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U.S. EPA
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Docket ID No.: EPA–HQ–OAR–2025–1348

Re: National Emission Standards for Hazardous Air Pollutants: Crude Oil and Natural Gas Production Facilities and Natural Gas Transmission and Storage Facilities; Technology Review and Reconsideration (91 FR 21672, April 22, 2026)

Dear Mr. Witosky:

GPA Midstream Association ("GPA Midstream") appreciates the opportunity to comment on U.S. Environmental Protection Agency's ("EPA") proposed National Emission Standards for Hazardous Air Pollutants: Crude Oil and Natural Gas Production Facilities and Natural Gas Transmission and Storage Facilities; Technology Review and Reconsideration, 91 Fed. Reg. 21672 (April 22, 2026) (the "Proposed Rule"). GPA Midstream filed petition for reconsideration on May 2, 2024, and GPA Midstream member companies submitted data to EPA in response to EPA's Information Collection Requests (2023 ICR and 2024 Phase II ICR).

GPA Midstream has served the U.S. energy industry since 1921 and represents approximately 45 domestic corporate members that directly employ 57,000 employees engaged in the gathering, transporting, processing, treating, storage, and marketing of natural gas, natural gas liquids, crude oil and refined products, commonly referred to as "midstream activities." The work of our members indirectly creates or impacts an additional 470,000 jobs across the U.S. economy. In 2024, GPA Midstream members had an economic impact of $191 billion through operating 502,900 miles of gas gathering pipelines, gathering more than 91 billion cubic feet per day of natural gas, and operating more than 342 natural gas processing facilities that delivered pipeline quality gas into markets across a majority of the U.S. interstate and intrastate pipeline systems.

EPA solicited comment on numerous issues. Because question numbers in the preamble did not always match the numbers in Table 3, in this letter, we use the EPA question numbers from Table 3.

GPA Midstream endeavored to provide thorough and detailed comments to assist EPA to develop a final rule that is technically sound, reasonable, and practicable. This rulemaking significantly impacts GPA Midstream members, and we were grateful for the comment deadline extension granted. We appreciate your consideration of these comments as you develop the final rule.

Sincerely,

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1. GPA Midstream supports comments submitted by API and A2C.

GPA Midstream supports EPA's proposal to retain the existing standards under National Emission Standards for Hazardous Air Pollutants ("NESHAP") Subparts HH and HHH without revision, and EPA's determination that BTEX (benzene, toluene, ethylbenzene and xylenes) is an appropriate surrogate for all hazardous air pollutants ("HAPs") except methanol. The detailed comments provided by API in response to these issues provide additional references and justification, which GPA Midstream supports. Thus, GPA Midstream supports API's comments on the specific issues referenced in this letter.

The Proposed Rule also raises whether Clean Air Act ("CAA") § 112(d)(6) requires EPA to set emission standards for currently unregulated sources in the given source category when conducting a section 112 periodic technology review. The Air Advocacy Coalition ("A2C") has provided robust input on this matter, and GPA Midstream agrees with A2C that CAA § 112(d)6) does not impose such an obligation on EPA.

2. Small Dehydrators at Maximum Achievable Control Technology ("MACT") Major Sources.

GPA Midstream appreciates that EPA's effort to address the longstanding defect in BTEX emission limit equations for small dehydrators: for units with low throughput or low inlet BTEX concentration, the equation can yield impossibly low BTEX limits approaching zero. However, as described below, there appear to be deficiencies in EPA's proposed solution. As such, GPA Midstream requests that small dehydrators at major sources be allowed to comply with the large dehydrator requirements as an optional compliance pathway. These requirements are achievable and better aligned with the data in the record.

2a. RDLs developed for (and based on data from) Lime Manufacturing Plants should not be applied to the oil and gas source category (EPA Question 12a).

GPA Midstream urges EPA to not import the Lime Manufacturing Plants Representative Detection Limit ("RDL") analysis into the oil and gas source category. A detection limit derived from a different category and dataset does not reflect measurement performance for oil and gas dehydrator inlet streams.

EPA is proposing an alternative equation may be used by small glycol dehydrators whose BTEX inlet concentration is three times the BTEX RDL in the inlet stream to the dehydrator or lower. EPA proposes a BTEX RDL of 0.116 ppm based on RDL analysis conducted for the Lime

Manufacturing Plants NESHAP rulemaking.[1] EPA also indicates they believe the RDLs for BTEX may be higher than 0.116 ppmv in the oil and natural gas source category and are specifically requesting data specific to the relative detection limits of BTEX in inlet streams of glycol dehydrators (EPA Question 12a).

However, RDLs developed for and based on data from Lime Manufacturing Plants should not be applied to the oil and natural gas source category. It is our understanding that an RDL reflects the measured performance for a specific source category and test dataset, not a generic detection threshold. EPA should develop any oil and natural gas RDL from a carefully designed sampling campaign to ensure the required information is gathered and representative of affected sources. GPA Midstream is willing to work with EPA to collect the necessary data for EPA to conduct a proper analysis of RDL for BTEX in the oil and natural gas industry sector.

Standard test methods further call into question EPA's approach. GPA Midstream Standard 2286-24 "Method for the Extended Analysis of Natural Gas and Similar Gaseous Mixtures by Temperature Program Gas Chromatography" requires a Flame Ionization Detection (FID) that is capable of detecting component concentrations at 10 ppm. Although some analyses may achieve lower detection levels, EPA should recognize the substantial gap between expected industry analytical performance and the RDLs proposed here. EPA's proposed 0.116 ppm RDL is nearly two orders of magnitude below the routine analytical capability specified by the accepted industry standard. That substantial disparity calls into question whether the proposed RDLs reflect achievable, routine measurement performance across the source category.

If EPA nevertheless proceeds with finalizing the proposed equations, GPA Midstream requests EPA to acknowledge that applying the "RDL" developed for Lime Manufacturing Plants in this rulemaking does not mean this RDL is appropriate for use in future oil and natural gas source rulemakings.

2b. Small dehydrators with BTEX emissions lower than the MACT floor should be exempt from control requirements.

EPA states that industry feedback indicated that using the small dehydrator emissions limit equations provided in NESHAP subparts HH and HHH and the GlyCalc™ software can generate BTEX emission limits approaching zero.[2]

The cited feedback, however, was unrelated to GlyCalc™. The straightforward point GPA Midstream raised in our petition was that controls are not necessary for these small glycol units

[1] 91 Fed. Reg. at 21,698.

[2] *Id.* at 21,697.

because inlet BTEX concentrations are so low that controlling those units provides insignificant HAP reductions at unreasonable compliance costs:

> [M]any major sources under 40 C.F.R. § 63 Subparts HH and HHH are major because of the formaldehyde emitted in engine exhaust. The concentration of heavier hydrocarbons (C6+), and thus BTEX, in the natural gas at many of these sources can be negligible or even approach zero, especially at sites associated with coal-bed methane production or CO_2 floods. Thus, controlling BTEX from small glycol units at these sites will have an insignificant effect on total HAP emissions. Using the small dehydrator emission limits equations provided in HH and HHH, the cost to control reaches infinite values, which is unreasonable because the equation potentially results in emissions limits of zero. Therefore, controls should not be required on small glycol units at a major source that dehydrates gas with very low inlet BTEX concentrations (i.e., less than 1% VOC and 0.01% HAP). Facilities with inlet BTEX concentrations that are below the BTEX emissions rates used for establishing the MACT floors should be exempt from control requirements.[3]

This distinction matters. Most GPA Midstream member sites are not major sources of HAP, and the term "small glycol dehydrators" applies only at major sources. At natural gas processing plants, it is the engine emissions—not elevated HAP concentrations in process gas—that cause a natural gas processing plant to become a NESHAP HH major source. It is incorrect for EPA to assume that NESHAP HH major sources process gas with high levels of HAPs, and therefore have appreciable HAP emissions from dehydrators, storage vessels, fugitive components, or other emission sources.

The 2012 MACT floor analysis established a MACT floor in terms of tons per year equivalent. As explained in the 2012 rulemaking:

> Therefore, a direct comparison to the MACT floor in the form of an emission factor was not possible. Instead, an equivalent value for the MACT floor in terms of tons per year was established. Appendix A presents the BTEX emissions associated with the MACT floor of 2.05x10-2 lb BTEX/MMscf-ppmv. As shown in Appendix A, we calculated an equivalent value 0.955 tpy BTEX. Any glycol dehydration unit identified as a small glycol dehydration unit with controlled or

[3] Gas Processors Association (now GPA Midstream Association), et al., Petition for Reconsideration of Oil and Natural Gas Sector: National Emission Standards for Hazardous Air Pollutants Reviews, 77 Fed. Reg. 49,490 (Aug. 16, 2012), filed Oct. 16, 2012, Docket No. EPA-HQ-OAR-2010-0505.

uncontrolled BTEX emissions greater than 0.955 tpy would be required to reduce their emissions to a level below 0.955 tpy BTEX.[4]

In the production source category (which includes compressor stations and natural gas processing plants), EPA estimated the number of glycol dehydrators impacted, the total HAP reduced, and the associated costs based on dehydrators with emissions above 0.955 tpy BTEX. However, the original and now proposed equations to determine BTEX emission lists for small dehydrators do not incorporate the same 0.995 tpy-BTEX-and-above control threshold. As such, the proposed regulatory requirements do not align with EPA's cost analysis and the actual cost implications.

EPA performed a similar analysis for the transmission and storage source category and found that "the MACT floor of 1.93x10-2 lb BTEX/MMscf-ppmv for the transmission and storage source category is equivalent to 11.84 tpy of BTEX. Of the 110 small glycol dehydration units identified, 7 would be required to install controls to achieve the MACT floor."[5] EPA then estimated the number of glycol dehydrators impacted, the total HAP reductions, and the associated costs based on dehydrators with emissions above 11.84 tpy BTEX.

In the Proposed Rule, EPA relies on the existing MACT framework without addressing this mismatch, as it does not reexamine whether the agency's prior impact analysis adequately reflects the population of affected sources. Because the 2012 impacts analysis evaluated only small dehydrators with BTEX emissions above the MACT-floor-equivalent thresholds, EPA has not justified applying control requirements to units below those thresholds. Accordingly, EPA should exempt small dehydrators with BTEX emissions below the MACT floor from control requirements, or, at a minimum, provide the alternative compliance pathway described in Section 2c.

2c. Small dehydrators at major sources should be allowed to comply with the large dehydrator requirements.

In both the primary and alternate proposals, EPA would subject small dehydrators to a more complicated and burdensome compliance framework than for large dehydrators.

Under the Proposed Rule, § 63.765(b)(1)(iv) would appear to add methanol controls for all small dehydrators, while continuing to apply the existing BTEX control (in § 63.765(b)(1)(iii))

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[4] Memorandum. Brown, H., EC/R Inc., to Nizich, G. and Moore, B., EPA. Impacts of Final MACT Standards for Glycol Dehydration Units - Oil and Natural Gas Production and Natural Gas Transmission and Storage Source Categories. (April 17, 2012). Docket ID EPA–OAR–2010–0505–4494.

[5] *Id.*

approach for small dehydrators. Because the proposal does not clearly explain how the methanol control requirement of § 63.765(b)(1)(iv) is intended to interact with the rest of § 63.765(b)(1), the small dehydrator requirements could reasonably be read as requiring compliance with both § 63.765(b)(1)(iii) and § 63.765(b)(1)(iv).

By contrast, large dehydrators are allowed to comply under § 63.765(b)(1)(i) or the alternate approach in § 63.765(b)(1)(ii), each of which controls HAP emissions without a separate methanol provision. The proposal does not appear to provide small dehydrators an equivalent alternate option. As a result, the proposed structure may place small dehydrators on a more complex regulatory path than large dehydrators, even though the large dehydrator provisions already provide control approaches that address methanol, without requiring an additional standalone methanol provision.

To address this burden, as well as address the issues raised above regarding the RDL and MACT floor analyses for small dehydrators, EPA should allow a small dehydrator to follow the large dehydrator requirements as an alternative. To accomplish this, the rule would allow compliance with § 63.765(b)(1)(i) or (ii) (i.e., the large dehydrator approach) within 36 months for small dehydrators. This would supersede the BTEX emission limit equations of § 63.765(b)(1)(b)(iii), which would then sunset. Under this approach, the proposed revisions to § 63.765(c) on alternate options would remain, but EPA would not finalize the proposed methanol requirements for small dehydrators at § 63.765(b)(1)(iv) as methanol control will be consistent with the methods allowed for large dehydrators § 63.765(b)(1)(i) through (iii) should be modified accordingly.

This approach would resolve the ambiguity in the proposal by making clear that small dehydrators are not expected to comply with both the existing BTEX equation-based requirements and a new, separate methanol control requirement.

It would also provide regulatory consistency. If the control methods allowed for large dehydrators are sufficient to address methanol, then those same methods should be available for small dehydrators rather than creating an additional standalone requirement in § 63.765(b)(1)(iv). Using the large dehydrator framework for small dehydrators would provide a clearer and more workable compliance pathway, reduce unnecessary complexity, and avoid creating a situation where small dehydrators are subject to a more complicated regulatory structure than large dehydrators. It would also eliminate the need to rely on the misapplication of an RDL analysis for the Lime Manufacturing source category for the oil and natural gas source category. Additionally, it would better align the control thresholds with the thresholds used in the 2012 impact analysis.

In short, the better solution is to transition small dehydrators to the same primary and alternate compliance approaches already available for large dehydrators.

2d. For the purposes of evaluating methanol emission reductions for the 95% reduction compliance option, baseline operations should be April 22, 2026 for small dehydrators.

For the methanol compliance option, EPA should allow April 22, 2026 to serve as the baseline for small dehydrators, because operators may lack the data needed to establish a methanol 2011 baseline. In both the primary and alternate approaches, EPA has proposed methanol standards for small dehydration units under § 63.765(b)(1)(iv). Both proposals also allow an owner or operator to demonstrate compliance under § 63.765(c)(2) by showing that methanol emissions from a small dehydrator unit process vent are reduced by 95 percent through process modifications, or through a combination of process modifications and one or more control devices, in accordance with the requirements of §63.771(e). Section 63.771(e)(1) requires determination of glycol dehydration unit baseline operations as defined in § 63.761, which for small dehydrators is defined to mean the operations in effect on August 23, 2011. For the proposed methanol standard, however, April 22, 2026 should be allowed to be used as the baseline. This is because operators may not have sufficient data from August 23, 2011 to establish a methanol baseline. Operators should be allowed to account for process modifications made at any point that contributed to methanol reductions, and those modifications should be considered in evaluating compliance.

> *§63.771(e) Process modification requirements. Each owner or operator that chooses to comply with § 63.765(c)(2) shall meet the requirements specified in paragraphs (e)(1) through (e)(3) of this section.*
>
> *§63.771(e)(1) The owner or operator shall determine glycol dehydration unit baseline operations (as defined in § 63.761). Records of glycol dehydration unit baseline operations shall be retained as required under § 63.774(b)(10).*
>
> *§63.771(e)(2) The owner or operator shall document, to the Administrator's satisfaction, the conditions for which glycol dehydration unit baseline operations shall be modified to achieve the 95.0 percent overall HAP emission reduction, or BTEX limit determined in §63.765(b)(1)(iii), as applicable, either through process modifications or through a combination of process modifications and one or more control devices.*
>
> *§63.761 Glycol dehydration unit baseline operations means operations representative of the large glycol dehydration unit operations as of June 17, 1999,*

and the small glycol dehydrator unit operations as of August 23, 2011, except April 22, 2026 may be used to establish baseline operations for the purposes of evaluating methanol emission reductions. For the purposes of this subpart, for determining the percentage of overall HAP emission reduction attributable to process modifications, baseline operations shall be parameter values (including, but not limited to, glycol circulation rate or glycol-HAP absorbency) that represent actual long-term conditions (i.e., at least 1 year). Glycol dehydration units in operation for less than 1 year shall document that the parameter values represent expected long-term operating conditions had process modifications not been made.

2e. BTEX limits are an appropriate surrogate for limits on methanol emissions from small dehydrators.

BTEX limits are an appropriate surrogate for limits on methanol emissions in all dehydrators, including in small dehydrators. Combustion controls reduce both BTEX and methanol, and with that control, the reduction in BTEX will be essentially the same as the reduction in methanol. Dehydrators that are using a method other than combustion typically employ methods that condense both water and BTEX (e.g. BTEX condenser, reflux). Those types of controls may actually provide even greater methanol reductions than BTEX. Methanol is a highly polar molecule that is fully miscible in water and will preferentially follow where the water goes in the system, whereas BTEX are only partially soluble in water. As such, dehydrators that comply using these condensers for BTEX reduction will by extension reduce methanol even more than BTEX since more methanol will condense with the water than BTEX. GPA Midstream conducted modelling in ProMax to compare the relative percent reduction of BTEX and methanol emissions for various control scenarios, including uncontrolled emissions as a basis of comparison, a simple regenerator column reflux, a BTEX condenser, and the combination of both a regenerator reflux and BTEX condenser. Simulations were run using a glycol circulation ratio of 3 to 3.15 gallons of TEG per pound of water (the ratios suggested per HH (63.764(d)(2)(i))) across a range of inlet gas compositions representative of different basins, high and medium absorber column pressures, gas throughputs, a range of inlet gas methanol concentrations, and several BTEX condenser temperatures. Modeling results confirmed this predictable relationship between BTEX emissions and methanol emissions and resulted in a greater reduction percentage for methanol compared to BTEX.

Given the known chemistry of such systems and the model validation, the existing BTEX control framework provides an effective surrogate for methanol emissions control at both large and small dehydrators.

3. EPA should adopt OGI and Appendix K as an alternative to EPA Method 21 at processing plants (EPA Question 1).

Adopting OGI and Appendix K would align Subpart HH leak detection with the approach already proven under New Source Performance Standards ("NSPS") Subpart OOOOb and reduce duplicative Method 21 monitoring. GPA Midstream therefore supports the adoption of OGI and Appendix K as an alternative to EPA Method 21 for leak detection at processing plants. Additionally, GPA Midstream supports API's comments on this issue.

4. EPA should recognize that NSPS or emissions guideline compliance would satisfy the subpart HH equipment leak requirements and account for the "in VHAP-service" burdens of adding methanol to Table 1.

EPA's proposal to add methanol to Table 1 of Subpart HH would impose significant burdens and costs that EPA should consider and take steps to mitigate if EPA retains methanol in Table 1.

First, adding methanol is not a change that imposes no additional compliance burden. Because only Table 1 compounds are counted for compliance, and "VHAP (volatile hazardous air pollutant) concentration" is defined as the fraction by weight of all HAP in a material (§ 63.761), adding methanol increases the VHAP weight fraction of any methanol-containing stream. The equipment leak provisions presume that each piece of ancillary equipment and each compressor is in VHAP service unless the operator demonstrates that the stream's VHAP content can reasonably be expected never to exceed 10.0 percent by weight (§ 63.772(a)).

The practical consequences are significant and unaddressed in EPA's proposal. Existing § 63.769 applicability determinations were made without methanol in the VHAP pool. Adding methanol could therefore compel operators to re-characterize streams, and in many cases, sample across entire gas processing plants to re-establish which equipment are not in VHAP service. That burden is compounded by methanol's seasonality. Methanol is injected as a hydrate inhibitor primarily in cold weather, causing concentrations to peak seasonally. Because the demonstration under § 63.772(a) depends on a worst-case showing, sampling would need to occur during the coldest period of the year.

The approved analytical methods further complicate compliance. § 63.772(a) permits only EPA Method 18 or ASTM D6420-99 (2004), yet ASTM D6420 is not validated for methanol (CAS No. 67-56-1) and Method 18 relies on detectors that may respond weakly to methanol. EPA has not identified a validated method for measuring methanol under these provisions or demonstrated that a single approved method can reliably characterize methanol together with the other Table 1 compounds. Adding methanol is therefore not the costless change EPA describes, as it imposes analytical costs that may recur across numerous streams within a facility. EPA's "no additional

burden" finding does not account for these considerations and impacts, which section 112(d)(2) of the Clean Air Act directs EPA to consider.

Rather than imposing duplicative compliance obligations for equipment already controlled under other rules, EPA should build on the existing overlap exemption in § 63.769(b). Section 63.769(b) currently exempts ancillary equipment and compressors at natural gas processing plants from the equipment leak standards when they are subject to and controlled under 40 C.F.R. part 63, subpart H (the HON) or 40 C.F.R. part 60, subpart OOOO, and the Proposed Rule retains that exemption under both the primary and alternate proposals. At a minimum, EPA should extend the exemption to ancillary equipment and compressors subject to and controlled under 40 C.F.R. part 60, subparts OOOOa and OOOOb, as well as equipment regulated under state programs implementing the subpart OOOOc emissions guideline.

Extending the exemption alone, however, would not resolve the underlying burden associated with VHAP-service determinations. Exempt equipment must still submit the § 63.775(e) periodic reports, and § 63.769 applies only to equipment "in VHAP service." An operator must therefore still determine VHAP-service status, either by accepting the § 63.772(a) presumption or by making the demonstration necessary to rebut it. As a result, adding methanol could still expand § 63.775(e) reporting obligations unless the VHAP-service determination itself is addressed.

EPA should therefore go a step further and treat compliance with an applicable NSPS or emissions guideline as satisfying the Subpart HH equipment leak requirements. Every compound listed in Table 1, including methanol as proposed, is also a volatile organic compound (“VOC”). An NSPS leak detection and repair program that finds and repairs VOC leaks therefore reduces HAP emissions from the same equipment and achieves the same equipment-leak reductions that Subpart HH is intended to achieve.

That duplication has direct cost consequences. Adding methanol to Table 1 would impose real costs associated with VHAP-service re-characterization, sampling, analytical work, recordkeeping, reporting, and the resulting expansion of Subpart HH applicability, while producing little or no incremental HAP reduction where the same equipment is already monitored and repaired under an applicable NSPS or emissions guideline. Where costs increase without corresponding incremental emissions reductions, the cost-effectiveness of the additional requirements becomes increasingly difficult to justify.

EPA should expressly conclude that, where equipment is already monitored and repaired under an applicable NSPS or emissions guideline, compliance with that program satisfies the Subpart HH equipment leak requirements for those streams, without a separate VHAP concentration re-characterization and without duplicative Subpart HH reporting. Such an approach would extend

the existing exemption to the VHAP-service determination that drives much of the burden, eliminate unnecessary duplication, and become even more important if methanol is retained on Table 1. Regardless of how EPA proceeds, it should account for the equipment-leak and VHAP-service consequences of listing methanol which the Proposed Rule does not currently address.

5. Emissions Modeling Software.

5a. GPA Midstream supports the addition of ProMax® as an alternative to GLYCalc™ within the regulatory text (EPA Question 15a).

GPA Midstream supports adding ProMax® as an alternative to GLYCalc™ within the regulatory text. ProMax version 6.0 or later is acceptable and commonly available, although GPA Midstream notes that Subpart W 40 C.F.R. §98.233(e)(1) and EPA's letter of alternative approval of ProMax for use in subpart HH dated March 31, 2022 mention ProMax version 5.0 or later as acceptable versions of the software for similar systems. EPA should likewise allow ProMax® version 5.0 or later here. Additionally, ProMax can be used for all relevant HAP emission calculations, including BTEX and methanol, making it especially suitable for NESHAP subparts HH and HHH.

5b. GPA Midstream supports generic allowance of simulation software (EPA Question 15b).

GPA Midstream also supports generic allowance of simulation software and recommends an approach similar to Subpart W 40 C.F.R. § 98.233(e)(1) where examples of software are provided but software not explicitly listed in the rule can still be used as appropriate. This would allow flexibility for a broader range of applicable tools, while also providing several possible options commonly used in industry. If generic simulation software is allowed, EPA should use similar language to 40 C.F.R. § 98.233(e)(1) for agreement between federal rules that require similar simulations (e.g., from Subpart W: "A minimum of the parameters listed in paragraph (e)(1)(i) through (xi) of this section, as applicable, must be used to characterize emissions."). Different simulation software programs require different inputs, so it is not possible to require a single list of input parameters that are required for every software, but some general possibilities could be listed. As an example, the current § 63.772(b)(2)(i) could be updated as follows:

> The owner or operator shall determine actual average benzene or BTEX emissions using a software program such as Bryan Research & Engineering ProMax® version 5.0 or higher, or GRI-GLYCalc™ version 3.0 or higher. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and may be determined using the procedures documented in the software's user information guide. Inputs may include, as applicable: feed natural

gas flow rate, natural gas composition, feed natural gas water content, absorbent circulation rate, absorbent type (e.g., triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG)), use of stripping gas, use of flash tank separator, etc.

If methanol is added to the list of reportable HAP emissions through this proposal, simulation software examples may need to distinguish between methanol versus BTEX emissions. Some simulation software like ProMax can accurately predict both methanol and BTEX emissions, but since GRI-GLYCalc and possibly some others may not include appropriate methanol-water interactions, a different list of example software may be relevant for BTEX and methanol calculation methodologies. GPA Midstream notes that for ProMax, it is recommended to use a polar property package when methanol and water are present to accurately account for these interactions.

5c. GPA Midstream supports keeping references to GRI-GLYCalcTM in both NESHAP subpart HH and subpart HHH (EPA Question 15c).

GPA Midstream likewise supports retaining references to GRI-GLYCalc™ in both NESHAP subpart HH and subpart HHH. For those who already have and use a copy of the software, it should continue to be allowed as an option for calculating BTEX emissions from dehydration facilities, and any legacy calculations using this software should still be valid. Many existing operating permits have requirements to use GRI-GLYCalc™, so continuing to allow use of GRI-GLYCalc in subparts HH and HHH will prevent unnecessary burden of using both GRI-GLYCalc™ for permit requirements and a different software for NESHAP subpart HH and HHH requirements. While GRI-GLYCalc™ does not include methanol and should not be included as an example software for methanol emission calculations, it should remain as a possible software in the list of examples for BTEX emissions if methanol is not present.

6. Alternative Proposed Standards.

GPA Midstream agrees with EPA that CAA § 112(d)(6) does not obligate EPA to promulgate standards for previously unregulated emission points and supports EPA not promulgating the alternative approach. GPA is aligned with the justification and reasoning in A2C's comment letter and thus, GPA supports A2C's comments on this issue. However, if EPA chooses to implement alternative standards for acid gas removal units ("AGRUs"), transport vessel loading, or pumps and process controllers, then there are several that the agency should consider and address before finalizing standards for the previously unregulated emission points.

6a. AGRUs at facilities located prior to the point of custody transfer to a plant are unlikely to emit at major source levels (EPA Question 7a).

EPA requests comment on whether Acid Gas Removal Units (AGRUs) at facilities located prior to the point of custody transfer to a natural gas processing plant may also emit at major source levels and thus should be regulated to reduce emissions by 95 percent. GPA Midstream urges EPA not to regulate AGRUs as major sources without source-specific emissions, control, and cost data. AGRUs upstream of the point of custody transfer are unlikely to constitute major sources of HAP, and existing H_2S controls and state permitting already address the rare case in which emissions may be more significant.

The starting point is the definition of custody transfer in NESHAP Subpart HH (§ 63.761), which specifies that "the point at which…liquids or natural gas enters a natural gas processing plant is a point of custody transfer." As the EPA is aware, AGRUs can be located at facilities upstream of the point of custody transfer. These AGRUs upstream of the processing plant are typically located in areas that gather gas with lower natural gas liquid ("NGL") and BTU content and do not typically require a processing plant to prepare the gas for transmission through the pipeline. In other words, the natural gas may need to be conditioned to remove H_2S or CO_2, but its BTU content does not need to be reduced to meet the low-BTU requirements of an interstate transmission pipeline. Some examples of natural gas plays where these low-BTU conditions exist are the Barnett in North Texas, the Haynesville in Louisiana, the Marcellus in Northeast and Central Pennsylvania, and a portion of the Woodford Shale in Southeast Oklahoma. Due to the low BTU content of the gas in these areas, the BTEX content in the gas is typically low, so the acid gas stream from AGRUs would have a lower BTEX emission profile.

When H_2S removal is the primary reason for the AGRU, the acid-gas streams may already be routed to a combustion device or a sulfur recovery unit installed to control those emissions. The control for H_2S would provide at least 95% control efficiency on any of the HAP compounds as well, resulting in low emissions under major source levels. When CO2 removal is the primary reason for the AGRU (i.e., without H_2S present at high concentrations), the facility may vent the acid gas stream to the atmosphere, including any entrained HAP compounds. In a high CO_2 case, if the HAP concentrations exceed major source levels, existing state permitting already give operators the strong incentive to reduce the emissions to avoid major source requirements for ancillary equipment, like natural gas-fired engines under NESHAP Subpart ZZZZ, and to generally avoid Title V permit requirements.

As such, GPA Midstream contends it would be rare to find an AGRU major source of HAPs operating currently that would need to be addressed by this proposed rulemaking. It is likely that the acid gas stream will already be controlled by existing H2S controls or by state permitting

processes. Additionally, it appears that the cost/benefit of any additional controls on an AGRU upstream of custody transfer has not yet been addressed by EPA. Due to the volume of gas and the low-BTU content of an acid gas stream, EPA would need to gather additional information on the cost associated with adding a combustion control device that would require a large amount of additional assist natural gas to provide the BTU content required to combust the low-BTU acid gas streams.

In sum, EPA has not identified how many uncontrolled upstream AGRUs would exceed major-source thresholds or evaluated the costs and energy impacts of controlling low-heating-value acid-gas streams. Combustion of those streams may require substantial supplemental fuel. EPA should collect source-specific data before extending the alternative standard upstream of custody transfer.

6b. GPA Midstream requests that EPA define transport vessel loading.

If EPA finalizes the alternative control standards for previously unregulated sources, GPA Midstream requests that EPA define "transport vessel loading." A definition is needed to clarify whether the proposed alternative standards would apply only to loading racks or to all transport loading.

Section III.B.4.e of the Proposed Rule says, "Loading operations are used to conduct a transfer of liquids from storage vessels to a type of transportation (i.e., transport) vessel using **loading racks**."[6] Additionally, the MACT Floor Determination for transport vessel loading (section III.B.4.e.i of the Proposed Rule) references the NESHAP standards for Marine Tank Vessel Loading Operations (40 C.F.R. 63, Subpart Y) and Gasoline Distribution Terminals, Bulk Plants, and Pipeline Facilities (40 C.F.R. 64, Subpart BBBBBB). Loading racks are an affected source under Subpart BBBBBB. Subpart BBBBBB definitions reference the NSPS for Bulk Gasoline Terminals (Subpart XXa), which defines loading racks as "the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill delivery tank trucks." Industry understanding of what a loading rack constitutes is commensurate with this definition, as loading racks typically include elevated platforms, loading arms, gangways, and pumps.

However, many natural gas transmission facilities and gas processing plants are not equipped with these types of loading racks. Transport trucks are typically loaded via direct connection of a hose to tank loadout valves. If the alternative standards are implemented, owners and operators

[6] 91 Fed. Reg. at 21,693 (emphasis added)

need additional clarity to know whether the standards apply only to loading racks (as discussed above) or to all transport loading operations.

6c. Small glycol dehydration unit applicability and compliance dates.

As proposed under the alternative approach, the framework for new and existing small glycol dehydration units in § 63.760(b)(1)(i)(C)-(D) remains tied to August 23, 2011, but sections § 63.760(f)(9) and § 63.760(f)(10) reference the Proposed Rule Federal Register publication date as the trigger for the new methanol requirements. EPA should revise the alternative text to clearly distinguish these date concepts and avoid a gap for units constructed after August 23, 2011 and before the Federal Register publication date.

GPA Midstream proposes that the terms "new" and "existing" be removed from § 63.760(f)(9) and (10), which are the paragraphs that describe which small dehydrators must control methanol emissions and when. We propose the compliance and applicability dates in those paragraphs can be retained as proposed but removing the "new" and "existing" terminology avoids confusion regarding the two dates at play, August 23, 2011 and April 22, 2026. Section 63.760(b)(1)(i)(D) should also add "located at a natural gas processing plant" for consistency.

Proposed RLSO:

> *§63.760(b)(1)(i)(D) Each small glycol dehydration unit located at a natural gas processing plant for which construction commenced after August 23, 2011, is a new small glycol dehydration unit.*
>
> *§63.760(f)(9) Each affected ~~existing~~ small glycol dehydration unit, as defined in § 63.761, located at a major source, that commenced construction ~~after August 23, 2011 but~~ before [INSERT DATE OF PUBLICATION OF PROPOSAL IN THE FEDERAL REGISTER], must achieve compliance with methanol standards in § 63.765(b)(1)(iv) no later than [INSERT DATE 12 MONTHS AFTER PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER], except as provided in § 63.6(i).*
>
> *§63.760(f)(10) Each affected ~~new~~ small glycol dehydration unit, as defined in § 63.761, located at a major source, that commenced construction on or after [INSERT DATE OF PUBLICATION OF PROPOSAL IN THE FEDERAL REGISTER], must achieve compliance with the methanol standards in § 63.765(b)(1)(iv) immediately upon initial startup or [INSERT DATE OF PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER], whichever is later.*

6d. Any new standards for previously unregulated source categories should include an overlap exemption for sources already controlled under NSPS subparts OOOO, OOOOa, and OOOOb or a State Plan conforming with the subpart OOOOc Emission Guideline.

Finally, should EPA finalize the alternative proposal and extend coverage to previously unregulated emission points, the final rule should provide relief for sources already controlled for VOC or methane under NSPS subparts OOOO, OOOOa, OOOOb, or OOOOc, or a conforming state program.

EPA's own baseline analysis projects no incremental emission reductions from the alternative approach precisely because these sources – storage vessels, transport vessel loading operations, natural gas-driven process controllers, and pumps – are already subject to baseline controls. Because every HAP this rule targets is itself a VOC, an NSPS that controls VOC or methane from these sources necessarily controls HAPs as well, so layering a duplicative MACT or GACT obligation on the same source produces no environmental benefit while adding monitoring, recordkeeping, and reporting costs.

EPA can provide that relief in two ways. It could extend the existing overlap exemption structure (as used for equipment leaks under § 63.769 and storage vessels under § 63.766(d)) to these categories; or, rather than exempt them, it could include "comply with the applicable NSPS" as an express compliance option within each new standard, allowing a source already controlled under the applicable NSPS or state program to satisfy the requirement through that compliance. Either approach avoids duplicative obligations. At a very minimum, the compliance obligations and timelines for these categories should be aligned with the corresponding NSPS OOOOb and OOOOc requirements, which EPA is separately reconsidering, so that operators are not subject to conflicting mandates.

7. Additional evaluation of metal HAPs is not warranted (Question 14).

EPA solicited comment on whether it should collect additional information on potential metal HAP emissions. There is no need for further data collection from dehydration units and AGRUs. The 2023 and 2024 ICRs covered 231 production and processing facilities and 57 transmission and storage facilities across a range of geographic regions, operations, and facility sizes. Moreover, as current industry dehydration unit operation practices have largely remained consistent with practices in 2023 and 2024, further broad data collection and analysis is unlikely to yield different results or change EPA’s conclusion.

The previous analyses included liquid samples on rich TEG from glycol dehydrators and rich amine from AGRU’s to detect metals transferred from raw natural gas to rich glycol during

dehydration or rich amine solution during acid gas removal. These liquid sample results showed negligible concentrations of metals for both unit types and, and to estimate potential HAP emissions, the EPA evaluated the metal vapor pressures and found those results to be negligible as well.

Finally, the evaluated metals have boiling points far above the temperature at which TEG and amine begin to rapidly degrade (404°F for TEG[7] and 350°F - 400°F for various amines[8]). Most of the metal boiling points exceed 1000°F. Thus, dehydration units and AGRUs are not operated anywhere close to conditions that would be expected to result in metal HAP emissions.

Thus, the resources needed to conduct further analysis to derive information beyond theoretical data are not justified. Should EPA pursue additional evaluation, ICRs should be limited to sites where previous samples showed results exceeding detection levels.

8. EPA should retain an option to use the current Major Source threshold assessment for production field facilities.

In the Proposed Rule, EPA proposes to change the definition of Major Source such that for production field facilities, HAP emissions would not be aggregated for a major source determination. Instead, individual glycol dehydration units and storage vessels located at production field facilities would be evaluated separately and a unit or vessel would only be a major source if the unit or vessel itself emits or has the potential to emit considering controls 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of HAP.

GPA Midstream notes that in some cases this change may add burden and complexity for operators to have per-source major source threshold assessments and to change rule applicability. Moreover, as outlined previously, each HAP this rule targets is also a VOC. As such, in many cases, the affected sources are also subject to NSPS requirements that control VOC or methane. Therefore, reclassification of major sources to area sources is unlikely to result in removal of emission control standards or work practices and leads to additional administrative burden to conduct reclassification analyses.

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[7] Moshfeghian, Mahmood. "Teg Dehydration: Stripping Gas Charts for Lean Teg Regeneration – Campbell Tip of the Month." PetroSkills John M. Campbell, 2013. http://www.jmcampbell.com/tip-of-the-month/2013/06/teg-dehydration-stripping-gas-charts-for-lean-teg-regeneration/.

[8] Lyddon, Lili. "Amine Thermal Degradation." Bryan Research & Engineering, 2008. https://www.bre.com/Blog/Amine-Thermal-Degradation.aspx.

EPA states that the proposed change would not affect prior determinations or the current status of existing sources and that a change in an existing source's status would take effect only upon application by the operator. 91 Fed. Reg. at 21,701. GPA Midstream supports that elective approach because it allows operators that prefer to retain their existing classifications and controls to avoid unnecessary unit-by-unit analyses and permitting changes.

GPA Midstream requests that EPA codify or otherwise expressly preserve this approach in the final rule so that operators may voluntarily maintain their current major/area source classifications and allow determinations to be based on facility-level assessments.