



December 8, 2017

Re: Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements, 82 Fed. Reg. 51,788 (Nov. 8, 2017) (Docket No. EPA-HQ-OAR-2010-0505); and Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Three Month Stay of Certain Requirements, 82 Fed. Reg. 51,794 (Nov. 8, 2017) (Docket No. EPA-HQ-OAR-2017-0346)

Dear Sir or Madam,

GPA Midstream Association ("GPA Midstream") appreciates this opportunity to provide comments on the two Notices of Data Availability ("NODAs") published by the U.S. Environmental Protection Agency ("EPA") pertaining to the proposed three month and two year stay of the 2016 Oil and Gas New Source Performance Standards. 81 Fed. Reg. 35,824 (June 3, 2016) ("2016 Rule" or "Subpart OOOOa Rule" or "OOOa Rule"). 82 Fed. Reg. 51,788 ("Two-Year Stay"); 82 Fed. Reg. 51,794 ("Three-Month Stay").

GPA Midstream has served the U.S. energy industry since 1921. GPA Midstream is composed of nearly 100 corporate members that are engaged in the gathering and processing of natural gas into merchantable pipeline gas, commonly referred to in the industry as "midstream activities." Such processing includes the removal of impurities from the raw gas stream produced at the wellhead as well as the extraction for sale of natural gas liquid products ("NGLs") such as ethane, propane, butane, and natural gasoline or in the manufacture, transportation, or further processing of liquid products from natural gas. GPA Midstream membership accounts for more than 90% of the NGLs produced in the United States from natural gas processing.

Introduction

GPA Midstream supports EPA's request for additional information to support the agency's proposed compliance extension during its reconsideration of the 2016 Rule. GPA Midstream has previously submitted comments, white papers, and a petition for reconsideration discussing why EPA must revise Subpart OOOOa, including issues on which the NODAs specifically seek further comment.¹ GPA Midstream has attached these prior submissions here and incorporates them by reference.

¹ See GPA, Comments on Oil and Gas Sector: Emission Standards for New and Modified Sources, Proposed Rule (Dec. 4, 2015) Docket ID No. EPA-HQ-OAR-2010-0505-6881 ("GPA Dec. 2015 Cmts"); GPA, Submission to

More specifically, GPA Midstream submits that EPA has ample authority to delay the 2016 Rule's compliance dates by more than two years under both Sections 111 and 301 of the Clean Air Act, including by staying or extending the compliance deadlines, as proposed in the Two-Year and Three-Month Stays. However, to the extent that EPA is also considering whether it should extend the compliance deadlines for the 2016 Rule's leak detection and repair ("LDAR") requirements by extending the initial one-year phase-in period under the 2016 Rule, GPA Midstream also supports this alternative approach, which is likewise authorized by the same broad EPA rulemaking authorities under the Clean Air Act.

Further, the various legal and logistical challenges presented by the 2016 Rule's LDAR requirements provide significant support for extending or phasing in the compliance deadlines during EPA's reconsideration of the 2016 Rule. For example, it remains unclear whether equipment located within a well site's physical boundary but maintained by third parties, such as meters for midstream companies' gathering systems or separators, are excluded from the definition. EPA should clarify or amend the definition of a "well site" to clearly specify that it does not include third-party midstream equipment which are part of the gathering system and not the well site. Such a clarification to exclude midstream equipment reduces potential undue burdens and costs on the midstream sector; burdens and costs that do not result in significant environmental benefits, particularly when weighed against the cost and complexities associated with the efforts to comply or through the renegotiation of contractual provisions to provide for potential compliance. Indeed, even were it feasible to address this issue by new agreements, the current rule would require countless, costly negotiations across the tens of thousands of well-sites without demonstrable benefit.

In addition, the proposed extension or further phasing of deadlines is also needed to defer any requirement to repair or replace components during vent blowdowns or unscheduled shutdowns. If the compliance deadlines were not extended, the 2016 Rule would cause technical and logistical difficulties that would require compressor stations to stay off-line for extended periods of time. Off-line compressors would result in natural gas supply disruptions, safety concerns, and increased emissions by delaying fuel delivery to end users and requiring well-sites and midstream operators to vent or flare significant volumes of natural gas until upstream production wells can be shut in.

Administrative Record of Supplemental Comments on Oil and Gas Sector: Emission Standards for New and Modified Sources, Proposed Rule, (Apr. 15, 2016) at 2-3, EPA-HQ-OAR-2010-0505-7552 ("GPA Apr. 2016 Suppl. Cmts"); GPA Midstream, Request for Partial Reconsideration and Stay of EPA's Final Rule entitled Oil and Natural Gas Sector: Emission Standards for New, Modified, and Reconstructed Sources, 81 Fed. Reg. 35,824 (Aug. 2, 2016), Docket ID No. EPA-HQ-OAR-0505-12247 ("GPA Pet. for Recon."); GPA Midstream New Source Performance Standards ("NSPS") Subpart OOOOa Petition for Review Technical Issues (Mar. 1, 2017), Docket ID No. EPA-HQ-OAR-2010-0505-12247 ("GPA White Paper"); GPA Midstream, Comments on Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements, Proposed Rule (Aug. 9, 2017) Docket ID No. EPA-HQ-OAR-2017-0346-0328 ("GPA Aug. 2017 Cmts").

Lastly, GPA Midstream wishes to remind the agency that its prior submissions identified many other problems with the 2016 Rule other than those discussed in the NODAs. We hope that EPA will continue to consider these issues as it proceeds through the reconsideration process.

I. EPA Should Extend the Compliance Dates for the 2016 Rule Requirements

A. EPA has clear legal authority under the Clean Air Act and ample justification to extend the compliance dates for the 2016 Rule

The NODAs requested comments on EPA's legal authority to implement both the Three-Month Stay and Two-Year Stay of the 2016 Rule compliance deadlines. 82 Fed. Reg. 51,791; 82 Fed. Reg. at 51,797. GPA Midstream agrees with the legal justification for the proposed extensions cited in the NODAs and refers EPA to our prior comments on the proposed stays, which expressly discussed and detailed why the Clean Air Act authorizes EPA to extend the compliance LDAR and any other OOOOa deadlines. *See* GPA Aug. 2017 Cmts at 7-9. As EPA issued the OOOOa regulations, after considering notice and comment, the agency is fully authorized by the Clean Air Act to extend, phase-in or otherwise adjust compliance deadlines for its regulations. *See id.* (discussing case law).

Not only does EPA have ample legal authority, but there is ample justification to extend the compliance dates by at least two years given the 2016 Rule's significant legal defects, ambiguities, and practical difficulties. *See id.* at 3-7; *see generally* GPA Pet. for Recon; GPA White Paper. In particular, extending the compliance dates until EPA can substantively revise the rule will avoid the waste of limited resources and unnecessarily exposing industry to potential legal liabilities for requirements under review and subject to revision by EPA. Moreover, as detailed in previous comments and highlighted here, *see* Sections II-IV, *infra*, there are compelling reasons to extend or phase-in compliance.

B. While GPA Midstream prefers that EPA stay all compliance dates, EPA is likewise authorized by the Act to extend the compliance phase-in period

The NODAs also requested comment on "whether a phase-in period" for compliance with the 2016 Rule's various requirements "would be an appropriate alternative to the proposed stay." 82 Fed. Reg. at 51,789; 82 Fed. Reg. at 51,795. GPA Midstream submits that the sheer volume of legally and pragmatically flawed issues that must be reconsidered require a complete stay of the compliance dates during the reconsideration process. *See, e.g.,* GPA Aug. 2017 Cmts at 3-6; GPA White Paper at 1-4; GPA Pet. for Recon. at 2-3. Hence, that remains GPA Midstream's preference.

That said, as EPA has already determined to phase-in the LDAR requirements for Subpar OOOOa, extending the phase in for the compliance dates would be an entirely lawful alternative approach for the agency. For the same reasons that after conducting a notice and comment rulemaking EPA has the inherent authority to stay regulatory deadlines that it has established, the agency unquestionably has the authority to extend the period it originally established to phase-in

compliance with the requirements of the 2016 Rule until after the EPA has addressed these significant compliance issues. *See* 42 U.S.C. § 7601(a)(1) (authorizing Administrator “to prescribe such regulations as are necessary to carry out his functions under this chapter”); *Alabama Power Co. v. Costle*, 636 F.2d 323, 394 n. 170 (D.C. Cir. 1979) (Clean Air Act § 301(a)(1) grants Administrator “general rulemaking authority”); *Natural Resources Defense Council, Inc. v. Reilly*, 976 F.2d 36, 41 (D.C. Cir. 1992) (Section 301 constitutes a “broad grant of rulemaking power” from Congress); *see also* GPA Aug. 2017 Cmts at 8 (no clear statutory command under Clean Air Act governing implementation of OOOOa Rule that would circumscribe or limit EPA’s authority to revise the compliance deadlines under the Act). EPA originally chose to phase-in the LDAR requirements one year after the 2016 Rule was promulgated. If EPA chose to extend the phase-in, GPA Midstream urges EPA to extend the phase-in of the LDAR requirements by a minimum of an additional two years and three months consistent with the proposed stays. Further, GPA Midstream would like EPA to consider backdating the phase-in period to June 3, 2017 in order to include the period of time covered by EPA’s initial stay of the 2016 Rule, 82 Fed. Reg. 25,730 (June 5, 2017), which was subsequently vacated.

Regardless of which approach EPA follows, GPA Midstream encourages EPA to move promptly to propose revisions to the 2016 Rule through the reconsideration process. A revised rule could eliminate ambiguities, inconsistencies, and requirements that are not feasible or practical and would impose significant costs and undue burdens.

II. Applying LDAR Requirements to Midstream Equipment Co-Located at “Well Sites” Imposes Substantial Undue Burdens on the Midstream Sector That Amply Justify the Proposed Compliance Date Extensions

Under the 2016 Rule, EPA defined a “well site,” in relevant part, as “one or more surface sites ... constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well.” 81 Fed. Reg. at 35,936. The NODAs correctly acknowledge that this requirement has resulted in “confusion as to the appropriate scope of components that are included in the definition of the well site for the fugitive emission requirements,” particularly with respect to “ancillary midstream assets (*e.g.*, meters)” that are “owned by legally distinct companies from the well site owner and operator and could have limited emissions.” 82 Fed. Reg. at 51,798; 82 Fed. Reg. at 51,792 (citing GPA Dec. 2015 Cmts); *see also* GPA White Paper at 5-9 (outlining issue). As such, EPA has specifically asked for comment and additional information on several facets of this issue.

A. Legal and logistical issues demonstrate the significant compliance issues and the need for the proposed extensions

For one, EPA has asked for comments on the “legal and logistical issues that could prevent midstream operators, or other operators of ancillary third-party equipment, from compliance with the 2016 Rule, and suggestions for addressing this issue.” 82 Fed. Reg. at 51,792; 82 Fed. Reg. at 51,799.

GPA Midstream explained these very significant legal and logistical issues in its prior submissions, starting with the distinct functions and commercial arrangements of the upstream and midstream industries. *See* GPA Apr. 2016 Suppl. Cmts. at 2-3; GPA White Paper at 8-9; GPA Dec. 2015 Cmts at 8-12. In summary, most wellhead gathering metering systems are located near or on the producer's well pad. GPA Apr. 2016 Suppl. Cmts at 1.; *see also* GPA Dec. 2015 Cmts at 8-12. Even though these meters are often located on a producer's well site, they are owned and operated by the midstream gas gathering company, not the producer. *Id.* A single midstream company could have hundreds of meters on the property of multiple third-party producers. GPA Dec. 2015 Cmts at 8. Moreover, each company cannot access the other's equipment for monitoring, repair, and replacement purposes, thereby potentially requiring two separate LDAR programs at one site. *See* GPA White Paper at 8. Indeed, midstream operators cannot allow producers to access a gas gathering meter due to its crucial commercial purpose in calculating gas accepted by the gathering company and the related revenue accounting. GPA Apr. 2016 Suppl. Cmts at 1.²

However, these co-located equipment face significant, undue compliance burdens and obstacles under the 2016 Rule, if it is not clarified that the definition of a well site does not include midstream equipment located at a well site. If it were so interpreted, midstream equipment physically located at the production site could become subject to OOOOa's LDAR requirements when the third party producer constructs a new well, re-fractures an existing well, or takes any number of other actions that increase emissions at the well site. Midstream operators have no way of confirming and controlling when a well site becomes modified and subject to the leak detection and monitoring requirements for well sites. In 40 CFR §60.5365a(i)(3), the actions which create a modification of a well site include any time a new well is drilled or when an existing well is hydraulically fractured or refractured. Midstream operators have no control over nor advance knowledge of when a well site operator may conduct such operations that may constitute a modification. There are many instances where insignificant equipment owned by a midstream company, such as a meter run, is located at a well site along with equipment owned and operated by the producer. There are legal and logistical issues that can prevent the midstream operator from being able to comply with Subpart OOOOa for that small piece of equipment based on actions made by another operator.

This presents significant practical issues with renegotiating contractual obligations on the thousands of sites that may eventually be impacted by these requirements, particularly as facilities are modified over time. It is not a reasonable expectation that these arrangements can readily provide for these circumstances. If subject to Subpart OOOOa under this scenario, midstream companies would then be required to undertake LDAR monitoring, repair, and replacement of their co-located equipment solely due to the actions of a third party and not by any action of the

² The meter is effectively the midstream operator's cash register. No reasonable company allows its customers to access and monitor its cash register.

midstream company. Further, the midstream company may not even *know* that it became subject to 2016 Rule's LDAR requirements because the upstream gas producer would have no obligation to notify the midstream company that it was constructing a new well, modifying an existing well, or taking any other action to increase emissions. *See* GPA Dec. 2015 Cmts at 10.

EPA can and should easily address this issue by recognizing the distinct midstream function. EPA should clarify or amend the definition of a "well site" to clearly specify that it does not include third-party midstream equipment which are part of the gathering system and not the well site. In addition, GPA Midstream has previously recommended that, in order to avoid subjecting third-party midstream companies to these potential legal liabilities for well site LDAR requirements, EPA should amend Section 60.5365a(i) to read as follows:

Except as provided in § 60.5365a(i)(2), the collection of fugitive emission components **owned, operated, or leased by the producer** at a well site, as defined in § 60.5430a, **to the point of custody transfer**, is an affected facility.

See GPA April 2016 Suppl. Cmts at 3; GPA White Paper at 7. EPA should also amend its definition of fugitive emission components to read as follows:

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, flanges, covers and closed vent systems not subject to § 60.5411a, thief hatches or other openings on a controlled storage vessel not subject to § 60.5395a, compressors, instruments, and meters.

GPA White Paper at 20. These revisions would clarify that only those components owned, operated, leased, or otherwise under the control of the producer, and are prior to the point of custody transfer (*i.e.*, the meter), are subject to LDAR. Further, there is precedent at the state level closest to these issues, as Colorado adopted a similar distinction between upstream and midstream equipment co-located at a single well site, eliminating many of the complications created by the 2016 Rule. *See* GPA Dec. 2015 Cmts at 11-12. Adopting the approach taken by Colorado would avoid the issues unnecessarily imposed by the 2016 Rule.

B. The compliance obstacles and costs created by the 2016 Rule for co-located midstream equipment cannot be solved by contractual arrangement between producers and midstream operators

1. The established physical and commercial arrangements demonstrate why these issues cannot be remedied by renegotiated contracts and that a compliance extension for co-located midstream equipment is essential

EPA has also asked for comments “on the number of contracts that would need to be renegotiated and associated burden” to address midstream equipment co-located at a well site. 82 Fed. Reg. at 51,792; 82 Fed. Reg. at 51,799. We appreciate EPA’s current request for additional information on this issue. However, even before considering the contractual burdens, EPA should also reconsider its earlier presumption that the significant complications caused for midstream companies by the definition of “well site” even could be remedied through new or different contractual provisions with well-site owner/operators. *See* EPA, Response to Public Comments, Ch. 4: Fugitives Monitoring at 221, Docket ID No. EPA-HQ-OAR-2010-0505-7632 (“EPA Resp. to Cmts.”) (asserting that confusion caused by “well site” definition can be remedied through unspecified “cooperative agreements” between producers and midstream companies).

GPA Midstream does not believe that the ambiguities and potential liabilities raised by the 2016 Rule’s “well site” definition, as it is currently written and interpreted by EPA, can be resolved through contractual provisions. A single midstream company could have hundreds of meters on the property of multiple third-party producers. GPA Dec. 2015 Cmts at 8. However, by industry custom and agreement between the parties, the upstream flange of these meters typically serves as the legal point of custody transfer, thus marking the end of upstream production and the beginning of midstream gas gathering operations. *Id.*; *see also* GPA White Paper at 5. The meter also serves as the point of acceptance and movement for all revenue accounting and the basis for calculating production taxes and royalties. GPA Dec. 2015 Cmts at 8. Because the meter must be used to accurately measure and record the transferred volume of gas, the producer and gas gathering company cannot arbitrarily re-define by contract some other point beyond the meter as the point of custody transfer. Nor would it be feasible to separate the meters from the well site by requiring the gas gathering company to physically re-locate each meter outside of the producer’s well site.³ Not only would this needlessly interfere with well-established commercial operations and impose unnecessary costs, it would often require midstream companies to seek to obtain leases, rights of way, or other permissions from another property owner as well as associated environmental or archeological reviews to accommodate the meter – who may not even make their property available for this purpose. *See* GPA Dec. 2015 Cmts at 8 (co-location necessary due to the need

³ No agreement or physical movement of the meter would likely be effective at freeing midstream companies from the rule’s LDAR requirements given the unduly expansive interpretation of “well site” proffered by EPA’s Response to Comments document. The Response to Comments document states that “[o]ur intent is to limit the oil and natural gas production segment up to the point of custody transfer to an oil and natural gas mainline pipeline (including transmission pipeline) or a natural gas processing plant” and that all equipment prior to the transmission pipeline or processing plant becomes “part of the well site.” EPA Resp. to Comments at 194. Where the midstream company that owns the gathering system is different than the midstream company that owns the transmission pipeline or processing plant, it would be impossible for the gas gathering company to select *any* point beyond the “well site” under Response to Comments’ interpretation. This is because, according to the Response to Comments document, the *entire gathering system* is subsumed into the upstream sector and part of the “well site.” This interpretation is premised on a view of the point of custody transfer that would grossly expand the scope of a “well site” to far beyond the well site’s physical boundaries, and is wholly inconsistent with how the upstream and midstream sectors are structured. *See* GPA Pet. for Recon. at 9-10. The Response to Comments document’s interpretation of “well site” should be explicitly rescinded as part of the reconsideration process.

to leave available land for development and the need to reduce surface disturbances at other properties).

GPA Midstream does not see a practicable way to resolve these obstacles through new contract terms. *See* GPA Pet. for Recon. at 10. Nor is GPA Midstream aware of anything in the administrative record that would support the assertion that the parties could work out these issues through revised agreements. EPA’s earlier Response to Comment document in support of the 2016 Rule simply asserted, without support, that it believes this issue “can be managed by the operator through cooperative agreements with other potential owners at the site.” EPA Resp. to Cmts. at 221. This pronouncement, however, failed to either grapple with the necessity of metering produced gas at the well site or discuss what such a “cooperative agreement” would involve.

2. Even if some form of agreement between well-sites and midstream operators would be feasible, the costs to negotiate thousands of agreements across well sites would impose a significant and undue burden on the midstream sector.

As noted, the 2016 Rule defines a well site as a single source for LDAR compliance purposes, which may implicate separately owned and maintained midstream equipment. However, because each company generally cannot access the other’s equipment, there would potentially be two separate LDAR programs at one site. *See* GPA White Paper at 8; GPA Apr. 2016 Suppl. Cmts at 1. Yet, as the 2016 Rule requires one of the companies’ corporate officers to certify the truth, accuracy, and completeness of the other company’s LDAR monitoring, repair, and replacement efforts, subjecting that corporation and its certifying officer to potential civil and criminal liability for the failings of the other company. GPA White Paper at 8; GPA Pet. for Recon. at 10. It is hard to imagine how any type of agreements could be negotiated to overcome these types of issues.

Even assuming for the sake of argument that it might be theoretically possible to negotiate some form of indemnity agreements between producers and midstream companies, this would require the parties to invest countless hours and spend tens of thousands of dollars in legal fees per wellsite with negotiations required for each of the approximately half a million well sites across the country that may potentially be subject to OOOOa requirements.⁴ Given that such indemnity agreements are unprecedented, and neither producers nor midstream companies would likely be comfortable as indemnitee and indemnitor, contract negotiations could be protracted. The midstream industry as a whole would incur tens of millions of dollars in new legal costs that are neither accounted for under the rule’s cost-benefit analysis nor necessary given the simplicity of revising Section 60.5365a(i) as indicated above.⁵ Even then, parties cannot contract away potential

⁴ *See* EIA, Number of Producing Gas Wells (Oct. 31, 2017), *available at*, https://www.eia.gov/dnav/ng/ng_prod_wells_sl_a.htm.

⁵ In addition, upon the sale of one of the companies, each indemnity agreement would have to be reviewed as part of the transactional due diligence, imposing additional costs on the industry. Further, where a party is found liable for

criminal liability. Therefore, even if the 2016 Rule’s problematic definition of “well site” could be adequately remedied through the negotiation of new contracts (which it cannot), such negotiations would impose exorbitant new costs that outweigh any potential benefits under the rule.

As such, given the concerns regarding applying the 2016 Rule to midstream companies identified by GPA Midstream and other commenters, “EPA should stay or otherwise extend the phase-in period as it applies to third-party equipment on well sites until after the EPA has addressed this compliance issue.” 82 Fed. Reg. at 51,792; 82 Fed. Reg. at 51,799. Indeed, GPA Midstream fully supports postponing the 2016 Rule’s compliance dates with respect to third-party equipment on well sites until after EPA reconsiders the 2016 Rule and substantively revises these requirements. As discussed above, and in GPA Midstream’s prior submissions, imposing LDAR obligations on third party midstream companies through an overly expansive definition of “well site” is arbitrary, capricious, and unlawful, and would impose tens of millions of dollars in unnecessary costs. *See* GPA White Paper at 5-9; GPA Pet. for Recon. at 7-10; GPA Dec. 2015 Cmts at 8-12.

3. Under no scenario is optical gas imaging for gas gathering meters owned, operated, and controlled by midstream companies cost effective

Unless EPA amends the current definition of “well site,” any “cooperative agreement” between midstream companies and well site owners or operators would still likely obligate midstream companies to pay the cost of LDAR compliance for midstream components on a “well site,” as currently written and interpreted by EPA. EPA failed to account for the costs of LDAR compliance for midstream assets that may fall within the definition of “well sites.” When these costs are examined, as GPA Midstream previously demonstrated to EPA,⁶ they greatly exceed typical New Source Performance Standard cost-benefit thresholds. The cost of using optical gas imaging (“OGI”) to monitor gas gathering meters under any monitoring scenario – annually, semi-annually, or quarterly – all exceed EPA’s cost threshold of \$5,700.⁷ Avoiding the imposition of these unintended and unacceptable costs and burdens for the midstream industry provides ample justification for extending or phasing-in the compliance dates so that EPA may thoughtfully re-evaluate the 2016 Rule.

III. During Reconsideration, EPA Should Extend the Deadline for or Stay the Requirement to Repair or Replace Components During Unscheduled or Emergency Vent Blowdowns

LDAR violations, attempting to exercise the indemnity agreement could lead to satellite litigation regarding which party is at fault for violations.

⁶ *See* GPA Apr. 2016 Suppl. Cmts at 4-12.

⁷ *Compare id.* at 5-8 (OGI costs of \$7,731 per ton for annual monitoring, \$10,309 per ton for semi-annual monitoring, and \$15,463 per ton for quarterly monitoring) *with* 80 Fed. Reg. 56,593, 56,636 (Sept. 18, 2015) (proposed rule determining that control options at \$5,700 per ton or more are not cost effective).

The NODAs seek comment on whether requiring the repair or replacement of components “during unscheduled or emergency vent blowdowns could result in natural gas supply disruptions, safety concerns, and increased emissions.” 82 Fed. Reg. at 51,793; 82 Fed. Reg. at 51,799. GPA Midstream explained in a white paper jointly submitted to EPA with the Interstate Natural Gas Association of America (“INGAA”) in March 2017 that requiring the repair or replacement of components during these events can prolong natural gas supply disruptions, jeopardize safety, and potentially release more methane emissions than will be avoided through repair or replacement of a leaking component. *See generally*, GPA & INGAA, The Delay of Repair Obligations in 40 C.F.R. § 60.5397a(h)(2) Create Compliance Issues that Need to be Addressed Through Regulatory Revisions (Mar. 2017) (“GPA/INGAA White Paper”). GPA Midstream attaches the GPA/INGAA White Paper here and incorporates it by reference into these comments.

As explained in more detail in the GPA/INGAA White Paper, EPA should limit repair or replacement requirements to unscheduled or emergency compressor station blowdowns or shutdowns. The final 2016 Rule, without prior notice in the proposed rule, added a requirement to repair or replace components during unscheduled or emergency vent blowdowns and shutdowns. 81 Fed. Reg. 35,824, 35,858 (June 3, 2016); 40 C.F.R. § 60.5397a(h)(2).

Left unchanged, this requirement would lead to natural gas supply disruptions. When compressors are taken off-line, as demand may require, they must be blown down for equipment safety purposes. GPA/INGAA White Paper at 2. Under the current rule, however, a compressor cannot come back on-line to move natural gas to meet demand before any leaking components are repaired or replaced. Not only will this prevent the compressor from subsequently meeting immediate demand, but the 2016 Rule would keep the compressor shut down for an extended period of time, further disrupting the supply of gas needed to serve customers. Further, many compressor stations are unmanned and in remote areas. Arrangements for adequate personnel and parts to effectuate repairs requires advanced notice and planning, with some valves requiring several months to procure. *Id.* Emergency or unscheduled shutdowns present similar problems. Compressors are typically controlled and monitored remotely. *Id.* at 3. Any number of reasons can cause an unscheduled or emergency shutdown, including upsets, power loss, flooding, upstream or downstream releases, fires, or instrument malfunctions. *Id.* Although some of these causes can allow for a remote restart, others require the company to dispatch personnel to diagnose the problem, remedy the issue, and get the compressor back on-line as quickly as possible. *Id.* Due to compression demand, the compressor must be restored to operation as soon as possible to limit customer service disruptions. *Id.*

Prohibiting compressors from re-starting after vent blowdowns or emergency shutdowns could also lead to significant methane emissions. Even after the compressor shuts down, gas will continue to enter gathering lines until all production wells routed to the compressor are shut in or diverted to another compressor station. *Id.* Production wells, which also tend to be unmanned and may be in remote locations, cannot be shut down immediately. *Id.* Therefore, gas in the gathering lines must be vented or flared for safety reasons to prevent pressure from building up. *Id.* Under

the 2016 Rule, this venting or flaring must continue until leaking components are repaired or replaced. *Id.* This may mean an extended period of venting or flaring of large volumes of natural gas even when parts are available, given the many potential technical and logistical complications involved in repairing or replacing compressor station equipment. *Id.* at 3-4 (discussing the potential need for hydrotesting, heavy equipment, multiple welders, and the need to fabricate equipment). Therefore, midstream companies require extensive lead time to repair and replace leaking compressor components. Even where leaks are discovered shortly before planned shutdowns, the compressor operator may need significant time to coordinate logistics and fabricate parts. *Id.* at 4.

IV. Other Issues Not Addressed Directly by the NODAs Provide Further Support for EPA's Proposed Stay/Extension of Compliance Deadlines

GPA Midstream appreciates that EPA has seriously considered comments and other submissions discussing the 2016 Rule's deficiencies, and we support EPA's request for additional information on certain of these issues to ensure all stakeholders have an opportunity to be heard on this important rulemaking. In addition to the issues EPA has identified, GPA Midstream has raised over a dozen deficiencies requiring revision that were not specifically mentioned in the NODAs that provide further support for EPA's proposed stay/revisions to the compliance deadlines while EPA reconsiders its approach to the 2016 Rule. These include, but are not limited to, the following:

- The temperature threshold for waiving leak detection monitoring needs to be changed from 0° Fahrenheit to 32° Fahrenheit. This is a safety issue that is necessary to protect workers from exposure at remote locations with high winds, heavy snowfall and snowpack, and little or no access to shelter. EPA did not provide any notice of such a temperature waiver in the proposed rule, depriving GPA Midstream and others from explaining to EPA the extent of the safety risks involved in frequent cold-weather monitoring. *See* GPA Pet. for Recon. at 4-7; GPA White Paper at 21-23.
- The deadline for initial leak detection monitoring at compressor stations needs to be extended from 60 days to 180 days. Sixty days does not allow sufficient time for remote, unmanned compressor stations to be accessed safely in areas subject to extreme cold, snow, and other inclement weather. *See* GPA Dec. 2015 Cmts at 21-22; GPA White Paper at 23-24. These safety issues warrant an extended compliance deadline until EPA can reconsider this deadline.
- The deadline for repairing or replacing leaking components should be enlarged from 30 days to 60 days, given that many compressor stations are unmanned and in remote areas without access to warehouses for parts or maintenance shops. Since many areas are subject to inclement weather, such as severe cold or prolonged snowpack, 30 days for repair is impracticable. *See* GPA Dec. 2015 Cmts at 24-25; GPA White Paper at 25-26.

- The threshold for leak detection should be the same regardless of the instrument used. By defining a “leak” for operators using optical gas imaging at 10,000 parts per million while separately defining a leak at 500 parts per million for those using Method 21, this difference in “leak” thresholds can create significant compliance concerns. For instance, an inspector could find many unreported leaks using Method 21 when the operator has used optical gas imaging. *See* GPA White Paper at 24.
- EPA should clarify that vapor recovery unit compressors are exempt from the definition of compressors for purposes of LDAR monitoring, repair, and replacement programs. These vapor recovery unit compressors act to reduce methane emissions. GPA White Paper at 13. Further, EPA should clarify that vapor recovery units associated with storage vessels and other equipment at compressors are not required to run continuously as these units, by design, only run intermittently. *Id.* at 26-27.
- EPA should remove compressors from the definition of fugitive emission components as they are separately regulated under Subpart OOOOa. *See* 40 C.F.R. § 60.5380a (regulating emissions from centrifugal compressors); *id.* § 60.5385a (regulating emissions from reciprocating compressors). Regulating these same components under both the specific emission reduction provisions at Section 60.5380a and 60.5385a, as well as under the more broadly applicable leak detection requirements for fugitive emission components, will impose unnecessary and costly burdens on the midstream industry without any environmental benefits. *See* GPA Pet. for Recon. at 10-11.
- EPA should exempt compressor fugitive emission components from reconstruction notification requirements under 40 C.F.R. § 60.15. These components are subject to the same notification requirements as other sources listed in 40 C.F.R. § 60.5420(a) and midstream companies that own or operator compressors should be allowed to use the same exemptions as those sources. *See* GPA Pet. for Recon. at 11-12; GPA White Paper at 24-25, 29.
- EPA should not employ a “once in, always in” policy for LDAR monitoring at compressor stations. Once the triggering event that caused the compressor station to be subject to LDAR is removed, then the facility should no longer have to comply with fugitive emission monitoring requirements. This will prevent midstream companies from having to unnecessarily conduct costly fugitive emission monitoring. *See* GPA White Paper at 18-20; GPA Dec. 2015 Cmts at 30-31.
- EPA should revise its definition of “capital expenditure” for purposes of defining a “modification” under Subparts OOOO and OOOOa. This definition makes unsupported assumptions of a high inflation rate, includes a mathematical error, and should not be applied retroactively. *See* GPA White Paper at 13-17.
- EPA should simplify LDAR monitoring plan requirements to reduce the number of overlapping and redundant procedures. *See* GPA White Paper at 11; GPA Dec. 2015 Cmts at 19-21.

- EPA should simplify LDAR recordkeeping requirements by eliminating redundant and overly burdensome requirements. As written, the final rule's documentation requirements go far beyond what is necessary to document compliance. *See* GPA White Paper at 11-13; GPA Dec. 2015 Cmts at 26-28.

GPA Midstream requests that EPA consider these issues during any substantive revisions to the 2016 Rule in addition to those identified in the NODAs. Given the number of issues, many of which are technical in nature, GPA Midstream believes that there is ample reason to extend or lengthen the phase-in period for the 2016 Rule's compliance dates as EPA has proposed, if not longer.

GPA Midstream appreciates the opportunity to submit these comments on the NODAs and is standing by to answer any questions that EPA may have.

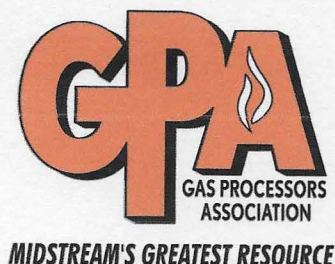
Respectfully submitted,

A handwritten signature in black ink that reads "Matt Hite". The signature is written in a cursive, flowing style.

Matt Hite
Vice President of Government Affairs
GPA Midstream Association

ATTACHMENT

GPA Midstream (f/k/a Gas Processors Association), Submission to Administrative Record of Supplemental Comments on Oil and Gas Sector: Emission Standards for New and Modified Sources, Proposed Rule (Docket EPA-HQ-OAR-2010-0505)



April 15, 2016

Via electronic mail

U.S. Environmental Protection Agency
EPA Docket Center
Mailcode 2822IT
Attention: Docket ID No. EPA-HQ-OAR-2010-0505
12000 Pennsylvania Avenue, NW
Washington, DC 20460

Re: Submission to Administrative Record of Supplemental Comments on Oil and Gas Sector: Emission Standards for New and Modified Sources, Proposed Rule (Docket EPA-HQ-OAR-2010-0505)

Dear Docket Clerk:

The Gas Processors Association ("GPA") appreciates this opportunity to submit supplemental comments on the Environmental Protection Agency's ("EPA's") proposed rulemaking "Oil and Gas Sector: Emission Standards for New and Modified Sources," 80 Fed. Reg. 56,593 (Sept. 18, 2015) ("proposed rule" or "proposal"), and respectfully requests that they be included in the administrative record for this rule. These supplemental comments respond to EPA's requests for additional information following a February 11, 2016, meeting in Research Triangle Park, North Carolina.

GPA initially submitted comments on the proposed rule on December 4, 2015. *See* Docket ID No. EPA-HQ-OAR-2010-0505-6881 ("GPA Comments"). Among other things, GPA's comments requested EPA to clarify (1) that midstream assets would be excluded from the definition of "well site" for purposes of fugitive emission monitoring, GPA Comment at 8-12, and (2) that like-kind replacements of pneumatic pumps at compressor stations should not be considered "modifications" for purposes of triggering new regulatory obligations, GPA Comments at 14.

On February 11, 2016, GPA and several member companies met with EPA in Research Triangle Park, North Carolina, to discuss GPA's comments on the proposed rule and to clarify any questions that EPA had with respect to those comments. During the meeting EPA asked GPA to provide additional information with respect to the exclusion of midstream assets from the definition of well site and the exclusion of like-kind replacement of pneumatic pumps from the definition of modifications for compressor stations. Our responses to EPA's request for additional information are attached to these supplemental comments. *See* Attachment A: Requested Supplemental Information—EPA Must Clarify That Midstream Equipment Nearby a Producer's Well Are Excluded From the Definition of Well Site for Purposes of Fugitive

Emissions Monitoring ; Attachment B: Pneumatic Pumps at Example Compressor Station with Nine Compressor Engines and Two Glycol Dehydrators.

We respectfully request that these Attachments be included in the rulemaking docket for EPA's consideration.

Respectfully Submitted,

A handwritten signature in blue ink, appearing to read "Matthew Hite", with a stylized flourish at the end.

Matthew Hite
Vice President of Government Affairs
Gas Processors Association

Attachment A: Requested Supplemental Information – EPA Must Clarify That Midstream Equipment Nearby a Producer’s Well Are Excluded From the Definition of Well Site for Purposes of Fugitive Emissions Monitoring

From GPA’s February 2016 meeting with EPA in Research Triangle Park, GPA is providing the following information as it relates to necessary clarification of EPA’s proposed well site LDAR Optical Gas Imaging (“OGI”) requirements.

The proposed definition of “fugitive emissions component”¹ when applied to producers’ well sites² has the effect of including certain midstream infrastructure, specifically including gathering system meters, owned and operated by midstream or gathering companies nearby the producers’ wells. Considering the supplemental information herein, EPA’s proposed well site LDAR OGI requirements and responsibilities, should be clarified so they are restricted to the producer’s equipment and the producer’s well site.

Midstream gathering system meters are located nearby or in proximity to producer well pads, but they are not part of the producing operations; the upstream flange (closest to the well pad) of these meters are typically the legal point of custody transfer, demarcating the end of upstream producing/production operations and the beginning of midstream gas gathering operations. Producing and gathering are two fundamentally distinct segments of the natural gas industrial sector, and there are legal elements defining separate responsibilities between the two segments. As such, components like gathering system meters that are owned and operated by midstream gathering companies are separate in all contexts, legally, physically, operationally and commercially, from equipment owned, operated or leased by upstream producers at a producer well site. Furthermore, in a typical configuration a producer is precluded from touching or affecting a midstream gas gathering meter as the meter is the device through which the acceptance and movement of natural gas for gathering and processing, and all revenue accounting related thereto, are measured and assessed. The point of custody transfer of the

¹ Section 60.5430a; 80 Fed. Reg. at 56695.

² Section 60.5397a; 80 Fed. Reg. at 56667.

natural gas is typically at the upstream flange of these meters. As such, a producer cannot implement or effect well site LDAR OGI on midstream gathering company equipment, and thus costs for such well site LDAR activities, if imposed, will not be defrayed across a producer's other well site LDAR activities; such costs would relate specifically to a discrete gathering system meter itself, a minor piece of equipment away from the producer well pad, and would be borne by the midstream gathering entity (not the producer). Note that wellhead gathering system meter equipment does not exist in concentrated areas for the midstream gathering entities, e.g., at a compressor station or at a gas processing plant, where there might be economies of scale for LDAR; they reside on the gas gathering system in a geographically diffuse manner, independently, requiring travel of great distance to attend to one limited piece of equipment.

This distinction between midstream assets and producer assets was expressly acknowledged by the Colorado Air Quality Control Commission in the Statement of Basis and Purpose for that State's February 2014 oil and gas methane/VOC emissions control rulemaking, which states as follows:

“Well production facilities’ are also subject to leak detection and repair requirements and storage tank maintenance requirements. This definition is meant to include all of the emission points, as well as any other equipment and associated piping and components, *owned, operated, or leased by the producer located at the same stationary source (a defined term specific to permitting)*. The “owned, operated, or leased” qualifier in the definition is not meant to reduce the stringency of LDAR requirements in situations where there are multiple owners or operators of the well production facility. (Emphasis added).³

Since NSPS regulations “apply to the owner or operator of any stationary source which contains an affected facility”⁴ and “an owner or operator” is defined in the NSPS General Provisions as “any person who owns, leases, operates, controls, or supervises an affected facility

³ Colorado Regulation No. 7 (5 CCR 1001-9) at 123 (Statement of Basis, Specific Statutory Authority, and Purpose, February 24, 2014).

⁴ 40 C.F.R. § 60.1(a).

or a stationary source of which an affected facility is a part,”⁵ it is appropriate that EPA, like Colorado, recognize that producers are the “owners or operators” of the well site LDAR “affected facility” (*i.e.*, the “fugitive emissions components”), and, conversely, that well site LDAR thus does not include nearby or relatively proximate midstream infrastructure, including midstream gathering system meters (and that, by extension, gathering meters are not part of the producers’ well pad stationary sources).

Well site LDAR is intended to address the producer’s well site fugitive emissions components. To ensure that production equipment at the producer well site is subject to well site LDAR, and to accurately reflect that midstream gathering system meters that are separately owned, operated and controlled by midstream gathering companies are physically, operationally, commercially and legally distinct from upstream producers’ well site assets in the oil and gas industrial sector, EPA’s proposed Section 60.5365a(i)⁶ should be revised as follows:

“Except as provided in § 60.5365a(i)(1) through (i)(2), the collection of fugitive emissions components owned, operated or leased by the producer at a well site, as defined in § 60.5430a, is an affected facility.”

This revision is necessary to clarify that only fugitive emissions components that are owned, operated or leased by a producer are part of the affected facility for producer well site LDAR. It is wholly consistent with, for example, EPA’s historical use of custody transfer concepts to subdivide the oil and gas sector⁷ in NSPS regulations by reference to where certain operations and processes end and others commence, as well as the agency’s historical interpretation of the term “stationary source” to assess NSPS program applicability, *e.g.*, for grain terminal elevators or for municipal landfills.⁸

⁵ *Id.* at § 60.2.

⁶ *See* 80 Fed. Reg. at 56664.

⁷ For NSPS programs, use of custody transfer as a process-based means of segmenting the oil and gas sector into upstream producing operations and downstream processing operations stems from as early as EPA’s March 8, 1974 promulgation of NSPS Subpart K (39 Fed. Reg. 9317), which applies to petroleum liquids storage vessels, and continues through NSPS Subparts Ka, Kb, VV, VVa, KKK and OOOO, as well as 40 C.F.R. Part 63, Subpart HH.

⁸ The agency has issued a number of NSPS determinations over the years finding that where relative proximity may exist, but common ownership and control is lacking, a distinct stationary source is found for purposes

Under No Scenario Is LDAR OGI for Gas Gathering Meters Owned, Operated and Controlled By Gathering Companies Cost Effective.

Using EPA assumptions and EPA-provided information from the rule proposal, as augmented by GPA estimated repair cost information, LDAR OGI on midstream gathering system equipment, specifically gathering system meters, near or in relative proximity to a producer's well site is significantly in excess of EPA's stated cost effectiveness threshold, as explained below.

EPA's economic impact analysis for LDAR OGI at well sites fails to account for components like gas gathering meters in the definition of "fugitive emissions component" that are not owned, operated and controlled by producers (*i.e.*, well site owners and operators). Since gathering system meters are not owned, operated or controlled by producers, OGI monitoring cost and repair assumptions cannot be lumped into a single generic "other" monitoring and costing category and defrayed across the grouping of all components actually owned, operated and controlled by producers. Rather the costs to monitor and repair midstream company gathering system meters must be assessed independent of other producer well site components to accurately assess the cost effectiveness of requiring midstream gathering companies to incur the cost to monitor and repair these discrete, and separately owned, operated and controlled pieces of equipment. The result, as explained below, is that LDAR as applied to midstream gathering system equipment nearby well sites does not meet EPA's stated cost effectiveness threshold for OOOOa.

of assessing NSPS applicability. See *e.g.*, (i) *EPA Applicability Determination Index, Control Number 0800083*,⁸ – April 12, 2007, Letter from George T. Czerniak, Chief, Air Enforcement and Compliance Branch, EPA OECA, to Edward Bakowski, Acting Manager Acting Manager, Permit Section Division of Air Pollution Control Illinois Environmental Protection Agency (concerning NSPS Subpart DD common ownership and control and grain terminal elevator), (ii) *Municipal Solid Waste Landfill New Source Performance Standards (NSPS) and Emission Guidelines (EG) – Questions and Answers*, Revised, USEPA, OAQPS, November 1998 (Section D, Question/Answer 10, common ownership or control informs NSPS applicability); (iii) *Municipal Solid Waste Landfills, Volume 1: Summary of the Requirements for the New Source Performance Standards and Emission Guidelines for Municipal Solid Waste Landfills* (EPA-453R/96-004) FINAL, February 1999 (common ownership or control informs NSPS applicability); and (iv) *EPA Applicability Determination Index, Control Number 9800102* – Memorandum, Request for Clarification (40 CFR 60, Subparts Cc and WWW), from Michele Laur, Environmental Engineer, Waste and Chemical Processes Group, ESD, to Larry Harrell, Air Programs Manager, Browning-Ferris Industries (concerning common ownership and control informing NSPS applicability).

OGI Cost Analysis

A typical gas gathering meter run is discrete, small in size, and is shown in the attached Exhibit. The following cost analysis is conservatively low and effectively overstates the cost effectiveness figures for gathering system meter OGI because, while it does not include the small amount of natural gas that may be saved by completing repairs, it also does not account for gas/production lost by necessity during repairs, the latter of which is estimated to have a significantly higher cost impact since many, if not all, meter repairs will require production from producing well(s) associated with an individual gathering system meter(s) to be shut down during the repair and the meter to be blocked-in and depressurized to effect the repairs. At \$7,731 per tpy for annual, \$10,309 per tpy for semi-annual, and \$15,463 per tpy for quarterly LDAR OGI, imposing such requirements on midstream gathering meters LDAR is not cost effective by EPA's stated standards.

Cost Assumptions			
<ul style="list-style-type: none"> Monitoring and Re-Monitoring costs: \$400/wellsite/monitoring event⁹ Repair costs: \$670/wellsite/monitoring event (below) Administrative cost: 50% of monitoring cost (below) EPA Cost effective threshold = \$5,700¹⁰ Emissions Reductions Assumptions: ¹¹ <ul style="list-style-type: none"> 80% reduction with quarterly monitoring 60% reduction with semi-annual monitoring 40% reduction with annual monitoring 			
Repair & Administrative Costs			
Repair Costs, per site, per monitoring event	\$670		GPA information - assumes monitoring by third party contractor and repairs by gathering company subsequent to monitoring event.
	Technician	\$400	37 components per well site meter location. 2 component repairs per monitoring event. 2 repairs per day per tech. 250 work days per year. \$100,000 per tech per year (pay and benefits). [37*0.054/2/250*100000]
	Tech Vehicle (vehicle, fuel, maintenance)	\$70	\$30,000 per tech per 4 years. \$5,000/year for fuel. \$5,000/year for maintenance. [37*0.054/2/250]*((30000/4)+5000+5000)]

⁹ Section 3.1.2, Report Oil and Natural Gas Sector Leaks, U.S. EPA Office of Air Quality Planning and Standards, April 2014 at 40.

¹⁰ 80 Fed. Reg. 56593, 56636 (September 18, 2015).

¹¹ *Id.* at 56635.

	Repair Parts	\$200	37 components per site. 2 components leak during any given monitoring event (5.4%). \$100 per repair. [37*0.054*100]
Administrative Costs: Recordkeeping, Reporting, Oversight	50% of Monitoring costs		Source: Carbon Limits (CL). 2013. Quantifying cost-effectiveness of systematic Leak Detection and Repair Programs using Infrared cameras. December 24, 2013. ¹²

Emission Factors & Monitoring Frequency

- Monitoring Frequency: EPA has proposed semi-annual with quarterly if > 3% leakers.¹³ EPA found routine quarterly monitoring is not cost effective.
- Meter Run – Component Counts & Emissions Assumptions (typical meter run):¹⁴
 - 7 flanges * 3.90E-04 kg/hr/source = 52.6 lbs/yr
 - 11 valves * 4.50E-03 kg/hr/source = 954.0 lbs/yr
 - 19 connector * 2.00E-04 kg/hr/source = 73.2 lbs/yr
 - Total annual emissions = 0.54 tpy

¹² Docket ID: EPA-HQ-OAR-2015-0216, <http://www.regulations.gov/?s#!documentDetail;D=EPA-HQ-OAR-2015-0216-0013>

¹³ 80 Fed. Reg. at 56668; §60.5397a(g)-(h).

¹⁴ Emission factors from: Total organics from U.S. Environmental Protection Agency, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995 EPA-453/R-95-017, <https://www3.epa.gov/ttnchie1/efdocs/equiplks.pdf>

Cost Effectiveness

Annual monitoring

40% reduction assumption = 0.216 tpy

Monitoring cost = \$400

Repair = \$670

Admin = \$200

Re-monitoring = \$400

$\$1670/0.216 \text{ tpy} = \$7731/\text{tpy}$

Semi-Annual monitoring

60% reduction assumption = 0.324 tpy

Monitoring cost = \$800

Repair = \$1340

Admin = \$400

Re-monitoring = \$800

$\$3340/0.324 \text{ tpy} = \$10309/\text{tpy}$

Quarterly monitoring

80% reduction assumption = 0.432 tpy

Monitoring cost = \$1600

Repair = \$2680

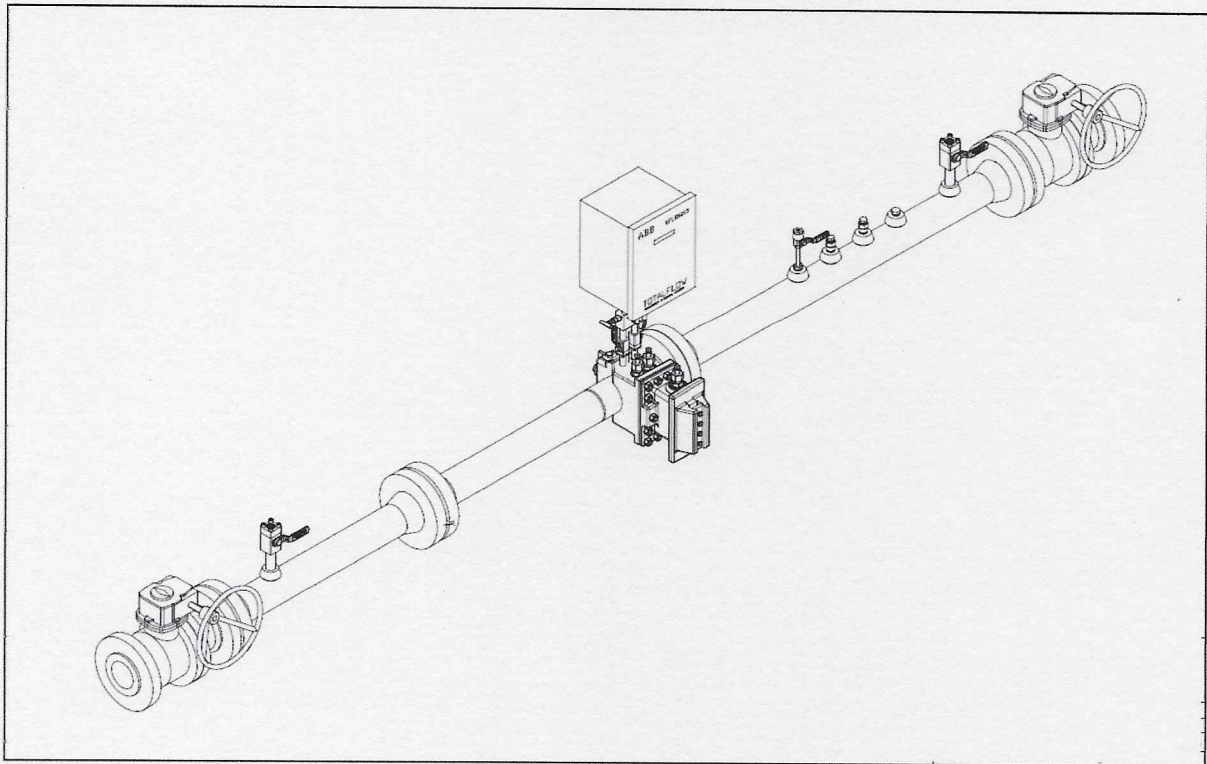
Admin = \$800

Re-monitoring = \$1600

$\$6680/0.432 \text{ tpy} = \$15463/\text{tpy}$

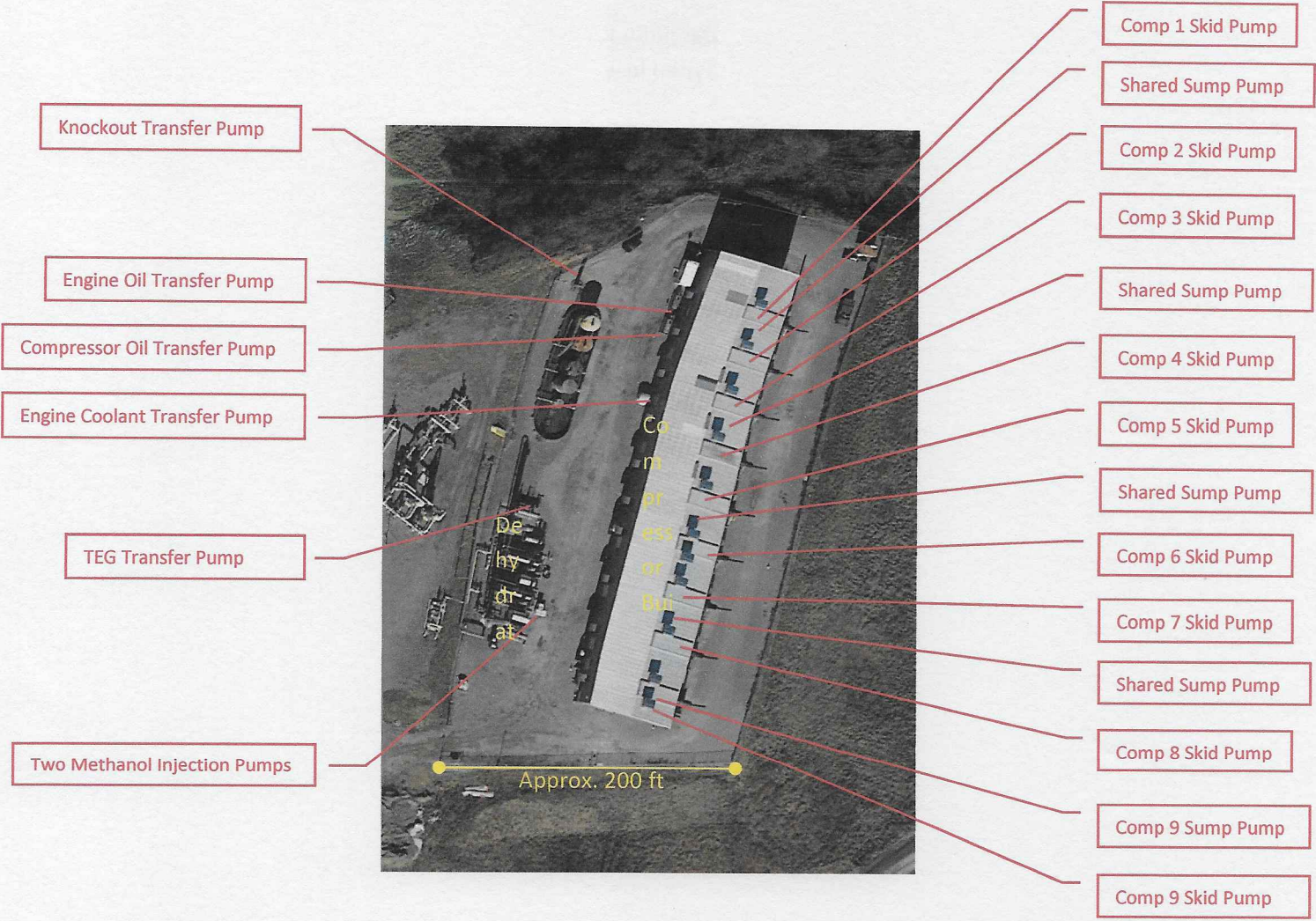
This analysis demonstrates that under no scenario evaluated by EPA is LDAR OGI for gas gathering system meters cost effective. Even if EPA were to choose not to distinguish between midstream assets and producer assets in the definition of “fugitive emissions component” affected facilities at well sites as requested and supported herein, legally binding commercial relationships between producers and gathering companies in the midstream segment of the oil and gas industry preclude producers from touching or tampering with gathering meters. As a result, gathering companies, not producers, will be required to comply with the OGI and repair requirements and to thereby incur costs not considered to be reasonable on a semiannual or any other basis. Gathering system meters should therefore be excluded from NSPS Subpart OOOOa by clarifying regulatory language as set forth above.

Exhibit



Attachment B: Pneumatic Pumps at Example Compressor Station with Nine Compressor Engines and Two Glycol Dehydrators

This site is a real-world compressor station intended to be a representative example for the industry of a large station with pneumatic pumps.



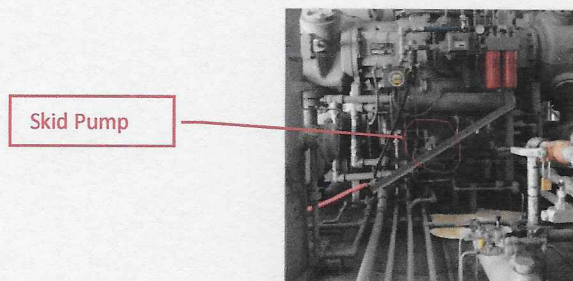
Methanol injection pumps – These pumps are used to inject methanol during the colder months to prevent freezing. Usage varies highly depending on the local climate. At this northern location, methanol injection is used six months per year.

Oil and Coolant Transfer pumps – These pumps are used to transfer engine oil, compressor oil, and coolant from the respective storage tank to a header for use in the engines and compressors. Each pump may run for one hour at a time, but only be used once every 2-4 weeks depending on demand.

TEG Transfer pumps – This pump is used to transfer triethylene glycol into the dehydrators. Usage is similar to the oil transfer pumps.

Sump Pumps and Knockout Transfer Pumps – These pumps are used to transfer slop water into a slop storage tank. They start automatically based on a float system and may run for 10 minutes. Usage varies, but a rough estimate is once every 4-7 days.

Compressor Skid Pumps – These pumps are used to pre-lube the compressor before starting or post-lube after stopping. They start automatically and may run for 3 minutes at a time. Usage is proportional to the number of compressor starts and stops. A rough estimate for this location is 1-5 times per month. As shown in the picture below, these pumps are not easily accessible.



Replacement

Currently, if a pump becomes inoperable, it can be replaced fairly quickly and at a low cost. For example, if a sump pump must be replaced, this can be done in about an hour and an estimated cost would be \$1,000.

Under a NSPS OOOOa replacement scenario, the amount of effort and cost would increase exponentially. As discussed in GPA's comments, an engineering analysis of the pump and control device must be first conducted. Assuming even feasible, the connections and collection system must then be designed. Additional parts to make connections and route pump discharge vapor to the control device must be procured. Then, construction could take place. A shutdown would likely be required due to the excavation and other work inside and around the compressor building, thus causing an operational disruption and lost revenue. Finally, before startup, testing would need to occur. This entire process could take months to complete, and some equipment cannot run without an available pump (e.g., skid pumps).

In addition, emissions from equipment blowdowns for the shutdown are potentially much higher than the pump itself. For example, assume a compressor skid pump must be replaced. Based on the estimated operation noted above, the annual operation is 180 minutes, or 3 hours per year. Multiplying this operation by the emission factor in Table W-1A for pneumatic pumps yields annual emissions of 40 scf/yr. In order for this compressor skid pump to be changed, the associated compressor would need to be shut down and blown down. A *single blow down* of this compressor would emit significantly more gas (greater than 3,500 scf) than the pneumatic pump emits in an *entire year*.