Interstate Natural Gas Association of America

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RE: Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems, Docket ID No. EPA-HQ-OAR-2023-0234

The Interstate Natural Gas Association of America (INGAA), the trade association that represents the interstate natural gas pipeline industry, respectfully submits these comments in response to the United States Environmental Protection Agency's (EPA or Agency) proposed rule, "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems" (hereinafter, "Proposed Rule"), which was published in the Federal Register on August 1, 2023.[1]

INGAA members own and operate the vast majority of the interstate natural gas transmission and storage segment in the U.S. and Canada. INGAA member companies transport more than 95 percent of the nation's natural gas through approximately 200,000 miles of interstate natural gas pipelines. In 46 of the 48 contiguous United States, INGAA member companies operate over 5,400 natural gas compressors at over 1,300 compressor stations and storage facilities along the pipelines to transport natural gas to local gas distribution companies, industrials, gas marketers, and gas-fired electric generators.

Since the Proposed Rule would amend Subpart W of the Greenhouse Gas Reporting Program (GHGRP)[2] as mandated by the August 2022 Inflation Reduction Act (IRA)[3], this rulemaking is of tremendous importance to INGAA and its members. Indeed, INGAA has participated in all EPA rulemakings involving regulation of methane from the oil and natural gas source category, including, within the past year, INGAA comments on two related GHGRP proposals: INGAA comments submitted on October 6, 2022 (October 2022 Comments)[4] on an EPA proposal to amend Subpart W and other GHGRP sections (2022 Proposal)[5], and INGAA comments submitted

[1] 88 Fed. Reg. 50282.
[2] 40 CFR, Part 98.
[3] https://www.govinfo.gov/content/pkg/BILLS-117hr5376rh/pdf/BILLS-117hr5376rh.pdf.
[4] Docket Document No. EPA-HQ-OAR-2019-0424-0224. Enclosed.
[5] 87 Fed. Reg. 36290, "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule," June 21, 2022.

July 21, 2023[6] on EPA's supplemental notice that addressed aspects of the 2022 proposal other than Subpart W provisions[7].

INGAA members currently invest significant resources to report greenhouse gas (GHG) emissions in accordance with Subpart W and the revisions reflected in the Proposed Rule will have a significant impact on INGAA's members ongoing reporting obligations, as well compliance with the methane waste emissions charge mandated by the IRA and to be implemented by EPA.

GHG emission data must be accurate, representative, and timely to fulfill the various uses of the data. Accuracy and data considerations specific to each of the affected natural gas industry segments are an absolute imperative due to the financial obligations stemming from the IRA's waste emissions charge. Accordingly, INGAA appreciates the opportunity to submit comments on the Proposed Rule and offers them in the spirit of efficiently and effectively improving the accuracy and quality of GHG data reported by the natural gas transportation and storage (T&S) sector. As you will see in INGAA's comments below, we advocate for improved data quality and further quantification, which aligns with Congress's goal of utilizing empirical data. However, we also support migrating towards development of improved emission factors (EFs) to supplant measurement when adequate measured data is available and considering the relative importance of the emissions sources.

It is important to note that INGAA members are continuously looking for new and innovative ways to measure and reduce GHG emissions from T&S sources. Technological advances that reduce emissions or improve emissions measurement often outpace the regulatory process. Accordingly, INGAA strongly encourages EPA to include flexibility for affected facilities to implement new GHG reduction and measurement technologies when those technologies are supported with defensible data and defined methods. The ability to rapidly deploy new technology to reduce and measure GHG emissions will become even more important as the waste emissions charge is implemented.

INGAA's comments follow:

1. **INGAA supports improving emissions estimates through measurement. The Proposed Rule should ensure that measurement is an acceptable option for all relevant sources and not overly constrain use of measured data for estimates or development of improved EFs. For example, measurement should be included as an option for the newly added crankcase vent emissions source and other criteria for crankcase vents should be clarified.**

Consistent with the IRA directive to rely on more empirical data for Subpart W GHG estimates, INGAA supports improving emission estimates through measurement. The Proposed Rule adds measurement requirements in some cases (e.g., for pneumatic controller venting) and includes measurement or other data / EF options in other cases (e.g., for reciprocating engine exhaust

[6] Docket Document No. EPA-HQ-OAR-2019-0424-0321.
[7] 88 Fed. Reg. 32852, "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, Supplemental Notice of Proposed Rulemaking," May 22, 2023.

methane emissions). However, in other cases, measurement is not allowed and EFs are required (e.g., for estimating emissions from the newly added "crankcase vent" emissions source).

There are several important issues to consider regarding emissions estimation via measurement. Three are addressed in this comment:

- Measurement should be included as an alternative option, implemented as desired by the operator, to using prescribed EFs for all relevant emission sources, such as crankcase vents. Additional items related to crankcase vent emissions are also addressed below.
- The Proposed Rule should be more flexible in allowing EF development by operators or through collaborative projects that develop improved datasets from measurement.
- Measurement should not be overly prescribed and should consider the relative importance of the emissions source. For example, new requirements that add ongoing annual measurement for pneumatic devices in the T&S segments, which is a relatively small emissions source for those segments, is not warranted and EFs should be allowed.

A fourth issue related to measurement methods is discussed in Comment 8: streamlining the process to integrate technological advances in measurement and monitoring and allowing acoustic device technology to identify the line(s) in a manifolded system that include flow.

<u>Measurement should be included as an optional alternative to emissions estimation using prescribed EFs</u>

The Proposed Rule preamble acknowledges EPA's objective to address the IRA directive to include improved Subpart W emission estimates by using empirical data. INGAA supports the use of measured data to improve emission estimates. However, in some cases the Proposed Rule includes an EF-based method without the option to use measured data as an alternative. For those emission sources, measurement should be included as an alternative option used at the operator's discretion. Thus, for T&S sources, measurement (and EF development, as discussed below) should be added as an option for the following emission sources:

- Crankcase vent emission estimates as defined in §98.233(ee);
- Transmission pipeline leak estimates required in §98.232(m)(3) for interconnect metering-regulating (M&R) stations, (m)(4) for farm taps and direct sales M&R, and (m)(5) for pipeline leaks, where emissions are estimated using population EFs per §98.233(r).

Methods included in Subpart W (e.g., calibrated bag, high volume sampler, and direct measurement with a meter) can be used for these measurements. For the two emission sources described above, the EFs are based on older data and/or limited datasets, thus use of measured data is an important option.

For example, the Proposed Rule adds reporting of crankcase emissions for several segments, but related issues need to be addressed.

<u>Crankcase venting emissions estimate and EF basis</u>

Crankcase venting should **not** be associated with gas turbines / centrifugal compressors. The Proposed Rule adds this emissions source for reciprocating engines (i.e., driving reciprocating compressors) and combustion turbines (i.e., driving centrifugal compressors) with a prescribed EF used with unit counts to estimate emissions. References and applicability to combustion turbines / centrifugal compressors is erroneous and should be eliminated.

Crankcase venting is associated with *reciprocating internal combustion engines*. Crankcase ventilation systems exhaust "blow-by" that results from the in-cylinder air-fuel mixture and combustion gases leaking past the piston rings on a reciprocating engine. The pressurized mixture and combustion gases migrate into the reciprocating engine crankcase through small gaps between the piston rings and cylinder walls. Crankcase emissions may also result from reciprocating compressor seals leakage which enters the crankcase through the distance piece. This description is consistent with the proposed definition of "crankcase venting" added to §98.238. The crankcase is typically vented to atmosphere as part of normal operations to prevent excessive crankcase pressure, which can contribute to oil leaks through engine seals and affect unit performance.

Since the crankcase and related vent is associated with reciprocating engines, §98.233(ee) should eliminate reference to "gas turbines" and the definition of "Count" in Equation W-45 should be revised to eliminate that terminology. In addition, the EF basis is *unit* count (i.e., engine count) rather than vent count. INGAA recommends the following revisions to properly define the term:

> "Count = Total number of ~~crankcase vents on~~ reciprocating internal combustion engines~~ or gas turbines~~."

Measured data should be allowed as an alternative to the prescribed EF, especially since the EF is based on very limited data. The proposed methane EF for crankcase ventilation (2.28 standard cubic feet per hour per source),[8] cites the API Compendium which in turn references the "EPA Phase 2 study"[9] conducted at five natural gas-processing plants and seven gathering gas compressor stations. The first phase study was conducted at four natural gas processing plants.

These two studies are based on limited data from nearly 20 years ago at gas processing and upstream gathering and boosting facilities and may not be representative of other sectors or current operations. The Phase 2 study measured crankcase vents on 27 units and found 2 (approximately 7 percent) leaking.[10] The crankcase vent EF is based on those measurements, and the emissions were only observed on a small percentage of the engines evaluated.

A final issue is the methane content of the crankcase vent stream, which is parameter "GHGCH4" in equation W-45. This vent stream can be diluted and may have a much lower methane content

[8] Compendium of Greenhouse Gas Emissions Methodologies For The Natural Gas And Oil Industry. Produced by URS Corporation for American Petroleum Institute. November 2021. Available at https://www.api.org/-/media/files/policy/esg/ghg/2021-api-ghg-compendium-110921.pdf.

[9] Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites. EPA Phase II Aggregate Site Report prepared for U.S. EPA; Natural Gas STAR Program by Natural Gas Machinery Laboratory, Clearstone Engineering Ltd., and Innovative Environmental Solutions, Inc. March 2006. Available at https://www.epa.gov/sites/default/files/2016-08/documents/clearstone_ii_03_2006.pdf.

[10] See Phase 2 Report, Table 5, pg. 59 of 70.

than the methane content of gas stream entering the reciprocating internal combustion engine or the default value referenced. Thus, operators should have the option to measure the methane content of the crankcase gas vent and use that measured value as the basis for "GHGCH4". This should be clearly stated because it is not clear if this option is allowed under the "engineering estimates" language currently proposed. Measured (i.e., empirical) data will improve the emission estimate.

Thus, to improve crankcase vent emissions estimates: (1) operators should be allowed to screen the vent for leakage using §98.234 leak survey methods (e.g., OGI, method 21) and assume zero emissions if leakage is not observed; (2) measurement of the vent rate should be added as an option for estimating emissions; and (3) measurement of the vent stream methane content should be clearly stated as an option for estimating emissions.

<u>The Proposed Rule should include more flexibility to use measurement data to develop improved EFs</u>

While INGAA supports measurement to improve emission estimates, measurement should not necessarily be required in perpetuity if improved EFs can be developed based on measured data. The Proposed Rule should include streamlined and straightforward paths for developing EFs as an alternative to ongoing measurement and should consider the relative importance of the emissions source (e.g., percent contribution to the segment methane emissions inventory) when considering data needs. In addition, EF development should be allowed based on company-wide data or data from collaborative, multi-company projects. In some cases, the Proposed Rule includes "site-specific" data limitations for EF development, which is too constraining and not warranted. In fact, INGAA strongly believes that broader company-wide or collaborative projects to develop EFs is consistent with the intent of the IRA. Such programs should <u>not</u> be precluded by unnecessary Subpart W constraints.

For example, and as discussed further in Comment 4, §93.233(q)(2)(vi) and (vii) indicate that "site-specific" EFs can be developed for transmission compressor stations or underground storage facilities following the criteria defined in §93.233(q)(4). As discussed in Comment 4, leak counts are typically low at T&S facilities, so it could take many years to meet data objectives defined by EPA at the site level. Broader datasets – i.e., company-wide or from multi-company collaborative projects – should be allowed for EF development and have access to IRA funds, consistent with IRA section 136(a) objectives. Additional discussion on this topic is included below – e.g., regarding pneumatic devices in Comment 3 and component leaker EFs in Comment 4.

<u>Emission estimation should not be limited to mandatory, ongoing measurement, especially for emission sources that are relatively minor contributors to segment emissions</u>

While INGAA supports measurement-based estimates, other options are viable and measurement criteria should not be overly prescriptive. For example, as discussed in Comment 3, the Proposed Rule adds measurement for T&S pneumatic devices, and annual (or bi-annual) measurements will be typical at most T&S facilities based on device counts. Pneumatic devices are a relatively minor contributor for the T&S segment and EF-based approaches should be retained. At a minimum, a streamlined path for efficient development of improved T&S pneumatic device EFs should be included in the rule. Ongoing annual measurement is not warranted for such sources.

2. INGAA supports EPA's update to the 2022 Proposal that allows company measurement data or vendor EFs for estimating reciprocating engine exhaust methane emissions and responds to EPA's request for feedback on original equipment manufacturer (OEM) data.

INGAA's October 2022 Comments on the 2022 Proposal recommended additional options to the newly proposed EFs for reciprocating engine exhaust methane emissions. INGAA acknowledged that higher EFs than those published in Subpart C for natural gas combustion are warranted but requested additional options to the prescribed EFs proposed by EPA – i.e., INGAA recommended allowing other data sources such as company data or engine vendor data. The Proposed Rule includes additional options for estimating methane emissions from natural gas combustion, and INGAA supports EPA's proposal to allow company measurement data or OEM EFs as a basis for estimating these emissions.

OEM *or third-party service provider* EFs should be allowed

Since existing T&S engines often include after-market technology from third party service providers, such as low emission combustion (LEC) technology to reduce NOx emissions, it is imperative that Subpart W allow *service provider* EFs in addition to OEM EFs. For example, OEM EFs may not be available for methane or may not be appropriate if the engine includes technology upgrades provided by after-market companies. To address this, INGAA recommends using the term "third-party service provider" (or similar terminology defined by EPA), and §93.233(z)(4)(ii) of the Proposed Rule should be revised to state:

> "(ii) Original equipment manufacturer **or third-party service provider** information, which may include ~~manufacturer~~ specification sheets, emissions certification data, or other ~~manufacturer~~ data providing expected emission rates from the reciprocating internal combustion engine or gas turbine."

EPA request for feedback on OEM data

The Proposed Rule preamble solicits feedback on criteria associated with OEM EFs[11],

> "…seeking comment on whether OEM data is expected to be representative of field conditions. Further, we are considering proposing requirements for the OEM supplied data…"

INGAA member experience indicates that OEMs and third-party technology providers use standard test methods and develop technically sound EFs, ensuring that EFs / emissions data presented in engine specification sheets or other documentation are representative. Since the EFs may be guarantees, there may be a margin included which results in an EF nominally higher than expected emissions – e.g., EF includes a margin to address uncertainty, and would thus provide a conservatively high emission estimate.

Regarding related criteria or OEM requirements, these EFs should not be encumbered with additional requirements or burden within Subpart W, and the information stipulated in

[11] 88 Fed. Reg 50,356.

§98.223(z)(4)(ii) quoted above is adequate for exhaust methane EFs. No further requirements should be imposed on OEMs or third-party service providers regarding exhaust methane EFs.

<u>§93.233(z) title should be revised to clearly reflect segments addressed</u>

§93.233(z) currently addresses select segments (i.e., upstream, distribution) and is titled accordingly. However, the Proposed Rule section added to address exhaust methane emissions more broadly addresses Subpart W segments including T&S, so the section title should be revised for clarity. INGAA recommends the following revision:

> "(z) ~~Onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and n~~**<u>N</u>**atural gas ~~distribution~~ combustion emissions"

3. Pneumatic device emission estimates for T&S should include EF-based options, especially since this source is a relatively small contributor for the T&S sector.

As discussed in Comment 1, measurement requirements should not be overly prescriptive and burdensome, and the need for ongoing measurement should consider the relative importance of the emissions source. Despite a wealth of data indicating that pneumatic device emissions are a relatively small contributor for the T&S segments, the Proposed Rule adds measurement of pneumatic venting and, based on typical facility device counts, would require measurement either annually or every two years at compressor stations and storage facilities. INGAA recommends retaining current methods that allow EF-based calculations for estimating pneumatic device emissions for T&S, including intermittent devices. EPA requested feedback on whether to retain a "Calculation Method 4" for intermittent devices that relies on EFs,[12] and INGAA strongly supports retaining the EF option for T&S and retaining the current T&S pneumatic device EFs. Measurement should be included as an option.

If mandatory measurement is retained for T&S, EPA should add a pathway to develop updated EFs and allow EF use after adequate data is collected in initial years. In fact, an IRA-based program could address this perceived data gap to avoid unnecessary burden and costs associated with this relatively minor T&S emissions source. As proposed, the new requirements would double site survey times for T&S facilities, and EPA has not adequately justified this incremental cost for a small emissions source.

Available information from the EPA Annual Inventory Report, Subpart W as summarized in a Pipeline Research Council International (PRCI) report[13], and more recent Subpart W data available online indicate that pneumatic devices comprise a relatively small percentage of T&S emissions. Additional details are included in INGAA's February 2023 comments[14] on proposed amendments to the methane NSPS for natural gas systems, but example information includes:

- The EPA Annual Inventory GHG Report indicates T&S pneumatic devices comprise approximately 3% of total T&S sector emissions;

[12] 88 Fed. Reg. 50,314.
[13] PRCI Catalog No. PR-312-16202-R03, "Methane Emissions from Transmission and Storage Subpart W Sources," August 2019.
[14] INGAA Comments, Docket Document Number EPA-HQ-OAR-2021-0317-2483, February 13, 2023.

- The PRCI report that compiled 2011 – 2016 data shows that a facility-level EF for the larger compressor stations subject to the GHGRP based on Subpart W device counts is lower than the GHGi EF used by EPA, implying lower emissions that EPA estimates;
- A paper from Zimmerle, et al.[15] based on an Environmental Defense Fund and industry sponsored study noted that the GHGi over-estimates T&S pneumatic device emissions; and
- In more recent years, voluntary and mandatory programs have likely resulted in further decreases in T&S pneumatic device emissions, and NSPS amendments and federal guidelines for existing sources will further decrease these emissions.

This information supports use of EFs rather than measurement for T&S pneumatic devices; at a minimum, measurement should be required for a short time span to facilitate the adequacy of current EFs and develop, as needed, updated EFs. Ongoing measurement every year or every two years is not necessary for T&S pneumatic devices. If retained, mandatory measurement criteria should include an efficient pathway for developing updated EFs, and/or an IRA funded Methane Emissions Reduction Program (MERP) project could be devised to collect and analysis Subpart W measurement data to develop updated EFs after a year or two of measurements are completed.

4. Leak emissions estimates for T&S should not rely on upstream datasets and more flexibility should be included for leak estimates, including measurement-based approaches.

§98.233(q) "Equipment Leak Surveys" includes the procedures for estimating emissions from leaking components in natural gas service. Leak detection surveys are conducted at least once in each calendar year and annual emissions from detected leaks are estimated using leaking component EFs (e.g., scf THC[16]/hr), estimated annual component hours in service, and concentrations of CH4 and CO2 in the hydrocarbon stream (Equation W-30). Proposed revisions for estimating leaking component emissions in the natural gas transmission and storage (T&S) sectors include: (1) revised (increased) EFs for leaks detected using optical gas imaging (OGI) based on "OGI enhancement factors", and (2) application of a leak detection method-based "k" factor to adjust emission estimates for undetected leaks (see Equation W-30 in Proposed Rule).

INGAA's October 2022 Comments addressed similar issues with the proposed EF updates, and although EPA's analysis was updated, similar flaws remain. Thus, INGAA strongly opposes EPA's proposed revisions to the T&S gas leak emission estimation methodology, and the proposed revisions should not be adopted. The OGI enhancement factors (i.e., the ratios of the OGI EFs and the Method 21 EFs) and the application of k factors are based on an EPA analysis, described in the Technical Support Document (TSD)[17], that selectively uses data from gas leak emissions studies conducted on "upstream" natural gas production wells and gathering and boosting stations. EPA has not provided a sound technical basis for its conclusion that the OGI enhancement factors and

[15] EPA-HQ-OAR-2023-0234-0051.
[16] total hydrocarbons
[17] "Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule; Proposed Rule – Petroleum and Natural Gas Systems", U.S. Environmental Protection Agency, June 2023.

"k" factors based on upstream segment studies should apply to T&S leaker emission estimates. Further considerations include:

- The EPA analysis has shortcomings, including a small dataset, which are further discussed below;
- The leak rates implied by the proposed T&S OGI leaker EFs are large and inconsistent with OGI detection thresholds; and
- The majority of upstream equipment are outdoors; thus, leak surveys are complicated by wind and a range of OGI detection backgrounds. Such adverse conditions likely contributed to undetected leaks identified by the upstream studies and the application of k-factors. Conversely, the majority of leaking T&S components are on compression equipment which are housed; wind and background have much less adverse impact on leak surveys (i.e., far fewer undetected leaks). Thus, k-factors developed for upstream operations should not be applied for T&S.

Unless study design and in-depth analysis clearly supports applying upstream data to T&S segments, any future revisions to T&S component leak emissions estimation methodologies should be based on data from T&S sector-specific leak surveys.

Upstream Studies

As discussed in the TSD, the gas leak emissions studies conducted on "upstream" natural gas production wells and gathering and boosting stations that are the basis for the proposed revised EFs and application of k-factors are Pasci et al, 2019[18] and Zimmerle et al., 2020[19]. The Pasci study detected leaks using OGI and EPA Method 21 at 67 production and gathering and boosting oil and gas sites, and quantified leak rates with a high-flow sampler. The Zimmerle study detected gas leaks using OGI at 180 gathering stations, and quantified leak rates with high-flow samplers. During these studies, fewer, yet larger leaks were detected with OGI than by Method 21 and EPA concluded that leaker EFs based on OGI detection should be larger than leaker EFs based on Method 21 detection. EPA also used the data from these studies to update natural gas production and gathering and boosting leaker EFs for Method 21 (500 ppm and 10,000 ppm leak definition). The basic steps for calculating these revised upstream EFs were:

1. Develop OGI leaker EFs using combined data from the Pasci (101 OGI-detected leaks) and Zimmerle (593 OGI-detected leaks) studies; and
2. Calculate leaker EFs for Method 21 at 500 and 10,000 ppm leak definitions from the OGI leaker EFs times the ratio of Method 21 (at 500 and 10,000 ppm leak definitions) EFs to OGI EFs from the Pasci study alone (this ratio is the reciprocal of the OGI enhancement factor).

EPA then calculated three leak detection method-based "k" factors from the Pasci data to adjust upstream emission estimates for undetected leaks by dividing total emissions from all leaks

[18] Pacsi, A. P., Ferrara, T., Schwan, K., Tupper, P., Lev-On, M., Smith, R., & Ritter, K. 2019. Equipment leak detection and quantification at 67 oil and gas sites in the Western United States. *Elementa: Science of the Anthropocene*, *7*(29). https://doi.org/10.1525/elementa.368.

[19] Zimmerle, D., Vaughn, T., Luck, B., Lauderdale, T., Keen, K., Harrison, M., Marchese, A., Williams, L., & Allen, D. 2020. Methane emissions from gathering compressor stations in the U.S. *Environ. Sci. Technol*. 2020, *54*(12) 7552–7561.

detected by OGI and Method 21 (some leaks were detected by one of the methods but not both) and:

- Total emissions from leaks detected by OGI;
- Total emissions from leaks detected by Method 21 with a leak definition of 10,000 ppm; and
- Total emissions from leaks detected by Method 21 with a leak definition of 500 ppm.

The proposed increased T&S OGI EFs were calculated from existing Subpart W Method 21 EFs and the OGI enhancement factors calculated in Step 2 above. Notably, and as discussed in October 2022 Comments, the original basis for upstream EFs (evolved from EPA's historical leak protocol document) differs significantly from the basis for T&S factors which were developed from measured leak data. The resulting component-specific EFs currently in Subpart W are thus much larger than the analogous EFs for upstream sources. Despite this significant difference, and the historical records already showing higher component level EFs for T&S, EPA adds a factor to further increase the T&S EFs. The legitimacy of the added bias is not adequately justified by EPA. In addition, the proposed T&S k-factors that further bias the calculation of leak emissions are assumed to be the same as the upstream k-factors.

The analysis and data used to calculate the revised upstream EFs and the k-factors have many shortcomings:

- The dataset for the Pasci study that is the basis for the OGI enhancement factors (i.e., reciprocal of above Step 2 calculation) and the calculation of the k-factors is relatively small, with a total of 300 leaks from ten different component types: connectors, flanges, instruments, OELs, other, piping, PRVs, regulators, valves, and vents[20] in both oil and gas service. Over half of the leaking components were connectors in gas service. This is not a large representative dataset suitable for calculating EFs and developing regulations, especially when significant positive bias is introduced for emission estimates. Notably, this dataset does NOT meet the "50 measurements per component" criteria specified by EPA in the Proposed Rule for developing *facility-specific* component leaker EFs. It is startling that EPA would propose *industry-wide*, bias factors that are *not from the associated industry segment* when the dataset does not meet criteria for "*facility level*" leaker EF updates in the Proposed Rule.
- The single, small Pasci dataset is the sole basis for the OGI enhancement factor and the k-factors. Thus, any biases or anomalies in the measurements will fully propagate to the proposed rule revisions. For example, Table 1 lists the 15 largest leaks that were solely detected by OGI. For each of these leaks the high-flow sampler gas concentration was orders of magnitude greater than the 500 ppm leak definition, and it is questionable how such large leaks were not detected by the Method 21 survey. The largest leak for the entire study is an 83.65 scfh OEL leak, and OELs are typically the simplest components on which to detect leaks. These results suggest an inexperienced survey person or other study deficiencies. If these large leaks had been detected by the Method 21 survey, then there would have been very little difference between the Method 21-detected leaks emissions and the OGI-detected leaks emissions. Basing a rule on a single small study – especially a study where questionable

[20] Instruments, other, piping, regulators, and vents combined into "Other" category.

results are reported – is not good practice. Segment-specific and replicate studies should be conducted to develop more robust and reliable dataset for updating prescribed Subpart W EFs.

Table 1. Fifteen Largest Leaks *Solely* Detected by OGI from Pasci Study

Subpart W Equipment Class	Component Type	Emission Rate (scfh)	High-Flow Concentration (ppm)
Compressor	OELs	83.65	191,600
Compressor	Connectors	44.81	70,100
Compressor	Connectors	28.66	50,000
Other	Connectors	25.78	97,500
Minor Separator	Valves	17.98	21,000
Compressor	Piping	15.53	23,200
Separator	Regulator	12.70	40,100
Compressor	Connectors	8.74	20,000
Compressor	Valves	8.66	18,700
Separator	Valves	7.83	20,700
Compressor	Valves	6.98	22,200
Compressor	Connectors	6.53	11,600
Separator	Connectors	5.62	11,300
Separator	Instrument	4.41	10,800
Separator	Valves	2.88	9,200
	Total	**280.74**	

- The assumption that the OGI EF to Method 21 EF ratio is the same for the Zimmerle data as for the Pasci data (the basis for the Step 2 calculation above) adds a large uncertainty to the upstream Method 21 EFs. The Pasci data are only 15% of the OGI-detected leak measurements and the majority of the OGI-detected leak measurements (85%) are from the Zimmerle study (without corresponding Method 21 leak concentration measurements). The upstream segments Method 21 EFs thus have a very high uncertainty, which implies additional measurements should be conducted to develop updates to mandatory EFs.
- The OGI data are highly biased towards compressor components leaks. Over 80% of the gas-service components surveyed and measured for the Zimmerle and Pasci studies were at gathering and boosting facilities or otherwise in compressor-service (i.e., all 180 facilities in the Zimmerle study were gathering and boosting and over 40% of the leaking components for the Pasci study were at gathering and boosting facilities or otherwise in compressor-service). Thus, the EFs are very likely not representative of all upstream operations and this could be a contributing factor to the proposed rule upstream leaker EFs being greater than the current Subpart W EFs.

Large leaks of the magnitude of the proposed T&S EFs would be readily detected

The proposed OGI leaking component EFs for T&S are very large (e.g., 65 scfh for PRVs, 32 scfh for meters, 28 scfh for OEL, and 24 scfh for valves). These equate to 1 to 2+ lbs/hr, about an order of magnitude or more above OGI methane leak detection thresholds[21]. Since EFs are averages of all measurements (i.e., total emissions divided by number of measurements), these EFs infer that only very large leaks, with emissions rates much higher than established (or work practice required) detection limits, are all that are detected by OGI at T&S facilities. INGAA is not aware of any study or EPA analysis that supports this conclusion.

Similarly, the bias factors imply that fugitive emissions are significantly under-estimated for T&S and implying that a significant percentage of emissions (i.e., compounding bias factors for the EFs and k-factor would nearly double estimates) are missed for T&S. This is not consistent with published *T&S segment studies*, where results consistently show that a small percentage of leaks comprise the vast majority of emissions. The bias factors proposed imply that "missed leaks" or erroneous leak measurements comprise a significant portion of total leak emissions, which is inconsistent with T&S sector literature. In fact, other papers by Zimmerle and colleagues from an industry-EDF sponsored study conducted contemporaneously with the upstream studies indicated that current estimation methods provided a relatively accurate estimate of T&S segment emissions and may *over-predict* emissions. This conclusion was in contrast to Zimmerle/EDF published papers for upstream sectors – and also inconsistent with applying bias factors to T&S leaker EFs and the leak emissions calculation equation.

Summary and Conclusions

EPA has not provided adequate justification or support to apply the OGI enhancement factor to T&S leaker EFs or to apply k-factors to T&S leaker emission estimates. The current OGI leaker EFs should be retained since it is inappropriate to apply an "enhancement" based on analysis of a small dataset from the upstream segment that includes significant disparities in both operational equipment and leak detection environment (e.g., wind conditions). In fact, the TSD does not provide any T&S data to support its conclusion or the proposed revisions. The TSD states:

> "As described previously, our analysis of measurement study data from onshore production and gathering and boosting facilities demonstrates the need for separate OGI leaker emission factors to more accurately account for emissions. We ***expect*** [emphasis added] that the leaker factors for other industry segments that are based on measurements of Method 21-identified leaks ***may*** [emphasis added] similarly underestimate the emissions from leaking equipment when OGI (or other alternative methods besides Method 21) are used to detect the leaks."

An unsupported "expectation" that upstream segment emissions measurement data "may" similarly impact T&S does not adequately justify applying an OGI enhancement factor to T&S OGI EFs or applying k-factors to T&S leaker emission estimates, especially when under-estimation of T&S segment emissions is not indicated by other literature / studies.

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[21] EPA alternative work practice criteria, proposed Appendix K requirements, and OGI vendor publications document detection thresholds significantly less than 100 g/hr.

EPA's proposed revisions to the T&S gas leak emission estimation methodology should not be adopted. The related analysis and cited study are flawed and the supporting upstream data insufficient to warrant the proposed revisions. Further, there is no technical basis for applying these flawed revisions to T&S segments, which are not represented in the studies, especially since the original Subpart W EFs for T&S are based on a different methodology and dataset than the original Subpart W EFs for upstream operations.

The current Subpart W T&S EFs are supported by existing studies, including data specific to those segments, and should be retained and not updated. Comprehensive studies on T&S equipment would be needed to support changes to prescribed, industry-wide T&S leaking component EFs as well as application of adjustment to the leak emission estimation calculation using k-factors.

<u>Company-wide or collaborative program data should be allowed for updating leaker EFs</u>

As discussed in Comment 1, the Proposed Rule should include more flexibility for developing EF updates, including updates to segment-specific leaker EFs. As proposed, at least 50 *site-specific* measurements would be required for a particular component to develop an EF. Rather than limiting the dataset to site-specific measurements, EF development should allow company-wide data as well as data from multi-company collaborative efforts. Such programmatic approaches are consistent with IRA objectives to advance the use of empirical data and to fund MERP projects to assist operators with Subpart W reporting.

Requiring 50 component-specific and site-specific measurements implies that EPA fails to understand the prevalence and frequency of T&S facility leaks. For example, a Pipeline Research Council International (PRCI) report[22] previously provided to EPA shows that 2011 – 2016 Subpart W data indicated an average of 12 to 25 total leaks per facility annually across all ten component types and services. GHGRP data also shows that T&S methane emissions have decreased since that PRCI data collection effort, thus leak counts are likely lower due to voluntary and mandatory leak survey and LDAR requirements. Thus, it would take years or decades to acquire 50 component-specific measurements at a site. There is no reason to not allow larger datasets for development of leaker EFs. Company-wide and collaborative-program data should be allowed for developing leaker EFs, and related projects could leverage IRA funds to assist operators with GHGRP reporting, which is consistent with IRA MERP objectives.

<u>"Leak time" for emission estimates should be based on component-specific repair confirmation</u>

Rather than requiring a complete survey to validate that a repair has been completed, repair verification that meets regulatory LDAR requirements should be allowed. For LDAR, repair confirmation is directed at the affected component; Subpart W requires a complete facility survey to use a "leaking time" indicative of the time that an affected component leak. It is not reasonable or rational to include more stringent criteria for leak verification in a reporting rule than in emissions control regulations, reflected in NSPS and NESHAPs LDAR requirements. The Subpart W criteria should be adjusted accordingly and should allow the leak "time" in Equation W-30 to be based on component-specific repair confirmation. This approach is consistent with IRA direction to improve emission estimates based on empirical data. Leaking component repair may

[22] PRCI Catalog No. PR-312-16202-R03, "Methane Emissions from Transmission and Storage Subpart W Sources," August 2019.

occur and be confirmed immediately after leak discovery and this "empirical data" should be used as the basis for estimating emissions, rather than current methods which would assume the leak remains for many days or months – up to as long as a year if another complete survey is not conducted unit the next annual Subpart W survey. The current estimation approach clearly conflicts with Congress' direction toward empirical data, and component-level repair confirmation, which is sufficient to demonstrate LDAR compliance, is a clear example of definitive empirical data.

5. The proposed thresholds for the new "other large release events" category establish emission thresholds not consistent with a "super emitter" event and does not adequately consider event duration for instantaneous measurements. Subpart W should not include flawed program requirements from the third-party program proposed for the NSPS (Subparts OOOOb and OOOOc guidelines). In addition, tons emitted rather than rate should be the basis for defining such an event, and operators should be allowed to use available data to define the event duration.

INGAA commented extensively on this topic in October 2022 and also commented on the new 100 kilogram per hour (kg/hr) threshold in February 2023 comments ("February 2023 NSPS Comments")[23] on the proposed NSPS rulemaking. Those comments are not repeated here, but the cited documents should be reviewed by EPA. For example, previous comments discuss relative emission levels, noting that the proposed emission thresholds are not consistent with a "super emitter" event.

The apparent intent is to capture blowouts and other failures related to well releases, catastrophic equipment failure, fire, and explosion. For T&S sources, the related venting events (i.e., blowdowns associated with maintenance, emergency events, etc.) are reported per §98.233(i). For example, the preamble highlights maintenance related venting[24] as an important source that would be addressed by the "other large release events" category, but those emissions are already addressed for T&S sources because blowdown reporting is already required (e.g., for compressor stations and transmission pipelines) or is added by the Proposed Rule (e.g., for underground storage facilities). The added burden for tracking these events is not adequately considered by EPA. A higher threshold as discussed in previous INGAA comments should be adopted to ensure that Subpart W focuses on "large release" / "super emitter" events that occur within the T&S segment. For example, the preamble also discusses emissions associated with production wells, which is consistent with a lower threshold than the other event types discussed (i.e., events that have occurred with emissions several orders of magnitude higher than the proposed thresholds). Analogous events from the T&S segments are not identified, and the rule could define segment- and source-specific methods or thresholds to address emissions sources such as well releases discussed in the preamble.

INGAA's concerns are exacerbated by the new threshold of 100 kg/hr based on proposed Subpart OOOOb criteria, including events identified by third parties. As discussed in INGAA's February 2023 NSPS Comments, the proposed thresholds and third-party program are fraught with issues. Rather than copying the related flawed regulatory criteria into Subpart W, EPA should cite the relevant NSPS sections because the proposed NSPS program may change in the final rule or in

[23] INGAA Comments, Docket Document Number EPA-HQ-OAR-2021-0317-2483, February 13, 2023.
[24] 88 Fed. Reg. 50,296 – 50,300.

response to potential challenges to final NSPS provisions. This is imperative in order to avoid additional, unnecessary changes or program inconsistencies in the future.

For example, the February 2023 NSPS Comments discuss the 100 kg/hr threshold and the need to consider event duration rather than an "instantaneous" measurement, as described by EPA in the preamble.[25] An instantaneous measurement at a rate of 100 kg/hr that lasts for one minute emits less than 0.05 metric tons CO_2e. Clearly, such a release that could potentially be identified by a third party is not indicative of a "large release event" and should not trigger operator requirements. INGAA recommends a tonnage (i.e., total mass of emissions) based threshold rather than an emission rate. If an emission rate basis is included in the final rule, an associated duration should be defined to ensure the occurrence of a large release *event*.

Examples of additional implementation issues discussed in INGAA's February 2023 NSPS Comments include the need for standardized methods and other criteria for measurement and third-party qualifications, and verification that an "event" actually occurred because it is likely that faulty or erroneous third-party notices will occur. Significant additional discussion is available in INGAA's NSPS comments.

INGAA also recommends clarifying the basis for defining event duration. §93.233(y)(2) indicates that measurement "or a combination of process knowledge, engineering estimates, and best available data" can be used to estimate event volume. However, §93.233(y)(2)(ii) states, "The start time of the event must be determined based on monitored process parameters," which could be interpreted stringently. As implied in the introductory text, it may be possible to estimate event start by inference from available process or other facility or system data. Engineering judgment should be allowed to define event start, which would preclude the use of default event times that may significantly over-estimate emissions. For clarity, INGAA recommends revising the proposed text in §93.233(y)(2)(ii) to restate the introductory text on "process knowledge, engineering estimates," etc. rather than solely referring to "monitored process parameters."

EPA should reconsider the thresholds for large release events and consider a higher mass-based threshold than proposed, commensurate with a "super emitter" event. In addition, if an emission rate threshold is retained, EPA should define a reasonable duration for a rate (i.e., kg/hr) based threshold. EPA should also: (1) clarify §93.233(y)(2)(ii) to ensure that engineering estimates and available data can be used to estimate event duration; (2) cite NSPS criteria rather than copying flawed NSPS propositions in the Proposed Rule; and (3) preclude duplicative reporting and recordkeeping requirements in Subpart W associated with the NSPS third party large release program.

6. Estimates should account for reductions that occur via vapor recovery, combustion, thermal or other control for all sources.

The Proposed Rule should be clarified to ensure that emissions reductions or control and vapor recovery are clearly included in emission estimates and related terms are defined. This appears to be EPA's intent, but additional clear definitions are needed to improve clarity.

[25] 88 Fed. Reg. 50,296.

The Proposed Rule includes revisions to related text, such as deleting the term "thermal oxidizer" from several sections. In its place, the Proposed Rule refers to flares and "combustion devices." A definition is included in Subpart A and Subpart W for "flare", but other control technology, including "combustion device" are not defined. It may not be clearly understood that a thermal oxidizer is a "combustion device," and other control technology such as catalytic reduction should not be precluded.

EPA should ensure that Subpart W clearly accounts for control of methane emissions that result from routing emissions to a process or device that reduces the methane content of the stream before emitting to atmosphere. Definitions should be added for "combustion device" that clearly identify candidate technologies such as thermal oxidizers, and other types of potential control options, such as catalytic control should also be included in emission estimates. Thus, "control device" and/or "other control device" (i.e., non-combustion) should also be defined. In addition, EPA should consider an offramp or simplification of ongoing monitoring, reporting, and recordkeeping requirements if a source clearly demonstrates zero or reduced emissions from control.

7. Subpart W should not mandate default flare / combustion destruction efficiencies that differ from state or federal rules or permits, or other information such as manufacturer guarantees.

The Proposed Rule includes default destruction efficiency tiers (98%, 95% or 92%) based on aerial surveys conducted in the production sector that should not be mandated for T&S. For example, operators should be able to document an alternative as reflected in a permit or due to a federal or state regulation, or from a performance guarantee. Federal or state regulations or permits are better designed to address performance than mandated performance levels in a reporting regulation. A guarantee from a flare manufacturer is another example of support documentation that should be sufficient for estimating emissions.

The proposed three-tier approach for defining destruction efficiency (98%, 95% or 92%) is based on a study using airborne sampling from three gas production basins.[26] Similar to the discussion in Comment 4 on use of upstream data for other segments, EPA has not adequately justified applicability to T&S, and T&S operators should be able to document an alternative, such as a control efficiency document in a permit, emission limit, or from a federal or state regulation.

Alternatives to the defaults are warranted because there are questions about the cited top-down study, its conclusions regarding destruction and removal efficiency (DRE), and its application to downstream segments. For example, the study contains uncertainty in the alignment of the airborne dataset with the location of flares/wells and states that further work is required to access infrastructure details to obtain more accurate attribution of individual DRE values to factors pertaining to the flare design and operation. The Tier 3 default value is based on the low end of the range of empirical results observed in testing from 3 production basins; there is no indication that these processes and gas streams are representative of flare applications at T&S facilities. No additional justification for this lower value has been provided and further analysis of the DRE uncertainty (i.e., volumes of ±50%) is warranted. The default Tier 3 DRE value is poorly

[26] Plant, G., et al. 2022. "Inefficient and unlit natural gas flares both emit large quantities of methane." Science, 377 (6614).

supported, based on aerial surveys with inherent measurement limitations, and appears to arbitrarily rely on low end destruction efficiencies from the dataset.

Information from existing permits or related federal or state regulations is more appropriate to address performance than mandated performance levels in Subpart W, as is a manufacturer guarantee. Flare monitoring and regulatory criteria have a long history and are mostly related to refinery and natural gas industry upstream applications, where process streams differ considerably from T&S. Burdensome Tier 1 (NESHAP CC) and Tier 2 continuous monitoring requirements are not typically required for T&S facilities. Thus, the DRE selection hierarchy results in a Tier 3 default requirement of 92%. This could result in differences in reported or permitted emissions as compared to methodologies previously used – e.g., for state reporting for facility permits. The mandatory default should not be required, especially for T&S sources. Rather than mandating default DREs based on the proposed tiers, T&S operators should be allowed to use an alternative based on other information, including facility permits and state regulations or reporting criteria as well as manufacturer guarantees.

8. INGAA recommends the rule allow flexibility to integrate advanced technologies that become available, such as the option of using an OGI emissions quantification system as an accepted technology for methane emissions quantification. Use of acoustic technology for manifolded systems should not be eliminated.

INGAA's October 2022 Comments emphasized the need to accommodate technology advances that improve the quality of reported GHG data, and that objective is consistent with the IRA and provides the ability to more readily integrate the results of successful IRA-funded MERP measurement and monitoring projects into Subpart W. To accommodate measurement and monitoring technological progress, the rule should add more flexibility for integrating new technologies.

For example, INGAA recommends the rule allow flexibility to integrate advanced technologies that become available, such as the option of using optical gas imaging (OGI) emissions quantification system as an accepted technology for methane emissions quantification. Technology advancements may confirm the performance of OGI emissions quantification systems that are under development, but the current regulations do not provide an efficient mechanism to incorporate such technological advances into Subpart W. It's possible that related projects will be funded under the IRA MERP program, and that program could even be used as a technical platform to expedite and facilitate technology approval, including using the MERP to develop standardized methodology for streamlined technology review and acceptance. INGAA's previous comments include additional discussion, and INGAA welcomes the opportunity to explore with EPA the methodologies and metrics that could be used to facilitate and expedite acceptance of new measurement and monitoring technologies.

<u>Acoustic technology should be allowed to identify the leak source in a manifolded system</u>

The Proposed Rule retains the acoustic device for quantification of through-valve leakage but eliminates its use for manifolded lines. EPA should *selectively* retain the use of acoustic devices for manifolds when determining which line (e.g., which compressor valve) is leaking in manifolded systems. In this application, the technology is used to identify the source, but not used to quantify emissions, which would be measured downstream of the manifold using accepted methods such as a high-volume sampler, calibrated bag, or meter.

As noted in October 2022 Comments, INGAA understands that acoustic technology is a method allowed for measuring through valve leakage and should not be used to quantify emissions in manifolded systems. However, acoustic technology can be a valuable tool for assessing manifolded systems, where the acoustic signal may be used to identify which line includes flow – i.e., identify the leak or vent source that is passing through a line into the manifold.

INGAA believes that eliminating the use of acoustic leak detection from manifold groups ignores the important function that can be provided – i.e., not leak quantification but rather the fact that acoustic leak detection is a valuable tool in *attributing source contribution to manifolded compressors*. A real-world example is application by an INGAA member where the leak source from four reciprocating engines venting to a single stack (i.e., manifolded compressors) was identified with the acoustic device so that the compressor emissions could be attributed to the appropriate compressor source / leaking valve and operating mode. The acoustic detection was done upstream of the manifold to identify which valve was leaking and the associated flowrate was measured downstream.

INGAA recommends that Subpart W continue to allow the use of acoustic leak detection for manifolds to *identify which line (e.g., which compressor valve) is leaking*.

9. Consistent with past practice when Subpart W was promulgated and amended, Best Available Monitoring Methods (BAMM) should be allowed in select cases during the initial (2025) reporting year.

When Subpart W was promulgated and in subsequent amendments, selective use of BAMM was allowed in the first one or two reporting years. The Proposed Rule eliminates those previously applicable provisions in §98.234(f) and (g) and does not allow BAMM for any of the new requirements proposed. The Proposed Rule implements significant new requirements, and BAMM should be allowed in select cases for the initial reporting year. An appropriate BAMM section should be added to §98.234.

INGAA recommends that BAMM be included in select cases where new data or operational requirements may take some time to implement. Three examples follow for T&S:

- New requirements for natural gas transmission pipelines require data gathering on interconnects, farm taps, and other M&R stations along affected pipelines. These assets can be spread over hundreds of pipeline miles across several states. Operators can initiate programs to collect accurate and complete data, but more than a single year may be needed. BAMM should be allowed in the first applicable year for these transmission pipeline activity data so that operators have adequate time to complete data collection.
- New measurements are required for pneumatic devices and centrifugal compressor dry seals. For the former, the Proposed Rule will require annual measurement in most cases. If an EF option is not included (see Comment 3), operators in T&S should be allowed two years to complete pneumatic device vent measurements. For centrifugal compressor dry seals, ports may need to be installed that require planning and a maintenance shutdown to be completed.

Operators should be allowed two years to complete the initial measurements; EFs based on measured data acquired over the first two years can be used to estimate emissions from units not measured in a particular year.

- Throughput reporting adds QA/QC requirements that may not be met by meters currently installed at a subject facility. For example, custody transfer metering along a pipeline may meet the proposed QA/QC, but meters at a compressor station may need to be upgraded or replaced, and/or operating and maintenance practices may need to be upgraded. Systemwide implementation within a year may be challenging and two years should be allowed for implementing throughput metering criteria at all affected facilities.

10. Three additional examples from INGAA's October 2022 Comments.

As discussed above, INGAA's October 2022 Comments on the previous notice to amend Subpart W include additional discussion on comments above, and also identify additional issues. INGAA's comments are enclosed. EPA is referred to those comments for additional details and content, and three additional items from the October 2022 Comments are highlighted here:

- For dry seal monitoring, clarity is needed to ensure that only the compressor side dry seal is monitored. As explained in previous comments, the measurement should be conducted on the "inboard" / compressor side but should not be required on the "outboard" seal on the air side motor and shaft bearing.
- §98.2326(n) includes unnecessary reporting requirements that should be eliminated. Information that is not used to calculate or validate GHG emissions should not be included; if EPA requires information for something other than GHG reporting, it should obtain it through a formal information request that includes rationale for why this information is needed instead of requiring the information for Subpart W.
- Based on the complexity of liquefied natural gas (LNG) systems, INGAA recommends that EPA allow site-specific engineering estimates based on best available data for LNG import/export facility acid gas removal (AGR) vents, as well as nitrogen removal unit vents. The latter is added in the Proposed Rule.

INGAA appreciates EPA's continued efforts to improve the GHGRP and believes that the comments we have provided will improve T&S sector emission estimates and ensure consistency with IRA objectives. INGAA welcomes the opportunity for additional discussion regarding our comments or other engagement or additional dialogue. My contact information is below.

Regards,

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Encl: INGAA's October 6, 2022 comments to EPA re: "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, Docket ID No. EPA-HQ-OAR-2019-0424"

Interstate Natural Gas Association of America

October 6, 2022

U.S. EPA Docket Center
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RE: Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, Docket ID No. EPA-HQ-OAR-2019-0424

The Interstate Natural Gas Association of America (INGAA), the trade association that represents the interstate natural gas pipeline industry, respectfully submits these comments in response to the United States Environmental Protection Agency's (EPA or Agency) proposed "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule" (hereinafter, Proposed Rule), which was published in the Federal Register on June 21, 2022[1].

INGAA members own and operate the vast majority of the interstate natural gas transmission and storage segment in the U.S. and Canada. INGAA member companies transport more than 95 percent of the nation's natural gas through approximately 200,000 miles of interstate natural gas pipelines. In 46 of the 48 contiguous United States, INGAA member companies operate over 5,400 natural gas compressors at over 1,300 compressor stations and storage facilities along the pipelines to transport natural gas to local gas distribution companies, industrials, gas marketers, and gas-fired electric generators.

Accordingly, this rulemaking is of tremendous importance to INGAA and its members. Indeed, INGAA has participated in all EPA rulemakings involving regulation of methane from the oil and natural gas source category, including recently proposed preamble language entitled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review."[2]

INGAA members currently invest significant resources to report Greenhouse Gas (GHG) emissions in accordance with 40 CFR 98 Subpart W (Subpart W) and the proposed revisions as reflected in the Proposed Rule will have a significant impact on INGAA's members. In fact, by EPA's cost estimates, sources subject to Subpart W will bear approximately 82% of incremental burden associated with the Proposed Rule[3] even though based on 2020 Greenhouse Gas Reporting Program data[4] are responsible for about 12% of GHG emissions.

[1] 87 Fed. Reg, 118 (June 21, 2022)
[2] EPA Docket ID No. EPA-HQ-OAR-2021-0317 (INGAA's comments on Proposed Preamble Language) (Attachment 1 to these comments) (hereinafter INGAA's Preamble Comments)
[3] 87 Fed. Reg, 118 (June 21, 2022), Table 7, page 37032
[4] https://www.epa.gov/ghgreporting/ghgrp-reported-data

THE INFLATION REDUCTION ACT & THE PROPOSED RULE

On August 16, 2022, President Biden signed into law the Inflation Reduction Act (IRA).[5] The IRA mandates the EPA impose and collect a charge on methane emissions from the petroleum and natural gas sector where methane emissions from an applicable facility exceed a pre-determined waste emissions threshold.[6] The fee starts at $900 per metric ton of methane in calendar year 2024, increasing to $1,200 in 2025, and then tapering off at $1,500 in 2026 and later years. Congress determined that relevant aspects of the program, including *which* facilities are subject to the charge and *how* to calculate the amount of methane subject to the charge, will be based on EPA's Greenhouse Gas Reporting Program (GHGRP) Subpart W.

To implement the methane charge program, Congress mandated EPA to revise Subpart W within two years (by August 16, 2024) to ensure that reporting and calculation of the methane charge are based on empirical data, accurately reflect the total methane emissions and waste emissions from the applicable facilities, and to allow owners/operators to submit empirical emissions data to demonstrate the extent to which a charge is owed.

With this clear direction from Congress, INGAA recommends EPA forgo finalization of the portion of the Proposed Rule related to Subpart W. In a final rule, EPA can justify forgoing the Subpart W revisions due to the congressional mandate in the IRA and state that it will propose comprehensive Subpart W revisions to fulfill the mandate in the IRA. After finalization, EPA can analyze the IRA and develop a new rulemaking that responds to the congressional mandate. This rulemaking can include new requirements that respond directly to the IRA, as well as portions of the Proposed Rule related to Subpart W that EPA deems to be of continued relevance and importance to the program. A single rulemaking will reduce the burden on both industry and the Agency.

As you will see below, INGAA advocates for improved data quality and further quantification, which aligns with Congress's goal of utilizing empirical data. Working through these (often highly complicated) issues in the context of a new rulemaking will provide EPA, regulated stakeholders, and the public at-large the needed time and proper regulatory vehicle to make a single, comprehensive update to GHGRP Subpart W.

INGAA is committed to being at the table for those discussions and to work together to help EPA achieve the goals of the IRA.

EXECUTIVE SUMMARY

INGAA recognizes that EPA's GHGRP data are used by a variety of stakeholders for information purposes, for benchmarking purposes, and to report US GHG emissions. GHG emission data must be accurate, representative, and timely to fulfill the various uses of the data. Accordingly, INGAA appreciates the opportunity to submit comments on the Proposed Rule and offers them in the spirit of efficiently and effectively improving the accuracy and quality of GHG data reported by the natural gas transmission and storage (T&S) sector.

[5] https://www.govinfo.gov/content/pkg/BILLS-117hr5376rh/pdf/BILLS-117hr5376rh.pdf.
[6] See Sec. 60113. Methane Emissions Reduction Program.

INGAA is particularly pleased with EPA's efforts to reduce burdensome and in some cases, duplicative, reporting requirements as reflected by more than 35 data elements that are proposed to be removed because they do not add value. For example, INGAA believes the proposed removal of the requirement to conduct reciprocating and centrifugal compressor measurements in not-operating-depressurized mode at least once every three years will eliminate extra work that did not provide any meaningful GHG data.

It is important to note that INGAA members are continuously looking for new and innovative ways to reduce GHG emissions from T&S sources. In many cases, technological advances that reduce GHG emissions or improve GHG emissions measurement outpace the regulatory process. Accordingly, INGAA strongly encourages EPA to include flexibility for affected facilities to implement new GHG reduction and measurement technologies when those technologies are supported with defensible data. The ability to rapidly deploy new technology to reduce and measure GHG emissions will become even more important with the anticipated revisions to the GHGRP mandated by the IRA.

INGAA is providing comments on several items that can be grouped into the following three areas:

1. **Accommodate Technology Advances that Improve the Quality of Reported GHG Data**

1.1. To achieve reductions in emissions from technological advancements, the rule should provide flexibility that allows operators the option to use either the factors provided in Table W-9 or improved emission factors (EF) based on company or vendor test data.

1.2. INGAA recommends the rule allow flexibility to integrate advanced technologies that become available, such as the option of using optical gas imaging (OGI) emissions quantification system as an accepted technology for methane emissions quantification. Technology advancements may confirm the performance of OGI emissions quantification systems that are under development, but the current regulations do not provide a mechanism to incorporate such technological advances into Subpart W.

2. **Apply Appropriate Emission Factors for the T&S Sector**

2.1. The current T&S emission factors for OGI should be retained. The current emission factors are based on studies and leak rate measurement from the T&S sector. The proposed emission factors for optical gas imaging OGI are based on studies from upstream emission sources and those studies are not representative of methane emissions from T&S sources.

2.2. EPA should allow operators the option to use emission factors based on past Subpart W measurements for the calculation of emissions from T&S sources instead of requiring ongoing annual testing. Affected sources in the T&S sector have completed Subpart W measurements for over a decade and this data allows for the generation of defensible emission factors.

2.3. The final rule should provide clear explanations that year-over-year increases do not necessarily reflect changes in actual emissions, but rather changes in accounting methods. In particular, an explanation is needed for updates to natural gas-fired reciprocating engine methane exhaust emission factors and for facility leak emissions should EPA adopt a higher emission factor for OGI leak surveys.

2.4. Instead of mandating new measurements for centrifugal compressor dry seals, INGAA recommends that EPA allow operators the option to use emission factors established by equipment vendors or on-board measurements available from the unit's system. Further, INGAA and Pipeline Research Council International (PRCI) have provided EPA defensible emission factor data for rod packing emissions, and company-specific factors are available based on measurements conducted since 2011. Accordingly, INGAA recommends that EPA allow operators the option to use emission factors for rod packing emissions instead of ongoing annual measurements and a new requirement to measure rod packing in standby pressurized mode.

3. Address a Diverse Range of General Issues

3.1. In lieu of a resurvey of the entire facility, INGAA recommends that EPA allow operators to use leak detection and repair records to determine the number of hours a component leaked instead of using the default value of 8,760 hours.

3.2. EPA should reconsider limiting the use of automatic Best Available Monitoring Methods (BAMM) to the first year of reporting and allow requests for the use of BAMM beyond the first year. INGAA members, as do others affected by the proposed regulations, use a variety of systems to collect, compile, reduce, and report GHG data. INGAA recommends that EPA extend the compliance date to January 1 of the year following rule promulgation thereby establishing a compliance date that allows operators at least six months to modify and verify data collection and management systems. Further, EPA established precedents when GHGRP (specifically Subpart W) was first promulgated allowing operators' use of BAMM for up to two years through a combination of automatic BAMM and subsequent requests. While INGAA members appreciate the opportunity for the use of BAMM, a limited extension of those provisions beyond the first reporting year is necessary to allow operators the necessary time to establish compliance programs given the broad revisions to the GHGRP.

3.3. It is difficult for INGAA to fully assess the requirements and impacts of the Proposed Rule, because the underlying compliance requirements of OOOOb and OOOOc are not yet known. At the time INGAA submitted these comments, the proposed regulatory text was still under review at the White House's Office of Information and Regulatory Affairs and not publicly available.

3.4. INGAA recommends that EPA increase the threshold for reportable large leaks to 5.5% of the 40 CFR Part 98 threshold of 25,000 metric tons CO_2e per year, bringing the quantity in line with the Pipeline Hazardous Materials and Safety Administration (PHMSA) threshold of 3,000,000 standard cubic feet (49 CFR 191.3(1)(ii)).

3.5. INGAA recommends that EPA remove tank monitoring requirements when tanks are routed to a flare because as noted in the preamble to the proposed rule, there have been no leaks reported over the past 6 years.

3.6. INGAA is requesting that EPA provide clarity on dry seal monitoring to indicate that only gas side monitoring is required.

3.7. The Proposed Rule establishes new flare activity reporting requirements that are irrelevant to the calculation of GHG emissions and should be removed. Specifically, the proposed new requirements in 98.236(n)(2)(ii) do not validate or improve GHG emissions reporting and should be removed.

3.8. Based on the complexity of liquefied natural gas (LNG) systems, INGAA recommends that EPA allow site-specific engineering estimates based on best available data for acid gas removal (AGR) vents.

3.9. INGAA recommends that acoustic leak detection be allowed for manifolded compressors in some situations.

DETAILED COMMENTS

INGAA's detailed comments are provided below.

1.1. INGAA supports the emission factor updates for combustion exhaust methane emissions from reciprocating engines but recommends flexibility that allows operators to use emission factors, when appropriate, that reflect technological innovation that decreases emissions.

INGAA Supports Exhaust Methane Emission Factors Updates

The Proposed Rule updates combustion exhaust methane emission factors (EF) for natural gas-fired reciprocating engines that drive compressors. INGAA has consistently supported more accurate methane EFs for natural gas-fired reciprocating engines since the original 2009 Subpart C proposal.[7] As discussed in previous INGAA comments, the longstanding Subpart C EF is adequate for some combustion equipment (e.g., turbines, boilers) but under-estimates combustion exhaust methane emissions from reciprocating engines. The proposed emission factor updates, presented in Table W-9, represent reasonable average values and INGAA supports this revision.

Flexibility is Needed to Ensure Reported Emissions Reflect Technological Advancements

However, additional flexibility is warranted so that operators can reflect technological advancements in the exhaust methane emissions estimate for reciprocating engines. While oxidation catalysts do not effectively reduce methane from lean burn engines, advanced combustion-based technologies can reduce exhaust methane. For example, improved in-cylinder bulk mixing through approaches such as high-pressure fuel injection can reduce emissions of both NOx and methane / products of incomplete combustion. EPA should allow the use of operator- or vendor-defined EFs, based on measurement data, so that technological advancements that reduce methane are reflected in the annual inventory. If not, the GHGRP will not incorporate mitigation program results. This is especially important because these emissions could result in imposition of a "methane fee" under the recently passed Inflation Reduction Act. For example, EPA's recent Good Neighbor proposal[8] would require nitrogen oxides (NO_x) reductions on thousands of T&S reciprocating engine compressor drivers.[9] Two-stroke lean-burn (2SLB) engines requiring NO_x control may install low emissions combustion (LEC) technology that includes high-pressure fuel injection and ignition timing control. In some cases, LEC control may reduce methane emissions. The 2SLB EF in Table W-9 does not accurately reflect methane emissions for such LEC-equipped engines, and those units should be allowed to use an appropriate EF based on company or LEC vendor data. Since these facilities may also be subject to methane fees, this erroneous EF could result in financial penalties for the operator. Thus, it is imperative that EPA provide flexibility to use defensible operator data or vendor data or specifications as an alternative to Table W-9 EFs.

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[7] For example, see EPA-HQ-OAR-2008-0508-0480, INGAA Comments on Proposed GHG Reporting Rule, June 9, 2009; and INGAA presentation for meeting with EPA staff on November 19, 2019

[8] "Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard," 87 FR 20036, April 6, 2022

[9] INGAA comments on "Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard," June 21, 2022.

Subpart C Common Pipe and Aggregation Methodologies Should Be Retained

Subpart C allows emission calculations for natural gas-fired combustion units to be completed using Tier 1 or Tier 2 common pipe or aggregation methods. Implementation of updated emission factors dependent on unit type should not compromise access to those calculation methods for natural gas-fired units, and Subpart C should clearly indicate that operators can use available data to identify the fraction of fuel assigned to different unit types (with different combustion exhaust methane EFs). Compressor stations often include different types and sizes of compressor drivers, such as one or more two-stroke lean-burn engines, four-stroke lean-burn engines, and turbines at the same facility. Operators should be allowed to use available records (e.g., unit size, heat rate, annual run time) to estimate annual fuel usage and assign the appropriate exhaust methane EF from Table W-9 (for engines) or Table C-2 (for turbines, boilers, etc.) for aggregated or common pipe estimates.

1.2 The Proposed Rule should support and encourage advanced technologies, such as OGI emissions quantification technologies, and create a pathway where proven systems can be an accepted measurement technology for methane emissions.

The OGI camera is used across numerous industries to visualize emissions from leaks and vents. Currently, Subpart W allows the use of the OGI cameras for the identification of leaks and may be used to screen for emissions from certain vented sources, such as transmission storage tanks. Once emissions are identified with an OGI camera, additional measurement technologies or emissions calculation methodologies are employed to quantify the emissions.

Recent technology advancements have resulted in the development of OGI emissions quantification systems and offer a significant improvement opportunity in emissions quantification if/when technology performance is validated. For example, the QL320 developed by Providence Photonics and marketed by FLIR systems uses the output from a FLIR GF320 camera and translates the collected data into gas-specific emission measurements using a combination of an algorithm and gas-specific response factors. Once performance is proven, the QL320 and other advances in OGI quantification technology could be used to directly quantify methane emissions from equipment leaks, vents, and/or certain pneumatic devices as an alternative to using emission factors, currently approved monitoring technologies, and related assumptions.

The use of OGI or other leak quantification technology would be particularly beneficial for centrifugal and reciprocating compressor vent emissions. The onshore natural gas transmission compression industry segment is required to report emissions from transmission storage tanks that are attributable to leakage through the scrubber dump valve. Where required, emissions from these vents are estimated based on measurements performed using calibrated bagging, high volume samplers, flow meters, or acoustic leak detection devices.

A calibrated vent bag is a plastic bag of known volume that is placed over a vent and inflated via the vent emissions. The time required for the bag to fully inflate is recorded by the technician. This process is repeated three times and the average of the inflation times is used along with the known volume of the bag to compute the flow rate. This measurement method has obvious potential inaccuracies that are largely attributable to human error (e.g., judgement of when the bag is “full”, precision of inflation start and stop time, changes to flow rate due to backpressure caused by the bag). A flow meter may also be used to measure vent flow rate.

Alternatively, an acoustic leak detector could be used to measure flow across a normally closed valve upstream of the vent. Calibrated vent bags, flow meters, and acoustic leak detectors all have the potential to contribute to inaccurate emissions quantification. These techniques measure total exhaust flow, not pollutant emission rate.

The only vent measurement technology currently approved for use under Subpart W that directly measures methane emission rate is a high-volume sampler (HVS). However, the primary manufacturer of the HVS stopped production several years ago and HVS systems are being introduced into the market now but are not well established. An OGI emissions quantification system would provide a comparable alternative to the high-volume sampler for directly measuring methane emissions from vents. This example is indicative of the general concern – Subpart W should be updated to support a reasonable pathway for integrating methane emissions monitoring and measurement technological advances.

An OGI emissions quantification system or other systems under development that provide the ability to quantify leaks without directly measuring at the equipment interface would also provide benefits in the areas of efficiency and safety. When using currently approved vent measurement methods, personnel are often required to access the vent via an elevated support surface (e.g., ladder), which takes additional time and poses safety risks. A proven OGI emissions quantification system would provide accurate measurements that can be performed safely and efficiently at ground level.

2.1 For OGI-based leak surveys, the analysis for the T&S sector using data from upstream sectors is not representative of T&S operations and T&S leaker emission factors (EFs) should not be revised.

The Proposed Rule would add new emission factors for estimating equipment leak (leaker) emissions when using an alternative method to Method 21, including the OGI camera. The OGI Alternative method leaker EFs are approximately 4 times higher and based on an EPA technical support memorandum[10] ("Subpart W TSD Memo") that analyzes emission factors for operations in upstream segments – i.e., onshore production and gathering and boosting. For leak surveys using the OGI camera (and other methods in section 98.234(a) other than Method 21), EPA developed an "OGI enhancement factor." The OGI enhancement factor, a 4.1 multiplier, is based on EPA analysis of upstream data. EPA then applies that factor to T&S (and other sector) leak emission factors based on Method 21 leak detection. However, EPA failed to acknowledge that current leaker EFs for the "downstream" segments are already significantly higher than the analogous EF for upstream segments. The current T&S EFs are higher because the T&S EFs are based on more robust datasets from studies[11,12,13] that included direct measurement of leaks, while the current upstream segment EFs are based on studies that applied "correlation equations" to

[10] EPA-HQ-OAR-2019-0424-0120

[11] Clearstone (Clearstone Engineering Ltd.). 2002. *Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants*. Prepared for Gas Technology Institute under USEPA Grant No. 827754-01-0. June 20, 2002.

[12] NGML (National Gas Machinery Laboratory, An Institute of Kansas State University), Clearstone Engineering Ltd and Innovative Environmental Solutions, Inc. 2006. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites.*

[13] Clearstone (Clearstone Engineering Ltd.). 2007. *Fugitive Emissions Pilot Project: Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry*. Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). April 16, 2007.

estimate leak rates.

INGAA strongly opposes EPA's proposed approach to adjust transmission, storage, and LNG leak EFs for OGI due to several factors:

- EPA has not provided a sound technical basis for its conclusion that an OGI enhancement factor based on studies of different segments using different study design and different methodological approaches should apply to T&S leaker emission factors.
- The differences for the upstream sector are likely due, at least in part, to the equipment / components surveyed (e.g., production well pad versus gathering compression) and not solely due to the different detection methods. EPA has already accounted for compression versus non-compression service components for transmission compressor stations.
- The leak rates implied by the proposed factors for transmission OGI leak EFs are very large and inconsistent with OGI detection thresholds. The T&S leak EFs are based on different studies and more detailed methods (e.g., direct leak rate measurement) than the historical EFs for upstream sources.
- Significant disparities (i.e., significant under-estimation) in leak emission estimates for T&S sources is not supported by recent studies of this segment.

EPA has not provided adequate justification or support to apply the OGI enhancement factor to T&S and LNG leaker emission factors. The current leaker EFs should be retained since it is inappropriate to apply an "enhancement" based on analysis of data from a different segment that includes significant disparities in both study design (e.g., direct measurement versus correlation equation-based emission estimates) and operational equipment. In fact, the <u>Subpart W TSD Memo does not provide any T&S data to support its conclusion or the proposed revision.</u>

The Subpart W TSD Memo states:

> "…our analysis of measurement study data from onshore production and gathering and boosting facilities demonstrates the need for separate OGI leaker emission factors to more accurately account for emissions. We ***expect*** [***emphasis added***] that the leaker factors for other industry segments that are based on measurements of Method 21-identified leaks ***may*** [***emphasis added***] similarly underestimate the emissions from leaking equipment when OGI (or other alternative methods besides Method 21) are used to detect the leaks.

An unsupported "expectation" that upstream segment emissions measurement data "may" similarly impact T&S is not sound justification for applying the 4.1 multiplier to T&S emission factors. Discussion of additional technical issues that raise questions about data applicability to T&S follows.

<u>A high-level review of data from upstream studies does not support a 4.1 multiplier</u>

EPA has concluded that the "multiplier" for upstream emission factors is due to the leak detection method (i.e., Method 21 versus OGI leak screening), but there are other significant factors that must be considered. For example, the more recent OGI data reviewed by EPA has a prevalence of different components when compared to the historical leaker EFs for upstream segments.

EPA calculated the 4.1 multiplier by dividing emission factors developed from two recent leak emissions quantification studies (Zimmerle[14] and Pasci[15]) and the current Table W-1E leaker emission factors based on the Method 21 10,000 ppm leak definition. EPA then proposes to apply the 4.1 multiplier to current Subpart W Method 21 10,000 ppm leaker emission factors for natural gas transmission and storage, and LNG facilities to develop emission factors that would apply to leaking components found during leak surveys conducted using OGI. One of many EPA conclusions is that the differences for the upstream segments are due solely to the detection method. However, that may not be the case, because it appears different equipment categories are represented. Over 80% of the gas-service components surveyed and measured for the Zimmerle and Pasci studies were at gathering and boosting facilities or otherwise in compressor-service (i.e., all 180 facilities in the Zimmerle study were gathering and boosting and about 40% of the components surveyed at 67 facilities for the Pasci study were at gathering and boosting facilities or otherwise in compressor-service).

The Subpart W TSD Memo does not demonstrate that this prevalence of compressor components surveyed for the Zimmerle and Pasci studies is representative of the components for the onshore natural gas production and gathering and boosting industry segments, where there are many components associated with the wellhead and non-compressor components in proximity. It is likely that the newly proposed (OGI) Table W-1E emission factors are significantly higher than the current Table W-1E emission factors because the new emission factors are based on measurements that over-represent compressor components.

For the transmission segment, EPA has already addressed this issue by publishing different emissions factors for compressor and non-compressor service. Compressors are subject to vibration and thermal cycling and thus EFs are greater than non-compressor components in Table W-3A; for example, the average "compressor component emission factor / non-compressor component emission factor" ratio for T&S in Subpart W is about 5.4. The fact that EPA has accounted for this characteristic for transmission compressor station leak EFs is cause enough to conclude that the 4.1 multiplier proposed by EPA is not appropriate.

<u>Large leaks of the magnitude of the proposed T&S emission factors would be readily detected</u>

The proposed leaking component emission factors for T&S are very large (e.g., 163 scfh for PRVs, 79 scfh for meters, 71 scfh for OEL, and 61 scfh for valves). This equates to over one kg/hr in all cases, which is several orders of magnitude higher than OGI methane leak detection thresholds[16]. Since EFs are averages of all measurements (i.e., total emissions divided by number of measurements), these emission factors infer that only very large leaks, with emissions rates orders of magnitude higher than established (or work practice required) detection limits, are all that is detected by OGI at T&S facilities. INGAA is not aware of any

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[14] Zimmerle, D., K. Bennett, T. Vaughn, B. Luck, T. Lauderdale, K. Keen, M. Harrison, A. Marchese, L. Williams, and D. Allen. 2019. *Characterization of Methane Emissions from Gathering Compressor Stations: Final Report*. Prepared for the U.S. Department of Energy under Contract No. DE-FE0029068. October 2019 Revision.

[15] Pacsi, A. P., T. Ferrara, K. Schwan, P. Tupper, M. Lev-On, R. Smith, and K. Ritter. 2019. "Equipment leak detection and quantification at 67 oil and gas sites in the Western United States." *Elementa: Science of the Anthropocene*, 7: 29.

[16] EPA alternative work practice criteria, proposed Appendix K requirements, and OGI vendor publications document detection thresholds significantly less than 100 g/hr.

study or EPA analysis that supports this conclusion.

Similarly, the EPA 4.1 multiplier presumes the "frequency" of leaks detected by Method 21 that are missed by EPA. Leak EFs are based on study data that divides total emissions (measured or estimated emissions, by component type) by the number of leaking components ("N"). Example calculations can be performed that define the number, N, of OGI missed leaks that are required to result in a 4.1 multiplier, and N is dependent on the total emissions not found (e.g., assume 10 to 30% of the total emissions are due to the leaks missed with OGI). This exercise indicates that OGI would need to miss the vast majority of leaks (e.g., on the order of 70% or more leaks would be missed with OGI, or OGI would detect only 1 in 3 to 1 in 4 leaks compared to leaks detected with Method 21 at 10,000 ppm screening threshold) which is not supported based on current understanding of leak detection methods (e.g., for gathering and boosting, Pasci found approximately 30% more (small) leaks with Method 21).

<u>T&S leak EFs are based on direct measurement and T&S estimates do not indicate leak emissions are under-estimated</u>

It is important to understand that the technical basis for the leaker EFs that apply in the existing regulation is very different, depending upon the segment. As noted in the EPA support memo, upstream EFs used estimation methods (e.g., correlation equations) following the EPA "Leak Protocol" document. In contrast, T&S EFs are based on robust data sets from studies that conducted direct measurement of leaks (e.g., with High Volume Sampling System). Because a more thorough and complete T&S dataset is available, the historical EFs for T&S are significantly higher than EFs for upstream segments. Recent studies for T&S[17] that include OGI leak surveys indicate that current methodologies provide a reasonably accurate estimate of facility emissions. The cited study was funded cooperatively by T&S companies and the Environmental Defense Fund and concluded that T&S emissions are *not* under-estimated (see Figure 4 of the study), and that transmission fugitive (i.e., leak) emissions are *not* under-estimated. The EPA proposed change would increase those emissions by a factor of 4, which contradicts data from the T&S sector.

In conclusion, EPA should not update leak EFs in the Proposed Rule using data from studies that use different methodologies to correlate leaker EFs for segments that are not represented in the studies. EPA should also consider other factors (e.g., differences in component types surveyed, measured versus inferred emission estimates) rather than concluding detection methods are the sole reason for differences between studies. EPA's approach leads to flawed conclusions, and it is not appropriate to apply the "correction factor" from upstream studies to EFs in downstream sectors. The current Subpart W EFs for transmission, storage, and LNG facilities are supported by existing studies, including data specific to those segments, and should be retained and not updated.

2.2. Over fourteen thousand measurements conducted at transmission and storage facilities to meet Subpart W requirements were documented in PRCI reports that analyzed 2011 – 2016 data. With eleven years of data now available for analysis, EPA should allow operators the option to use available measurements data to develop emission factors rather than

[17] Methane Emissions from the Natural Gas Transmission and Storage System in the United States," Zimmerle, et.al., Environmental Science and Technology, July 2015 (e.g., see Figure 4 and Figure 5).

requiring ongoing annual measurements.

In the 2010 Subpart W rulemaking, EPA required compressor vent measurements in sections 98.233(o) and (p) due to the lack of emissions data.[18] With tens of thousands of measurements completed since the initial 2011 reporting year, EPA should allow operators the option to use emission factors rather than continuing to mandate annual compressor vent measurements. The emission factors could be based on analysis of 2011 through 2016 measurement data in PRCI reports[19,20,21] provided to EPA and/or company specific EFs based on measurement data used to develop emission factors for "modes not measured" in any particular annual survey. For the former case, PRCI EFs could be used following the same methodology currently available to upstream sectors that apply an EF (e.g., emission estimates based on unit counts and EFs). For the latter case, the Subpart W calculations used to development mode-specific emission factors based on company measurements since 2011 could be used as the basis for ongoing calculations. Subpart W uses a three-year average for company-specific EFs, and companies could use either the most recent 3-year average or compile and average measurement data since 2011 as the basis for their EFs. With EFs available as an option, new measurements would no longer be mandatory.

For example, the August 2018 PRCI report compiled and analyzed over 14,000 measurements of emissions / leaks from compressor isolation valves, compressor blowdown valves, rod packing, and wet seal degassing vents. The September 2018 companion PRCI white paper presented compressor emission factors based on that Subpart measurement data compiled it the PRCI report. The PRCI emissions factors could be used in conjunction with unit counts, similar to the Subpart W methods that have been used for upstream segments since 2011.

In addition, Subpart W already includes calculation methods for developing company-specific estimates based on the company's measurements. Annual measurements are completed "as found", so every source and operating mode (i.e., operating, standby pressurized, and not operating depressurized) is not measured every year. Sections 98.233(o) and (p) require operators to calculate compressor emission factors for modes where measurements are not completed based on previous company measurements. If ongoing measurement is eliminated or optional, ongoing estimates could be completed using those same methods based on the available data.

The measurement dataset available industry-wide or at a company-level has resolved the data deficiency EPA identified over a decade ago. In addition, the GHGRP rarely requires direct measurements for other industries, and this disparity for T&S sources under Subpart W should not continue. EPA should no longer require this additional measurement burden and, instead, should allow the T&S sources the option to calculate emissions using emission factors rather than mandated annual measurements. INGAA offers its assistance to work with EPA to develop Subpart W regulatory text to achieve this objective.

Similarly, annual transmission tank measurements (to detect a leaking scrubber dump valve) and

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[18] 76 FR 18620. Proposed rule (April 12, 2010) preamble discussion – e.g., direct measurement required because, "no credible engineering estimation methods or emissions factors exist."

[19] PRCI Report Catalog No. PR-312-16202-R02, "GHG Emission Factor Development for Natural Gas Compressors," April 2018.

[20] PRCI White Paper, Catalog No. PR-312-18209-E01, "Methane Emission Factors for Compressors in Natural Gas Transmission and Underground Storage based on Subpart W Measurement Data," September 2019.

[21] PRCI Report Catalog No. PR-312-16202-R03, "Methane Emissions from Transmission and Storage Subpart W Sources," August 2019.

annual leak surveys should be optional rather than a mandatory requirement. Leak survey results and transmission tank measurements over the last decade provide insight into the associated emissions and prevalence of anomalies such as scrubber dump valve leaks. For example, the August 2019 PRCI report documented leak prevalence based on 2011 – 2016 GHGRP data in a report[22] provided to EPA. Operators should have the option to calculate emissions based on industry-wide or company-level emission factors based on available measurement data. Additional context on reporting for leaky scrubber dump valves is provided in Comment 3.4, as substantive emissions from an operational anomaly would be addressed under the "other large release event" category that is being added to Subpart W.

Extensive data collected over more than a decade allows for the development of emission factors that characterize T&S operations. Accordingly, EPA should allow operators to use available emission factors – based on industry-wide or company-specific measurement data – rather than continuing to require ongoing annual leak measurements and leak surveys at T&S facilities.

2.3. The Proposed Rule incorporates new emission factors and establishes new monitoring requirements leading to increased GHG emissions reporting which are the result of expanding the rule and changing the accounting procedures, not necessarily in increases in actual GHG emission from reporting facilities.

INGAA members have worked diligently over the years to accurately report and reduce GHG emissions. The proposed emission factors, if adopted in a final rule, along with new emission sources will result in significant increases in year-over-year GHG emissions for the first year even if facilities operate exactly as they had in the prior year. This apparent increase in emissions on paper might be misunderstood. It is therefore important that EPA carefully craft messaging that can help the public, environmental advocacy groups, shareholders, and the international community understand that increased emissions numbers due to the Proposed Rule are associated with changes to calculating methodologies and are not necessarily reflective of actual increases in GHG emissions from reporting facilities.

2.4. The Proposed Rule would add new measurements for T&S centrifugal compressors with dry seals and for reciprocating compressor rod packing in standby pressurized mode. Mandatory new measurement requirements are not warranted, and EPA should allow operators the option of using other data sources for estimating emissions.

EPA has acknowledged that the GHGRP is not intended to include 100% of facility emissions but rather focus on key sources. Thus, EPA chose not to include centrifugal compressor dry seal emissions (in operating or standby pressurized mode) or reciprocating compressor emissions in standby pressurized mode in Subpart W reporting. The Proposed Rule would add measurement for those emission sources. In Comment 2.2, INGAA recommends allowing operators to use emissions factors for compressors based on a wealth of measurement data for operating modes included in Subpart W since 2011. INGAA does not support new measurement requirements for compressors based on perceived data gaps that EPA did not deem relevant when Subpart W was originally adopted. If EPA's position has changed, operators should be provided the option to conduct additional measurements or estimate dry seal emissions and standby pressurized rod

[22] *See citation 21.*

packing emissions based on other emissions rate data available and the annual hours in the respective modes.

For centrifugal compressors with dry seals, emissions could be estimated based on vendor data (e.g., data from Solar, which is the prevalent manufacturer of T&S turbines) or measurement data available from on-board instrumentation for some units. For the former, a Solar Product Information Letter (PIL)[23] presents typical dry seal leak rates as a function of operating pressure. For the latter, some units measure this rate with the onboard operational control system to track seal health. The rule should allow and provide clarity for clear operating and maintenance requirements for such devices (e.g., follow manufacturer specifications) so that the continuous measurement data can be used. These data sources are also preferred because the systems are not designed to accommodate access for a periodic measurement. Positive line pressure would result in leakage into the compressor house, and potentially trigger gas sensors, which could result in unit shutdown and venting to atmosphere.

For reciprocating compressor rod packing, measurements are currently required in operating mode and a wealth of measurement data is available. For standby pressurized mode, the emission rate could be based on previous studies (e.g., see discussion in PRCI compressor emission factor paper), measurement data from operating mode, or other data available in the literature. The larger contributing factor to these "missing" emissions is the amount of time not accounted for in the current rule (i.e., 2011 – 2016 data analyzed by PRCI indicated reciprocating compressors, on average, are in standby pressurized mode 30% of the time) rather than deviation in the hourly leak rate for the two modes where rod packing leakage occurs.

EPA previously determined that rod packing emissions in standby pressurized mode was not warranted but the Proposed Rule changes that perspective. This conclusion is questionable because the collective emissions from rod packing is very likely lower than when Subpart W was initially adopted and will continue to decrease (and not significantly contribute to total facility emissions) because rod packing is regulated for new sources and is or will be regulated for existing sources by the EPA (Subparts OOOO, OOOOa, and proposed OOOOb and OOOOc) and/or by state regulations.

At a minimum, if EPA believes that this previously excluded source should be added to Subpart W reporting, available data from rod packing measurements in operating mode and from the literature should be closely scrutinized to assess whether the emissions implications justify this change in EPA's position, and justify the need for new measurements rather than relying on other available emission rate data.

For both sources, information or related data are available to provide an emission rate for estimating annual emissions. Thus, new measurement requirements for dry seals and for rod packing in standby pressurized mode are not warranted. At most, EPA should require

[23] Solar Turbines, Product Information Letter (PIL) 251, "Emissions from Centrifugal Compressor Gas Seal Systems," January 2019.

measurement for two or three years then eliminate the new measurement requirement once data is available for this source and allow operators to use company-specific emission factors based on their past measurement data.

3.1. The Proposed Rule must allow operators to use leak detection and repair records to determine the number of hours a component leaked instead of using the default value of 8,760 hours.

In the Proposed Rule, the total annual total volumetric emissions of GHG are calculated by multiplying the leaker emissions factor by the total time the surveyed component was assumed to be leaking (63.233(q)(2) Calculation Method 1: Leaker emission factor calculation methodology Equation W-30)[24]. The procedure assumes a component continuously leaks since the prior annual survey. In cases where a Subpart W survey is only done once per year (the rule requirement), this assumption results in using 8,760 hours as the total time a component was leaking.

Whereas official Subpart W leak surveys of the entire facility are only required once per year, many facilities have mandated Leak Detection and Repair (LDAR) programs that survey components on a more frequent schedule and require first attempt at repair within as little as 15 days. The recordkeeping and reporting provisions of these programs are required to document and verify the repair of the leak. In these cases, it can be proven that the component was not leaking for the entire year. A date of when the leak stopped is specifically documented.

The calculation procedures in the proposed rule do not allow a facility to account for the emissions eliminated by repairing the leak off cycle from the leak survey schedule. Ignoring the cessation of emissions from fixing a leak between Subpart W surveys overestimates the GHG emissions. Allowing for documented leak repair records to be used will result in more accurate emission estimation and is consistent with the goals of the proposed rules is to improve the accuracy of the emission estimations.

Therefore, INGAA is asking EPA to develop a method where operators can use documented leak repairs to calculate the total time a component is assumed to be leaking.

3.2. The Proposed Rule establishes a compliance date of January 1, 2023, which does not allow industry sufficient time to prepare.

INGAA members appreciate EPA's recognition that affected facilities might not have all of the equipment, systems, and QA/QC procedures in place to support the monitoring requirements in the Proposed Rule beginning on the proposed effective date of January 1, 2023. For that reason, the Proposed Rule is allowing the use of best available monitoring methods from January 1, 2023, to December 31, 2023. However, EPA is requiring that the calculation methodologies and equations set forth in the Proposed Rule be used if best available monitoring methods are used. Further, the Proposed Rule references 40 CFR subparts OOOOb and OOOOc and 40CFR part 60 Appendix K, which are yet to be promulgated.

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[24] 87 Fed. Reg, 118 (June 21, 2022), page 37081

INGAA members, as do others affected by the proposed regulations, use a variety of systems to collect, compile, reduce, and report GHGRP data. Modifying the configurations of environmental reporting systems requires the effort of specialized personnel working with the technical end users. The process requires programming development, user testing, user acceptance testing, then validation before it is successfully used. The industry will need, at a minimum, several months to modify and update these data collection and reporting systems and verify that updates yield accurate data. To update these systems effectively and efficiently, INGAA members need to understand the requirements of 40 CFR subparts OOOOb and OOOOc and 40 CFR part 60 Appendix K. The effort required to modify and verify the accuracy of GHGRP reporting systems is dependent upon finalization of these rules. Given the uncertainty surrounding the release of final versions of these proposed rules, INGAA recommends that EPA establish an effective date of January 1 of the year following promulgation of all related regulations, provided that facilities have at least six months to develop, implement, and verify the accuracy of new data collection, reduction, and reporting systems.

Given the breadth of factors affecting GHG reporting, INGAA also recommends that EPA allow affected facilities two years for automatic BAMM with the option to request BAMM for specific items for a third year. This will enable affected facilities to properly implement and verify the monitoring methods that are affected by proposed revisions to the GHGRP, 40 CFR subparts OOOOb, OOOOc, and 40 CFR part 60 Appendix K.

3.3. It is difficult for INGAA to fully assess the requirements and impacts of the Proposed Rule, because the underlying compliance requirements of OOOOb and OOOOc are not known.

On November 15, 2021, EPA proposed preamble language entitled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (hereinafter, Proposed OOOOb, c)[25]. As INGAA noted in INGAA's comments to Proposed OOOOb, c (hereinafter, INGAA OOOO Comments, provided as Attachment 1), "the absence of proposed regulatory text makes it difficult to provide meaningful comments on proposed OOOOb and OOOOc." Proposed OOOOb, c indicated that EPA would be issuing a supplemental proposal with proposed regulatory text; however, as of the date of publication of the Proposed Rule, EPA has not issued the supplemental proposal with proposed text. Until INGAA understands the requirements of subparts OOOOb and OOOOc, INGAA cannot fully assess the requirements and impacts of the Proposed Rule with respect to GHG emission data accuracy, quality, and representativeness.

INGAA recommends that EPA withhold references to 40 CFR part 60 subparts OOOOb and OOOOc requirements until the regulatory text has been promulgated. At that time, EPA should

[25] 86 Fed, Reg, 217 (November 15, 2021)

once again seek stakeholder comment and then amend the rule to include appropriate references to 40 CFR part 60 subparts OOOOb and OOOOc.

3.4. The emission threshold for "other large release events" should be increased, and INGAA recommends the "incident" reporting threshold in PHMSA regulations.

INGAA understands EPA's desire to include otherwise unreported "large release events" that may occur in a particular year, and the Proposed Rule preamble discusses examples from recent years. However, the emissions from the two examples are orders of magnitude higher than the proposed threshold. For example, the Aliso Canyon event was 100 times larger than the applicability threshold for natural gas facilities and 10,000 times larger than the proposed threshold of 250 metric tons CO_2e emissions or approximately 500,000 standard cubic feet (SCF) of natural gas. The proposed Subpart W threshold, which is 1% of the applicability threshold, should be increased slightly to a threshold of 3,000,000 SCF of natural gas, or approximately 5.5% of the GHGRP applicability threshold for natural gas facilities, which is consistent with the "incident" reporting threshold in Department of Transportation (DOT) Pipeline Hazardous Materials and Safety Administration (PHMSA) regulations.[26]

INGAA believes that defining a large release event at 1% of the applicability threshold is inappropriately low. As an example, and to provide context, while INGAA strongly disagrees with the proposed increase in T&S leaker emission factors for OGI-based surveys (see Comment 1), a single leak that occurs for a year for four of the six component types would exceed the "large release event" threshold proposed by EPA using those increased EFs. This context speaks to both the inappropriateness of the increase in T&S OGI-based leaker EFs, and the inappropriately low threshold for "other large release events". Surely emissions from a single leak from a common component like a valve or meter, estimated using emission factors that are intended to be indicative of average leak emissions, should not be equated to a "large release event."

Using the PHMSA threshold provides consistency with other federal reporting, a precedent from PHMSA regulations, and a much more reasonable threshold. And, for comparison to the preamble example, the Aliso Canyon event was still approximately 1,800 times larger than a reporting threshold of 3 million SCF (or approximately 1,400 mt CO_2e emissions).

Additional Implications for Anomalous Events

Adding reporting for other large release events addresses anomalies that may occur that are not covered by Subpart W methodologies. For transmission compressor stations, Subpart W includes an annual measurement to assess anomalous operation – i.e., transmission tank vent screening and measurement. The associated source for that measurement is not the tank, but rather a leaky or stuck condensate tank dump valve. In effect, that measurement was required so that EPA could assess the frequency and magnitude of dump valve leakage or anomalous performance. As discussed in comments above, INGAA recommends allowing emission factor-

[26] 49 CFR 191.3(1)(ii)

based estimates rather than ongoing annual transmission tank measurements. In addition, by adding reporting for “other larger release events”, anomalous dump valve performance would be addressed regardless of the transmission tank reporting requirement.

PRCI compiled data[27] shows that the related emissions “on average” were relatively minor based on 2015 and 2016 Subpart W data, with a facility-level emission factor of approximately 300 mt CO2e per year, but only about 10% of facilities finding a leaky dump valve. Interestingly, the PRCI data[28] indicates just over 50 instances for both 2015 and 2016 where scrubber dump valve leakage occurred, and for those leaks, the average leak rate was just approximately 310 SCF per hour. That equates to 2.7 million SCF if the leak occurs for an entire year, or similar in magnitude to the PHMSA based threshold discussed in this comment and recommended for Subpart W other large release events. Event frequency and magnitude for scrubber dump valves have likely decreased since that data was collected as mandatory or voluntary LDAR programs have become more common for compressor stations. Analysis of data available to EPA from eleven years of Subpart W measurements would document that trend. Thus, INGAA recommends that EPA eliminate the transmission storage tank requirements in Subpart W since the new “other large release event” requirement in §98.233(y) would address those emissions when a leaking dump results in emissions exceeding the threshold.

3.5. Historical GHG reporting data indicate that it is not necessary to monitor tank vents annually when tank emissions are routed to a flare.

EPA is proposing that transmission tanks emissions routed to a flare should not be a specific source but be classified as miscellaneous flared source. EPA has proposed this because, as is documented in the preamble to the Proposed Rule, over the past 6 years for transmission tank vent stacks routed to a flare there have been no leaks reported and the reported flared emissions have been 0 metric tons of GHGs. INGAA agrees with this reclassification.

However, the EPA is proposing to retain the current requirements in 40 CFR 98.233(k)(1) and (2) to monitor the tank vent stack annually for leaks and to quantify the leak rate if a leak is detected. As was stated in the preamble, there have been no leaks reported over the past 6 years. Therefore, we believe that the requirements to continue to monitor for leaks should be eliminated. Eliminating the monitoring requirements for the transmission storage tanks when there have been no emissions reported over the past 6 years is consistent with the stated intent to streamline monitoring and calculation methodologies where "continuing to collect data on the same frequency would unlikely provide significantly different values.”

As an additional point, it is INGAAs understanding from the preamble that the transmission tank monitoring is required because "it would not be possible to tell if there were any scrubber

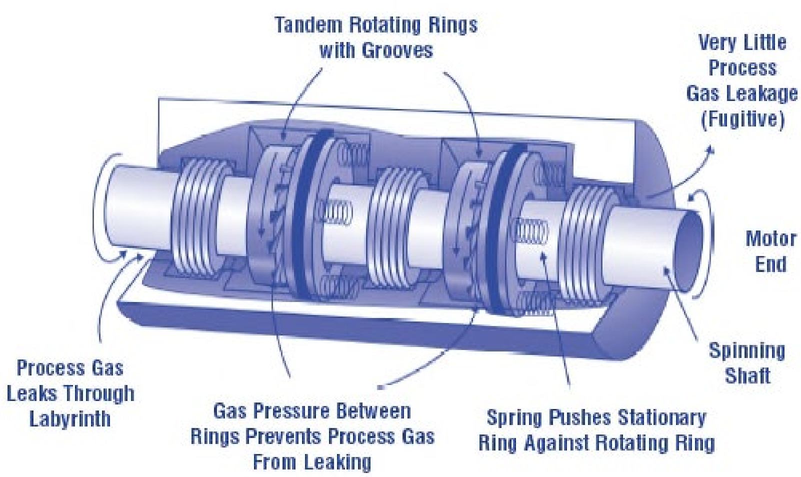
[27] PRCI Report Catalog No. PR-312-16202-R03, “Methane Emissions from Transmission and Storage Subpart W Sources,” August 2019.
[28] PRCI August 2019 Report, Figure 8 and Section 5

dump valve leaks if only a combined emission stream is measured.[29]" INGAA does not believe the tracking of dump valves emissions is reason enough to justify the monitoring of every transmission tank given the low-GHG emissions from this category of sources. This does not advance Objective II.A.2 "Improvements to Existing Emission Estimation Methodologies" and we believe it goes against Objective II.B.2 "Revisions to Streamline Monitoring and Calculation Methodologies." The rules requiring the knowledge of the total flare volume and composition are adequate to accurately account for emissions from the transmission tanks.

For these reasons INGAA recommends that EPA remove the requirement to monitor transmission storage tanks when they are routed to a flare.

3.6. Clarity is needed on dry seal monitoring.

63.233(o)(2)(iii) requires volumetric measurements for centrifugal compressor dry seal vents. As a point of clarification, a dry seal compressor has two dry seals (see figure below[30]): a dry seal on the gas side compressor (inboard) and a dry seal on the air side motor and shaft bearing (outboard). There are "very little" gas emissions from the dry seal on the outboard side according to EPA's documentation on reducing emissions from compressor seals, and therefore there is no reason to require volumetric emissions from the outboard dry seal.



INGAA requests that EPA clarify that 233(o)(2)(iii) include only measuring volumetric emissions from the compressor side dry seal.

[29] Page 285 of 820 in the "revisions-and-confidentiality-determinations-for-data-elements-under-the-greenhouse-gas-reporting-rule."
[30] From https://www.epa.gov/sites/default/files/2017-09/documents/reducingemissionsfromcompressorseals.pdf p.16

Additionally, permitted measurement techniques proposed in 40 CFR 98.233(o)(2)(ii)(A) through (D) consist of manual methods such as temporary anemometers and flow meters (e.g., rotameters) and other rudimentary methods. Orifice, venturi, and nozzle devices are covered in 98.3(i)(3).

Other devices for measuring vented emissions may include thermal dispersion meters and Coriolis meters. The rule should allow for such meters or other measurement devices to be used either thru BAMM application or as outlined in the monitoring plan. OEMs and third party vendors may already provide monitoring systems for dry seal vents; however, they would be excluded for use under the Proposed Rule because they don't fall under the specific measurement techniques or standards as noted in 98.238(o)(2)(ii)(A) through (D). EPA should add language allowing operators to use other measurement techniques (including BAMM) for all years starting in 2023 and beyond.

For orifice, venturi, and nozzle devices, 98.3(i)(3) states 'initial quality assurance consists of in-situ calibration of the differential pressure (delta-P), total pressure, and temperature transmitters.' It should be noted that in order to calibrate pressure or temperature transmitters in situ, cutting and alterations of the vent piping will be required which will require the gas compressor to be shut down and taken out of service. The in-situ calibration clause should be removed from the above citation so that these transmitters could be removed from service and replaced with factory or site-calibrated transmitters, allowing minimal disruption to pipeline operations.

For these reasons volumetric emissions should not be required on the motor and shaft bearing side.

3.7. The proposed flare activity reporting requirements found at 98.236(n)(2)(ii) do not support GHG emissions reporting or validate reported GHG emissions.

Proposed section 98.236(n)(2)(ii) includes requirements to report information such as the flare name or other identification information, the types of emission sources routed to the flare, total volume of gas routed to the flare, the type of flare, estimated fraction of the total volume routed to the flare when it is not lit, flare assist type, whether the flare has a continuous pilot or autoigniter, whether a continuous pilot is continuously monitored, and if the continuous pilot is not monitored, how periods when the pilot is not lit are identified. None of this information is used to calculate or validate GHG emissions. If EPA requires this information for something other than GHG reporting, it should obtain it through a formal information request that includes rationale for why this information is needed instead of including the information in this rulemaking. INGAA therefore recommends that EPA remove the proposed requirements found at 98.236(n)(2)(ii).

3.8. Based on the complexity of liquefied natural gas (LNG) systems, INGAA recommends that EPA allow site-specific engineering estimates based on best available data for AGR vents.

EPA requested comments on whether all four calculation methods currently provided in 40 CFR 98.233(d) are appropriate for facilities in the LNG Import/Export industry segment and if not, how specific calculation methods could be adjusted to be more applicable to this industry segment. 98.233(d)(1) through (4) documents four calculation methodologies for CO_2 vented directly to the atmosphere: Calculation Method 1 (if there is a Continuous Emission Monitor System (CEMS)), Calculation Method 2 (vent meter is installed), Calculation Method 3 (estimation method using inlet or outlet gas flow rates), and Calculation Method 4 (estimation method using simulations from software packages). EPA further states that the estimations under Calculation Methods 3 and 4 (i.e., 98.233(d)(3) or (4)) may provide incorrect and impossible calculated volumetric emissions. Therefore, EPA correctly proposed new provisions for specific situations for AGR vents comingled with other sources and routed to a flare or thermal oxidizer. Some of these methods still utilize Calculation Methods 3 and 4. With the possible errors in these methods and the further complexity of liquefied natural gas (LNG) systems, INGAA suggests the estimation methods under 98.233(d)(3) and (4) should not be utilized for acid gas removal vents at LNG facilities under any circumstance. LNG facilities are very complex with a variety of technologies and processed integrated. Streams at an LNG facility are often comingled with emissions from other source types. Further, the volume and composition of the streams (directly or comingled) are not necessarily monitored continuously. In these stream situations at an LNG facility the four calculation methodologies do not fit with typical plant procedures. Under certain circumstances, data may be available to utilize Calculation Methods 1 and 2 appropriately. LNG facilities have found that site-specific engineering estimates based on best available data is the most accurate, and sometimes the only way, to calculate emissions.

INGAA recommends that the Proposed Rule be modified to make it clear that site-specific engineering estimates based on best available data will be allowed for calculation emissions from all AGR vents at LNG facilities whenever Calculation Methods 1 and 2 are inappropriate.

3.9. The Proposed Rule removes acoustic leak detection from screening methods allowed for manifold groups of compressor seals. INGAA believes acoustic leak detection should be allowed for manifolded compressors in some situations.

As noted in 40 CFR 98.234(a)(5), acoustic leak detection is applicable only for through-valve leakage. The acoustic method can be applied to individual compressor sources, but it cannot be applied to a vent that contains a group of manifolded compressor sources downstream from the individual valves or other streams that may be manifolded together. The inclusion of this method for manifolded compressor sources was in error and we are proposing to remove it from 40 CFR 98.233(o)(4)(ii)(D) and (E) and 40 CFR 98.233(p)(4)(ii)(D) and (E) to improve accuracy of the measurements, consistent with section II.A.2 of this preamble.

INGAA believes eliminating the use of acoustic leak detection from manifold groups of compressors is ignoring the fact that there is acoustic leak detection is a valuable tool in attributing source contribution to manifolded compressors. The acoustic device is a good tool for identifying leaks. For example, we have seen a case where a company has 4 reciprocating engines venting to a single stack (i.e., manifolded compressors). A high flow meter was used to take a measurement at the common vent. There was a leak identified but and a VPAC acoustic device was used to try to isolate which unit was leaking. Three units were in standby pressurized mode, and one was in standby depressurized. In this case the acoustic detection was done upstream of where the streams were comingled.

INGAA requests EPA to continue to allow the use of acoustic leak detection in manifold compressor situations to identify which valve is leaking.

INGAA appreciates EPA's continued efforts to improve the GHGRP and hope that the comments we have provided will be helpful and constructive. INGAA appreciates the opportunity to comment and welcomes the opportunity to elaborate or respond to any questions.

Regards,

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Attachments: Attachment 1, INGAA OOOO Comments

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