a control device; recordkeeping requirements for repair logs for control devices failing a visible emissions test; clarification of the due date for the initial annual report; flare design and operation standards; leak detection and repair (LDAR) for open-ended valves or lines; the compliance period for LDAR for newly affected units; exemption to the notification requirement for reconstruction; disposal of carbon from control devices; the definition of capital expenditure; and continuous control device monitoring requirements for storage vessels and centrifugal compressor affected facilities. We are finalizing changes to address these issues to clarify the current NSPS requirements, improve implementation, and update procedures.

3. Costs and Benefits

The EPA has carefully reviewed the comments and additional data submitted on the costs and benefits associated with this rule. Our conclusion and responses are summarized in section IX of the preamble and addressed in greater detail in the Regulatory Impact Analysis (RIA) and RTC. The measures finalized in this action achieve reductions of GHG and VOC emissions through direct regulation and reduction of hazardous air pollutant (HAP) emissions as a co-benefit of reducing VOC emissions. The data show that these are cost-effective measures to reduce emissions and the rule's benefits outweigh these costs.

The EPA has estimated emissions reductions, benefits, and costs for 2 years of analysis: 2020 and 2025. Therefore, the emissions reductions, benefits, and costs by 2020 and 2025 (*i.e.,* including all emissions reductions, costs, and benefits in all years from 2016 to 2025) would be potentially significantly greater than the estimated emissions reductions, benefits, and costs provided within this rule. Actions taken to comply with the final NSPS are anticipated to prevent significant new emissions in 2020, including 300,000 tons of methane; 150,000 tons of VOC; and 1,900 tons of HAP. The emission reductions anticipated in 2025 are 510,000 tons of methane; 210,000 tons of VOC; and 3,900 tons of HAP. Using a 100-year global warming potential (GWP) of 25, the carbon dioxide-equivalent (CO_2 Eq.) methane emission reductions are estimated to be 6.9 million metric tons CO_2 Eq. in 2020 and 11 million metric tons CO_2 Eq. in 2025. The methane-related monetized climate benefits are estimated to be $360 million in 2020 and $690 million in 2025 using a 3-percent discount rate (model average).[4]

While the only benefits monetized for this rule are GHG-related climate benefits from methane reductions, the rule will also yield benefits from reductions in VOC and HAP emissions and from reductions in methane as a precursor to global background concentrations of tropospheric ozone. The EPA was unable to monetize the benefits of VOC reductions due to the difficulties in modeling the impacts with the current data available. A detailed discussion of these unquantified benefits appears in section IX of this preamble, as well as in the RIA available in the docket.

Several VOC that are commonly emitted in the oil and natural gas source category are HAP listed under Clean Air Act (CAA) section 112(b), including benzene, toluene, ethylbenzene and xylenes (this group is commonly referred to as ''BTEX'') and n-hexane. These pollutants and any other HAP included in the VOC emissions controlled under the NSPS, including requirements for additional sources being finalized in this action, are controlled to the same degree. The co-benefit HAP reductions for the final measures are discussed in the RIA and in the technical support document (TSD), which are included in the public docket for this action.

The HAP reductions from these standards will be meaningful in local communities, as members of these communities and other stakeholders across the country have reported significant concerns to the EPA regarding potential adverse health effects resulting from exposure to HAP emitted from oil and natural gas operations. Importantly, these communities include disadvantaged populations.

The EPA estimates the total capital cost of the final NSPS will be $250 million in 2020 and $360 million in 2025. The estimate of total annualized engineering costs of the final NSPS is $390 million in 2020 and $640 million in 2025 when using a 7-percent discount rate. When estimated revenues from additional natural gas are included, the annualized engineering costs of the final NSPS are estimated to be $320 million in 2020 and $530 million in 2025, assuming a wellhead natural gas price of $4/thousand cubic feet (Mcf). These compliance cost estimates include revenues from recovered natural gas, as the EPA estimates that about 16 billion cubic feet in 2020 and 27 billion cubic feet in 2025 of natural gas will be recovered by implementing the NSPS.

Considering all the costs and benefits of this rule, including the revenues from

[2] See sections VI and VIII of this preamble for detailed discussion on emission sources.

[3] The final fugitive standards apply to low production wells. For the reasons discussed in section VI of the preamble, we are not finalizing the proposed exemption of low production wells from these requirements.

[4] We estimate methane benefits associated with four different values of a 1 ton methane reduction (model average at 2.5-percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For the purposes of this summary, we present the benefits associated with the model average at a 3-percent discount rate. However, we emphasize the importance and value of considering the full range of social cost of methane values. We provide estimates based on additional discount rates in preamble section IX and in the RIA.

of adverse impacts, especially if the sensitivity of the climate to GHGs is on the higher end of the estimated range.

• Waiting for unacceptable impacts to occur before taking action is imprudent because the effects of GHG emissions do not fully manifest themselves for decades and, once manifested, many of these changes will persist for hundreds or even thousands of years.

• In the committee's judgment, the risks associated with doing business as usual are a much greater concern than the risks associated with engaging in strong response efforts.

Methane is also a precursor to ground-level ozone, which can cause a number of harmful effects on health and the environment (see section IV.B.2 of this preamble). Additionally, ozone is a short-lived climate forcer that contributes to global warming. In remote areas, methane is a dominant precursor to tropospheric ozone formation.[42] Approximately 50 percent of the global annual mean ozone increase since preindustrial times is believed to be due to anthropogenic methane.[43] Projections of future emissions also indicate that methane is likely to be a key contributor to ozone concentrations in the future.[44] Unlike NO_X and VOC, which affect ozone concentrations regionally and at hourly time scales, methane emissions affect ozone concentrations globally and on decadal time scales given methane's relatively long atmospheric lifetime compared to these other ozone precursors.[45] Reducing methane emissions, therefore, will contribute to efforts to reduce global background ozone concentrations that contribute to the incidence of ozone-related health effects.[46 47 48] The benefits of such reductions are global and occur in both urban and rural areas.

2. VOC

Many VOC can be classified as HAP (*e.g.,* benzene[49]) which can lead to a variety of health concerns such as cancer and noncancer illnesses (*e.g.,* respiratory, neurological). Further, VOC are one of the key precursors in the formation of ozone. Tropospheric, or ground-level, ozone is formed through reactions of VOC and NO_X in the presence of sunlight. Ozone formation can be controlled to some extent through reductions in emissions of ozone precursors VOC and NO_X. A significantly expanded body of scientific evidence shows that ozone can cause a number of harmful effects on health and the environment. Exposure to ozone can cause respiratory system effects such as difficulty breathing and airway inflammation. For people with lung diseases such as asthma and chronic obstructive pulmonary disease (COPD), these effects can lead to emergency room visits and hospital admissions. Studies have also found that ozone exposure is likely to cause premature death from lung or heart diseases. In addition, evidence indicates that long-term exposure to ozone is likely to result in harmful respiratory effects, including respiratory symptoms and the development of asthma. People most at risk from breathing air containing ozone include: Children; people with asthma and other respiratory diseases; older adults; and people who are active outdoors, especially outdoor workers. An estimated 25.9 million people have asthma in the United States, including almost 7.1 million children. Asthma disproportionately affects children, families with lower incomes, and minorities, including Puerto Ricans, Native Americans/Alaska Natives, and African-Americans.[50]

Scientific evidence also shows that repeated exposure to ozone can reduce growth and have other harmful effects on sensitive plants and trees. These types of effects have the potential to impact ecosystems and the benefits they provide.

3. SO_2

Current scientific evidence links short-term exposures to SO_2, ranging from 5 minutes to 24 hours, with an array of adverse respiratory effects including bronchoconstriction and increased asthma symptoms. These effects are particularly important for asthmatics at elevated ventilation rates (*e.g.,* while exercising or playing).

Studies also show an association between short-term exposure and increased visits to emergency departments and hospital admissions for respiratory illnesses, particularly in at-risk populations including children, the elderly, and asthmatics.

SO_2 in the air can also damage the leaves of plants, decrease their ability to produce food—photosynthesis—and decrease their growth. In addition to directly affecting plants, SO_2, when deposited on land and in estuaries, lakes, and streams, can acidify sensitive ecosystems resulting in a range of harmful indirect effects on plants, soils, water quality, and fish and wildlife (*e.g.,* changes in biodiversity and loss of habitat, reduced tree growth, loss of fish species). Sulfur deposition to waterways also plays a causal role in the methylation of mercury.[51]

C. GHGs, VOC and SO_2 Emissions From the Oil and Natural Gas Source Category

The previous section explains how GHGs, VOCs, and SO_2 emissions are ''air pollution'' that may reasonably be anticipated to endanger public health and welfare. This section provides estimated emissions of these substances from the oil and natural gas source category.

1. Methane Emissions in the United States and From the Oil and Natural Gas Industry

The GHGs addressed by the 2009 Endangerment Finding consist of six well-mixed gases, including methane. For the analysis supporting this regulation, we used the methane 100-year GWP of 25 to be consistent with and comparable to key Agency emission quantification programs such as the Inventory of United States Greenhouse Gas Emissions and Sinks (GHG Inventory), and the GHGRP.[52] The use of the 100-year GWP of 25 for methane value is currently required by the United Nations Framework Convention on Climate Change (UNFCCC) for reporting of national inventories, such as the United States GHG Inventory.

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[42] U.S. EPA. 2013. ''Integrated Science Assessment for Ozone and Related Photochemical Oxidants (Final Report).'' EPA–600–R–10–076F. National Center for Environmental Assessment—RTP Division. Available at *http://www.epa.gov/ncea/isa/.*

[43] Myhre, G., D. Shindell, F.-M. Bréon, W. Collins, J. Fuglestvedt, J. Huang, D. Koch, J.-F. Lamarque, D. Lee, B. Mendoza, T. Nakajima, A. Robock, G. Stephens, T. Takemura and H. Zhang, 2013: Anthropogenic and Natural Radiative Forcing. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Pg. 680.

[44] *Ibid.*

[45] *Ibid.*

[46] West, J.J., Fiore, A.M. 2005. ''Management of tropospheric ozone by reducing methane emissions.'' *Environ. Sci. Technol.* 39:4685–4691.

[47] Anenberg, S.C., et al. 2009. ''Intercontinental impacts of ozone pollution on human mortality,'' *Environ. Sci. & Technol.* 43: 6482–6487.

[48] Sarofim, M.C., Waldhoff, S.T., Anenberg, S.C. 2015. ''Valuing the Ozone-Related Health Benefits of Methane Emission Controls,'' *Environ. Resource Econ.* DOI 10.1007/s10640–015–9937–6.

[49] Benzene IRIS Assessment: *https://cfpub.epa.gov/ncea/iris2/chemicalLanding.cfm?substance_nmbr=276.*

[50] National Health Interview Survey (NHIS) Data, 2011. *http://www.cdc.gov/asthma/nhis/2011/data.htm.*

[51] U.S. EPA. Intergrated Science Assessment (ISA) for Oxides of Nitrogen and Sulfur Ecological Criteria (2008 Final Report). U.S. Envieronmental Protection Agency, Washington, DC, EPA/600/R–08/082F, 2008.

[52] See, for example, Table A–1 to subpart A of 40 CFR part 98.

Updated estimates for methane GWP have been developed by IPCC (2013).[53] The most recent 100-year GWP estimates for methane range from 28 to 36. In discussing the science and impacts of methane emissions generally, here we use the GWP range of 28 to 36. When presenting emissions estimates, we use the GWP of 25 for consistency and comparability with other emissions estimates in the United States and internationally. Methane has an atmospheric life of about 12 years.

Official United States estimates of national level GHG emissions and sinks are developed by the EPA for the United States GHG Inventory to comply with commitments under the UNFCCC. The United States GHG Inventory, which includes recent trends, is organized by industrial sectors. Natural gas and petroleum systems are the largest emitters of methane in the United States. These systems emit 32 percent of United States anthropogenic methane.

Table 3 below presents total United States anthropogenic methane emissions for the years 1990, 2005, and 2014.

TABLE 3—UNITED STATES METHANE EMISSIONS BY SECTOR

[Million metric ton carbon dioxide equivalent (MMT CO_2 Eq.)]

Sector	1990	2005	2014
Oil and Natural Gas Production, and Natural Gas Processing and Transmission	201	203	232
Landfills	180	154	148
Enteric Fermentation	164	169	164
Coal Mining	96	64	68
Manure Management	37	56	61
Other Methane Sources [54]	95	71	57
Total Methane Emissions	774	717	731

Emissions from the Inventory of United States Greenhouse Gas Emissions and Sinks: 1990–2014 (published April 15, 2016), calculated using GWP of 25. Note: Totals may not sum due to rounding.

Oil and natural gas production and natural gas processing and transmission systems encompass wells, natural gas gathering and processing facilities, storage, and transmission pipelines. These components are all important aspects of the natural gas cycle—the process of getting natural gas out of the ground and to the end user. In the oil industry, some underground crude oil contains natural gas that is entrained in the oil at high reservoir pressures. When oil is removed from the reservoir, associated natural gas is produced.

Methane emissions occur throughout the natural gas industry. They primarily result from normal operations, routine maintenance, fugitive leaks, and system upsets. As gas moves through the system, emissions occur through intentional venting and unintentional leaks. Venting can occur through equipment design or operational practices, such as the continuous bleed of gas from pneumatic controllers (that control gas flows, levels, temperatures, and pressures in the equipment), or venting from well completions during production. In addition to vented emissions, methane losses can occur from leaks (also referred to as fugitive emissions) in all parts of the infrastructure, from connections between pipes and vessels, to valves and equipment.

In petroleum systems, methane emissions result primarily from field production operations, such as venting of associated gas from oil wells, oil storage tanks, and production-related equipment such as gas dehydrators, pig traps, and pneumatic devices.

Tables 4 (a) and (b) below present total methane emissions from natural gas and petroleum systems, and the associated segments of the sector, for years 1990, 2005, and 2014, in MMT CO_2 Eq. (Table 4 (a)) and kilotons (or thousand metric tons) of methane (Table 4 (b)).

TABLE 4(a)—UNITED STATES METHANE EMISSIONS FROM NATURAL GAS AND PETROLEUM SYSTEMS

[MMT CO_2]

Sector	1990	2005	2014
Oil and Natural Gas Production and Natural Gas Processing and Transmission *(Total)*	201	203	232
Natural Gas Production	83	108	109
Natural Gas Processing	21	16	24
Natural Gas Transmission and Storage	59	31	32
Petroleum Production	38	48	67

Emissions from the Inventory of United States Greenhouse Gas Emissions and Sinks: 1990–2014 (published April 15, 2016), calculated using GWP of 25. Note: Totals may not sum due to rounding.

[53] IPCC, 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 1535pp.

[54] Other sources include remaining natural gas distribution, petroleum transport and petroleum refineries, forest land, wastewater treatment, rice cultivation, stationary combustion, abandoned coal mines, petrochemical production, mobile combustion, composting, and several sources emitting less than 1 MMT CO_2 Eq. in 2013.

TABLE 4(b)—UNITED STATES METHANE EMISSIONS FROM NATURAL GAS AND PETROLEUM SYSTEMS

[kt CH_4]

Sector	1990	2005	2014
Oil and Natural Gas Production and Natural Gas Processing and Transmission *(Total)*	8,049	8,131	9,295
Natural Gas Production	3,335	4,326	4,359
Natural Gas Processing	852	655	960
Natural Gas Transmission and Storage	2,343	1,230	1,282
Petroleum Production	1,519	1,921	2,694

Emissions from the Inventory of United States Greenhouse Gas Emissions and Sinks: 1990–2014 (published April 15, 2016), in kt (1,000 tons) of CH_4. Note: Totals may not sum due to rounding.

2. United States Oil and Natural Gas Production and Natural Gas Processing and Transmission GHG Emissions Relative to Total United States GHG Emissions

Relying on data from the United States GHG Inventory, we compared United States oil and natural gas production and natural gas processing and transmission GHG emissions to total United States GHG emissions as an indication of the role this source plays in the total domestic contribution to the air pollution that is causing climate change. In 2014, total United States GHG emissions from all sources were 6,871 MMT CO_2 Eq.

TABLE 5—COMPARISONS OF UNITED STATES OIL AND NATURAL GAS PRODUCTION AND NATURAL GAS PROCESSING AND TRANSMISSION CH_4 EMISSIONS TO TOTAL UNITED STATES GHG EMISSIONS

	2010	2011	2012	2013	2014
Total U.S. Oil & Gas Production and Natural Gas Processing & Transmission methane Emissions (MMT CO_2 Eq.)	207.0	214.3	218.8	228.0	232.4
Share of Total U.S. GHG Inventory	3.0%	3.1%	3.3%	3.4%	3.4%
Total U.S. GHG Emissions (MMT CO_2 Eq.)	6,985	6,865	6,643	6,800	6,870

Emissions from the Inventory of United States Greenhouse Gas Emissions and Sinks: 1990–2014 (published April 15, 2016), calculated using CH_4 GWP of 25. Note: Totals may not sum due to rounding.

In 2014, emissions from oil and natural gas production sources and natural gas processing and transmission sources accounted for 232.4 MMT CO_2 Eq. methane emissions (using a GWP of 25 for methane), accounting for 3.4 percent of total United States domestic GHG emissions. The natural gas and petroleum systems source is the largest emitter of methane in the United States. The sector also emitted 43 MMT of CO_2, mainly from acid gas removal during natural gas processing (24 MMT) and flaring in oil and natural gas production (18 MMT). In total, these emissions (CH_4 and CO_2) account for 4.0 percent of total United States domestic GHG emissions.

Methane is emitted in significant quantities from the oil and natural gas production sources and natural gas processing and transmission sources that are being addressed within this rule.

3. United States Oil and Natural Gas Production and Natural Gas Processing and Transmission GHG Emissions Relative to Total Global GHG Emissions

TABLE 6—COMPARISONS OF UNITED STATES OIL AND NATURAL GAS PRODUCTION AND NATURAL GAS PROCESSING AND TRANSMISSION CH_4 EMISSIONS TO TOTAL GLOBAL GHG EMISSIONS

	2010	2011	2012	2013	2014
Total U.S. Oil & Gas Production and Natural Gas Processing & Transmission methane Emissions (MMT CO_2 Eq.)	207.0	214.3	218.8	228.0	232.4
Share of Total U.S. GHG Inventory	3.0%	3.1%	3.3%	3.4%	3.4%
Total U.S. GHG Emissions (MMT CO_2 Eq.)	6,985	6,865	6,643	6,800	6,870

Emissions from the Inventory of United States Greenhouse Gas Emissions and Sinks: 1990–2014 (published April 15, 2016), calculated using CH_4 GWP of 25.

For additional background information and context, we used 2012 World Resources Institute/Climate Analysis Indicators Tool (WRI/CAIT) and International Energy Agency (IEA) data to make comparisons between United States oil and natural gas production and natural gas processing and transmission emissions and the emissions inventories of entire countries and regions. Though the United States methane emissions from oil and natural gas production and natural gas processing and transmission are a seemingly small fraction (0.5 percent) of total global emissions of all GHG from all sources, ranking United States emissions of methane from oil and natural gas production and natural gas processing and transmission against total GHG emissions for entire countries (using 2012 WRI/CAIT data), shows that these emissions are comparatively large as they exceed the national-level emissions totals for all GHG and all anthropogenic sources for Greece, the Czech Republic, Chile, Belgium, and about 150 other countries.[55] Furthermore, United States emissions of methane from oil and natural gas production and natural gas processing and transmission are greater than the sum of total emissions of 54 of the lowest-emitting countries, using the 2012 WRI/CAIT data set.[56]

4. Global GHG Emissions

TABLE 7—COMPARISONS OF UNITED STATES OIL AND NATURAL GAS PRODUCTION AND NATURAL GAS PROCESSING AND TRANSMISSION CH_4 EMISSIONS TO TOTAL GLOBAL GREENHOUSE GAS EMISSIONS IN 2012

	2012 (MMT CO_2 Eq.)	Total U.S. oil and natural gas production and natural gas processing and transmission share (%)
Total Global GHG Emissions	44,816	0.5

As illustrated by the domestic and global GHG comparison data summarized above, the collective GHG emissions from the oil and natural gas source category are significant, whether the comparison is domestic (where this sector is the largest source of methane emissions, accounting for 32 percent of United States methane and 3.4 percent of total United States emissions of all GHG), global (where this sector, while accounting for 0.5 percent of all global GHG emissions, emits more than the total national emissions of over 150 countries, and combined emissions of over 50 countries), or when both the domestic and global GHG emissions comparisons are viewed in combination. Consideration of the global context is important. GHG emissions from United States oil and natural gas production and natural gas processing and transmission will become globally well-mixed in the atmosphere, and thus will have an effect on the United States regional climate, as well as the global climate as a whole for years and indeed many decades to come.

As was the case in 2009, no single GHG source category dominates on the global scale. While the oil and natural gas source category, like many (if not all) individual GHG source categories, could appear small in comparison to total emissions, in fact, it is a very important contributor in terms of both absolute emissions, and in comparison to other source categories globally or within the United States.

5. VOC Emissions

The EPA National Emissions Inventory (NEI) estimated total VOC emissions from the oil and natural gas sector to be 2,729,942 tons in 2011. This ranks second of all the sectors estimated by the NEI and first of all the anthropogenic sectors in the NEI. These facts only serve to further the notion that emissions from the oil and natural gas sector contribute significantly to harmful air pollution.

6. SO_2 Emissions

The NEI estimated total SO_2 emissions from the oil and natural gas sector to be 74,266 tons in 2011. This ranks 13th of the sectors estimated by the NEI. Again, it is clear that emissions from the oil and natural gas sector contribute significantly to dangerous air pollution.

7. Conclusion

In summary, the 1979 Priority List broadly covers the oil and natural gas industry, including the production, processing, transmission, and storage of natural gas. As such, the 1979 Priority List covers all segments that we are regulating in this rule. To the extent that there is any ambiguity in the prior listing, the EPA hereby finalizes as an alternative its proposed revision of the category listing to broadly include the oil and natural gas industry. As revised, the listed oil and natural gas source category includes oil[57] and natural gas production, processing, transmission, and storage. Pursuant to CAA section 111(b)(1)(A), the Administrator has determined that, in her judgment, this source category, as defined above, contributes significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. In support, the EPA notes its previous determination under CAA section 111(b)(1)(A) for the oil and natural gas source category. In addition, the EPA provides in this section information and analyses detailing the public health and welfare impacts of GHG, VOC and SO_2 emissions and the amount of these emission from the oil and natural gas source category (in particular from the various segments of the natural gas industry). Although the EPA does not believe the revision to the category listing is required for the standards we are promulgating in this action, even assuming it is, the revision is well justified.

D. Establishing GHG Standards in the Form of Limitations on Methane Emissions

A petition for reconsideration of the 2012 NSPS urged that ''EPA must reconsider its failure to adopt standards for the methane pollution released by the oil and gas sector.'' [58] Upon reconsidering the issue, and with the benefit of additional information now available to us, the EPA is establishing GHG standards, in the form of limitations on methane emissions, throughout the oil and natural gas source category.

During the 2012 oil and natural gas NSPS rulemaking, we had a considerable amount of data and a good understanding of VOC emissions from the oil and natural gas industry and the available control options, but data on methane emissions were just emerging at that time. In light of the rapid expansion of this industry and the growing concern with the associated emissions, the EPA proceeded to establish a number of VOC standards in the 2012 NSPS, while indicating in the 2012 rulemaking an intent to revisit methane at a later date when additional information was available from the GHGRP.

We have since received and evaluated considerable additional data, which confirms that the oil and natural gas industry is one of the largest emitters of methane in the United States. As

[55] WRI CAIT Climate Data Explorer. *http://cait.wri.org/*. Accessed March 30, 2016.

[56] *Ibid.*

[57] For the oil industry, the listing includes production, as explained above in footnote 27.

[58] Sierra Club et al., Petition for Reconsideration, In the Matter of: Final Rule Published at 77 FR 49490 (August 16, 2012), titled ''Oil and Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews; Final Rule,'' Docket ID No. EPA–HQ–OAR–2010–0505, RIN 2060–AP76 (2012).

total, the facts presented in sections IV.B and C of this preamble, along with prior EPA analysis, including that found in the 2009 Endangerment Finding, provide a rational basis for regulating GHG emissions from affected oil and gas sources by expressing GHG limitations in the form of limits on methane emissions.

To reiterate, the ''air pollution'' defined in the 2009 Endangerment Finding is the atmospheric mix of six long-lived and directly emitted GHGs: CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6.[72] This is the same pollutant that is regulated by this rule. However, the standards of performance adopted in the present rulemaking address only one constituent gas of this air pollution: Methane. This is reasonable, given that methane is the constituent gas emitted in the largest volume by the source category and for which there are available controls that are technically feasible and cost effective. There is no requirement that standards of performance address each component of an air pollutant. Clean Air Act section 111(b)(1)(B) requires the EPA to establish ''standards of performance'' for listed source categories, and the definition of ''standard of performance'' in CAA section 111(a)(1) does not specify which air pollutants must be controlled. So, while the limitations in this rule are expressed as limits on methane, the pollutant regulated is GHGs.

Some commenters have argued that the EPA is required to make a new endangerment finding before it may set limitations for methane from the oil and natural gas source category. We disagree, for the reasons discussed above. Moreover, even if CAA section 111 required the EPA to make an endangerment finding as a prerequisite for this rulemaking, then, the information and conclusions described above in sections IV.B and C of this preamble should be considered to constitute the requisite finding (which includes a finding of endangerment as well as a cause-or-contribute significantly finding). The same facts that support our rational basis determination would support such a finding. The EPA's rational basis for regulating GHGs, by setting methane limitations, under CAA section 111 is based primarily on the analysis and conclusions in the EPA's 2009 Endangerment Finding and 2010 denial of petitions to reconsider that Finding, coupled with the subsequent assessments from the IPCC, USGCRP, and NRC that describe scientific developments since those EPA actions and other facts contained herein.

More specifically, our approach here—reflected in the information and conclusions described above—is substantially similar to that reflected in the 2009 Endangerment Finding and the 2010 denial of petitions to reconsider. The D.C. Circuit upheld that approach in *Coalition for Responsible Regulation* v. *EPA*, 684 F.3d 102, 117–123 (D.C. Cir. 2012) (noting, among other things, the ''substantial . . . body of scientific evidence marshaled by EPA in support of the Endangerment Finding'' (id. at 120); the ''substantial record evidence that anthropogenic emissions of greenhouse gases very likely caused warming of the climate over the last several decades'' (id. at 121); ''substantial scientific evidence . . . that anthropogenically induced climate change threatens both public health and public welfare . . . [through] extreme weather events, changes in air quality, increases in food- and water-borne pathogens, and increases in temperatures'' (id.); and ''substantial evidence . . . that the warming resulting from the greenhouse gas emissions could be expected to create risks to water resources and in general to coastal areas. . . .'' (id.)). The facts, unfortunately, have only grown stronger and the potential adverse consequences of GHG to public health and the environment more dire in the interim.[73] The facts also demonstrate that the current methane emissions from oil and natural gas production sources and natural gas processing and transmission sources contribute substantially to nationwide GHG emissions.

The EPA also reviewed comments presenting other scientific information to determine whether that information has any meaningful impact on our analysis and conclusions. For both the rational basis analysis and for any endangerment finding, assuming for the sake of argument that one would be necessary for this final rule, the EPA focused on public health and welfare impacts within the United States, as it did in the 2009 Endangerment Finding. The impacts in other world regions strengthen the case because impacts in other world regions can in turn adversely affect the United States and its citizens.[74]

Lastly, EPA identified technically feasible and cost effective controls that can be applied nationally to reduce methane emissions and, thus, GHG emissions, from the oil and natural gas source category.

The EPA considered whether the costs (*e.g.,* capital costs, operating costs) are reasonable considering the emission reductions achieved through application of the controls required. For a detailed discussion on how we evaluated control costs and our cost analysis for individual emission sources, please see the proposal and the final TSD in the public docket.

V. Summary of Final Standards

This section presents a summary of the specific standards we are finalizing for various types of equipment and emission points. More details of the rationale for these standards and requirements, including alternative compliance options and exemptions to the standards, are provided in sections VI, VII, and VIII of this preamble, the TSD, and the RTC document in the public docket.

A. Control of GHG and VOC Emissions in the Oil and Natural Gas Source Category—Overview

In this action, the EPA is finalizing emission standards for GHG, in the form of limitations on methane, and VOC

published on Table A–1 to subpart A of 40 CFR part 98 should still be used.

[72] See 74 FR 66496, 66497 (December 15, 2009).

[73] Nor does the EPA consider the cost of potential standards of performance in making this finding. Like the endangerment finding under section 202(a) at issue in State of Massachusetts v. EPA, 549 U.S. 497 (2007), the pertinent issue is a scientific inquiry as to whether an endangerment to public health or welfare from the relevant air pollution may reasonably be anticipated. Where, as here, the scientific inquiry conducted by the EPA indicates that these statutory criteria are met, the Administrator does not have discretion to decline to make a positive endangerment finding to serve other policy grounds. Id. at 532–35. In this regard, an endangerment finding is analogous to setting national ambient air quality standards under CAA section 109(b), which similarly call on the Administrator to set standards that in her ''judgment'' are ''requisite to protect the public health''. The EPA is not permitted to consider potential costs of implementation in setting these standards. Whitman v. American Trucking Assn's, 531 U.S. 457, 466 (2001); see also *Michigan* v. *EPA*, U.S. (no. 14–46, June 29, 2015) slip op. pp. 10–11 (reiterating *Whitman* holding). The EPA notes further that section 111(b)(1) contains no terms such as ''necessary and appropriate'' which could suggest (or, in some contexts, require) that costs may be considered as part of the finding. Compare CAA section 112(n)(1)(A); see *State of Michigan,* slip op. pp. 7–8. The EPA, of course, must consider costs in determining whether a best system of emission reduction is adequately demonstrated and so can form the basis for a section 111(b) standard of performance, and the EPA has carefully considered costs here and found them to be reasonable. See sections V and VI below. The EPA also has found that the rule's quantifiable benefits exceed regulatory costs under a range of assumptions were new capacity to be built. See RIA. Accordingly, this endangerment finding would be justified if (against our view) it is both required, and (again, against our view) costs are to be considered as part of the finding.

[74] See 74 FR 66514 and 66535, December 15, 2009.

emissions, for certain new, modified and reconstructed emission sources across the oil and natural gas source category at subpart OOOOa. For some of these sources, there are VOC requirements currently in place that were established in the 2012 NSPS, and we are now establishing GHG limitations for those emission points. For others, for which there are no current requirements, we are finalizing both GHG and VOC standards. We are also finalizing improvements to enhance implementation of the current standards at subpart OOOO. For the reasons explained in the previous section, the EPA believes that GHG standards, in the form of limitations on methane, are warranted, even for those already subject to VOC standards under the 2012 NSPS. Further, as shown in the final TSD, there are cost effective controls that achieve simultaneous reductions of GHG and VOC emissions.

Pursuant to CAA section 111(b), we are both amending subpart OOOO and adding a new subpart, OOOOa. We are amending subpart OOOO, which applies to facilities constructed, modified or reconstructed after August 23, 2011, (*i.e.,* the original proposal date of subpart OOOO) and on or before September 18, 2015 (*i.e.,* the proposal date of the new subpart OOOOa), and is amended only to include the revisions reflecting implementation improvements in response to issues raised in petitions for reconsideration. We are adding subpart OOOOa, which will apply to facilities constructed, modified or reconstructed after September 18, 2015, to include current VOC requirements already provided in subpart OOOO (as updated) as well as new provisions for GHGs and VOCs across the oil and natural gas source category as highlighted below in this section.

As the purpose of this action is to control and limit emissions of GHG and VOC, EPA seeks to confirm that all regulatory standards are met. Any owner or operator claiming technical infeasibility, nonapplicability, or exemption from the regulation has the burden to demonstrate the claim is reasonable based on the relevant information. In any subsequent review of a technical infeasibility or nonapplicability determination, or a claimed exemption, EPA will independently assess the basis for the claim to ensure flaring is limited and emissions are minimized, in compliance with the rule. Well-designed rules ensure fairness among industry competitors and are essential to the success of future enforcement efforts.

B. Centrifugal Compressors

We are finalizing amendments to the 2012 NSPS, and adding new requirements to establish both VOC and GHG standards (in the form of limitations on methane emissions) for new, modified or reconstructed wet seal centrifugal compressors located across the oil and natural gas source category. Specifically, the final rule adds GHG standards to the current VOC standards for wet seal centrifugal compressors, as well as establishing GHG and VOC standards for those that are currently unregulated, with one exception. We are not establishing requirements for centrifugal compressors at well sites. As finalized, the standards require a 95 percent reduction of the emissions from each wet seal centrifugal compressor affected facility. The standard can be achieved by capturing and routing the emissions, using a cover and closed vent system, to a control device that achieves an emission reduction of 95 percent, or routing to a process.

C. Reciprocating Compressors

We are finalizing amendments to the 2012 NSPS and adding new requirements to establish both VOC and GHG standards (in the form of limitations on methane emissions) for new, modified, or reconstructed reciprocating compressors located across the oil and natural gas source category. Specifically, the final rule adds GHG standards to the current VOC standards for reciprocating compressors, as well as establishing GHG and VOC standards for those that are currently unregulated, with one exception. We are not establishing requirements for reciprocating compressors at well sites. The standards, which are operational standards, require either replacement of the rod packing based on usage or routing of rod packing emissions to a process via a closed vent system under negative pressure. The owner or operator of a reciprocating compressor affected facility is required to monitor the duration (in hours) that the compressor is operated, beginning on the date of initial startup of the reciprocating compressor affected facility. On or before 26,000 hours of operation, the owner or operator is required to change the rod packing. Owners or operators can elect to change the rod packing every 36 months in lieu of monitoring compressor operating hours. As an alternative to rod packing replacement, owners and operators may route the rod packing emissions to a process via a closed vent system operated at negative pressure.

D. Pneumatic Controllers

We are finalizing amendments to the 2012 NSPS and adding new requirements to establish both VOC and GHG standards (in the form of limitations on methane emissions) for new, modified, or reconstructed pneumatic controllers located across the oil and natural gas source category. Specifically, the final rule adds GHG standards to the current VOC standards for pneumatic controllers and establishes GHG and VOC standards for those that are currently unregulated. We are finalizing GHG (in the form of limitations on methane emissions) and VOC standards to control emissions by requiring use of low-bleed controllers in place of high-bleed controllers (*i.e.,* natural gas bleed rate not to exceed 6 standard cubic feet per hour (scfh)) at all locations within the source category except for natural gas processing plants. For natural gas processing plants, we are finalizing standards to control GHG and VOC emissions by requiring that pneumatic controllers have a zero natural gas bleed rate (*i.e.,* they are operated by means other than natural gas, such as being driven by compressed instrument air). These standards apply to each newly installed, modified or reconstructed pneumatic controller (including replacement of an existing controller). The finalized standards provide exemptions for certain critical applications based on functional considerations.

E. Pneumatic Pumps

We are finalizing standards for natural gas-driven diaphragm pumps.[75] The standards require that GHGs (in the form of limitations on methane emissions) and VOC emissions from new, modified and reconstructed natural gas-driven diaphragm pumps located at well sites be reduced by 95 percent if either a control device or the ability to route to a process is already available onsite, unless it is technically infeasible at sites other than new developments (*i.e.*, greenfield sites). In setting this requirement, the EPA recognizes that there may not be a control device or process available onsite. Our analysis shows that it is not cost-effective to require the owner or operator of a pneumatic pump affected facility to install a new control device or process onsite to capture emissions. If a control device or ability to route to a process is not available onsite, the pneumatic pump affected facility is not

[75] A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump. For more details, please see section VI.

subject to the emission reduction provisions of the final rule. In other instances, there may be a control device available onsite, but it may not be capable of achieving a 95 percent reduction. In those cases, we are not requiring the owner or operator to install a new control device onsite or to retrofit the existing control device, however, we are requiring the owner or operator of a pneumatic pump affected facility at a well site to route the emissions to an existing control device even it if achieves a level of emissions reduction less than 95 percent. In those instances, the owner or operator must maintain records demonstrating the percentage reduction that the control device is designed to achieve. In this way, the final rule will achieve emission reductions with regard to pneumatic pump affected facilities even if the only available control device cannot achieve a 95 percent reduction. For pneumatic pumps located at natural gas processing plants, the standards require that GHG and VOC emissions from natural gas-driven diaphragm pumps be zero.

F. Well Completions

We are finalizing GHG standards (in the form of limiting methane emissions) for well completions of hydraulically fractured (or refractured) gas wells as well as GHG and VOC standards for well completions of hydraulically fractured (or refractured) oil wells. As explained in the proposal preamble, the BSER for these emission reductions are the same as the BSER for reducing VOC emissions from hydraulically fractured gas wells. Therefore, the operational standards finalized in this action are essentially the same as the VOC standards for hydraulically fractured gas wells promulgated in the 2012 NSPS. For the reason stated above, the well completion standards in this final rule apply to both gas and oil well completions.

As with gas wells, for well completions of hydraulically fractured (or refractured) oil wells, we identified two subcategories of hydraulically fractured wells for which well completions are conducted: (1) Non-wildcat and non-delineation wells (subcategory 1 wells); and (2) wildcat and delineation wells (subcategory 2 wells). A wildcat well, also referred to as an exploratory well, is a well drilled outside known fields or is the first well drilled in an oil or gas field where no other oil and gas production exists. A delineation well is a well drilled to determine the boundary of a field or producing reservoir.

We are finalizing operational standards for subcategory 1 wells that require a combination of reduced emissions completion (REC) and combustion. Compared to combustion alone, the combination of REC and combustion will maximize gas recovery and minimize venting to the atmosphere. The finalized standards for subcategory 2 wells require combustion.

For subcategory 1 wells, we define the flowback period of a well completion as consisting of two distinct stages, the ‘‘initial flowback stage’’ and the ‘‘separation flowback stage.’’ The initial flowback stage begins with the onset of flowback and ends when the flowback is routed to a separator. Routing of the flowback to a separator is required as soon as a separator is able to function (*i.e.*, the operator must route the flowback to a separator unless it is technically infeasible for a separator to function). Any gas in the flowback prior to the point at which a separator begins functioning is not subject to control. The point at which the separator can function marks the beginning of the separation flowback stage. During this stage, the operator must do the following, unless technically infeasible to do so as discussed below: (1) Route all salable quality gas from the separator to a gas flow line or collection system; (2) re-inject the gas into the well or another well; (3) use the gas as an onsite fuel source; or (4) use the gas for another useful purpose that a purchased fuel or raw material would serve. If the operator assesses all four options for use of recovered gas, and still finds it technically infeasible to route the gas as described, the operator must route the gas to a completion combustion device with a continuous pilot flame and document the technical infeasibility assessment according to § 60.5420a(c) of this final rule, which describes the specific types of information required to document that the operator has exercised due diligence in making the assessment. No direct venting of gas is allowed during the separation flowback stage unless combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways. The separation flowback stage ends when the well is shut in and the flowback equipment is permanently disconnected from the well or on startup of production. This also marks the end of the flowback period.

The operator has a general duty to safely maximize resource recovery and minimize releases to the atmosphere over the duration of the flowback period. For subcategory 1 wells (except for low gas to oil ratio (GOR) and low pressure wells discussed below), the operator is required to have a separator onsite during the entirety of the flowback period. The operator is also required to document the stages of the completion operation by maintaining records of (1) the date and time of the onset of flowback; (2) the date and time of each attempt to route flowback to the separator; (3) the date and time of each occurrence in which the operator reverted to the initial flowback stage; (4) the date and time of well shut in; and (5) the date and time that temporary flowback equipment is disconnected. In addition, the operator must document the total duration of venting, combustion and flaring over the flowback period. All flowback liquids during the initial flowback period and the separation flowback period must be routed to a well completion vessel, a storage vessel or a collection system. Because the BSER for oil wells and gas wells are the same, the final rule applies these requirements to both oil and gas wells.

For subcategory 2 wells, we are finalizing an operational standard that requires either (1) routing all flowback directly to a completion combustion device with a continuous pilot flame (which can include a pit flare) or, at the option of the operator, (2) routing the flowback to a well completion vessel and sending the flowback to a separator as soon as a separator will function and then directing the separated gas to a completion combustion device with a continuous pilot flame. For option 2, any gas in the flowback prior to the point when the separator will function is not subject to control. In either case, combustion is not required if combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways. Operators are required to maintain the same records described above for category 1 wells.

As with gas wells, we similarly recognize the limitation of ‘‘low pressure’’ oil wells from conducting REC. Therefore, consistent with the 2012 NSPS, low pressure wells are affected facilities and have the same requirements as subcategory 2 wells (wildcat and delineation wells). We have revised the definition of a ‘‘low pressure’’ well in response to comment.

Further, wells with a GOR of less than 300 scf of gas per stock tank barrel of oil produced are affected facilities, but have no well completion requirements, providing the owner or operator maintains records of the low GOR certification and a claim signed by the certifying official.

We are also retaining the provision from the 2012 NSPS, now at § 60.5365a(a)(1), that a well that is refractured, and for which the well completion operation is conducted according to the requirements of § 60.5375a(a)(1) through (4), is not considered a modified well and, therefore, does not become an affected facility for purposes of the well completion standards. We point out that such an exclusion of a ''well'' from applicability under the NSPS has no effect on the affected facility status of the ''well site'' for purposes of the fugitive emissions standards at § 60.5397a.

G. Fugitive Emissions From Well Sites and Compressor Stations

We are finalizing standards to control GHGs (in the form of limitations on methane emissions) and VOC emissions from fugitive emission components at well sites and compressor stations. Specifically, we are finalizing semiannual monitoring and repair of fugitive emission components at well sites and quarterly monitoring and repair at compressor stations. Monitoring of the components must be conducted using optical gas imaging (OGI), and repairs must be made if any visible emissions are observed. Method 21 may be used as an alternative monitoring method at a repair threshold level at 500 parts per million (ppm). Repairs must be made within 30 days of finding fugitive emissions and a resurvey of the repaired component must be made within 30 days of the repair using OGI or Method 21 at a repair threshold of 500 ppm. A monitoring plan that covers the collection of fugitive emissions components at well sites or compressor stations within a company-defined area must be developed and implemented.

H. Equipment Leaks at Natural Gas Processing Plants

We are finalizing standards to control GHGs (in the form of limitations on methane emissions) from equipment leaks at new, modified or reconstructed natural gas processing plants. These requirements are the same as the VOCs equipment leak requirements in the 2012 NSPS and require the level of control established in NSPS part 60, subpart VVa, including a detection level of 500 ppm for certain pieces of equipment, as in the 2012 NSPS. As with VOC reduction, we believe that subpart VVa level of control reflects the best system of emission reductions for reducing methane emissions.

I. Liquids Unloading Operations

The EPA stated in the proposal that we did not have sufficient information to propose a national standard for liquids unloading.[76] However, the EPA requested comment on nationally applicable technologies and techniques that reduce GHG and VOC emissions from these events. Although the EPA received valuable information from the public comment process, the information was not sufficient to finalize a national standard representing BSER for liquids unloading.

Specifically, we requested data and information on the level of GHG and VOC emissions per unloading event, the number of unloading events per year, and the number of wells that perform liquids unloading. In addition, we requested comment on (1) characteristics of the well that play a role in the frequency of liquids unloading events and the level of emissions; (2) demonstrated techniques to reduce the emissions from liquids unloading events, including the use of smart automation and the effectiveness and cost of these techniques; (3) whether there are demonstrated techniques that can be employed on new wells that will reduce the emissions from liquids unloading events in the future; and (4) whether emissions from liquids unloading can be captured and routed to a control device and whether this has been demonstrated in practice.

The EPA received some information pertaining to our request for information. Specifically, the EPA received information on the frequency of unloading and on techniques to reduce emissions through capture or flaring and learned of some operators that have been able to achieve capture in practice. While we have gained better understanding of the practice of liquids unloading, the EPA did not receive the necessary information to identify an emission reduction technology that can be applied across the category of sources. We also considered the possibility of subcategorization. However, according to the information received, the differences in liquids unloading events (with respect to both frequency and emission level) are not due to differences in well size or type of wells at which liquids unloading is performed, but rather the specific conditions of a given well at the time the operator determines that well production is impaired such that unloading must be done. Operators select the technique to perform liquids unloading operations based on the conditions of the well each time production is impaired. Because well conditions change over time, each iteration of unloading may require repeating a single technique or attempting a different technique that may not have been appropriate under prior conditions. Given the differences in conditions at different wells when liquids unloading must be performed, the EPA did not receive information about techniques, individually or as a group, that helped us to identify a BSER under our CAA section 111(b) authority. The EPA continues to search for better means to address emissions associated with liquids unloading and is including this emissions source in the upcoming information gathering effort.[77] Please refer to the RTC for additional discussion on liquids unloading.[78]

J. Recordkeeping and Reporting

We are finalizing recordkeeping and reporting requirements that are consistent with those in the current NSPS. The final rule requires owners or operators to submit initial notifications and annual reports, in addition to retaining records to assist in documenting that they are complying with the provisions of the NSPS.

For new, modified, or reconstructed pneumatic controllers, owners and operators are not required to submit an initial notification for each piece of equipment; rather, they must report the installation of these affected facilities in their first annual report following the compliance period during which they were installed. Owners or operators of well affected facilities (consistent with current requirements for gas well affected facilities) are required to submit an initial notification no later than two days prior to the commencement of each well completion operation. This notification must include contact information for the owner or operator, the United States Well Number (formerly the American Petroleum Institute (API) well number), the latitude and longitude coordinates for each well, and the planned date of the beginning of flowback.

In addition, initial annual reports are due no later than 90 days after the end of the initial compliance period, which is established in the rule. Subsequent annual reports are due no later than the same date each year as the initial annual report. The annual reports include information on all affected facilities that were constructed, modified or reconstructed during the previous year. A single report may be submitted covering multiple affected facilities,

[76] *See* 80 FR 56614 and 80 FR 56644, September 18, 2015.

[77] *See* section III.E of this preamble for a discussion of the upcoming information gathering effort.

[78] *See* RTC document in EPA Docket ID No. EPA–HQ–OAR–2010–0505.

provided that the report contains all the information required by § 60.5420a(b). This information includes general information on the company (*e.g.*, company name), as well as information specific to individual affected facilities, such as the well ID associated with the affected facility (*e.g.*, storage vessels) and the facility site name (*e.g.*, ''Compressor Station XYZ'' or ''Tank Battery 123'') and the address of the affected facility.

For well affected facilities, the information required in the annual report includes the location of the well, the United States well number, the date and time of the onset of flowback following hydraulic fracturing or refracturing, the date and time of each attempt to direct flowback to a separator, the date and time of each occurrence of returning to the initial flowback stage, and the date and time that the well was shut in and the flowback equipment was permanently disconnected or the startup of production, the duration of flowback, the duration of recovery to the flow line, duration of the recovery of gas for another useful purpose, duration of combustion, duration of venting, and specific reasons for venting in lieu of capture or combustion. For each well for which a technical infeasibility exemption is claimed, to route the recovered gas to any of the four options specified in § 60.5375a(a)(1)(ii), the report includes the reasons for the claim of technical infeasibility with respect to all four options provided in that subparagraph.

For each well for which an exemption is claimed the owner or operator must maintain records of the low GOR certification and submit a claim signed by the certifying official in the annual report. For each well for which an exemption is claimed for conditions in which combustion may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways, the report should include the location of the well, the United States Well Number, the specific exception claimed, the starting date and ending date for the period the well operated under the exception, and an explanation of why the well meets the claimed exception. The annual report must also include records of deviations where well completions were not conducted according to the applicable standards.

For centrifugal compressor affected facilities, information in the annual report must include an identification of each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period, as well as records of deviations in cases where the centrifugal compressor was not operated in compliance with the applicable standards.

For reciprocating compressors, information in the annual report must include the cumulative number of hours of operation or the number of months since initial startup or the previous reciprocating compressor rod packing replacement, whichever is later, or a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

Information in the annual report for pneumatic controller affected facilities includes location and documentation of manufacturer specifications of the natural gas bleed rate of each pneumatic controller installed during the reporting period. For pneumatic controllers for which the owner is claiming an exemption from the standards, the annual report includes documentation that the use of a pneumatic controller with a natural gas bleed rate greater than 6 scfh is required and the reasons why. The annual report also includes records of deviations from the applicable standards.

For pneumatic pump affected facilities, information in the annual report includes an identification of each pneumatic pump constructed, modified or reconstructed during the compliance period; if applicable, a certification that no control was available onsite and that there is no ability to route to a process; an identification of any sites that contain pneumatic pumps and installed a control device during the reporting period, where there was previously no control device or ability to route to a process at a site; and records of deviations in cases where the pneumatic pump was not operated in compliance with the applicable standards.

The final rule includes new requirements for monitoring and repairing sources of fugitive emissions at well sites and compressor stations. An owner or operator must submit an annual report, which covers the collection of fugitive emissions components at well sites and compressor stations within an area defined by the company. The report must include the date and time of the surveys completed during the reporting year, the name of the operator performing the survey; the ambient temperature, sky conditions, and maximum wind during the survey; the type of monitoring instrument used; the number and type of components that were found to have fugitive emissions; the number and type of components that were not repaired during the monitoring survey; the number and type of difficult-to-monitor and unsafe-to-monitor components that were monitored; the date of the successful repair of the fugitive emissions component if it was not repaired during the survey; the number and type of fugitive emission components that were placed on delay of repair and the explanation of why the component could not be repaired and was placed on delay of repair; and the type of monitoring instrument used to resurvey a repaired component that could not be repaired during the initial monitoring survey. If an owner or operator chooses to use Method 21 to conduct the monitoring survey, they are required to keep records that include the type of monitoring instrument used and the fugitive emissions component identification. The owner or operator is required to keep a log for each affected facility. The log must include the date the monitoring survey was performed, the technology used to perform the survey, the number and types of equipment found to have fugitive emissions, a digital photograph or video of the monitoring survey when an OGI instrument is used to perform the monitoring survey, the date or dates of first attempt to repair the source of fugitive emissions, the date of repair of each source of fugitive emissions that could not be repaired during the initial monitoring survey, any source of fugitive emissions found to be technically infeasible or unsafe to repair and an explanation of why the component was placed on delay of repair, a list of the fugitive emissions components that were tagged as a result of not being repaired during the initial monitoring survey, and a digital photograph or video of each untagged fugitive emissions component that could not be repaired during the monitoring survey when the fugitive emissions were initially found. These digital photographs and logs must be available at the affected facility or the field office.

Consistent with the current requirements of subpart OOOO, records must be retained for 5 years and generally consist of the same information required in the initial notification and annual reports. The records may be maintained either onsite or at the nearest field office.

K. Reconsideration Issues Being Addressed

The EPA is finalizing numerous items in subpart OOOO on which we granted reconsideration and proposed changes with some further adjustments as a result of public comment. To the extent that these items relate to subpart OOOOa, we are also finalizing the same provisions for purposes of consistency between the two rules. First, we are finalizing corrections to the storage vessel control device monitoring and testing provisions related to in-field performance testing of enclosed combustors, initial and ongoing performance testing for any enclosed combustors used to comply with the emissions standard for an affected facility, and consistent requirements for monitoring of visible emissions for all enclosed combustion units. We are also finalizing clarified applicability requirements for storage vessel affected facilities. Next, we are finalizing amendments to include initial compliance requirements for bypass devices and certain closed vent systems and provide an alternative in subpart OOOO. Specifically, the rule allows for either an alarm at the bypass device or a remote alarm. The EPA is not finalizing our proposal to require both forms of alarm under subpart OOOO to avoid retroactive requirements.

Additionally, the EPA is finalizing recordkeeping requirements for repair logs for control devices failing a visible emissions test. We are clarifying the due date for the initial annual report and finalizing that flares used to comply with subpart OOOO are subject to the design and operation requirements in the general provisions. Next, we clarify that the monitoring provisions of subpart VVa applicable to affected units of subpart OOOO do not extend to open-ended valves or lines. We are finalizing clarification to the initial compliance requirement specifically to identify that the 2012 rule already includes a provision similar to subpart KKK. The EPA is finalizing the exemption from the notification required for reconstruction to affected facility pneumatic controllers, centrifugal compressors, and storage vessels in subpart OOOOa. The EPA is finalizing provisions for management of waste from spent carbon canisters. The EPA is finalizing a definition of the term ''capital expenditure'' in subpart OOOO. The EPA is finalizing an exemption for certain water recycling vessels that EPA did not intend to be affected facility storage vessels under subparts OOOO or OOOOa. By exempting such vessels, EPA will address a disincentive for recycling of water for hydraulic fracturing. Lastly, the EPA is not finalizing continuous control device monitoring requirements for storage vessels and centrifugal compressor affected facilities in subpart OOOO. For additional discussion of these issues, please refer to section VI of this preamble and the RTC.

L. Technical Corrections and Clarifications

We discovered 22 drafting errors in the proposal and have corrected these errors in the final rule. Please see section VI for a complete list of technical corrections and clarifications.

M. Prevention of Significant Deterioration and Title V Permitting

In the proposed rule, we stated that the pollutant we were proposing to regulate was GHGs, not methane as a separately regulated pollutant. 80 FR 56593, 56600–01 (Sept. 18, 2015). As explained in section VII of this preamble, we are adding provisions to the final rule, analogous to what was included in Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 FR 64509 (Oct. 23 2015), to make clear in the regulatory text that the pollutant regulated by this rule is GHGs.

N. Final Standards Reflecting Next Generation Compliance and Rule Effectiveness

In making decisions on the final requirements for this rule, we have emphasized the value of requirements that reflect principles of Next Generation Compliance and Rule Effectiveness. EPA's Next Generation Compliance strategy includes designing rules that promote improved compliance and better environmental outcomes. Specifically, we are finalizing standards with the following Next Generation Compliance strategies: (1) Electronic reporting via the EPA's Central Data Exchange (CDX), (2) clear applicability criteria (*e.g.*, modification criteria), (3) incentives for intrinsically lower emitting equipment (*e.g.*, solar pumps at gas plants are not affected facilities), (4) OGI technology for monitoring fugitive emissions, (5) digital picture reporting as an alternative for well completions (''REC PIX'') and manufacturer installed control devices, (6) qualified professional engineer certification of technical infeasibility to connect a pneumatic pump to an existing control device, and (7) qualified professional engineer certification of closed vent system design. These requirements, or options for compliance, provide opportunities for owners and operators to reduce obligations by making particular choices, reduce the burden for both the regulated industry and the agencies providing oversight, and provide greater transparency for all parties, including the public.

VI. Significant Changes Since Proposal

This section identifies significant changes in this rule from the proposed rule. These changes reflect the EPA's consideration of over 900,000 comments submitted on the proposal and other information received since the proposal, while preserving the aims underlying the proposal. The final rule protects human health and the environment by improving the existing NSPS and adding emission reduction standards for additional significant sources of GHGs and VOCs, consistent with the CAA. The EPA sought to achieve this important goal by endeavoring, where possible, to consistently expand the 2012 NSPS requirements across the oil and natural gas sector while also accounting for the unique characteristics of each type of source in setting emission reduction requirements. In this section, we discuss the significant changes since proposal by source category and the broad background for those changes. More specific information regarding comments and our responses appears in section VIII and in materials available in the docket.

A. Centrifugal Compressors

For centrifugal compressors, comments and information available led us to finalize the standards as proposed. In the proposed rule, we proposed to require 95 percent reduction of emissions from each centrifugal compressor affected facility. The standard can be achieved by capturing and routing the emissions using a cover and closed vent system to a control device (*i.e.*, combustion control device) that achieves an emission reduction of 95 percent, or by routing the captured emissions to a process. For additional details, please refer to section VIII, the TSD, and the RTC supporting documentation in the public docket.

B. Reciprocating Compressors

For the reciprocating compressors requirements, we are finalizing the standards as proposed, except with a slight modification to the definition of reciprocating compressor rod packing. In the proposed rule, we proposed to require replacement of rod packing on or before 26,000 hours or 3 years of operation, or alternatively to route emissions via a closed vent system under negative pressure. To account for segments of the industry in which reciprocating compressors operate in a pressurized mode for a fraction of the calendar year, the standard is based on the determination that 26,000 hours of operation are comparable to 3 years of continuous operation.

In the final rule, we revised the definition of reciprocating compressor rod packing. The EPA received comment that the definition of rod packing should be included in the rule to clarify the intent to replace any component of the rod packing that was contributing to emissions from the rod packing assembly. Because we agree that this clarification is useful, we have revised the definition of reciprocating compressor rod packing in the final rule to mean a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes from the compressor, or any other mechanism that provides the same function of limiting the amount of compressed natural gas that escapes from the compressor. For additional details, please refer to section VIII, the TSD, and the RTC supporting documentation in the public docket.

C. Pneumatic Controllers

For pneumatic controllers, comments and information available led us to finalize the standards as proposed. We proposed to require the use of low-bleed controllers in place of high-bleed controllers (*i.e.,* natural gas bleed rate not to exceed 6 scfh)[79] at all locations within the source category, except for natural gas processing plants. For natural gas processing plants, the standards require control of GHG and VOC emissions by requiring that pneumatic controllers have a zero natural gas bleed rate (*i.e.,* they are operated by means other than natural gas, such as being driven by compressed instrument air).

The final rule provides that certain pneumatic controllers, reflecting the particular functions they perform, have only tagging and recordkeeping and reporting requirements. As discussed in the proposal, the EPA identified situations where high-bleed controllers (*i.e.,* controllers with a natural gas bleed rate greater than 6 scfh) are necessary because of functional requirements, such as positive actuation or rapid actuation. An example would be controllers used on large emergency shutdown valves on pipelines entering or exiting compressor stations. The 2012 NSPS accounts for this by providing an exemption to pneumatic controllers for which compliance would pose a functional limitation due to their actuation response time or other operating characteristics. The EPA is finalizing the same exemption for all pneumatic controllers across the source category. For additional details, please refer to section VIII, the TSD, and the RTC supporting documentation in the public docket.

D. Pneumatic Pumps

In the final rule, the EPA is finalizing requirements for pneumatic pumps that use control devices or processes that are already available onsite. At natural gas processing plants, the EPA proposed to require reductions of 100 percent of GHG (in the form of methane) and VOC emissions from all diaphragm pneumatic pumps. For locations other than natural gas processing plants, the EPA proposed to require reductions of 95 percent of GHG (in the form of methane) and VOC emissions from all natural gas-driven diaphragm pumps, if an existing control or process was available.

The public comment process helped us to identify aspects of the proposed requirements that may not be practical or feasible in all cases, and commenters submitted additional information for us to analyze. In this final rule, based on our consideration of the comments received and other relevant information, we have made certain changes to the proposed standards for pneumatic pumps. The final standards require the GHG (in the form of a limitation on methane) and VOC emissions from new, modified, or reconstructed natural gas-driven diaphragm pumps located at well sites to be routed to an available control device or process onsite, unless such routing is technically infeasible at non-greenfield sites. We are not finalizing a technical infeasibility exemption at greenfield sites, where circumstances that could otherwise make control of a pneumatic pump technically infeasible at an existing location can be addressed in the site's design and construction. For pneumatic pumps located at a natural gas processing plant, the final rule requires the GHG (in the form of a limitation on methane) and VOC emissions from natural gas-driven diaphragm pumps to be zero.

While we acknowledge that solar-powered, electrically-powered, and air-driven pumps cannot be employed in all applications, we encourage operators to use pumps other than natural gas-driven pneumatic pumps where their use is technically feasible. To incentivize the use of these alternatives, the final rule's definition of ''pneumatic pump affected facility'' described in § 60.5365a(h) only includes natural gas-driven pumps. Pumps that are driven by means other than natural gas are not affected facilities subject to the pneumatic pump provisions of the NSPS and are not subject to any requirements under the final rule.

Provided below are the significant changes since proposal that result from the information in the record and the comments that we received and our rationale for these changes. For additional details, please refer to section VIII, the TSD, and the RTC supporting documentation in the public docket.

1. Piston Pumps

The EPA received several comments concerning the level of GHG and VOC emissions from natural gas-driven pneumatic piston pumps. The comments focused on the small volume of gas discharged by these pumps and the intermittent nature of their use. Other commenters suggested that the EPA treat pneumatic pumps consistently with pneumatic controllers. The commenters state that the same bleed rate considerations should be applied to pneumatic pumps because they are similar devices. Other commenters discussed the technical infeasibility of controlling emissions from piston pumps due to the inability to move such a small and intermittent gas flow through a duct or pipe to a control device.

We agree with commenters that pneumatic controller bleed rate considerations can serve as a useful guide in considering emission reduction requirements for pneumatic pumps. In response to these comments, we further evaluated the natural gas flow rate of pneumatic pumps and agree that piston pumps are inherently low-emitting because of their small size, design, and usage patterns. As discussed in the TSD to the proposed rule, we used natural gas emission rates between 2.2 to 2.5 scf/hr during operation of piston pumps. We determined these emission rates based on a joint report from the EPA and the Gas Research Institute on methane emissions from the natural gas industry. Our analysis of the currently available data, the information in the record, and consideration of public comments lead us to the conclusion that we should exclude piston pumps from coverage under the NSPS based on their inherently low emission rates. This approach is consistent with the manner in which we addressed low-bleed pneumatic controllers. After considering the inherently low emission rates of low-bleed pneumatic controllers, we determined that they should not be subject to the final rule requirements. Similarly, based upon the information

[79] Low-bleed controllers are not affected facilities under this final rule.

that we have on the low emission rates of piston pumps, we are not establishing requirements for them in this final rule.

We note that our best available emissions data for diaphragm pumps, as discussed in the TSD, indicates that the emission rate ranges from about 20 to 22 scf/hr during operation of a diaphragm pump. Based on our analysis of this data, we do not believe exclusion of diaphragm pumps from the definition of a pneumatic pump affected facility is warranted. As a result, we are retaining requirements for diaphragm pumps in the final rule.

2. Pneumatic Pumps Located in the Gathering and Boosting and Transmission and Storage Segments

We received comment that pneumatic pumps located in the transmission and storage segment generally have very low emissions. Similar to the arguments presented above for piston pumps, commenters contend that these low emission rate pumps should not be subjected to the final rule. In response to these comments, we reviewed our available information used in the proposed rule TSD to estimate the number of pneumatic pumps and the emission rates of these pumps in all segments of the oil and natural gas sector. In the TSD for the final rule, we noted that neither the GHGRP nor the GHG Inventory include data about pneumatic pumps or their emission rates in the natural gas transmission and storage segment. Because we currently have no reliable source of information indicating the prevalence of use of pneumatic pumps in this segment, nor what their emission rates would be if they are used, we are not finalizing pneumatic pump requirements for the transmission and storage segment at this time.

We also reviewed the available GHGRP and GHG Inventory data for pneumatic pumps, which was limited to the production segment. We consider the production segment to include both well sites and the gathering and boosting segment. Our available data indicate that pneumatic pumps are used at well sites as well as emission data for those pumps, but are silent on the prevalence of use of pneumatic pumps in the gathering and boosting segment, and what their emission rates would be if they are used. As with pneumatic pumps in the transmission and storage segment, we are not finalizing pneumatic pump requirements for the gathering and boosting segments at this time because of the lack of information in the record to support finalizing requirements for these pumps.

We note that the EPA is currently conducting a formal process to gather additional data on existing sources in the oil and natural gas sector. We believe that this data collection effort will provide additional information on the use and emissions of pneumatic pumps in the transmission and storage segment and gathering and boosting segment. Once we have obtained and analyzed these data, we will be better equipped to determine whether regulation of pneumatic pumps in the transmission and storage segment and gathering and boosting segment is warranted. See section III.E for more detail regarding the EPA's information collection request for existing sources.

3. Technical Infeasibility

We agree with comments that there may be circumstances, such as insufficient pressure or control device capacity, where it is technically infeasible to capture and route pneumatic pump emissions to a control device or process, and we have made changes in the final rule to include an exemption for these instances. The owner or operator must maintain records of an engineering evaluation and certification providing the basis for the determination that it is technically infeasible to meet the rule requirements. The rule does not allow the operator to claim the technical infeasibility exemption for a pneumatic pump affected facility at a greenfield site (defined as a site, other than a natural gas processing plant, which is entirely new construction), where circumstances that could otherwise make control of a pneumatic pump technically infeasible at an existing location can be addressed in the site's design and construction.

4. Efficiency of Existing Control Devices

As noted above, we are finalizing emission standards for new, modified, and reconstructed natural gas-driven diaphragm pumps located at well sites requiring emissions be reduced by 95 percent if either a control device or the ability to route to a process is already available onsite. In setting this requirement, the EPA recognizes that there may not be a control device or process available onsite. Our analysis shows that it is not cost-effective to require the owner or operator of a pneumatic pump affected facility to install a new control device or process onsite to capture emissions. In those instances, the pneumatic pump affected facility is not subject to the emission reduction provisions of the final rule.

Commenters have also raised concerns, and we agree, that the control device available onsite may not be able to achieve a 95 percent emission reduction. We evaluated whether this requirement should only be triggered when a NSPS subpart OOOO or OOOOa compliant control device was onsite, which would alleviate the control efficiency concern raised by commenters. However, the EPA is concerned that significant emissions reductions would be lost as a result of limiting the required type of equipment that must be used to control pneumatic pump emissions to only those that are designed to achieve 95 percent emission reductions. We are not requiring the owner or operator to install a new control device on site that is capable of meeting a 95 percent reduction nor are we requiring that the existing control device be retrofitted to enable it to meet the 95 percent reduction requirement. However, we are requiring that the owner or operator of a pneumatic pump affected facility at well sites to route the emissions to an existing control device even if it achieves a level of emissions reduction less than 95 percent. In those instances, the owner or operator must maintain records demonstrating the percentage reduction that the control device is designed to achieve. In this way, the final rule will achieve emission reductions with regard to pneumatic pump affected facilities even if the only available control device on site cannot achieve a 95 percent reduction.

5. Compliance Requirements

In response to concerns about applicability of subpart OOOO or OOOOa compliance requirements, the EPA has clarified our intent in the final rule that existing control devices that are not already subject to subparts OOOO or OOOOa compliance requirements (*i.e.,* control devices that are subject to other federal or state compliance requirements) are not subject to the performance specifications, performance testing, and monitoring requirements in this rule solely because they are controlling pneumatic pump emissions. We believe that control devices covered by other federal, state, or other regulations would be subject to compliance requirements under those provisions and, therefore, we have reasonable assurance that the devices will perform adequately, and we do not need to include existing controls that are not already covered by subparts OOOO and OOOOa under the compliance requirements for these subparts.

6. Cost Analysis

In response to commenters' concerns that the costs were underestimated for compliance with the pneumatic pump requirements, we revised the cost analysis using the average of our annualized costs and two additional annualized cost estimates provided by commenters.[80] Commenters' cost estimate methodologies and inputs varied from EPA's cost estimate which prevented us from conducting a side-by-side comparison with our cost estimate, nor could we directly compare the commenters' estimates with one another. However, in order to take into account the cost estimates provided by the commenters, we revised our cost analysis using the average of our annualized costs and the two additional annualized cost estimates provided by commenters. This is the same approach we would have taken had we obtained cost quotes from three separate vendors to install the closed vent system, and which we believe is the most equitable procedure when there is insufficient information to distinguish between the three cost estimates. One commenter gave an estimated capital cost of $5,800 which is annualized to be $826. A second commenter gave an estimated capital cost of $8,500 which annualized to be $1,210. The proposed capital cost to route emissions through a closed vent system was $2,000 which when annualized is $285. Based on our revised cost analysis, the capital cost for routing the emissions to an existing control device or process is $5,433, and the annualized cost is $774. We more fully discuss our cost estimate analysis in the TSD.

We evaluated the cost of control for routing emissions to an existing combustion device or process where we assign the cost equally to methane and VOC. For diaphragm pumps at well sites, the cost of reducing methane emissions is $235 per ton and the cost of reducing VOC emissions is $847 per ton, using the single-pollutant approach. Based on this revised cost analysis using additional cost information, we find that the cost of control for reducing methane emissions remains reasonable.

7. Affected Facility Definition

The EPA received comment that there was contradictory language in the proposal preamble and regulatory text regarding recordkeeping requirements for pneumatic pumps where no control device was on site. This lack of clarity was the result of the affected facility definition for pneumatic pumps. In the final rule, we have revised the definition to clarify that coverage under this rule is independent of availability of a control device on site. Specifically, all natural gas-driven diaphragm pumps at natural gas processing plants or well sites are affected facilities, except for pumps at well sites that operate less than 90 days per calendar year. The EPA has revised the final regulatory text to make clear that all pneumatic pumps affected facilities must be reported on the annual report and records maintained as applicable to control status of the pump.

8. Timing of Initial Compliance

The EPA is also finalizing requirements for pneumatic pump affected facilities at natural gas processing plants. The EPA is finalizing GHG and VOC emissions control requirements for pneumatic pump affected facilities at well sites if there is a control device or ability to route to a process available on site or subsequently installed on site. We are also finalizing a technical infeasibility exception when it is infeasible to route the pneumatic pump to the control device (or route to a process) at non-greenfield sites. An owner or operator applying this exemption must obtain a professional engineering assessment demonstrating the reasons for the exemption.

As pointed out by commenters, the technical infeasibility exemption may be based on safety concerns that could arise when a control device is not designed to handle the additional stream from the pneumatic pump. Commenters also expressed concern about safety issues related to increased pressure on the rest of the closed vent system connected to the control device. In light of these comments, we believe that the proposed 60-day compliance period may be insufficient to identify a qualified professional engineer, obtain the necessary design documents for the existing control device and associated ductwork, evaluate the design documents in light of the increased flow from the pneumatic pump, make an assessment of the technical feasibility of routing the pneumatic pump to the control device, and issue the required certification. Therefore, we are finalizing the compliance period to begin on November 30, 2016 to allow sufficient time for these necessary tasks to be completed.

E. Well Completions

For the well completion requirements, we proposed to require RECs, when technically feasible and in combination with a completion combustion device, for subcategory 1 wells. For subcategory 2 wells, we proposed an operational standard that would require minimization of venting of gas and hydrocarbon vapors during the completion operation through the use of a completion combustion device, with provisions for venting in lieu of combustion for situations in which combustion would present safety hazards. The proposed rule identified challenging issues for which we solicited comment in order to obtain additional information.

The public comment process helped us to identify aspects of the proposed requirements that in practice may not be practical in all cases, and commenters submitted additional information for us to analyze. In this final rule, based on our consideration of the comments received and other relevant information, we have made certain changes to the proposed standards for well completions. The final rule refines the well completion requirements to reduce emissions and provide clarity for both operators and regulators. The EPA is finalizing well completion standards for hydraulically fractured or refractured wells.[81] The final standards require a combination of REC and combustion at subcategory 1 wells and combustion at subcategory 2 wells and low pressure wells. Provided below are the significant changes since proposal that result from the comments we received and our rationale for these changes. For additional details, please refer to section VIII, the TSD, and the RTC supporting documentation in the public docket.

1. Separator Function

The EPA solicited comment on the use of a separator during flowback and whether a separator can be employed for every well completion. We received several comments identifying situations where a separator cannot function. Specifically, commenters noted instances where a separator cannot function due to very low gas flow from the well, contaminated gas flow, or low reservoir pressure requiring artificial lift techniques. Commenters indicate that because of these scenarios there can be a complete absence of a separation flowback stage during the well completion (which, according to the commenters, can be particularly common in some basins and fields). Commenters asserted that many of these circumstances can be anticipated prior to the onset of flowback. Furthermore, commenters stated that the requirement to have a separator onsite would likely

[80] *See* EPA docket ID No. EPA–HQ–OAR–2010–0505.

[81] As noted earlier in section IV, in 2012 EPA promulgated VOC standards for completions of hydraulically fractured or refractured gas wells. Today's action establishes GHG standards for gas well completions, as well as GHG and VOC standards for hydraulically fractured and refractured oil well completions.

cause the operator to incur a cost with no environmental benefit derived.

We believe that commenters have presented legitimate situations where it would be technically infeasible to use a separator, which is required for performing a REC. The challenge is, however, that the factors that lead to technical infeasibility of a separator to function may not be apparent until the time the well completion occurs, at which time it is too late to provide the equipment and, as a result, the well completion will go forward without controls. Further, the commenters did not provide data, and we do not have sufficient data to consistently and accurately identify the subcategory or types of wells for which these circumstances occur regularly or what criteria would be used as the basis for an exemption to the REC requirement such that a separator would not be required to be onsite for these specific well completions. In order to accommodate these concerns raised by commenters, the final rule requires a separator to be onsite during the entire flowback period for subcategory 1 wells (*i.e.,* non-exploratory or non-delineation wells, also known as development wells), but does not require performance of REC where a separator cannot function. We anticipate a subcategory 1 well to be producing or near other producing wells. We therefore anticipate REC equipment (including separators) to be onsite or nearby, or that any separator brought onsite or nearby can be put to use. For the reason stated above, we do not believe that requiring a separator onsite would incur cost with no environmental benefit.

However, unlike subcategory 1 wells, subcategory 2 wells are in areas where gas composition is likely unknown and, therefore, there is less certainty that a separator can work at these wells. If the separator does not work, there are unlikely subcategory 1 wells nearby that can put the separator to use. For the reasons stated above, we are not requiring that a separator be onsite for the well completion of subcategory 2 wells.

The EPA had proposed that, for subcategory 2 wells and low pressure wells, operators would be required to route flowback to a completion combustion device as soon as the separator was able to function. We had based the proposed requirement for these wells on our determination that BSER was combustion, and efficient combustion using traditional combustion devices could be achieved through separation of the gas from the liquid and solid flowback materials prior to routing to the completion combustion device.

As discussed in the 2015 proposal, traditional combustion devices (*e.g.,* flares or enclosed combustors) cannot work initially because the flowback following hydraulic fracturing consists for liquids, gases and sand in high-volume, multiphase slug flow. As a result, these devices can work only after a separator can function. While pit flares can be installed and used from the start, considering the makeup of the initial flowback, we believe there is little gas to be burned, and so we assume there is not an appreciable difference between the amount of emissions reductions between a traditional combustion device and a pit flare. In addition, we believe that pit flares have increased potential for secondary impacts compared to traditional flares, due to the potential for the incomplete combustion of natural gas across the pit flare plume.

Although not required, some owners and operators may choose to separate the gas from the other flowback materials for water management or other purposes. If a separator is used, any separated gas can be routed to combustion. In light of all of the above, we are providing in the final rule two options for completions of subcategory 2 wells: (1) Route all flowback directly to a completion combustion device (in that case a pit flare); or (2) should an owner or operator choose to use a separator, route the separated gas to a completion combustion device as soon as a separator is able to operate.

We are providing the same two options for low pressure wells. We believe that wells cannot perform a REC if there is not sufficient well pressure or gas content during the well completion to operate the surface equipment required for a REC, and low pressure gas could prevent proper operation of the separator. Alternatively, when feasible, some owners and operators may choose to separate the gas from the other flowback materials for water management or other purposes. If a separator is used, any separated gas must be routed to combustion.

2. REC Feasibility

The second instance for potential technical infeasibility occurs during the separation flowback stage, where operators cannot perform a REC and, therefore, must combust. The EPA received comment that additional requirements are necessary to ensure that flaring of the recovered gas during the separation flowback stage is limited to scenarios where all options included in our definition for REC—(1) route the recovered gas from the separator into a gas flow line or collection system, (2) re-inject the recovered gas into the well or another well, (3) use the recovered gas as an onsite fuel source, or (4) use the recovered gas for another useful purpose that a purchased fuel or raw material would serve—have been pursued and their technical infeasibility documented.[82] Commenters identified factors such as the availability and capacity of gathering lines, right of way issues, the quality of gas, and ownership issues that could impact the ability of operators to capture and use gas. Commenters stated that the provision for technical infeasibility for operators to use the recovered gas is vague and runs counter to the improvements the EPA seeks to establish within the oil and gas industry. Other commenters urged the EPA to allow flaring only as a last resort by requiring advanced notification and detailed documentation of the technical infeasibility of capturing and using salable quality gas. Commenters further stated that flaring should be very rarely necessary, as the EPA has identified four separate options for using recovered gas. The commenter recommends that EPA add additional notification and reporting requirements to ensure that all four options have been pursued and their technical infeasibility documented. The EPA agrees that the exemption from REC due to technical infeasibility should be limited. However, as illustrated by the comments received, the circumstances under which a REC is technically infeasible are varied. It is, therefore, difficult to provide one definition that can address all scenarios.

The EPA considered, but declined to require, advanced notification for the following reasons. Technical infeasibility can be an after-the-fact occurrence (*i.e.,* gas was contaminated and not of salable quality or had characteristics prohibiting other beneficial use and, therefore, the gas was combusted); therefore, advanced notification may not always be possible. A case-by-case advance evaluation by a regulatory agency is also not feasible considering the large number of completions, the wide geographic dispersion of the completions and the remote location of many well sites. For these reasons, we are not requiring prior notification of the claim of the technical infeasibility exemption.

Rather we have expanded recordkeeping requirements in the final

[82] This definition is the same as the definition for REC in subpart OOOO which, in response to public comment, included options in addition to routing to a gas line.

rule to include: (1) Detailed documentation of the reasons for the claim of technical infeasibility with respect to all four options provided in section 60.5375a(a)(1)(ii), including but not limited to, names and locations of the nearest gathering line; capture, re-injection, and reuse technologies considered; aspects of gas or equipment prohibiting use of recovered gas as a fuel onsite; and (2) technical considerations prohibiting any other beneficial use of recovered gas onsite. We emphasize that the exemption is limited to ''technical'' infeasibility (*e.g.,* lack of infrastructure, engineering issues, safety concerns).

In addition to the detailed documentation and recordkeeping requirement, the final rule requires that a separator be onsite during the entirety of the flowback period at subcategory 1 (developmental) wells, as described earlier. We believe these additional provisions will support a more diligent and transparent application of the intent of the technical infeasibility exemption from the REC requirement in the final rule. This information must be included in the annual report made available to the public 30 days after submission through the Compliance and Emissions Data Reporting Interface (CEDRI), allowing for public review of best practices and periodic auditing to ensure flaring is limited and emissions are minimized.

3. Gas to Oil Ratio (GOR) Exclusion

We are not finalizing the proposed exclusion of wells with low GOR from the definition of a well affected facility. However, in the final rule, low GOR wells are not subject to REC or combustion requirements. In order to ensure that low GOR claims are not being made without sufficient analysis and oversight, the final rule requires that records used to make the GOR determination must be retained and a certifying official must sign the low GOR determination.

The EPA proposed that wells with a GOR of less than 300 scf of gas per barrel of oil produced would not be affected facilities subject to the well completion provisions of the NSPS.[83] The reason for the proposed threshold GOR of 300 is that separators typically do not operate at a GOR less than 300, which is based on industry experience rather than a vetted technical specification for separator performance. Though in theory any amount of free gas could be separated from the liquid, in reality this is not practical given the design and operating parameters of separation units operating in the field.

The EPA also solicited comment on how operators could identify low GOR wells (*i.e.,* those with a GOR of less than 300 scf of gas per stock tank barrel of oil produced) prior to well completion, specifically the question of whether the GOR of nearby wells would be a reliable indicator in determining the GOR of a new or modified well. The EPA received comment stating that wells in the same area or reservoir could be used to indicate GOR prior to well completion. In light of the comments received and, upon further consideration, the EPA concludes that GOR of a well can be determined in advance. The EPA, therefore, does not believe that it is appropriate to prescribe in the final rule any specific way to determine the GOR for purposes of exempting low GOR wells from performing REC or combustion. However, to ensure that only those that, in fact, have GOR of less than 300 are exempt from the REC or combustion requirement; these wells remain affected facilities under the final rule. To ensure that their GORs are accurately determined, the final rule requires detailed documentation of their GOR determination as well as annual reporting and recordkeeping requirements. However, they are not subject to the REC or combustion requirement.

4. Low Pressure Wells

We have revised the low pressure well definition in the final rule. In the 2012 NSPS, the EPA recognized that certain wells, which the EPA called ''low pressure gas wells,'' cannot implement a REC because of a lack of necessary reservoir pressure to flow gas at rates appropriate for the transportation of solids and liquids from a hydraulically fractured gas well against additional back pressure that would be caused by the REC equipment, thereby making a REC infeasible. The 2012 NSPS exempts these wells from REC and instead requires combustion of the recovered gas.

In the EPA's proposed rule (80 FR 56611, September 18, 2015), in which we proposed to also regulate VOC and GHG emissions from oil wells, we proposed to amend the current requirements for low pressure gas wells to apply to all low pressure wells. We proposed to change the term ''low pressure gas well'' to ''low pressure well'' but keep the definition the same. The substance of the definition at proposal for ''low pressure well'' is the same as the currently codified definition for ''low pressure gas well'' in the 2012 NSPS. We solicited comment on whether this definition appropriately defined hydraulically fractured wells for which conducting a REC would be technologically infeasible or whether the definition should be revised to better characterize the criteria for all low pressure wells.

In our proposed definition, the pressure of the flowback fluid (oil, gas, and water) immediately before it enters the flow line is calculated by equation (1) below:

$$P_L\,(psia) = 0.445 \cdot P_R\,(psia) - 0.038 \cdot L(ft) + 67.578 \quad \text{Equation (1)}$$

Where:

P_L (*psia*) is the pressure of flowback fluid immediately before it enters the flow line;

P_R (*psia*) is the pressure of the reservoir containing oil, gas, and water; and

L(*ft*) is the depth of the well.

The EPA proposed that if the pressure of flowback fluid immediately before it enters the flow line, P_L, calculated using the above equation is less than the available line pressure, the well would be considered a low pressure well. Such a well would not be required to do a REC during flowback (*i.e.,* collect and send the associated gas to the flow line). Instead, such a well would only be required to combust the gas in a completion combustion device.

Commenters asked the EPA to provide a new definition of ''low pressure oil well'' to differentiate oil wells from gas wells. They stated that the definition of ''low pressure well'' set out in proposed section 60.5430a and taken from the definition of ''low pressure gas well'' in subpart OOOO (section 60.5430) is not appropriate for a low pressure oil well, because the surface and back pressure for oil wells is higher than that for gas wells. They further state that ''. . . once the hydraulic fracture load stops coming back, a gas well will typically have much less liquids in the production tubing, making the surface pressure actually higher for the gas well vs. an oil well. This difference would be reflected in the 0.038 number which represents the gas gradient in the well, which would impart a back pressure. For oil wells this back pressure would be higher . . .'' In response to these comments, the EPA modified the existing low pressure gas well equation (equation (1) above) to add pressure drop resulting from flow of oil and water in a well.

The EPA's evaluation of the steady flow of petroleum fluid (gas and oil) during flowback in wells resulted in the following modified equation, hereafter

[83] On February 24, 2015, API submitted a comment to the EPA stating that oil wells with GOR values less than 300 do not have sufficient gas to operate a separator. *http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2014-0831-0137.*

referred to as the low pressure well equation (equation 2 below):

$$P_L\,(psia) = 0.495 \times P_R - \frac{q_g}{q_g+q_o+q_w}[0.05 \times P_R + 0.038 \times L - 67.578] - \left[\frac{q_o}{q_g+q_o+q_w} \times \frac{\rho_o}{144} + \frac{q_w}{q_g+q_o+q_w} 0.433\right] \cdot L \qquad \text{Equation (2)}$$

Where:

P_L is the pressure of flowback fluid immediately before it enters the flow line, expressed in psia;

P_R is the pressure of the reservoir containing oil, gas, and water, expressed in psia;

L is the true vertical depth of the well, expressed in feet;

q_o, q_g, q_w are the flow rates of oil, gas, and water, respectively, in the well, expressed in cubic feet/second; and

ρ_o is the density of oil in the well, expressed in pounds per cubic feet.

EPA's low pressure well equation is used to predict the pressure of the flowback fluid (oil, gas, and water) immediately before it enters the flow line. The low pressure well equation uses inputs similar to those required for the gas well definition and for which information is understood to be available before well completion activity starts at a well site. These inputs include reservoir (or formation) pressure; true vertical depth of the well; flow rates of oil, gas, and water in the well; and the density of oil in the well.

As oil-gas-water mixture flows upwards in a well to a lower pressure location, oil and gas volumes change and some of the dissolved gas evolves out of solution in oil. These phenomena result in oil and gas densities and volumetric flows changing with well depth. Therefore, oil density, ρ_o, and volumetric flow rate, q_o, for use in equation (2) are calculated using the known value of oil API gravity at a well site and the widely used correlations provided in Vasquez and Beggs (1980).[84] The gas volumetric flow, q_g, is calculated using widely used correlations provided in Guo and Ghalambor (2005).[85] Details on using equation (2) to calculate the pressure of flowback fluid immediately before it enters the flow line, P_L, can be found in the TSD in the public docket.

As noted above, equation (2) is the low pressure well equation for all wells in the final rule. This equation predicts the pressure, P_L, of the flowback fluid (oil, gas, and water) immediately before it enters the flow line during the separation flowback period. In response to comments, the EPA's final regulations require that this pressure be compared to the actual flow line pressure available at the well site. Wells with insufficient predicted pressure to produce into the flow line are required to combust the gas in a control device. Wells with sufficient pressure to produce into the flow line are required to capture the gas and produce it into the flow line.

EPA further notes that equation (2) is a modification of equation (1) and adds pressure drop resulting from flows of oil and water. When characterizing a well with conditions of gas flow only (*i.e.,* $q_o = q_w = 0$), equation (2) reduces to equation (1), the equation for gas wells. Also note that equation (2) for line pressure is derived using a vertical well. It is known that inclined wells exist in the field, which will experience a somewhat higher frictional drop due to longer flow length. Nonetheless, it is expected that equation (2) would be able to account for minor increases in pressure drop due to increased frictional drop at inclined wells because the frictional pressure drop component contributes a small amount to the total pressure drop (about 1 percent on average) and conservative assumptions were used in deriving equation (2)—notably, bottom hole pressure equals one-half of formation pressure.

In addition to the revised low pressure well equation, we are providing, in the final definition of low pressure well, other characteristics of the well that would indicate that a well is a low pressure well. We believe that if the static pressure (*i.e.,* pressure with the well shut in and not flowing) at the wellhead following hydraulic fracturing, and prior to the onset of flowback, is less than the flow line pressure at the sales meter, the well is a low pressure well without having to demonstrate that it is such by using the low pressure well equation in the final rule.

Instead of using the equation, under the final rule, operators who suspect that a well may be a low pressure well have the option, for screening purposes, of performing a wellhead static pressure (*i.e.,* pressure with the well shut in and not flowing) check following fracturing and prior to the onset of flowback. If the static pressure at the wellhead was less than the flow line pressure at the sales meter, then the well would be a low pressure well. We believe that such a comparison would be conservative because, for a given well, the static pressure (*i.e.,* with no fluid movement through the well) would be higher than the dynamic pressure (*i.e.,* with the well flowing) because there would be no pressure losses brought about by friction caused by material movement in the tubing string. For some wells, use of this method could eliminate the need for the detailed calculations provided in the low pressure well equation discussed above. For other wells (*i.e.,* those wells where the static pressure was greater than the flow line pressure), it would be necessary for the operator to use the low pressure well equation.

Commenters asserted that many oil reservoirs have pressure that is insufficient for wells to naturally flow even after hydraulic fracturing. The commenters stated that this can be evidenced by the prevalence of artificial lift equipment such as rod pumps visible across the landscape of many oil producing areas. The commenters cited examples of reservoirs such as the Permian Basin, where horizontal drilling is used to extend the life of existing producing formations. The commenters explained that many oil wells that are hydraulically fractured do not have sufficient reservoir pressure to flowback fracture fluids. One company estimated that 30 percent of its hydraulically fractured horizontal wells and 80 percent of its hydraulically fractured vertical wells in the Permian Basin require artificial lift to flowback. In these cases, the commenter explained, rod pumps are installed on the wells to artificially lift the fracture fluids to the surface. In light of the comments received, the EPA believes that wells that require artificial lift equipment for flowback of fracture fluids should be classified as low pressure wells, as we believe that

[84] Vasquez, M. and Beggs, H.D., ''Correlations for fluid physical property prediction,'' JPT, 1980.

[85] Guo, B. and Ghalambor, A., ''Natural Gas Engineering Handbook,'' Gulf Publishing Company, 2005.

performing a REC is technically infeasible for these wells.

To meet the definition of low pressure well, the well must satisfy any of the criteria above. We have revised the definition in the regulatory text to reflect this change. Section VIII, the RTC document, the TSD, and other materials available in the docket provide more discussion of these topics.

5. Timing of Initial Compliance

The EPA proposed the well completion requirements that, if finalized, would apply to both oil and gas well completions using hydraulic fracturing. In the 2012 NSPS, we provided a phase-in approach in the gas well completion requirements due to the concern with insufficient REC and trained personnel if REC were required immediately for all gas well completions. However, we did not provide the same in this proposal on the assumption that the supplies of REC equipment and trained personnel have caught up with the demand and, therefore, are no longer an issue. While some commenters agreed, other commenters indicated that the proposed rule, which would dramatically increase the number of well completions subject to the NSPS, would lead to REC equipment shortages. One commenter estimated that it would take at least 6 months to obtain the necessary equipment, while another commenter estimated that it would take 24 months. One commenter noted that owners and operators have been drilling wells, but delaying completion, due to the current economic conditions affecting the industry, causing a suppressed equipment demand. Finally, one state regulatory agency recommended extending the compliance period to 120 days to allow sufficient time to contract for the necessary completion equipment.

After reviewing the comments, we agree that some owners and operators may have difficulty complying with the REC requirements in the final rule in the near term due to the unavailability of REC equipment. Although REC equipment suppliers have increased production to meet the demand for gas well completions under subpart OOOO, the affected facility under subpart OOOOa includes both gas and oil wells and will more than double the number of wells requiring REC equipment over subpart OOOO. We believe this demand will likely lead to a short-term shortage of REC equipment. However, based on the prior experience, we believe that suppliers have both the capability and incentive to catch up with the demand quickly, as opposed to the longer terms suggested by the commenters; they likely already stepped up production since this rule was proposed last year in anticipation of the impending increase in demand. In light of the above, the final rule provides a phase-in approach that would allow a quick build-up of the REC supplies in the near term. Specifically, for subcategory 1 oil wells, the final rule requires combustion for well completions conducted before November 30, 2016 and REC if technically feasible for well completions conducted thereafter. For subcategory 2 and low pressure oil wells, the final rule requires combustion during well completion, which is the same as that required for completion of subcategory 2 and low pressure gas well in the 2012 NSPS. For gas well completions, which are already subject to well completion requirements in the 2012 NSPS, the requirements remain the same.

F. Fugitive Emissions From Well Sites and Compressor Stations

For fugitive emissions requirements for the source category, three principles or aims directed our efforts. The first aim was to produce a consistent and accountable program for a source to use to identify and repair fugitive emissions at well sites and compressor stations. A second aim was to provide an opportunity for companies to design and implement their own fugitive emissions monitoring and repair programs. The third aim was to focus the fugitive emissions monitoring and repair program on components from which we expected the greatest emissions, with consideration of appropriate exemptions. The fourth aim was to establish a program that would complement other programs currently in place. With these principles in mind, we proposed a detailed monitoring plan; semiannual requirements using OGI technology for monitoring to find and repair sources of fugitive emissions, which we had identified as the BSER; a shifting monitoring schedule based on performance; a 15-day timeframe for repairing and resurveying leaks; and an exemption for low production wells.

The public comment process helped us to identify additional information to consider and provided an opportunity to refine the standards proposed. Commenters specifically identified concerns with the definition of modification for well sites and compressor stations, the monitoring plan, the fluctuating survey frequency, the overlap with state and federal requirements, use of emerging monitoring technologies, the initial compliance timeframe, and the relationship between production level and fugitive emissions.

In this final rule, based on our consideration of the comments received and other relevant information, we have made changes to the proposed standards for fugitive emissions from well sites and compressor stations. The final rule refines the monitoring program requirements while still achieving the main goals. Below we describe the significant changes since proposal for specific topics related to fugitive emissions and our rationale for these changes. For additional details, please refer to section VIII, the TSD, and the RTC supporting documentation in the public docket.

1. Fugitive Emissions From Well Sites

a. Monitoring Frequency

In conjunction with semiannual monitoring, the EPA co-proposed annual monitoring and solicited comment on the availability of trained OGI contractors and OGI instrumentation. 80 FR 56637, September 18, 2015. Commenters provided numerous comments and data regarding annual, semiannual and quarterly monitoring surveys. These comments largely focused on the cost, effectiveness, and feasibility of the different program frequencies. The EPA evaluated these comments and information, as well as certain production segment equipment counts from the 2016 public review draft GHG Inventory, which were developed from the data reported to the GHGRP. Based on the above information, the EPA updated its proposal assumptions on equipment counts per well site to use data from the 2016 public review draft update. This resulted in changes to the well site model plant. Specifically, the equipment count for meters/piping at a gas well site increased from 1 to 3, which tripled the component counts from meters/piping at these sites. In addition, the EPA developed a third model plant to represent associated gas well sites. This category includes wells with GOR between 300 and 100,000 standard cubic feet per barrel (scf/bbl), and the model plant is assumed to have the same component counts as the model oil well site, as well as components associated with meters/piping. The EPA used this information to re-evaluate the control options for annual, semiannual and quarterly monitoring. As shown in the TSD, the control cost, using OGI, based on quarterly monitoring is not cost-effective, while both semiannual and annual monitoring remain cost-effective for reducing GHG (in the form of methane) and VOC emissions. Because control costs for both semiannual and annual monitoring are cost-effective, we evaluated the difference in emissions reductions between the two monitoring frequencies and concluded that semiannual monitoring would achieve greater emissions reductions. Therefore, the EPA is finalizing the proposed semiannual monitoring frequency. Please see the RTC document in the public docket for further discussion.[86] Even though the EPA has determined that semi-annual surveys for well sites is the BSER under this NSPS, this does not preclude the EPA from taking a different approach in the future, including requiring more frequent monitoring (*e.g.,* quarterly).

b. Low Production Well Sites

The EPA proposed to exclude low production well sites (*i.e.,* well sites where the average combined oil and natural gas production is less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production) from the fugitive emissions monitoring and repair requirements for well sites. As we explained in the preamble to the proposed rule, we believed that these wells are mostly owned by small businesses and that fugitive emissions associated with these wells are generally low. 80 FR 56639, September 18, 2015. We were concerned about the burden on small businesses, in particular, where there may be little emission reduction to be achieved. Id. We specifically requested comment on the proposed exclusion and the appropriateness of the 15 boe per day threshold. We also requested data that would confirm that low production sites have low GHG and VOC fugitive emissions.

Several commenters indicated that low production well sites should be exempt from fugitive emissions monitoring and that the 15 boe per day threshold averaged over the first 30 days of production is appropriate for the exemption, however, commenters did not provide data. Other commenters indicated that the low production well sites exemption would not benefit small businesses since these types of wells would not be economical to operate and few operators, if any, would operate new well sites that average 15 boe per day.

Several commenters stated that the EPA should not exempt low production well sites because they are still a part of the cumulative emissions that would impact the environment. One commenter indicated that low production well sites have the potential to emit high fugitive emissions. Another commenter stated that low production well sites should be required to perform fugitive emissions monitoring at a quarterly or monthly frequency. One commenter provided an estimate of low producing gas and oil wells that indicated that a significant number of wells would be excluded from fugitive emissions monitoring.

Based on the data from DrillingInfo, 30 percent of natural gas wells are low production wells, and 43 percent of all oil wells are low production wells. The EPA believes that low production well sites have the same type of equipment (*e.g.,* separators, storage vessels) and components (*e.g.,* valves, flanges) as production well sites with production greater than 15 boe per day. Because we did not receive additional data on equipment or component counts for low production wells, we believe that a low production well model plant would have the same equipment and component counts as a non-low production well site. This would indicate that the emissions from low production well sites could be similar to that of non-low production well sites. We also believe that this type of well may be developed for leasing purposes but is typically unmanned and not visited as often as other well sites that would allow fugitive emissions to go undetected. We did not receive data showing that low production well sites have lower GHG (principally as methane) or VOC emissions other than non-low production well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites because the type of equipment and the well pressures are more than likely the same. In discussions with us, stakeholders indicated that well site fugitive emissions are not correlated with levels of production, but rather based on the number of pieces of equipment and components. Therefore, we believe that the fugitive emissions from low production and non-low production well sites are comparable.

Based on these considerations and, in particular, the large number of low production wells and the similarities between well sites with production greater than 15 boe per day and low production well sites in terms of the components that could leak and the associated emissions, we are not exempting low production well sites from the fugitive emissions monitoring program. Therefore, the collection of fugitive emissions components at all new, modified or reconstructed well sites is an affected facility and must meet the requirements of the fugitive emissions monitoring program.

c. Monitoring Using Method 21

The EPA's analysis for the proposed rule found OGI to be more cost-effective at detecting fugitive emissions than the traditional protocol for that purpose, Method 21, and the EPA, therefore, identified OGI as the BSER for monitoring fugitive emissions at well sites. See 80 FR 56636, September 18, 2015. The EPA solicited comment on whether to allow Method 21 as an alternative fugitive emissions monitoring method to OGI. 80 FR 56638, September 18, 2015. We also solicited comment on the repair threshold for components that are found to have fugitive emissions using Method 21. *Id.*

Numerous industry, state, and environmental commenters indicated that Method 21 is preferred or should be allowed as an alternative to OGI, citing availability, costs, and training associated with OGI.

Several commenters indicated that the EPA should set the Method 21 fugitive emissions repair threshold at 10,000 ppm, the level at which our recent work indicates that fugitive emissions are generally detectable using OGI instrumentation provided that the right operating conditions (*e.g.,* wind speed and background temperature) are present. 80 FR 56635, September 18, 2015. Some commenters stated that the repair threshold should be 500 ppm to achieve a high level of fugitive emission reductions while other commenters state that a 500 ppm repair threshold would target fugitive emissions that would not provide meaningful reductions.

The issue of the repair threshold when Method 21 is used is a critical decision. As discussed in the preamble to the proposed rule, Method 21, at an appropriate repair threshold, is capable of achieving the same or better emission reductions as OGI. However, at proposal, we determined that Method 21 was not cost-effective at a semiannual monitoring frequency with a repair threshold of 500 ppm.

While we agree with the importance of allowing the use of Method 21 as an alternative, we need to ensure that its use does not result in fewer emissions reductions than what would otherwise be achieved using OGI, which is the BSER based on our analysis. Available data show that OGI can detect fugitive emissions at a concentration of at least 10,000 ppm when restricting its use during certain environmental conditions

[86] See EPA docket ID No. EPA–HQ–OAR–2010–0505.

such as high wind speeds. Due to the dynamic nature for the OGI detection capabilities, OGI may also image emissions at a lower concentration when environmental conditions are ideal. Because an OGI instrument can only visualize emissions and not the corresponding concentration, any components with visible emissions, including those emissions that are less than 10,000 ppm, would be repaired. Method 21 is capable of detecting fugitive emissions at concentrations well below 10,000 ppm. However, if the repair threshold was set at 10,000 ppm, an owner or operator would not have to repair any leaks that are less than 10,000 ppm, thereby foregoing the reductions that would otherwise be achieved by using the OGI. For the reason outlined in this section, 10,000 ppm is not an appropriate repair threshold for Method 21.

Using information provided by commenters, we evaluated the methane and VOC emission reductions associated with the use of Method 21 at repair thresholds of 10,000 ppm and 500 ppm, the two levels recommended by the various commenters. We used AP–42 emission factors to determine the emissions from fugitive emissions components that were found to be leaking using a Method 21 instrument and concluded that emissions reductions are lower than when OGI is used to survey the same components. The lower emission reductions are due to fugitive emissions with a concentration lower than 10,000 ppm not being found using the Method 21 instrument when it is calibrated to detect emissions at a threshold of 10,000 ppm or greater.

We then calculated the emission reductions that result from using a Method 21 instrument to conduct a monitoring survey at a repair threshold of 500 ppm. At this threshold, the operator would have to repair every component found to have fugitive emissions over 500 ppm threshold. This results in emission reductions greater than the emissions reductions that would be achieved if OGI were used instead. For the reasons stated in this section, using Method 21 to conduct monitoring surveys at a repair threshold of 500 ppm is better than, or at least equivalent to, using OGI to conduct the same survey; we are allowing it in the final rule as an alternative to the use of OGI. We acknowledge that the cost of conducting a survey using Method 21 may be more expensive than using OGI; however, some owners or operators may still chose to use Method 21 for convenience or due to the lack of availability of OGI instruments or trained personnel. Therefore, to ensure that it achieves at least the level of emission reduction to be achieved using the OGI, the final rule allows the use of Method 21 with a repair threshold of 500 ppm.

Based on interest in having Method 21 as an approved alternative, we are finalizing it as an alternative to OGI. Allowing Method 21 as an alternative will address some of the uncertainty expressed by small entities that indicated a concern with needing to purchase an OGI instrument or hire trained OGI contractors to perform their monitoring surveys. We are finalizing Method 21 as an alternative to OGI for monitoring fugitive emissions components at a repair threshold of an instrument reading of 500 ppm or greater. We are also finalizing specific recordkeeping and reporting requirements when Method 21 is used to perform a monitoring survey.

d. Shifting of Monitoring Frequency Based on Performance

The EPA proposed shifting monitoring frequencies (ranging from annual to quarterly monitoring) based on the percentage of components that are found to have fugitive emissions during a monitoring survey. We solicited comment on the proposed monitoring approach, including the proposed metrics of one percent and three percent to determine monitoring frequency or whether the monitoring frequency thresholds should be based on a specific number of components that are found to have fugitive emissions. In addition, the EPA solicited comment on whether a performance-based frequency or a fixed-frequency program was more appropriate.

Most commenters opposed performance-based monitoring frequency. They raised specific concerns that performance-based monitoring and shifting monitoring frequencies would be costly, time-consuming, and impose a complex administrative burden for the industry and states. For example, commenters pointed out that an owner may have hundreds or even thousands of well sites and a potentially ever-changing survey schedule for each of those sites would present an untenable logistical hurdle. Most of the commenters stated that the EPA should finalize a fixed monitoring frequency to provide a level of certainty to owners and operators for planning future schedules of survey crews.

The EPA considered these comments and agrees that imposing a performance-based monitoring schedule would require operators to develop an extensive administrative program to ensure compliance. Under the performance-based monitoring, owners and operators would need to count all of the components at the well sites, affix identification tags on each component or develop detailed piping and instrument diagram. During each monitoring survey, owners and operators would need to calculate the percentage of leaking fugitive emissions components to determine the next monitoring frequency schedule.

We also agree that the shifting monitoring frequencies could cause regulated entities additional administrative burden to determine compliance since the monitoring frequencies could change each year, but the correct frequency may not be reflected in the operating permit. This could also result in fugitive emissions being undetected longer due to less frequent monitoring. We believe that the potential for a performance–based approach to encourage greater compliance is outweighed in this case by these additional burdens and the complexity it would add. Therefore, the EPA is finalizing a fixed-frequency monitoring instead of performance-based monitoring.

e. Fugitive Emissions Components Repair and Resurvey

The EPA proposed that components that are a source of fugitive emissions must be repaired or replaced as soon as practicable and, in any case, no later than 15 calendar days after detection of the fugitive emissions. For sources of fugitive emissions that cannot be repaired within 15 days of finding the emissions, due to technical infeasibility or unsafe conditions, the EPA proposed that the components could be placed on a delay of repair until the next scheduled shutdown or within six months, whichever is earlier. We also proposed that a repaired fugitive emissions component be resurveyed within 15 days of the repair. The EPA solicited comment on all three aspects.

Commenters voiced various opinions regarding the requirements. Many commenters shared concerns that the 15-day window for repairs is too short, due to factors such as remoteness of equipment locations, unsuccessful repair attempts, and multiple components needing repair. Other commenters preferred the 15-day window, in the interest of achieving immediate mitigation of health and safety risks and alignment with standards in several states.

Multiple commenters provided comments on the proposed delay of repair standards, including concerns about delays lasting longer than six months due to availability of supplies needed to complete repairs and information regarding the frequency of delayed repairs. Some commenters also indicated that in some cases, requiring prompt repairs could lead to more emissions than if repairs were able to be delayed, for example if a well shut-in or vent blow-down is required.

Regarding the 15-day window to resurvey repairs to fugitive emissions components, multiple commenters stated that the final rule should allow 30 days for the resurvey, due to the potential need for specialized personnel for the resurvey, while others considered 15 days to be adequate. Regarding performance of the resurvey, many commenters also suggested that soap bubbles, as specified in section 8.3.3 of Method 21, be allowed to determine if the components have been repaired.

After considering the comments above, the EPA agrees that repairs for some sources of fugitive emissions at a well site may take multiple attempts or require additional equipment that is not readily available and may take longer than 15 days to repair. Well sites, unlike chemical plants or refineries, may be located in remote areas and it is unlikely that they would have warehouses or maintenance shops nearby where spare equipment or tools are kept that would be needed to perform repairs within 15 days. We also recognize that fugitive emissions must be alleviated as soon as practicable. We believe that allowing an additional 15 days for repair would give owners and operators enough time to get the parts or the personnel needed to repair or replace the components that could not be repaired during the initial monitoring survey. Therefore, we are finalizing 30 days for the repair of fugitive emissions sources. However, we do recognize that some state LDAR programs require repairs to be made within 5 to 15 days of finding a leak. We encourage operators to continue to fix leaks within that timeframe, since the majority of leaks are fixed when they are found. We do expect that the majority of components will not need the additional 15 days for repair.

The EPA agrees, based on our review of the comments, that only a small percentage of components would not be able to be repaired during that 30 day period. We also agree that a complete well shutdown or a well shut-in may be necessary to repair certain components, such as components on the wellhead, and this could result in greater emissions than what would be emitted by the leaking component. The EPA does not agree that unavailability of supplies or custom parts is a justification for delaying repair (*i.e.*, beyond the 30 days for repair provided in this final rule) since the operator can plan for repair of fugitive emission components by having stock readily accessible or obtaining the parts within 30 days after finding the fugitive emissions.

Based on available information, it may be two years before a well is shut-in or shutdown. Therefore, to avoid the excess emissions (and cost) of prematurely forcing a shutdown, we are amending the rule to allow 2 years to fix a leak where it is determined to be technically infeasible to repair within 30 days; however, if an unscheduled or emergency vent blowdown, compressor station shutdown, well shutdown, or well shut-in occurs during the delay of repair period, the fugitive emissions components would need to be fixed at that time. The owner or operator will have to record the number and types of components that are placed on delay of repair and record an explanation for each delay of repair.

Method 21 allows a user to spray a soap solution on components that are operating under certain conditions (*e.g.*, no continuous moving parts or no surface temperatures above the boiling point or below the freezing point of the soap solution) to determine if any soap bubbles form. If no bubbles form, the components are deemed to be operating with no detected emissions. We note that spraying soap solution to confirm whether a component has been repaired may not work for all fugitive emissions components, such as a leak found under the hood of the thief hatch because it would be difficult to apply the soap solution or observe bubbles. However, we believe that this alternative will provide some owners and operators a simple, low cost way to confirm that a fugitive emissions component has been repaired. This would also allow the resurveys to be performed by the same personnel that completed the repairs instead of other certified monitoring personnel or hired contractors that would have to come back to verify the repairs. Therefore, we are finalizing the use of the alternative screening procedures specified in Section 8.3.3 of Method 21 for resurveying repaired fugitive emissions components, where appropriate.

For owners or operators that cannot use soap spray to verify repairs, we are allowing an additional 30 days for resurvey of the repaired fugitive emissions components, to allow time for contractors or designated OGI personnel to perform the resurvey because they are not typically the same personnel that would perform the repairs.

f. Definition of ''Fugitive Emission Component''

As just discussed, we proposed monitoring, repair, and resurvey of ''fugitive emission components.'' The EPA solicited comment on the proposed definition of fugitive emissions components. Commenters indicated that, as proposed, the fugitive emissions component definition is too broad and vague, because it contains both equipment and component types, and suggested that the EPA modify the definition to be more targeted and easier for states and other regulatory authorities to determine compliance, and recommended other definitions, such as that used by the state of Colorado.

The EPA agrees with commenters that, as proposed, the fugitive emissions component definition may cause confusion due to inclusion of equipment types, such as uncontrolled storage vessels that are potential sources of vented emissions (as opposed to fugitive emissions), in the definition.

Therefore, we are finalizing changes to the definition to remove equipment types and identify specific components, such as valves and flanges, that have the potential to be sources of fugitive emissions and that, when surveyed and repaired, would significantly reduce GHG and VOC emissions. This targeted list will remove the ambiguity of the proposed definition and will allow owners and operators to consistently identify fugitive emissions at well sites. We are finalizing the definition for fugitive emissions components in § 60.4530a of this final rule.

As finalized, the definition also aligns closely with other states' and federal agencies' definitions of fugitive emissions components by targeting similar components to the components in those definitions. Owners and operators can therefore monitor one set of components while complying with the requirements of this final rule and other state or federal fugitive emissions monitoring programs.

g. Timing of the Initial Monitoring Survey

The EPA proposed that the initial monitoring be conducted within 30 days after the initial startup of the first well completion or modification of a well site. EPA solicited comment on whether the proposal provides an appropriate amount of time to begin conducting fugitive emissions monitoring. We received a wide variety of comments and suggestions for the appropriate time for fugitive emissions monitoring to begin.

Several commenters indicated that initial monitoring should begin after production starts, because time is needed to close out the drilling activities. The commenters further stated that completion activities and the transition from completion to production at well sites is unpredictable and temporary completion equipment may still be onsite 30 days after the ''initial startup of the first well completion.'' One commenter indicated that production may not begin immediately after a well completion, so initial monitoring should not begin until after production starts.

The EPA acknowledges that at the time of a well completion all of the associated permanent equipment may not be present and conducting the initial monitoring survey may not capture all of the fugitive emissions components that would be in operation during production. In addition, we believe it is important to conduct the initial survey soon after the permanent equipment is in place to catch any improperly installed or defective equipment that may have substantial fugitive emissions immediately after installation. We believe that the permanent equipment will be in place at the startup of production (*i.e.*, the initial flow following the end of the flowback when there is continuous recovery of saleable quality gas). Therefore, the startup of production more accurately reflects the start of normal operations and would capture any fugitive emissions from the newly constructed or modified components at the well site. Therefore, we are finalizing that the startup of production marks the beginning of the initial monitoring survey period for the collection of fugitive emissions components.

Furthermore, based on the comments received, we are concerned that the tasks required prior to conducting an initial survey would take more than the 30 days we had proposed. Because each new or modified well site must be covered by a monitoring plan for a company-defined area, owners and operators must visit and assess each new or modified well site in order to incorporate it into a newly developed or modified monitoring plan for that area. They also need to secure certified monitoring survey contractors or monitoring instruments. In addition, they need to ensure that other compliance requirements will be met, such as recordkeeping and reporting. In light of the activities described above, the EPA is requiring in the final rule that the initial survey be conducted within 60 days from the startup of production.

While 60 days from startup of production is sufficient time to conduct the initial survey once the underlying program infrastructure is established, we recognize that the initial establishment of the required program's infrastructure and the initial round of monitoring surveys will require additional time. Most importantly, additional time is needed to secure the necessary equipment or trained personnel, according to one OGI instrument manufacturer, which commented that they would need to increase production of key components for the OGI instrument to meet demand. The OGI manufacturer also indicated that they would need to scale up the number of personnel needed to provide OGI training and service of the equipment. We are concerned that currently there is not sufficient equipment and trained personnel to meet the demand imposed by this final rule in the near term. Accordingly, it will be necessary to have a window of time for trained personnel to work through this backlog. Furthermore, as previously mentioned, an owner or operator will need to develop a monitoring plan that would apply to each well site located within the company-defined area, which requires an assessment of each well site. Therefore, before a plan can be developed or modified, the owner or operator would need time to visit each well site within the company-defined area. Based on the information that we used to develop the model well site plants, each company-defined area may consist of up to 22 well sites within a 70-mile radius of a central or district office. In light of the above, the initial site visits and development of the monitoring plan would require a significant amount of time. Time is also needed to secure certified monitoring survey contractors or monitoring instruments. In addition, owners and operators will need to plan the logistics of the initial activities in order to comply with the requirements. This includes time to set up recordkeeping systems and to train personnel to manage the fugitive emissions monitoring program. These corporate systems are critical for submitting the notification of initial and subsequent annual compliance status.

As noted above, once programs are established and equipment supplies have caught up, well owners will be able to add additional affected facilities to existing programs and, thus, this longer timeline will not be needed. Therefore, in order to provide time for owners and operators to establish the initial groundwork of their fugitives program, we are requiring that the initial monitoring survey must take place by June 3, 2017 or within 60 days of the startup of production, whichever is later.[87] We anticipate that sources will begin to phase in these requirements as additional devices and trained personnel become available. For additional discussion, please refer to the materials in the docket.

h. Monitoring Plan

The EPA proposed that owners or operators develop a corporate-wide fugitive emissions monitoring plan that specifies the measures for locating sources and the detection technology to be used. We also proposed that, in addition to the corporate-wide monitoring plan, owners or operators develop a site-specific fugitive emissions monitoring plan that specifies information such as the number of fugitive emission components that pertains to that single site.[88] The EPA solicited comment on the required elements of the proposed corporate-wide monitoring plan; specifically, the EPA asked for comment on whether other techniques, such as visual inspections to help identify indicators of potential leaks, should be included within the monitoring plan.

Some commenters agreed with the EPA's proposal to require a corporate-wide fugitive monitoring plan but expressed concerns about the elements of the plan, while others objected that the proposed plan is overly prescriptive and costly, with particular concerns about including requirements for a walking path and for digital photographs. Other commenters suggested changing the scope of monitoring plans to accommodate variations in locations of contractors and equipment.

We considered these comments, and we have made the following changes to the proposal in the final rule.

First, the final rule requires owners or operators to develop a fugitive emission monitoring plan for well sites within a company-defined area instead of corporate-wide and site-specific monitoring plans. This will give companies the flexibility to group well sites that are located within close proximity, under common control within a field or district, or that are

[87] For well site activities, such as the installation of a new well, a hydraulically fractured or refractured well, which commenced on or after September 18, 2015 are subject to this rule once it is finalized.

[88] See 80 FR 56612 (September 18, 2015).

managed by a single group of personnel. This would also afford owners and operators of well sites within different basins the ability to tailor their plans for the specific elements within each basin (*i.e.*, geography, well site characterization, emission profile). Information we received indicates that, in many cases, several sites within a specific geographic area may have similar equipment and would use the same contractors, company-owned monitoring instruments, or company personnel to perform the monitoring surveys. Based on a study conducted for the city of Fort Worth, Texas, we estimate that, on average, there are 22 well sites within a company's specific geographic region.[89] In this study, a total of 375 well pads were identified in the Fort Worth area, and these well pads were owned and operated by 17 different companies, or an average of 22 well pads per company. We believe these data provide a reasonable estimate of the number of well sites operated by a company in a specific geographic region. Therefore, we are removing the proposed corporate-wide and site-specific monitoring plan requirements and finalizing requirements that owners and operators develop a fugitive emissions monitoring plan for each of the company-defined areas that covers the collection of fugitive emissions components at well sites. As a result, the final rule requires owners and operators to develop a plan that describes the sites generally, including descriptions of equipment, plans for how they will monitor, etc., that apply to all similar sites. This will allow owners and operators to develop a monitoring plan for groups of similar well sites within an area for ease of implementation and compliance.

Second, we have made changes in the final rule to the proposed digital photograph requirements. We believe concerns regarding the burden of printing or transmitting digital pictures within the annual report are the result of unclear language in the proposed rule. Our intent was to require the owner or operator to include one or more digital photographs of the survey being performed. However, we inadvertently included that text within the requirement for each fugitive emission. It was not our intent to require a digital photograph of each fugitive emission in the annual report; instead we wanted to ensure, through pictorial documentation, that the monitoring survey had been performed. After consideration of the comments received, we believe we can further streamline this requirement. Because a source with fugitive emissions during the reporting period is subject to other recordkeeping and reporting requirements, this provides sufficient documentation that the survey was performed. Therefore, we have removed the proposed requirement to provide a digital photograph in the annual report for each required monitoring survey. We are requiring owners and operators to retain a record of each monitoring survey performed with optical gas imaging by keeping one or more digital photographs or videos captured with the OGI instrument. The photograph or video must either include the latitude and longitude of the collection of fugitive emissions components imbedded within the photograph or video or must consist of an image of the monitoring survey being performed with a separately operating GPS device within the same digital picture or video, provided that the latitude and longitude output of the GPS unit can be clearly read in the image.

Third, with the allowance for Method 21 monitoring as an alternative to OGI instrument monitoring, we are finalizing a requirement that sources of fugitive emissions (*e.g.*, a leaking fugitive emissions component) that cannot be repaired during the initial monitoring survey either be temporarily tagged for identification for repair or be digitally photographed or video recorded in a way that identifies the location of the fugitive emissions component needing repair. If an owner or operator chooses to digitally photograph the leaking component(s) instead of using identification tags, the photograph will meet the requirement to take a digital photograph during a monitoring survey, as long as the digital photograph is taken with the OGI instrument and includes the latitude and longitude either imbedded in the photograph or visible in the picture.

Fourth, we are finalizing the walking path requirement with minor changes. We are revising the walking path terminology to observation path in order to clarify that our intent is focused on the field of view of the OGI instrument, not the physical location of the OGI operator. We believe this terminology change will alleviate commenters' concerns regarding the potentially overly prescriptive nature of the defined walking path with transient interferences, environmental obstructions, weather conditions and safety issues. This revision also clarifies our intent to allow for the use of all types of OGI instruments (*e.g.*, mounted, handheld or remote controlled).

The purpose of the observation path is to ensure that the OGI operator visualizes all of the components that must be monitored, just as a Method 21 operator in a traditional leak detection program surveys all of the components. In the traditional scenario, the owner or operator tags all of the equipment that must be monitored, and when the Method 21 operator subsequently inspects the affected facility, the operator scans each component's tag and notes the component's instrument reading. The EPA realizes that this is a time-consuming practice. Additionally, while the Method 21 operator must contact each component with the probe of the Method 21 instrument and monitor it individually, we recognize that with OGI, the operator can be away from the components and still monitor several components simultaneously.

Recognizing these aspects of traditional and OGI leak detection methods, we want to offer owners and operators an alternative to the traditional tagging approach. However, because we are no longer requiring a traditional log of instrument readings, the rule must provide another way to ensure that the compliance obligation to monitor all equipment is met. We believe that the observation path requirement effectively ensures that an operator looks at all of the required components but reduces the burden of tagging and logging associated with traditional Method 21 programs. Unlike the tagging and logging requirement associated with traditional Method 21 programs, the requirement to develop an observation path is a one-time requirement (as long as the path does not need to change due to the addition of components). We do not expect facilities to create overly detailed process and instrumentation diagrams to describe the observation path. The observation path description could be a simple schematic diagram of the facility site or an aerial photograph of the facility site, as long as such a photograph clearly shows locations of the components and the OGI operator's walking path. As a result, we do not believe that the requirement to document the observation path is burdensome.

i. Provision for Emerging Technology

As the EPA noted in the 2015 proposal, fugitive emissions monitoring is a field of emerging technology, and major advances are expected in the near future. 80 FR at 56639. We are seeing a rapidly growing push to develop and

[89] ERG and Sage Environmental Consulting, LP. City of Fort Worth Natural Gas Air Quality Study, Final Report. Prepared for the City of Fort Worth, Texas. July 13, 2011. Available at *http://fortworthtexas.gov/gaswells/default.aspx?id=87074.*

be added to subpart OOOO. The owner or operator would be required to use the appropriate electronic form in CEDRI for the subpart or an alternate electronic file format consistent with the form's extensible markup language (XML) schema. If the reporting form specific to the subpart is not available at the time that the report is due, the owner or operator would submit the report to the Administrator at the appropriate address listed in § 60.4 of the General Provisions. The owner or operator would begin submitting reports electronically with the next report that is due once the electronic form has been available for at least 90 days. The EPA is currently working to develop the form for subpart OOOO.

In the proposal for subpart OOOOa, the EPA included the same electronic reporting requirements for subpart OOOOa that were included for subpart OOOO in the March 2015 proposal. The EPA is finalizing the requirement to report certain performance test reports, excess emission reports, annual reports and semiannual reports electronically through the EPA's CDX using the CEDRI. The EPA believes that the electronic submittal of the reports addressed in this rulemaking will increase the usefulness of the data contained in those reports, is in keeping with current trends in data availability, will further assist in the protection of public health and the environment, and will ultimately result in less burden on the regulated community. Electronic reporting can also eliminate paper-based, manual processes, thereby saving time and resources, simplifying data entry, eliminating redundancies, minimizing data reporting errors, and providing data quickly and accurately to the affected facilities, air agencies, the EPA and the public.

The EPA Web site that stores the submitted electronic data, WebFIRE, will be easily accessible to everyone and will provide a user-friendly interface that any stakeholder can access. By making the records, data and reports addressed in this rulemaking readily available, the EPA, the regulated community and the public will benefit when the EPA conducts its CAA-required reviews. As a result of having reports readily accessible, our ability to carry out comprehensive reviews will be increased and achieved within a shorter period of time.

The EPA anticipates fewer or less substantial information collection requests (ICRs) in conjunction with prospective CAA-required reviews may be needed, resulting in a decrease in time spent by industry to respond to data collection requests. The EPA also expects the ICRs to contain less extensive stack testing provisions, as we will already have stack test data electronically. Reduced testing requirements would be a cost savings to industry. The EPA should also be able to conduct these required reviews more quickly. While the regulated community may benefit from a reduced burden of ICRs, the general public benefits from the Agency's ability to provide these required reviews more quickly, resulting in increased public health and environmental protection.

Air agencies will benefit from more streamlined and automated review of the electronically submitted data. Having reports and associated data in electronic format will facilitate review through the use of software ''search'' options, as well as the downloading and analyzing of data in spreadsheet format. The ability to access and review air emission report information electronically will assist air agencies to more quickly and accurately determine compliance with the applicable regulations, potentially allowing a faster response to violations that could minimize harmful air emissions. This benefits both air agencies and the general public.

For a more thorough discussion of electronic reporting, see the discussion in the preamble of the March 2015 proposal. In summary, in addition to supporting regulation development, control strategy development, and other air pollution control activities, having an electronic database populated with performance test data will save industry, air agencies, and the EPA significant time, money, and effort while improving the quality of emission inventories, air quality regulations, and enhancing the public's access to this important information.

2. Digital Picture Reporting as an Alternative for Well Completions (''REC PIX'') and Manufacturer Installed Control Devices

The EPA is finalizing digital picture reporting as an alternative for well completions and manufacturer installed control devices as proposed. Specifically, the final rule allows digital picture reporting as an alternative for well completions (''REC PIX'') and manufacturer installed control devices. These alternative reporting options provide flexibility for owners and operators, provide enhanced ''visibility'' for regulators, and take advantage of the advances of the digital age with the ability to capture geospatial accuracy at any location.

Digital picture reporting as an alternative for well completions (''REC PIX'') reflects the 2012 NSPS. As with the 2012 NSPS, we continue to promote an optional mechanism by which owners and operators could streamline annual reporting of well completions by using a digital camera to document that a well completion was performed in compliance with subpart OOOOa. Although we understand that commenters have concerns about the amount of electronic storage capability necessary to store digital pictures, we believe that by allowing either the REC PIX or the elements required under the recordkeeping requirements for well completions, the owner or operator may determine what is most advantageous for their company. Should an owner or operator choose to submit the REC PIX, the REC PIX must consist of a digital photograph of the REC equipment in use, with the date and geospatial coordinates shown on the photographs. These photographs must be submitted with the next annual report, along with a list of well completions performed with identifying information for each well completed.

Digital picture reporting as an alternative for manufacturer installed control devices provides further opportunity and flexibility to owners and operators to advance data capture to ensure that compliance practices are in effect. This alternative recordkeeping and reporting option is allowed specifically for centrifugal compressors and storage vessels routed to control devices, where the control device used is one tested in accordance with the manufacturer testing procedures in the rule and is posted to the EPA Oil and Gas page. In lieu of a written record with the location of the centrifugal compressor or storage vessel and its associated control device in latitude and longitude, the digital picture alternative must have the date the photograph was taken and the latitude and longitude of the centrifugal compressor and control device or storage vessel and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital picture, the digital picture may consist of a photograph of the centrifugal compressor and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph. Furthermore, as discussed in section VI.F of this preamble, digital pictures and frame captures will help ensure that OGI for fugitive emissions is being performed properly.

3. Certification of Technical Infeasibility of Connecting a Pneumatic Pump to an Existing Control Device

In response to comment, the final rule requires that a new, modified, or reconstructed pneumatic pump be routed to an existing control device or process onsite, unless the owner or operator obtains a certification that it is technically infeasible to do so. The EPA understands that some factors such as capacity of the existing control device and back pressure on the exhaust of the pneumatic pump imposed by the closed vent system and control device can contribute to infeasibility of routing a pneumatic pump to an existing control device onsite. Due to the various scenarios that could make routing a pneumatic pump to an onsite control device or process technically infeasible, we do not think we could prescribe a specific set of criteria or factors that must be considered for making such determination that could capture all such circumstances. However, we want to ensure that the owner or operator has effectively assessed these factors before making a claim of infeasibility. To that end, we have included provisions in the final rule to require certification by a qualified professional engineer of such technical infeasibility. In addition, we are requiring that the owner or operator maintain records of that certification for a period of five years.

4. Professional Engineer Design of Closed Vent Systems

It is the EPA's experience, through site inspections and interaction with the states, that closed vent systems and control devices for storage vessels and other emission sources often suffer from improper design or inadequate capacity that results in emissions not reaching the control device and/or the control device being overwhelmed by the volume of emissions. Either of these conditions can seriously compromise emissions control and can render the system ineffective. We also discussed the issue in the September 2015 Compliance Alert ''EPA Observes Air Emissions from Controlled Storage Vessels at Onshore Oil and Natural Gas Production Facilities'' (See *https://www.epa.gov/sites/production/files/2015-09/documents/oilgascompliancealert.pdf*).

We believe it is important that owners and operators make real efforts to provide for proper design of these systems to ensure that all the emissions routed to the control device reach the control device and that the control device is sized and operated to result in proper control. As a result, we have included in the final rule provisions for certification by a qualified professional engineer that the closed vent system is properly designed to ensure that all emissions from the unit being controlled in fact reach the control device and allow for proper control.

Although the final rule does not include requirements for specific criteria for proper design, the EPA believes there are certain minimum design criteria that should be considered to ensure that the closed vent and control device system are designed to meet the requirements of the rule; *i.e.,* the closed vent system must be capable of routing all gases, vapors, and fumes emitted from the affected facility to a control device or to a process that meets the requirements of the rule.

Furthermore, because other emissions may be collected into the closed vent system and routed to the control device, these design criteria include consideration of the contribution of these additional emissions to ensure proper sizing and operation. The minimum design elements include, but are not limited to, based on site-specific considerations:

1. Review of the Control Technologies to be Used to Comply with §§ 60.5380a and 60.5395a.

2. Closed Vent System Considerations:

a. Piping—

i. Size (include all emissions, not just affected facility);

ii. Back pressure, including low points which collect liquids;

iii. Pressure losses; and

iv. Bypasses and pressure release points.

3. Affected Facility Considerations:

a. Peak Flow from affected facility, including flash emissions, if applicable; and

b. Bypasses, pressure release points.

4. Control Device Considerations:

a. Maximum volumetric flow rate based on peak flow, and

b. Ability to handle future gas flow.

K. Provision for Equivalency Determinations

In recent years, certain states have developed programs to control various oil and gas emission sources in their own states. Due to the differences in the sources covered and the requirements, determining equivalency through direct comparison of the various state programs with the NSPS has proven to be difficult. We also did not find that any state program as a whole would reflect what we have identified as the BSERs for all emissions sources covered by the NSPS. In any event, federal standards are necessary to ensure that emissions from the oil and natural gas industry are controlled nationwide.

However, depending on the applicable state requirements, certain owners and operators may achieve equivalent or more emission reduction from their affected source(s) than the required reduction under the NSPS by complying with their state requirements. States may adopt and enforce standards or limitations that are more stringent than the NSPS. See CAA section 116 and the EPA's regulations at 40 CFR 60.10(a). For states that are being proactive in addressing emissions from the oil and natural gas industry, it is important that the NSPS complement such effort. Therefore, in the final rule, through the process described in section VI.F.1.i for emerging technology, owners and operators may also submit an application requesting that the EPA approve certain state requirement as ''alternative means of emission limitations'' under the NSPS for their affected facilities. The application would include a demonstration that emission reduction achieved under the state requirement(s) is at least equivalent to the emission reduction achieved under the NSPS standards for a given affected facility. Consistent with section 111(h)(3), any application will be publicly noticed, which the EPA intends to provide within six months after receiving a complete application, including all required information for evaluation. The EPA will provide an opportunity for public hearing on the application and on intended action the EPA might take. The EPA intends to make a final determination within six months after the close of the public comment period. The EPA will also publish its determination in the **Federal Register**.

VII. Prevention of Significant Deterioration and Title V Permitting

A. Overview

This final rule will regulate GHGs under CAA section 111. In this section, the EPA is addressing how regulation of GHGs under CAA section 111 could have implications for other EPA rules and for permits written under the CAA Prevention of Significant Deterioration (PSD) preconstruction permit program and the CAA Title V operating permit program. The EPA is adopting provisions in the regulations that explicitly address some of these potential implications based on our review of the proposed regulatory text and comments received on the proposal.

For purposes of the PSD program, the EPA is finalizing provisions in part 60 of its regulations and explaining in this preamble that the current threshold for determining whether a PSD source must satisfy the best available control technology (BACT) requirement for GHGs continues to apply after promulgation of this rule. This rule does not require any additional revisions to state implementation plans (SIPs). With respect to the Title V operating permits program, we are finalizing provisions in part 60 and explaining in this preamble that this rule does not affect whether sources are subject to the requirement to obtain a Title V operating permit based solely on emitting or having the potential to emit GHGs above major source thresholds.

B. Applicability of Tailoring Rule Thresholds Under the PSD Program

EPA received several comments asking for clarification or changes to make clear that this rule did not directly regulate methane as a separate pollutant from GHG and that it would not cause sources to trigger PSD or Title V permitting requirements based solely on methane emissions.[96] This section discusses changes made in response to these comments as well as clarification as to what, if any, impact this rule has on PSD permitting. Section VII.C below addresses Title V-specific issues.

Under the PSD program in part C of title I of the CAA, in areas that are classified as attainment or unclassifiable for NAAQS pollutants, a new or modified source that emits any air pollutant subject to regulation at or above specified thresholds is required to obtain a preconstruction permit. This permit ensures that the source meets specific requirements, including application of BACT to each pollutant subject to regulation under the CAA. Many states (and local districts) are authorized by the EPA to administer the PSD program and to issue PSD permits. If a state is not authorized, then the EPA issues the PSD permits for facilities in that state.

To identify the pollutants subject to the PSD permitting program, EPA regulations contain a definition of the term ''regulated NSR pollutant.'' 40 CFR 52.21(b)(50); 40 CFR 51.166(b)(49). This definition contains four subparts, which cover pollutants regulated under various parts of the CAA. The second subpart covers pollutants regulated under section 111 of the CAA. The fourth subpart is a catch-all provision that applies to ''[a]ny pollutant that is otherwise subject to regulation under the Act.''

This definition and the associated PSD permitting requirements applied to GHGs for the first time on January 2, 2011, by virtue of the EPA's regulation of GHG emissions from motor vehicles, which first took effect on that same date. 75 FR 17004 (Apr. 2, 2010). GHGs became subject to regulation under the CAA and the fourth subpart of the ''regulated NSR pollutant'' definition became applicable to GHGs.

On June 3, 2010, the EPA issued a final rule, known as the Tailoring Rule, which phased in permitting requirements for GHG emissions from stationary sources under the CAA PSD and Title V permitting programs (75 FR 31514). Under its understanding of the CAA at the time, the EPA believed the Tailoring Rule was necessary to avoid a sudden and unmanageable increase in the number of sources that would be required to obtain PSD and Title V permits under the CAA because the sources emitted GHGs in amounts over applicable major source and major modification thresholds. In Step 1 of the Tailoring Rule, which began on January 2, 2011, the EPA limited application of PSD or Title V requirements to sources of GHG emissions only if the sources were subject to PSD or Title V ''anyway'' due to their emissions of non-GHG pollutants. These sources are referred to as ''anyway sources.'' In Step 2 of the Tailoring Rule, which began on July 1, 2011, the EPA applied the PSD and Title V permitting requirements under the CAA to sources that were classified as major and, thus, required to obtain a permit based solely on their potential GHG emissions and to modifications of otherwise major sources that required a PSD permit because they increased only GHG emissions above applicable levels in the EPA regulations.

In the PSD program, the EPA implemented the steps of the Tailoring Rule by adopting a definition of the term ''subject to regulation.'' The limitations in Step 1 of the Tailoring Rule are reflected in 40 CFR 52.21(b)(49)(iv) and 40 CFR 51.166(b)(48)(iv). With respect to ''anyway sources'' covered by PSD during Step 1, this provision established that GHGs would not be subject to PSD requirements unless the source emitted GHGs in the amount of 75,000 tons per year (tpy) of CO2 Eq. or more. The primary practical effect of this paragraph is that the PSD BACT requirement does not apply to GHG emissions from an ''anyway source'' unless the source emits GHGs at or above this threshold. The Tailoring Rule Step 2 limitations are reflected in 40 CFR 52.21(b)(49)(v) and 51.166(b)(48)(v). These provisions contain thresholds that, when applied through the definition of ''regulated NSR pollutant,'' function to limit the scope of the terms ''major stationary source'' and ''major modification'' that determine whether a source is required to obtain a PSD permit. See *e.g.,* 40 CFR 51.166(a)(7)(i) and (iii); 40 CFR 51.166(b)(1); 40 CFR 51.166(b)(2).

On June 23, 2014, the United States Supreme Court, in *Utility Air Regulatory Group* v. *Environmental Protection Agency,* issued a decision addressing the application of PSD permitting requirements to GHG emissions. The Supreme Court held that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source (or modification thereof) for the purpose of PSD applicability. The Court also said that the EPA could continue to require that PSD permits, otherwise required based on emissions of pollutants other than GHGs, contain limitations on GHG emissions based on the application of BACT. The Supreme Court decision effectively upheld PSD permitting requirements for GHG emissions under Step 1 of the Tailoring Rule for ''anyway sources'' and invalidated application of PSD permitting requirements to Step 2 sources based on GHG emissions. The Court also recognized that, although the EPA had not yet done so, it could ''establish an appropriate *de minimis* threshold below which BACT is not required for a source's greenhouse gas emissions.'' 134 S. Ct. at 2449.

In accordance with the Supreme Court decision, on April 10, 2015, the United States Court of Appeals for the District of Columbia Circuit (the D.C. Circuit) issued an amended judgment vacating the regulations that implemented Step 2 of the Tailoring Rule but not the regulations that implement Step 1 of the Tailoring Rule. The court specifically vacated 40 CFR 51.166(b)(48)(v) and 40 CFR 52.21(b)(49)(v) of the EPA's regulations, but did not vacate 40 CFR 51.166(b)(48)(iv) or 40 CFR 52.21(b)(48)(iv). The court also directed the EPA to consider whether any further revisions to its regulations are appropriate in light of *UARG* v. *EPA* and, if so, to undertake such revisions.

The practical effect of the Supreme Court's clarification of the reach of the CAA is that it eliminates the need for Step 2 of the Tailoring Rule and subsequent steps of the GHG permitting phase-in that the EPA had planned to consider under the Tailoring Rule. This also eliminates the possibility that the

[96] As is discussed elsewhere, the EPA has made clear that the pollutant subject to regulation is GHG, in the form of methane. Additional regulatory language in 40 CFR 60.5360a has been added to provide additional clarity.

maintenance cost. When the incremental lost gas value exceeded the maintenance/replacement cost, the rod packing maintenance was determined to be cost-effective.

Other commenters noted that because operators in transmission and storage segment do not own the gas, a different performance metric could be used and recommended a metric based on a defined leak rate or change in leak rate over time. Commenters recommended possibly setting a threshold at a leak rate above 2 scfm, combined with annual monitoring, which would require rod packing maintenance/replacement within nine months or during the next unit shutdown, whichever is sooner and which is consistent with a draft California Air Resources Board (CARB) regulation for oil and gas operations.

Response: The EPA disagrees with the commenters that the rule should include an alternative maintenance program and allow operators flexibility to use condition-based maintenance approach to reduce emissions rather than a prescribed maintenance schedule. While we received comment supporting the addition of a threshold-based or condition-based maintenance provision, we did not receive sufficient technical details to properly evaluate this alternative for inclusion in the rule. Although condition-based maintenance has been shown to be effective under the Natural Gas STAR program, the criteria on which rule requirements could be based would require significantly more data and analysis. Specifically, in order to evaluate such a provision for the rule, we would need to determine an appropriate leak-rate threshold which would trigger rod packing replacement. Commenters suggested 2 scfm demonstrated acceptable rod packing leakage; however, the commenters provided no substantive data as to the reason for this threshold. Commenters also recommended that we model the provision after the California Air Resources Board proposed regulation which was based on input from rod packing vendors. Although some valuable information was provided, the level of technical data and information necessary to analyze all aspects of such a provision were not provided. Therefore, we are unable to evaluate the condition-based maintenance provision for inclusion in the rule at this time.

D. Major Comments Concerning Pneumatic Controllers

1. Studies That Indicate Emission Rates for Low-Bleed Pneumatic Controllers That Are Higher Than the EPA Estimates

Comment: The EPA received comment that several recent studies report that pneumatic controllers emit more than they are designed to emit and that their emission rate is higher than the currently estimated EPA emission rate for pneumatic controllers. Specifically, the commenters noted that studies indicated that controllers were observed to have emissions inconsistent with the manufacturer's design and were likely operating incorrectly due to maintenance or equipment issues. Low-bleed pneumatic controllers were observed to have emission rates that were 270 percent higher than the EPA's emission factor for these devices, in some cases approaching the emission rate of high-bleed controllers.

Response: The emissions estimates presented in the proposal were based on the most robust data available at the time of their development. The EPA is familiar with the studies discussed in the comments summarized here and several of those studies were discussed in the EPA's Oil and Gas White Paper. The EPA has reviewed available data; because of the lack of emissions data that are straightforward to use in assessment of emissions from specific bleed rate categories (*i.e.,* high-bleed and low-bleed), the EPA has retained the emission factors for pneumatic controllers used in the proposal analysis and has retained the requirements for pneumatic controllers.

2. Capture and Control of Emissions From Pneumatic Controllers

Comment: The EPA received comment that pneumatic controllers should be required to capture emissions through a closed vent system and route the captured emissions to a process or a control device, similar to the approach the EPA has taken in its proposed standards for pneumatic pumps and compressors. The commenters cite recent Wyoming proposed rules for existing pneumatic controllers that allow operators of existing high-bleed controllers to route emissions to a process and the California Air Resources Board (CARB) proposed rules which requires that operators capture emissions and route to a process or control device. Commenters state that this approach would work for all types of pneumatic controllers and that this approach would be cost effective based on the costs identified for pneumatic pumps in the TSD.

Response: The EPA disagrees with the commenters that capturing and routing emissions from pneumatic controllers to a process or control device is a viable control option under our BSER analysis. While the commenter stated that a few permits in Wyoming indicate that a facility is capturing emissions from controllers and routing to a control device, we believe that there is insufficient information and data available for the EPA to establish the control option as the BSER. For more information, please see the RTC.

E. Major Comments Concerning Pneumatic Pumps

1. Compliance Date

Comment: Commenters stated that the EPA requires that new or modified pneumatic pumps at a site that currently lack an emission control device will become an affected facility if a control device is later installed; and, the facility must be in compliance within 30 days of installation of the new control device. One commenter states that 30 days does not provide such sources sufficient time to come into compliance. The commenter suggests that the rule be revised to require compliance within 30 days of startup of the control device so that the operator can ensure that the control device is properly tested after installation without concern over triggering non-compliance for pneumatic pump controls.

Response: We agree that additional time is appropriate for designing connections and testing after control device installation. Therefore, we have revised the compliance date in the final rule with respect to control devices that are installed on site after installation of the pneumatic pump affected facility. In the final rule, the compliance date for pneumatic pump affected facilities to be routed to a newly installed onsite control device 30 days after startup of the control device.

2. Subsequent Removal of Control Device

Comment: Several commenters expressed concern that the rule did not provide a way to remove control equipment from a site when it is no longer needed for the purpose for which it was installed. Further, they requested that the EPA clarify that a source ceases to be an affected facility if the control device is no longer needed for other equipment. The commenters cite an example where the exiting control device onsite is installed for a subpart OOOO storage vessel and subsequently the storage vessel's potential to emit falls below 6 tpy. If this were to occur, the storage vessel would no longer be subject to regulation and the control device would no longer be necessary.

Response: The EPA agrees that the intent of the proposal was not to require existing control devices that are no longer required for their original purposes to remain at a site only to control pneumatic pump affected facility emissions. Therefore, the final rule clarifies that subsequent to the removal of a control device and provided that there is no ability to route to a process, a pneumatic pump affected facility is no longer required to comply with § 60.5393a(b)(1) or (2). However, these units will continue to be affected facilities and we are requiring pneumatic pump affected facilities to continue following the relevant recordkeeping requirements of § 60.5420a even after an existing control device is removed.

3. Limited-Use Pneumatic Pumps

Comment: Commenters state that there are natural gas-driven pneumatic pumps which are used intermittently to transfer bulk liquids. These limited use pumps may be manually operated as needed or may be triggered by a level controller or other sensor. Specific examples provided by the commenters include engine skid sump pumps, pipeline sump pumps, tank bottom pumps, flare knockout drum pumps, and separator knockout drum pumps that are used to pump liquids from one place to another. The commenters contend that 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, the commenters requested that the final rule include an exemption for limited-use pneumatic pumps.

Response: In the TSDs to the proposed and final rule, the emission factors we used for pneumatic pumps assumed that the pumps operated 40 percent of the time. While we understood that pneumatic pumps typically do not run continuously, we did assume that the 40 percent usage was distributed evenly throughout the year. However, based upon the comments we received, the usage of some pneumatic pumps is much more limited than we previously determined and not spread evenly throughout the year. We did not intend to regulate these limited-use pneumatic pumps and are not including limited-use pneumatic pumps in the definition of pneumatic pump affected facilities that are located at well sites. Specifically, if a pump located at a well site operates for any period of time each day for less than a total of 90 days per year, this limited-use pneumatic pump is not an affected facility under this rule. We believe this requirement is sufficient to address the commenters' concerns for both intermittent use and temporary use pneumatic pumps.

Because we believe there are multiple viable alternatives available at natural gas processing plants that are not available at well sites, we do not believe it is necessary to exclude limited-use pneumatic pumps located at natural gas processing plants from the definition of pneumatic pump affected facility. Based on our best available information, both instrument air and electricity are readily available at natural gas processing plants. We believe owners and operators will choose instrument air over natural gas-driven pumps since their other pumps will be air powered. We also believe owners and operators can utilize electric pumps for intermittent activities cited by the commenters such as sump pumps and transfer pumps where it is safe to use an electric pump. Given these options, we conclude that it is not necessary to exclude limited-use pneumatic pumps located at natural gas processing plants from the definition of pneumatic pump affected facility in the final rule.

4. Removal of Tagging Requirements

Comment: Several commenters requested that the EPA remove the tagging requirement for pneumatic pump affected facilities. As written, the proposed rule required that operators tag pumps that are affected facilities and those that are not affected facilities. The commenters contend that the tagging requirement appears to add little value and is confusing. Commenters suggest operators should only be required to maintain a list of make, model, and serial number, rather than individual tags and that a list of make, model, and serial number will achieve the same results desired by the EPA, without presenting the unnecessary operational hurdles associated with individual tagging and recordkeeping.

Response: The EPA has reviewed the proposed tagging requirements and agrees with the commenters that the recordkeeping in lieu of tagging for pneumatic pumps affected facilities is sufficient. Therefore, the EPA has removed the tagging requirements for pneumatic pump affected facilities in the final rule.

5. Lean Glycol Circulation Pumps

Comment: The EPA solicited comments on the level of uncontrolled emissions from lean glycol circulation pumps and how they are vented through the dehydrator system. We received comments corroborating our understanding at proposal and in the white papers that emissions from these pumps are vented through the rich glycol separator vent or the reboiler still vent and are already regulated under 40 CFR part 63 subparts HH and HHH.

Response: The EPA's understanding during the proposal was that the lean glycol pumps are integral to the operation of the dehydrator, and as such, emissions from glycol dehydrator pumps are not separately quantified because these emissions are released from the same stack as the rest of the emissions from the dehydrator system, including HAP emission that are being controlled to meet the standards under the National Emission Standards for Hazardous Air Pollutants (NESHAP) at 40 CFR part 63 subparts HH and HHH. It is also our understanding from white paper commenters that replacing the natural gas in gas-assisted lean glycol pumps with instrument air is not feasible and would create significant safety concerns. Commenters on the white paper stated that the only option for these types of pumps are to replace them with electric motor driven pumps; however, solar and battery systems large enough to power these types of pumps are not currently feasible. Therefore, we have clarified that lean glycol circulation pumps are not affected facilities under the final pneumatic pumps standards.

F. Major Comments Concerning Well Completions

1. Request for a Limited Use of Combustion

Comment: Several commenters support the requirements for reducing completion emissions at oil wells; however, they express concern that the proposed rule does not go far enough in establishing a hierarchy of preference for the beneficial use options provided in the rule (i.e., routing the recovered gas from the separator into a gas flow line or collection system, re-injecting the recovered gas into the well or another well, use of the recovered gas as an onsite fuel source or use of the recovered gas for another useful purpose that a purchased fuel or raw material would serve) over what the commenters perceive to be the least-preferable option to route the emission to a combustion control device. Further, one commenter states that the technical infeasibility exemption in the rule is vague and could detract significantly from the overall value of this standard if not narrowly limited in application. The commenter notes that because of the swiftly increasing production of oil (along with associated natural gas) in the United States which produces very high initial rates of oil and associated gas, it is vital that the rule's requirements apply rigorously.

Response: The EPA agrees that REC should be preferred over combustion due to the secondary environmental impact from combustion. The final rule reflects such preference by requiring REC unless it is technically infeasible, in which event the recovered gas is to be routed to a completion combustion device. Further, to ensure that the exemption from REC due to technical infeasibility is limited to those situations where the operator can demonstrate that each of the options to capture and use gas beneficially is not feasible and why, we have expanded recordkeeping requirements in the final rule to include: (1) Detailed documentation of the reasons for the claim of technical infeasibility with respect to all four options provided in § 60.5375a(a)(1)(ii), including but not limited to, names and locations of the nearest gathering line; capture, re-injection, and reuse technologies considered; aspects of gas or equipment prohibiting use of recovered gas as a fuel onsite; and (2) technical considerations prohibiting any other beneficial use of recovered gas on site.

We believe these additional provisions will support a more diligent and transparent application of the intent of the technical infeasibility exemption from the REC requirement in the final rule. This information must be included in the annual report made available to the public 30 days after submission through CEDRI and WebFIRE, allowing for public review of best practices and periodic auditing to ensure flaring is limited and emissions are minimized.

G. Major Comments Concerning Fugitive Emissions From Well Sites and Compressor Stations

1. Modification Definitions for Well Sites

Comment: Several commenters assert that the definition of ''modification'' of a well site under the proposed rule in § 60.5365a(i) is overly broad because it would bring many existing well sites under the Rule's requirements. The commenters believe that drilling a new well or hydraulically fracturing an existing well does not increase the probability of a leak from an individual component and no new components result from these activities, thus the potential emissions rate does not change and should not be consider a modification.

Response: The EPA believes the addition of a new well or the hydraulically fracturing or refracturing of an existing well will increase emissions from the well site for the following reasons. These events are followed by production from these wells which generate additional emissions at the well sites. Some of these additional emissions will pass through leaking fugitive emission components at the well sites (in addition to the emissions already leaking from those components). Further, it is not uncommon that an increase in production would require additional equipment and, therefore, additional fugitive emission components at the well sites. We also believe that defining ''modification'' to include these two events, rather than requiring complex case-by-case analysis to determine whether there is emission increase in each event, will ease implementation burden for owners and operators. For the reasons stated above, EPA is finalizing the definition of ''modification'' of a well site, as proposed.

2. Monitoring Plan

Comment: Commenters expressed concerns about the elements of the proposed monitoring plans and encouraged the EPA to consult with the oil and gas industry and states to adopt requirements that would meet their specific needs. Commenters suggested that an area-wide monitoring plan should be allowed instead of a corporate-wide or site specific plan. The area plan would allow owners to write a plan that covers various areas for each specific region since operators may rely on contractors in one area due to location while company-owned monitoring equipment may be used within another area.

Response: The EPA participated in numerous meetings with industry, environmental and state stakeholders to discuss the proposed rule. During these meetings industry stakeholders further explained why a corporate-wide monitoring plan would be difficult to develop due to their corporate structures, well site locations, basin characteristics and many other factors. They also indicated that a site-specific plan would be redundant since many well sites within a district or field office are similar and would utilize the same personnel, contractors or monitoring equipment. The industry stakeholders provided input on specific elements of the monitoring plan, such as the walking path requirement. Based on the comments that we received and subsequent stakeholder meetings, we have made changes to the monitoring plan and have further explained our intent for the walking path. We have also modified the digital photograph recordkeeping requirements for sources of fugitive emissions. See section VI.f.1.h of this preamble for further discussion.

H. Major Comments Concerning Final Standards Reflecting Next Generation Compliance and Rule Effectiveness Strategies

1. Electronic Reporting

Comment: While some commenters express support, several commenters oppose electronic reporting of compliance-related records. Some of the commenters state that they have an obligation under the rule to maintain these records and make them available to the regulatory agency upon request, and this should be sufficient. Providing all the records requested under the proposed rule would likely cause a backlog of correspondence between the regulatory agency and the industry. Other commenters expressed concern that sensitive company information could be present in the records, and other parties could use a FOIA request to obtain the records.

Additional commenters pointed out that the EPA should not require electronic reporting until CEDRI is modified to accommodate the unique nature of the oil and natural gas production industry. As the commenters understand the operational characteristics of CEDRI, the system links reports for each affected facility to the site at which they are located. Under subparts OOOO and OOOOa, there is no unique site identifier. This would result in owners and operators having to deconstruct the annual report in order to obtain the affected facility level data needed for CEDRI. The EPA did not account for this burden and cost. The commenters request that should electronic reporting be required, that CEDRI be revised to accept the annual reports as currently specified in the proposed rule as a pdf file or hardcopy until these issues can be resolved. Commenters also request that CEDRI be modified to accept area-wide reports rather than site-level reports. Additionally, commenters noted that the definition of ''certifying official'' under CEDRI is different than in the proposed rule.

Finally, since the EPA did not propose regulatory language for these requirements, some commenters believe that the EPA cannot finalize these requirements without first proposing the regulatory language.

Response: The EPA notes that regulatory language for the electronic reporting requirements was available in § 60.5420a, § 60.5422a and § 60.5423a of the proposed rule.

The EPA thanks the commenters for the support for electronic reporting. Electronic reporting is in ever-increasing use and is universally considered to be faster, more efficient and more accurate for all parties once the initial systems have been established and start-up costs completed. Electronic reporting of environmental data is already common practice in many media offices at the EPA; programs such as the Toxics Release Inventory (TRI), the Greenhouse Gas Reporting Program, Acid Rain and NO_X Budget Trading Programs and the Toxic Substances Control Act (TSCA) New Chemicals Program all require electronic submissions to the EPA. The EPA has previously implemented similar electronic reporting requirements in over 50 different subparts within parts 60 and 63. WebFIRE, the public access site for these data, currently houses over 5000 reports that have been submitted to the EPA via CEDRI.

The EPA notes that reporting is an essential element in compliance assurance, and this is especially true in this sector. Because of the large number of sites and the remoteness of sites, it is unlikely that the delegated agencies will be able to visit all sites. By providing reports electronically in a standardized format, the system benefits air agencies by streamlining review of data, facilitating large scale data analysis, providing access to reports and providing cost savings through a reduction in storage costs. The narrative and upload fields within the CEDRI forms can even be used to provide information to satisfy extra reporting requirements that state and local air agencies may impose.

The EPA is sensitive to the complexity of the oil and gas regulations and the unique challenges presented by this sector. CEDRI forms are designed to be consistent with the requirements of the underlying subparts and are unique to each regulation. The forms are reviewed multiple times before being finalized, and they are subjected to a beta testing period that allows end-users to provide feedback on issues with the forms prior to requiring their use. Also, if a form has not yet been completed by the time the rule is effective, affected facilities will not be required to use CEDRI until the form has been available for at least 90 days. The EPA notes that we have recently developed a bulk upload feature for several subparts within CEDRI. The bulk upload feature allows users to enter data for sites across the country in a single file instead of having to submit individual reports for each site. This feature should alleviate some of the commenters' concerns.

The EPA is aware that facility personnel must learn the new reporting system, but the savings realized by simplified data entry outweighs the initial period of learning the system. Electronic reporting can eliminate paper-based, manual processes, thereby saving time and resources, simplifying data entry, eliminating redundancies, minimizing data reporting errors and providing data quickly and accurately. Reporting form standardization can also lead to cost savings by laying out the data elements specified by the regulations in a step-by-step process, thereby helping to ensure completeness of the data and allowing for accurate assessment of data quality. Additionally, the EPA's electronic reporting system will be able to access existing information in previously submitted reports and data stored in other EPA databases. These data can be incorporated into new reports, which will lead to reporting burden reduction through labor savings.

In 2011, in response to Executive Order 13563, the EPA developed a plan to periodically review its regulations to determine if they should be modified, streamlined, expanded, or repealed in an effort to make regulations more effective and less burdensome.[104] The plan includes replacing outdated paper reporting with electronic reporting. In keeping with this plan and the White House's Digital Government Strategy,[105] in 2013 the EPA issued an agency-wide policy specifying that EPA will start with the assumption that reporting will be electronic and not paper. The EPA believes that the electronic submittal of the reports addressed in this rulemaking increases the usefulness of the data contained in those reports, is in keeping with current trends in data availability, further assists in the protection of public health and the environment and will ultimately result in less burden on the regulated community. Therefore, the EPA is retaining the requirement to report these data electronically.

2. Third-Party Verification for Closed Vent Systems

Comment: Several commenters express opposition to a third-party verification system for the design of closed vent systems. Some of the commenters explain that they design their closed vent system using in-house staff. Many of the details regarding actual flow volumes and gas composition are unknown at the initial design stage, so it would not be possible to certify the design's effectiveness prior to construction. Also, storage vessels are designed to have some level of losses, so it would also not be possible to certify that the closed vent system routes all emissions to the control device.

Several of the commenters also express concern that the verification process discussed in the preamble to the proposed rule would create a complex bureaucratic scheme with no measurable benefits. Many of the commenters believe such a verification process would add a significant labor and cost burden that the EPA has not quantified. The EPA's contention that third-party verification ''may'' improve compliance is presented without any analysis or support and does not justify the costs of such a program.

Concerning the impartiality requirements outlined by the EPA, some of the commenters believe that it would be impossible to find someone who is qualified to do verification that could pass those requirements due to the interrelationship between the production and support companies over decades of working with one another. Some commenters contend that the EPA overestimates the availability of qualified third-party consultants, assuming that an impartial one could be found, that understands the industry well enough to competently review designs for closed vent systems.

Some of the commenters remind the EPA of the conclusions the Agency reached after proposing a similar third-party verification system for the Greenhouse Gas Reporting Program, in which the EPA expressed concerns about establishing third-party verification protocols, developing a system to accredit third-party verifiers, and developing a system to ensure impartiality.

Response: The EPA continues to believe that independent third party verification can furnish more, and sometimes better, data about regulatory compliance. With better data about compliance, regulatory agencies, including the EPA, would have more

[104] EPA's Final Plan for Periodic Retrospective Reviews, August 2011. Available at: *http://www.epa.gov/regdarrt/retrospective/documents/eparetroreviewplan-aug2011.pdf.*

[105] Digital Government: Building a 21st Century Platform to Better Serve the American People, May 2012. Available at: *https://www.whitehouse.gov/sites/default/files/omb/egov/digital-government/digital-government-strategy.pdf.*

information to determine what types of regulations are effective and how to spend their resources. A critical element to independent third party verification is to ensure third-party verifiers are truly independent from their clients and perform competently. We continue to believe that this model best limits the risk of bias or ''capture'' due to the third-party verifier identifying or aligning his interests too closely with those of the client. However, in other rulemakings, we have explored and implemented an alternative to the independent third party verification, where engineering design is the element we wish to ensure is examined and implemented without bias. This is the ''qualified professional engineer'' model. In the ''Resource Conservation and Recovery Act (RCRA) Burden Reduction Initiative'' (Burden Reduction Rule) (71 FR 16826, April 4, 2006) and the ''Oil Pollution Prevention and Response; Non-Transportation-Related Onshore and Offshore Facilities rule (67 FR 47042, July 17, 2002), the Agency came to similar conclusions. First, that professional engineers, whether independent or employees of a facility, being professionals, will uphold the integrity of their profession and only certify documents that meet the prescribed regulatory requirements and that the integrity of both the professional engineer and the professional oversight of boards licensing professional engineers are sufficient to prevent any abuses. And second, that in-house professional engineers may be the persons most familiar with the design and operation of the facility and that a restriction on in-house professional certifications might place an undue and unnecessary financial burden on owners or operators of facilities by forcing them to hire an outside engineer. Also in the ''Burden Reduction Rule'' the Agency concluded that a professional engineer is able to give fair and technical review because of the oversight programs established by the state licensing boards that will subject the professional engineer to penalties, including the loss of license and potential fines if certifications are provided when the facts do not warrant it. A qualified professional engineer maintains the most important components of any certification requirement: (1) That the engineer be qualified to perform the task based on training and experience; and (2) that she or he be a professional engineer licensed to practice engineering under the title Professional Engineer which requires following a code of ethics with the potential of losing his/her license for negligence (see 71 FR 16868, April 4, 2006). The personal liability of the professional engineer provides strong support for both the requirement that certifications must be performed by licensed professional engineers. The Agency is convinced that an employee of a facility, who is a qualified professional engineer and who has been licensed by a state licensing board, would be no more likely to be biased than a qualified professional engineer who is not an employee of the owner or operator. The EPA has concluded that the programs established by state licensing boards provide sufficient guarantees that a professional engineer, regardless of whether he/she is ''independent'' of the facility, will give a fair technical review. As an additional protection, the Agency has re-evaluated the design criteria for closed vent systems to ensure that the requirements are sufficiently objective and technically precise, while providing site specific flexibility, that a qualified professional engineer will be able to certify that they have been met.

It is important to reiterate that state licensing boards can investigate complaints of negligence or incompetence on the part of professional engineers and may impose fines and other disciplinary actions, such as cease-and-desist orders or license revocation. (See 71 FR 16868.) In light of the third party oversight provided by the state licensing boards in combination with the numerous recordkeeping and recording requirements established in this rule, the Agency is confident that abuses of the certification requirements will be minimal and that human health and the environment will be protected.

In other rulemakings, which have allowed for a qualified professional engineer in lieu of an independent reviewer, the Agency has required that the professional engineer be licensed in the state in which the facility is located. (See ''Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities; Final Rule'' (Coal Ash Rule) (80 FR 21302, April 17, 2015)). The Agency has made this decision, in that rule, for a number of reasons, but primarily because state licensing boards can provide the necessary oversight on the actions of the professional engineer and investigate complaints of negligence or incompetence as well as impose fines and other disciplinary actions such as cease-and-desist orders or license revocation. The Agency concluded that oversight may not be as rigorous if the professional engineer is operating under a license issued from another state. While we believe this is the appropriate outcome for the Coal Ash Rule, in part due to the regional and geological conditions specific to the landfill design, we do not believe that we need to provide this restriction for the closed vent system design under this rulemaking. Closed vent system design elements are not predicated on regional characteristics but instead follow generally and widely understood engineering analysis such as volumetric flow, back pressure and pressure drops. We do believe that the professional engineer should be licensed in a minimum of one of the states in which the certifying official does business.

Whether to specify independent third-party reporting, some other type of third-party or self-reporting, or a Professional Engineer is a case-specific decision that will vary depending on the nature of the rule, the characteristics of the sector(s) and regulated entities, and the applicable regulatory requirements. Based on all relevant factors for this rule, the EPA has determined that a qualified Professional Engineer approach is appropriate and that it is unnecessary to require the individual making certifications under this rule to be ''independent third parties.'' Thus the final rule does not prohibit an employee of the facility from making the certification, provided they are a professional engineer that is licensed by a state licensing board.

3. The EPA's Authority and Costs for Standards Reflecting Next Generation Compliance and Rule Effectiveness

Comment: Several commenters believe that standards reflecting Next Generation Compliance and rule effectiveness strategies discussed in the preamble to the proposed rule are not legal and represent an overreach of its authority. While the EPA has authority to require reasonable recordkeeping, reporting and monitoring under the CAA, there is nothing in the CAA that can be construed to authorize the EPA to force the regulated community to hire a third-party contractor to do the EPA's work. The commenters point out that the EPA admitted in the preamble to the 2011 proposal of subpart OOOO that ensuring compliance with the well completion requirements would be very difficult and burdensome for regulatory agencies. The commenters believe that the EPA is using the requirements to relieve the regulatory agencies of some of this burden. One commenter stated that the requirements amount to an unfunded enforcement mandate on the facilities it is supposed to be regulating.

The commenters also state that the compliance requirements would violate the Anti-Deficiency Act because the third-party verification requirements would circumvent budget appropriations for EPA enforcement activities (see 31 U.S.C. 1341(a)(1)(A)).

Some of the commenters also object to the EPA justifying increased monitoring, recordkeeping and reporting requirements on consent decrees in enforcement actions. The commenters point out that consent decrees impose more stringent requirements on facilities that have been found to be in violation of a regulatory requirement; therefore, consent decree requirements would be inappropriate for generally applicable regulations. The commenters state that the EPA has provided no justification for imposing heightened requirements on all facilities regardless of their compliance history.

Several commenters also state that the EPA must propose the regulatory language for all of the compliance provisions reflecting Next Generation Compliance and rule effectiveness strategies before they can be finalized and doing otherwise would raise a notice and comment issue. One commenter added that the EPA's intent is to apply such compliance requirements to more industries than just oil and natural gas production. Therefore, the EPA must separately propose the compliance requirements in their entirety, including estimated costs and benefits, before using them in any specific rulemakings.

Many commenters believe the standards reflecting Next Generation and rule effectiveness strategies will add significant labor and cost burdens over and above the compliance costs that the EPA already estimated for complying with the proposed rule. For example, one commenter calculates that their company will have to generate 270,000 closed vent system monthly inspection reports in the first five years of the rule if current requirements are finalized. Another commenter estimates the cost of installing continuous pressure monitoring equipment at a single site to be $20,000, resulting in potential company-wide costs of about $15 million. One commenter adds, based on their own experience with third-party auditors, the cost of an audit can range from $8,000 to $15,000 per audit, per facility. In general, the commenters state that the compliance requirements raise technical and operational complexities which can only result in increased costs. Some of the commenters note that these costs would be untenable for small businesses.

Some of the commenters also expressed concern about a lack of necessary IT infrastructure, such as data acquisition hardware, data management software, and appropriate software, at remote oil and natural gas production and transmission facilities. The commenters also point out the lack of electricity at these sites. The commenters point out that dealing with these issues further increase the costs associated with these compliance measures.

Response: The EPA believes that the comment regarding our legal authority may be based upon a misunderstanding of EPA's Next Generation Compliance and rule effectiveness strategies. The EPA describes these strategies as follows:

''Today's pollution challenges require a modern approach to compliance, taking advantage of new tools and approaches while strengthening vigorous enforcement of environmental laws. Next Generation Compliance is EPA's integrated strategy to do that, designed to bring together the best thinking from inside and outside EPA.'' [106] Among the referenced modern approaches to compliance is to ''[d]esign regulations and permits that are easier to implement, with a goal of improved compliance and environmental outcomes.''

Thus EPA's Next Generation Compliance and rule effectiveness strategies, in and of themselves, impose no requirements or obligations on the regulated community. The strategies establish no regulatory terms for any sector or facility nor create rights or responsibilities in any party. Rather, the strategies describe general compliance assurance and regulatory design principles, approaches, and tools that EPA may consider in conducting rulemaking, permitting, and compliance assurance, and enforcement activities.

Regarding comments that in order to avoid notice and comment issues the EPA must propose regulatory language before finalizing any regulatory language, the EPA disagrees. Section 307(d)(3) of the CAA states that ''notice of proposed rulemaking shall be published in the **Federal Register**, as provided under section 553(b) of title 5, United States Code . . . .'' There is nothing in the remainder of section 307(d) that requires the EPA to publish the regulatory text. Similarly, section 553(b) of the Administrative Procedure Act (APA) does not require agencies to publish the actual regulatory text. See EMILY's List v. FEC, 362 F. Supp. 2d 43, 53 (D.D.C. 2005), where ''[t]he Court notes that section 553 itself does not require the Agency to publish the text of a proposed rule, since the Agency is permitted to publish 'either the terms or substance of the proposed rule or a description of the subjects and issues involved.' ''. For this rulemaking, the EPA has provided notice and opportunity to comment for all of the specific regulatory requirements applicable to the sector and facilities covered by the rulemaking, either through proposed regulatory language or a description in the preamble.

The EPA notes that the proposal for independent third party verification—replaced in the final rule with qualified Professional Engineer requirements—reflects the responsibility of regulated entities to comply with the new NSPS. CAA Section 111(a)(1) defines ''a standard of performance'' as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirement) the Administrator determines has been adequately demonstrated.'' Further, in directing the Administrator to propose and promulgate regulations under section 111(b)(1)(B), Congress provided that the Administrator should take comment and then finalize the standards with such modifications ''as he deems appropriate.'' The D.C. Circuit has considered similar statutory phrasing from CAA section 231(a)(3) and concluded that ''[t]his delegation of authority is both explicit and extraordinarily broad.'' National Assoc. of Clean Air Agencies v. EPA, 489 F.3d 1221, 1229 (D.C. Cir. 2007).

In addition, the information to be collected for the proposed NSPS is based on notification, performance tests, recordkeeping and reporting requirements which will be mandatory for all operators subject to the final standards. Recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414) which provides that for ''any standard of performance under section 7411,'' the Administrator may require the sources to, among other things, ''install, use, and maintain such monitoring equipment, and use such audit procedures, or methods'' and submit compliance certifications in accordance with subsection (a)(3) of this section,'' as the Administrator may require. CAA section 114(a)(1)(A)–(G).

As discussed in section VI and in this section, the EPA has determined that to comply with the new NSPS and meet its

[106] USEPA; Next Generation Compliance Web page at *https://www.epa.gov/compliance/next-generation-compliance*.

emissions standard, regulated entities must obtain certifications from qualified Professional Engineers to demonstrate technical infeasibility to connect a pneumatic pump to an existing control device and to ensure the proper closed vent system design. The EPA believes for the sources covered by this rule, a professional engineer can furnish more, and sometimes better, data about regulatory compliance, especially where engineering design (*e.g.*, closed vent system design) is the element we want to ensure is examined and implemented without bias.

The EPA notes that nothing in this rule relieves the EPA of any of its responsibilities under the CAA or implies that the EPA will not continue to use its enforcement authorities under the CAA or devote resources to monitoring and enforcing this rule. This rule simply ensures that regulated parties will have the tools available to assess and ensure their own compliance.

The EPA wishes to explain that unfunded mandates are typically rules that impose significant obligations, without funding, on state, local, or tribal governments.[107] Interpreting this comment as applying to the obligations this NSPS imposes on entities to which it will apply, all rules, by definition, impose some obligations and responsibilities on subject facilities. In this preamble, the EPA explains the benefits, costs, and justification for each regulatory requirement.

As discussed above, the EPA explains the emission standards in this NSPS apply to the subject regulated entities. The EPA remains responsible for ensuring and enforcing compliance with the rule. The EPA notes that nothing in this rule relieves the EPA of any of its responsibilities under the CAA to ensure and enforce regulatory compliance.

The EPA agrees, that if the EPA were to seek to apply the standards in this rule—or any other regulatory standards, reflecting the Agency's Next Generation Compliance and rule effectiveness strategies or otherwise—to additional sectors beyond oil and natural gas production, the EPA would need to separately propose and justify the standards. As discussed above, however, the EPA's Next Generation Compliance and rule effectiveness strategies, in and of themselves, impose no requirements on the regulated community. The strategies prescribe no specific regulatory terms for any sector or facility nor do they create rights or responsibilities in any party. Rather, they describe compliance assurance and regulatory design strategies and approaches that the EPA will consider in conducting rulemaking, permitting, and compliance assurance, and enforcement activities that are inappropriate for notice and comment rulemaking. If the EPA believes that these strategies and approaches should be applied in other circumstances and to other industry sectors, the Agency will do this through other regulatory actions.

The EPA agrees with the commenters that certain of the Next Generation and rule effectiveness strategies are the result of information that the Agency has gained from implementation of past consent decrees (*e.g.*, closed vent system design and fugitives monitoring program audit). It is not unusual for the Agency to require additional monitoring practices, and recordkeeping and reporting requirements through consent, as this provides us an opportunity to identify the effectiveness of these standards from those companies that have engaged in violative conduct. Furthermore, through our enforcement efforts, when we see common and widespread compliance problems that can be addressed through improved monitoring, reporting and recordkeeping practices, it is our duty to include these tools in rulemaking, resulting in greater environmental benefit. As discussed elsewhere in this preamble, we are not requiring an ''independent third party'' verification of closed vent system design, nor are we requiring that the fugitive emissions monitoring program be audited. However, because of the widespread issues we have found with closed vent system design, the Agency will require a certification by a qualified professional engineer.

Regarding the comment about necessary IT infrastructure, such as data acquisition hardware, data management software, and appropriate software, at remote oil and natural gas production and transmission facilities and the lack of electricity at these sites, the Agency does not believe that the next generation and rule effectiveness initiatives we are proposing directly require IT infrastructure beyond that already required by other aspects of the rule. Likewise, onsite electrical availability for remote well sites is not an issue for the Next Generation and Rule Effectiveness strategies that we are finalizing.

IX. Impacts of the Final Amendments

A. What are the air impacts?

For this action, the EPA estimated the emission reductions that will occur due to the implementation of the final emission limits. The EPA estimated emission reductions based on the control technologies proposed as the BSER. This analysis estimates regulatory impacts for the analysis years of 2020 and 2025. The analysis of 2020 represents the accumulation of new and modified sources from the first full year of compliance, 2016, through 2020 to illustrate the near-term impacts of the rule. The regulatory impact estimates for 2020 include sources newly affected in 2020 as well as the accumulation of affected sources from 2016 to 2019 that are also assumed to be in continued operation in 2020, thus incurring compliance costs and emissions reductions in 2020. We also estimate impacts in 2025 to illustrate the continued compound effect of this rule over a longer period. The regulatory impact estimates for 2025 include sources newly affected in 2025 as well as the accumulation of affected sources from 2016 to 2024 that are also assumed to be in continued operation in 2025, thus incurring compliance costs and emissions reductions in 2025.

In 2020, we have estimated that the final NSPS would reduce about 300,000 tons of methane emissions and 150,000 tons of VOC emissions from affected facilities. In 2025, we have estimated that the proposed NSPS would reduce about 510,000 tons of methane emissions and 210,000 tons of VOC emissions from affected facilities. The NSPS is also expected to concurrently reduce about 1,900 tons HAP in 2020 and 3,900 tons HAP in 2025.

As described in the TSD and RIA for this rule, the EPA projected affected facilities using a combination of historical data from the United States GHG Inventory, and projected activity levels, taken from the Energy Information Administration (EIA's) Annual Energy Outlook (AEO). The EPA also considered state regulations with similar requirements to the final NSPS in projecting affected sources for impacts analyses supporting this rule.

B. What are the energy impacts?

Energy impacts in this section are those energy requirements associated with the operation of emission control devices. Potential impacts on the national energy economy from the rule are discussed in the economic impacts section. There would be little national energy demand increase from the operation of any of the environmental

[107] See USEPA, Rulemakings by Effect: Unfunded Mandates Web site at *https://yosemite.epa.gov/opei/rulegate.nsf/content/effectsunfunded.html?OpenDocument&Count=1000&ExpandView*.

each month within the quarterly monitoring period must be determined using historical monthly average temperatures over the previous three years as reported by a National Oceanic and Atmospheric Administration source or other source approved by the Administrator. The requirements of paragraph (g)(2) of this section shall not be waived for two consecutive quarterly monitoring periods.

(h) Each identified source of fugitive emissions shall be repaired or replaced in accordance with paragraphs (h)(1) and (2) of this section. For fugitive emissions components also subject to the repair provisions of §§ 60.5416a(b)(9) through (12) and (c)(4) through (7), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (h)(1) and (2) of this section do not apply to those closed vent systems and covers.

(1) Each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than 30 calendar days after detection of the fugitive emissions.

(2) If the repair or replacement is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next compressor station shutdown, well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within 2 years, whichever is earlier.

(3) Each repaired or replaced fugitive emissions component must be resurveyed as soon as practicable, but no later than 30 days after being repaired, to ensure that there are no fugitive emissions.

(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 either Method 21 or optical gas imaging within 30 days of finding such fugitive emissions.

(ii) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken, must clearly identify the component by location within the site (*e.g.,* the latitude and longitude of the component or by other descriptive landmarks visible in the picture).

(iii) Operators that use Method 21 to resurvey the repaired fugitive emissions components are subject to the resurvey provisions specified in paragraphs (h)(3)(iii)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than 500 ppm above background or when no soap bubbles are observed when the alternative screening procedures specified in section 8.3.3 of Method 21 are used.

(B) Operators must use the Method 21 monitoring requirements specified in paragraph (c)(8)(ii) of this section or the alternative screening procedures specified in section 8.3.3 of Method 21.

(iv) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (h)(3)(iv)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the optical gas imaging instrument shows no indication of visible emissions.

(B) Operators must use the optical gas imaging monitoring requirements specified in paragraph (c)(7) of this section.

(i) Records for each monitoring survey shall be maintained as specified § 60.5420a(c)(15).

(j) 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 that include the information specified in § 60.5420a(b)(7). Multiple collection of fugitive emissions components at a well site or at a compressor station may be included in a single annual report.

§ 60.5398a What are the alternative means of emission limitations for GHG and VOC from well completions, reciprocating compressors, the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in GHG (in the form of a limitation on emission of methane) and VOC emissions at least equivalent to the reduction in GHG and VOC emissions achieved under § 60.5375a, § 60.5385a, and § 60.5397a, the Administrator will publish, in the **Federal Register**, a notice permitting the use of that alternative means for the purpose of compliance with § 60.5375a, § 60.5385a, and § 60.5397a. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities.

(d) Determination of equivalence to the design, equipment, work practice or operational requirements of this section will be evaluated by the following guidelines:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months to demonstrate the equivalence of the alternative means of emission limitation. The application must include the following information:

(i) A description of the technology or process.

(ii) The monitoring instrument and measurement technology or process.

(iii) A description of performance based procedures (*i.e.,* method) and data quality indicators for precision and bias; the method detection limit of the technology or process.

(iv) For affected facilities under § 60.5397a, the action criteria and level at which a fugitive emission exists.

(v) Any initial and ongoing quality assurance/quality control measures.

(vi) Timeframes for conducting ongoing quality assurance/quality control.

(vii) Field data verifying viability and detection capabilities of the technology or process.

(viii) Frequency of measurements.

(ix) Minimum data availability.

(x) Any restrictions for using the technology or process.

(xi) Operation and maintenance procedures and other provisions necessary to ensure reduction in methane and VOC emissions at least equivalent to the reduction in methane and VOC emissions achieved under § 60.5397a.

(xii) Initial and continuous compliance procedures, including recordkeeping and reporting.

(2) For each determination of equivalency requested, the emission reduction achieved by the design, equipment, work practice or operational requirements shall be demonstrated.

(3) For each affected facility for which a determination of equivalency is requested, the emission reduction achieved by the alternative means of emission limitation shall be demonstrated.

(4) Each owner or operator applying for a determination of equivalence to a work practice standard shall commit in writing to work practice(s) that provide for emission reductions equal to or

greater than the emission reductions achieved by the required work practice.

(e) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the **Federal Register**.

(f) An application submitted under this section will be evaluated as set forth in paragraphs (f)(1) and (2) of this section.

(1) The Administrator will compare the demonstrated emission reduction for the alternative means of emission limitation to the demonstrated emission reduction for the design, equipment, work practice or operational requirements and, if applicable, will consider the commitment in paragraph (d) of this section.

(2) The Administrator may condition the approval of the alternative means of emission limitation on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as the design, equipment, work practice or operational requirements. (g) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design or operational standard within the meaning of section 111(h)(1) of the CAA.

§ 60.5400a What equipment leak GHG and VOC standards apply to affected facilities at an onshore natural gas processing plant?

This section applies to the group of all equipment, except compressors, within a process unit.

(a) You must comply with the requirements of §§ 60.482–1a(a), (b), and (d), 60.482–2a, and 60.482–4a through 60.482–11a, except as provided in § 60.5401a.

(b) You may elect to comply with the requirements of §§ 60.483–1a and 60.483–2a, as an alternative.

(c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of methane and VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of § 60.5402a.

(d) You must comply with the provisions of § 60.485a except as provided in paragraph (f) of this section.

(e) You must comply with the provisions of §§ 60.486a and 60.487a except as provided in §§ 60.5401a, 60.5421a, and 60.5422a.

(f) You must use the following provision instead of § 60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169–93, E168–92, or E260–96 (incorporated by reference as specified in § 60.17) must be used.

§ 60.5401a What are the exceptions to the equipment leak GHG and VOC standards for affected facilities at onshore natural gas processing plants?

(a) You may comply with the following exceptions to the provisions of § 60.5400a(a) and (b).

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in § 60.485a(b) except as provided in § 60.5400a(c) and in paragraph (b)(4) of this section, and § 60.482–4a(a) through (c) of subpart VVa of this part.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in § 60.482–9a.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are onsite, instead of within 5 days as specified in paragraph (b)(1) of this section and § 60.482–4a(b)(1).

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section may be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of § 60.482–5a.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1), 60.482–7a(a), 60.482–11a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1), 60.482–7a(a), 60.482–11a(a), and paragraph (b)(1) of this section.

(f) An owner or operator may use the following provisions instead of § 60.485a(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °Celsius (302 °Fahrenheit) as determined by ASTM Method D86–96 (incorporated by reference as specified in § 60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °Celsius (302 °Fahrenheit) as determined by ASTM Method D86–96 (incorporated by reference as specified in § 60.17).

(g) An owner or operator may use the following provisions instead of § 60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A–7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in § 60.486a(e)(8). Divide these readings by the initial calibration values for each scale and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all

Attachment 4

U.S. Energy Information Administration, Natural Gas, Number of Gas Producing Oil Wells (available at https://www.eia.gov/dnav/ng/ng_prod_oilwells_s1_a.htm).

U.S. Energy Information Administration

NATURAL GAS

Number of Gas Producing Oil Wells

Period: Annual

Area	Graph Clear		2011	2012	2013	2014	2015	View History
U.S.	☐		181,241	195,869	203,990	215,815	215,867	2011-2015
Alabama	☐		346	367	402	436	414	2011-2015
Alaska	☐		2,040	1,981	2,006	2,042	2,096	2011-2015
Arizona	☐		1	1	1	0	1	2011-2015
Arkansas	☐		165	174	218	233	240	2011-2015
California	☐		25,958	26,061	26,542	26,835	27,075	2011-2015
Colorado	☐		5,963	6,456	6,799	7,771	7,733	2011-2015
Florida	☐		30	33	32	30	29	2011-2015
Gulf of Mexico	☐		3,046	3,012	3,022	3,038	2,965	2011-2015
Illinois	☐		NA	NA	NA	NA	NA	2011-2015
Indiana	☐		NA	NA	NA	NA	NA	2011-2015
Kansas	☐		0	0	0	0	0	2011-2015
Kentucky	☐		317	358	340	NA	NA	2011-2015
Louisiana	☐		5,201	5,057	5,078	5,285	4,968	2011-2015
Maryland	☐		0	0	0	0	0	2011-2015
Michigan	☐		510	514	537	584	532	2011-2015
Mississippi	☐		561	618	581	540	501	2011-2015
Missouri	☐		1	1	1	1	NA	2011-2015
Montana	☐		1,956	2,147	2,268	2,377	2,277	2011-2015
Nebraska	☐		84	73	54	51	51	2011-2015
Nevada	☐		4	4	4	4	4	2011-2015
New Mexico	☐		12,887	13,791	14,171	14,814	14,580	2011-2015
New York	☐		988	1,170	1,589	1,731	1,697	2011-2015
North Dakota	☐		5,561	7,379	9,363	11,532	12,799	2011-2015
Ohio	☐		6,775	6,745	7,038	7,257	5,941	2011-2015
Oklahoma	☐		6,723	7,360	8,744	7,105	8,368	2011-2015
Oregon	☐		0	0	0	0	0	2011-2015
Pennsylvania	☐		7,046	7,627	7,164	8,481	7,557	2011-2015
South Dakota	☐		72	69	74	68	65	2011-2015
Tennessee	☐		52	75	NA	NA	NA	2011-2015
Texas	☐		85,030	94,203	96,949	104,205	105,159	2011-2015
Utah	☐		3,119	3,520	3,946	4,249	3,966	2011-2015
Virginia	☐		2	1	1	2	2	2011-2015
West Virginia	☐		2,373	2,509	2,675	2,606	2,244	2011-2015
Wyoming	☐		4,430	4,563	4,391	4,538	4,603	2011-2015

Click on the source key icon to learn how to download series into Excel, or to embed a chart or map on your website.

- = No Data Reported; -- = Not Applicable; **NA** = Not Available; **W** = Withheld to avoid disclosure of individual company data.

Notes: Well counts include any well that produced natural gas at any time during the calendar year. For most states, "Oil Wells" refers only to oil wells that produce natural gas (a subset of all oil wells). However, oil well counts for Illinois, Indiana, and Kentucky (derived from World Oil) include all oil wells. See Definitions, Sources, and Notes link above for more information on this table.

Release Date: 05/31/2017
Next Release Date: 06/30/2017

<u>Attachment 5</u>

U.S. Energy Information Administration, Natural Gas, Number of Producing Gas Wells (available at https://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm).

U.S. Energy Information Administration

NATURAL GAS

Number of Producing Gas Wells

Period: Annual

Area	Graph Clear	2010	2011	2012	2013	2014	2015	View History
U.S.	☐	487,627	574,593	577,916	572,742	565,951	555,364	1989-2015
Alabama	☐	7,026	6,243	6,203	6,174	6,117	6,044	1989-2015
Alaska	☐	269	274	281	300	338	329	1989-2015
Arizona	☐	5	5	4	3	6	6	1989-2015
Arkansas	☐	7,397	8,428	9,012	9,324	9,778	9,965	1989-2015
California	☐	1,580	4,240	4,356	4,183	4,211	4,209	1989-2015
Colorado	☐	28,813	43,792	46,141	46,883	46,876	46,322	1989-2015
Gulf of Mexico	☐	1,852	2,226	1,892	1,588	1,377	1,163	1998-2015
Illinois	☐	50	40	40	34	36	35	1989-2015
Indiana	☐	620	914	819	921	895	899	1989-2015
Kansas	☐	22,145	25,362	25,013	24,802	24,840	24,451	1989-2015
Kentucky	☐	17,670	12,708	13,179	14,557	NA	NA	1989-2015
Louisiana	☐	19,137	19,318	19,345	18,802	18,660	18,382	1989-2015
Maryland	☐	7	7	7	7	5	7	1989-2015
Michigan	☐	10,100	10,480	10,381	10,322	10,246	9,929	1989-2015
Mississippi	☐	1,979	1,703	1,666	1,632	1,594	1,560	1989-2015
Missouri	☐	0	19	15	7	6	NA	1989-2015
Montana	☐	6,059	6,615	6,366	5,870	5,682	5,655	1989-2015
Nebraska	☐	276	307	299	246	109	140	1989-2015
Nevada	☐	0	0	0	0	1	1	1996-2015
New Mexico	☐	44,748	40,231	40,441	40,119	40,244	40,596	1989-2015
New York	☐	6,736	7,372	7,731	7,553	7,619	7,605	1989-2015
North Dakota	☐	188	526	451	423	398	462	1989-2015
Ohio	☐	34,931	31,966	31,647	30,804	31,060	26,599	1989-2015
Oklahoma	☐	44,000	51,712	51,472	50,606	50,044	49,852	1989-2015
Oregon	☐	26	28	24	24	12	14	1989-2015
Pennsylvania	☐	44,500	61,815	62,922	61,838	67,621	68,536	1989-2015
South Dakota	☐	102	155	159	133	128	124	1989-2015
Tennessee	☐	230	1,027	1,027	1,089	NA	NA	1989-2015
Texas	☐	95,014	139,368	140,087	140,964	142,292	142,368	1989-2015
Utah	☐	6,075	7,603	8,121	8,300	8,537	8,739	1989-2015
Virginia	☐	7,470	7,781	7,874	7,956	8,061	8,111	1989-2015
West Virginia	☐	52,498	51,629	51,646	50,097	53,060	47,938	1989-2015
Wyoming	☐	26,124	30,653	29,254	27,141	26,055	25,279	1989-2015

Click on the source key icon to learn how to download series into Excel, or to embed a chart or map on your website.

- = No Data Reported; **--** = Not Applicable; **NA** = Not Available; **W** = Withheld to avoid disclosure of individual company data.

Notes: Prior to 2001, the well counts for Federal Offshore Gulf of Mexico were included in the well counts for Alabama, Louisiana, and Texas. See Definitions, Sources, and Notes link above for more information on this table.

Release Date: 05/31/2017
Next Release Date: 06/30/2017

Attachment 6

Texas Commission on Environmental Quality, Air Quality Standard Permit for Oil and Gas Handling and Production Facilities (available at https://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/og-adopkg-2012.pdf).

Air Quality Standard Permit For
Oil and Gas Handling and Production Facilities

Note for all Readers: Acronym List at End of Document

I. Executive Summary

The Texas Commission on Environmental Quality (TCEQ or commission) is issuing amendments to the Air Quality Standard Permit for Oil and Gas Handling and Production Facilities.

II. Explanation and Background of Air Quality Standard Permit

On January 26, 2011, the TCEQ issued a non-rule standard permit for oil and gas production facilities. The standard permit became effective on April 1, 2011 and applied only in the following counties making up the Barnett Shale region of the state: Archer, Bosque, Clay, Comanche, Cooke, Coryell, Dallas, Denton, Eastland, Ellis, Erath, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Shackelford, Stephens, Somervell, Tarrant, and Wise. The commission is issueing a corrected standard permit to address typographical errors, formatting, and duplicative language.

III. Overview of Air Quality Standard Permit

The standard permit includes operating specifications and emissions limitations for typical equipment and facilities used during normal operation, which includes production and planned maintenance, startup, and shutdown (MSS). The standard permit references the new federal standards which have been promulgated by the United States Environmental Protection Agency (EPA), and includes criteria for registration and changes at existing, authorized sites. It also specifically addresses the appropriateness of multiple authorizations at one contiguous property.

IV. Permit Condition Analysis and Justification

The commission is amending subsection (m), table 8 to remove unnecessary, repetitive language under the heading Control Devices, Control with process combustion or heating devices (e.g. reboilers, heatersand furnaces). Additionally, there have been nonsubstantive corrections to typographical errors and formatting changes.

V. Protectiveness Review

None of the conditions affecting protectiveness are being changed in this amendment, therefore a protectiveness review was not produced.

VI. Public Notice and Comment Period

In accordance with 30 TAC §116.603, Public Participation in Issuance of Standard Permits, the TCEQ published notice of the proposed standard permit in the *Texas Register* and newspapers of the largest general circulation in the following metropolitan areas: Austin, Dallas, and Houston. The date for the newspaper publications was August 22, 2011. The date of the *Texas Register* notice was September 2, 2011. The public comment period ran from the date of newspaper publication until 5:00 p.m. on October 3, 2011. Written comments were received from the Texas Oil and Gas Association (TxOGA).

VII. Public Meeting

A public meeting was held on the proposed amendments to the Air Quality Standard Permit for Oil and Gas Handling and Production Facilities on October 3, 2011, and no comments were submitted.

VIII. Analysis of Comments

TxOGA expressed appreciation for the removal of unnecessary, repetitive language in section (m) of the standard permit provided that the change is not substantive.

The commission thanks TxOGA for its support of this amendment to the standard permit and confirms that the change is a non-substantive removal of a typographical error.

TxOGA also stated that it would object to any changes resulting from other comments made in reference this amendment to the standard permit. Additionally TxOGA stated that Senate Bill (SB) 1134 from the 82nd Regular Legislative Session precluded any changes to §106.352 unless accompanied by the requisite regulatory impact analysis and air monitoring data.

No other comments were received on this amendment, consequently, there will be no additional changes resulting from comments. Also, the commission will not make changes that would conflict with the requirements of SB 1134. However, the commission may make non-substantive corrections to typographical errors or formatting changes necessary for this standard permit amendment.

IX. Statutory Authority

The amendments to this standard permit are proposed under the Texas Clean Air Act (TCAA), Texas Health and Safety Code (THSC), §382.011, General Powers and Duties, which authorizes the commission to control the quality of the state's air, THSC §382.051, Permitting Authority of Commission; Rules, which authorizes the commission to issue permits, including standard permits for similar facilities, and THSC §382.0513, Permit Conditions, which authorizes the commission to establish and enforce permit conditions consistent with the TCAA, THSC §382.05195, Standard Permit, which authorizes the commission to issue standard permits according to the procedures set out in that standard permit, and THSC §382.051963 which authorizes the commission to make certain amendments to the standard permit.

Air Quality Standard Permit For
Oil and Gas Handling and Production Facilities
EffectiveJanuary 11, 2012

(a) **Applicability.** This standard permit applies to all stationary facilities, or groups of facilities, at a site which handle gases and liquids associated with the production, conditioning, processing, and pipeline transfer of fluids or gases found in geologic formations on or beneath the earth's surface including, but not limited to, crude oil, natural gas, condensate, and produced water with the following conditions.

(1) The requirements in paragraphs (a)-(k) of this standard permit are applicable in only for new projects and dependent facilities located in the Barnett Shale (Archer, Bosque, Clay, Comanche, Cooke, Coryell, Dallas, Denton, Eastland, Ellis, Erath, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Shackelford, Stephens, Somervell, Tarrant, and Wise Counties) on or after April 1, 2011. For all other new projects and dependent facilities in all other counties of the state, paragraph (l) of this standard permit is applicable.

(2) Only one Air Quality Standard Permit for Oil and Gas Handling and Production Facilities for an oil and gas site (OGS) may be registered for a combination of dependent facilities and authorizes all facilities in sweet or sour service. This standard permit may not be used if operationally dependent facilities are authorized by the permit by rule in Title 30, Texas Administrative Code (30 TAC) §106.352, Oil and Gas Handling and Production Facilities, or a permit under 30 TAC §116.111,General Application. Existing authorized facilities, or groups of facilities, at an OGS under this standard permit which are not changing certified character or quantity of emissions must only meet subsections (i) and (k) of this standard permit (protectiveness review and planned maintenance, startup, and shutdown (MSS) requirements) and otherwise retain their existing authorization. Other facilities which are not covered under this standard permit may be authorized by other authorizations at an OGS if (b)(6) and (k) of this standard permit are met.

(3) This standard permit does not relieve the owner or operator from complying with any other applicable provision of the Texas Health and Safety Code, Texas Water Code, rules of the Texas Commission on Environmental Quality (TCEQ), or any additional local, state or federal regulations. Emissions that exceed the limits in this standard permit are not authorized and are violations.

(4) Emissions from upsets, emergencies, or malfunctions are not authorized by this standard permit. This standard permit does not regulate methane, ethane, or carbon dioxide.

(b) **Definitions and Scope.**

(1) Facility is a discrete or identifiable structure, device, item, equipment, or enclosure that constitutes or contains a stationary source. Stationary sources associated with a mine, quarry, or well test lasting less than 72 hours are not considered facilities.

(2) Receptor includes any building which is in use as a single or multi-family residence, school, day-care, hospital, business, or place of worship at the time this standard permit is registered. A residence is a structure primarily used as a permanent dwelling. A business is a structure that is occupied for at least 8 hours a day, 5 days a week, and does not include businesses who are handling or processing materials as described in subsection (a). This term does not include structures occupied or used solely by the owner or operator of the oil and gas facility, or the mineral rights owner of the property upon which the facility is located. All measurements of distance to receptors shall be taken from the emission release point at the oil and gas facility that is nearest to the point on the building that is nearest to the oil and gas facility.

(3) An OGS is defined as all facilities which meet the following:
(A) Located on contiguous or adjacent properties;
(B) Under common control of the same person (or persons under common control); and
(C) Designated under same 2-digit standard industrial classification (SIC) codes.

(4) For purposes of determining applicability of 30 TAC Chapter 122, Federal Operating Permits, the definitions of 30 TAC §122.10, General Definitions, apply.

(5) A project under this standard permit is defined as the following and must meet all requirements of this standard permit prior to construction or implementation of changes.
(A) Any new facility or new group of operationally dependent facilities at an OGS; or
(B) Physical changes to existing authorized facilities or group of facilities at an OGS which increase the potential to emit over previously registered emission limits; or
(C) Operational changes to existing authorized facilities or group of facilities at an OGS which increase the potential to emit over previously registered emission limits.

(6) For purposes of registration under this standard permit, the following facilities shall be included:

(A) All facilities or groups of facilities at an OGS which are operationally dependent on each other;

(B) Facilities must be located within a 1/4 mile of a project emission point, vent, or fugitive component, except for those components excluded in (b)(6)(C) of this standard permit;

(C) If piping or fugitive components are the only connection between facilities and the distance between facilities exceeds 1/4 mile, then the facilities are considered separate for purposes of this registration;

(D) The boundaries of the registration become fixed at the time this standard permit is registered. No individual facility may be authorized under more than one registration;

(E) Any facility or group of facilities authorized under an existing standard permit registration which is operationally dependent on a project must be revised to incorporate the project; and

(F) A registration may include facilities which are claiming 30 TAC §116.620, Installation and/or Modification of Oil and Gas Facilities as well as projects which are claiming this standard permit. Existing authorized facilities, or group of facilities, at an OGS under this standard permit which are not changing registered and certified character or quantity of emissions must only meet paragraphs (i) and (k) of this standard permit (the protectiveness review and planned maintenance, startup, and shutdown (MSS) requirements) until the registration is renewed after December 31, 2015, after which paragraphs (a) – (k) of this standard permit apply.

(7) For purposes of all previous claims of this standard permit (or any previous version of this standard permit) where no project is occurring:

(A) Existing authorized facilities, or group of facilities, which have not registered planned MSS activity emissions prior to the effective dates in (a)(1) of this standard permit must meet paragraph (i) of this standard permit (planned MSS) no later than January 5, 2012; or

(B) Existing authorized facilities, or group of facilities, which have registered planned MSS activity emissions and compliance with 30 TAC §116.620(a)(1) has been demonstrated prior to the effective dates in (a)(1) of this standard permit, must meet paragraph (i) of this standard permit (planned MSS) no later than the registration renewal submitted after December 31, 2015.

(8) For purposes of ensuring protection of public health and welfare and demonstrating compliance with applicable ambient air standards and effects screening levels, the impacts analysis as specified in paragraph (k) of this standard permit must be completed.

(A) All impacts analysis must be done on a contaminant-by-contaminant basis for any net project increases. If a claim under this standard permit is only for planned MSS under paragraph (i) of this standard permit, the analysis shall evaluate planned MSS scenarios only.

(B) Hourly and annual emissions shall be limited based on the most stringent of paragraphs (h) or (k) of this standard permit.

(c) **Authorized Facilities, Changes and Activities.**

(1) For existing OGS which are authorized by previous versions of this standard permit:
(A) A project requires registration unless otherwise specified.
(B) The following projects do not require registration, but must comply with best management practices in paragraph (e) of this standard permit, compliance demonstrations in paragraphs (i) and (j) of this standard permit and must be incorporated into the registration at the next revision or certification:
(i) Addition of any piping, fugitive components, any other new facilities that increase registered emissions less than or equal to 1.0 tpy volatile organic compounds (VOC), 5.0 tpy nitrogen oxides (NOx), 0.01 tpy benzene, and 0.05 tpy hydrogen sulfide (H2S) over a rolling 12-month period;
(ii) Changes to any existing facilities that increase registered emissions less than or equal to 1.0 tpy VOC, 5.0 tpy nitrogen oxides (NOx), 0.01 tpy benzene, and 0.05 tpy H2S over a rolling 12-month period; or
(iii) Total increases over a rolling 60-month period that are less than or equal to 5.0 tpy VOC or NOX, 0.05 tpy benzene, or 0.1 tpy H2S; or
(iv) Addition of any new engine rated less than 100 horsepower (hp); or
(v) Replacement of any facility if the new facility does not increase the previous registered emissions.
(C) In lieu of registering proposed changes under this standard permit, incremental emissions increases associated with construction of new facilities or changes to existing facilities may be authorized by 30 TAC §106.261, Facilities (Emission Limitations) or §106.262, Facilities (Emissions and Distance Limitations), if the maximum worst-case emissions also meet the limitations established by paragraphs (b)(8) and (k) of this standard permit for all air contaminants with proposed increases.

(2) All authorizations under this standard permit shall meet the following:
(A) New, changed, or replacement facilities shall not exceed the thresholds for major source or major modification as defined in 30 TAC §116.12, Nonattainment and Prevention of Significant Deterioration Review Definitions, and in Federal Clean Air Act §112(g) or §112(j);
(B) All facilities shall comply with all applicable 40 Code of Federal Regulations (CFR), Parts 60, 61, and 63 requirements for New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), and Maximum Achievable Control Technology (MACT); and

(C) All facilities shall comply with all applicable requirements of 30 TAC Chapters 111, Control of Air Pollution from Visible Emissions and Particulate Matter, 112, Control of Air Pollution from Sulfur Compounds, 113, Standards of Performance for Hazardous Air Pollutants and for Designated Facilities and Pollutants, 115, Control of Air Pollution from Volatile Organic Compounds), and 117, Control of Air Pollution from Nitrogen Compounds.

(3) To be eligible for this standard permit an applicant:
(A) shall meet all applicable requirements as set forth in this standard permit;
(B) shall not misrepresent or fail to fully disclose all relevant facts in obtaining the permit; and
(C) shall not be indebted to the state for failure to make payment of penalties or taxes imposed by the statutes or rules within the commission's jurisdiction.

(4) All facilities related to the operation of any OGS, under any version of this standard permit (or co-located at a site with an OGS standard permit), previously authorized by, and continuing to meet, the conditions of a permit by rule under 30 TAC Chapter 106, Permits by Rule (or any historical version) must:
(A) Be incorporated into this standard permit in any initial registration, revision, or renewal for this standard permit. These facilities will become authorized by this standard permit and previous authorizations will be voided.
(B) Meet all emission limits established by this standard permit and review in accordance with paragraph (b)(8) of this standard permit.
(C) Meet requirements of paragraphs (e), (i), and (j) of this standard permit for Best Management Practices and Minimum Requirements, Planned MSS, and associated Records, Sampling and Monitoring of this standard permit.
(D) Only if facilities or groups of facilities are changed in such a way as to increase the potential to emit, production processing capacity, or registered emission rate, the requirements in paragraph (e) ~~(h)~~ (BACT) of this standard permit are required to be met. In all other cases, these facilities are not required to meet paragraph (e) ~~(h)~~ of this standard permit.

(d) **Facilities and Exclusions**

(1) Only the following specific facilities and groups of facilities have been evaluated for this standard permit, along with supporting infrastructure equipment and facilities, and may be included in a registration:

(A) Fugitive components, including valves, pressure relief valves, pipe flanges and connectors, pumps, compressors, stuffing boxes, instrumentation and meters, natural gas driven pneumatic pumps, and other similar devices with seals that separate process and waste material from the atmosphere and the associated piping;
(B) Separators, including all gas, oil and water physical separation units;

(C) Treatment and processing equipment, including heater-treaters, methanol injection, glycol dehydrators, molecular or mole sieves, amine sweeteners, H_2S scavenger chemical reaction vessels for sulfur removal, and iron sponge units;
(D) Cooling towers and associated heat exchangers;
(E) Gas recovery units, including cryogenic expansion, absorption, adsorption, heat exchangers and refrigeration units;
(F) Combustion units, including engines, turbines, boilers, reboilers, and heaters;
(G) Storage tanks for crude oil, condensate, produced water fuels, treatment chemicals, slop and sump oils and pressure tanks with liquified petroleum gases;
(H) Surface facilities associated with underground storage of gas or liquids;
(I) Truck loading equipment;
(J) Control equipment, including vapor recovery systems, glycol and amine reboiler condensers, flares, vapor combustors, and thermal oxidizers; and
(K) Temporary facilities used for planned maintenance, and temporary control devices for planned start-ups and shutdowns.

(2) **Exclusions.** The following are not authorized under this standard permit:
(A) Sour water strippers or sulfur recovery units;
(B) Carbon dioxide hot carbonate processing units;
(C) Water injection facilities (these facilities may otherwise authorized by 30 TAC §106.351, Salt Water Disposal);
(D) Liquefied petroleum gases, crude oil, or condensate transfer or loading into or from railcars, ships, or barges. These facilities may otherwise be authorized by 30 TAC §106.261, Facilities (Emission Limitations)) and §106.262, Facilities (Emissions and Distance Limitations);
(E) Incinerators for solid waste destruction;
(F) Remediation of petroleum contaminated water and soil. These facilities may otherwise authorized by 30 TAC §106.533, Remediation; and
(G) Cooling Towers and heat exchangers with direct contact with gaseous or liquid process streams containing VOC, H_2S, halogens or halogen compounds, cyanide compounds, inorganic acids, or acid gases.

(e) **Best Management Practices (BMP) and Best Available Control Technology (BACT) Requirements**. For any project, and any associated emission control equipment registered under this standard permit this paragraph shall be met as applicable. These requirements are not applicable to existing, unchanging facilities until any renewal submitted after December 31, 2015.

(1) All facilities which have the potential to emit air contaminants must be maintained in good working order and operated properly during facility operations. Each operator shall establish and maintain a program to replace, repair, and/or maintain facilities to keep them in good working order. The minimum requirements of this program shall include:
   (A) Compliance with manufacturer's specifications and recommended programs applicable to equipment performance and effect on emissions, or alternatively, an owner or operator developed maintenance plan for such equipment that is consistent with good air pollution control practices.
   (B) Cleaning and routine inspection of all equipment; and
   (C) Replacement and repair of equipment on schedules which prevent equipment failures and maintain performance.

(2) Any OGS facility shall be operated at least 50 feet from any property line or receptor (whichever is closer to the facility). This distance limitation does not apply to the following:
   (A) Any fugitive components that are used for isolation and or safety purposes may be located at one-half of the width of any applicable easement;
   (B) Any facility at a location for which the distance requirements were satisfied at the time this standard permit is registered (provided that the authorization was maintained) regardless of whether a receptor is subsequently built or put to use 50 feet from any OGS facility; or
   (C) Existing facilities which are located less than 50 feet from a property line or receptor when constructed and previously authorized. If modified or replaced, the operator shall consider, to the extent that good engineering practice will permit, moving these facilities to meet the 50 foot requirement. Replacement facilities must meet all other requirements of this standard permit.

(3) Engines and turbines shall meet the emission and performance standards listed in Table 6 in paragraph (m) and the following requirements:
   (A) Liquid fueled engines used for back-up power generation and periodic power needs at the OGS are authorized if the fuel has no more than 0.05% sulfur and the engine is operated less than 876 hours per rolling 12-month period.
   (B) Engines and turbines used for electric generation more than 876 hours per rolling 12-month period are authorized if no reliable electric service is readily available. In all other circumstances, electric generators must meet the technical requirements of the Air Quality Standard Permit for Electric Generating Unit (EGU) (not including the EGU standard permit registration requirements) and the emissions shall be included in the registration under this standard permit;
   (C) All applicable requirements of 30 TAC Chapter 117; and

(D) All applicable requirements of 40 CFR Part 60 and 40 CFR Part 63.
(E) Compression ignition engines that are rated less than 225 kW (300 hp) and emit less than or equal to the emission tier for an equivalent sized model year 2008 non-road compression ignition engine located at 40 CFR § 89.112, Table 1 are authorized.

(4) Open-topped tanks or ponds containing VOCs or H_2S are allowed up to a PTE equal to 1 tpy of VOC and 0.1 tpy of H_2S.

(5) All process equipment and storage facilities individually must meet the requirements of BACT listed in Table 10 in paragraph (m). Any combination of process equipment and storage facilities with an uncontrolled PTE of equal to or greater than 25 tpy of VOC must also meet the requirements of Table 10, row titled "Combined Control Requirements". All of the following streams and facilities must be included for this site-wide assessment:
(A) For any gaseous vent stream with a concentration of 1% VOC must be considered for capture and control requirements;
(B) For any liquid stream with a potential to emit of equal to or greater than 1 tpy VOC for each vessel or storage facility.

(6) The following shall apply to all fugitive components associated with the project:
(A) All seals and gaskets in VOC or H2S service shall be installed, checked, and properly maintained to prevent leaking. All components shall be physically inspected quarterly for leaks.
(B) New and replaced fugitive components and instrumentation in gas or liquid service with the uncontrolled potential to emit equal to or greater than 10 tpy VOC or 1 tpy H2S are subject to a leak detection and repair (LDAR) program as specified in Table 9 in paragraph (m). Additional requirements are applicable where uncontrolled potential to emit equal to or greater than 25 tpy VOC or 5 tpy H2S as specified in Table 9. Planned MSS from fugitive components must also meet the requirements of Table 9.
(C) All components found to be leaking shall be repaired. Every reasonable effort shall be made to repair a leaking component. All leaks not repaired immediately shall be tagged or noted in a log. At manned sites, leaks shall be repaired no later than 30 days after the leak is found. At unmanned sites, leaks shall be repaired no later than 60 days after the leak is found. If the repair of a component would require a unit shutdown, which would create more emissions than the repair would eliminate, the repair may be delayed until the next shutdown.
(D) Tank hatches, not designed to be completely sealed, shall remain closed (but not completely sealed in order to maintain safe design functionality) except for sampling, gauging, loading, unloading, or planned maintenance activities.

(E) To the extent that good engineering practices will permit, new and reworked valves and piping connections shall be located in a place that is reasonably accessible for leak checking during plant operation and underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

(7) Tanks and vessels must utilize a paint color that minimizes the effects of solar heating (including, but not limited to, white or aluminum). To meet this requirement the solar absorptance should be 0.43 or less, as referenced in Table 7.1-6 in Compilation of Air Pollutant Emission Factors (AP-42). Paint shall be applied according to paint producers recommended application requirements if provided and in sufficient quantity as to be considered solar resistant. Paint shall be maintained in good condition and will not compromise tank integrity. Minimal amounts of rust may be present not to exceed 10% of the external surface area of the roof or walls of the tank and in no way may compromise tank integrity. Additionally, up to 10% of the external surface area of the roof or walls of the tank or vessel may be painted with other colors to allow for identification and/or aesthetics. For tanks and vessels purposefully darkened to create the process reaction and help condense liquids from being entrained in the vapor or are in an area whereby a local, state, federal law, ordinance, or private contract predating this standard permit's effective date establishes in writing tank and vessel colors other than white, these requirements do not apply.

(8) All emission estimation methods including but not limited to computer programs such as GRI-GLYCalc, AmineCalc, E&P Tanks, and Tanks 4.0, must be used with monitoring data generated in accordance with Table 8 in subsection (m) of this section where monitoring is required. All emission estimation methods must also be used in a way that is consistent with protocols established by the commission or promulgated in federal regulations (NSPS, NESHAPS). Where control of emissions is relied upon to meet subsection (k) of this section, control monitoring is required.

(9) Process reboilers, heaters, and furnaces that are also used for control of waste gas streams may claim 50 to 99% destruction efficiency for VOCs and H2S depending on the design and level of monitoring applied. The 90% destruction may be claimed where the waste gas is delivered to the flame zone or combustion fire box with basic monitoring as specified in paragraph (j). Any value greater than 90% and up to 99% destruction efficiency may be claimed where enhanced monitoring and/or testing are applied as specified in paragraph (j). If the waste gas is premixed with the primary fuel gas and used as the primary fuel in the device through the primary fuel burners, 99% destruction may be claimed with basic monitoring as specified in paragraph (j). In systems where the combustion device is designed to cycle on and off to maintain the designed heating parameters, and may not fully utilize the waste gas stream, records of run time and enhanced monitoring is required to claim any run time beyond 50%.

(10) Vapor recovery Systems (VRSs) may claim up to 100% control. The control efficiency is based on whether it is a mechanical VRU (mVRU) or a liquid VRU (lVRU). The VRUs must meet the appropriate design, monitoring and record-keeping in Table 7 and Table 8 in paragraph (m).

(11) Flares used for control of emissions from production, planned MSS, emergency, or upset events may claim design destruction efficiency of 98% for VOCs and H2S and 99% for VOCs containing no more than three carbon atoms that contain no elements other than carbon and hydrogen. All flares must be designed and operated in accordance with the following:

- (A) Meet specifications for minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring found in 40 CFR §60.18;
- (B) If necessary to ensure adequate combustion, sufficient gas shall be added to make the gases combustible;
- (C) An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes;
- (D) An automatic ignition system may be used in lieu of a continuous pilot;
- (E) Flares must be lit at all times when gas streams are present;
- (F) Fuel for all flares shall be sweet gas or liquid petroleum gas except where only field gas is available and it is not sweetened at the site; and
- (G) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed at total of 5 minutes during any 2 consecutive hours. Acid gas flares which must comply with opacity limits and records in accordance with 30 TAC §111.111(a)(4), Requirements for Specified Sources, regarding gas flares, are exempt from this visible emission limitation.
- (I) Flares may be designed with steam or air assist to help reduce visible emissions from the flare but must meet the appropriate requirements in 40 CFR 60.18.
- (J) At no time shall minimum heating values fall below the associated minimum heating value in 60.18

(12) Thermal oxidation and vapor combustion control devices may claim design destruction efficiency from 90 to 99.9% for VOCs and H2S depending on the design and the level of monitoring and testing applied. A device designed for the variability of the waste gas streams it controls with basic monitoring to indicate oxidation or combustion is occurring when waste gas is directed to the device may claim 90% destruction efficiency. Devices with intermediate monitoring, designed for the variability of the waste gas streams they control, with a fire box or fire tube designed to maintain a temperature above 1,400 degrees Fahrenheit (F) for 0.5 seconds, residence time; or designed to meet the parameters of a flare with minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring as found in 40 CFR §60.18, but within a full or partial enclosure may claim a design destruction efficiency of 90 to 98%.

Devices with enhanced monitoring and ports and platforms to allow stack testing may claim a 99% efficiency where the devices are designed for the variability of the waste gas streams they control, with a fire box or fire tube designed to maintain a temperature above 1,400 degrees F for 0.5 seconds, residence time. The devices that can claim 99% destruction efficiency may claim 99.9% destruction efficiency if stack testing is conducted and confirms the efficiency and the enhanced monitoring is adjusted to ensure the continued efficiency. Temperature and residence time requirements may be modified if stack testing is conducted to confirm efficiencies.

(f) **Registration, Revision, and Renewal Requirements**

(1) For all previous claims of this standard permit (or any previous version of this standard permit) existing authorized facilities, or group of facilities, are not required to meet the requirements of this standard permit, with the exception of planned MSS, until a renewal under the standard permit is submitted after December 31, 2015.

(2) If no other changes except for authorizing planned MSS occurs at an existing OGS under this standard permit, or any previous version of this standard permit, (b)(7) applies.
(A) Records demonstrating compliance with paragraph (i) must be kept;
(B) If the OGS must certify emissions to establish nonapplicability of prevention of significant deterioration (PSD), nonattainment new source review (NNSR), or the federal operating permit programs, this certification may be filed using Form APD-CERT. No fee is required for this certification.
(C) Planned MSS shall be incorporated at the next revision or update to a registration under this standard permit after January 5, 2012, and no later than any renewal submitted after December 31, 2015.

(3) Facilities, groups of facilities or planned MSS from facilities registered under this standard permit cannot also be authorized by a permit under 30 TAC §116.111, General Application.

(4) Prior to construction or implementation of changes for any project which meets this standard permit a notification shall be submitted through the e-Permits system. This notification shall include the following:
(A) Identifying information (Core Data) and a general description of the project must be submitted through e-Permits (or if not available, hard-copy) using the "APD OGS New Project Notification."
(B) A fee of $25 for small businesses as defined in 30 TAC §106.50, or $50 for all others must be submitted through the commission's e-Pay system.

(5) For any registration which meets the emission limitations of this standard permit must meet the following:

(A) Within 90 days after start of operation or implemented changes (whichever occurs first), the facilities must be registered with a PI-1S Standard Permit Application.
(B) This registration shall include a detailed summary of maximum emissions estimates based on: site-specific or defined representative gas and liquid analysis; equipment design specifications and operations; material type and throughput; and other actual parameters essential for accuracy for determining emissions and compliance with all applicable requirements of this standard permit.
(C) The fee for this registration shall be $475 for small businesses, or $850 for all others.
(D) Construction may begin any time after receipt of written notification to the executive director. Operations may continue after receipt of registration if there are no objections or 45 days after receipt by the executive director of the registration, whichever occurs first.

(6) If an OGS emissions increase, either through a change in production or addition of facilities, the site may change authorization (Level 1 or Level 2 PBR in 30 TAC §106.352 or Standard Permit) in the following circumstances:
(A) Within 90 days from the initial notification of construction of an oil and gas facility, a registration can update the authorization mechanism by submitting an initial registration or revision to the PBR or Standard Permit.
(B) Within 90 days of the change of production or installation of additional equipment, by submitting an initial registration or revision to the PBR or Standard Permit.

(7) All registrations, registration revisions, and renewals shall be submitted to the commission through a PI-1S Standard Permit Registration Form. Fee requirements do not apply when there are changes in representations with no increase in emissions within 6-months after a standard permit registration has been issued.

(g) Any claim under this standard permit must comply with all applicable requirements of 30 TAC §116.610; §116.611, Registration to Use a Standard Permit; §116.614, Standard Permit Fees; and §116.615, General Conditions. This standard permit supersedes: the notification requirements of 30 TAC §116.615, General Conditions; and the emission limitations of 30 TAC §116.610(a)(1), Applicability.

(h) **Emission Limitations**. Total maximum estimated registered or certified emissions shall meet the most stringent of the following. All emissions estimates must be based on representative worst-case operations and planned MSS activities.

(1) Total maximum estimated annual emissions of any air contaminant shall not exceed the applicable limits for a major stationary source or major modification for PSD and NNSR as specified in 30 TAC §116.12.

(2) Emissions must meet the limitations established in paragraph (k) of this standard permit.

(3) Maximum emissions are limited to less than the following after any operator limitations or controls:

Air contaminant	steady-state or < 30 psig periodic releases lb/hr	≥ 30 psig periodic lb/hr up to 600 hr/yr	Total tpy
Total VOC*			250
Total crude oil or condensate VOC*	145	318	
Total natural gas VOC*	750	1635	
Benzene	7	15.4	10.2
Hydrogen sulfide	10.8	9.8	47
Sulfur dioxide	93.2		250
Nitrogen oxides	121		250
Carbon monoxide	104		250
PM10 and PM2.5	28		15

* VOC is defined in 101.1(115) and does not include methane and ethane

(i) **Planned Maintenance, Start-ups and Shutdowns (MSS).** For any facility, group of facilities or site using this standard permit or previous versions of this standard permit, the following shall apply:

(1) Prior to January 5, 2012, representations and registration of planned MSS is voluntary, but if represented must meet the applicable limits of this standard permit. After January 5, 2012, all emissions from planned MSS activities and facilities must be considered for compliance with applicable limits of this standard permit unless otherwise specified in (b)(7). This standard permit may not be used at a site or for facilities authorized under 30 TAC §116.111 if planned MSS has already been authorized under that permit.

(2) As specified, releases of air contaminants during, or as result of, planned MSS must be quantified and meet the emission limits in this standard permit, as applicable. This analysis must include:
- (A) Alternate operational scenarios or redirection of vent streams;
- (B) Pigging, purging, and blowdowns;
- (C) Temporary facilities if used for degassing or purging of tanks, vessels, or other facilities;
- (D) Degassing or purging of tanks, vessels, or other facilities; and
- (E) Management of sludge from pits, ponds, sumps, and water conveyances.

(3) Other planned MSS activities authorized by this standard permit are limited to the following. These planned MSS activities require only recordkeeping of the activity.
- (A) Routine engine component maintenance including filter changes, oxygen sensor replacements, compression checks, overhauls, lubricant changes, spark plug changes, and emission control system maintenance.
- (B) Boiler refractory replacements and cleanings.
- (C) Heater and heat exchanger cleanings.
- (D) Turbine hot standard permit swaps.
- (E) Pressure relief valve testing, calibration of analytical equipment; Instrumentation/analyzer maintenance; replacement of analyzer filters and screens.

(4) Engine/compressor start-ups associated with preventative system shutdown activities have the option to be authorized as part of typical operations if:
- (A) Prior to operation, alternative operating scenarios to divert gas or liquid streams are registered and certified with all supporting documentation;
- (B) Engine/compressor shutdowns shall result in no greater than 4 lbs/hr of natural gas emissions; and
- (C) Emissions which result from subsequent compressor start-up activities are controlled to a minimum of 98% efficiency for VOC and H_2S.

(j) **Records, Sampling and Monitoring**. The following records shall be maintained at a site in written or electronic form and be readily available to the agency or local air pollution control program with jurisdiction upon request. All required records must be kept at the facility site. If the facility normally operates unattended, records must be maintained at an office within Texas having day-to-day operational control of the plant site. Other requirements, including but not limited to, federal recordkeeping or testing requirements, can be used to demonstrate compliance if the other requirements are at least as stringent as the associated requirements in the table below. Any documentation that is already being kept for other purposes will suffice for demonstrating requirements. If a control or method is not relied upon to meet this standard permit, then the associated sampling, monitoring, and records are not applicable.

(1) Sampling and demonstrations of compliance shall include the requirements listed in Table 7 in paragraph (m) of this standard permit.

(2) Monitoring and records for demonstrations of compliance shall include the requirements listed in Table 8 in paragraph (m) of this standard permit.

(k) **Emission Limits Based on Impacts Evaluation**.

(1) All impacts evaluations must be completed on a contaminant-by-contaminant basis for only any net emissions increases resulting from a project and must meet the following as appropriate:

(A) Compliance with state or federal ambient air standards shall be demonstrated for NO_2, SO_2, and H_2S at any property-line within 1 mile of a project.

(B) Compliance with hourly effects screening levels (ESLs) for benzene and annual ESL for benzene, shall be demonstrated at the nearest receptor within 1 mile of a project.

(2) Distance measurements shall be determined using the following:

(A) For each facility or group of facilities, the shortest corresponding distance from any emission point, vent, or fugitive component to the nearest receptor must be used with the appropriate compliance determination method with the published ESLs as found through the commissioner's internet webpage.

(B) For each facility or group of facilities, the shortest corresponding distance from any emission point, vent, or fugitive component to the nearest property line must be used with the appropriate compliance determination method with any applicable state or federal ambient air quality standard.

(3) Impacts evaluations are not required under the following cases:

(A) If there is no receptor within 1 mile of a registration no further ESL review is required.

(B) If there is no property line within 1 mile of a registration no further ambient air quality review is required.

(C) If the project total emissions are less than any of the following rates, no additional analysis or demonstration of the specified air contaminant is required:

Air contaminant	**lb/hr**
Benzene	0.039
Hydrogen sulfide	0.025
Sulfur dioxide	2
Nitrogen oxides	4

(4) Evaluation of emissions shall meet the following.
  (A) For all evaluations of NOX to NO2 a conversion factor of 0.20 for 4-stroke rich and lean burn engines and 0.50 for 2-stroke engines may be used.
  (B) The maximum predicted concentration or rate at the property boundary or receptor, whichever is appropriate, must not exceed a state or federal ambient air standard or ESL.

(5) The impacts analysis shall be based on the following facility emissions:
  (A) The following shall be met for ESL reviews:
    (i) If a project's air contaminant maximum predicted concentrations are equal to or less than 10% of the appropriate ESL, no further review is required;
    (ii) If a project's air contaminant maximum predicted concentrations combined with project increases for that contaminant over a rolling 60-month period after the effective date of this revised standard permit are equal to or less than 25% of the appropriate ESL, no further review is required.
    (iii) In all other cases, all facility emissions at an OGS, regardless of authorization type, located within 1 mile of a project requiring registration under this standard permit shall be evaluated.
  (B) The following shall be met for state and federal ambient air quality standard reviews:
    (i) If a project's air contaminant maximum predicted concentrations are equal to or less than 10% the significant impact level (SIL) (also known as de minimis impact in 30 TAC 101, General Rules), no further review is required;
    (ii) In all other cases, all facility emissions at an OGS, regardless of authorization type, located within 1 mile of a project requiring registration under this standard permit shall be evaluated.

(6) Evaluation must comply with one of the methods listed with no changes or exceptions:
  (A) Tables.
    (i) Emission impact Tables 2 – 5F in paragraph (m) of this standard permit may be used in accordance with the limits and descriptions in Table 1 in paragraph (m).
    (ii) Values in Tables 2 - 5F in paragraph (m) of this standard permit may be used with linear interpolation between height and distance points. A distance of less than 50 feet or greater than 5,500 feet may not be used. Release heights may not be extrapolated beyond the limits of any table and instead the minimum or maximum height will be used.

If distances and release heights are not interpolated, the next lowest height and lesser distances shall be used for determination of maximum acceptable emissions. All facilities exempted from the distance to the property line restriction in paragraph (e)(2) of this standard permit must use 50 feet as the distance to the property line for those ambient standards based on property line.

(B) **Screening Modeling.** A screening model may be used to demonstrate acceptable emissions from an OGS under this standard permit if all of the parameters in the screening modeling protocol provided by the commission are met.

(C) **Dispersion Modeling**. A refined dispersion model may be used to demonstrate acceptable emissions from an OGS under this standard permit if all of the parameters in the refined dispersion modeling protocol provided by the commission are met.

(l) **Existing, Unchanged Facilities and Projects Before Effective Date.** The requirements in 30 TAC §116.620 are applicable to existing unchanged facilities and new or changing facilities as specified in paragraph (a)(1) of this standard permit.

(m) The following Tables shall be used as required by this standard permit.

Table 1 Emission Impact Tables Limits and Descriptions;
Table 2 Generic Modeling Results for Fugitives & Process Vents;
Table 3 Generic Modeling Results for Flares and Thermal Destruction Devices
Table 4 Generic Modeling Results for Blowdowns, Purging, and Pigging
Table 5A Generic Modeling Results for Engines Less Than or Equal to 250 hp
Table 5B Generic Modeling Results for Engines Greater Than 250 hp to Less Than or Equal to 500 hp
Table 5C Generic Modeling Results for Engines Greater Than 500 hp to Less Than or Equal to 1000 hp
Table 5D Generic Modeling Results for Engines Greater Than 1000 hp to Less Than or Equal to 1500 hp
Table 5E Generic Modeling Results for Engines Greater Than 1500 hp to Less Than or Equal to 2000 hp
Table 5F Generic Modeling Results for Engines Greater Than 2000 hp
Table 6 Engine and Turbine Emission and Operational Standards
Table 7 Sampling and Demonstrations of Compliance;
Table 8 Monitoring and Records Demonstrations;
Table 9 Fugitive Component Leak Detection and Repair (LDAR) Control Program ; and
Table 10 Best Available Control Technology (BACT) Requirements

Table 1 Emission Impact Tables Limits and Descriptions

Topic	Description	Details
Variables	$E_{MAX\ HOURLY}$	the maximum acceptable hourly (lb/hr) emissions for a specific air contaminant
	$E_{MAX\ ANNUAL}$	the maximum acceptable annual (tpy) emissions for a specific air contaminant
	P	ambient air standard for a specific air contaminant ($\mu g/m^3$)
	ESL	current published effects screening level for a specific air contaminant ($\mu g/m^3$)
	G	the most stringent of any applicable generic value from the Generic Modeling Results Tables at the emission point's release height and distance to property line ($\mu g/m^3/lb/hr$)
	WR_{EPNx}=	weighted ratio of emissions of a specific air contaminant for each EPN divided by the sum of total emissions for all EPNs that emit that contaminant or (E_{EPNx}/E_{total})
Single releases or co-located groups of similar releases	hourly ambient air standard	emissions are determined by: $\boldsymbol{E_{MAX\ HOURLY} = P/G}$
	hourly health effects review	emissions are determined by: $\boldsymbol{E_{MAX\ HOURLY} = ESL/G}$
	annual ambient air standard	emissions are determined by: $\boldsymbol{E_{MAX\ ANNUAL} = (8760/2000)\ P/(0.08*G)}$
	annual health effects review	emissions are determined by: $\boldsymbol{E_{MAX\ ANNUAL} = (8760/2000)\ ESL/(0.08*G)}$
Multiple release points	Limits	If weighted ratios are not used, the total quantity of emissions shall be assumed to be released from the most conservative applicable G value at the site.
	hourly ambient air standard	emissions are determined by: $\boldsymbol{E_{MAX\ HOURLY} = (WR_{EPN1})\ (P / G_{EPN1}) + (WR_{EPN2})\ (P / G_{EPN2}) + (WR_{EPNx})\ (P / G_{EPNx})}$
	hourly health effects review	emissions are determined by: $\boldsymbol{E_{MAX\ HOURLY} = (WR_{EPN1})\ (ESL\ /G_{EPN1}) + (WR_{EPN2})\ (ESL/G_{EPN2}) + .(WR_{EPNx})\ (ESL / G_{EPNx})}$
	annual ambient air standard	emissions are determined by: $\boldsymbol{E_{MAX\ ANNUAL} = (8760/2000)\ [(WR_{EPN1})\ (P / 0.08*G_{EPN1}) + (WR_{EPN2})\ (P / 0.08*G_{EPN2}) + (WR_{EPNx})\ (P / 0.08*G_{EPNx})]}$
	annual health effects review	emissions are determined by: $\boldsymbol{E_{MAX\ ANNUAL} = (8760/2000)\ [(WR_{EPN1})\ (ESL\ /0.08*G_{EPN1}]) + (WR_{EPN2})\ (ESL/0.08*G_{EPN2}) + WR_{EPNx})\ (ESL / 0.08*G_{EPNx})]}$

Table 2: Fugitives and Process Vents									
Distance	Fugitive 3ft height	Loading 10 ft height	Tank Vents 20 ft height	Process Vessel 10 ft Vent	Process Vessel 20 ft Vent	Process Vessel 30 ft Vent	Process Vessel 40 ft Vent	Process Vessel 50 ft Vent	Process Vessel 60 ft Vent
(ft)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)
50	4375	1232	305	469	168	90	70	65	28
100	4375	1232	305	469	168	90	70	65	28
150	3907	1232	305	469	168	90	70	65	28
200	3089	1232	305	440	168	90	70	65	28
300	1911	1193	294	412	168	90	70	65	28
400	1269	1048	291	319	168	90	70	65	28
500	901	858	274	243	157	90	70	65	28
600	674	698	271	189	138	89	70	65	28
700	525	574	271	150	120	88	70	65	28
800	423	479	261	124	105	85	70	65	28
900	349	406	244	105	93	81	70	65	28
1000	293	348	226	91	84	77	69	65	26
1100	250	302	208	90	77	72	67	63	25
1200	217	264	191	89	70	68	64	61	24
1300	189	233	176	88	65	64	61	58	24
1400	167	208	161	87	61	60	58	55	24
1500	149	186	149	84	57	57	55	53	24
1600	134	168	137	82	54	53	52	50	23
1700	121	153	127	79	51	51	49	47	23

Table 2: Fugitives and Process Vents *(continued)*									
Distance	Fugitive 3ft height	Loading 10 ft height	Tank Vents 20 ft height	Process Vessel 10 ft Vent	Process Vessel 20 ft Vent	Process Vessel 30 ft Vent	Process Vessel 40 ft Vent	Process Vessel 50 ft Vent	Process Vessel 60 ft Vent
(ft)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)
1800	110	139	117	76	50	48	47	45	22
1900	100	128	109	73	49	46	44	43	22
2000	92	117	102	70	49	44	42	41	21
2100	85	108	95	67	48	42	41	39	21
2200	78	101	89	64	47	40	39	38	20
2300	73	94	83	61	46	39	37	36	19
2400	68	88	78	59	45	37	36	35	19
2500	64	82	74	56	43	36	35	34	18
2600	60	77	70	54	42	34	33	32	18
2700	56	73	66	52	41	33	32	31	17
2800	53	69	63	50	40	32	31	30	17
2900	50	65	60	48	39	31	30	29	16
3000	48	62	57	46	37	30	29	28	16
3500	37	49	46	38	32	26	25	25	14
4000	30	40	38	32	28	24	23	22	12
4500	25	33	32	28	25	21	20	20	11
5000	22	28	27	24	22	19	18	18	10
5500	19	25	24	21	19	17	17	16	9

Table 3: Flares and Thermal Destruction Devices					
Generic Modeling Results					
Distance	20 ft height	30 ft height	40 ft height	50 ft height	60 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
50	58	43	26	25	23
100	58	43	26	25	23
150	58	43	26	25	23
200	58	43	26	25	23
300	58	43	26	25	23
400	58	43	26	25	23
500	58	43	26	25	23
600	56	43	26	25	23
700	52	43	26	25	23
800	47	43	26	25	23
900	45	43	26	25	23
1000	44	43	26	25	23
1100	42	41	25	24	23
1200	40	40	24	24	22
1300	38	38	23	23	21
1400	36	36	23	21	21
1500	34	34	23	21	20
1600	32	32	22	21	20
1700	31	31	22	21	20

Table 3: Flares and Thermal Destruction Devices *(continued)*					
Generic Modeling Results					
Distance	20 ft height	30 ft height	40 ft height	50 ft height	60 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
1800	29	29	22	20	20
1900	28	28	22	20	20
2000	26	26	21	20	19
2100	25	25	21	20	19
2200	24	24	20	20	19
2300	23	23	20	19	19
2400	22	22	20	19	18
2500	22	22	19	18	18
2600	21	21	19	18	17
2700	20	20	18	17	17
2800	19	19	18	17	16
2900	19	19	17	16	16
3000	18	18	17	16	16
3500	16	16	15	14	14
4000	14	14	13	12	12
4500	13	13	12	11	11
5000	11	11	11	10	10
5500	11	11	10	9	9

Table 4: Blowdowns, Purging, and Pigging Generic Modeling Results					
Distance	< 30 psig; 3 ft height	< 30 psig; 10 ft height	< 30 psig; 20 ft height	≥ 30 psig; 6 ft height	≥ 30 psig; 10 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
50	4304	791	244	51	25
100	4304	791	244	51	25
150	4250	777	244	51	25
200	3621	763	244	51	25
300	2367	750	225	51	25
400	1607	737	225	51	25
500	1156	671	224	51	25
600	871	581	218	48	25
700	682	498	212	44	25
800	551	427	210	40	24
900	456	368	204	36	23
1000	384	320	194	33	21
1100	328	281	182	30	20
1200	284	248	170	28	18
1300	249	221	159	27	17
1400	220	198	147	27	16
1500	196	178	137	27	15
1600	176	162	127	27	14
1700	159	147	118	27	13
1800	145	135	110	27	13

Table 4: Blowdowns, Purging, and Pigging Generic Modeling Results *(continued)*					
Distance	< 30 psig; 3 ft height	< 30 psig; 10 ft height	< 30 psig; 20 ft height	≥ 30 psig; 6 ft height	≥ 30 psig; 10 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
1900	132	124	103	27	13
2000	121	114	96	27	13
2100	112	106	90	27	13
2200	103	98	85	27	13
2300	96	91	80	27	13
2400	90	86	75	27	13
2500	84	81	71	27	13
2600	79	76	68	27	13
2700	74	72	64	26	13
2800	70	68	61	26	13
2900	67	64	58	26	13
3000	63	61	55	25	13
3500	50	48	45	23	13
4000	40	39	37	21	13
4500	34	33	31	19	13
5000	29	28	27	17	12
5500	25	24	23	16	11

Table 5A Engines Less Than or Equal to 250 hp											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
50	97	85	83	81	81	71	58	44	43	36	26
100	97	85	83	81	81	71	58	44	43	36	26
150	97	85	83	81	81	71	58	44	43	36	26
200	93	85	83	81	81	71	58	44	43	36	26
300	92	85	83	81	81	71	58	44	43	36	26
400	91	85	83	81	81	71	58	44	43	36	26
500	88	85	83	81	81	71	58	44	43	36	26
600	80	79	78	78	78	70	56	44	43	36	26
700	78	77	76	76	71	68	52	44	43	36	26
800	76	75	74	74	64	63	47	44	43	36	26
900	74	73	72	72	58	58	45	44	43	36	26
1000	72	71	71	71	53	53	44	43	43	36	26
1100	69	69	69	69	49	49	42	42	41	35	25
1200	66	66	66	65	45	45	40	40	40	35	24
1300	62	62	62	62	42	42	38	38	38	33	23

Table 5A Engines Less Than or Equal to 250 hp *(continued)*											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)
1400	59	59	59	59	39	39	36	36	36	32	23
1500	56	56	56	56	37	37	34	34	34	30	23
1600	53	53	53	53	35	35	32	32	32	29	22
1700	50	50	50	50	33	33	31	31	31	28	22
1800	48	48	48	48	31	31	29	29	29	26	22
1900	46	46	46	46	30	30	28	28	28	25	22
2000	44	44	44	44	28	28	26	26	26	24	21
2100	42	42	42	42	27	27	25	25	25	23	21
2200	40	40	40	40	26	26	24	24	24	22	20
2300	38	38	38	38	25	25	23	23	23	21	20
2400	37	37	37	37	24	24	22	22	22	20	20
2500	36	36	36	36	23	23	22	22	22	20	19
2600	34	34	34	34	22	22	21	21	21	19	19
2700	33	33	33	33	21	21	20	20	20	18	18
2800	32	32	32	32	21	21	19	19	19	18	18

Table 5A Engines Less Than or Equal to 250 hp *(continued)*											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
2900	31	31	31	31	20	20	19	19	19	17	17
3000	30	30	30	30	19	19	18	18	18	17	17
3500	26	26	26	26	17	17	16	16	16	15	15
4000	23	23	23	23	15	15	14	14	14	13	13
4500	21	21	21	21	13	13	13	13	13	12	12
5000	19	19	19	19	12	12	11	11	11	11	11
5500	17	17	17	17	11	11	11	11	11	10	10

Table 5B: Engines Greater Than 250 and Less Than or Equal to 500 hp											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)
50	60	59	54	43	43	34	34	24	21	20	17
100	60	59	54	43	43	34	34	24	21	20	17
150	60	59	54	43	43	34	34	24	21	20	17
200	60	59	54	43	43	34	34	24	21	20	17
300	60	59	54	43	43	34	34	24	21	20	17
400	60	59	54	43	43	34	34	24	21	20	17
500	60	59	54	43	43	34	34	24	21	20	17
600	57	57	52	41	41	34	34	24	21	20	17
700	52	52	47	38	38	31	31	24	21	20	17
800	47	47	43	34	34	28	28	24	21	20	17
900	42	42	39	31	31	26	26	23	20	20	17
1000	39	39	35	28	28	23	23	21	20	20	17
1100	37	36	32	26	26	23	23	20	20	19	17
1200	35	35	30	25	24	23	23	20	20	18	17
1300	34	34	28	24	23	23	23	20	20	18	16
1400	32	32	26	24	23	23	23	20	20	17	16
1500	31	31	24	23	23	23	23	20	20	16	16
1600	29	29	23	23	23	23	23	19	19	16	16

Table 5B: Engines Greater Than 250 and Less Than or Equal to 500 hp *(continued)*											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)
1700	28	28	23	23	23	23	22	19	19	16	15
1800	27	27	22	22	22	22	22	19	19	16	15
1900	25	25	22	22	22	21	21	18	18	16	15
2000	24	24	22	22	22	21	21	17	17	16	15
2100	23	23	21	21	21	20	20	17	17	16	15
2200	22	22	21	21	21	19	19	17	17	15	15
2300	21	21	20	20	20	19	19	17	16	15	14
2400	21	21	20	20	20	19	18	16	16	15	14
2500	20	20	19	19	19	18	18	16	16	14	14
2600	19	19	19	19	19	18	17	16	16	14	13
2700	18	18	18	18	18	17	17	15	15	14	13
2800	18	18	18	18	18	17	16	15	15	13	13
2900	17	17	17	17	17	16	16	15	15	13	13
3000	17	17	17	17	17	16	15	15	15	13	13
3500	15	15	15	15	15	14	14	13	13	12	11
4000	13	13	13	13	13	13	12	12	12	11	10
4500	12	12	12	12	12	11	11	10	10	10	9
5000	11	11	11	11	11	10	10	10	10	9	9
5500	10	10	10	10	10	9	9	9	9	8	8

Table 5C: Engines Greater Than 500 and Less Than or Equal to 1,000 hp											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
50	26	25	25	25	18	18	17	13	11	11	10
100	26	25	25	25	18	18	17	13	11	11	10
150	26	25	25	25	18	18	17	13	11	11	10
200	26	25	25	25	18	18	17	13	11	11	10
300	26	25	25	25	18	18	17	13	11	11	10
400	26	25	25	25	18	18	17	13	11	11	10
500	26	25	25	25	18	18	17	13	11	11	10
600	26	25	25	25	18	18	17	13	11	11	10
700	26	25	25	25	18	18	17	13	11	11	10
800	24	24	24	24	18	18	17	13	11	11	10
900	23	23	23	23	18	18	17	13	11	11	10
1000	21	21	21	21	17	17	17	13	11	11	10
1100	20	20	20	20	17	17	16	13	11	11	10
1200	18	18	18	18	16	16	16	12	11	11	10
1300	17	17	17	17	15	15	15	12	11	10	10
1400	17	17	17	17	14	14	14	11	11	10	10

Table 5C: Engines Greater Than 500 and Less Than or Equal to 1,000 hp *(continued)*											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
1500	17	17	16	16	13	13	13	11	11	10	9
1600	17	17	16	16	13	13	13	11	11	10	9
1700	16	16	15	15	13	12	12	11	11	9	9
1800	16	16	15	15	13	12	12	11	11	9	9
1900	15	15	14	14	13	12	12	11	10	9	9
2000	15	15	14	14	13	12	12	11	10	9	9
2100	14	14	13	13	12	12	12	11	10	9	9
2200	14	14	13	13	12	12	12	10	10	9	9
2300	13	13	12	12	12	11	11	10	10	9	8
2400	13	13	12	12	12	11	11	10	9	9	8
2500	12	12	12	12	11	11	11	10	9	9	8
2600	12	12	11	11	11	11	11	10	9	9	8
2700	12	12	11	11	11	10	10	10	9	8	8
2800	11	11	11	11	11	10	10	9	9	8	8
2900	11	11	10	10	10	10	10	9	9	8	8
3000	11	11	10	10	10	10	10	9	9	8	8
3500	9	9	9	9	9	9	9	8	8	7	7

Table 5C: Engines Greater Than 500 and Less Than or Equal to 1,000 hp *(continued)*											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
4000	8	8	8	8	8	8	8	7	7	7	6
4500	7	7	7	7	7	7	7	7	6	6	6
5000	7	7	7	7	6	6	6	6	6	6	5
5500	6	6	6	6	6	6	6	6	5	5	5

Table 5D: Engines Greater Than 1,000 and Less Than or Equal to 1,500 hp											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)
50	17	13	12	10	10	10	10	9	8	8	7
100	17	13	12	10	10	10	10	9	8	8	7
150	17	13	12	10	10	10	10	9	8	8	7
200	17	13	12	10	10	10	10	9	8	8	7
300	17	13	12	10	10	10	10	9	8	8	7
400	17	13	11	10	10	10	10	9	8	8	7
500	17	13	11	10	10	10	10	9	8	8	7
600	17	12	11	10	10	10	10	9	8	8	7
700	17	11	11	10	10	10	10	9	8	8	7
800	17	11	11	10	10	10	10	9	8	8	7
900	17	11	11	10	10	10	10	9	8	8	7
1000	17	11	11	10	10	10	10	9	8	8	7
1100	16	11	11	10	10	10	10	9	8	8	7
1200	15	10	10	10	9	9	9	9	8	7	7
1300	15	10	10	10	9	9	9	8	8	7	7
1400	14	10	10	10	9	9	8	8	8	7	7

Table 5D: Engines Greater Than 1,000 and Less Than or Equal to 1,500 hp *(continued)*											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
1500	13	10	10	10	8	8	8	8	8	7	6
1600	12	10	10	10	8	8	8	8	8	7	6
1700	12	10	10	10	8	8	8	8	8	7	6
1800	11	10	10	10	8	8	8	8	8	7	6
1900	11	10	9	9	8	8	8	7	7	7	6
2000	10	9	9	9	8	8	8	7	7	7	6
2100	10	9	9	9	8	8	8	7	7	6	6
2200	10	9	9	9	8	8	8	7	7	6	6
2300	9	9	8	8	8	8	8	7	7	6	6
2400	9	9	8	8	7	7	7	7	7	6	6
2500	9	8	8	8	7	7	7	7	6	6	5
2600	8	8	8	8	7	7	7	7	6	6	5
2700	8	8	8	8	7	7	7	7	6	6	5
2800	8	8	7	7	7	7	7	6	6	6	5
2900	8	7	7	7	7	7	7	6	6	6	5
3000	7	7	7	7	7	7	6	6	6	5	5

Table 5D: Engines Greater Than 1,000 and Less Than or Equal to 1,500 hp *(continued)*											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
3500	7	6	6	6	6	6	6	6	5	5	5
4000	6	6	6	6	5	5	5	5	5	4	4
4500	5	5	5	5	5	5	5	5	4	4	4
5000	5	5	5	5	5	5	4	4	4	4	4
5500	5	4	4	4	4	4	4	4	4	4	3

Table 5E: Engines Greater Than 1,500 and Less Than or Equal to 2,000 hp											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
50	10	9	8	8	8	7	7	7	6	5	5
100	10	9	8	8	8	7	7	7	6	5	5
150	10	9	8	8	8	7	7	7	6	5	5
200	10	9	8	8	8	7	7	7	6	5	5
300	10	9	8	8	8	7	7	7	6	5	5
400	10	9	8	8	8	7	7	7	6	5	5
500	10	9	8	8	8	7	7	7	6	5	5
600	10	9	8	8	8	7	7	7	6	5	5
700	9	8	8	8	8	7	7	7	6	5	5
800	9	8	8	8	8	7	7	7	6	5	5
900	9	8	8	8	8	7	7	7	6	5	5
1000	9	8	8	8	8	7	7	7	6	5	5
1100	9	8	8	8	8	7	7	7	6	5	5
1200	8	8	7	7	7	7	7	7	6	5	5
1300	8	8	7	7	7	7	7	6	6	5	5
1400	8	8	7	7	7	7	7	6	6	5	5

Table 5E: Engines Greater Than 1,500 and Less Than or Equal to 2,000 hp *(continued)*											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
1500	8	8	7	7	7	7	7	6	5	5	5
1600	8	8	7	7	7	7	7	6	5	5	5
1700	8	8	7	7	7	7	7	6	5	5	5
1800	8	8	7	7	7	7	7	6	5	5	5
1900	7	7	7	7	7	7	6	6	5	5	5
2000	7	7	7	7	7	7	6	6	5	5	5
2100	7	7	6	6	6	6	6	6	5	5	5
2200	7	7	6	6	6	6	6	6	5	5	4
2300	7	7	6	6	6	6	6	6	5	5	4
2400	7	7	6	6	6	6	6	5	5	5	4
2500	6	6	6	6	6	6	6	5	5	4	4
2600	6	6	6	6	6	6	5	5	5	4	4
2700	6	6	6	6	6	5	5	5	5	4	4
2800	6	6	6	6	5	5	5	5	4	4	4
2900	6	6	5	5	5	5	5	5	4	4	4
3000	6	5	5	5	5	5	5	5	4	4	4

Table 5E: Engines Greater Than 1,500 and Less Than or Equal to 2,000 hp *(continued)*											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
3500	5	5	5	5	5	4	4	4	4	4	3
4000	4	4	4	4	4	4	4	4	4	3	3
4500	4	4	4	4	4	4	4	3	3	3	3
5000	4	4	4	3	3	3	3	3	3	3	3
5500	3	3	3	3	3	3	3	3	3	3	3

Table 5F: Engines Greater Than 2,000 hp											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
50	7	6	6	6	5	5	5	5	4	4	4
100	7	6	6	6	5	5	5	5	4	4	4
150	7	6	6	6	5	5	5	5	4	4	4
200	7	6	6	6	5	5	5	5	4	4	4
300	7	6	6	6	5	5	5	5	4	4	4
400	7	6	6	6	5	5	5	5	4	4	4
500	7	6	6	6	5	5	5	5	4	4	4
600	7	6	6	6	5	5	5	5	4	4	4
700	7	6	6	6	5	5	5	5	4	4	4
800	6	6	6	6	5	5	5	5	4	4	4
900	6	6	6	6	5	5	5	5	4	4	4
1000	6	6	6	6	5	5	5	5	4	4	4
1100	6	6	6	6	5	5	5	5	4	4	4

Table 5F: Engines Greater Than 2,000 hp *(continued)*											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)
1200	6	6	6	6	5	5	5	5	4	4	4
1300	6	6	6	6	5	5	5	5	4	4	4
1400	6	6	6	6	5	5	5	5	4	4	4
1500	6	6	6	6	5	5	5	5	4	4	4
1600	6	6	6	6	5	5	5	5	4	4	4
1700	6	6	6	6	5	5	5	5	4	4	4
1800	6	6	6	6	5	5	5	5	4	4	4
1900	6	6	6	5	5	5	5	5	4	4	4
2000	6	6	6	5	5	5	5	5	4	4	3
2100	5	5	5	5	5	5	5	5	4	4	3
2200	5	5	5	5	5	5	5	4	4	4	3
2300	5	5	5	5	5	5	4	4	4	4	3
2400	5	5	5	5	5	5	4	4	4	4	3
2500	5	5	5	5	4	4	4	4	4	4	3

Table 5F: Engines Greater Than 2,000 hp *(continued)*											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
2600	5	5	5	5	4	4	4	4	4	3	3
2700	5	5	5	5	4	4	4	4	4	3	3
2800	5	5	5	4	4	4	4	4	4	3	3
2900	4	4	4	4	4	4	4	4	4	3	3
3000	4	4	4	4	4	4	4	4	3	3	3
3500	4	4	4	4	4	4	3	3	3	3	3
4000	3	3	3	3	3	3	3	3	3	3	3
4500	3	3	3	3	3	3	3	3	3	2	2
5000	3	3	3	3	3	3	3	2	2	2	2
5500	3	3	3	3	3	2	2	2	2	2	2

Table 6 Engine and Turbine Emission and Operational Standards

<table>
<tr><th>Engine Type</th><th>Engine Size</th><th>Manufacture Date</th><th>NOx (g/bhp-hr)</th><th>CO (g/bhp-hr)</th><th>VOC (g/bhp-hr)</th></tr>
<tr><td rowspan="4">Rich Burn, Non-emergency, Spark-ignited</td><td>less than 100 hp</td><td>All dates</td><td>no standard</td><td>no standard</td><td>no standard</td></tr>
<tr><td>greater than or equal to 100 hp</td><td>Before January 1, 2011</td><td>2</td><td>3</td><td>no standard</td></tr>
<tr><td>greater than or equal to 100 hp</td><td>After January 1, 2011</td><td>1</td><td>3</td><td>1</td></tr>
<tr><td colspan="5">After January 1, 2015, regardless of manufacture date, no rich burn engine greater than or equal to 240 hp authorized by this permit shall emit NOx in excess of 0.5 g/bhp-hr. After January 1, 2018, regardless of manufacture date, no rich burn engine greater than or equal to 100 hp authorized by this permit shall emit NOx in excess of 0.5 g/bhp-hr. If an authorization or authorizations is issued for a spark ignited rich burn engine under this standard permit after the applicable date of January 1, 2015 or January 1, 2018, NOx emissions from that engine shall not exceed 0.5 g/bhp-hr, except that the standard permit holder shall have a one year grace period from the date of the initial authorization under this standard permit to comply with the limit of 0.5 g/bhp-hr for NOx. The commission reserves the right to re-evaluate the upgrade requirement if EPA promulgates any standards for existing engines.</td></tr>
<tr><td rowspan="6">Lean Burn, 2SLB Non-emergency, Spark-ignited</td><td>less than 500 hp</td><td>All dates</td><td>no standard</td><td>no standard</td><td>no standard</td></tr>
<tr><td rowspan="5">greater than or equal to 500 hp</td><td>Before September 23, 1982</td><td>8</td><td>3</td><td>no standard</td></tr>
<tr><td>Before June 18, 1992 and rated less than 825 hp</td><td>8</td><td>3</td><td>no standard</td></tr>
<tr><td>After September 23, 1982, but prior to June 18, 1992 and rated 825 hp or greater</td><td>5</td><td>3</td><td>no standard</td></tr>
<tr><td>After June 18, 1992 but prior to July 1, 2010</td><td>2.0 except under reduced speed, 80-100% of full torque conditions may be 5.0</td><td>3</td><td>no standard</td></tr>
<tr><td>On or after July 1, 2010</td><td>1</td><td>3</td><td>1</td></tr>
</table>

Table 6 Engine and Turbine Emission and Operational Standards *(continued)*

Engine Type	Engine Size	Manufacture Date	NOx (g/bhp-hr)	CO (g/bhp-hr)	VOC (g/bhp-hr)
Lean Burn, 4SLB, Non-emergency, Spark-ignited, and Dual-fuel	less than 500 hp	Before July 1, 2008	no standard	no standard	no standard
		On or after July 1, 2008	2	3	1
	greater than or equal to 500 hp	Before September 23, 1982	5.0 except under reduced speed, 80-100% of full torque conditions may be 8.0	3	no standard
		Before June 18, 1992 and rated less than 825 hp	5.0 except under reduced speed, 80-100% of full torque conditions may be 8.0	3	no standard
		After September 23, 1982, but prior to June 18, 1992 and rated 825 hp or greater	5	3	no standard
		After June 18, 1992 but prior to July 1, 2010	2.0 except under reduced speed, 80-100% of full torque conditions, may be 5.0	3	no standard
		On or after July 1, 2010	1	3	1
	After January 1, 2020, no spark ignited 4-stroke lean burn engine authorized by this standard permit that existed on-site on January 1, 2012, shall emit NOx in excess of 2.0 g/bhp-hr. If an oil and gas standard permit authorization or authorizations are is issued for a spark ignited 4-stroke lean burn engine after January 1, 2012, NOx emissions from that engine shall not exceed 2.0 g/bhp-hr after January 1, 2015. However, if the date of the initial authorization is after January 1, 2015, the standard permit holder shall have a three year grace period from the date of the initial authorization under the oil and gas standard permit to comply with the limit of 2.0 g/bhp-hr for NOx. The commission reserves the right to re-evaluate the upgrade requirement if EPA promulgates any standards for existing engines.				
Turbines	Turbines shall not emit greater than 25 ppmvd @ 15% O2 for NOX and 50 ppmvd @ 15% O2 for CO.				

Table 7 Sampling and Demonstrations of Compliance

Category	**Description**	**Specifications and Expectations**
Exclusions	Control Systems	Control device monitoring and records are required only where the device is necessary for the site to meet emission rate limits
Sampling General	When Applicable Ports and Platforms, Methods, Notifications and Timing	(A)If necessary, sampling ports and platforms shall be incorporated into the design of all exhaust stacks according to the specifications set forth in "Chapter 2, Stack Sampling Facilities." Engines and other facilities which are physically incapable of having platforms are excluded from this requirement. For control devices with effectiveness requirements only, appropriate sampling ports shall also be installed upstream of the inlet to control devices or controlled recovery systems with control efficiency requirements. Alternate sampling facility designs may be submitted for written approval by the Texas Commission on Environmental Quality (TCEQ) Regional Director or his designee. (B) Where stack testing is required, Sampling shall be conducted within 180 days of the change that required the registration, in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and in accordance with the appropriate EPA Reference Methods. Unless otherwise specified, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. Where appropriate, sampling shall occur as three one-hour test runs and then averaged to demonstrate compliance with the limits of this authorization. Any deviations from those procedures must be approved in writing by the TCEQ Regional Director or his designee prior to sampling. (C) The Regional Office shall be afforded the opportunity to observe all such sampling. (D) The holder of this authorization is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense.

Table 7 Sampling and Demonstrations of Compliance *(continued)*

Category	Description	Specifications and Expectations
Sampling General	When Applicable Ports and Platforms, Methods, Notifications and Timing	(E) The TCEQ Regional Office that has jurisdiction over the site shall be contacted as soon as any testing is scheduled, but not less than 30 days prior to sampling. The region shall have discretion to amend the 30 day prior notification. Except for engine testing and liquid/gas analysis sampling, all other sampling shall include an opportunity for the appropriate regional office to schedule a pretest meeting. The notice shall include: (i) Date for pretest meeting, if required; (ii)Date sampling will occur; (iii) Name of firm conducting sampling; (iv)Type of sampling equipment to be used; (v) Method or procedure to be used in sampling; (vi)Procedure used to determine operating rates or other relevant parameters during the sampling period; (vii) parameters to be documented during the sampling event; (viii) any proposed deviations to the prescribed sampling methods. If held, the purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for submitting the test reports. (F) Within 60 days after the completion of the testing and sampling required herein, one original and one copy of the sampling reports shall be sent to the Regional Office. (G) When sampling is required, all Quality Assurance/Quality Control shall follow 30 TAC Ch 25 National Environmental Laboratory Accreditation Conference accreditation requirements.

Table 7 Sampling and Demonstrations of Compliance *(continued)*

Category	Description	Specifications and Expectations
Fugitive monitoring and LDAR	Analyzers	An approved gas analyzer or other approved detection monitoring device used for the volatile organic compound fugitive inspection and repair requirement is a device that conforms to the requirements listed in Title 40 CFR §60.485(a) and (b), or is otherwise approved by the Environmental Protection Agency as a device to monitor for VOC fugitive emission leaks. Approved gas analyzers shall conform to requirements listed in Method 21 of 40 CFR Part 60, Appendix A. The gas analyzer shall be calibrated with methane. In addition, the response factor of the instrument for a specific VOC of interest shall be determined and meet the requirements of Standard permit 8 of Method 21. If a mixture of VOCs is being monitored, the response factor shall be calculated for the average composition of the process fluid. If a response factor less than 10 cannot be achieved using methane, then the instrument may be calibrated with one of the VOC to be measured or any other VOC so long as the instrument has a response factor of less than 10 for each of the VOC to be measured. In lieu of using a hydrocarbon gas analyzer and EPA Method 21, the owner or operator may use the Alternative Work Practice in 40 CFR Part 60, §60.18(g) - (i). The optical gas imaging instrument must meet all requirements specified in 40 CFR §60.18(g) - (i), except the annual Test Method 21 requirement in 40 CFR §60.18(h)(7) and the reporting requirement in 40 CFR §60.18(i)(5) do not apply.
Verify composition of materials	All site-specific gas or liquid analyses	Reports necessary to verify composition (including hydrogen sulfide (H_2S) at any point in the process. All analyses shall be site specific or a representative sample may be used to estimate emissions if all of the parameters in the gas and liquid analysis protocol provided by the commission are met. A site-specific or define representative analysis shall be performed within 90 days of initial start of operation or implementation of a change which requires registration. When new streams are added to the site and the character or composition of the streams change and cause an increase in authorized emissions, or upon request of the appropriate Regional office or local air pollution control program with jurisdiction, a new analysis will need to be performed. Analysis techniques may include, but are not limited to, Gas Chromatography (GC), Tutweiler, stain tube analysis, and sales oil/condensate reports. These records will document the following: (A) H_2S content; (B) flow rate; (C) heat content; or (D) other characteristic including, but not limited to: (i) American Petroleum Institute gravity and Reid vapor pressure (RVP);(ii) sales oil throughput; or (iii) condensate throughput.

Table 7 Sampling and Demonstrations of Compliance *(continued)*

Category	Description	Specifications and Expectations
Verify composition of materials *(continued*	All site-specific gas or liquid analyses	Laboratory extended VOC GC analysis at a minimum to C10+ and H_2S analysis for gas and liquids for the following shall be performed and used for emission compliance demonstrations:(A) Separator at the inlet; (B) Dehydration Unit / Glycol Contactor prior to dehydrator;(C) Amine Unit prior to sweetening unit; (D) Separator dumping to gunbarrel or storage tank; (E) Tanks for liquids and vapors; or (F) P
Engines and Turbines	Initial Sampling of (i)Any engine greater than 500 horsepower; (ii) Any turbine	Perform stack sampling and other testing as required to establish the actual quantities of air contaminants being emitted into the atmosphere (including but not limited to nitrogen oxide (NO_X), carbon monoxide (CO), and oxygen (O2). Each combustion facility shall be tested at a minimum of 50% of the design maximum firing rate of the facility. Each tested firing rate shall be identified in the sampling report. Sampling shall occur within 180 days after initial start-up of each unit. Additional sampling shall occur as requested by the TCEQ Regional Director. If there are multiple engines at an oil and gas sites (OGS) of identical model, year, and control system, sampling may be performed on 50% of the units and used for compliance demonstration of all identical units at the OGS. The remaining 50% of the units not initially tested must be tested during the next biennial testing period. This sampling is not required upon initial installation at any location if the engine or turbine was previously installed and tested at any location in the United States and the test conformed with EPA Reference Methods. Regardless of engine location, records of performance testing, or relied upon sampling reports, must remain with each specific engine for a minimum of five years unless records are unavailable and the permit holder performs the initial sampling on-site. No one may claim records are unavailable for the time period in which an engine is at the site which is authorized by this standard permit. This testing is not required for emergency engines unless requested by the TCEQ Regional Director. Idle engines do not need to be re-started only for the purpose of completing required testing. If biennial testing is required for an engine that is re-started for production purposes, the biennial testing is required within 30 days after re-starting the engine.

Table 7 Sampling and Demonstrations of Compliance *(continued)*

Category	Description	Specifications and Expectations
Engines	Periodic Evaluation	The following is applicable to sites with federal operating permits only: (A) For any engine with a NOx standard under Table 6, conduct evaluations of each engine performance quarterly after initial compliance testing by measuring the NO_x and CO content of the exhaust. Tests shall occur more than 30 days apart. Individual engines shall be subject to the quarterly performance evaluation if they were in operation for 1000 hours or more during the quarter period. If an engine is not operating, the permit holder may delay the test until such time as the engine is expected to run for more than fourteen days. Idled engines do not need to be re-started only for the purpose of completing required testing. (B) The use of portable analyzers specifically designed for measuring the concentration of each contaminant in parts per million by volume is acceptable for these evaluations. The portable analyzer shall be operated at minimum in accordance with the manufacturer's instructions. The operator may modify the procedure if it does not negatively alter the accuracy of the analyzer. Also, colorimetric testing (stain tubes) maybe used in these periodic evaluations. The NO_x and CO emissions then shall be converted into units of grams per horsepower-hour and pounds per hour. (C) Emissions shall be measured and recorded in the as-found operating condition, except no compliance determination shall be established during start-up, shutdown, or under breakdown conditions. (D) In lieu of the above mentioned periodic monitoring for engines and biennial testing, the holder of this permit may install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) to measure and record the concentrations of NO_x and CO from any engine, turbine, or other external combustion facility. Diluents to be measured include O_2 or CO_2. Except for system breakdowns, repairs, calibration checks, zero and span adjustments, and other quality assurance tests, the Continuous Emission Monitoring Systems (CEMS) shall be in continuous operation and shall record a minimum of four, and normally 60, approximately equally spaced data points for each full hour. The NO_x and diluents CEMS shall be operated according to the methods and procedures as set out in 40 CFR Part 60, Appendix B, Performance Specifications 2 and 3. The CO CEMS shall be operated according to the methods and procedures as set out in 40 CFR Part 60, Appendix B, Performance Specifications 4, 4A, or 4B. CEMS shall follow the quality assurance requirements of Appendix F except that Cylinder Gas Audits may be conducted in all four calendar quarters in lieu of the annual Relative Accuracy Test Audit. A CEMS with downtime due to breakdown or repair of more than 10% of the facility operating time for any calendar shall be considered as a defective CEMS and the CEMS shall be replaced within 2 weeks.

Table 7 Sampling and Demonstrations of Compliance *(continued)*

Category	Description	Specifications and Expectations
Engines and Turbines	Biennial Testing Any engine greater than 500 horsepower or any turbine	Every two years starting from the completion date of the Initial Compliance Testing, any engine greater than 500 horsepower or any turbine shall be retested according to the procedures of the Initial Compliance Testing. Retesting shall occur within 90 days of the two year anniversary date. If a facility has been operated for less than 2000 hours during the two year period, it may skip the retesting requirement for that period. After biennial testing, any engine retested under the above requirements shall resume periodic evaluations within the next 6 calendar months (January to June or July to December). If biennial testing is required for an engine that is re-started for production purposes, the biennial testing shall be performed within 45 days after re-starting the engine.
Oxidation or Combustion Control Device	Initial Sampling and Monitoring for performance for VOC, Benzene, and H_2S	Stack testing, when a company wants to establish efficiencies of 99% or greater, must be coordinated and approved. Sampling is required for VOC, benzene and H_2S at Region's discretion. The thermal oxidizer (TO) must have proper monitoring and sampling ports installed in the vent stream and the exit to the combustion chamber, to monitor and test the unit simultaneously. The temperature and oxygen measurement devices shall reduce the temperature and oxygen concentration readings to an averaging period of 6 minutes or less and record it at that frequency. The temperature measurement device shall be installed, calibrated, and maintained according to accepted practice and the manufacturer's specifications. The device shall have an accuracy of the greater of ±0.75% of the temperature being measured expressed in degrees Celsius or ±2.5ºC. The oxygen or carbon monoxide analyzer shall be zeroed and spanned daily and corrective action taken when the 24-hour span drift exceeds two times the amounts specified Performance Specification No. 3 or 4A, 40 CFR Part 60, Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days.

Table 7 Sampling and Demonstrations of Compliance *(continued)*

Category	Description	Specifications and Expectations
Oxidation or Combustion Control Device	Initial Sampling and Monitoring for performance for VOC, Benzene, and H_2S	The oxygen or carbon monoxide analyzer shall be quality-assured at least semiannually using cylinder gas audits (CGAs) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, §5.1.2, with the following exception: a relative accuracy test audit is not required once every four quarters (i.e., two successive semiannual CGAs may be conducted). An equivalent quality-assurance method approved by the TCEQ may also be used. Successive semiannual audits shall occur no closer than four months. Necessary corrective action shall be taken for all CGA exceedances of ±15 percent accuracy and any continuous emissions monitoring system downtime in excess of 5% of the incinerator operating time. These occurrences and corrective actions shall be reported to the appropriate TCEQ Regional Director on a quarterly basis. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Director. Quality assured or valid data of oxygen or carbon monoxide analyzer must be generated when the TO is operating except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, inaccurate data, repair, maintenance, or calibration may be exempted provided it does not exceed 5% of the time (in minutes) that the oxidizer operated over the previous rolling 12 month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

Table 8 Monitoring and Records Demonstrations

Category	Description	Record Information
Site Production or Collection	natural gas, oil, condensate, and water production records	Site inlet and outlet gas volume and sulfur concentration, daily gas/liquid production and load-out from tanks
Equipment and facility summary	Current process description	Accurate and detailed plot plan with property line, off-site receptors, and all equipment on-site or drawings with sufficient detail to confirm all authorized facilities to confirm emission estimates, impact review, and registration scope
Equipment specifications	Process units, tanks, vapor recovery systems; flares; thermal oxidizers; and reboiler control devices	A copy of the registration and emission calculations including the fixed equipment sizes or capacities and manufacturer's specifications and programs to maintain performance, with the plan and records for routine inspection, cleaning, repair and replacement.
	Leaks in piping, fugitive components and process vessels	If a leak has been found and determined that there would be less emissions from the repair by delaying repair until the next shutdown, then a record of the calculation showing that the emissions would be less shall be kept.
Physical Inspection	Fugitive Component Check	A record of the component count shall be maintained. A record of the date each quarterly inspection was made and the date components found leaking were repaired or the date of the planned shutdown.
Voluntary LDAR Program	Details of fugitive component monitoring plan, and LDAR results, including QA, QC	The following records are required where a company uses an LDAR program to reduce the potential fugitive emissions from the site to meet emission limitations or certify fugitive emissions. (A) A monitoring program plan must be maintained that contains, at a minimum, the following information: (i) an accounting of all the fugitive components by type and service at the site with the total uncontrolled fugitive potential to emit estimate; (ii) identification of the components at the site that are required to be monitored with an instrument or are exempt with the justification, note the following can be used for this purpose: (a) piping and instrumentation diagram (PID); or (b) a written or electronic database.;

Table 8 Monitoring and Records Demonstrations *(continued)*

Category	Description	Record Information
Voluntary LDAR Program *(continued)*	Details of fugitive component monitoring plan, and LDAR results, including QA, QC	(iii) the monitoring schedule for each component at the site with difficult-to-monitor and unsafe-to-monitor valves, as defined by Title 30 Texas Administrative Code Chapter 115 (30 TAC Chapter 115), identified and justified, note if an unsafe-to-monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe-to-monitor times and a record of the plan to monitor shall be maintained; and (iv) the monitoring method that will be used (audio, visual, or olfactory (AVO) means; Method 21; the Alternative Work Practice in 40 CFR §60.18(g) - (i)); (v) for components where instrument monitoring is used, information clarifying the adequacy of the instrument response; (vi) the plan for hydraulic or pressure testing or instrument monitoring new and reworked components. (B) Records must be maintained of all monitoring instrument calibrations. (C) Records must be maintained for all monitoring and inspection data collected for each component required to be monitored with a Method 21 portable analyzer that include the type of component and the monitoring results in ppmv regardless if the screening value is above or below the leak definition.. (D) Leaking components must be tagged and a leaking-components monitoring log must be maintained for all leaks greater than the applicable leak definition (i.e.10,000 ppmv, 2000 ppmv, or 500 ppmv) of VOC detected using Method 21, all leaks detected by AVO inspection, and all leaks found using Alternative Work Practice specified in 40 CFR §60.18(g)-(i). The log must contain, at a minimum, the following: (i) the method used to monitor the leaking component (audio, visual, or olfactory inspection; Method 21; or the Alternative Work Practice in 40 CFR §60.18(g) - (i)); (ii) the name of the process unit or other appropriate identifier where the component is located; (iii) the type (e.g., valve or seal) and tag identification of component; (iv) the results of the monitoring (in ppmv if a Method 21 portable analyzer was used); (v) the date the leaking component was discovered;(vi) the date that a first attempt at repair was made to a leaking component; (vii) the date that a leaking component is repaired; (viii) the date and instrument reading of the recheck procedure after a leaking component is repaired; and (ix) the leaks that cannot be repaired until turnaround and the date that the leaking component is placed on the shutdown list. (E) If the owner or operator is using the Alternative Work Practice specified in 40 CFR §60.18(g) - (i), the records required by 40 CFR §60.18(i)(4).

Table 8 Monitoring and Records Demonstrations *(continued)*

Category	Description	Record Information
Voluntary LDAR Program *(continued)*	Details of fugitive component monitoring plan, and LDAR results, including QA, QC	(F) A record of the monitored value any open-ended line or valve for which is a repair or replacement is not completed within 72 hours and monitoring in lieu of covering is chosen. (G) Any open-ended line or valve caused by a repair or replacement not completed within 72 hours shall be monitored as specified in table 10 and the checks and any corrective actions taken shall be recorded. (H) Weekly audio, visual and olfactory inspections shall be noted in a log (I) A check of the reading for any pressure-sensing device to verify rupture disc integrity shall be performed weekly and noted in a log.
Minor Changes	Additions, changes or replacement	Records showing all replacements and additions, including summary of emission type and quantities, for a rolling 6-month period of time.
Equipment Replacement	Like-Kind replacement	Records on equipment specifications and operations, including summary of emissions type and quantity.
Process Units	Glycol Dehydration Units	For emission estimates, the worst-case combination of parameters resulting in the greatest emission rates must be used. If worst-case parameters are not used, then glycol dehydrator unit monitoring records include dry gas flow rate, absorber pressure and temperature, glycol type, and circulation rate recorded weekly. If worst-case parameters are not used, then in addition to weekly unit monitoring, where control of flash tank or reboiler emissions are required to meet the emission limitations of the section and emissions are certified, the following control monitoring requirements apply weekly: flash tank temperature and pressure, any reboiler stripping gas flow rate, and condenser outlet temperature. VRU, flare, or thermal oxidizer control or reboiler fire box used for control must comply with the monitoring and recordkeeping for those devices. Where all emissions from the flash tank and the reboiler or reboiler condenser vent are directed to a VRU, flare, or thermal oxidizer designed to be on-line at all times the glycol dehydrator is in operation, the control system monitoring for the glycol dehydrator is not required.
	Amine Units	Amine units may simply retain site production or inlet gas records if all sulfur compounds in the inlet are assumed to be emitted. Where only partial removal of the inlet sulfur is assumed, for emission estimates, the worst-case combination of parameters resulting in the greatest emission rates must be used. If worst-case parameters are not used, then records of the amine solution, contactor pressure, temperature and pump rate shall be maintained. Where the waste gas is vented to combustion control, the requirements of the control device utilized should be noted.

Table 8 Monitoring and Records Demonstrations *(continued)*

Category	Description	Record Information
Boilers, Reboilers, Heater-Treaters, and and Process Heaters	Combustion	Records of Operational Monitoring and Testing Records Records of the hours of operation of every combustion device of any size by the use of a process monitor such as a run time meter, fuel flow meter, or other process variable that indicates a unit is running unless, in the registration for the facility, the emissions from the facility were calculated using full year operation at maximum design capacity in which case no hours of operation records must be kept.
Internal Combustion Engines	Combustion	Records of Appropriate Operational Monitoring and Testing Records Records of the hours of operation of every combustion device and engine of any size by the use of a process monitor such as a run time meter, fuel flow meter, or other process variable that indicates a unit is running. The owner or operator may test and retest at the most frequent intervals identified in Table 7 in lieu of installing a process monitor and recording the hours of operation. If an engine has no testing requirements in Table 7, no records of the hours of operation must be kept. See fuel records below
Gas Fired Turbines	Combustion	Records of Appropriate Operational Monitoring and Testing Records Records of the hours of operation of every turbine greater than 500 hp by the use of a process monitor such as a run time meter, fuel flow meter, or other process variable that indicates a unit is running unless the permit holder determined emissions from the facility assuming full year operation at maximum design capacity in which case no hours of operation records must be kept.
Fuel Records	VOC and Sulfur Content	A fuel flow meter is not required if emissions are based on maximum fuel usage for 8,760 hr/yr. There are no specific requirements for allowable VOC content of fuel. If field gas contains more than 1.5 grains (24 ppmv) of H_2S or 30 grains total sulfur compounds per 100 dry standard cubic feet, the operator shall maintain records, including at least quarterly measurements of fuel H_2S and total sulfur content, which demonstrate that the annual SO_2 emissions do not exceed limitations
Tanks/Vessels	Color/Exterior	Records demonstrating design, inspection, and maintenance of paint color and vessel integrity.
Tanks/Vessels	Emission and emission potential	Maintain a record of the material stored in each tank/vessel that vents to the atmosphere and the maximum vapor pressure used to establish the maximum potential short-term emission rate. Where pressurized liquids can flash in the tank/vessel monitor and record weekly the maximum fluid pressure that can enter the tank / vessel. Records that tank / vessel hatches and relief valves are properly sealed when tank /vessel is directed to control and after loading events (as needed).

Table 8 Monitoring and Records Demonstrations *(continued)*

Category	Description	Record Information
Truck Loading	All Types	Records indicating type of material loaded, amount transferred, method of transfer, condition of tank truck before loading.
	Vacuum Trucks	Note loading with an air mover or vacuum. No additional record is needed where a vacuum truck uses only an on-board or portable pump to push material into the truck.
	Controlled Loading	Where control is required note the control that is utilized.
Control Devices	Vapor Capture and Recovery	Records of hours of use are required for all units and on-line time must be considered when emission estimates and actual emissions inventories are calculated. mVRU Basic Design Function Record: Record demonstrating the unit captures vapor and includes a sensing device set to capture this vapor at peak intervals. Additional Design Parameter Record: Record demonstrating additional design parameters are utilized such as additional sensing equipment, a properly designed bypass system, an appropriate gas blanket, an adequate compressor selection, and the ability to vary the drive speed for units utilizing electric driven compressors mVRUs that are used at oil and gas sites to control emissions may claim up to 100% control efficiency provided records of basic and additional design functions and parameters of a VRU along with appropriate records listed in Table 8 are satisfied. mVRUs may claim up to 99% control efficiency for units where records of basic and additional design functions are satisfied and parameters listed in Table 8 are not satisfied. mVRUs may claim up to 95% control efficiency for units where records listed in Table 8 are not satisfied.

Table 8 Monitoring and Records Demonstrations *(continued)*

Category	Description	Record Information
Control Devices (continued)	Vapor Capture and Recovery	lVRU The record of proper design must be kept to demonstrate how the unit was designed and for what capacity. The record of liquid replacement must be kept, along with the calculations for demonstrating that the VOC to liquid ratio has been maintained. Additionally, the system must be tested to demonstrate the efficiency. This testing needs to be performed and results recorded to receive 95% control efficiency no longer than: vacuum truck emissions: after 20 loads have been pulled through the lVRU, for tanks: Produced Water – Monthly, Crude – Bi-Monthly, Condensate – Weekly. This testing needs to be performed and results recorded to receive 98% control efficiency no longer than: vacuum truck emissions: after 15 loads have been pulled through the lVRU, for tanks: Produced Water – 3 weeks, Crude – 10 days, Condensate – 5 days. All valves must be designed and maintained to prevent leaks. All hatches and openings must be properly gasketed and sealed with the unit properly connected. Downtime is limited to a rolling 12 month average of 5% or 432 hr/per rolling 12 months and waste vents shall be redirected to an appropriate control device if possible during down time unless otherwise registered for alternate operating hours.
Cooling Tower	Design data	Records shall be kept of maximum cooling water circulation rate and basis, maximum total dissolved solids allowed as maintained through blowdown, and towers design drift rate. These records are only required if the cooling system is used to cool process VOC streams or control from drift eliminators or minimizing solids content is needed to meet particulate matter emission limits
Cooling Tower	VOC Leak Monitoring, Maintenance and Repair	Cooling tower heat exchanger systems cooling process VOC streams are assumed to have potential uncontrolled leaks repaired when obviated by process problems. If controlled emissions (systems monitored for leaks) are required to meet emission rate limits then the cooling tower water shall be monitored monthly for VOC leakage from heat exchangers in accordance with the requirements of the TCEQ Sampling Procedures Manual, Appendix P (dated January 2003 or a later edition) or another air stripping method approved by the TCEQ Executive Director.

Table 8 Monitoring and Records Demonstrations *(continued)*

Category	Description	Record Information
Cooling Tower *(continued)*	VOC Leak Monitoring, Maintenance and Repair	Cooling water VOC concentrations above 0.08 parts per million by volume (ppmv) indicate faulty equipment. Equipment shall be maintained so as to minimize VOC emissions into the cooling water. Faulty equipment shall be repaired at the earliest opportunity but no later than the next scheduled shutdown of the process unit in which the leak occurs. Records must be maintained of all monitoring data and equipment repairs.
	Particulate Monitoring, Maintenance and Repair.	Inspect and record integrity of drift eliminators annually, repairing as necessary. If a maximum solids content must be maintained through blowdowns to meet particulate emission rate limits, cooling water shall be sampled for total dissolved solids (TDS) once a month at prior to any periodic blow downs and maintain records of the monitoring results and all corrective actions.
Planned Maintenance, Start-up, and Shutdown (MSS)	Alternate Operational Scenarios and Redirection of Vent Streams	Records of redirection of vent streams during primary operational unit or control downtime, including associated alternate controls, releases and compliance with emission limitations.
Planned MSS	Pigging, Purging and Blowdowns	Pigging records, including catcher design, date, emission estimate to atmosphere and to control, and when controlled, the control device. Note where a control device is necessary to meet emission limitations the device is subject to the requirements of standard permit (e) and record requirements of this table. Purging and blowdown records, including the volume and pressure and a description of the piping and equipment involved, the date, emission estimate to atmosphere and to control, and when controlled, the control device. Where purging to control to meet a lower concentration before purging to atmosphere is conducted the concentrations of VOC, BTEX or H_2S as appropriate must be measured and recorded prior to purging to atmosphere. Note where a control device is necessary to meet emission limitations the device is subject to the requirements of standard permit (e) and record requirements of this table.
Planned MSS	Temporary Facilities for Bypass, and Degassing and Purging	Temporary facility records, including a description and estimate of potential fugitive emissions from temporary piping, size and design of facilities (eg. tanks or pan volume, fill method, and throughput; engine horse power, fuel and usage time, flare tip area, ignition method, and heating value assurance method; etc.) and the date and emission estimate to atmosphere and to control for their use

Table 8 Monitoring and Records Demonstrations *(continued)*

Category	Description	Record Information
Planned MSS	Management of Sludge from Pits, Ponds, Sumps and Water Conveyances	Records including the source identification, removal plan, emission estimate direct to atmosphere and through control. Note where a control device is necessary to meet emission limitations the device is subject to the requirements of standard permit (e) and record requirements of this table.
Planned MSS	Degassing or Purging of Tanks, Vessels, or Other Facilities	Records including: a) the EPN and description of vessels and equipment degassed or purged; b) the material, volume and pressure (if applicable); c) the volume of purge gas used; d) a description of the piping and equipment involved; e) clarifying estimates for a coated surface or heel; f) the date; g) emission estimate to atmosphere and to control; h) when controlled, the control device; and i) where purging to a control device to reduce concentrations before purging to atmosphere, the concentrations of VOC, BTEX or H_2S as appropriate must be measured and recorded prior to purging to atmosphere.
Planned MSS	Records	Records or copies of work orders, contracts, or billing by contractors for the following activities shall be kept at the site, or nearest manned site, and made available upon request: • Routine engine component maintenance including filter changes, oxygen sensor replacements, compression checks, overhauls, lubricant changes, spark plug changes, and emission control system maintenance; • Boiler refractory replacements and cleanings; • Heater and heat exchanger cleanings; • Turbine hot standard permit swaps; • Pressure relief valve testing, calibration of analytical equipment; instrumentation/analyzer maintenance; replacement of analyzer filters and screens.

Table 8 Monitoring and Records Demonstrations *(continued)*

Category	Description	Record Information
Control Devices	Flare Monitoring	Basic monitoring requires the flare and pilot flame to be continuously monitored by a thermocouple or an infrared monitor. Where an automatic ignition system is employed, the system shall ensure ignition when waste gas is present. The time, date, and duration of any loss of flare, pilot flame, or auto-ignition shall be recorded. Each monitoring device shall be accurate to, and shall be calibrated at a frequency in accordance with, the manufacturer's specifications. A temporary, portable or backup flare used less than 480 hours per year is not required to be monitored. Records of hours of use are required for all units and on-line time must be considered when emission estimates and actual emissions inventories are calculated.
Control Devices	Thermal Oxidation and Vapor Combustion Performance Monitoring Basic	Control device monitoring and records are required only where the device is necessary for the site to meet emission rate limits. Basic monitoring is a thermocouple or infrared monitor that indicates the device is working. Records of hours of use are required for all units and on-line time must be considered when emission estimates and actual emissions inventories are calculated.
	Intermediate	Intermediate monitoring and records include continuously monitoring and recording temperature to insure the control device is working when waste gas can be directed to the device and showing compliance with the 1400 degrees Fahrenheit if applicable.
	Enhanced	Enhanced monitoring requires continuous temperature and oxygen or carbon monoxide monitoring on the exhaust with six minute averages recorded to show compliance with the temperature requirement and the design oxygen range or a CO limit of 100 ppmv. Some indication of waste gas flow to the control device, like a differential pressure, flow monitoring or valve position indicator, must also be continuously recorded, if the flow to the control device can be intermittent.
	Alternate Monitoring	Records of stack testing and the monitored parameters during the testing shall be maintained to allow alternate monitoring parameters and limits.

Table 8 Monitoring and Records Demonstrations *(continued)*

Category	Description	Record Information
Control Devices	Control with process combustion or heating devices (e.g. reboilers, heaters and furnaces)	Basic monitoring is any continuous monitor that indicates when the flame in the device is on or off (other than partial operational use). The following are effective basic options: a fire box temperature monitor, rising or steady process temperature monitor, CO monitor, primary fuel flow monitor, fire box pressure monitor or equivalent. Enhanced monitoring for 91 to 99% control, where waste gas is not introduced as the primary fuel, must include the following monitors: continuous fire box or fire box exhaust temperature, and CO and O_2 monitoring, with at least 6 minute averages recorded. Additionally, enhanced monitoring where the waste gas may be flowing when the control device is not firing must show continuous disposition of the waste gas streams, including continuous monitoring of flow or valve position through any potential by-pass to the control where more than 50% run time of control is claimed..

Table 9 Fugitive Component LDAR BACT Table

Fugitive Component Leak Detection and Repair (LDAR) Best Available Control Technology Requirements Table	
Exceptions *All fugitive components must meet the minimum design, monitoring, control and other emissions techniques listed in this Table unless the component's service meets one of the following exceptions:*	**Additional Details** *Compliance with these requirements does not assure compliance with requirements of NSPS, NESHAPS or MACT, and does not constitute approval of alternate standards for these regulations.*
Total uncontrolled potential to emit from all components ≤ 10 tpy	
Nitrogen lines	No expectation to estimate emissions. Note this exemption does not include lines with nitrogen that has been used as a sweep gas.
Steam lines (non contact)	No expectation to estimate emissions.
Flexible plastic tubing ≤ 0.5 inches in diameter, unless it is subject to monitoring by other state or federal regulations.	No expectation to estimate emissions, unless it is subject to monitoring by other state or federal regulations.
The operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure	No expectation to estimate emissions.
Mixtures in streams where the VOC has an aggregate partial pressure of less than 0.002 psia at 68°F.	No expectation to estimate emissions.
Components containing only noble gases, inerts such as CO_2 and water or air contaminants not typically listed on a MAERT such as methane, ethane, and Freon.	No expectation to estimate emissions.
Instrument monitoring is not required for pipeline quality sweet natural gas	Uncontrolled Emissions should be estimated. Must meet pipeline quality specifications
Instrument monitoring is not required when the aggregate partial pressure or vapor pressure is less than 0.044 psia at 68 ºF or at maximum process operating temperature.	Uncontrolled Emissions should be estimated. This applies at all times, unless a control efficiency is being claimed for instrument monitoring, in which case there must be a record supporting that the instrument could detect a leak.
Instrument monitoring is not required for waste water lines containing less than 1% VOC by weight and operated at ≤ 1 psig	Uncontrolled Emissions should be estimated.
Instrument monitoring is not required for cooling water line components	Emissions are estimated and associated with the cooling tower

Table 9 Fugitive Component LDAR BACT Table *(continued)*

Fugitive Component Leak Detection and Repair (LDAR) Best Available Control Technology Requirements Table	
Exceptions *All fugitive components must meet the minimum design, monitoring, control and other emissions techniques listed in this Table unless the component's service meets one of the following exceptions:*	**Additional Details** *Compliance with these requirements does not assure compliance with requirements of NSPS, NESHAPS or MACT, and does not constitute approval of alternate standards for these regulations.*
Instrument monitoring is not required for CO_2 lines after VOC is removed. This is referred to as Dry Gas lines in 40 CFR Part 60 Subpart KKK, and defined as a stream having a VOC weight percentage less than 4 %; a weighted average Effects Screening Level (ESL) of the combined VOC stream is > 3,500 μg/m^3; and total uncontrolled emissions for all such sources is < 1 ton per year at any OGS.	Uncontrolled Emissions should be estimated. The weighted average ESL_x for process stream, X, with multiple VOC species will be determined by: $ESL_x = fa/ESL_a + f_b/ESL_b + f_c/ESL_c + . + fn/ESL_n$ Where: n =total number of VOC species in process stream; ESL_n = the effects screening level in µg/m^3 for the contaminant being evaluated (published in the most recent edition of the TCEQ ESL list); f_n=the weight fraction of the appropriate VOC species in relation to all other VOC in process stream.
At OGS sites where the total uncontrolled potential to emit from all components < 25 tpy, instrument monitoring is not required on components where the aggregate partial pressure or vapor pressure is less than 0.5 psia at 100 F or at maximum process operating temperature, unless the components are subject to monitoring by other state or federal regulations.	Uncontrolled Emissions should be estimated.
Minimum Design, Monitoring, Technique or Control for all fugitive components with uncontrolled potential to emit of ≥ 10 tpy VOC or ≥ 1 tpy H2S	
Requirements	**Additional Details**
Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.	To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation.

Table 9 Fugitive Component LDAR BACT Table *(continued)*

Minimum Design, Monitoring, Technique or Control for all fugitive components with uncontrolled potential to emit of ≥ 10 tpy VOC or ≥ 1 tpy H2S	
Requirements	**Additional Details**
New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. *Gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being returned to service. Where technically feasible new and reworked components may be screened for leaks with a soap bubble test within 8 hours of being returned to service in lieu of instrument testing. Adjustments shall be made as necessary to obtain leak-free performance.*	
Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line so that no leakage occurs. Except during sampling, both valves shall be closed.	If the removal of a component for repair or replacement results in an open ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period: the line or valve must have a cap, blind flange, plug, or second valve installed; or the open-ended valve or line shall be monitored once for leaks above background for a plant or unit turnaround lasting up to 45 days with an approved gas analyzer and the results recorded. For all other situations, the open-ended valve or line shall be monitored once at the end of the 72 hour period following the creation of the open ended line and monthly thereafter with an approved gas analyzer and the results recorded. For turnarounds and all other situations, leaks are indicated by readings 20 ppmv above background and must be repaired within 24 hours or a cap, blind flange, plug, or second valve must be installed on the line or valve.

Table 9 Fugitive Component LDAR BACT Table *(continued)*

Minimum Design, Monitoring, Technique or Control for all fugitive components with uncontrolled potential to emit of ≥ 10 tpy VOC or ≥ 1 tpy H2S	
Requirements	**Additional Details**
Components shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.	
Accessible valves shall be monitored by leak-checking for fugitive emissions quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. If an unsafe-to-monitor valve is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe-to-monitor times. A difficult-to-monitor component for which quarterly monitoring is specified may instead be monitored annually.	Sealless/leakless valves and relief valves equipped with rupture disc or venting to a control device and exempted from instrument monitoring are not counted in the fugitive emissions estimates. See Table 7 Sampling and Demonstrations of Compliance for Fugitive and LDAR Analyzer requirements. See Table 8, Monitoring and Records Demonstrations to identify Difficult-to-monitor and unsafe-to-monitor valves.
For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity.	All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.
All pump, compressor and agitator seals shall be monitored quarterly with an approved gas analyzer or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be instrument monitored. Seal systems that prevent emissions may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure or seals degassing to vent control systems kept in good working order. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.	Pumps compressor and agitator seals that prevent leaks or direct emissions from the seals to control and are exempt from instrument monitoring are not counted in the fugitive emissions estimates. Equipment equipped with alarms would still be counted. See Table 7 Sampling and Demonstrations of Compliance for Fugitive and LDAR Analyzer requirements.

Table 9 Fugitive Component LDAR BACT Table *(continued)*

Minimum Design, Monitoring, Technique or Control for all fugitive components with uncontrolled potential to emit of ≥ 10 tpy VOC or ≥ 1 tpy H2S	
Requirements	**Additional Details**
For a site where the total uncontrolled potential to emit from all components is **< 25 tpy**; Components found to be emitting VOC in excess of 10,000 parts per million by volume (ppmv) using EPA Method 21, found by visual inspection to be leaking (e.g. whistling, dripping or blowing process fluids or emitting hydrocarbon or H_2S odors) or found leaking using the Alternative Work Practice in 40 CFR §60.18(g) **-** (i) shall be considered to be leaking and shall be repaired, replaced, or tagged as specified. A first attempt to repair the leak must be made within 5 days. A leaking component shall be repaired as soon as practicable, but no later than 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging.	Components subject to routine instrument monitoring with an approved gas analyzer under this leak definition my claim a 75% emission reduction credit when evaluating controlled fugitive emission estimates. This reduction credit does not apply when evaluating uncontrolled emission or to any component not measured with an instrument quarterly, but is allowed for all components monitored by the Alternative Work Practice. See Table 7 Sampling and Demonstrations of Compliance for Fugitive and LDAR Analyzer requirements
Components **not** subject to a instrument monitoring program but found to be emitting VOC in excess of 10,000 ppmv using EPA Method 21, found by audio, visual or olfactory inspection to be leaking (e.g. whistling, dripping or blowing process fluids or emitting hydrocarbon or H_2S odors) shall be considered to be leaking and shall be repaired, replaced, or tagged as specified. All components are subject to monitoring when using the Alternative Work Practice in 40 CFR §60.18(g) - (i).	At the discretion of the TCEQ Executive Director or designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

Table 9 Fugitive Component LDAR BACT Table *(continued)*

Minimum Design, Monitoring, Technique or Control for all fugitive components with uncontrolled potential to emit of ≥ 25 tpy or ≥ 5 tpy H2S	
Requirements	**Additional Details**
For a site where the total uncontrolled potential to emit from all components is **≥ 25 tpy**; All the requirements for < 25tpy VOC above apply, except valves found to be emitting VOC in excess of 500 ppmv using EPA Method 21, found by audio, visual or olfactory inspection to be leaking (e.g. whistling, dripping or blowing process fluids or emitting hydrocarbon or H_2S odors) or found leaking using the Alternative Work Practice in 40 CFR §60.18(g) - (i) shall be considered to be leaking and shall be repaired, replaced, or tagged as specified and Pump, compressor, and agitator seals found to be emitting VOC in excess of 2,000 ppmv using EPA Method 21, found by audio, visual or olfactory inspection to be leaking (e.g. whistling, dripping or blowing process fluids or emitting hydrocarbon or H_2S odors) or found leaking using the Alternative Work Practice in 40 CFR §60.18(g) - (i) shall be considered to be leaking and shall be repaired, replaced, or tagged as specified.	Components subject to routine instrument monitoring under this leak definition my claim a 97% emission reduction credit for valves and an 85% emission reduction credit for pump, compressor and agitator seals when evaluating controlled fugitive emission estimates. This reduction credit does not apply when evaluating uncontrolled emission or to any component not measured with an instrument quarterly. See Table 7 Sampling and Demonstrations of Compliance for Fugitive and LDAR Analyzer requirements.
LDAR Monitoring Options	
Any site may reduce the controlled fugitive emission estimates by including components not required to be monitored in the quarterly instrument monitoring program or applying the lower leak definition of the more stringent program as appropriate.	Quarterly monitoring at a leak definition of 10,000 ppmv would equate to a 75% emission reduction credit when evaluating controlled fugitive emission estimates for the component. Quarterly monitoring at a leak definition of 500 ppmv would equate to a 97% emission reduction credit for valves, flanges and connectors, a 93% emission reduction credit for pumps, and a 95% emission reduction credit for compressor, agitator seals and other component groups when evaluating controlled fugitive emission estimates. This reduction credit does not apply when evaluating uncontrolled emission or to any component not measured with an instrument quarterly. See Table 7 Sampling and Demonstrations of Compliance for Fugitive and LDAR Analyzer requirements.

Table 9 Fugitive Component LDAR BACT Table *(continued)*

Requirements	**Additional Details**
LDAR Monitoring Options	
After completion of the required quarterly inspections for a period of at least two years, the operator of the OGS facility may change the monitoring schedule as follows:(i)After two consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip one of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.(ii)After five consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip three of the quarterly leak detection periods for the valves in gas/vapor and light liquid service. If the owner or operator is using the Alternative Work Practice in 40 CFR §60.18(g) - (i), the alternative frequencies specified in this standard permit are not allowed.	
Shutdown prior to Maintenance of Fugitive Components	**Start-up after Maintenance of components**
All components shall be kept in good repair. During repair or replacement, emission releases from the emptying of associated piping, equipment, and vessels must meet the emission limits and control requirements listed under pipeline or compressor blowdowns.	When returning associated equipment and piping to service after repair or replacement of fugitive components, appropriate leak detection shall occur and correction, maintenance or repair shall be immediately performed if fugitive components are not in good working order.

Table 10 Best Available Control Technology Requirements

Source or Facility	Air Contaminant	Minimum Acceptable Design, Control or Technique, Control Efficiencies, and Other Details during Production Operations
Combined Control Requirements	< 25 tpy VOC	No add on control is required if the continuous and periodic vents from all units, vessels and equipment (including normal operation process blow downs) is less than 25 tons of VOC per year.
	≥ 25 tpy VOC	All continuous and periodic vents on process vessels and equipment with potential emissions containing ≥ 1% VOC at any time must be captured and directed to a control device listed in the Control Device BACT Table with a minimum design control efficiency of at least 95%, if the sum of the uncontrolled PTE of the vents at the site will equal or exceed 25 tons of VOC per year. A site total potential to emit of 1 tpy of VOC from vent gas streams may be exempted from this control requirement.
Glycol Dehydration Unit	Uncontrolled PTE < 10 tpy VOC VOC, BTEX, H_2S	No control is required. Condensers included in the equipment constructed must be maintained and operated as specified by the manufacturer or design engineering.
	Uncontrolled PTE ≥ 10 tpy and < 50 tpy VOC VOC, BTEX, H_2S	All non-combustion VOC emissions shall be routed to a vapor recovery unit (VRU), the unit reboiler, or to an appropriate control device listed in the Control Device BACT Table. This includes the emissions from the condenser vent. Liquid waste or product material captured by a condenser must be enclosed and transferred to a unit compliant with the requirements of this table and the condenser must meet the requirements listed in the Control Device BACT Table with a minimum design control efficiency of 80%. For condensors, greater efficiencies may be claimed where enhanced monitoring and testing are applied following Table 7. If the unit reboiler is used to control the VOC emissions from the dehydrator (e.g. to control the condenser vent and the flash tank if one is present) the unit must be designed to efficiently combust those vented VOCs at least 50% of the time the unit is operated.
	Uncontrolled PTE ≥ 50 tpy VOC VOC, BTEX, H_2S	All non-combustion VOC emissions shall be captured and directed to an appropriate control device listed in the Control Device BACT Table with a minimum design control efficiency of at least 95%.

Table 10 Best Available Control Technology Requirements *(continued)*

Source or Facility	Air Contaminant	Minimum Acceptable Design, Control or Technique, Control Efficiencies, and Other Details during Production Operations
Atmospheric Oil/Water separators	VOC with partial pressure < 0.5 psia at maximum liquid temperature or 95 F which ever is greater. VOC, BTEX, H_2S	May vent to atmosphere through vent no larger than 3 inch diameter. If H_2S can exceed 24 ppmv in the vapor space the separator vent shall be captured and directed to a control device listed in the Control Device BACT Table with a minimum design control efficiency of at least 95%.
	VOC with partial pressure ≥ 0.5 psia at maximum liquid surface temperature or 95 F which ever is greater, VOC, BTEX, H_2S	The oil layer must have a floating cover over the entire liquid surface with a conservation vent to atmosphere or the vents must be captured and directed to a control device listed in the Control Device BACT Table with a minimum design control efficiency of at least 95%. If H_2S can exceed 24 ppmv in the vapor space the separator vent shall be captured and directed to a control device listed in the Control Device BACT Table with a minimum design control efficiency of at least 95%. If the separator operates with more than 25,000 gallons (595 barrels) of liquid contained or is used as an oil storage tank, it shall be treated as a storage tank and meet those requirements.
	Oil water separators where the material entering the separator may flash. VOC, BTEX, H_2S	These separators must be treated as process separators with a gas stream and follow those requirements.
Fuel Combustion Units including auxiliary fuel for combustion control devices	H_2S	Fuel for all combustion units at the site shall be sweet natural gas or liquid petroleum gas, fuel gas containing no more than ten grains of total sulfur per 100 dry standard cubic feet (dscf), or field gas.

Table 10 Best Available Control Technology Requirements *(continued)*

Source or Facility	Air Contaminant	Minimum Acceptable Design, Control or Technique, Control Efficiencies, and Other Details during Production Operations
Boilers, Reboilers, Heater-Treaters, and Process Heaters	NOx, CO, $PM_{10/2.5}$, VOC, HCHO, SO_2	If any unit has a designed maximum firing rate of < 40 MMBTU/hr and greater than 10 MMBtu/hr, it must be designed and operated for good combustion and meet 0.10 lb/MMBtu for NO_X. For boilers and reboilers greater than or equal to 40 MMBtu/hr, emission shall not exceed 0.036 lb/MMBtu for NOx. For heaters and heater treaters greater than or equal to 40 MMBtu/hr but less than 100 MBtu/hr, emissions shall not exceed 0.06 lb/MMBtu for NOx. Heaters and heater treaters greater than or equal to 100 MMBtu/hr shall not exceed 0.036 lb/MMBtu for NOx. For boilers, reboilers, process heaters, and heater treaters with heat inputs equal to or greater than 10 MMBtu/hr, the emission limit for CO is 0.074 lb CO/MMBtu
GasFired Turbines	NOx, CO, $PM_{10/2.5}$, VOC, HCHO, SO_2	Units shall be designed and operate with low NOx combustors and meet 25 ppmvd @ 15% O_2 for NO_X and 50 ppmvd @ 15% O_2 for CO.
All Tanks	Uncontrolled PTE of < 1.0 tpy VOC or < 0.1 tpy H2S	Open-topped tanks or ponds containing VOCs or H_2S are allowed
All Tanks	Uncontrolled PTE of ≥ 1.0 tpy VOC or ≥ 0.1 tpy H2S	Open-topped tanks or ponds containing VOCs or H_2S are not allowed. Tank hatches and valves, which emit to the atmosphere, shall remain closed except for sampling or planned maintenance activities. All pressure relief devices (PRD) shall be designed and operated to ensure that proper pressure in the vessel is maintained and shall stay closed except in upset or malfunction conditions. If the PRD does not automatically reset, it must be reset within 24 hours at a manned site and within one week if located at an unmanned site.

Table 10 Best Available Control Technology Requirements *(continued)*

Source or Facility	Air Contaminant	Minimum Acceptable Design, Control or Technique, Control Efficiencies, and Other Details during Production Operations
Process Separators, Crude oil, Condensate, Treatment chemicals, Produced water, Fuel, Slop/Sump Oil and any other storage tanks or vessels that contain a VOC or a film of VOC on the surface of water.	VOC with partial pressure < 0.5 psia at maximum liquid surface temperature or 95 F which ever is greater, or with uncontrolled PTE of < 5 tpy VOC from working and breathing losses, including flash emissions VOC, BTEX, H_2S	All storage tanks with a storage capacity greater than 500 gallons must be submerged fill. Existing tanks and vessels (including temporary liquid storage tanks) which are not increasing emissions at an OGS shall also meet this requirement no later than 180 days after a registration renewal as of January 1, 2016
	VOC with partial pressure ≥ 0.5 psia at maximum liquid surface temperature or 95 F (which ever is greater), and with uncontrolled PTE of < 5 tpy from working and breathing losses, including flash emissions VOC, BTEX, H_2S	All storage tanks with a storage capacity greater than 500 gallons must be submerged fill. Un-insulated tank exterior surfaces exposed to the sun shall be of a color that minimizes the effects of solar heating (including, but not limited to, white or aluminum). To meet this requirement the solar absorptance should be 0.43 or less, as referenced in Table 7.1-6 in AP-42. Paint shall be maintained in good condition. If a new or modified tank cannot be painted white or other reflective color, then another control device may be used to control emissions. Exceptions to the color requirement include the following: (A) Up to 10% of the external surface area of the roof or walls of the tank or vessel may be painted with other colors to allow for identifying information or aethestic purposes; and (B) If a local, state or federal law or ordinance or private contract which predates this standard permit's effective date establishes in writing tank and vessel colors other than white. If applicable, a copy of this documentation must be provided to the commission upon registration. (C) Tanks and vessels purposefully darkened to create the process reaction and help condense liquids from being entrained in the vapor. Existing tanks and vessels (including temporary liquid storage tanks) which are not increasing emissions at an OGS using shall also meet this requirement no later than 180 days after a registration renewal as of January 1, 2016.

Table 10 Best Available Control Technology Requirements *(continued)*

Source or Facility	Air Contaminant	Minimum Acceptable Design, Control or Technique, Control Efficiencies, and Other Details during Production Operations
	VOC with uncontrolled PTE of ≥ 5 tpy	Vents Vents shall be captured and directed to an appropriate control device as listed in standard permit (e) BMP and BACT. Un-insulated tank exterior surfaces exposed to the sun shall be of a color that minimizes the effects of solar heating (including, but not limited to, white or aluminum). To meet this requirement the solar absorptance should be 0.43 or less, as referenced in Table 7.1-6 in AP-42. Paint shall be maintained in good condition. Exceptions to the color requirement include the following: (A) Up to 10% of the external surface area of the roof or walls of the tank or vessel may be painted with other colors to allow for identifying information or aethestic purposes; and (B) If a local, state or federal law or ordinance or private contract which predates this standard permit's effective date establishes in writing tank and vessel colors other than white. If applicable, a copy of this documentation must be provided to the commission upon registration. (C) Tanks and vessels purposefully darkened to create the process reaction and help condense liquids from being entrained in the vapor. Existing tanks and vessels (including temporary liquid storage tanks) which are not increasing emissions at an OGS using shall also meet this requirement no later than 180 days after a registration renewal as of January 1, 2016.
Truck Loading	VOC with partial pressure < 0.5 psia at maximum liquid surface temperature or 95 F whichever is greater, or with uncontrolled PTE of < 5 tpy VOC VOC, BTEX, H_2S	Loading is recommended to be performed with submerged filling, or vapor balancing back to the tank and any subsequent recovery or control device.

Table 10 Best Available Control Technology Requirements *(continued)*

Source or Facility	Air Contaminant	Minimum Acceptable Design, Control or Technique, Control Efficiencies, and Other Details during Production Operations
	VOC with partial pressure ≥ 0.5 psia at maximum liquid surface temperature or 95 F which ever is greater VOC, BTEX, H_2S	Splash loading and uncontrolled vacuum truck loading is not allowed. Loading shall be performed with a control effectiveness of at least 42% as compared to splash loading. Loading may occur by submerged filling or equivalent prevention or recovery technique as listed in Table 10.
	VOC with uncontrolled PTE of ≥ 5 tpy VOC VOC, BTEX, H_2S	Loading vapors shall be captured and directed to an appropriate control device listed in the Control Device BACT Table with a minimum design control efficiency of at least 98%, routed to a vapor recovery unit (VRU) with a control effectiveness of at least 95%, or vapor balanced back to the delivering storage tank equipped with a VRU, or connected to a control device listed in the Control Device BACT Table with a minimum design control efficiency of at least 95%.
	Controlled Loading	Where loading control is required, the collection or capture system must be connected to the tank truck so all displaced vapors are directed to the control device and the control device is operational before loading is commenced. When properly connected the capture efficiency will be assumed to be 70% efficient at capturing the displaced truck vapors. The capture efficiency may be assumed to be 98.7 percent efficient when the tanker truck has certification that the tank has passed vapor-tightness testing within the last 12 months using the methods described in 40 CFR 60, Subpart XX. The capture efficiency may be assumed to be 99.2 percent efficient when the tanker truck has certification that the tank has passed vapor-tightness testing within the last 12 months using the methods described in 40 CFR 63, Subpart R. Loading shall be discontinued when liquid or gas leaks from the loading or collection system are observed.

Table 10 Best Available Control Technology Requirements *(continued)*

Source or Facility	Air Contaminant	Minimum Acceptable Design, Control or Technique, Control Efficiencies, and Other Details during Production Operations
Cooling Tower Heat Exchange System	VOC, BTEX, $PM_{10/2.5}$	Heat exchange systems must be non-contact design (i.e. designed and operated to avoid direct contact with gaseous or liquid process streams containing VOC, H2S, halogens or halogen compounds, cyanide compounds, inorganic acids, or acid gases). Systems with heat exchangers that cool a fluid with VOC shall meet the following: The cooling water must be at a higher pressure than the process fluid in the heat exchangers or the cooling tower water must be monitored monthly for VOC emissions using TCEQ Sampling Procedures Manual, Appendix P dated January 2003 or a later edition. Equipment shall be maintained so as to minimize VOC emissions into the cooling water. Cooling water VOC concentrations greater than 0.08 ppmw indicate faulty equipment. If the repair of a heat exchanger would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next planned shutdown or 180 days if no shutdowns are scheduled. Cooling towers shall be designed and operated with properly functioning drift eliminators. New cooling towers shall be designed with drift eliminators designed to meet ≤ 0.001% drift.

List of Acronyms

°C	Degrees Celsius
°F	Degrees Fahrenheit
$\mu g/m^3$	Micrograms per cubic meter
acfm	Actual cubic feet per minute
ADMT	Air Dispersion Modeling Team
AMINECalc	Amine Unit Air Emissions Model Ver 1.0
AP-42	Air Pollutant Emission Factors, 5th ed
APD	Air Permits Division
API	American Petroleum Institute
APWL	Air Pollutant Watch List
AREACIRC	Co-located circular area source from the EPAAERMOD Modeling System
AWP	Alternative Work Practices
BACT	Best Available Control Technology
bbl	Barrel
bbl/day	Barrels per day
BMP	Best Management Practices (includes equipment manufacturer's guidelines and specifications)
BTEX	Benzene, Toluene, Ethylbenzene, Xylene
Btu/scf	British thermal units per standard cubic feet
CEMS	Continuous Emissions Monitoring System
cf/day	Cubic feet per day
cfm	Cubic feet per minute
CFR	Code of Federal Regulations
CO_2	Carbon dioxide
COS	Carbonyl sulfide
CPR	Considerable personnel and resources
CS_2	Carbon disulfide
CT	Cooling towers
DEA	Diethanolamine
DGA	Diglycolamine
DIPA	Di-isopropylamine
DOT	Department of Transportation
DRE	Destruction rate efficiency
dscf	Dry standard cubic feet
DV	Designated value

List of Acronyms*(continued)*

E	Maximum acceptable emission rate (lb/hr)
EF	Emission factor
EFR	External floating roof tank
E_{max}	Maximum acceptable emission rate (lb/hr)
EPA	Environmental Protection Agency
EPN	Emission point number
ESL	Effects screening level
FR	Federal Register
ft	Feet
ft/sec	Feet per second
gal/wk	Gallons per week
gal/yr	Gallons per year
GLC_{max}	Max predicted ground-level concentration
GOP	General Operating Permit
H_2S	Hydrogen sulfide
HAP	Hazardous air pollutant
HB	House Bill
HCl	Hydrogen chloride
hp	Horsepower
hr	Hour
HRVOC	Highly reactive volatile organic compounds
HYSIM®	Hydrologic Simulation Model computer program
HYSIS®	Process simulator computer program
ICE	Internal combustion engine
IFR	Internal floating roof tank
IR	Infrared
ISCST3	Industrial Source Complex Short-term Model V02035
LACT	Lease automatic custody transfer unit
lb	Pound
lb/hr	Pounds per hour
lb/MMBtu	Pounds per million British thermal units
lbs/day	Pounds per day

List of Acronyms*(continued)*

LDAR	Leak detection and repair
L_L	Loading losses
LPG	Liquid petroleum gas
LT/D	Long ton per day
m/sec	Meters per second
MACT	Maximum Available Control Technology
MDEA	Methyl-diethanolamine
MEA	Monoethanol amine
MERA	Modeling and Effects Review Applicability
MMBtu	Million British thermal units
MMBtu/hr	Million British thermal units per hour
MMCFD	Million cubic feet per day
MSS	Maintenance, start-up, and shutdown
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGL	Natural gas liquids
NNSR	Nonattainment New Source Review
NO_2	Nitrogen dioxide
NO_x	Oxides of nitrogen
NSPS	New Source Performance Standards
NSR	New Source Review
O_2	Oxygen (molecular form)
OGS	Oil and gas site
PBR	Permit by Rule
PM_{10}	Particulate matter less than or equal to 10 microns
POC	Products of combustion
ppm	Parts per million
Ppmvd	Parts per million by volume, dry
PROSIM®	DOS based process simulator computer program
PSD	Prevention of Significant Deterioration
psi	Pounds per square inch
psia	Pounds per square inch, absolute
psig	Pounds per square inch, gage

List of Acronyms*(continued)*

RICE	Reciprocating internal combustion engine
RVP	Reid vapor pressure
scfh	Standard cubic feet per hour
scfm	Standard cubic feet per minute
scmd	Standard cubic feet per day
SCREEN3	Air dispersion modeling computer program forwindows, Version 5.0. BEE-line Software c1998-2002
SE	Standard Exemption
SIC	Standard Industrial Classification System
SO_2	Sulfur dioxide
SOP	Site Operating Permit
Standard permit	Standard Permit
SRU	Sulfur recovery unit
T&S	Transfer and storage
TAC	Texas Administrative Code
TCAA	Texas Clean Air Act
TCEQ	Texas Commission on Environmental Quality
TEA	Triethanolamine
THSC	Texas Health and Safety Code
tpy	Tons per year
V-B	Vasquez-Beggs correlation equation
VOC	Volatile organic compounds
VRU	Vapor recovery unit or system
WINSIM®	Windows process simulator computer program

Attachment 7

EPA, Oil and Natural Gas Section: Emission Standards for New, Reconstructed, and Modified Sources, Background Technical Support Document for the Final New Source Performance Standards 40 CFR Part 60, subpart OOOOa (May 2016) (excerpts).

United States Environmental Protection Agency

Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources

Background Technical Support Document for the

Final New Source Performance Standards

40 CFR Part 60, subpart OOOOa

May, 2016

Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources

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ACRONYMS AND ABBREVIATIONS

Acronyms/Abbreviations	**Description**
µg/L	micrograms per liter
AEO	Annual Energy Outlook
ANGA	America's Natural Gas Alliance
API	American Petroleum Institute
bbl	barrels
BSER	best system of emission reduction
BTEX	benzene, toluene, ethylbenzene and xylenes
Btu	British thermal unit
CAA	Clean Air Act
CAGR	compound annual growth rate
CD	combustion device
CETAC-WEST	Canadian Environmental Technology Advancement Corporation-WEST
cfm	cubic foot per minute
CFR	U.S. Code of Federal Regulations
CH_4	methane
CIPs	chemical injection pumps
CO	carbon monoxide
CO_2	carbon dioxide
CO_2Eq.	carbon dioxide equivalents
COOGCC	Colorado Oil and Gas Conservation Commission
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FR	Federal Register
GE	General Electric
GHG	greenhouse gas
GOR	gas to oil ratio
GRI	Gas Research Institute
H_2S	hydrogen sulfide
HAP	hazardous air pollutants
Inj/With	injection/withdrawal
IR	infrared
kg/hr/comp	kilograms per hour per component
kg/hr/source	kilograms per hour per source
kW	kilowatt
lbs	pounds
LDAR	leak detection and repair
Mcf	thousand cubic feet
MMcf	million cubic feet
MMT	million metric tons

Acronyms/Abbreviations	Description
$MMtCO_2e$	million metric tons of CO_2-equivalents
Mscf	thousand standard cubic feet
Mscf/cyl	thousand standard cubic feet per cylinder
Mscf/yr	thousand standard cubic feet per cylinder per year
NEMS	National Energy Modeling System
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NGL	natural gas liquids
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operations & maintenance
OAQPS	Office of Air Quality and Standards
OAR	Office of Air and Radiation
OEL	open-ended line
OGI	optical gas imaging
OVA	organic vapor analyzers
PES	Preliminary Environmental Study
PG&E	Pacific Gas & Electric
PM	particulate matter
PNAS	Proceedings of the National Academy of Sciences
ppmv	parts per million by volume
PRV	pressure relief valve
psig	pounds per square inch gage
REC	renewable energy certificate
scf	standard cubic feet
scf/hr-cylinder	standard cubic feet per hour-cylinder
scf/minute or scfm	standard cubic feet per minute
scfh	standard cubic feet per hour
SO_2	sulfur dioxide
THC	total hydrocarbon
TOC	total organic compounds
tpy	tons per year
TSD	Technical Support Document
TVA	toxic vapor analyzers
U.S.	United States
U.S.C.	United States Code
URS Corporation	United Research Services Corporation
UT Austin	University of Texas, Austin
VOC	volatile organic compounds
VRU	Vapor recovery unit
WAQD	Wyoming's Air Quality Division

ppm level, and achieve similar reductions as a Method 21 monitoring program. Based on this information, we believe the expected emission reductions from an OGI monitoring and repair program falls somewhere in the 500 and 10,000 ppm range found in the Method 21 monitoring programs, but closer to the 500 ppm level.

A study performed by ICF[42] using data from Subpart W, EPA/ GRI, City of Fort Worth Natural Gas Air Quality Study, UT Study - Methane Emissions in the Natural Gas Supply Chain: Production, UT Study - Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States Pneumatic Controllers and Jonah Energy LLC WCCA Spring Meeting Presentation determined that the Year 3 fugitive emissions reductions from a quarterly LDAR program to be 78 percent. The data provided in the study supports 40, 60, 80 percent emission reductions for annual, semi-annual and quarterly monitoring, respectively.

On the basis of the analysis and the data described here, it was concluded that an OGI monitoring program in combination with a repair program can reduce fugitive methane and VOC emissions from these segments by 40 percent on an annual frequency, 60 percent on a semiannual frequency and 80 percent on a quarterly frequency as well as minimize the loss of salable gas.

To be conservative, we performed a sensitivity analysis using the midpoint between the potential emissions reductions that were calculated for each of the Method 21 monitoring frequencies at leak definitions of 10,000 ppm and 500 ppm, which were determined to be 55, 65, and 75 percent for annual, semiannual and quarterly monitoring, respectively. We then compared the potential emissions reductions from 40, 60, 80 percent reductions with the Method 21 midpoint reduction percentages of 55, 65 and 75 and found that the annual methane and VOC emission reductions at each of the monitoring frequency intervals were comparable.[43]

4.3.2.3 Cost Impacts

Costs for preparing an OGI fugitive emission monitoring and repair plan for a company defined area (i.e., field or district) were estimated using hourly estimates for each of the monitoring and repair plan elements. The costs are based on the following assumptions:

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[42] ICF International, Leak Detection and Repair Cost-Effectiveness Analysis, Prepared for Environmental Defense Fund, December 4, 2015, Revised May 2, 2016.

[43] See Emission Reduction Comparison - Well Sites.xls and Emission Reduction Comparison – Compressor Stations.xls in the docket for more information.

- Labor cost for each of the monitoring plan elements, such as reading the rule, was estimated to be $57.80 per hour.
- Reading of the rule and instructions would take 1 person 4 hours to complete at a cost of $231.
- Development of a fugitive emission monitoring plan would take 2.5 people a total of 60 hours to complete at a cost of $3,468.
- Initial activities planning are estimated to take 2 people a total of 8 hours per person for each monitoring event. Cost for annual monitoring was estimated to be $925 semiannual monitoring was estimated to be $1,850 and quarterly monitoring $3,699.
- Notification of compliance status was estimated to take 1 person 1 hour to complete at a cost of $58 for compressor stations (i.e., gathering and boosting stations, transmission stations, and storage facilities). For companies that own and operate well sites, the cost notification of compliance status was estimated to be $58 per well site for each company defined area, which is estimated to operate 22 well sites within the defined area for a total of $1,272.
- Cost of a Method 21 Monitoring Device of $10,800.
- Costs for implementing a fugitive emission monitoring plan for a company defined area (i.e., field or district) were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:
- Subsequent activities planning are estimated to take 2 people a total of 8 hours per person to complete at a cost of $925 per monitoring event. For oil and natural gas production well sites, this cost was divided among the total number of well sites owned in a company defined area, which was assumed to be 22. The cost per well site was estimated to be $42 per monitoring event.
- The cost for OGI monitoring using an outside contractor was assumed to be $600 for a well site and $2,300 for a compressor station.[44]
- Annual repair costs were estimated to be $299 per monitoring event for well sites, $3,436 per monitoring event for gathering and boosting stations, $3,361 per monitoring event for transmission stations, and $6,946 per monitoring event for storage facilities. These costs were estimated assuming that 1.18 percent of the components are found to leak[45] during monitoring and 75 percent are repaired online and 25 percent are repaired offline.

[44] Costs for contractor based OGI monitoring obtained from the Carbon Limits report.
[45] The assumption of 1.18% leak rate for OGI monitoring was obtained from Table 5 of the Uniform Standards memorandum. The 1.18% value is the baseline leak frequency for valves in gas/vapor service. None of the other baseline frequencies in this table were used because the equipment are in liquid service (e.g., pumps LL, valve LL, agitators LL). There is no information

- Costs to resurvey the repaired components that could not be fixed during the initial survey using a Method 21 device was estimated using a resurvey time of 5 minutes per leak at a cost of $58 per hour. This assumes the company is able to perform the resurvey without retaining contractors. The capital costs include the cost of Method 21 instrumentation (estimated to be $10,800[46]). For compressor stations, the cost to resurvey repaired components was estimated to be $2.00 per component.
- Preparation of annual reports was estimated to take 1 person a total of 4 hours to complete at a cost of $231.

The initial setup cost or capital cost for oil and natural gas well sites was calculated by summing up the costs for reading the rule, development of fugitive emissions monitoring plan, initial activities planning, notification of initial compliance status, and purchase of a Method 21 instrumentation. The total capital cost of these activities was calculated to be $17,620 per company defined areas for semiannual monitoring and $19,470 per company define areas for quarterly monitoring. Assuming that each company owns and operates 22 well sites within a company defined area[47], the capital cost per well site was estimated to be $759 for annual monitoring, $801 for semiannual monitoring and $885 for quarterly monitoring. For compressor stations (gathering and boosting stations, transmission stations and storage facilities) the capital cost for reading the rule, development of fugitive emissions monitoring plan, initial activities planning notification of initial compliance status, and purchase of a Method 21 instrumentation was calculated to be $16,407 per facility. For gathering and boosting stations, this capital cost was assumed to be shared with other gathering and boosting stations within the company defined area. These stations are estimated to be approximately 70 miles apart. Therefore, within a 210 mile radius of a central location, there would be an estimated 7 gathering and boosting stations, and the capital cost of each of these stations was estimated to be $2,393.

For all oil and natural gas segments, the annual cost includes; subsequent activities planning, OGI survey, cost of repair of fugitive emissions found, resurvey of repaired components, preparation and

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on the number of leaks located at uncontrolled facilities, only average percentages of the total number of components at a facility. Therefore, our methodology was to use the 1.18% leak frequency value from the Uniform Standards memorandum and apply that value to the total number of components at the oil and natural gas model plant. (Uniform Standards Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180).

[46] Average of subsequent monitoring costs in Table 13 from the Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180

[47] The number of well sites owned and operated by companies was calculated using data from the Fort Worth study.

submittal of an annual report, and the amortized capital cost over 8 years at 7 percent interest. For our analysis the EPA calculated the annual cost for annual, semiannual and quarterly OGI surveys. The OGI monitoring cost memorandum[48] present the analyses for other costing methodologies, including a company-based OGI monitoring program and an OGI program using cost methodologies developed for the Colorado fugitive leak program to estimate the annual cost of implementing an OGI monitoring and repair program for oil and natural gas well sites, gathering and boosting, transmission and storage compressor stations for the respective OGI monitoring frequencies.

The cost per ton of emissions reduced was calculated using two separate methods. The first method allocated all of the costs to one pollutant and zero to the other (single-pollutant approach) using representative unit costs for each control option. The second method allocates the annual cost among the pollutants (multi-pollutant approach) that a given technology reduced (i.e., GHG (in the form of limiting methane emissions) and VOC). This proration was based on estimates of the percentage reduction expected for each pollutant. In the case of fugitives, the percent reductions for methane and VOC emissions are equal; and therefore the proration of the annual cost was divided equally and applied to the methane and VOC reductions.

Based on estimated emissions reductions and the estimated cost for implementing an OGI fugitive emissions monitoring and repair program at the affected facilities, the EPA calculated a cost of control for methane and VOC for the various options for oil and natural gas production well sites, gathering and boosting, and transmission and storage compressor stations. The EPA then calculated the cost of control of well sites and compressor stations using the weighted average cost of control for all well sites and all compressor stations (i.e., gathering and boosting, transmission and storage). Table 4-9, 4-10 and 4-11 presents a summary of the cost of control for methane and VOC for the three OGI monitoring frequency options (i.e., annual, semiannual and quarterly, respectively) based on the single-pollutant method. Tables 4-12, 4-13 and 4-14 present a summary of the capital and annual costs, and the cost of control for methane and VOC using the multi-pollutant method (i.e., 50 percent of the cost attributed to methane and 50 percent of the cost attributed to VOC).

[48] Memorandum from Bradley Nelson, EC/R to Jodi Howard, EPA, Evaluation of Cost methodologies for OGI Monitoring, April 6, 2016.

4.3.2.4 Secondary Impacts

No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of fugitive emissions components. There are some emissions that would be generated by the OGI camera monitoring contractors with respect to driving to and from the site for the fugitive emissions survey. Using AP-42 mobile emission factors[49] and assuming a distance of 70 miles to the well site or compressor station, the emissions generated from semiannual monitoring at a well site (140 miles to and from the well site twice a year) is estimated to be 0.35 pounds per year (lb/yr) of hydrocarbons, 6.0 lb/yr of carbon monoxide (CO) and 0.40 lb/yr of nitrogen dioxides (NO_X). The emissions generated from quarterly monitoring at a compressor station (140 miles to and from the compressor station four times a year) is estimated to be 0.70 lb/yr of hydrocarbons, 12.0 lb/yr of CO and 0.80 lb/yr of NO_X.

[49] AP-42: Compilation of Air Pollutant Emission Factors. Highway Vehicles, Light-Duty Gasoline Truck I, Model Year 1998+, 50,000 miles. https://www3.epa.gov/otaq/ap42.htm#highway

Table 4-9. Summary of the Model Plant Cost of Control for Annual OGI Monitoring Option – Single Pollutant[50]

Model Plant	Annual Emission Reductions[a] (tpy)		Capital Cost[b] ($)	Annual Cost ($/year)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[c] ($/ton)	
	CH_4	VOC		without savings	with savings	CH_4	VOC	CH_4	VOC
Natural Gas Well Site[d]	2.20	0.61	$759	$1,318	$809	$600	$2,158	$368	$1,324
Oil Well Site (GOR < 300)[d]	0.49	0.13	$759	$1,318	$1,204	$2,670	$9,953	$2,438	$9,089
Oil Well Site (GOR > 300 GOR)[d]	1.10	0.30	$759	$1,318	$1,063	$1,198	$4,380	$967	$3,533
Well Site Program Weighted Average[h]						**$1,224**	**$4,464**	**$993**	**$3,619**
Gathering & Boosting Station[e]	14.1	3.91	$2,393	$7,777	$7,777	$553	$1,990	$553	$1,990
Transmission Station[f]	16.2	0.45	$16,407	$10,117	$10,117	$626	$22,626	$626	$22,626
Storage Facility[g]	57.0	1.58	$16,407	$13,798	$13,798	$242	$8,751	$242	$8,751
Compressor Stations Program Weighted Average[h]						**$541**	**$3,098**	**$541**	**$3,098**

a. Assumes 40% reduction with the implementation of annual IR camera monitoring.
b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between 7 stations within a company defined area. The capital cost for transmission and storage segments includes the cost of implementing the monitoring program.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $4 Mcf.
d. Annual cost for well sites includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.
f. Annual cost for transmission station includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.
g. Annual cost for storage facilities includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.
Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

[50] As explained earlier, this control option simultaneously reduces both methane (which is being evaluated for controlling the pollutant GHG) and VOC. Under the single pollutant approach, all costs are attributed to one pollutant and zero to the other. For simplicity, the table presents the cost per ton of the assigned pollutant; the table does not present the cost per ton of the one that is assigned zero cost because it is always zero.

Table 4-10. Summary of the Model Plant Cost of Control for the Semiannual OGI Monitoring Option – Single Pollutant[51]

Model Plant	Annual Emission Reductions[a] (tpy)		Capital Cost[b] ($)	Annual Cost ($/year)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[c] ($/ton)	
	CH_4	VOC		without savings	with savings	CH_4	VOC	CH_4	VOC
Natural Gas Production Well Site[d]	3.3	0.917	$801	$2,285	$1,521	$693	$2,494	$461	$1,660
Oil Well Sites (GOR < 300) [d]	0.74	0.199	$801	$2,285	$2,114	$3,085	$11,503	$2,854	$10,639
Oil Well Site (GOR > 300 GOR)[d]	1.65	0.451	$801	$2,285	$1,903	$1,385	$5,062	$1,153	$4,215
Well Site Program Weighted Average[h]						**$1,415**	**$5,160**	**$1,183**	**$4,314**
Gathering & Boosting Station[e]	21.1	5.86	$2,393	$13,534	$13,534	$642	$2,309	$642	$2,309
Transmission Station[f]	24.2	0.67	$16,407	$15,868	$15,868	$655	$23,659	$655	$23,659
Storage Facility[g]	85.5	2.37	$16,407	$23,230	$23,230	$272	$9,822	$272	$9,822
Compressor Stations Program Weighted Average[h]						**$625**	**$3,480**	**$625**	**$3,480**

a. Assumes 60% reduction with the implementation of semiannual IR camera monitoring.
b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between 7 stations within a company defined area. The capital cost for transmission and storage segments includes the cost of implementing the monitoring program.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $4 Mcf.
d. Annual cost for well sites includes annual monitoring and repair cost of $2,151 and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $13,133 and amortization of the capital cost over 8 years at 7% interest.
f. Annual cost for transmission station includes annual monitoring and repair cost of $13,120 and amortization of the capital cost over 8 years at 7% interest.
g. Annual cost for storage facilities includes annual monitoring and repair cost of $20,482 and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.
Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

[51] *Ibid.*

Table 4-11. Summary of the Model Plant Cost of Control for the Quarterly OGI Monitoring Option -Single-Pollutant[52]

Model Plant	Annual Emission Reductions[a] (tpy)		Capital Cost[b] ($)	Annual Cost ($/year)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[c] ($/ton)	
	CH_4	VOC		without savings	with savings	CH_4	VOC	CH_4	VOC
Natural Gas Production Well Site[d]	4.4	1.222	$885	$4,220	$3,201	$960	$3,453	$728	$2,619
Oil Well Sites (GOR < 300) [d]	0.99	0.265	$885	$4,220	$3,991	$4,272	$15,929	$4,041	$15,064
Oil Well Site (GOR > 300 GOR)[d]	2.20	0.602	$885	$4,220	$3,710	$1,918	$7,010	$1,686	$6,163
Well Site Program Weighted Average[h]						**$1,960**	**$7,145**	**$1,728**	**$6,299**
Gathering & Boosting Station[e]	28.1	7.81	$2,393	$25,049	$25,049	$891	$3,205	$891	$3,205
Transmission Station[f]	32.3	0.89	$16,407	$27,369	$27,369	$847	$30,606	$847	$30,606
Storage Facility[g]	114.0	3.15	$16,407	$42,093	$42,093	$369	$13,348	$369	$13,348
Compressor Stations Program Weighted Average[h]						**$864**	**$4,732**	**$864**	**$4,732**

a. Assumes 80% reduction with the implementation of quarterly IR camera monitoring.
b The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $19,470 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of $16,407.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $4 Mcf.
d. Annual cost for well sites includes annual monitoring and repair cost of $4,071 and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $24,649 and amortization of the capital cost over 8 years at 7% interest.
f. Annual cost for transmission station includes annual monitoring and repair cost of $24,622 and amortization of the capital cost over 8 years at 7% interest.
g. Annual cost for storage facilities includes annual monitoring and repair cost of $39,345 and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.

Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

52 *Ibid.*

Table 4-12. Summary of the Model Plant Cost of Control for the Annual OGI Monitoring Option - Multi-Pollutant Method

Model Plant	Annual Emission Reductions[a] (tpy)		Capital Cost[b] ($)	Annual Cost ($/year)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[c] ($/ton)	
	CH_4	VOC		without savings	with savings	CH_4	VOC	CH_4	VOC
Natural Gas Production Well Site[d]	2.20	0.61	$759	$1,318	$809	$300	$1,079	$184	$662
Oil Well Sites (GOR < 300) [d]	0.49	0.13	$759	$1,318	$1,204	$1,335	$4,977	$1,219	$4,545
Oil Well Site (GOR > 300 GOR)[d]	1.10	0.30	$759	$1,318	$1,063	$599	$2,190	$483	$1,767
Well Site Program Weighted Average[h]						**$612**	**$2,232**	**$496**	**$1,810**
Gathering & Boosting Station[e]	14.1	3.91	$2,393	$7,777	$7,777	$277	$995	$277	$995
Transmission Station[f]	16.2	0.45	$16,407	$10,117	$10,117	$313	$11,313	$313	$11,313
Storage Facility[g]	57.0	1.58	$16,407	$13,798	$13,798	$121	$4,375	$121	$4,375
Compressor Stations Program Weighted Average[h]						**$271**	**$1,549**	**$271**	**$1,549**

a. Assumes 40% reduction with the implementation of annual IR camera monitoring.
b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $16,696 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was estimated to be $16,753 divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of $16,407.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $4 Mcf.
d. Annual cost for well sites includes annual monitoring and repair cost of $1,191 and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $7,376 and amortization of the capital cost over 8 years at 7% interest.
f. Annual cost for transmission station includes annual monitoring and repair cost of $7,369 and amortization of the capital cost over 8 years at 7% interest.
g. Annual cost for storage facilities includes annual monitoring and repair cost of $11,050 and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.
Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

Table 4-13. Summary of the Model Plant Cost of Control for the Semiannual OGI Monitoring Option - Multi-Pollutant Method

Model Plant	Annual Emission Reductions[a] (tpy)		Capital Cost[b] ($)	Annual Cost ($/year)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[c] ($/ton)	
	CH_4	VOC		without savings	with savings	CH_4	VOC	CH_4	VOC
Natural Gas Production Well Site[d]	3.3	0.917	$801	$2,285	$1,521	$347	$1,247	$231	$830
Oil Well Sites (GOR < 300) [d]	0.74	0.199	$801	$2,285	$2,114	$1,543	$5,752	$1,427	$5,319
Oil Well Site (GOR > 300 GOR)[d]	1.65	0.451	$801	$2,285	$1,903	$693	$2,531	$577	$2,108
Well Site Program Weighted Average[h]						**$708**	**$2,580**	**$592**	**$2,157**
Gathering & Boosting Station[e]	21.1	5.86	$2,393	$13,534	$13,534	$321	$1,155	$321	$1,155
Transmission Station[f]	24.2	0.67	$16,407	$15,868	$15,868	$327	$11,829	$327	$11,829
Storage Facility[g]	85.5	2.37	$16,407	$23,230	$23,230	$136	$4,911	$136	$4,911
Compressor Stations Program Weighted Average[h]						**$312**	**$1,740**	**$312**	**$1,740**

a. Assumes 60% reduction with the implementation of semiannual IR camera monitoring.
b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $17,620 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was estimated to be $16,753 divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of $16,407.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $4 Mcf.
d. Annual cost for well sites includes annual monitoring and repair cost of $2,151 and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $13,133 and amortization of the capital cost over 8 years at 7% interest.
f. Annual cost for transmission station includes annual monitoring and repair cost of $13,120 and amortization of the capital cost over 8 years at 7% interest.
g. Annual cost for storage facilities includes annual monitoring and repair cost of $20,482 and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.
Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

Table 4-14. Summary of the Model Plant Cost of Control for the Quarterly OGI Monitoring Option - Multi-Pollutant Method

Model Plant	Annual Emission Reductions[a] (tpy)		Capital Cost[b] ($)	Annual Cost ($/year)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[c] ($/ton)	
	CH_4	VOC		without savings	with savings	CH_4	VOC	CH_4	VOC
Natural Gas Production Well Sites[d]	4.40	1.222	$885	$4,220	$3,201	$480	$1,726	$364	$1,310
Oil Well Sites (GOR < 300) [d]	0.99	0.265	$885	$4,220	$3,991	$2,136	$7,964	$2,020	$7,532
Oil Well Sites (GOR > 300 GOR)[d]	2.20	0.602	$885	$4,220	$3,710	$959	$3,505	$843	$3,081
Well Site Program Weighted Average[h]						**$980**	**$3,572**	**$864**	**$3,150**
Gathering & Boosting Station[e]	28.1	7.8	$2,393	$25,049	$25,049	$445	$1,603	$445	$1,603
Transmission Station[f]	32.3	0.9	$16,407	$27,369	$27,369	$424	$15,303	$424	$15,303
Storage Facility[g]	114.0	3.2	$16,407	$42,093	$42,093	$185	$6,674	$185	$6,674
Compressor Stations Program Weighted Average[h]						**$432**	**$2,366**	**$432**	**$2,366**

a. Assumes 80% reduction with the implementation of quarterly IR camera monitoring.
b The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $19,470 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was estimated to be $16,753 divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of $16,407.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $4 Mcf.
d. Annual cost for well sites includes annual monitoring and repair cost of $4,071 and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $24,649 and amortization of the capital cost over 8 years at 7% interest.
f. Annual cost for transmission station includes annual monitoring and repair cost of $24,622 and amortization of the capital cost over 8 years at 7% interest.
g. Annual cost for storage facilities includes annual monitoring and repair cost of $39,345 and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.
Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

4.4 Regulatory Options

Monitoring of fugitive emissions was evaluated using OGI and Method 21 in the TSD for the proposed rule. For OGI, monitoring frequencies of annual, semiannual and quarterly were evaluated for well sites and compressor stations. Annual, semiannual and quartering monitoring was also evaluated for Method 21 at three different leak definitions; 500 ppm, 2,500 ppm and 10,000 ppm. Based on the results of these evaluations, semiannual monitoring using OGI was selected as BSER for well sites and compressor stations.

For this analysis, the OGI monitoring options were updated for the final rule using information received since proposal for the proposed rule. The OGI monitoring options include;

- Regulatory Option 1 – The implementation of an annual OGI fugitive emissions monitoring and repair program.
- Regulatory Option 2 - The implementation of a semiannual OGI fugitive emissions monitoring and repair program.
- Regulatory Option 3 - The implementation of a quarterly OGI fugitive emissions monitoring and repair program.

4.4.1 OGI Monitoring Options

As noted above, the EPA calculated a weighted average cost of control for well sites (which includes oil wells, oil wells with associated gas, and natural gas production well sites) and compressor stations (which includes gathering and boosting stations, transmission stations and storage facilities). For ease of review the EPA has summarized the cost of control for the options for well sites and compressor stations in Table 4-15.

Table 4-15. Summary of the Cost of Control for the OGI Monitoring Options[53]

Option	Cost of Control (without gas savings)				Cost of Control (with gas savings)			
	Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)		Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)	
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Well Sites								
1 - Annual	$1,224	$4,464	$612	$2,232	$993	$3,619	$496	$1,810
2 - Semiannual	$1,415	$5,160	$708	$2,580	$1,183	$4,314	$592	$2,157
3 - Quarterly	$1,960	$7,145	$980	$3,572	$1,728	$6,299	$864	$3,150
Compressor Stations								
1 - Annual	$504	$2,225	$252	$1,112	$272	$1,201	$136	$601
2 - Semiannual	$580	$2,562	$290	$1,281	$396	$1,749	$198	$875
3 - Quarterly	$802	$3,540	$401	$1,770	$618	$2,728	$309	$1,364

4.4.2 EPA Method 21 as an Alternative to OGI Monitoring

4.4.2.1 Description

As an alternative to OGI monitoring, the EPA evaluated allowing the use of Method 21 to detect fugitive emissions from the collection of the fugitive emissions components at well sites and compressor stations to determine if the emissions reductions were equal to or greater than the emissions reductions achieved using OGI monitoring. As with OGI monitoring, emissions reductions vary based on the frequency of the monitoring of the components as well as the repair threshold. Based on comments received on the proposed rule, the EPA evaluated repair thresholds of 500 ppm and 10,000 for Method 21fugitive emissions monitoring.

4.4.2.2 Emission Reduction Potential

The EPA based the emission reduction analysis on the method for estimating leak detection and repair (LDAR) control effectiveness from Chapter 5.3.1 of the Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017). Under this method, the control effectiveness is calculated using a stepwise approach that starts from the initial leak frequency and adds monitoring cycles until the leak frequency after monitoring reaches steady state. The difference between the initial leak rate and the final leak rate provides the control effectiveness for the fugitive emissions monitoring program. Other parameters included in the monitoring cycle calculations are the percentage of successfully repair

[53] *Ibid.*