INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

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Waste Emissions Charge for Petroleum and Natural Gas Systems

The Independent Petroleum Association of America (IPAA) submits these comments regarding the Environmental Protection Agency (EPA) proposal to implement a Waste Emissions Charge for Petroleum and Natural Gas Systems (WEC) under the Inflation Reduction Act Methane Emissions Reduction Program (Methane Tax).

IPAA represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will be significantly affected by the actions resulting from this regulatory proposal. Independent producers drill about 91 percent of American oil and natural gas wells, produce 83 percent of American oil and produce 90 percent of American natural gas.

In addition to the comments filed here, unless there are specific comments presented herein, IPAA endorses the comments filed by the American Petroleum Institute (API).

The Methane Tax process includes multiple features. However, a key factor in conjunction with this WEC proposal is the application of information from Subpart W. IPAA previously filed comments on the EPA proposal to modify Subpart W (EPA-HQ-OAR-2023-0234-0265). These comments are included in this submission as Appendix A.

Because the emissions calculations under Subpart W are the building blocks for calculation of the WEC, these comments will reiterate and expand on those prior comments. Then, it will address key issues in the WEC proposal.

A. Subpart W

There are several key issues within EPA's Subpart W proposal that remain unresolved and yet essential to the consideration of the WEC proposal because they define the emissions amounts that will ultimately be taxed. One of these is a fundamental issue related to the definition of a facility under the Methane Tax as it relies on Subpart W. A second issue relates to EPA's failure to properly assess emissions factors that become the emissions basis. These will be addressed below.

1. *EPA fails to properly develop a facility definition for the Methane Tax that is consistent with the Clean Air Act.*

The issue of the Subpart W facility definition is not a new one, but it has returned to focus because of EPA's choice to use it without addressing whether it is appropriate for the Methane Tax. The underlying structure of the Subpart W facility definition has been contentious since it was first proposed and adopted for the Greenhouse Gas Reporting Program (GHGRP). The principal issue continues to be that the definition fails to reflect the realities of oil and natural gas production operations. It fails to track other definitions of oil and natural gas production facilities in the Clean Air Act (CAA). EPA's default to the use of the Subpart W definition in the GHGRP context is inappropriate and not required by the Methane Tax.

IPAA has consistently recommended that EPA more properly define Subpart W facilities in the context of the general understanding of facilities within the CAA and the industry. In 2010 comments filed when the facility definition was first developed, IPAA stated the following:

> Most notably, we believe that use of the CAA denies EPA the authority to create a definition of a facility that differs from that in the CAA. EPA proposes the following definition:
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> > Onshore petroleum and natural gas production facility means all petroleum or natural gas equipment associated with all petroleum or natural gas production wells under common ownership or common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin as defined by the American Association of Petroleum Geologists which is assigned a three digit Geologic Province Code. Where an operating entity holds more than one permit in a basin, then all onshore petroleum and natural gas production equipment relating to all permits in their name in the basin is one onshore petroleum and natural gas production facility.
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> Under this definition, for example, all wells under common ownership along the Gulf Coast of Texas and Louisiana and deeply into the mainland of those states would be considered as one facility. This would be analogous to proposing that every McDonalds restaurant in the State of Texas should be considered as one facility because they have the same name and are franchised from a common source.
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> Nothing in the CAA suggests that EPA can define an onshore petroleum and natural gas production facility as broadly as it proposes. In reality, the only guidance provided to EPA in the CAA resides in Section 112(n)(4)(A) where it states:
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> > … in the case of any oil or gas exploration or production well (with its associated equipment), such emissions shall not be aggregated for any purpose ….
>
> EPA proposes its basin approach and solicits comment on the option of using a similar approach involving "field-level reporting". In doing so, the Agency discounts the obvious choice – the well pad. Clearly, the well pad looks like a facility under the definition in the CAA and is the typical permitting unit under CAA regulations. EPA considered a well pad approach and "EPA analyzed the average emissions associated with each of the four well pad facility cases and determined that average emissions at these operations were low (from about 370 metric tons of CO2e per year to slightly less than 5,000 metric tons of CO2e per

year)." Recognizing that individual sources were small, EPA chose to create its novel basin approach.

We identified this issue in our comments to EPA's proposal in 2009 when we stated:

> We believe that including onshore petroleum and natural gas production facilities in the reporting requirements runs counter to EPA's focus in this proposal. EPA structured the proposal by selecting its 25,000 tons/year facility reporting threshold in part based on a cost effectiveness test to capture most of the GHG emissions while limiting excessive costs. Despite this effort, under the current proposal 43 percent of the first year capital costs to comply with the rule will be borne by the petroleum and natural gas industry to report an estimated 3 percent of the nation's GHG emissions. Expanding the reporting requirements to onshore facilities will dramatically increase these costs unnecessarily.
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> American petroleum and natural gas production comes from approximately 933,000 wells – roughly 500,000 oil wells and 433,000 natural gas wells. These facilities are spread across 33 states. Offshore facilities would be within the scope of the reporting requirements. EPA estimates that 50 offshore facilities would be covered under the 25,000 tons/year threshold. If EPA were to expand the reporting requirements to onshore facilities, it is highly unlikely that any production well facility would meet the reporting threshold. For example, approximately 85 percent of oil wells and 74 percent of natural gas wells are marginal wells producing less than 15 barrels/day of oil and 90 mcf/day of natural gas, respectively. Most of these operations are owned by small businesses. None of them would exceed the reporting threshold individually.
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> EPA largely seems to recognize this reality when it states:
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>> …this segment is not proposed for inclusion primarily due to the unique difficulty in defining a ''facility'' in this sector and correspondingly determining who would be responsible for reporting.
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> EPA has requested comments on how to define a facility for onshore petroleum and natural gas production and whether to require reporting on a basin level. We believe that the appropriate facility definition tracks the nature of the operation – essentially a well pad which may contain one or several wells and the attendant separation and storage facilities. As we discussed above, these operations will fall well below the reporting threshold. To approach the reporting on a basin level would result in compelling this industry to use a reporting threshold far below the 25,000

> tons/year threshold required for other industries. In essence, all production operations would have to determine emissions levels by whatever estimation or monitoring requirements would apply. This would impose dramatically different costs. To put all of this in some perspective, EPA's INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS: 1990- 2007 (Released on April 15, 2009) would suggest that the GHG emissions from natural gas systems and petroleum systems account for roughly 2.3 percent of U.S. GHG emissions. EPA suggests that about 27 percent of these emissions come from onshore petroleum and natural gas production operations – or roughly 0.6 percent of U.S. GHG emissions.
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> There is no compelling rationale to justify imposing on this segment of American industry a far costlier reporting requirement, capturing hundreds of thousands of wells many owned by small businesses, solely for the purpose of minimally improving the U.S. GHG emission inventory.

This circumstance has not changed appreciably. EPA argues that it has underestimated the amount of GHG emissions from onshore petroleum and natural gas production systems. The 2008 U.S. Inventory of Greenhouse Gases reported 131 MMTCO2e from petroleum and natural gas systems. EPA believes the emissions are 351 MMTCO2e. To put this in the same perspective as our 2009 comments, these systems would account for slightly more than 6 percent of U.S. GHG emissions and the onshore petroleum and natural gas production systems would be approximately 3.9 percent. EPA must recognize the burden it will impose on the small businesses that operate the majority of these systems.

Small Business Implications

EPA cavalierly asserts that this proposal "…will not have a significant economic impact on a substantial number of small entities." But, can this be true? Comparing numbers of wells that must report against the number of wells operated by small businesses shows a different result.

In creating its basin-level reporting approach, EPA indicates that it will capture 81 percent of the onshore petroleum and natural gas production GHG emissions. It also states – in rejecting the logical well pad facility definition – that individual well pad emissions were low. Consequently, we must conclude that EPA's definition must capture something close to 80 percent of the operating wells.

In 2008, there were 960,303 operating wells in the U.S. (525,287 oil wells and 435,016 natural gas wells, with about 7,000 of these in the federal offshore). The Energy Information Administration reports that 85 percent of these oil wells and 73.3 percent of these natural gas wells are marginal wells. Assuming a proportional distribution across wells, the following results would be produced:

	Wells Reported Under Rule	Marginal Wells Reported Under Rule
Oil Wells	417,300	354,815
Natural Gas Wells	345,213	253,041
Total	762,513	607,856

> Clearly, there will be a pervasive burden borne by America's marginal well producers. EPA is well aware that the companies operating marginal wells are dominated by small businesses. To suggest that the proposed rule will not have a significant impact on small businesses is simply incorrect.

EPA rejected these arguments with the following rationale in its publication of the GHGRP Subpart W regulations:

> We are also including two distinctive definitions of facility for onshore petroleum and natural gas production and for natural gas distribution. Defining a facility in these cases is not as straightforward as other industry segments covered under subpart W. For some segments of the industry (e.g., onshore natural gas processing, onshore natural gas transmission compression, and offshore petroleum and natural gas production), identifying the facility is clear since there are physical boundaries and ownership structures that lend themselves to identifying the scope of reporting and responsible reporting entities. However, in onshore petroleum and natural gas production and natural gas distribution such distinctions are more challenging. As explained in the April 2010 proposal, EPA evaluated existing definitions used under current regulations and determined that it was necessary to provide a unique definition of facility for each of these two segments in order to ensure that the reporting delineation is clear, avoid double counting, and ensure appropriate emissions coverage. For more information please see the preamble for the April 2010 proposal (75 FR 18608) and the Greenhouse Gas Emissions from Petroleum and Natural Gas Industry: Background Technical Support Document (EPA–HQ–OAR–2009–0923).
>
> These definitions are intended only for purposes of subpart W and are not intended to affect to definition of a facility as it might be applied in any other context of the Clean Air Act.

This commitment will no longer be true if EPA applies the Subpart W facility definition in the Methane Tax.

There is nothing in the CAA nor in the Methane Tax that justifies EPA transferring the facility definition component of Subpart W to the Methane Tax. Rather, it is more pertinent to look to other agency actions addressing the definition of oil and natural gas production facilities.

The general concept of a "facility" under the CAA revolves around a typical plant site composed of a single operation or multiple interlocking operations like a refinery or chemical plant or steel mill. Certainly, the dispersed historical nature of oil and natural gas production facilities has made defining those facilities more difficult. However, the only place in the CAA where Congress has spoken is under Section 112 where the language states:

> ...emissions from any oil or gas exploration or production well (with associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources, and in the case of any oil or gas exploration or production well (with its associated equipment), such emissions shall not be aggregated for any purpose under this section.

Where EPA is so frequently referring to the plain reading of the language of the Methane Tax in this proposal, this Congressional directive should bear strongly on EPA's interpretation.

Supporting the concept of using a tightly drawn definition of a facility is EPA's actions in defining a "major source" under its federal operating permit requirements as follows:

> *Major source* means any stationary source (or any group of stationary sources that are located on one or more contiguous or adjacent properties, and are under common control of the same person (or persons under common control)), belonging to a single major industrial grouping and that are described in paragraph (1), (2), or (3) of this definition. For the purposes of defining "major source," a stationary source or group of stationary sources shall be considered part of a single industrial grouping if all of the pollutant emitting activities at such source or group of sources on contiguous or adjacent properties belong to the same Major Group (*i.e.,* all have the same two-digit code) as described in the Standard Industrial Classification Manual, 1987. For onshore activities belonging to Standard Industrial Classification (SIC) Major Group 13: Oil and Gas Extraction, pollutant emitting activities shall be considered adjacent if they are located on the same surface site; or if they are located on surface sites that are located within 1/4 mile of one another (measured from the center of the equipment on the surface site) and they share equipment. Shared equipment includes, but is not limited to, produced fluids storage tanks, phase separators, natural gas dehydrators or emissions control devices.

This interpretation was developed through an extensive rulemaking and did not come quickly. Yet, it, too, provides evidence that EPA can come to a rational decision on defining an oil and natural gas production facility. Significantly, this action occurred in 2016, well after the Subpart W facility definition was created.

EPA now faces a different more compelling situation than it did in 2010 when it drafted Subpart W. Congress not only created the Methane Tax, it also intended that the tax should not apply to small well producers. As Senator Manchin stated in his June 2023 letter to EPA:

- The statute clearly intends to exempt marginal wells and smaller producers from the fee.[3] EPA must make it clearly understood that those entities not subject to the current Subpart W Greenhouse Gas Reporting Program are not subject to EPA fees under MERP.
- ...
- EPA should draw reasonable boundaries around the definition of individual "facilities" (such as pad site, compressor site, or reporting field) for emissions intensity calculations so that aggregations of large amounts of disparate wells

and gathering lines does not lead to charging a fee on marginal facilities that Congress intended to exempt or on facilities that have minimal actual emissions.

EPA's use of the facility definition from Subpart W thwarts both these mandates. EPA's sweeping scope of a facility using the American Association of Petroleum Geologists (AAPG) basins to define a facility compels small producers to aggregate all their small producing wells over huge areas, like the entire state for West Virginia or Michigan.

To give some perspective to the potential impact of the use of the sweeping facility definition under Subpart W, a few facts can provide some insight. First, it's important to understand that small business oil and natural gas producers typically need to operate hundreds of small wells across an AAPG basin to be economic. Second, looking at the most recent GHGI (providing data on 2022 emissions), it shows that the distribution of CO_2eq emissions for natural gas production wells is approximately 9 percent CO_2 and 91 percent methane (as CO_2eq). For petroleum (oil) wells the distribution is approximately 33 percent CO_2 and 67 percent methane (as CO_2eq). Third, the following table shows how these distributions result in emissions to make up the 25,000 tonnes/year threshold in the Methane Tax.

Emissions Producing 25,000 tonnes/year				
CO_2 Emissions	Methane Emissions (CO_2eq)	Methane Emissions (21 GWP)	Methane Emissions (25 GWP)	Methane Emissions (28 GWP)
Natural Gas Production (tonnes/year)				
2187	22813	1086	913	815
Oil Production (tonnes/year)				
8188	16812	801	672	600

This table shows the mass of methane emissions based on three methane Global Warming Potentials (GWP) -- 21 (2010 GWP), 25 (the current GWP) and 28 (EPA's proposed revision to the GWP). In this discussion, it is assumed that EPA will finalize its proposed GWP revision and change the methane GWP to 28. Fourth, when EPA proposed its Subpart OOOOb and OOOOc regulations in 2021, it set a threshold for its Leak Detection and Repair (LDAR) program of 3 tons/year (2.722 tonnes/year) from a well site. This can be considered as a proxy for a marginal well.

Using this information, a small business well producer with operations across an AAPG basis would be subject to the Methane Tax threshold with as few as 220 oil wells or 300 natural gas wells. These totals are well within the operations of a typical small producer. Clearly, this application violates the Congressional intent to exclude small businesses and marginal wells from the scope of the Methane Tax.

2. *EPA's proposed approach to a WEC applicable facility egregiously worsens the impact on small producers that own Gathering and Boosting operations*

As adverse as the Subpart W facility definition is for small producers, EPA would make it extraordinarily harsher if the producer operates Gathering and Boosting. First, the Gathering and Boosting (G&B) Emissions Factors (EF) under Subpart W for methane emissions are based on mileage of pipe, not on actual emissions. Second, the WEC emissions threshold for G&B is one quarter of the threshold for natural gas production. Third, EPA is proposing that production (oil and natural gas) and G&B be treated as one applicable facility under the Methane Tax. Under this approach, which will be discussed in more detail below, using the EF in EPA's proposed Subpart W revisions, a small producer with as little as 560 miles of unprotected pipe in an AAPG region would equate to the 300 marginal natural gas wells described above and thereby pull that producer into the Methane Tax.

3. *EPA fails to properly address the accuracy of the emissions factors it was mandated to improve under the Methane Tax.*

As stated above, IPAA has previously addressed its concerns about EPA's actions to fulfill its mandate under the Methane Tax to revise Subpart W. While those comments present a more extensive view, a key aspect is restated here:

> EPA actions to revise component emissions factors raise serious questions about both the approach and the proposal. As discussed above, the Inflation Reduction Act mandate to revise Subpart W requires EPA to conduct thorough analyses of the numerous emissions factors and either independently validate them or develop its own valid factors. It failed to do either.
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> Instead, it turned to three reports as the basis for new emissions factors. These reports are generally referenced as Zimmerle[1], Pacsi[2] and Rutherford[3].
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> However, EPA's use of these materials demonstrates a callous disregard for the mandate EPA must meet in revising Subpart W. The Zimmerle report addresses emissions from gathering compressor stations; the Pacsi report addresses emissions from oil and natural gas production equipment leaks. Each of these studies conclude that the current emissions factor calculation process under Subpart W overstates emissions that they studied. The Zimmerle report states:
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>> Combining study emission data with 2017 GHGRP activity data, the study indicated statistically lower national emissions of … 66% … of current GHGI estimates, despite estimating 17% … more stations than the 2017 GHGI ….
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> The Pacsi report states:
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>> The most common EPA estimation method for greenhouse gas emission reporting for equipment leaks, which is based on major site equipment counts and population-average component emission factors, would have overestimated equipment leak emissions by 22% to 36% for the sites surveyed in this study as compared to direct measurements of leaking components because of a lower frequency of leaking components in this work than during the field

[1] Zimmerle, D., et al. "Methane Emissions from Gathering Compressor stations in the U.S." Environmental Science & Technology 2020, 54(12), 7552-7561, available at https://doi.org/10.1021/acs.est.0c00516.

[2] Pacsi, A. P., et al. "Equipment leak detection and quantification at 67 oil and gas sites in the Western United States." Elem Sci Anth, 7: 29, available at https://doi.org/10.1525/elementa.368. 2019

[3] Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P. et al. Closing the methane gap in US oil and natural gas production inventories. Nat Commun 12, 4715 (2021). https://doi.org/10.1038/s41467-021-25017-4

> surveys conducted more than 20 years ago to develop the current EPA factors.

To show the EPA lack of regard for its mandate, EPA ignores these conclusions and cherry picks elements of the reports to increase the component emissions factors in Subpart W. The Rutherford study takes a different approach. It makes the assumption that component based emissions estimates understate actual emissions because it believes that ambient monitoring presents more accurate results. Consequently, it surveys a variety of component based emissions studies to create emissions factors higher than those in the current Subpart W and adopts them as more accurate.

Critically, EPA embraces all these various changes that increase the Subpart W emissions factors, but it never attempts to independently validate them. The effect of this action is increases in virtually every component emissions factor, some of which would yield emissions estimates 5 times or more than the current Subpart W calculations. Not only is this approach a clear dereliction of EPA's responsibilities, but it also has the effect (along with changing the GWP for methane) of de facto lowering the 25,000 mt/year threshold and raising the emissions subject to methane tax. Enverus Intelligence Research, a subsidiary of the energy-focused Software as a Service firm Enverus, has found the proposed regulations would more than double 2021 reported methane and increase overall carbon dioxide-equivalent emissions by 41%. If EPA is intentionally revising the Congressionally enacted methane tax through its rulemaking actions, it should be held to a standard that requires it prove that its revisions are valid.

B. Waste Emissions Charge

Because the Methane Tax contains no legislative history and frequently fails to truly define its terms, EPA must interpret the legislative text. In its proposal EPA frequently refers to terms like "a plain reading" of the statute. However, EPA manipulates its reading of the text by only partially reading the text or ignoring key terms. As a result, it creates inappropriate conclusions and therefore inappropriate regulatory proposals.

Definition of Applicable Facility

As described previously, EPA fails to address the inappropriate use of the GHGRP Subpart W facility definition in the Methane Tax – a definition that EPA characterized by describing as follows:

> These definitions are intended only for purposes of subpart W and are not intended to affect to definition of a facility as it might be applied in any other context of the Clean Air Act.

But, in the definition of "applicable facility", EPA proposes a definition that compounds this misuse outrageously. EPA proposes that:

> In cases where a subpart W facility reports under two or more of the industry segments listed in the previous paragraph, the EPA proposes that the 25,000 mt CO2e threshold would be evaluated based on the total facility GHG emissions

reported to subpart W across all of the industry segments (i.e., the facility's total subpart W GHGs).

This proposal appears to create a structure that would compel operators to sum emissions of their operations in an AAPG basin to include, for example, their oil and natural gas production operations and their G&B operations such that if both were below 25,000 mt/year but the sum were above 25,000 mt/year, their operations would then become subject to the WEC. This proposal extends an already inappropriate approach to a facility definition to arbitrarily capture even more operations for what is solely intended to make them subject to the Methane Tax. It should be summarily rejected.

Calculations of WEC Emissions Thresholds

1. *EPA fails to use natural gas when the term is in the text of the statute.*

A key and clear failure in EPA's interpretation of the legislative text is its failure to use natural gas as the basis of WEC thresholds when the term is in the text. This failure results in EPA effectively raising the WEC emissions threshold by about 30 percent. Most of the WEC emissions thresholds are based on natural gas sales or throughput. This discussion will focus on the emissions threshold for the onshore petroleum and natural gas production industry segment that sends natural gas to sales. EPA presents this calculation as follows:

$$TH_{is,Prod} = 0.002 \times \rho_{CH4} \times Q_{ng,Prod} \qquad \text{(Eq. B-1)}$$

Where:

$TH_{is,Prod}$	=	The methane waste emissions threshold for the industry segment at a WEC applicable facility for the reporting year in the production sector that has natural gas sent to sale, metric tons (mt) CH_4.
0.002	=	Industry segment-specific methane intensity threshold, as specified in CAA section 136(f), for methane emissions for applicable facilities with natural gas sales in the production sector, thousand standard cubic feet (Mscf) CH_4 per Mscf of natural gas sent to sale.
ρ_{CH4}	=	Density of methane = 0.0192 kilograms per standard cubic foot (kg/scf) = 0.0192 metric tons per thousand standard cubic feet (mt/Mscf).
$Q_{ng,Prod}$	=	The total quantity of natural gas that is sent to sale from the WEC applicable facility in the reporting year, as reported pursuant to part 98, subpart W of this chapter. For onshore petroleum and natural gas production, you must use the quantity reported pursuant to proposed § 98.236(aa)(1)(i)(B) of this chapter, in Mscf. For offshore petroleum and natural gas production, you must use the quantity reported pursuant to proposed § 98.236(aa)(2)(i) of this chapter, in Mscf.

The two key factors in this equation are the use of natural gas sales as the basis of the emissions threshold and the use of methane density to convert volume to mass. Methane is not natural gas.

Natural gas is denser than methane. By using methane density instead of natural gas density, EPA lowers the emissions threshold and effectively raises the Methane Tax payment.

Then, in one of its more disingenuous statements, EPA argues that its use of methane density instead of natural gas density is actually intended to decrease the reporting burden on industry.

> With the exception of production facilities that only produce oil, the statutory text clearly lists natural gas as the throughput value. Further, the proposed approach can be implemented with data currently reported under subpart W, while alternative methane intensity methodologies would require reporting of additional data and increase the burden on the oil and gas industry. ... An approach that calculates methane intensity as the mass of methane emissions divided by the mass of natural gas would require facilities to collect and report detailed information on all of the constituents of natural gas throughput. ... The EPA therefore believes that the proposed approaches not only follow a plain reading of CAA section 136(f) but are also the best and most reasonable approaches.

If EPA really believes in plainly reading the statute, it will clearly conclude that the statute uses natural gas as the basis for the WEC and the emissions threshold. Consequently, its task is to present options to use natural gas density in its calculations.

Certainly, one option should be for operators to provide natural gas density information based on their operations and EPA needs to provide a framework for the submission of such data.

However, other approaches are also available. For example, since 2011, EPA has used a memorandum, "Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking" (included as Appendix B in this document) to provide natural gas composition data for its regulations. Using this document, a natural gas density of approximately 0.0535 lb/scf can be calculated. This demonstrates the significance of using a natural gas density rather than the methane density of 0.0416 lb/scf. It is nearly 30 percent higher. Given that EPA has been using this document for its rulemaking for over a decade, it can certainly be used as a default value if no other information is available.

Another approach that EPA could take would be to work with organizations like the Energy Information Administration or the Gas Technology Institute or Enverus that may have databases with AAPG basin average natural gas densities. If such databases do not exist, EPA could initiate an effort by one of these organizations to obtain such information. These densities could then be used as AAPG basin default values when no other information is available.

Any approach to define default natural gas densities and to provide for operator supplied natural gas densities are clearly plausible approaches to address the issue of needing a natural gas density to calculate the emissions threshold.

But what is clear is that EPA's approach of using a methane density is not a valid plain reading of the statute and must be altered.

2. *The current approach is unfair to oil dominated production and must be changed.*

Some of the emissions thresholds in the Methane Tax seem to be derived from various voluntary emissions intensity programs related to natural gas production. At least this appears to be the case for the onshore production emissions threshold for operators with natural gas sales. This emissions intensity target was developed by companies operating production that is dominated by natural gas sales. While it may be a rational target for such operations, it is inappropriate for production that is primarily petroleum with minimal or limited natural gas sales. Similarly, the emissions threshold for petroleum production with no natural gas sales is wholly inconsistent with the threshold for natural gas production facilities and generates a likely impossible target to meet.

The following are some examples of the implications of the emissions thresholds for different operations. For illustrative purposes, they will be based on petroleum production of one million barrels/year. One million barrels per year can be converted to natural gas production based on energy equivalency which is 6 mcf of natural gas is equivalent to one barrel of oil. Therefore, one million barrels of oil is equivalent to 6 million mcf of natural gas.

For petroleum production with no gas sales, the Methane Tax emissions threshold is 10 metric tons per one million barrels. If this production was natural gas where the emissions threshold is 0.2 percent of natural gas sales, then for 6 million mcf of production (using natural gas density in the calculation), the threshold would be 292 metric tons. This multiple of 29 is wholly inappropriate.

A similar issue exists for a petroleum producer with limited natural gas sales. Assume that the same petroleum producer had an additional one percent of its oil production as natural gas – 60,000 mcf. This would produce a natural gas emissions threshold of about 2.9 mt. Again, a threshold that is wholly inconsistent with a comparable natural gas energy producer.

3. *The G&B emissions threshold has no identifiable basis and is inequitable*

There is nothing in the Methane Tax that explains why the emissions threshold for G&B was selected. It is well below the emissions threshold for other segments of the industry. This low threshold is complicated by the egregious use of the Subpart W EF for G&B. As noted above, the G&B EF are based on miles of pipe and do not reflect control measures or emissions data that could show dramatically different emissions profiles. EPA needs to justify the G&B emissions threshold and generate valid EF for this sector.

Compliance Date for the Submission of Methane Tax Payments

EPA's proposed approach for the payments of the Methane Tax is unjustified and flies in the face of historic filing issues with the GHGRP. For the many years that the GHGRP has been in operation, the filing date has been March 31 of the year following the year of emissions reporting (e.g., March 2024 for 2023 data). However, given the short time frame to develop the data, verification of data has extended into November in many instances.

Now, EPA is proposing that the WEC filing and payment must be submitted on March 31. It allows modifications to the WEC filing to be made until November 1. However, while any reductions in emissions would allow for a rebate, increases would have penalties applied to them. This approach is unnecessary. Given the history of the GHGRP, EPA knows there will likely be modifications needed for many filings. Consequently, a fair approach would delay the payment date until November 1, after the revisions and verifications have been completed.

Regulatory Compliance Exemption

IPAA has doubted that the Regulatory Compliance Exemption (Exemption) would be realistically available; it has always appeared a false promise. Consistent with this perception, EPA's proposal demonstrates that it will use every measure possible to prevent the application of the Exemption.

1. *The Exemption Proposal is Inconsistent with the Plain Reading of the Statute*

To begin with, EPA shows its bias by choosing to cleverly try to parse the language of the statute and make it as unworkable as it can. Its first act is to misread the following language:

> ...methane emissions standards and plans pursuant to subsections (b) and (d) of section 111 have been approved and are in effect in all States with respect to the applicable facilities.

EPA chooses to focus on the term "all States" in isolation from the reference to "applicable facilities". A clear plain reading of the statute would reflect Congress' already punitive limitation on companies that would prevent them from using the Exemption as soon as a state in which they operate has plans in place by requiring that all the states where they had applicable facilities have approved section 111(b) and section 111(d) plans in place. That is, if a company had applicable facilities in Texas and West Virginia, it could not benefit from the Exemption in Texas if West Virginia's plans had not been approved. Both Texas and West Virginia must have approved plans.

EPA drives the issue to an absurd conclusion by interpreting the language to mean that if a company had operations in Texas and West Virginia and both had approved plans, the company could not utilize the Exemption if, say, South Dakota did not have approved plans – a state where it had no applicable facilities.

EPA's rationale for this interpretation can have no purpose other than to prevent the Exemption from being used and compel higher taxes on companies when they are, if fact, acting as the statute would envision – reducing their methane emissions and complying with the regulations.

2. *The Equivalency Proposal is Unfair and Designed to Prevent Use of the Exemption*

The second major task for EPA involving the Exemption relates to determining whether the promulgated Subpart OOOOb regulations and the forthcoming Subpart OOOOc state regulations "will result in equivalent or greater emissions reductions as would be achieved by the [2021] proposed rule…". EPA's course of action here is to punt. EPA merely states it will address this action in a future rulemaking after all the state plans have been approved.

This deferral of action by EPA leaves the entire process in an unacceptable limbo. This decision has always been fraught with confusion and EPA does nothing to create a framework for industry or states as it avoids any action – even when some actions are possible.

At issue here is that not only will this determination affect the Methane Tax, it can influence the state planning process if EPA were to conclude that the Subpart OOOOb regulations failed to meet the equivalency test. If so, it would mean that state plans would have to fill the gap perhaps compelling existing source regulations that are more extreme than those in the EG – or Subpart OOOOb.

Confounding the decision-making process is the fundamental challenge inherent in interpreting the 2021 Subparts OOOOb and OOOOc proposals. The 2021 proposal was largely devoid of true regulatory language, raising the issue of how EPA will evaluate this amorphous proposal. Numerous questions arise. For example:

a. How will EPA interpret the 2021 Subpart OOOOb proposal against the final 2024 Subpart OOOOb regulations? This comparison can be made now since the Subpart OOOOb regulations are final.
b. How will EPA address the 2021 Subpart OOOOc proposal given that the EG process allows states to develop comparable regulations and that the Remaining Useful Life and Other Factors (RULOF) provisions of Section 111(d) can be applied and applied differently in each state? Understanding this framework could potentially significantly affect EPA's conclusion.

EPA's failure to suggest how it will grapple with these complex decisions leaves the regulated community and states in a position of trying to make key regulatory and investment decisions in a void. Also, EPA's failure to address these decisions allows it to prevent applicable facilities from accessing the Exemption by not taking any action. Under the deferral approach, all state plans could be approved, but EPA could just defer the Exemption by making no decision.

There is nothing in the statute that prevents EPA from making segmented determinations on the equivalency of regulatory programs relative to the 2021 proposal. For example, as suggested above, EPA could determine if the final Subpart OOOOb regulations are equivalent to the 2021 Subpart OOOOb proposal. If they are not, it largely closes out the availability of the Exemption. Similarly, state-by-state determinations regarding Subpart OOOOc are feasible with the larger question being how EPA will assess how the 2021 Subpart OOOOc EG would have been implemented when there is virtually no regulatory language available. At least under a state-by-state approach, the potential for the Exemption to be available in a timely manner would be far higher, particularly if EPA junks the current proposal that all states must have approved plans before any applicable facility can utilize the Exemption and returns to a more logical plain reading of the statute that is described above.

EPA's approach in comparing the 2021 proposal to the 2024 final Subpart OOOOc EG would be inappropriate and unfair to the most vulnerable of existing sources. EPA asserts that it would assume that the 2021 EG would be implemented as proposed (although the proposal was not regulatory language). However, it would compare that assessment with the approved state plan that includes RULOF facilities. Such an approach is inequitable. First, there is no reason to assume that the RULOF facilities under the 2024 EG would not have been RULOF facilities under the 2021 proposal since they are clearly facilities where the regulations pose such a severe burden that they qualify as RULOF facilities. Second, penalizing all applicable facilities in a state because it has RULOF facilities is completely unwarranted and inequitable. Third, if the impact of the approach is to deny facilities that deserve RULOF treatment its application in order to obtain the Exemption for the remaining facilities in a state is an egregiously harsh punishment for those uneconomic facilities that are likely mature operations and probably small businesses. Therefore, a more equitable approach would compare whatever EPA concludes in the efficacy of the 2021 EG proposal with the basic regulatory structure in an approved state plan under the 2024 EG.

3. Actual Noncompliance Needs to be the Basis for Denying an Exemption

The third key ingredient to obtaining the Exemption is compliance with the Subpart OOOO family of regulations and state plans implementing the EG. Here, again, EPA proposes an approach intended to preclude the use of the Exemption. As EPA describes:

> CAA section 136(f)(6)(A) states that the WEC shall not be imposed "on an applicable facility that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 111." For the purpose of determining WEC facility eligibility for the regulatory compliance exemption, the EPA proposes that the compliance status of CAA section 111(b) and (d) facilities contained within a WEC applicable facility would be assessed based on compliance with the applicable methane emissions requirements for the Oil & Natural Gas Source Category (40 CFR part 60, subparts OOOOa, OOOOb, and OOOOc).

The statutory language gives EPA wide latitude to determine what constitutes compliance with the federal and state regulations. There is nothing in this language that prohibits EPA from using a test such as substantive compliance which would be appropriate, despite EPA's assertion otherwise.

In fact, to create a fair compliance test, there are several key components that should be included. First, the compliance test should be substantive compliance, not some shallow failure to adhere to some trivial detail. Second, the noncomplying events should be identified as a result of regulatory actions by the appropriate governing regulator. Third, the events should be adjudicated to assure that they are actual noncompliance with fines, penalties or specific performance actions assessed. Fourth, only the applicable facility where the noncompliance occurred should be denied the Exemption; other applicable facilities should not be affected.

Auditing, Compliance and Enforcement

EPA devotes two paragraphs of largely boilerplate material describing its auditing, compliance and enforcement policies. Nothing in them suggests that EPA has any intent not to use these authorities in the harassing fashion that has been the history of its actions related to the American oil and natural gas production industry.

The creation of the Methane Tax gives pervasive and largely unfettered opportunities to use auditing and enforcement actions to adversely affect oil and natural gas producers. EPA can audit any producer, challenging every calculation that is made, or challenging whether a small producer should have filed Subpart W and Methane Tax information. It can threaten large and crippling fines without any standards regarding the development of the information.

IPAA has raised this issue previously because of past experiences with the Office of Enforcement and Compliance Assurance (OECA). OECA's actions to target small businesses with crippling fines generates a harsh adverse dynamic. Since EPA seems intent on using the

Methane Tax to capture small businesses and marginal wells in its scope, EPA needs to determine how it will use these enforcement tools and make those policies public. It has not.

Conclusion

IPAA opposed the Methane Tax when it was being developed. It is clearly a punitive tax, cast as a backstop to the Subpart OOOO family of regulations. It presents itself as necessary to deal with an urgent need to reduce American methane emissions in the context of a global climate challenge; however, it only addresses the thirty percent of American methane emissions from the oil and natural gas industry, leaving the other seventy percent untaxed. That seventy percent is also largely unregulated; certainly, it is not regulated to the extent of oil and natural gas. The Methane Tax exemplifies the worst in legislation – no hearings, no committee reports, no conference report, no statements during floor debate. Now, EPA is using its regulatory authority to interpret the statute to consistently increase the taxable entities, to increase emissions calculations and to increase waste emissions thresholds while limiting the availability of the Exemption. IPAA urges EPA to reverse this course, withdraw this proposal and the Subpart W proposal, and limit the adverse effects of the Methane Tax.

If IPAA can provide further information, please contact Dan Naatz at dnaatz@ipaa.org.

Sincerely,

Dan Naatz
Chief Operating Officer and
Executive Vice President

APPENDIX A

IPAA Comments: Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems
September 30, 2023

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

September 30, 2023

ENVIRONMENTAL PROTECTION AGENCY
40 CFR Part 98
[EPA-HQ-OAR-2023-0234; FRL-10246-01-OAR]
RIN 2060-AV83

Re: Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems

These comments are filed on behalf of the Independent Petroleum Association of America (IPAA). IPAA represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will be significantly affected by the actions resulting from this regulatory proposal. Independent producers drill about 91 percent of American oil and natural gas wells, produce 83 percent of American oil and produce 90 percent of American natural gas.

In addition to the specific comments made herein, IPAA has joined comments submitted separately by the American Petroleum Institute (API).

These comments address proposals by the Environmental Protection Agency (EPA) to revise reporting requirements for Petroleum and Natural Gas Systems for the Greenhouse Gas Reporting Program (GHGRP) under Subpart W.

Subpart W Mandate

Initial efforts to revise Subpart W were included in 2022 as a part of a similarly titled proposal – Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule; Docket No. EPA-HQ-OAR-2019-0424. However, enactment of the Inflation Reduction Act (IRA) mandated that EPA revise Subpart W because of its use as the emissions basis for inclusion in and the calculation of the Methane Emissions Reduction Program (MERP) methane tax. In fact, no action taken now to revise Subpart W cannot be evaluated without considering and understanding its implications under the methane tax.

The mandate to revise Subpart W is no small task. The history of Subpart W demonstrates that its accuracy was never intended to be the basis for use as a taxing mechanism. Generally, its emissions factors were developed from limited emissions studies that were never structured to develop precise emissions estimates. The Inflation Reduction Act mandate requires EPA to:

> Not later than 2 years after August 16, 2022, the Administrator shall revise the requirements of subpart W of part 98 of title 40, Code of Federal Regulations, to ensure the reporting under such subpart, and calculation of charges under

> subsections (e)[1] and (f)[2] of this section, are based on empirical data, including data collected pursuant to subsection (a)(4)[3], accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c)[4] is owed.

The current proposal fails to remotely meet this mandate regarding either time or substance.

One obvious element of the MERP is that its timelines for action are completely inconsistent with reality. It initiates the methane tax in 2025 based on 2024 emissions reporting while falsely promising that compliance with federal Subpart OOOO, OOOOa, OOOOb, and OOOOc regulations and emissions guidelines will void the tax when these regulations will not be fully implemented until at least 2028. Regarding the Subpart W revisions, it requires EPA to finish its revisions by August 2024. The scope of actions that must be undertaken for the full revision of Subpart W, as described in the Inflation Reduction Act, cannot be completed in a two-year window. However, rather than execute its mandated task, EPA proposes a thinly disguised cosmetic rework of the same material that has existed for years with little or no validation by EPA – and, even then, EPA does not apply its changes for a year after its mandated deadline.

If Congress intends to impose millions of dollars of taxes on methane emissions from the petroleum and natural gas industries, potentially crippling the production of millions of barrels and cubic feet of these American products, its mandate to EPA to revise the appallingly inaccurate emissions tools of Subpart W must be read as a serious and thorough methodological effort.

Such an effort would have several key elements. First, it must recognize the nature of emissions particularly from petroleum and natural gas production and production related emissions. Second, it must recognize that some emissions can be measured and others will continue to need emissions estimates from factors; these decisions will be particularly influenced by the economic status of the facility operator. Third, it must recognize that EPA will need to validate these measurement tools and the emissions factors.

Emissions from petroleum and natural gas systems are characterized by leaks from pieces of equipment that cannot be readily or continuously measured. They differ by an array of numerous factors – crude oil versus natural gas, associated gas or low volatility crude, wet or dry gas wells. All wells decline as they produce, changing the volume and composition of their production. Studies have shown that low production wells differ from high volume wells. The economics of production differs between high and low production wells, frequently an indication of the capitalization of the operations. The amount of active equipment at a facility changes with production. Some facilities have gathering and compression equipment on site; others do not. Many low production wells do not operate daily. Many small natural gas wells have booster compressors to suck natural gas from the well bore. Emissions analyses show that 90 percent of

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[1] Emissions charge amount
[2] Waste emissions threshold
[3] Direct and indirect costs required to administer this section, prepare inventories, gather empirical data, and track emissions
[4] Waste emissions charge

emissions come from about 10 percent of facilities, with storage tanks and some pneumatic controllers accounting for the predominant percentage of these emissions.

Because so many of the potential emissions sources from petroleum and natural gas production facilities are diverse components like valves, flanges, storage tanks, connectors, and controllers that are individually small, there are not straightforward methods to routinely monitor these emissions. Studies that have been conducted have used methods like bagging equipment to collect emissions for a short period of time. This technique is infeasible for routine operations. Newer facilities with higher volumes of production and more equipment at a site have been able to collect emissions from equipment like pneumatic controllers and pneumatic pumps and route them to vapor capture or combustion. However, such technology is limited if not impossible for older, low production facilities. Consequently, while EPA has been directed to expand the use of actual facility-based emissions data to quantify emissions, there will continue to be a certain need for emissions factors for emissions that are too difficult to measure or too expensive to collect for low production operations.

Perhaps most importantly for EPA and where EPA has failed most clearly in this proposal is the need to produce validated emissions calculations and validated emissions factors for Subpart W. Subpart W presents a long history of relying on limited studies from the 1990s appended using questionable analyses by environmental lobbyists to produce reports on petroleum and natural gas production facilities. Many of these same analyses have been used for the development of EPA methane regulations in Subpart OOOO, OOOOa, OOOOb and OOOOc. Missing from all these EPA actions is careful, thorough validation of the analyses by EPA and replication of these analyses. Many of these studies have been based on a small number of facilities, based on drive-by analysis with no information on facilities' operation, based on recalibrating data in different ways without any new information, based on applying statistical manipulation to produce headline grabbing allegations. Congress' mandate to EPA is connected to very real methane tax consequences. EPA cannot meet this mandate without collecting and analyzing its own data to develop sound, robust emissions calculation methods and emissions factors. This proposal fails completely to meet this essential test.

These challenges for EPA to meet its Subpart W mandate demonstrate clearly that it cannot be done properly in the two-year window of the MERP timeline. For EPA to do it job right, it needs to get changes made to the Inflation Reduction Act to make its timelines for both Subpart W and the completion and implementation of the Subpart OOOOb regulations and OOOOc emissions guidelines to complete these actions before collecting methane taxes from American producers.

New Implications of Subpart W

When Subpart W was solely related to filing under the GHGRP, determining whether a facility needed to file and the accuracy of submitted information carried limited further scrutiny. However, because the MERP imposes a methane tax, all filing decisions now become auditable and subject to penalties under the enforcement provisions of the Clean Air Act (CAA). These new burdens compel EPA to address them in Subpart W, but it does not.

Both the MERP and Subpart W establish a filing threshold of 25,000 mt/year of CO_2eq. This threshold was set initially by EPA when it initiated Subpart W reporting to limit the burden on small businesses while maintaining reporting by the preponderance of emissions sources. It was specifically retained in the MERP legislation. At issue then is the challenge to small producers to determine whether they are subject to the Subpart W filing requirements without compelling them to complete a costly full-blown inventory that is unnecessary. EPA provides no simple estimating procedure to determine whether small producers are near the 25,000 mt/year threshold. Both EPA and Congress have shown that small producers are not the target of the methane tax; however, EPA must now provide a mechanism to easily exclude them without the threat of audit and enforcement by the Office of Enforcement and Compliance Assurance (OECA).

A different, but similar, issue arises for all reporting entities. With Subpart W becoming the basis for the methane tax, any and all information submitted become the subject of audit and enforcement under the CAA. This creates the potential for frivolous and harassing actions by OECA. The history of OECA interaction with American petroleum and natural gas producers has been characterized by OECA actions to target smaller producers with fine threats that would bankrupt them. These actions have included interpretations of regulations by OECA that differed from the interpretation and guidance from the regulatory authors within EPA. Filing under Subpart W creates hundreds of thousands of opportunities to challenge any submitted information. Since EPA has proposed numerous different approaches to submitting information and creates the opportunity for reporters to submit facility specific information, EPA must now assure that good faith actions by reporters are not windows of opportunity for OECA to pursue harassing actions. However, EPA has not provided clear and straightforward guidance in this Subpart W proposal. Nor has it shown that OECA will use such guidance.

Property Transfer

When property transfers, the reporting of emissions takes on a different context because of the introduction of the methane tax. Previously, these issues have been largely related to assuring that there was a source responsible for assuring emissions were reported. The methane tax changes the process because substantial amounts of money are involved and there are equities that need addressed. Essentially, no new owner should be responsible for the methane taxes generated by the prior owner. This EPA proposal regarding the transfer of property fails to set forth clear delineations to create the equity that is essential.

Facility Definition

When EPA set its facility definition for the GHGRP, it was based on the 25,000 mt/year on information indicating that it would exclude small wells and producers. However, experience is showing that the current structure of the definition is capturing facilities comprised of low production wells and gathering and boosting facilities (that were not part of the original threshold selection). EPA is now proposing that emissions calculations be made at the well pad level. It should also revise the facility definition to exclude low production wells and to alter the gathering and boosting calculation to limit the use of arbitrary emissions estimates based on pipeline mileage.

Specific Proposals

EPA actions to revise component emissions factors raise serious questions about both the approach and the proposal. As discussed above, the Inflation Reduction Act mandate to revise Subpart W requires EPA to conduct thorough analyses of the numerous emissions factors and either independently validate them or develop its own valid factors. It failed to do either.

Instead, it turned to three reports as the basis for new emissions factors. These reports are generally referenced as Zimmerle[5], Pacsi[6] and Rutherford[7].

However, EPA's use of these materials demonstrates a callous disregard for the mandate EPA must meet in revising Subpart W. The Zimmerle report addresses emissions from gathering compressor stations; the Pacsi report addresses emissions from oil and natural gas production equipment leaks. Each of these studies conclude that the current emissions factor calculation process under Subpart W overstates emissions that they studied. The Zimmerle report states:

> Combining study emission data with 2017 GHGRP activity data, the study indicated statistically lower national emissions of … 66% … of current GHGI estimates, despite estimating 17% … more stations than the 2017 GHGI ….

The Pacsi report states:

> The most common EPA estimation method for greenhouse gas emission reporting for equipment leaks, which is based on major site equipment counts and population-average component emission factors, would have overestimated equipment leak emissions by 22% to 36% for the sites surveyed in this study as compared to direct measurements of leaking components because of a lower frequency of leaking components in this work than during the field surveys conducted more than 20 years ago to develop the current EPA factors.

To show the EPA lack of regard for its mandate, EPA ignores these conclusions and cherry picks elements of the reports to increase the component emissions factors in Subpart W. The Rutherford study takes a different approach. It makes the assumption that component based emissions estimates understate actual emissions because it believes that ambient monitoring presents more accurate results. Consequently, it surveys a variety of component based emissions studies to create emissions factors higher than those in the current Subpart W and adopts them as more accurate.

Critically, EPA embraces all these various changes that increase the Subpart W emissions factors, but it never attempts to independently validate them. The effect of this action is increases in virtually every component emissions factor, some of which would yield emissions estimates 5 times or more than the current Subpart W calculations. Not only is this approach a clear dereliction of EPA's responsibilities, but it also has the effect (along with changing the GWP for methane) of de facto lowering the 25,000 mt/year threshold and raising the emissions subject to methane tax. Enverus Intelligence Research, a subsidiary of the energy-focused Software as a Service firm Enverus, has found the proposed regulations would more than double 2021 reported methane and increase overall carbon dioxide-equivalent emissions by 41%. If EPA is intentionally revising the Congressionally enacted methane tax through its rulemaking actions, it should be held to a standard that requires it prove that its revisions are valid.

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[5] Zimmerle, D., *et al.* "Methane Emissions from Gathering Compressor stations in the U.S." *Environmental Science & Technology* 2020, 54(12), 7552-7561, available at *https://doi.org/10.1021/acs.est.0c00516*.
[6] Pacsi, A. P., *et al.* "Equipment leak detection and quantification at 67 oil and gas sites in the Western United States." *Elem Sci Anth*, 7: 29, available at *https://doi.org/10.1525/elementa.368*. 2019
[7] Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P. *et al. Closing the methane gap in US oil and natural gas production inventories*. Nat Commun 12, 4715 (2021). *https://doi.org/10.1038/s41467-021-25017-4*

Intermittent Pneumatic Controllers

EPA is proposing a series of different emissions calculations for intermittent pneumatic controllers – one of the largest emissions sources at production facilities based on the current EF. While using more accurate analysis is highly desirable, these proposals have not been independently verified by EPA. Additionally, this approach requires much higher data acquisition for each controller which could be burdensome for smaller companies. At the same time EPA eliminates the EF for intermittent pneumatic controller rather than modify what has clearly been a flawed EF.

Each EF carries with it a history of its development and evolution. Intermittent pneumatic controllers used in oil and natural gas production have been an example of the challenge of developing accurate information. Intermittent pneumatic controllers operate only when they activate. Correspondingly, they emit when they activate unless they are failing for some reason. Intermittent pneumatic controllers are one of the most pervasive pieces of equipment at oil and natural gas production facilities. Consequently, they are one of the largest emissions sources for these operations. At issue is the validity of the EF and the proposed revisions for this equipment.

To illustrate the issue, EPA need look no farther than its own proposed GHGRP revisions for calculating emissions associated with intermittent-bleed pneumatic devices, both those from the 2022 proposed rule (Docket ID No. EPA-HQ-OAR-2019-0424) and those from the 2023 proposed rule that is the focus of these comments (Docket ID No. EPA–HQ–OAR–2023–0234; FRL–10246–01–OAR). The first obvious observation is that the EPA cannot itself decide how to accurately calculate emissions from pneumatic devices, as evidenced by the widely varying proposed revisions.

The current GHGRP - Subpart W rules require reporters to calculate emissions from intermittent-bleed pneumatic devices by:

Utilizing Equation "W-1", where

- EF_t = 13.5 scf/hr/component for intermittent-bleed pneumatic device vents (from Table W-1A), and
- T_t = Average estimated number of hours in the operating year the devices, of each type "t", were operational using engineering estimates based on best available data. Default is 8,760 hours. (every hour of every day in a year)

In the 2022 Proposed GHGRP – Subpart W revisions for calculating emissions from intermittent-bleed pneumatic devices, the EPA proposal allowed one of two calculation methods:

- Utilize Equation "W-1A", where
- EFt = 8.8 scf/hr/component for intermittent-bleed pneumatic device vents (from Table W-1A), and
- Tt = Average estimated number of hours in the operating year the devices, of each type "t", were in service (i.e., supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours (every hour of every day in a year). **This represents a nearly 35% reduction compared to the current emissions factor**,

OR

- Utilize Equation “W-1B”, which contemplates an entirely new proposed alternative calculation methodology allowing reporters that perform approved leak surveys (i.e. LDAR surveys with OGI cameras) to identify properly operating v. malfunctioning intermittent-bleed pneumatic devices, and
- Proposes an EF of 24.1 scf/hr/component for malfunctioning/leaking devices and specifies the method for determining the amount of time a device was assumed to be leaking, and
- Proposes an EF of 0.30 scf/hr/component for properly operating devices and specifies the method for determining the amount of time a device was assumed to be leaking. **This represents a nearly 98% reduction from the current required EF for intermittent-bleed pneumatic devices.**

And, now in its latest proposed GHGRP – Subpart W revisions for calculating emissions from intermittent-bleed pneumatic devices, the EPA proposal allows one of three calculation methods. Proposed “Calculation Method 3” is most analogous to the alternative method from the 2022 Proposed Rule and allows for the following:

- Utilize Equation “W-1C”, which, similar to the method described above, allows reporters that perform approved leak surveys (i.e., LDAR surveys with OGI cameras) to identify properly operating v. malfunctioning intermittent-bleed pneumatic devices, and
- Proposes an EF of 16.1 scf/hr/component for malfunctioning/leaking devices and specifies the method for determining the amount of time a device was assumed to be leaking, and
- Proposes an EF of 2.82 scf/hr/component for properly operating devices and specifies the method for determining the amount of time a device was assumed to be leaking. **This represents a nearly 80% reduction from the current required EF for intermittent-bleed pneumatic devices.**

Although many Subpart W reporters currently perform OOOOa compliant LDAR surveys utilizing OGI cameras, in-line with the proposed GHGRP revisions, and are able to identify properly operating devices versus malfunctioning devices, the current rules do not allow the data to be used. And, as such, significantly overstates GHG emissions from intermittent-bleed pneumatic devices.

To demonstrate how GHG emissions from intermittent-bleed pneumatic devices are significantly overstated by the current GHGRP Subpart W rules versus EPA’s proposed revisions from both 2022 and 2023, see the hypothetical scenario below:

Comparison of Methane Emissions Associated with Intermittent-Bleed Pneumatic Devices as Determined by Current GHGRP "Eq. W-1" v. 2022 Proposed GHGRP "Eq. W-1A" AND "Eq. W-1B" v. 2023 Proposed GHGRP "Eq. W-1C" (aka "Calculation Method 3")	
Assumptions: – One Subpart W Reporter – 100 Intermittent-bleed Pneumatic Devices @ 20 Locations – Performs compliant OGI leak surveys at all 20 locations one-time per annum – Identifies 10 malfunctioning (i.e. leaking) Devices (10% leak rate) – Remaining 90 Devices, verified to be operating normally – Uses default of 8760 hours for device "operating" (current rule) and "In-service" (proposed rule) times – Produces dry gas with a 98% CH4 Fraction	
Current – "Eq. W-1"	$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t$ (Eq. W-1) **100 devices x 13.5 scf/hr/device x 0.98 CH4 % x 8760 hours = 11,589,480 scf CH4 emissions**
2022 Proposed – "Eq. W-1A"	$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t$ (Eq. W-1A) **100 devices x 8.8 scf/hr/device x 0.98 CH4 % x 8760 hours = 7,554,624 scf CH4 emissions**
2022 Proposed – "Eq. W-1B"	$E_i = GHG_i * \left[\left(24.1 * \sum_{z=1}^{x} T_z\right) + (0.3 * Count * T_{avg})\right]$ (Eq. W-1B) **0.98 CH4 % x [(24.1 scf/hr/device x 10 leaking devices x 8760 hours) + (0.3 scf/hr/device x 90 non-leaking devices x 8760 hours)] = 2,300,726 scf CH4 emissions**
2023 Proposed – "Eq. W-1C"	$E_i = GHG_i \times \left[\sum_{z=1}^{x}\{16.1 \times T_{mal,z} + 2.82 \times (T_{t,z} - T_{mal,z})\} + (2.82 \times Count \times T_{avg})\right]$ (Eq. W-1C) **0.98 CH4 % x [10 leaking devices ((16.1 scf/hr/device x 8760 hours) + (2.82 scf/hr/device (8760 hours – 8760 hours)) + (2.82 scf/hr/device x 90 non-leaking devices x 8760 hours)] = 3,560,975 scf CH4 emissions**
Summary – In the scenario above, current GHGRP requirements ("Eq. W-1") overstate methane emissions associated with intermittent-bleed pneumatic devices by approx. 35% compared to 2022 proposed GHGRP alternative 1 ("Eq. W-1A"), by approx. 80% compared to 2022 proposed GHGRP alternative 2 ("Eq. W-1B") and by approx. 69% compared to 2023 proposed GHGRP Calculation Method 3 ("Eq. W-1C").	

This example demonstrates that the agency is well aware that current GHGRP rules and associated mandated calculation methodologies significantly overstate emissions for intermittent-bleed pneumatic devices.

IPAA generally supports EPA's proposal to allow multiple calculation methods for determining emissions from natural gas driven intermittent-bleed pneumatic devices. However, there are concerns with each proposed method as described below:

Calculation Method 1 – Direct measurement with flow monitoring device

This calculation method as an alternative for reporters that have or can cost-effectively install flow monitoring devices to directly measure fuel gas supplied to intermittent-bleed pneumatic devices. For many, if not most, reporters that do not already have flow monitoring devices installed, it will be cost prohibitive to install these devices and currently this is the only proposed method that fully allows the use of "empirical data" as mandated by the IRA. Consequently, EPA should amend calculation Methods 2 & 3 as described below.

Calculation Method 2 – Direct measurement of device vent rates and use of "In-service" times

This proposed calculation method allows reporters to use empirical data in the form of direct measurement to determine vent rates from intermittent-bleed pneumatic devices. Unfortunately, this method, as proposed, is only a half-solution, in-terms of allowing empirical data, because it still requires reporters to use the non-empirical factor of "in-service (i.e., supplied with natural gas)" hours to calculate emissions.

Under proposed Calculation Method 2, reporters are required to determine emissions using the actual "number of hours the pneumatic device was in-service (i.e., supplied with natural gas) in the calendar year" for devices where vent rates were measured AND to use proposed "Eq. W-1B" for devices that did not have vent rates directly measured during the calendar year. Variable "T_t" in proposed Eq. W-1B, requires reporters to determine the "Average estimated number of hours in the operating year the devices of each type "t", were in-service (i.e., supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours." In both instances the requirement to determine emissions based on the concept of "in-service" hours completely contradicts the IRA mandate to allow the use of "empirical data."

Interestingly, EPA proposes that, absent any measured volume during a 5-minute or 15-minute sampling period, as applicable, reporters can use "company records or engineering estimates" to estimate per actuation emissions and actuation cycle counts to estimate emissions. See the proposed rule excerpt below:

> For intermittent bleed devices, the lack of any emissions during a 5-minute or 15-minute period, as applicable, would indicate that the device did not actuate and that the device is seating correctly when not actuating. As such, we are proposing that engineering calculations would be made to estimate emissions per activation and that company records or engineering estimates would be used to assess the number of actuations per year to calculate the emissions from that device for the reporting year." (FR p. 50311)

This approach represents "empirical data" consistent with the IRA mandate and would yield more accurate emissions estimates for intermittent-bleed pneumatic devices. As such, EPA should amend the Calculation Methods 2 & 3 to allow the use of this approach more broadly, in lieu of the "In-service" hours concept and not only when there is a lack of emissions measured during a sampling period, but in all cases.

Under proposed Calculation Method 2, EPA proposes to require the vent rate for every pneumatic device to be directly measured every 5 years. This measurement frequency is overly burdensome and unnecessary to determine a statistically representative average vent rate for devices of the same type (i.e., intermittent bleed). EPA should amend the proposed rule to only require 10% of devices to be surveyed each year.

Further, under proposed Calculation Method 2, EPA proposes to require a 15-minute vent rate sampling period for each pneumatic device, except isolation valve actuators, which would only be required to be sampled for a minimum of 5 minutes. See excerpt below:

> We are proposing a reduced monitoring duration for isolation valve actuators specifically because these devices actuate very infrequently, and the monitoring is targeted to confirm the valve actuators are not malfunctioning (i.e., emitting when not actuating) rather than to develop an average emission rate considering some limited number of actuations." (FR p. 50311)

A reduced monitoring frequency of only 5 minutes is adequate to confirm a pneumatic device is not malfunctioning. It is not only true for isolation valve actuators, but for all intermittent bleed pneumatic devices. Accordingly, EPA should amend the proposed rule to only require a 5-minute sampling period for all devices. The currently proposed 15-minute sampling period is overly burdensome and unnecessary to accurately estimate emissions.

Calculation Method 3 – Intermittent-bleed Pneumatic Device Surveys

As EPA acknowledges in its proposed revisions to the GHGRP rule, it is possible to identify and distinguish malfunctioning or "leaking" intermittent-bleed pneumatic devices from properly operating intermittent-bleed pneumatic devices via leak surveys (see below).

> As part of our review to characterize pneumatic device emissions, we found a significant difference in the emissions from intermittent bleed pneumatic devices that appeared to be functioning as intended (short, small releases during device actuation) and those that appeared to be malfunctioning (continuously emitting or exhibiting large or prolonged releases upon actuation). For natural gas intermittent bleed pneumatic devices, it is possible to identify malfunctioning devices through routine monitoring using optical gas imaging (OGI) or other technologies.
> (FR 50312)

This alternative method for calculating emissions from intermittent bleed pneumatic devices should be included for reporters that are unable to justify the costs associated with proposed calculation Methods 1 & 2, even though it does not allow the use of empirical data.

However, proposed calculation Method 3, in its current form, like the current Subpart W rules, will still likely overstate emissions from intermittent bleed pneumatic devices significantly, because it continues to rely upon the use of one-size fits all leaker emissions factors and a determination of "in-service" hours based on a default of 8760 hours (every hour of every day in a reporting year). This approach, even though properly operating devices are confirmed via approved leak surveys, requires reporters to assume properly operating intermittent bleed pneumatic devices are leaking continuously or nearly continuously.

Properly operating intermittent bleed pneumatic devices, as acknowledged by the agency, do not vent continuously. By design and definition, intermittent-bleed pneumatic devices only vent ("process emissions") when they actuate. Therefore, EPA should amend Calculation Methods 3 to allow reporters to use "company records or engineering estimates" to determine actuation cycle counts, when the data is available, in lieu of the "In-service" hours concept. This approach would allow the use of "empirical data" and yield more accurate emissions estimates.

The currently proposed EFs for Calculation Method 3 vary significantly from the 2022 proposed rule, see table below, without sufficient basis. From available information, it appears that EPA used the Zimmerle study to develop its 2023 proposal. However, these values are based on controllers under very different operating conditions than those in the oil and natural gas production component of the industry. Experts who have evaluated the 2023 proposal conclude that the 2022 factors are more appropriate. EPA should amend the proposed leaker factors to align with the 2022 proposed rule, which was consistent with the "API Field Measurement Study: Pneumatic Controllers" (Tupper 2019)

	Whole Gas EF – Properly Operating Intermittent Bleed Pneumatic Device	Whole Gas EF – Malfunctioning Intermittent Bleed Pneumatic Device
2022 Proposed Rule	0.03 scf/hr/device	24.1 scf/hr/device
2023 Proposed Rule	2.82 scf/hr/device	16.1 scf/hr/device

Retain a Calculation Method Similar to the Current Subpart W Regulations

EPA should allow a fourth calculation method similar to the method in the current Subpart W rules and that which was included in the 2022 proposed rule, that allows small operators to use a single whole gas emissions factor-based approach for calculating emissions from intermittent-bleed pneumatic devices. EPA suggests that such an alternative is unnecessary because of the Subpart OOOOb and OOOOc proposals. However, neither of those are finalized and alternative approaches to managing emissions have been proposed. In particular, the Subpart OOOOc Emissions Guidelines are not binding on states and state regulations may continue to allow natural gas driven pneumatic controllers.

The current EF for intermittent pneumatic controllers is 13.5 scf/hour/component. This EF was developed in the mid-1990s based on data collected from 19 controllers. It is hardly an example of robust data acquisition. Since then, the validity of this EF has been consistently questioned. It has become a higher profile issue as various environmental lobbying groups have produced reports based on the GHGI that is largely developed using the GHGRP.

Over the years other studies have been done to address this EF. However, the quality of EPA's 2022 analysis of this EF that has been such a target is wanting. In general, EPA discusses six studies that have been done with information on intermittent pneumatic controllers for production operations (GRI/EPA 1996, Allen, Thoma, Prasino, OIPA and API 2019). Additionally, EPA assessed a Department of Energy study on Gathering and Boosting operations (DOE G&B). In each case EPA discusses the limitations of the studies – short sampling times with assumptions about the activation period for intermittent controllers, emissions that are calculated rather than measured, and classification issues. Then, EPA eliminates two studies (Thoma, OIPA) apparently because of their use calculated emissions (which were far lower than some of the other studies). Subsequently, it produced the following summary table:

Table 2-9. Comparison of Population Emission Factors for Natural Gas Pneumatic Device Venting for Production and G&B Industry Segments

Device Type	Whole Gas Emission Factor (scf/hr/device)					
	Subpart W[a]	GRI/EPA (1996e)[b]	Allen *et al.* (2015)	Prasino Group (2013a)[c]	DOE G&B Study (2019)	API Field Study (2019)
Low continuous bleed pneumatic devices	1.39	27.3[b]	13.6[d]	6.1	7.6	2.6
High continuous bleed pneumatic devices	37.3		22.8	10.4	19.3	16.4
Intermittent bleed pneumatic devices	13.5	13.5	6.0[d]	4.2	11.1	9.2

Next, EPA averaged the intermittent factors for these studies to produce a new EF of 8.8 scf/hr. However, this appears to include the EF from the DOE G&B study; if it had not, the EF would appear to be 8.2 scf/hr. If EPA had included the Thoma and OIPA studies instead of the DOE G&B study, the EF would be 6.8 scf/hr. None of these calculations appear to be weighted based on the number of controllers tested. Consequently, for example, the 19 controllers in the GRI/EPA 1996 study are treated equally with the 128 controllers in the Prasino report. If EPA had weighted the data and used the Thoma and the OIPA studies, the EF would be closer to 3.7 scf/hr/device.

EPA should include a fourth calculation option that provides a single EF and that EF should be 3.7 scf/hr/device.

Gathering and Boosting/Centralized Production Facilities

The Gathering and Boosting category in the methane tax has an inordinately low threshold for its tax basis without any apparent justification. EPA needs to explain the source of the excess emissions fee threshold for gathering and boosting facilities and why it is appropriate. Clearly though only truly separate gathering and boosting operations should be included in it. The current Subpart W proposal creates a critical issue in this regard. The types of equipment used for gathering and boosting of natural gas can be used independently to move natural gas from production facilities to natural gas processing facilities, but it can also be used at oil and natural gas production operations as an integral part of those operations. The proposed Subpart W creates a designation of upstream operators' centralized tank batteries. "Centralized oil production sites" are defined as sites collecting oil from multiple well pads without compressors "that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well pads". In the proposed rule, EPA has classified centralized oil production sites under the Gathering and Boosting segment. Subpart W needs to be clarified to assure that those centralized oil production operations are included within the reporting for the production facility.

Centralized Oil Production Facility Issues

EPA has recognized centralized production sites as a facility type in the proposed rule and required its emissions to be reported at the site-level, rather than per well ID, which streamlines the reporting for tank batteries. However, there are challenges with including "centralized oil production sites" in the Gathering and Boosting segment.

First, EPA included "production" clearly in the name and it is nonsensical that centralized production sites would be considered part of the Gathering and Boosting segment.

Second, these sites are considered by many operators as part of the upstream production process as these tank batteries are likened to "production supportive facilities." Facility design efficiency gains over the years have led to centralization of production surface equipment. The centralization of surface equipment generally results in emissions reductions relative to dispersed facilities (separation and tanks installed at each well pad) because the total equipment counts are significantly reduced (fewer emission points), there is a reduction of tank batteries/spill risk, increased operational efficiencies, and better ability to site major facilities away from sensitive areas/populations. This segment classification is contradictory to previous interpretations and may have unintended consequences such as companies electing not to centralize such operations (even though consolidation serves to minimize environmental footprint) due to the more burdensome methane fee implications. Facilities comprised of centralized surface equipment are owned and operated by producers, supportive of production, and may or may not include a well head or pump jack collocated on a single pad.

However, because EPA re-defined the production segment in 2016 as "associated with a single well pad", this has created reporting confusion and centralized tank batteries have been categorized differently both by individual owners/operators, as well as other federal rules (NSPS OOOOb). For example, under the proposed OOOOb regulations, the "centralized oil production facilities" (referred to in NSPS OOOOb as "centralized production facility") are grouped under the production segment by definition rather than as Gathering and Boosting as explained below.

Currently Subpart W calls and defines the subject facility as:

> "**Centralized oil production site** means any permanent combination of one or more hydrocarbon liquids storage tanks located on one or more contiguous or adjacent properties that does not also contain a permanent combination of one or more compressors that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well-pads. A centralized oil production site is a type of gathering and boosting site for purposes of reporting under §98.236."

Meanwhile NSPS OOOOb/OOOOc calls and defines it as:

> "**Centralized production facility** means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations."

In addition, in the Pipeline and Hazardous Material Safety Administration's ('PHMSA") proposed Gas Pipeline Leak Detection and Repair rule, PHMSA does not define or regulate *any* production facilities as "gathering and boosting". Specifically, as defined in API's

Recommended Practice-80 and incorporated in 49 CFR 192: "The production function, in most cases, extends well downstream of the wellhead and may include several processes required to prepare the gas for transportation. In this context:

> 'Production Operation' means piping and equipment used for production and preparation for transportation or delivery of hydrocarbon gas and/or liquids and includes the following processes: (a) extraction and recovery, lifting, stabilization, treatment, separation, production processing, storage, and measurement of hydrocarbon gas and/or liquids; and (b) associated production compression, gas lift, gas injection, or fuel gas supply."

Both the NSPS OOOOb/OOOOc and PHMSA's name and definition of what are essentially tank batteries are much more consistent with how these facilities operate and are managed in the field. In an effort to mitigate confusion and create more rule alignment, EPA should align the name and definition of the subject facility type between Subpart W and NSPS OOOOb/OOOOc.

In this proposal, EPA claims to be striving for consistency when EPA states, on page 50288 of the proposal, "as in the 2016 rule, the proposed amendments would also allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs." Also, even though EPA uses the word "gather" in the definition in OOOOb/OOOOc, these sites are still properly defined as "part of the producing operations."

Further, the fact that EPA has proposed the definition of "centralized production sites" as sites that do <u>not</u> include compressors that are part of the Gathering and Boosting segment is puzzling. If these sites are part of the Gathering and Boosting segment as EPA has proposed, why would these sites not be allowed to have compressors that are part of the Gathering and Boosting segment on them? This demonstrates that EPA <u>*does*</u> understand the distinction between gathering and boosting compressors that should appropriately be included in the Gathering and Boosting segment and centralized tank batteries that clearly should not.

As such, EPA should change both the name and definition of "centralized oil production site" in the Subpart W rule to match NSPS OOOOb/OOOOc, to align with other federal programs for consistency, and to reflect how the industry owns and operates these facilities. EPA should delete "associated with a single well pad" from the Onshore Petroleum and Natural Gas Production definition in Subpart W in order to clear up the confusion and properly have centralized production sites in the production segment where they belong.

Further, and most importantly, EPA's proposed definitions are contrary to the MERP waste emissions thresholds, where gathering and boosting sites are considered "non-production". In this language on the Waste Emission Threshold, Congress created two categories for applicability of the threshold: "Production" and "Non-Production". The Gathering and Boosting segment (segment #8) is listed under "Non-Production". Clearly, Congress did not intend for sites associated with production, such as "centralized **production** sites" to be considered gathering and boosting. EPA may have been able to impose reporting obligations for emissions from centralized tank batteries under the Gathering and Boosting segment in the past but for application of the tax, these sites should be considered production. Doing otherwise would result in an inequitable application of the tax that would most likely not be applied uniformly by all upstream operators. If EPA does not wish to clear up the confusion and include centralized production sites in the Production segment, EPA should carve out these sites for threshold determination and make these sites subject to the 0.2% threshold as Congress has clearly mandated in the law.

In addition, the categorization of a centralized production site into Gathering and Boosting could result in a backslide from the progress industry has made in minimizing its overall footprint and emission sources. Due to the higher methane taxes that may accompany categorizing production sites as Gathering and Boosting (subjecting these facilities to the 0.05% threshold instead of the 0.2% threshold) operators may be economically incentivized to migrate back to individual well pad installations, dramatically increasing the amount of equipment in the field and increasing GHG emissions.

Gathering and Boosting Emissions Factor Issues

A consistent criticism of the current emissions estimation process for gathering and boosting operations relates to its use of emissions factors based on the mileage of pipelines. These factors cannot be altered based on any operational actions other than changing the nature of the pipeline material or structure. These factors from 1996 are unchanged in this proposal despite studies showing that pipeline emissions are overestimated. The consequence of this failure will be to impose the harshest excess emissions tax on this essential component of the natural gas value chain without providing any plausible recourse to alter the emissions calculations. This inaction by EPA flies in the face of its mandate to make the Subpart W emissions estimate more accurate, more reflective of actual operations.

Pipelines are inspected routinely, leaks are fixed, and emissions are eliminated. Only actual emissions should be reported under Subpart W and used for any excess emissions tax calculation; not simply based upon miles of pipeline for which the vast majority are not leaking. There should be an option to demonstrate that emissions are being managed, to show that there are no leaks, or, where leaks are identified, the emissions be based on the leaks found

Pipeline leaks are easily detected through regular inspection using airborne overflights, easement riding and operator inspections. Arguably, these have lower detection limits based on the type of technology used. Larger leaks can easily and quickly be determined by sudden drops in production. The pipeline can be isolated, and the volume of gas lost can easily be determined with great accuracy. Following are some options to determine pipeline factors and credit for inspection:

> Pipeline flyovers have a lower detection limit but do detect methane. If no leaks are found, then no emissions factor should be used for that segment and there should be no excess emissions tax or emissions calculated.
>
> Similarly, when laser-based and acoustic based technology is employed while riding the pipeline easement, leaks are detected. If no leak is detected, then no excess emissions tax or emission factor should be used. If a leak is found, then the actual leak can be measured or an emission factor should be developed. This is currently allowed in the detection of fugitives and a comparable approach for pipelines can be developed.

Use of Advanced Monitoring and Measurement Technologies

For many source categories under Subpart W, EPA has included several options for operators to be able to provide empirical data, such as measurement with metering or using updated emissions factors based on recent field measurement studies. However, under this proposed rule, EPA has not included a pathway for using the results of advanced methane detection and measurement surveys as a source of empirical data for key source categories, like tanks, flares, and compressors.

Methane detection and measurement technologies have advanced in the last few years due to early-phase research efforts, including from the Department of Energy, to develop technologies that have now become commercially available. Some operators have included these technologies in their voluntary methane management programs. Including a pathway for utilization of these technologies for emissions reporting would improve the quality of data submitted under Subpart W while supporting a growing methane detection and measurement industry. A final rule for changes to Subpart W should include a pathway for utilizing survey results from technologies, particularly those approved for use under NSPS OOOOb and OOOOc, for emissions reporting.

Large emissions events

The comments filed by API extensively address the complexity and flaws in the EPA Subpart W proposal on large emissions events. IPAA commends these comments, which it joined in submitting, as a detailed assessment of the issues that need to be resolved.

Flares

The comments filed by API extensively address the complexity and flaws in the EPA Subpart W proposal on emissions issues related to oil and natural gas production flaring. IPAA commends these comments, which it joined in submitting, as a detailed assessment of the issues that need to be resolved.

Environmentalists' Recommendations Inappropriate and Unworkable

As a component of its efforts to suppress American oil and natural gas production, professional environmental lobbying organizations have orchestrated initiatives to press for additions to the Subpart W reporting regulations that are either inappropriate or unworkable. This effort was evident during the August 2023 EPA public hearing on its current Subpart W proposal where about 40 testifiers used exactly the same terms to demand changes to the Subpart W proposal. These demands reflect comments made by the Environmental Defense Fund in several forums regarding Subpart W and the methane tax.

Following is a list of the key demands:

- Integrating top-down, basin-level data alongside site- and equipment-level measurement data. Top-down, basin-level data provides a full picture of total emissions in a region, while site-level, population-based measurement data can provide insights of emissions at a finer resolution, all of which strengthen the accuracy of reported emissions.
- Building in appropriate statistical analysis of measurement data to provide a representative assessment of pollution at the facility and basin levels. Measurement data requires statistical analysis to account for intermittent emission events that may be missed by individual, one-time measurements.
- Defining guardrails and requiring independent verification for self-reported measurements from companies to ensure any company reported data accurately represents operations and is not limited to unrepresentative sites or equipment known to have lower emissions.

One of the key issues here is the relationship between these recommendations and Subpart W. Everyone would like to have the relationship between top-down basin-level data and site- and equipment-level measurement data better understood to resolve the recurring contentious debates regarding these issues. However, such an analysis is well outside the scope of facility reporting under Subpart W. Subpart W is predicated on individual companies reporting emissions estimates based on artificially contrived facilities, e.g., all their operations in an APGA basin. Even if EPA alters the reporting structure to require reporting by well pad, the reporting remains a company-based report. Conversely, basin level data is just that – basin level. It contains information that reflects emissions from numerous well pads, owned and operated by different companies. Moreover, Subpart W information reports annual emissions; top-down basin-level data is temporal in nature perhaps hours, perhaps days, perhaps minutes. No analysis that compares the top-down data and equipment-level measurement data can realistically use Subpart W reporting. These analyses must have a coordinated effort to assess data from both components simultaneously.

Similarly, while statistical analysis can be valuable, it is not in the purview of Subpart W reporting. If EPA wants to conduct appropriate statistical analysis, it must design a more rigorous direct sampling or estimating strategy. Such an effort could be valuable if developed by and validated by EPA. To date, the analyses that have been generated have been thinly veiled advocacy efforts designed to press for regulations so quickly that EPA has never developed a full and accurate understand of the emissions profiles of oil and natural gas production operations.

The final recommendation reflects the environmental lobbying position that only it can be trusted; everyone else must be put to a higher level of scrutiny. The American oil and natural gas production industry is committed to managing its emissions, including methane emissions. It has invested millions of dollars in meeting its requirements and will continue to make necessary investments. While differences may exist regarding the best, most cost-effective actions that should be taken, producers will continue their commitment to protect the environment. Certainly, the idea of having independent verification of self-reported emissions data is appealing. Presently, many of the Subpart W reports are prepared by independent consultants because of the complexity of the current requirements, particularly for smaller producers. The larger issue may well be whether the restructuring of Subpart W reporting in the context of the methane tax will adversely affect access to independent consultants. This issue has arisen in previous EPA NSPS regulations where EPA required professional engineers (PE) to certify information. Two issues arose. First, there were not enough PEs with expertise to undertake the tasks. Second, the license risks for the PE in undertaking the task were too great to bring more into the arena. A similar dynamic may occur in the methane tax context. Because OECA can challenge any reported information and because OECA has a history of using its enforcement power in this industry to target smaller producers, independent contractors may conclude that the risks to their businesses to too high to participate given the magnitude of penalties under the CAA.

Taken as a whole, these environmental lobbying organizations' recommendations are either inappropriate in the context of Subpart W or unworkable or both.

Conclusion

The task mandated to EPA by Congress requires the agency to comprehensively review, revise and validate its Subpart W regulations to make them accurate and reliable because of the role their implementation will play in the MERP, defining exposure and calculating its methane tax. Congress' deadline of EPA's action failed to reflect the reality of the task. EPA, faced with the choice of meeting a deadline or meeting its mandate to comprehensively revise Subpart W, chose the deadline and produced a wholly inadequate compendium of emissions calculations. At its best, the Subpart W proposal collects revisions to the current calculation process that EPA failed to validate as either accurate or appropriate. At its worst, the Subpart W proposal is a thinly disguised effort to raise the MERP methane tax rates through careful selection of higher emissions factors and unworkable calculation procedures. EPA should withdraw the current Subpart W proposal and execute its mandate to make it accurate, including taking the necessary steps to validate the emissions factors or emissions calculation procedures that it ultimately puts in place.

If there are questions or if EPA needs additional information on these comments, please contact Dan Naatz at 202-857-4722 or dnaatz@ipaa.org.

Respectfully submitted,

Dan Naatz
Chief Operating Officer
and Executive Vice President

APPENDIX B

Memorandum to Bruce Moore: Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking

June 2011

MEMORANDUM

DATE: July 28, 2011

SUBJECT: Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking

FROM: Heather P. Brown, P.E.

TO: Bruce Moore, EPA/OAQPS/SPPD

The purpose of this memorandum is to document the development of a representative natural gas composition for use in the oil and natural gas sector rulemaking. This composition will be used to determine hazardous air pollutant (HAP) and volatile organic compound (VOC) emissions from several segments of the oil and natural gas sector.

Gas composition data was compiled from several sources across the industry. The following is a list of the sources of data used for this analysis:

- CENRAP database. "Recommendations for Improvements to the CENRAP States' Oil and Gas Emissions Inventory", November 13, 2008. Covers the following States: Texas, Louisiana, Arkansas, Oklahoma, Kansas, Nebraska, Missouri, Iowa, and Minnesota
- GTI Database. "GTI's Gas Resource Database, Second Edition – August 2001"
- TX Barnett Shale. "Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements", January 26, 2009
- INGAA/API Compendium. "Greenhouse Gas Emission Estimation Guidelines for Natural Gas Transmission and Storage Volume 1 – GHG Emission Estimation Methodologies and Procedures" September 28, 2005
- GOADS Offshore. "Year 2005 Gulfwide Emission Inventory Study" December 2007
- NREL LCA. "Life Cycle Assessment of a Natural Gas Combined-Cycle Power Generation System" September 2000
- Union Gas. Chemical Composition of Natural Gas found online at http://www.uniongas.com/aboutus/aboutng/composition.asp
- Marcellus. "Supplemental Generic Environmental Impact Statement On The Oil, Gas and Solution Mining Regulatory Program - Well Permit Issuance for Horizontal Drilling And High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs" September 2009
- Wyoming DEQ. Speciation of Natural Gas and Condensate. Courtesy of Cynthia Madison, Wyoming DEQ

Tables 1 and 2 present a summary of the methane, VOC, and HAP contents provided in the above data sources for the production and transmission sectors, respectively, along with an identification of the basins/areas of the country covered by the gas composition.

In addition to the above, gas composition data were collected from the industry in 1995 during the development of the original maximum achievable control technology (MACT) standards for this sector. These data are presented in Tables 3 and 4 for production and transmission, respectively.[1] This 1995 GRI data represents gas samples from across the United States.

Gas Composition for Pneumatics, Equipment Leaks, and Compressors

Tables 1 and 2 also present a comparison of the 1995 GRI data to the other data sources. For production, the 1995 GRI data is well within the ranges of the other data sources which range from 1.19 to 11.6 percent for VOC by volume. The 1995 GRI data is also within the 95 percent confidence interval of the production data which range from 2.81 to 7.82 percent volume for VOC. Of the data sources that provide data on HAP emissions, the GRI data represent gas compositions across the United States, while the CENRAP, TX Barnett, and Marcellus data are specific to the regions specified in Tables 1 and 2. In addition, it can be expected that the gas composition for pneumatic controllers, equipment leaks, and compressors associated with these emissions units are associated with gas from oil wells and gas wells making the range of VOC composition widely varied. Therefore, it was determined that the 1995 GRI data was appropriate to use to develop a representative gas composition for pneumatic controllers, equipment leaks, and compressors.

For the transmission sector, the average 1995 GRI VOC concentration of 0.89 percent volume was compared to other data sources and was found to be in the range of the VOC composition, which ranged from 0.29 to 6.84 percent VOC by volume. It was determined that the 1995 GRI gas composition would be used to represent the average composition of natural gas in the transmission sector, because the other data sources represented natural gas compositions outside the U.S.[i]

The gas compositions from the 1995 GRI data were then converted to weight percents. First, because the average volume percent was not equal to 100, the volume percents were normalized for each component. Then the weight of each component present in the gas was calculated using the molecular weight (MW) for each component in pounds per pound mole (lb/lbmol) and an assumed gas volume of 385 cubic feet (ft^3), which represents one pound mole of gas. Finally, relative weight percents for each component were calculated. These weight percents are presented in Table 5.

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[i] It should be noted that the GRI data contains a statement that the BTEX data are "skewed toward high BTEX and VOC content gases…." However, the 1995 GRI data are within the ranges of the other data and very close to the average of other data identified. Therefore, these data were determined to be appropriate to use to develop a representative gas composition for pneumatics, equipment leaks and compressors.

Table 1. Gas Composition (volume %) for Production Sector

Data Source[a]	Source of Natural Gas	Area Covered	Volume % Methane	Volume % VOC	Volume % HAP
CENRAP [b]	Conventional Gas Wells	11 Basins: Louisiana Mississippi Salt, Southern Oklahoma, Nemaha Uplift, Arkoma, Cambridge Arch Central Kansas Uplift, Fort Worth, Cherokee Platform, Permian, East TExas, Western Gulf, and Anadarko	87.8	3.50	0.019
GTI Database[c]	Gas Wells	Nationwide, proven reserves, and undiscovered reserves data from 462 basins/formations	82.8	3.61	n/a
INGAA	Unprocessed Natural Gas	Unknown	80.0	5.00	n/a
NREL LCA[d]	Gas Well	Worldwide	65.7	5.66	n/a
MARCELLUS[e]	Gas Well	Marcellus	97.2	2.02	0.03345
WYOMING DEQ[b]	Gas Well	Wyoming	92.4	1.19	0.08
		Minimum	**65.7**	**1.2**	**0.0**
		Maximum	**97.2**	**5.7**	**0.1**
		Average	**84.3**	**3.50**	**0.0**
Gas Composition	Production	Nationwide	83.1	3.66	0.164

n/a = not available

[a] Data from the Barnett Shale database was not speciated and therefore not included in this analysis.
[b] HAP data contains BTEX and n-Hexane
[c] HAP Speciation not provided; hexanes reported as Hexanes Plus
[d] Data provided were ranges for each pollutant (min and max). These values represent normalized averages of these values and may not be valid representations
[e] HAP data only reported for hexane

Table 2. Gas Composition (volume %) for Transmission Sector

Data Source	Source of Natural Gas	Area Covered	Volume %		
			Methane	**VOC**	**HAP**
INGAA	Pipeline Gas	Unknown	91.9	6.84	n/a
GOADS Offshore[a]	Sales Gas	Offshore Gas in the Gulf of Mexico	94.5	1.27	0.099
NREL LCA	Pipeline Gas	Worldwide	94.4	0.90	n/a
Union Gas	Pipeline Gas	United States, Western Canada, and Ontario	95.2	0.29	n/a
	Minimum		**91.9**	**0.3**	**0.099**
	Maximum		**95.2**	**6.8**	**0.099**
	Average		**94.0**	**2.3**	**0.099**
GRI-MACT	Transmission/Unknown	Nationwide	92.7	0.89	0.014

n/a = not available

[a] HAP data contains BTEX and n-Hexane

Table 3. 1995 MACT Correspondence with GRI & EC/R- Production Data

Sector	Production											
Site	**GRI1**	**GRI2**	**GRI3**	**GRI4**	**GRI5**	**GRI6**	**GRI7**	**GRI8**	**GRI9**	**GRI10**	**GRI11**	**GRI12**
Mole %												
Nitrogen	2.72	0.44	0.78	0.46	0.79	1.52	1.18	1.74	1.90	1.30	0.52	6.81
Carbon Dioxide	0.04	0.90	0.29	3.37	1.00	0.38	1.67	0.68	0.00	0.47	0.54	8.12
Methane	95.60	93.26	90.62	56.62	80.40	78.38	79.55	74.67	83.90	91.93	88.40	79.83
Ethane	1.04	3.16	4.31	10.87	10.41	10.88	10.40	12.57	7.90	3.80	7.25	2.89
Propane	0.33	1.14	1.90	13.90	4.25	5.41	4.15	5.98	3.86	1.23	1.53	0.94
Butanes	0.16	0.64	1.15	8.59	1.65	2.10	1.74	2.55	1.70	0.70	0.90	0.54
Pentanes	0.07	0.22	0.51	3.61	0.65	0.77	0.69	1.21	0.49	0.24	0.36	0.30
Hexanes+	0.03	0.20	0.37	2.03	0.60	0.36	0.43	0.35	0.17	0.24	0.42	0.52
ppmv												
n-Hexane	88.7	277	664	2783	965	1173	937	2125	517	307	510	681
Isooctane	8.0	31.5	63.5	1552	151	145	112	103	52.0	49.6	32.0	87.0
Benzene	4.9	257	218	328	294	74.4	294	102	57.9	143	617	196
Toluene	2.9	108	117	251	468	92.4	263	31.4	45.6	142	222	213
Ethylbenzene	0	19.7	6.7	27.3	14.5	4.3	3.3	0.8	1.2	11.2	9.0	10.4
m,p-Xylenes	0	34.0	26.6	26.0	87.9	21.7	16.7	1.7	7.3	56.6	45.0	66.0
o-Xylene	0	19.9	5.0	6.2	16.1	3.2	2.4	0.3	0.6	16.9	10.0	16.4

NR = Not Reported

Table 4. 1995 MACT Correspondence with GRI & EC/R (Transmission Data)

Sector	Transmission		Unknown[a]		Transmission	Unknown[a]	Transmission					
Site	GRI13	GRI14	GRI15	GRI16	GRI17	GRI18	GRI19	GRI20	GRI21	GRI22	GRI23	GRI24
Mole %												
Nitrogen	9.89	8.68	2.96	2.55	0.22	1.25	1.16	1.1	1.15	1.12	0.3	1.85
Carbon Dioxide	0.28	0.40	0.58	0.54	0.35	2.62	0.15	0.12	0.07	1.06	1.36	0.66
Methane	81.97	82.61	91.8	92.7	97.4	95.4	98.5	88.2	81.1	94.6	95.8	93
Ethane	6.84	7.06	3.68	3.35	1.94	0.31	0.09	9.69	11.8	2.81	2.03	3.13
Propane	0.78	0.99	0.59	0.52	0.042	0.075	0.005	0.67	3.95	0.155	0.4	0.8
Butanes	0.14	0.17	0.159	0.148	<0.006	0.059	<0.006	0.035	1.189	0.116	0.075	0.314
Pentanes	0.04	0.05	0.045	0.042	<0.003	0.039	<0.003	<0.003	0.341	0.039	0.014	0.132
Hexanes+	0.04	0.03	0.042	0.042	0.004	0.202	<0.002	<0.002	0.226	0.129	0.015	0.103
ppmv												
n-Hexane	63.2	66.9	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
Isooctane	17.5	14.5	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
Benzene	5.0	7.9	51	36	<0.2	471	<0.2	<0.2	10	<0.2	4.5	15
Toluene	5.1	8.1	16	13	<0.1	100	<0.1	<0.1	13	<0.1	3.7	14
Ethylbenzene	0.5	0.6	3	3	<0.1	15	<0.1	<0.1	9	<0.1	0.1	1
m,p-Xylenes [1]	1.4	2.2	12	7	<0.1	11	<0.1	<0.1	1	<0.1	0.6	3
o-Xylene [1]	0.4	0.4										

[1] Sites 15-36 reported only a total xylene result that includes all xylene isomers.

NR = Not Reported

[a] Based on the high methane content (greater than 90 percent) of this datapoint, it was assumed that they were samples from the transmission segment.

Table 4. 1995 MACT Correspondence with GRI & EC/R - Transmission Data (Continued)

Sector	Transmission					Unknown [a]	
Site	GRI25	GRI26	GRI27	GRI28	GRI29	GRI30	GRI31
Mole %							
Nitrogen	1.24	1.75	1.02	1.04	0.49	0.42	0.54
Carbon Dioxide	0.3	0.13	0.44	0.65	1.76	0.87	0.92
Methane	90.2	97.8	96.6	96.1	95.5	96	95.7
Ethane	7.02	0.26	1.78	1.86	1.74	2	2.12
Propane	1	0.014	0.091	0.213	0.351	0.413	0.414
Butanes	0.146	<0.006	0.025	0.06	0.093	0.181	0.175
Pentanes	0.03	0.0015	0.0089	0.0218	0.0354	0.0675	0.0665
Hexanes+	0.021	0.0037	0.0052	0.0219	0.0322	0.073	0.069
ppmv							
n-Hexane	NR	NR	NR	NR	NR	NR	NR
Isooctane	NR	NR	NR	NR	NR	NR	NR
Benzene	9	1.2	0.8	6	7	59	58
Toluene	13	0.4	<0.4	6	6	23	26
Ethylbenzene	<0.3	0.3	<0.1	0.3	0.5	1.8	2
m,p-Xylenes [1]	4	0.2	<0.1	1	1.5	7	5
o-Xylene [1]							

[1] Sites 15-36 reported only a total xylene result that includes all xylene isomers.

NR = Not Reported

[a] Based on the high methane content (greater than 90 percent) of this datapoint, it was assumed that they were samples from the transmission segment.

Table 5. Gas Composition Conversion to Weight Percent

Component	MW (lb/lbmol)	Production				Transmission			
		Avg Vol %[b]	Normalized Vol %	Weight per 385 ft^3 Gas (lbs)	Weight %	Avg Vol %[b]	Normalized Vol %	Weight per 385 ft^3 Gas (lbs)	Weight %
Carbon Dioxide	44.01	1.46	1.5%	0.002	3.2%	0.70	0.70%	0.001	1.8%
Nitrogen	28.02	1.68	1.7%	0.001	2.3%	2.04	2.0%	0.001	3.3%
Methane	16.04	82.76	82.9%	0.035	65.7%	92.68	92.8%	0.039	86.2%
Ethane	30.07	7.12	7.1%	0.006	10.6%	3.66	3.7%	0.003	6.4%
Propane	44.09	3.72	3.7%	0.004	8.1%	0.60	0.60%	0.001	1.5%
Butane	58.12	1.87	1.9%	0.003	5.4%	0.16	0.16%	0.000	0.55%
Pentane	72.15	0.76	0.76%	0.001	2.7%	0.05	0.052%	0.000	0.22%
n-Hexane	86.17	0.09	0.092%	0.000	0.39%	0.01	0.0065%	0.000	0.032%
Other hexanes	86.17	0.32	0.32%	0.001	1.4%	0.001	0.00086%	0.000	0.0043%
Isooctane-a	114.23	0.02	0.020%	0.000	0.11%	0.002	0.0016%	0.000	0.011%
Benzene	78.11	0.02	0.022%	0.000	0.083%	0.004	0.0039%	0.000	0.018%
Toluene	92.14	0.02	0.016%	0.000	0.074%	0.001	0.0013%	0.000	0.0070%
Ethylbenzene	106.17	0.001	0.00090%	0.000	0.0047%	0.0002	0.00020%	0.000	0.0012%
Xylene	106.17	0.004	0.0041%	0.000	0.021%	0.0003	0.00030%	0.000	0.0019%
Total		99.85	100.0%	0.053	100.0%	99.91	100.0%	0.045	100.0%

a- Isooctane = 2,2,4, Trimethylpentane

b- Average of all gas compositions presented in Tables 1 and 2 for production and transmission, respectively.

Once the weight percents were calculated for each natural gas component, relative ratios were calculated for methane:total organic compounds (TOC), VOC:TOC, HAP:TOC, VOC:Methane, HAP:Methane, BTEX:Methane, HAP:VOC, and BTEX:VOC. These relative ratios are presented in Table 6.

Natural Gas Composition for Completions and Recompletions

The gas composition for completions and recompletions from gas wells were determined by performing a sensitivity analysis on the compositions of the gas well data using a larger sample size which included data from hydraulically fractured wells. The results of this analysis are shown in Table 7. A mean of 3.63 percent VOC with a 95 percent confidence interval that ranges from 3.30 to 3.96 percent VOC by volume was determined. Based on the summary statistics, these data appear to be reasonable for use in developing an average natural gas composition to use for completions and recompletions of gas wells.

Once it was determined that this data was appropriate, the average gas composition was calculated and then normalized so that the total volume percent equaled 100. This average gas composition is presented in Table 8. The gas composition data was then converted to weight percent by normalizing the volume percent for each component, then calculating the weight of each component using the MW for each component in lb/lbmol and a standard gas volume of 385 ft^3. Finally, relative weight percents for each component were calculated. Once the weight percents were calculated for each natural gas component, relative ratios were calculated for methane:total organic compounds (TOC), VOC:TOC, HAP:TOC, VOC:Methane, HAP:Methane, BTEX:Methane, HAP:VOC, and BTEX:VOC. These relative ratios are presented in Table 9.

A similar analysis was performed for completions and recompletions from oil wells. The results of this analysis are presented in Table 10. The average VOC composition was 11.62 percent by volume, with a 95 percent confidence interval that ranges from 6.73 to 16.5 percent VOC by volume. As was done for gas wells, the average composition was normalized. The gas composition used for completions and recompletions for oil wells is presented in Table 8. The gas composition data was converted to weight percent using the same approach detailed for gas wells and are presented in Table 9.

Table 6. Weight Ratios to Use in Estimating Emissions

	Production	Transmission
Methane:TOC[a]	0.695	0.908
VOC[b]:TOC[a]	0.193	0.0251
HAP:TOC[a]	0.00728	0.000746
VOC[b]:Methane	0.278	0.0277
HAP:Methane	0.0105	0.000822
BTEX:Methane	0.00280	0.000322
HAP:VOC[b]	0.0377	0.0297
BTEX:VOC[b]	0.0101	0.0116

[a] TOC = all organic compounds listed in Table 3.
[b] VOC = all organic compounds listed in Table 3, except ethane and methane.

Table 7. Summary Statistics of Sensitivity Analysis on Gas Composition for Gas Well and Hydraulically Fractured Wells

Methane		*VOC*	
Mean	83.238	Mean	3.630
Standard Error	0.709	Standard Error	0.170
Median	86.581	Median	3.104
Mode	0	Mode	0.000
Standard Deviation	15.207	Standard Deviation	3.626
Sample Variance	231.244	Sample Variance	13.149
Kurtosis	12.943	Kurtosis	9.258
Skewness	-3.08	Skewness	2.262
Range	99.75	Range	29.560
Minimum	0	Minimum	0.000
Maximum	99.748	Maximum	29.560
Sum	38289.387	Sum	1655.427
Count	460	Count	456.000
Confidence Level(95.0%)	1.393	Confidence Level(95.0%)	0.334
	Volume Percent		Volume Percent
(Lower of 95% conf interval)	81.844	(Lower of 95% conf interval)	3.297
Methane	83.238	VOC	3.630
(Higher of 95% conf interval)	84.631	(Higher of 95% conf interval)	3.964

Table 8. Average Gas Composition for Completions and Recompletions of Gas and Oil Wells

	Average Volume Percent	
Pollutant	**Gas Wells**	**Oil Wells**
Carbon dioxide (CO_2)	1.631	1.00162
Nitrogen (N_2)	4.455	29.19
Methane (C1)	**83.081**	46.73
Ethane (C2)	4.924	10.17
Propane (C3)	2.144	6.62
i-Butane (i-C4)	0.348	1.067004
n-Butane (n-C4)	0.643	2.136346
i-Pentane (iC5)	0.095	0.550849
n-Pentane (nC5)	0.119	0.515798
Cyclopentane	0.005	0.001091
n-Hexane (n-C6)	0.155	0.005182
Hexanes (C6)	0.000	-
Cyclohexane	0.001	0.001455
Other Hexanes	0.010	0.007636
Methylcyclohexane	0.002	0.001818
C6+ Heavies	0.114	-
Heptanes (C7)	0.009	0.697080
n- Heptanes (C7)	0.000	0.001909
C8+ Heavies	0.004	0.005182
Benzene	0.005	0.006182
Toluene	0.003	0.000223
Ethylbenzene	0.000	0.000445
Xylenes	0.001	-
2,2,4-Trimethylpentane	0.000	0.000223
Helium	0.140	-
Oxygen	0.084	-
Hydrogen	0.001	0.575909
Hydrogen disulfide (H_2S)	2.027	0.709092
Total	**100**	**100**
VOC	**3.66**	**11.62**

Table 9. Weight Ratios to Use in Estimating Emissions for Completion and Recompletions

	Gas Wells	Oil Wells
Methane:TOC[a]	0.796	**0.4453**
VOC[b]:TOC[a]	0.116	**0.3729**
HAP:TOC[a]	0.0084	**0.0006**
VOC[b]:Methane	0.146	**0.8374**
HAP:Methane	0.0106	**0.0001**
BTEX:Methane	0.0006	**0.0007**
HAP:VOC[b]	0.0726	**0.0016**
BTEX:VOC[b]	0.0040	**0.0009**

[a] TOC = all organic compounds listed in Table 3.
[b] VOC = all organic compounds listed in Table 3, except ethane and methane.

Table 10. Summary Statistics of Sensitivity Analysis on Gas Composition for Oil Wells

Methane		*VOC*	
Mean	46.73157	Mean	11.61755
Standard Error	4.196101	Standard Error	2.193276
Median	49.63115	Median	9.697621
Mode	49.63115	Mode	#N/A
Standard Deviation	19.68146	Standard Deviation	7.274275
Sample Variance	387.3598	Sample Variance	52.91508
Kurtosis	1.385922	Kurtosis	1.438744
Skewness	-1.15094	Skewness	1.127773
Range	71.93094	Range	25.91599
Minimum	0.156	Minimum	1.381007
Maximum	72.08694	Maximum	27.297
Sum	1028.095	Sum	127.793
Count	22	Count	11
Confidence Level(95.0%)	8.72627	Confidence Level(95.0%)	4.886924
(Lower of 95% Conf interval)	38.0053	(Lower of 95% Conf interval)	6.730621
Methane	46.73157	VOC	11.61755
(Higher of 95% Conf. Interval)	55.45784	(Higher of 95% Conf. Interval)	16.50447

REFERENCES

1. Letter and Attachments from Evans, J. M., Gas Research Institute, to G. Viconovic, EC/R Incorporated. Natural Gas BTEX Content. April 19, 1005. Legacy Docket Number A-94-04, Item II-D-35.