June 16, 2014

U.S. Environmental Protection Agency
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Washington, D.C. 20460
Submitted electronically to: oilandgas.whitepapers@epa.gov

Re: Comments of the Gas Processors Association Regarding the White Papers on Methane and VOC Emissions in the Oil and Gas Sector

The Gas Processors Association ("GPA") respectfully submits the attached comments to the Environmental Protection Agency ("EPA" or the "Agency") on the White Papers on Methane and VOC Emissions in in the Oil and Gas Sector (collectively the "White Papers") published on EPA's website on April 15, 2014.

GPA is a non-profit trade organization made up of approximately 130 corporate members, all of whom are engaged in the processing of natural gas into a merchantable pipeline gas, or in the manufacture, transportation, or further processing of liquid products from natural gas. GPA's membership accounts for approximately 92% of all natural gas liquids produced by the midstream energy sector in the United States. Our members also produce, gather, transmit, and market natural gas and natural gas liquids, and include a number of Canadian and international companies that produce natural gas liquids on a global scale.

GPA's membership is deeply familiar with sources and methods of control of emissions of methane and VOCs in our industry, based on participation of individual member companies in the Natural Gas Star Program, the Greenhouse Gas Reporting Program (GHGRP), and various recent studies of methane emissions throughout the natural gas sector.

We appreciate this opportunity to review and comment on the White Papers.

I. General Comments

Though GPA appreciates EPA's efforts to obtain further technical information about the extent of emissions and means of control, we have some general concerns and recommendations about the White Papers.

First, we urge EPA to more clearly identify the White Papers as "drafts." Further, we strongly recommend that EPA revise, correct, and reissue the White Papers after the Agency has received comments from the technical reviewers and the general public. In their current form, the White Papers contain many errors and omissions. If EPA does not label the White Papers as "drafts" and correct and re-publish the White Papers after receiving comments, we are concerned that the public will perceive the current, flawed versions of the White Papers to be authoritative, expert statements of the government on the topics they cover.

Second, we recommend that, in any further action on the White Papers, EPA take into account the issue of split incentives. Some of the papers cited in the White Papers make a broad assertion that the costs of implementing methane control measures are wholly or partially offset by the value of recovered gas. The White Papers acknowledge that actors in the transmission sector do not own the gas they transmit. However, many gas gathering and processing entities also do not own the gas they gather and process and therefore, like the transmission entities, do not benefit from recovered gas revenue.

Third, we observe that many parts of the White Papers seem to grossly aggregate various segments and processes in the natural gas sector; the White Papers fail to break down information about what is and is not known about various segments of the sector. For example, data and findings about the production segment are not necessarily applicable to gathering and processing. Similarly, control measures that work in the gathering segment might not work in the processing segment. Sometimes "gathering and boosting" is referenced as a distinct industry segment, sometimes it is lumped together with production, sometimes it is lumped together with processing, and sometimes it is completely ignored. In general, NSPS and NESHAP rules also do a poor job of describing this distinct industry segment. This is a distinct industry segment that is separate from production and separate from processing. The White Papers do not sufficiently identify the segments for which cited studies are valid, and the segments for which studies would not apply.

Also, for those entities that *can* obtain the benefit of recovered gas, it is important to assign the correct value to that recovered gas. The value is *not* the Henry Hub price. Rather, one must first subtract royalties, transportation costs, and the distribution to other owners or operators. Accordingly, for the average producer, recovery of gas priced at, for example, $4/bcf at Henry Hub might only yield $2.50 to $3.00 after taking into account these additional costs.

Finally, we observe that the White Papers are inconsistent in their treatment of gathering and boosting. In some instances, the White Papers discuss gathering and boosting in the context of production; in other places, the White Papers discuss gathering and boosting as a sub-segment of processing.

II. Compressors

What follows are GPA's comments on the White Paper on Compressors.

- It is not clear to us why EPA is not reviewing the substantial, "bottom-up" data on compressors that EPA has from Subpart W reports under the GHGRP. Furthermore, going forward, EPA will have even more Subpart W compressor data as it discontinues BAMM. The Compressor White Paper observes that a significant percentage of sources are still submitting data under BAMM, yet the paper fails to acknowledge that BAMM is being discontinued. Even now, EPA has received 1000 measurements of compressor related methane emissions in the processing sector, including 200 from centrifugal compressors. Furthermore, this data comes from multiple regions and various types of operations. This is more data than EPA typically uses to develop emission factors.

- Note that while many oil and gas sites do not have access to power sufficient to run an air compressor, there may be sufficient power available for control *signals*. In other words, some gathering and boosting stations are able to have a Programmable Logic Control (PLC) system, which would provide a signal to an I/P converter.

- It is difficult to assess the data in the White Paper on Compressors because the paper does not sub-categorize the relevant studies. Specifically, it is difficult to discern which studies address rod-packing; which address converting from wet seals to dry seals; and which address fugitives and other sources related to compressors

- EPA should not rely on the GRI report[1], nor on the related emission factors because the data is now 18 years old.

- As discussed above, the White Papers generally make confusing and muddled references to the "gathering and boosting" industry segment. The segment consists of the compressor stations that are located downstream of production facilities and upstream of gas processing plants. Thus, statements like the following do not adequately describe the industry: "Compressors have been identified as an emission source that has the potential to produce emissions to the atmosphere during oil and gas production (gathering and boosting), processing, transmission and storage." This statement should instead read as, "Compressors have been identified as an emission source that has the potential to produce emissions to the atmosphere during oil and

[1] Gas Research Institute (GRI)/U.S. Environmental Protection Agency. 1996. National Risk Management Research Library. *GRI/EPA Research and Development, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks.*

gas production, gathering and boosting, processing, transmission and storage." A place where the gathering and boosting industry segment is inaccurately ignored in the White Paper is in the statement: "However, the primary use of compressors is in the natural gas processing, transmission and storage (particularly underground storage) segments of the industry." This should read: "However, the primary use of compressors is in the gathering and boosting, processing, transmission and storage (particularly underground storage) segments of the industry."

- Additionally, because EPA does not consistently describe the gathering and boosting industry segment, it is extremely unclear how emissions from these compressors are accounted for within the various studies that EPA attempts to summarize.

- The first description of vented emissions (in the first paragraph on page 3) is not articulated correctly and should be changed to: "Vented emissions from centrifugal compressors occur from seals. Vented emissions from reciprocating compressors occur from packing surrounding the mechanical compression components. Vane compressors and screw compressors are not addressed in this white paper."

- In section 2.1, EPA indicates that all reciprocating compressors are driven by internal combustion engines, which is incorrect. Compressors can be driven by electric motors as well.

- In section 4, EPA correctly states that rods on reciprocating compressor deteriorate over time. The life of both the rod and packing will be highly variable and dependent upon site specific conditions, including maintenance. GPA notes that because the rod is generally much harder than the packing rings, the rod life is much longer than the packing rings.

- In section 4.1.2, under "Economic Rod Packing Replacements", EPA states: "Updated rod packing components made from newer materials can also help improve the life and performance of the rod packing system. Another potential option is replacing the bronze metallic rod packing rings with longer lasting carbon-impregnated Teflon rings. Compressor rods can also be coated with chrome or tungsten carbide to reduce wear and extend the life of the piston rod (U.S. EPA, 2006a)." While this statement is accurate, GPA notes that there are extensive materials options for both the rod packing rings and rod coating. In other words, there are many more options than listed in this paragraph, and each compressor is evaluated to determine appropriate materials selection.

- In section 4.1.3, EPA notes that "The Natural Gas STAR Lessons Learned document estimates the cost to replace the packing rings on reciprocating compressors to be $1,620 per cylinder." GPA notes that replacement costs are highly variable and could be significantly more or less expensive (from hundreds of dollars to thousands of dollars). Cost will be determined by the size of the compressor, the technology selected, and the materials selected

- In section 4.2, EPA seems to indicate that if a VRU system is already available at a facility, the incremental cost to route rod packing gas to the VRU is minimal. GPA notes that depending on how the VRU is configured at the facility and its function (*e.g.*, capturing tank emissions), it may not be technically or economically feasible to capture this rod packing gas. We caution EPA against assuming that any existing VRU at a facility can easily and cheaply capture rod packing gases. We also caution EPA against this approach because it may discourage operators from installing VRUs on other emission sources. For example, an operator may choose to combust tank emissions instead of installing a VRU to capture tank emissions because installation of a VRU would then mandate that the operator also capture rod packing emissions. In addition, EPA should not assume that it is straightforward to capture rod packing gas and route to any kind of flare. Due to back pressure issues, any rod packing vents that are routed to a flare require that the flare flow rates and operational parameters be maintained in a constant and predictable manner. To achieve this, a dedicated flare will most likely be required. A flare that is also used for Emergency Shutdown Discharges (ESD) is unlikely to be technically suitable for use in controlling rod packing vents.

  In Section 4.2, EPA indicates a control technique that recovers natural gas leaking past the piston rod packing as a potential emission reduction option for reciprocating compressors. A commercially available option is the REM Technology Slipstream system, which captures the gas that would otherwise be vented and routes it back to the compressor engine to be used as fuel (REM, 2012). The capital cost for a SlipStream system, as it applies to reciprocating compressor packing vents, varies depending on whether the system is a Stand Alone system, an integrated system (integrated into a GE Fanuc, Allen Bradley, or REMVue PLC for example), or if the system is taking vented gases from two compressors. All configurations listed are currently being applied in the field, but most of the installations currently being used are of an integrated system configuration. An estimated $15,000 would make up the portion of a PLC cost where SlipStream is applied and where the technology is being applied to one engine/compressor. Operating cost would consist of a yearly maintenance inspection of the valve train and a quarterly check on oil levels in the knockout pot and demister.

- In section 4.3.1, EPA states: "Wet seals generate vented emissions during degassing of the circulating oil. Gas separated from the seal oil before the oil is recirculated is usually vented to the atmosphere, bringing the total leakage rate for tandem wet seals to 47.7 scfm natural gas per compressor (U.S. EPA/ICR, 2009) (U.S. EPA, 2011a, Annex 3, page A-153)." If this is the single emission rate that EPA is using in its description of an emissions mitigation option, GPA is confused as to why this study was not included in section 3.0 "Emissions Data and Emissions Estimates".

- Section 4.3.2 grossly mischaracterizes the information being presented. EPA uses emissions data from compressors with wet seals and data from *completely different compressors* with dry seals. Then EPA performs an arithmetic exercise to determine the difference between these emissions. However, EPA then presents the data as "the emission reduction from the *replacements* of wet seals with dry seals" and titles Table 4-3 "Estimated Annual Centrifugal Compressor Emission Reductions *from Replacing* Wet Seals with Dry Seals." (Emphasis added). This is grossly inaccurate. EPA does not present any data on any single compressor that underwent a *replacement* of a wet seal system with a dry seal system". At most, EPA can present the emissions from wet seals and dry seal as a *comparison*. To do otherwise would be negligent and misleading.

- EPA makes the same mischaracterizations in the second paragraph of Section 4.3.3 and Table 4.4. Here, EPA is discussing the costs and savings associated with installing/operating a wet seal compressor versus a dry seal compressor. However, EPA repeatedly uses the word "replacement", which is wholly inaccurate. Table 4.4 is erroneously titled, "Costs for *Replacing* Centrifugal Compressor Wet Seals with Dry Seals". An appropriate title is, "Costs for *Installing* a Dry Seal Compressor *Instead of* a Wet Seal Compressor".

- Only the final paragraph in Section 4.3.3 actually addresses *replacement* of wet seals with dry seals. As GPA previously commented (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 Fed. Reg. 52,738 (Aug. 23, 2011)), GPA estimates the cost for materials alone would be approximately $100,000 and total installation cost would be up to $500,000. The cost could be as high as $1,000,000 where a total rebuild of the compressor is required. Indeed, a rebuild of a compressor could be considered a fundamental change to the emission unit, and therefore retrofitting wet seals to dry seals should not be considered an appropriate control option.

- Additionally, it is important to recognize the replacement of a wet seal with a dry seal adds 3-4 weeks to the otherwise 1-2 week process of a rebuild, thereby adding cost (related to downtime) and complexity.

- GPA confirms that the vast majority of new centrifugal compressors are equipped with dry seals.

- In Section 5, EPA again fails to acknowledge that replacing wet seals with dry seals is extremely expensive. The fourth bullet point should read, "Centrifugal compressor emissions may be controlled by using dry seals *instead* of wet seals. Dry seal centrifugal compressors have lower emissions, require less maintenance, and are more energy efficient than wet seal centrifugal compressors and the cost of the two technologies is similar. *Replacing wet seals with dry seals on an existing compressor is very costly*."

Charge Questions

- With regard to Charge Question #1 (national estimates of methane emissions, emission factors, and activity data): When presenting emission factors, it is critically important to articulate (1) the industry segment and (2) what emissions are being characterized. EPA does a very poor job of both. As previously described, it is extremely unclear how and where EPA has accounted for emissions from compressors within the "Gathering and Boosting" industry segment. On the second item, EPA never fully articulates or describes what emissions were analyzed in the various studies presented. Rod packing emissions from reciprocating compressors, wet seal oil degassing venting from centrifugal compressors, and dry seal emissions from dry seal compressors are not the only emissions associated with compressors. Other possible emissions include valve covers (related to having adequate gaskets and the right crush on the cover), the head gasket, variable volume pockets/heads, and realistically, any place where two metals are being drawn together (these are leak points especially as the machine settles and vibrates). EPA fails to articulate which of these other emission sources may have been included in each of the studies. Packing/seal emissions are generally the larger source of emissions from compressors, and other types of compressor emissions should be quantified and characterized; however, it is incorrect to overinflate the packing/seal emissions estimates by including these other emissions in with the packing/seal emissions.

- With regard to Charge Question #2 (different studies and data sources): As discussed above, it is puzzling that EPA has not made use of the extensive Subpart W data it has on compressors.

- With regard to Charge Question #3 (range of technologies to reduce vented emissions from compressors):

  - ***Low Emissions Packing.*** "Low emissions packing" and a similar phrase "low friction packing" are both terms that are used in the marketing of packing systems (in other words, a "buzz word"), but do not necessarily indicate a specific technology or performance level. In the 1990s, with the revised Clean Air Act and new requirements in California, reciprocating compressor packing designs began to advance. One of the first steps was to place O-rings between packing cups. Also, purge packing was introduced as a means of ensuring that sour gas emissions would be adequately captured and collected (at refineries). These innovations primarily involved changing the packing case design, but not the ring design.

    More recently, ring innovations have begun to occur. These innovations include many different types of technologies. One technology being applied to certain compressors is an "uncut" ring, which eliminates the three ring segments and garter springs (which are illustrated in the White Paper in Figure 2-1). The single one-segment system eliminates weeping within the ring. In this configuration, O-rings are still used between packing cups. Another innovation is a wedge ring; this can be used in a variety of configurations to create better sealing along the rod, the sides of the cup, and/or between rings. Yet another technology is low friction packing, which uses springs and pressure plates to side-load standard seal rings. There are likely many other packing technologies that are not mentioned here.

Thus, there are many technologies (and various configurations combining these technologies) that are all designed to minimize rod packing emissions. However, there is no one standard design that is "low emissions packing". The appropriate technology, materials, and design for a compressor packing system will depend on the gas being compressed, operating pressure, operating temperature, other operating conditions (such as demand and speed). A technology that reduces emissions in one compressor may result in higher emissions in another compressor. For example, at 50 psi compressor discharge pressure, a wedge ring design might be appropriate for the entire packing system and result in emissions reductions. However, at 100 psi compressor discharge pressure, a wedge ring used throughout the packing would create a very tight seal, which will cause more heat buildup in the packing, which will translate into faster wear of the packing (rings, rod, and case). Faster wear mean that emissions increase sooner after ring replacement, and could also result in more costly packing replacements (i.e., replacing the rings *and* other components).

Finally, rod packing ring technology application may be restricted by the packing case. Each ring requires a certain packing cup depth. If the cup depth is not adequate for the ring, the only way to use the ring might be to change the packing case. There may be some compressors that are limited on what they can accommodate for packing case size/type/design.

The appropriate packing selection is based on many factors including the size of the compressor, the composition of the gas being compressed, operating pressures, operating temperatures, and other operating conditions (such as demand and speed). There is not a single packing configuration that works effectively on every compressor. All of these factors determine the type of packing configuration, which includes the material selection, the design of the rings, the design of the packing case, the design of the rod, where captured gases should be routed, etc. Additionally, as the compressor runs, the operator may discover what packing configuration aspects work (or don't work) and try new configurations based on operational experience.

In general, low emission packings are more expensive to install and maintain. The systems typically have a lifespan longer than 26,000 hours, and therefore do not fit well within the Subpart OOOO mandated maintenance schedule. Given the increased costs and potentially longer lifespan of such systems, they provide a poor return on investment. The industry would need a managed inspection/maintenance program as an option under Subpart OOOO in order to consider using them in lieu of standard packings.

In summary, while there are advanced technologies on the market for minimizing packing emissions, it is wholly impossible to prescribe a particular technology to any compressor.

- ***Emissions Monitoring.*** Another option to reduce rod packing emissions that EPA does not fully discuss in the White Paper is the flexibility to monitor for emissions associated with rod packing and replace rod packing only when deemed appropriate (for example, when an emissions threshold is exceeded). In NSPS OOOO, EPA requires replacement of rod packing every three calendar years or 26,000 operating hours, whichever comes first. This type of requirement dissuades operators from choosing certain rod packing configurations that may be more expensive, last longer, and leak less. As GPA previously commented (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 Fed. Reg. 52,738 (Aug. 23, 2011)): "A set replacement interval could encourage operators to use split ring configurations for rod packing — which are easier to replace, but also tend to leak at higher rates. Some operators may prefer to replace rod packing on a set schedule without the burden of additional monitoring, but others may prefer a different strategy which has unfortunately been precluded by the NSPS OOOO set schedule replacement requirement. Indeed, to encourage the continued development of packing systems that leak less for a longer period of time, more regulatory flexibility is needed than currently exists in NSPS OOOO."

- ***Preventative Maintenance.*** EPA does not mention preventative maintenance (PM) as a means of reducing reciprocating compressor packing emissions. Typical PM activities include checking that vent lines and lube lines are clear and open. If these lines are not open, the packing system will run hot, which will wear out the parts more quickly resulting in equipment failure. Another PM activity is to check for rod drop (indication of the vertical piston movement inside the cylinder) and rod run-out (plunger or piston rod oscillation), which can both indicate and result in faster wear of compressor parts.

- ***Summary.*** To reduce reciprocating compressor rod packing emissions, operators should be allowed to perform (and take credit for) preventative maintenance, periodically monitor the packing emissions rate if they choose to do so, and change or perform maintenance on the packing components when a threshold is reached (such as emission rate or calendar time or operating hours). Operators must have the full flexibility to determine the appropriate packing configuration. Additionally, if rod packing emissions are captured, operators should not also be required by regulation to replace regularly rod packing.

- With regard to Charge Question #4 (emission reductions achievable from technologies for compressors): In Section 4.1.1, EPA states, "Reciprocating compressor rod packing consists of a series of flexible rings that fit around a shaft to create a seal against leakage." First, GPA notes that rod packing systems are not designed to create a complete “seal against leakage”. Some leakage is necessary, as these systems must be able to “breathe” to a reasonable extent to prevent heat buildup. Otherwise, “hot spots” will be created in the packing system which will accelerate packing degradation.

- With regard to Charge Question #5 (costs for technologies), see previous comments on costs for wet seals versus dry seals.

- With regard to Charge Question #7 (technical limitations making replacement of wet seals with dry seals), wet seals may be required in certain applications. Dry seals are only feasible where an inert gas or a “sweet” gas is available for the dry seal. Sour gases or acid gases cannot be used for a dry seal because of their corrosive nature. So for example, if the facility is compressing acid gas or sour gas, and an inert gas or dry gas is not available, then a wet seal would be required. This is a unique situation that is not common, but it certainly occurs at some facilities. Thus, some new centrifugal compressors will need to have wet seals.

  In addition to this technical limitation, as noted previously, “replacement” of a wet seal with a dry seal on an existing compressor is prohibitively expensive. Unlike reciprocating compressor rod packing, which can readily be replaced with a different packing type/design, centrifugal compressors are designed to have either a wet seal or a dry seal. A wet seal centrifugal compressor would need to be significantly modified in order to change from a wet seal to a dry seal because the housing design is substantially different. The cost of doing so is prohibitive. As GPA previously noted [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 Fed. Reg. 52,738 (Aug. 23, 2011)], GPA estimates the cost for materials alone to retrofit a wet seal compressor to a dry seal compressor would be approximately $100,000 and total installation cost would be up to $500,000. The cost could be as high as $1,000,000 where a total rebuild of the compressor is required. Indeed, a rebuild of a compressor could be considered a fundamental change to the emission unit, and therefore retrofitting wet seals to dry seals should not be considered an appropriate control option for wet seal compressors. In light of these considerations, GPA proposes that retrofitting wet seals to dry seals on existing centrifugal compressors should not be technically feasible option for emissions reduction.

- With regard to Charge Question #8 (technical reasons for use of a wet seal centrifugal compressor without a gas recovery system), GPA is not aware of technical reasons why an operator would use a wet seal centrifugal compressor without a gas *capture* option. Recovery of the gas (i.e., routing to a useful purpose such as a process line or fuel) might not always be feasible depending on system pressures and feasibility of installing and operating a VRU. In instances where recovery is not an option, capture and destruction would likely be possible.

- With regard to Charge Question #9 (technical limitations making installation of gas capture systems at certain reciprocating compressors impractical), it is important to recognize that, where levels of H_2S are present, the SlipStream technology would not be a well-suited system due to the corrosive nature of the sour gas.

- With regard to Charge Question #10 (continued use of wet seal compressors), see previous comments regarding specific applications that require wet seal compressors.

III. Pneumatic Devices White Paper

- The White Paper fails to address the wide range of emission rates observed in various direct measurement studies. There is insufficient data to explain the variations, but it appears that there is some particularly high-emitting equipment (i.e., "fat tails"). EPA should fund additional research.

- EPA should recognize that conversions are limited by the lack of electricity at facilities, and the difficulty of bringing electricity to many of those facilities. Furthermore, it often does not make sense to put in a combustion engine to generate power for an air compressor, and fuel cells are currently not sized appropriately to provide an alternative source of power.

- One of our members reports costs of switching from low bleed pneumatics to intermittent or snap acting pneumatics as being in the range of $17,000 (high bleed) to $50,000 (low bleed).

- In section 1.1.1, EPA states: "Non-natural gas-driven pneumatic controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air." However, this statement is far from clear. In particular, it is unclear whether EPA means "Non-natural gas-driven pneumatic controller" or if the Agency simply means "controller". In the case of the latter, GPA agrees that there are different ways to power controllers.

  However, if EPA means "Non-natural gas-driven pneumatic controller", it is important to clarify what this means. Let us assume that "controller" means an actual valve. The position of this valve is changed with an actuator. The actuator can be electrical, pneumatic, or may be operated by other means. Electric actuators use an electric motor. Pneumatic actuators can use natural gas, air, or some other gas (*i.e.*, an inert gas). The actuator moves the controller. For pneumatic actuation, often a positioner is needed to provide "assistance" to the actuator. "A valve positioner relates the input signal and the valve position, and will provide any output pressure to the actuator to satisfy this relationship, according to the requirements of the valve, and within the limitations of the maximum supply pressure."[2]

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[2] http://www.spiraxsarco.com/resources/steam-engineering-tutorials/control-hardware-el-pn-actuation/control-valve-actuators-and-positioners.asp.

A pneumatic positioner will receive a signal from the control system. This signal can be pneumatic or electrical. If the control signal is electrical, a current-to-pneumatic (I/P) converter is needed to convert the electrical signal to a pneumatic signal. The converter can be located in a separate place at a facility (where safety is an issue), or, if there is not a safety concern, the converter and the positioner can be combined into one unit.

Thus, GPA clarifies that a "pneumatic controller" may refer to any, or all, or a combination of the following instrumentation pieces being pneumatic (1) actuator (2) positioner (3) signal transmission line.

- In section 1.2.1, EPA states, "In general, intermittent controllers serve functionally different purposes than bleed controllers and, therefore, cannot replace bleed controllers in most (but not all) applications. Furthermore, zero bleed controllers are 'closed loop' systems that can be used only in applications with very low pressure and therefore may not be suitable to replace continuous bleed pneumatic controllers in many applications." GPA supports this statement. GPA also adds that, conversely, replacing intermittent bleed devices with continuous bleed devices is also not technically feasible in many situations. This is important to note, as some studies show that intermittent controller overall emissions are higher than continuous low bleed controller overall emissions. While this is possibly due to skewed results due to a handful of bad actors (i.e. "fat tails"), it is important to note that replacing intermittent bleed devices with, for example, continuous low bleed devices, is not necessarily technically feasible due to their functionally different purposes.

  While EPA does not allude to this in the paper, GPA also notes that throttling controllers (whether continuous bleed or intermittent bleed) and on/off controllers (whether continuous bleed or intermittent bleed) serve different purposes and cannot be interchanged.

  Finally, GPA agrees that zero-bleed controller application is limited to locations where a line at near atmospheric or vacuum pressure is available. EPA does not seem to discuss it in the paper, but routing these emissions to some sort of combustion device would be highly challenging in order to address combustion safety concerns.

- *"Pneumatic pumps, commonly referred to as "Kimray" pumps, used for glycol circulation recover energy from the high-pressure rich glycol/gas mixture leaving the absorber and use that energy to pump the low-pressure lean glycol back into the absorber (GRI/EPA, 1996e)."*
  Comment: Kimray is a company that manufactures pumps that are often used for glycol circulation. While this brand is widely used, it is certainly not the only manufacturer/make of pumps.

- In section 2.2.1.2, EPA makes another reference to the GRI/EPA 1996 study: *For many glycol dehydrators in the natural gas industry, small gas-assisted pumps are used to circulate the glycol. These pumps use energy from the high-pressure rich* *glycol/gas mixture leaving the absorber to pump the low-pressure lean glycol back to the absorber. Natural gas is entrained in the rich glycol stream feeding the pump and is discharged from the pump at a lower pressure to the regenerator. If the glycol unit has a flash tank, most of the natural gas in the low-pressure stream can be recovered and used as a fuel or stripping gas. If the natural gas from the pump is used as a stripping gas, or if there is no flash tank, all of the pump exhaust gas will be vented through the regenerator's atmospheric vent stack (GRI/EPA, 1996e).* This description is not right for our industry, which uses mostly gas driven pumps. This paragraph should be revised as follows:

> For many glycol dehydrators in the natural gas industry, small gas-assisted pumps are used to circulate the glycol. There are two scenarios of operation – a natural gas driven pump or a rich glycol driven pump. If natural gas drives the pump, the natural gas is typically vented at the pump. If rich glycol drives the pump, the high-pressure rich glycol leaving the absorber is supplemented with a small amount of high pressure gas. The rich glycol/gas stream feeding the pump is discharged from the pump at a lower pressure to the regenerator. In either case, the pump moves the low-pressure lean glycol back to the absorber. If the glycol unit has a flash tank, most of the natural gas in flash stream can be recovered and routed back to the facility process, used as a fuel, or used as stripping gas. However, this flash stream is unrelated to the pump. If the natural gas from the pump is used as a stripping gas, the pump exhaust gas will be vented through the regenerator's atmospheric vent stack. The vent stack emissions can be controlled with a condenser and/or a combustor.

- Regarding "Maintenance of Natural Gas-Driven Pneumatic Controllers" as discussed in Section 3.1.5, GPA concurs that proper methods of maintaining a device are highly variable. We also note that some controllers will need maintenance more frequently than others; typically controllers in areas of high vibration will need to be maintained more frequently.

- In Section 3.2.1. and throughout section 3, EPA assumes that a facility has an existing instrument air system. That is often not the case, and the cost described in this section and in Table 3-5 should reflect the cost of installing an instrument air system, just as EPA did in Table 3-1 and Section 3.1.3. Alternatively, EPA should more clearly indicate that this mitigation strategy is not feasible for a facility without an existing instrument air system.

- With regard to Charge Question #8, (limitations of electric-powered pneumatic controllers and pneumatic pumps): In some areas of a facility that experience high vibration (such as on compressor skids, which would have scrubber dump valves), electronic instruments may be too fragile to handle the vibrations.

  "One advantage of a pneumatic control is that it is intrinsically safe, i.e. there is no risk of explosion in a dangerous atmosphere, and it can provide a large amount of force to close a valve against high differential pressure… Another limitation of an electric actuator is the speed of valve movement, which can be as low as 4 seconds / mm, which in rapidly varying systems may be too slow."[3]

IV. Leaks and LDAR

- The Introduction states: "Potential sources of leak emissions from these sites include agitator seals, *compressors seals*, connectors, pump diaphragms, flanges, hatches, instruments, meters, open-ended lines, pressure relief devices, pump seals, valves, and *improperly controlled liquids storage*." (Emphasis added). There are a number of flaws in this statement. First, compressor seals are the subject of a separate White Paper, so it is unclear why they are also included here. Also, EPA goes on to say, "For the purposes of this paper, emissions from equipment intended to vent as part of normal operations, such as gas driven pneumatic controllers, are not considered leaks." Compressor seals are intended to vent during normal operation, so again, compressor seals should not be the subject of this White Paper. Second, improperly controlled liquids storage is just that: improperly controlled liquids storage. To consider these types of emissions as "leaks" is a fundamental change from over 30 years of federal leak detection programs. Improperly sized control equipment, stuck separator dump valves, and open thief hatches are fundamentally different than leaking "connection points" and should be treated separately. Addressing these types of emissions involves entirely different approaches than what would be used to address emissions from connection points. Mitigating emissions from connection points typically involves some type of leak detection methodology and equipment repair. Mitigating emission from improperly sized control equipment, stuck separator dump valves, and open thief hatches typically involves operational monitoring, engineering solutions, and operational practices/procedures.

  GPA acknowledges that many available studies lump together these different emissions sources and calls them all "leaks" or "fugitives". However, EPA has not historically treated these as one emission source type; doing so does not make sense for the reasons stated above; and lumping these emission sources together due to lack of granularity in some of the available studies is not sound science or policy.

- The methodology for estimating emissions based on combining emission factors and number of components is flawed. The actual component counts used are inaccurate. It is not appropriate to rely on subpart W data for this purpose. Furthermore, estimating the number of components would constitute an enormous administrative burden, and yet yield relatively little good information. In addition, the use of average component counts is not helpful because the number of components differs significantly based on a variety of factors, including the geography of the site, the company operating the site, the type of facility, and the type of gas (wet vs. dry).

- With regard to the study referenced in Section 2.8, "Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras (CL,

[3] http://www.spiraxsarco.com/resources/steam-engineering-tutorials/control-hardware-el-pn-actuation/control-valve-actuators-and-positioners.asp

2013)": GPA fails to understand the premise of this study for compressor stations. The study has one category called "Compressor station", which is described as follows: "This category includes mainly gathering and boosting compressors (upstream of processing plants) and compressor stations in the transmission and storage sector. Compressor stations in this category in general range from one to three compressors and from 200 to 1,000 horsepower each. The majority of these compressor stations are more than five years old." First, gathering and boosting compressor stations are markedly different than compressor stations in the transmission and storage segment. Because gathering and boosting compressor stations are located upstream of gas plants, the gas at these facilities may be higher in VOC content and lower in methane content than transmission and storage sector compressor stations, which are located downstream of gas plants. Thus, lumping these types of facilities together when determining cost per ton of VOC and/methane is not valid. Additionally, gathering and boosting compressor stations typically operate at lower discharge pressure than transmission compressor stations, which also can impact leak rates. Combining these two industry segments together does not make sense, at least for purposes of making cost-per-ton determinations.

Second, the horsepower claim is so out of line with reality that the integrity of this report is immediately called into question. According to the EIA[4], "Compressor units that are used on a natural gas mainline transmission system are usually rated at 1,000 horsepower or more and are of the centrifugal (turbine) or reciprocating (piston) type. The larger compressor stations may have as many as 10-16 units with an overall horsepower rating of from 50,000 to 80,000 HP and a throughput capacity exceeding three billion cubic feet of natural gas per day." One GPA member company operates over 650 gathering and boosting stations, and the average facility total horsepower at those compressor stations is 2,500 HP. A second GPA member, which has over 60 gathering compressor stations, has an average station horsepower of 8,000 HP. Thus, this study's claim that each "compressor station" (lumping together gathering and boosting compressor stations and transmission and storage compressor stations) has 200-1,000 horsepower each is so flawed that it calls into question the technical merits of this study.

- Under Section 3.1, EPA describes a limited set of methods for leak detection. Many methods are missing or not well articulated.

  The first missing method is audio-visual-olfactory (AVO) inspections. This is a common technique used for leak detection that is included in federal leak detection and repair rules[5]. It is also the *one* technique that is currently used ubiquitously by operators across the oil and gas industry. It is unclear why this method is wholly ignored in this section.

  EPA fails to discuss other types of leak detection methods that use either infrared or laser technology. One example is the Remote Methane Leak Detector, which uses a

[4] http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/process.html
[5] Examples at 40 CFR 60.842-8a(a), 60.482-10a(f)(1)(i), 61.242-2(d)(4), 61.242-8(a), 61.242-11(f)(1)(ii)

laser beam to survey up to 100 feet of pipeline at once. There are also technologies that use an infrared optical gas detection system, which utilizes a light beam to detect methane. This type of technology can be used in a mobile mounted unit (designed for the mobile inspection of buried natural gas distribution, transmission and gathering pipelines) or in a handheld unit.[6] GPA is unsure about the availability and cost of these technologies. However, EPA should not stifle innovation of leak detection technologies by requiring certain technologies to be used.

- Section 3.1.1 discusses portable analyzers. Portable analyzers are widely used in the Gas Processing industry segment to comply with federal rules NSPS KKK, NSPS OOOO, and NESHAP HH. GPA is confused why Section 3.1.1 does not have a subsection regarding use of portable analyzers (such as the subsection presented in 3.1.2 "Current OGI Usage in the Oil and Gas Industry"), as this is a prevalent monitoring technique.

- GPA is unsure about the statement: "Screening with TVAs and OVAs can be a slow process, requiring approximately one hour for every 40 components, and the instruments require frequent calibration." First, it is unclear what "slow" is in relation to. GPA acknowledges that it takes time to physically survey each component in a facility; however, one member company uses a TVA-1000 (which can monitor methane) on FID mode to perform surveys, and the response time is less than 3.5 seconds for 90% of final value, using 10,000 ppm of methane as the calibration gas, with a recovery time of less than 5 seconds.[7] The number of components per hour will be highly variable depending on the location of the components, the size of the components, whether the component identification tags are in good order, and how many leaks a technician is finding. Finally, these types of instruments are calibrated each day before use, and a drift test is also completed at the end of the day of monitoring. A calibration precision test is also completed each quarter. We note that these calibrations are all required by EPA Reference Method 21. We also note that the EPA's alternative work practice (i.e., optical gas imaging camera method) in 40 CFR 60.18 also requires a daily instrument check.

- Regarding costs for portable analyzers, EPA fails to mention costs associated for recordkeeping and database management. Given the large number of components at a facility, this is a significant and necessary expenditure. Also excluded are costs for equipment maintenance and calibration, training, calibration gas, and travel.

- Section 3.1.2 discusses "Optical Gas Imaging (IR Camera)." Regarding algorithms that translate IR Camera images into leak rates, GPA has heard of this possibility, but we are not aware of any such algorithms that have been thoroughly tested, substantiated, and/or are being utilized in practice.

- GPA takes issue with the statement, "However, in addition to algorithms, operators can use quantification equipment such as a Hi-Flow™ Sampler." First, there are not

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[6] http://www.heathus.com/_hc/index.cfm/products/gas
[7] http://www.enviroequipment.com/rentals/PDF/Foxboro-Thermo%20TVA%201000%20Manual.pdf

algorithms currently available. Second, while operators *can* use devices to quantify emissions, doing so should always remain an option. If the intent of detecting leaks is to repair them, having leak quantification data is not always necessary to achieve the objective of cost-effectively reducing emissions. In fact, an additional quantification step typically adds cost and resource burden.

- EPA states that, "Lastly, the effectiveness of an OGI instrument is dependent on the training and expertise of the operator. Well-trained and experienced operators are able to detect leaks with the OGI system that lesser experienced operators do not detect." This statement is true, but it is also true for all other leak detection technologies. This includes AVO, portable analyzers, other laser and infrared technologies, the Hi-Flow Sampler, acoustic devices, mobile laboratories, and any other method or technology used to detect leaks.

- EPA states that, "The State of Colorado recently proposed regulations that would require leak inspections at all well sites, compressor stations upstream of the processing plant and storage vessels." As noted earlier, GPA does not concur that engineering and operational issues related to storage tanks (such as an undersized combustor, stuck dump valves, and open thief hatches) should be considered leaks. It is true that Colorado requires the use of the IR Camera or Method 21 to periodically ensure that tank emissions are being properly captured and controlled (i.e., not *<u>venting</u>*). However, these requirements are located within the *tanks control* section of the rule; they are distinct and separate from the *<u>leak</u>* inspections section of the rule (which addresses component leaks at well production facilities and gathering and boosting compressor stations). The rule refers to tank emissions as "venting" emissions, and it refers to component connection point emissions as "leaking" emissions.

- In Section 3.1.3 EPA discusses the through-valve acoustic leak detection device. GPA supports the conclusions of the URS/UT study that, "there was no statistically significant correlation between the VPAC and the direct flow measurements, and the study authors determined that the VPAC method was not considered to be an accurate alternative to direct measurement for the sources tested." GPA and other industry groups have been trying to make this clear to the EPA in the context of Subpart W reporting for years. One reason BAMM has been used under Subpart W for compressor measurements is that some emissions points are not accessible and cannot be measured with a meter, high volume sampler, or bagging. Rather than accepting this fact, EPA instead allowed the use of this acoustic device to measure those inaccessible emissions, even though the device has been shown to not work. While some operators use the device for lack of another option, other operators have chosen to use BAMM rather than collect bad data.

- In Section 3.1.4, EPA discusses Ambient/Mobile Monitoring. EPA claims that "A growing number of research and industry groups are using mobile measurement approaches to investigate a variety of source emissions and air quality topics." While individual companies may be exploring this technology as a joint effort with research or environmental groups, GPA is not aware of "industry groups" that are using these approaches.

- GPA takes issue with the statement: "It is believed that future forms of mobile leak detection techniques for the oil and gas sector may include lower cost, work truck-mounted systems that provide fully autonomous detection capability for anomalous emissions in support of such an onsite OGI inspection." As EPA states in the introduction, "This paper presents the Agency's understanding of emissions and *available* emissions mitigation techniques from a potentially significant source of emissions in the oil and natural gas sector." (Emphasis added). It serves no purpose for EPA to make a grossly speculative statement about non-existent technologies and EPA's "belief" of the future availability of non-existent technologies.

- GPA concurs with the statement in the Section 4 that "the majority of methane and VOC emissions from leaks come from a minority of components." One GPA member company analyzed data from recent NSPS KKK leak detection surveys at three of its gas plants. They found that less than 2% of surveyed components were leaking above 10,000 ppm, yet these leaking components contributed to about 75% of the component fugitive emissions (using the "Correlation Approach" from EPA's "Protocol for Equipment Leak Emission Estimates" document (Nov 1995)).

- Additionally, repairing components leaking between 2,000 ppm and 10,000 ppm would only yield a 5% reduction in emissions but increase the number of components needing repair by about 60%. To summarize, there are diminishing returns for repairing low-leak rate components.

- The White Paper fails to capture the full extent of costs associated with LDAR, particularly in remote areas. What follows is a categorization of typical LDAR costs:

Program set up cost

- Subcost: Tagging, component identification
- Subcost: Software, database, recordkeeping set up
- Subcost: Program training
- Subcost: Travel for above tasks
- Subcost: Hiring personnel either in-house or establishing contract with third party

Initial inspection cost

- Subcost: Third party inspections (assume contract includes equipment, travel, training, etc.)

OR for In-House:

- Subcost: Monitoring equipment purchase
- Subcost: Monitoring equipment rental
- Subcost: Monitoring equipment maintenance
- Subcost: Inspection training
- Subcost: Vehicle purchase, maintenance, gas
- Subcost: Personnel (inspectors, supervision)

- Subcost: Travel for above tasks

Initial inspection repair costs (parts, personnel, travel, vehicles, supervision)

<u>If first attempt did not work…</u>

- Subsequent inspection repair cost (parts, personnel, travel, vehicles, supervision), Remonitoring cost
- Subcost: Third party remonitoring (assume contract includes equipment, travel, training, etc.)

OR for In-House:

- Subcost: Remonitoring equipment purchase
- Subcost: Remonitoring equipment rental
- Subcost: Remonitoring equipment maintenance
- Subcost: Remonitoring training
- Subcost: Vehicle purchase, maintenance, gas
- Subcost: Personnel (inspectors, supervision)
- Subcost: Travel for above tasks

<u>Total Recordkeeping and reporting cost</u>

- Subcost: Third party (assume contract includes database maintenance, etc.)

OR for In-House:

- Subcost: Recordkeeping personnel for inspection (including supervision)
- Subcost: Recordkeeping personnel for remonitoring (including supervision)
- Subcost: Software/database/recordkeeping maintenance

Some third party vendors handle reporting, but this is typically done in-house regardless if third party is used for monitoring:

- Subcost: Reporting personnel (including supervision)

➢ With regard to Charge Question #1: EPA used emission factor estimates from studies conducted in 1995 and 1996 for valves, pump seals, compressor seals, pressure relief valves, connectors, open-ended lines, and sampling connections. Since these studies were conducted 20 years ago, equipment and operation practices have improved, resulting in lower average emission rates per component or grouping of components. These emission factors are outdated.

➢ With regard to Charge Question #2: Once again, we note the use of outdated emission factors.

➢ With regard to Charge Question #3: The answer is No. The distortions associated with use of outdated emission factors do not apply equivalently among the wide varieties of equipment and configurations present in the production, gathering and boosting, processing, transmission and storage sectors.

➢ With regard to Charge Question #4: It does not appear that the following study was taken into account: Anderle, Gary, and Michael Webb. Shaw Environmental and

Infrastructure, Star Environmental, LLC. www.EPA.gov (2014). "New Field Study Improves GHG Emission Factors for Petroleum Industry" available at http://www.epa.gov/ttnchie1/conference/ei19/session10/webb.pdf.

- With regard to Charge Question #5: The answer is Yes. Equipment counts and configuration vary greatly depending on the site. Volume, pressure, and temperature of gas streams determine the size and configuration of the equipment necessary to process the gas. This equipment is operated based on the factors previously mentioned to maximize efficiency while minimizing emissions due to local and federal regulations. Local climate has a large impact on the equipment used and the products needed to move/process the gas. The local geology determines the gas composition produced from a well site. Two sites that lie within close surface proximity but drawing from differing formations/depths will produce gas that varies greatly in composition.

- With regard to Charge Question #6: GPA is confused why Section 3.1.1 does not have a subsection regarding use of portable analyzers (such as the subsection presented in 3.1.2 "Current OGI Usage in the Oil and Gas Industry"), as this is a prevalent monitoring technique.

- With regard to Charge Question #7: OGI – FLIR GF320 cameras cost approximately \$100,000 each. They require expensive training for operators to use. The camera has flaws, including cool-down time and short battery life. The battery configuration also is not inherently safe due to the connection required to change a battery. This conflicts with EPA's definition of an "intrinsically safe device" under EPA's Method 21. The camera will not accept any card larger than 8G, which means that operators must carry around several cards to record video data of an entire facility. Storing HD video data will create major data storage issues for even the largest companies and/or for EPA archiving purposes. This technology cannot detect CO or CO_2, nor can it currently quantify leaks.

  Ambient/Mobile Monitoring – There is not nearly enough data available from the testing of these devices to make them cost-effective or feasible for immediate use. In order for this equipment to be moderately effective (at best), the vehicle or equipment would have to be positioned downwind of the site – this is often times impossible to accomplish due to extreme terrain. High winds are often present at oil and gas sites due to their geographical location, making small scale dispersion modeling difficult. Sites are often located in close proximity to each other, regardless of the operator. Sites located upwind from the site being tested would inevitably influence the readings taken by the device, measuring a comingled "leak".

  An assumption of \$20,000-\$100,000 per device means that it is not an economically viable option for outfitting vehicles with this equipment. \$20,000 seems unrealistically low for a technology that is not yet past its testing stages. Several vehicles would be needed to conduct this type of monitoring. In addition, unless the device is easily remounted, vehicles and trained operators would have to be designated for this purpose alone. This technology cannot currently quantify leaks.

AVO – This technique has been proven effective. Inspectors and operators consistently detect leaks using this method on a daily basis. It is more cost effective, requires less specialized training, no equipment, and can be conducted by individuals that are already onsite for daily duties.

- With regard to Charge Question #8: AVO is most commonly used by the most operators. Depending on the type of facility being monitored, different equipment may be necessary for leak detection. A single dehy would require less specialized equipment to pinpoint a leak than the equipment required to detect a leak from a compressor station (engine).

- With regard to Charge Question #10: There is not enough data available to determine the effectiveness or feasibility of ambient/mobile monitoring at this time. See our response to Charge Question #7 for explanation.

- With regard to Charge Question #11: Cost is dependent on the type and location of the leak. This can vary greatly depending on its severity. Further, the benefits from recovered product do not necessarily accrue to the operator, as they may not own the gas.

- With regard to Charge Question #12: It is not important to quantify emissions when implementing a program to detect and repair leaks.

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GPA appreciates this opportunity to comment on the White Paper process. If you have questions or need additional information, please contact Jeff Applekamp, Vice President of Government Affairs, at japplekamp@GPAglobal.org or (918) 493-3872