



Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments

2011 Technical Revisions to the Petroleum and Natural Gas Systems Category of the Greenhouse Gas Reporting Rule

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December 2011

**2011 Technical Revisions to the Petroleum and Natural Gas Systems Category of the Greenhouse
Gas Reporting Rule**

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FOREWORD

This document provides EPA's responses to public comments on EPA's Proposed Technical Revisions to the Petroleum and Natural Gas Systems Category of the Greenhouse Gas Reporting Rule. EPA published a Notice of Proposed Rulemaking in the Federal Register on September 9, 2011 (76 FR 56010). In addition, this document contains EPA's responses to public comments pertaining to Subpart W from the 2011 Technical Corrections, Clarifying, Other Amendments to Certain Provisions published August 4, 2011 (76 FR 47392). EPA received comments on these proposed rules via one or more of the following methods: regulations.gov, e-mail, fax, mail or courier.

This Response to Comments document provides the verbatim text of comments extracted from the original comment letter. For each comment, the name and affiliation of the commenter, the document control number (DCN) assigned to the comment letter, and the number of the comment excerpt is provided. Note that footnote numbers in this Response to Comments document do not correspond to the exact footnote numbers in the commenter's original submissions.

While EPA has made every effort to ensure the accuracy of the discussion in the response to comment document, the obligations of the regulated community are determined by statutes, regulations or other legally binding requirements. In the event of a conflict between the discussion in these responses to comment and the Subpart W rule or any statute or regulation, the response to comment document would not be controlling.

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Section 1 - Field-level to Sub-Basin Discussion

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 17

Commenter Type: Industry - oil and gas

Comment: However, we object to the imposition of a sub-basin reporting obligation for emissions from pneumatic devices. As noted above in Section A.8, EPA proposed defining GHGi in Eq. W-1 and Eq. W-2 by using a cross reference to 40 C.F.R. § 98.233(u)(2)(i). Reporting this information on a sub-basin basis will only serve to add an additional layer of complexity to an already onerous process of counting all of the devices – a process that EPA has already determined may take facilities up to three years to conduct. Additionally breaking this data down on a sub-basin level will provide few, if any, environmental or policy oriented benefits, but will impose a great burden on reporters.

Response: EPA agrees with this comment. EPA does not require reporting of pneumatic devices at a sub-basin level. In this final rule, EPA has retained the reference to 98.233(u)(2)(i), however, has clarified that gas mole fractions can be determined either at a sub-basin or facility level as applicable to the emission source. Since the pneumatic devices' emissions are reported at a facility level, 98.233(u)(2)(i) is also applicable at a facility level for pneumatic devices. EPA notes that companies must still report pneumatic device activity data at the facility level.

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 9

Commenter Type: Industry - oil and gas

Comment: Sub-basin category – As Chesapeake and AXPC noted in our petition for reconsideration, Subpart W currently is unclear regarding how reporting entities are to map wells to a particular “field.” Section 98.238 defines a “field” as “oil and gas fields identified in the United States as defined by the Energy Information Administration Oil and Gas Field Code Master List 2008, DOE/EIA 0370(08).” No coordinates are provided in the EIA O&G Field Code Master List. There is no formal way to designate appropriate field names. Furthermore, Subpart W does not explain how to deal with wells that are not in a recognized field in the EIA Master List. 76 Fed. Reg. 56,025 (providing an explanation of why industry members petitioned EPA to review fieldlevel reporting).

Mapping wells to the proper field is central to compliance with the rule because the rule as currently written requires aggregation of information by field for the following items:

1. Liquid unloading (75 Fed. Reg. 74,493)
2. Completions and workovers with fracing (75 Fed. Reg. 74,494)
3. Completions and workovers without fracing (75 Fed. Reg. 74,495)
4. Storage tank venting (75 Fed. Reg. 74,496)
5. Associated gas venting/flaring (75 Fed. Reg. 74,497)
6. Major equipment counts (75 Fed. Reg. 74,510)
7. Gas composition (75 Fed. Reg. 74,496, 74,498, 74,500, 74,503, 74,504)

Recognizing that reporting on a field basis is problematic, EPA has proposed that entities report on a sub-basin basis for gas emitted from produced oil sent to atmospheric tanks, well venting for liquids unloading (for each tubing diameter and pressure grouping within the sub-basin category) and well completions and workovers (by sub-basin and well type combination).

Chesapeake and AXPC support EPA's proposal to delete all references in Subpart W to the EIA O&G Field Code Master List and field codes. We further support the agency's sub-basin proposal as an improvement over field-level reporting for gas wells. However, we object to EPA's expansion of the sub-basin reporting obligation to pneumatic devices and pumps. By defining GHGi in Eq. W-1 and Eq. W-2 of 40 C.F.R. § 98.233(a) through a cross reference to 40 C.F.R. § 98.233(u)(2)(i), EPA has implied that pneumatic devices and pumps must report on a sub-basin basis. The final rule did not require sub-basin reporting for such emission sources and therefore, reporters do not have their calculations and reporting systems set up to comply with this obligation. This cross-reference should be removed from the rule. See also Section C.1 *infra*.

For oil wells, the proposal still lacks the detail necessary for sources to comply with sub-basin reporting. EPA's proposed rule does not provide a definition for sub-basin as applied to oil wells. Such a definition is necessary for reporters to meet the requirement that they report emissions from storage tank venting on a sub-basin level. See W.25 [EPA-HQ-OAR-2011-0512-0040, Excerpt 41] of Section 2 of API's October 24, 2011 letter to EPA. AXPC and Chesapeake support API's recommendation as a fundamental pre-requisite to compliance with that reporting obligation.

Response: In this final rule, EPA has finalized the use of sub-basin category to monitor and report emissions from certain sources that earlier used the field designation. However, EPA is allowing the use of field designation for reporting year 2011 only for those reporters who have already conducted their monitoring using the field designation for reporting year 2011. Therefore, the reference to the field designation is being maintained in section 98.7. Please see response to EPA-HQ-OAR-2011-0512-0040, Excerpt 3 for further details.

EPA agrees with the comment on pneumatic devices and pumps in Equation W-1 and Equation W-2; please see the response to comment EPA-HQ-OAR-2011-0512-0033, Excerpt 17 for further details.

EPA agrees with the comment regarding an oil sub-basin and has revised the definition for sub-basin in 40 CFR 98.238 to include an oil formation within the sub-basin category. For further details, please see the preamble Section II.C. – Final Amendments to the Petroleum and Natural Gas Systems Source Category – Major Changes Since Proposal and Section II.D.9 - Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Addition of oil formation type in the sub-basin category definition.

Commenter Name: Jessica Stark

Commenter Affiliation: SLR International Corp

Document Control Number: EPA-HQ-OAR-2011-0512-0040

Comment Excerpt Number: 3

Commenter Type: Industry - oil and gas

Comment: 98.233(f) and other locations where ‘field’ was replaced by ‘sub-basin category’

I have clients who would prefer the rule continue to use field as a classification mechanism for groups of wells within each basin. Field names are more commonly known and are easier to identify than the parameters defining the sub basin categories. For this and other locations in the rule where the term ‘sub-basin category’ was used, we request retaining the term ‘field.’ For example:

“For one well of each unique well tubing diameter grouping and pressure grouping in each gas producing field....”

Response: EPA recognizes that this rule was finalized later in the 2011 reporting year and that some facilities may have been collecting data at the field level consistent with the 2010 final rule. Consistent with the ability to automatically use BMM for the 2011 reporting year, facilities may use the data collected at the field level, apply these measurements to the equivalent sub-basins applicable to their facility using best available information. For further details, please see the preamble Section I.E – How Do These Amendments Apply to 2012 Reports?. EPA notes that for data collection in 2012 and beyond for the applicable emission sources, reporters must use the sub-basin level for data collection, unless a request for use of BMM is submitted and approved by EPA according to the procedures and criteria outlined in 40 CFR 98.234.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 13

Commenter Type: Industry - oil and gas

Comment: Revision: In 98.7(q), EPA deleted the reference to EIA’s field code master list.

Comment: API supports this revision. As stated in API’s letter to Bill Irving, dated April 19, 2011, referencing the EIA field code master list presents significant issues:

- Annual updates to the list, usually in March, typically result in combining, changing or otherwise modifying field names. With each annual update, EPA’s reference to the 2008 list will

become more and more outdated, and the old list will fail to include many wells and new areas developed after publication.

- Revising the rule language to require use of the most current EIA field listing would place reporters in the impossible situation of collecting episodic data after the operation/event is concluded and/or trying to quickly assign and reassign wells to fit within a particular field. This work would have to be done quickly, since the updated field list is only available in March, shortly before the March 31 reporting deadline under Subpart W. Such an approach is plainly unworkable.
- EIA has not mapped, furnished boundary descriptions for, or provided shape files for all of the fields that it lists. This makes assignment of a particular well or piece of equipment to a particular field extremely difficult.
- Named fields may overlap, and a single well may be within the boundaries of more than one field.
- Despite the immense number of fields in the EIA list, it is common for reporters to have wells which are not assigned to any named EIA field.

Response: Please see response to EPA-HQ-OAR-2011-0512-0040, Excerpt 3. To provide the option for reporters to use the “field” designation as BMM for 2011, in this final rule, reference to EIA’s field code master list is being retained in section 98.7(q).

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 6

Commenter Type: Industry - oil and gas

Comment: Alternative approach to field level reporting

In page 56025 in the preamble EPA states, “In this action we are proposing an alternative approach to replace “field level” with “sub-basin categories”. EPA considered, but is not proposing at this time modifications to the current field level reporting method that would address the outstanding concerns raised by industry. Specifically, EPA considered an amendment that would allow reporters to use a temporary field name when submitting reports to EPA in instances where a well does not fall within a designated EIA field code.”

API Response:

API acknowledges and strongly supports the fact that among these technical corrections, EPA is proposing an alternative to field level reporting by using a sub-basin approach that is based on reporting at the county level and by formation type.

API rejects the optional approach of patching-up the 2008 EIA FCML to try and “force” it to

work for GHG reporting. Such an approach is not warranted, does not provide the needed clarity and is unnecessarily burdensome. Although the ‘sub basin’ approach as proposed by EPA in the regulatory text, might still need some changes (see the technical comments in Section 2 below) it is a far superior approach and would provide EPA with quality representative data that EPA may need for future policy actions.

However, if EPA chooses to reconsider its amendment to the rule and revert back to a field level approach API expects that it should be done by means of a full reproposal with an opportunity to provide specific comments on the alternative approach.

Response: Please see response to EPA-HQ-OAR-2011-0512-0040, Excerpt 3.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 41

Commenter Type: Industry - oil and gas

Comment: Revision: For onshore production storage tanks, EPA has replaced field with sub-basin category for determining the separator oil composition and Reid vapor pressure.

Comment: EPA has not defined sub-basins for oil. This is needed since the sub-basin categories for gas wells are not applicable to the emissions from onshore production storage tanks. API proposes that a 5th sub-basin category - oil formations - be added for oil wells. Furthermore, API doesn't believe that pressure groupings are necessary or useful for oil formations

Response: EPA agrees with the comment regarding an oil sub-basin and has revised the definition for sub-basin in 40 CFR 98.238 to include an oil formation within the sub-basin category. For further details, please see the preamble Section II.C. – Final Amendments to the Petroleum and Natural Gas Systems Source Category – Major Changes Since Proposal and Section II.D.9 - Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Addition of oil formation type in the sub-basin category definition.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 94

Commenter Type: Industry - oil and gas

Comment: Changes in Requirements for Field Level Reporting

The September 9, 2011 preamble on page 56020 notes, “The one exception where both the underlying calculation requirements and reporting requirements in subpart W are proposed to be changed is related to the requirements for field level reporting for four emissions sources in the

onshore petroleum and natural gas production segment.”

In the current proposed rule EPA specifies that it intends to implement the amended procedures for the four specified source categories starting with the 2011 reporting year. This amendment will require that for those four emission sources, calculations and reporting will be undertaken at the county level and by geologic formation starting with the 2011 reporting year. EPA further indicated that facilities concerned about their ability to implement those provisions for the 2011 reporting year may use best available monitoring methods (BAMM) pursuant to 40 CFR 98.234(f).

API Response:

API and its members have been working with EPA technical experts to develop a less burdensome approach for the calculation and reporting requirements for several source types to allow for the implementation of data collection, calculation and GHG emissions reporting at the county level and by geologic formation type. The proposed approach represents an improvement over the large burden and ambiguity associated with the previously promulgated requirements with using the EIA 2008 Field Code Master List (FCML). [Footnote 2: November 30, 2010, Final Rule at 75 FR 74458]

Several API member facilities have, in fact, already designed their data collection systems and taken some measurements at the field level for 2011. API strongly supports EPA’s position that those facilities may “still use those same measurements for the 2011 reporting year, but apply them to the sub-basin categories based on BAMM.” [Footnote 3: 76 Federal Register at 56020]

API requests that the flexibility for those facilities to use BAMM - as EPA has suggested - be expressly incorporated into the final rule.

Response: EPA is allowing the use of "field" designation as a best available monitoring method for the purposes of taking measurement in calendar year 2011 as is noted in the preamble to this final rule. Please see the response to EPA-HQ-OAR-2011-0512-0040, Excerpt3.

Commenter Name: William W. Grygar II

Commenter Affiliation: Anadarko Petroleum Corporation

Document Control Number: EPA-HQ-OAR-2011-0512-0028

Comment Excerpt Number: 4

Commenter Type: Industry - oil and gas

Comment: Under §98.233(a) and (c), EPA requires for GHG_i the concentration of GHG_i, CH₄, or CO₂ as defined in paragraph (u)(2)(i) of this section. Reference to paragraph (u)(2)(i) requires reporters to use an annual average of gas compositions for individual sub-basin categories. Unexpected reference to paragraph (u)(2)(i) is also found for dehydrators under §98.233(e)(1)(xi)(A), (B), and §98.233(e)(6), and flares under §98.233(n)(2)(i). In order to categorize these sources at the sub-basin category level, a significant amount of work must be performed to associate specific wells and gas compositions to individual pieces of equipment. For Anadarko, this could mean that we would have up to 336 different sub-basin categories for which to calculate and assimilate emissions for these sources. We do not believe it was EPA's

intent to increase the complexity and burden associated with reporting for these emission sources. Anadarko asks that these gas compositions be limited to annual average gas compositions based on available sample analysis of the facility or basin for the onshore production industry segment.

Response: In this final rule, EPA has clarified in 40 CFR 98.233 (u)(2)(i) that gas mole fractions can be determined either at a sub-basin or facility level as applicable to the emission source. Therefore, reporters are not required to categorize pneumatic devices (40 CFR 98.233(a)), pneumatic pumps (40 CFR 98.233(c)), dehydrators (40 CFR 98.233(e)), and flares (40 CFR 98.233(n)) in a sub-basin category to either determine or report emissions.

Section 2 - Purpose and Scope (98.1); Who must report? (98.2)

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 7

Commenter Type: Industry - oil and gas

Comment: (6) “Owner and operator” – In our petition for reconsideration, we noted several problems with the certifications required for Designated Representatives under § 98.4(i). 40 C.F.R. § 98.4(i) requires the Designated Representative, an individual, to make the following four Certifications:

- (i) "I was selected as the designated representative...by an agreement binding on the owners and operators of the facility. . . ." (Certification 1)
- (ii) "... each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions." (Certification 2)
- (iii) "...the owners and operators of the facility...shall be bound by any order issued to me by the administrator or a court regarding the facility. . . ." (Certification 3)
- (iv) ". . . I have given a written notice of my selection as the ‘designated representative’ . . . and of the agreement by which I was selected to each owner and operator of the facility. . . ." (Certification 4)

The oil and gas industry explores for, and develops hydrocarbons pursuant to a customary form of agreement, the joint operating agreement (JOA). There are thousands of JOAs outstanding, each with multiple parties. A JOA is an agreement between co-owners of the rights to explore for and develop the oil and gas in certain described property. The parties typically designate one of the co-owners as operator to manage property operations, subject to the terms of the JOA. The scope of an operator’s authority is derived from the terms and conditions of the JOA. Although multiple standard forms of JOAs are in use by industry, contracting parties amend the terms of the standard forms to achieve the desired contractual relationships among the parties.

Before issuing the final Subpart W rule, EPA did not adequately evaluate whether these JOAs enable an operator to make Certifications 1 through 4 without obtaining the consent of other affected parties. The industry operates thousands of properties, each of which can have multiple interest owners of varying levels of sophistication and willingness to cooperate. Accordingly, obtaining consent could prove daunting and unsuccessful. Most JOAs give the operator some form of control or management of property operations and directly or indirectly contemplate compliance with applicable laws or filing of reports with government authorities. Typically, the operator certifies to the accuracy of the reports submitted, but is not required to additionally make other legally binding certifications that would necessitate the operator to act as a fiduciary or agent for the owners.

Multiple provisions commonly included in JOAs raise the question of possible legal impediments to compliance with the Certification requirements if EPA did not modify the definition of “owner and operator” to account for the unique nature of the onshore production industry. For example, some form JOAs include provisions such as the following:

- “The Operator is not the agent or fiduciary of the Non-Operating Parties.”
- “It is not the intention of the parties to . . . render them liable as partners” (i.e., to make them jointly and severally liable).
- “This agreement is not intended to . . . impose a partnership duty, obligation, or liability with regard to any one or more of the parties hereto.

The inclusion of such provisions in executed JOAs may prohibit an operator from being able to make the Designated Representative Certifications required under Subpart A of the reporting rule. The specificity of the Certifications EPA requires – and the breadth of their legal implications – would require lawyers to review every JOA now in effect. While much of the industry tends to use form JOAs, not all the terms of those form JOAs are uniformly accepted and therefore each executed contract would need to be individually reviewed.

To respond to these concerns, EPA has proposed adding a new provision to 40 C.F.R. § 98.1(c). This new provision clarifies that for Subpart W, the term "owner and operator" used in Subpart A would have the same meaning as "onshore petroleum and natural gas owner or operator" provided in 40 C.F.R. § 98.238. Section 98.238 defines "onshore owner or operator" as the entity that holds the permit to operate the wells. The effect of EPA’s proposal is that references to "owners and operators" in the 40 C.F.R. § 98.4(i) Designated Representative certification provisions would refer to the entity that holds the permit. Chesapeake and AXPC support this change because this proposal will resolve our concerns about JOAs and minority ownership interests that would have otherwise made the compliance with the Designated Representative certifications difficult.

Response: EPA thanks the commenter for their remarks.

Section 3 - What are the general monitoring, reporting, recordkeeping and verification requirements of this part? (98.3)

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 29

Commenter Type: Trade Association

Comment: Comments solicited in the preamble:

The reporting deadline should be September 28, 2011, consistent with the August 4 proposed revisions to Subpart W.

EPA requests comment on whether it is appropriate for Subpart W reporting to be delayed beyond March 31, 2012 to allow adequate time to adjust to the Proposed Rule [76 FR 56021]. This inquiry is puzzling, because the August 4 proposed revisions would change the reporting deadline to September 28, 2012, and INGAA anticipates that revision will be finalized. At any rate, a March 31, 2011 deadline is not appropriate, and INGAA supports delaying reporting until at least September 28, 2012. As INGAA indicated in its comments on the August 4 proposed revisions, INGAA supports the later deadline and recommends that reporting for all sources – including Subpart C and Subpart W emissions sources – should be deferred until the September deadline for facilities subject to Subpart W. Please refer to INGAA's comments on the August 4 proposed revisions for additional details.

Response: EPA agrees with the commenter that 2011 reporting for Subpart W sources – and for any other subpart for which those sources previously reported 2010 data for – should be deferred until September 28, 2012. Note that if the reporter provided 2010 data under any other subpart, they are to file a notification in eGGRT of the 2011 deferral by March 31, 2012. Please see the preamble for the Mandatory Reporting of Greenhouse Gases Rule 2011 Technical Corrections, Clarifying, Other Amendments to Certain Provisions, Section II.A.2, Subpart A – General Provisions: Summary of Comments and Responses, for further details on the 2012 reporting deadline for facilities and suppliers with a source category required to begin data collection in 2011 and source categories that began data collection in 2010.

Commenter Name: Jessica Stark

Commenter Affiliation: SLR International Corp

Document Control Number: EPA-HQ-OAR-2011-0512-0040

Comment Excerpt Number: 2

Commenter Type: Industry - oil and gas

Comment: 40 CFR 98.3(b)(1)(iv)

For facilities reporting under Subpart W that are not in the ‘Onshore Petroleum and Natural Gas Production’ industry sector, it is not clear whether the combustion emissions calculated under

Subpart C would have to be reported by March 31, 2012 or whether the combustion emissions for those facilities would be included in the first Subpart W reports due by September 28, 2012. I have a client with facilities in the Underground Storage and Transmission Compression sectors that are not required to report under Subpart C alone.

Response: Source categories considered new 2011 reporting year source categories are allowed to defer reporting of all their data until September 28, 2012. Please see the preamble for the Mandatory Reporting of Greenhouse Gases Rule 2011 Technical Corrections, Clarifying, Other Amendments to Certain Provisions, Section II.A.2, Subpart A – General Provisions: Summary of Comments and Responses, for further details on the 2012 reporting deadline for facilities and suppliers with a source category required to begin data collection in 2011 and source categories that began data collection in 2010.

Commenter Name: Gregory L. Ryan
Commenter Affiliation: DTE Energy
Document Control Number: EPA-HQ-OAR-2011-0512-0041
Comment Excerpt Number: 5
Commenter Type: Industry - oil and gas

Comment: IV. Delay of Reporting Beyond March 31, 2012 for Subpart W Requirements

DTE Energy supports moving the timeline for reporting of natural gas emissions under Subpart W by 6 months to the end of September 2012. Given that the final rule is not expected to be promulgated until December 2012, it is unreasonable to expect us to update the Greenhouse Gas Monitoring Plan and verify that all leak detection surveys, population counts, quality control and quality assurance requirements, emission calculations and other required elements of Subpart W have been completed in accordance with the GHG Monitoring Plan, and submit the 2012 data in the span of just 3 months.

Response: EPA agrees with the commenter that new 2011 reporting year source categories are allowed to defer reporting of all their data until September 28, 2012. Please see the preamble for the Mandatory Reporting of Greenhouse Gases Rule 2011 Technical Corrections, Clarifying, Other Amendments to Certain Provisions, Section II.A.2, Subpart A – General Provisions: Summary of Comments and Responses, for further details on the 2012 reporting deadline for facilities and suppliers with a source category required to begin data collection in 2011.

Commenter Name: Lisa Beal
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2011-0512-0029
Comment Excerpt Number: 23
Commenter Type: Trade Association

Comment: 16. To address evolving requirements associated with Confidential Business

Information, EPA needs to revise Subpart A, Table A-7 to address data elements where reporting should be deferred until 2015.

INGAA provided a similar comment in response to the August 4 proposed revisions to Subpart W. To address ongoing concerns regarding Confidential Business Information (CBI), EPA published a rule in the August 25, 2011 Federal Register, "Change to the Reporting Date for Certain Data Elements Required Under the Mandatory Reporting of Greenhouse Gases Rule" (76 FR 53057). That rule identifies data elements for Subpart W emission estimation calculations where reporting is deferred until March 31, 2015. Reporting criteria affected by the Proposed Rule have not been reconciled with the August 25 CBI Rule, and EPA will need to propose additional corrections to Subpart A to reconcile ongoing revisions in Subpart W with the recently adopted CBI rule. The technical revisions in the Proposed Rule will result in anomalies and additional data elements will need to be added to Subpart A, Table A-7. EPA should adopt changes expediently so that 2012 reporting obligations are clearly defined in Table A-7 and reflect the pending technical corrections to Subpart W.

Response: With respect to revisions to Subpart A Table A-7 deferrals and additional corrections to Subpart A, please see the response to Mandatory Reporting of Greenhouse Gases Rule 2011 Technical Corrections, Clarifying, Other Amendments to Certain Provisions EPA-HQ-OAR-2011-0147-0029, Excerpt 8.

Commenter Name: Curtis J. Winner

Commenter Affiliation: New Mexico Gas Company (NMGC)

Document Control Number: EPA-HQ-OAR-2011-0512-0047

Comment Excerpt Number: 10

Commenter Type: Industry - oil and gas

Comment: CBI

The August 25, 2011 CBI final rule lists SPW data in Table 7 that do not need to be reported until March 31, 2015. If the proposed technical revisions for the mandatory reporting rule for SPW are finalized, the data elements in the "Change to the reporting date for certain data elements" final rule from August 25, 2011 may need to be reviewed and updated.

Response: EPA is addressing changes to CBI and deferrals as a result of these technical corrections and revisions and will be publishing an updated list of data elements and their disposition in an upcoming rulemaking.

Section 4 - Subpart A Definitions (98.6)

Section 4.1 - Blowdown vent stack

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 14

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] Blowdown vent stacks:

7. EPA should clarify that emergency events are excluded from blowdown vent stack reporting. Revisions in the Proposed Rule conflict with the August 4 proposed revisions. Additional revisions are needed to clarify Subpart W requirements.

As indicated in September 19, 2011 comments to EPA, INGAA supports the August 4 proposed revision that excludes emergency events from the definition of "blowdown vent stack ". However, the Proposed Rule confuses this issue in revisions to the introductory text of §98.233(i). The Proposed Rule should be revised to clearly indicate that emergency events are excluded from blowdown vent stack reporting.

The August 4 proposed rule revisions [76 FR 47392] revised the definition of blowdown vent stack:

"Blowdown vent stack emissions mean natural gas and/or CO₂ released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing. [add: Emissions from emergency events are not included]."

The new closing sentence clearly indicates that emergency venting is excluded from blowdown vent stack reporting. INGAA supports this revision. However, the Proposed Rule introduction to §98.233(i) confuses issue. Revised text from EPA's redline version of the rule available in the docket is shown here, but the last sentence is not included in the published Proposed Rule:

"Calculate CO₂ and CH₄ blowdown vent stack emissions from depressurizing equipment to [add: reduce system pressure for planned or emergency shutdowns or to take equipment out of service for maintenance] [delete: the atmosphere] (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraph (e)(5) of this section) as follows [add: (Emissions from emergency vents are not included.)]:"

In this revised text, the text "or emergency" contradicts the revised §98.6 definition of blowdown vent stack and the text in the closing sentence of the EPA redline version. Both of these exclude emergency events and indicate EPA intended to exclude the reporting of emergency venting emissions. To clarify and avoid conflict with the §98.6 definition, the phrase "or emergency"

should be deleted. INGAA also recommends including the closing sentence with the other list of excluded activities and referring to emergency events rather than emergency vents. The INGAA recommended revisions based on the EPA redlines above follows:

"Calculate CO₂ and CH₄ blowdown vent stack emissions from depressurizing equipment to [add: reduce system pressure for planned or emergency shutdowns or to take equipment out of service for maintenance] [delete: the atmosphere] (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases [add: , and emissions from emergency events]; desiccant dehydrator blowdown venting before reloading is covered in paragraph (e)(5) of this section) as follows [delete: (Emissions from emergency vents are not included)]:"

Response: EPA disagrees with the commenter and requires reporting from certain types of emergency blowdowns. Please see preamble Section II.C – Final Amendments to the Petroleum and Natural Gas Systems Source Category, and Section II.D.8 – Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Blowdown vent stacks: emergency blowdown.

Section 4.2 - Continuous bleed

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 61

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] Definitions for Pneumatics in Subpart A

§ 98.6 Definitions.

Continuous bleed means a continuous flow of pneumatic supply gas to the process [add: control] [delete: measurement] device (e.g. level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

Response: EPA agrees with the commenter and is revising the definition in this final rule accordingly. Please see preamble Section II. A – Final Amendments to the General Provisions for the definition of continuous bleed.

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 3

Commenter Type: Industry - oil and gas

Comment: “Continuous bleed” – AXPC and Chesapeake support and incorporate here by reference the comments provided in A.1 [EPA-HQ-OAR-2011-0512-0033, Excerpt 11] of Section 2 of API’s comment letter to EPA regarding the definition “continuous bleed.”

Response: EPA agrees with the commenter and is revising the definition in this final rule accordingly. Please see preamble Section II. A – Final Amendments to the General Provisions for the definition of continuous bleed.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 11

Commenter Type: Industry - oil and gas

Comment: Revision: In the definition of “continuous bleed”, EPA replaced “process measurement device” with “process control device”.

Comment: API supports the revised terminology, which is more correct. However, there is an inconsistency between the definitions of intermittent bleed pneumatic devices and continuous bleed pneumatic devices. The definition for intermittent bleed pneumatic devices indicates that these devices are powered by natural gas; while the definition for continuous bleed pneumatic devices only refers to “supply gas”. API requests that the definition for continuous bleed pneumatic be modified to be specific to the use of natural gas as the supply gas, so as not to inadvertently include pneumatic controllers powered by air.

Response: EPA agrees with the commenter and is revising the definition in this final rule accordingly. Please see preamble Section II. A. – Final Amendments to the General Provisions – for the definition of continuous bleed.

Section 4.3 - Intermittent bleed pneumatic devices

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 11

Commenter Type: Trade Association

Comment: Pneumatic controllers:

Updated definitions for pneumatic controllers are generally consistent with previous INGAA recommendation, but additional clarification is needed. In addition, EPA should ensure that

nomenclature for Subpart W sources are reconciled with similar sources included in the recently proposed NSPS for oil and natural gas operations (40 CFR, Part 60, Subpart OOOO).

Definitions for pneumatic devices are generally consistent with previous INGAA comments and recommendations, including INGAA's June 2011 redline recommendations. However, additional clarity on affected pneumatic devices is desired. In addition, the recently proposed New Source Performance Standard (NSPS), Part 60, Subpart OOOO, includes pneumatic controllers as an affected source. EPA should ensure similar nomenclature and definitions are used unless rule context requires differences.

In recent meetings and in its June 2011 letter to EPA, INGAA noted that confusion remains regarding classification of pneumatic devices, especially the types of intermittent devices that are subject to the rule and the types that are excluded from Subpart W. Including this level of detail in the Subpart A definition is unwieldy, so INGAA recommended including preamble discussion that would add clarity. As rules are implemented, preamble text often addresses questions that arise. As Subpart W has been implemented in 2011, it is clear that questions remain regarding pneumatic devices. Thus, INGAA recommends that the Final Rule include discussion of this issue, and example preamble text previously provided is reiterated here:

"The definition of "intermittent bleed pneumatic device" has been revised and examples of devices that are categorized as intermittent pneumatics, as well as devices that are excluded, are provided here. Examples of intermittent pneumatic or control loop devices include level switches, positioners, pressure switches, thermostats, flow integrators, controller-pilots, and volume boosters. Gas actuated isolation valves and recording or control measurement devices are not considered pneumatic devices under Subpart W. Manual assist devices and pneumatic controller devices that are infrequently actuated, sealed, or do not emit to atmosphere are not considered pneumatic devices under Subpart W, including transmitters, transducers, relays (also called a booster, transmitter, or amplifier), gauges, control valve operator/actuators, and self-contained regulators. Subpart W intermittent bleed pneumatic device emissions are only associated with the pneumatic controller, and actuator venting is not counted as a device."

In addition, when multiple EPA regulations affect the same equipment, it is desirable for similar nomenclature and definitions across rules, accepting that minor differences may be necessary to address different regulatory context. On August 23, 2011, an NSPS was proposed for oil and natural gas operations (40 CFR, Part 60, Subpart OOOO), and the rule includes pneumatic controllers as an affected source. Common nomenclature should be used for Part 98, Subpart W (and Subpart A) and Part 60, Subpart OOOO. For example, Subpart OOOO refers to pneumatic controllers, but also uses the term pneumatic devices. For consistency and to better describe the affected source, INGAA recommends consistently using the term "pneumatic controller" for both rules.

Response: EPA disagrees with the commenter on changes to the intermittent bleed pneumatic device definition. For the response on the intermittent bleed pneumatic devices, please see preamble Section II.A – Final Amendments to the General Provisions. EPA has determined that certain clarifications of the definition of these devices were acceptable, in particular, the specification that they automatically maintain a process condition and discharge all or a portion of the full volume of the actuator intermittently. However, EPA has decided not to list examples

of intermittent bleed pneumatic devices in the preamble as the definitions are considered sufficient for operators to determine whether any particular device meets the definitions provided in the final rule.

Regarding coordination of Subpart W definitions with the proposed NSPS Part 60, Subpart OOOO definitions, EPA has maintained the definition "pneumatic device(s)" in this rulemaking. While EPA strives to maintain consistency in equipment nomenclature, EPA has determined that the term "pneumatic device" is necessary to meet the goals of this rulemaking. Furthermore, given this is a reporting rule and does not require reductions in air emissions, EPA has determined that it is appropriate to use potentially different nomenclature, as deemed necessary, from existing or contemplated regulatory air programs.

The commenter's recommendation for the use of the term "pneumatic controller" for Part 60, subpart OOOO is outside the scope of the part 98 rulemaking.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 25

Commenter Type: Trade Association

Comment: Miscellaneous items:

18. EPA should harmonize nomenclature and definitions in the Proposed Rule with similar elements in the recently proposed NSPS for oil and natural gas operations (40 CFR, Part 60, Subpart OOOO).

EPA recently proposed a new NSPS for oil and natural gas operations, 40 CFR, Part 60, Subpart OOOO. That rule proposes to regulate VOCs from three natural gas transmission and storage sources that are also subject to Subpart W reporting. Since both rules address the same equipment and processes, EPA should strive to harmonize nomenclature and definitions between the GHG Reporting Rule and Subpart OOOO. INGAA understands that regulatory context may demand differences between the rules in some cases, but EPA should strive for consistency when possible. It is apparent that EPA has cross-checked definitions in some cases, but in other cases there are differences. EPA should search the rules and compare definitions and nomenclature for common processes and equipment, and propose similar text unless rule context demands a difference.

This comment does not comprehensively address all relevant nomenclature and definitions, but several examples are provided. A similar comment will be included in INGAA's comments on Subpart OOOO, where EPA should consider adding several Subpart W definitions that are not in Subpart OOOO.

Subpart W refers to "pneumatic devices" and Subpart OOOO typically refers to "pneumatic controllers". INGAA recommends that "pneumatic controller" be consistently used in both rules. Although the listed process streams are different for part 98 and part 60, the definition of

"compressor" in §98.238 is preferable to the §60.5430 definition.

The definition of "controller" in §60.5430 should be added to §98.6, which contains related definitions for device types (e.g., high or low bleed) but not the general definition. Similarly, several definitions in §98.6 should be added to Subpart OOOO §60.5430, including "continuous bleed", "centrifugal compressor wet seal degassing vent emissions", and "centrifugal compressor dry seals".

Response: No rule change has been made as a result of this comment. Please see the response to EPA-HQ-OAR-2011-0512-0029, Excerpt 11 for further details.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 62

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] Intermittent bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for [add: automatically] maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. These are snap-acting or throttling devices that discharge [add: a portion or] the full volume of the actuator intermittently when control action is necessary, but does not bleed continuously.

[highlighted text: IN ADDITION – RECOMMEND EXPLANATORY PARAGRAPH FOR THE PREAMBLE TO PROVIDE EXAMPLES (PER DISCUSSION WITH EPA) OF DEVICES INCLUDED AND DEVICES EXCLUDED. Example text follows:]

The [comment bubble JMc13: INGAA considered including “examples” in the definition on “intermittent” device, but the list may be too large and cumbersome. As an alternative, INGAA recommends including a paragraph in the preamble that lists examples.] definition of “intermittent bleed pneumatic device” was revised and examples of devices that are categorized as intermittent pneumatics, as well as devices that are excluded, are provided here. Examples of intermittent pneumatic or control loop devices include level switches, positioners, pressure switches, thermostats, flow integrators, controller-pilots, and volume boosters. Gas actuated isolation valves and recording or control measurement devices are not considered pneumatic devices under Subpart W. Manual assist devices and pneumatic controller devices that are infrequently actuated, sealed, or do not emit to atmosphere are not considered pneumatic devices under Subpart W, including transmitters, transducers, relays (also called a booster, transmitter, or amplifier), gauges, control valve operator/actuators, and self contained regulators. Subpart W intermittent bleed pneumatic device emissions are only associated with the pneumatic controller, and actuator venting is not counted as a device.

Response: Please see response to EPA-HQ-OAR-2011-0512-0029, Excerpt 11. EPA has modified the definition as recommended, but is not providing examples in the preamble for reasons explained in the referenced response.

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 4

Commenter Type: Industry - oil and gas

Comment: “Intermittent bleed pneumatic devices” - AXPC and Chesapeake support and incorporate by reference the comments provided in A.1 [EPA-HQ-OAR-2011-0512-0042, Excerpt 11] and A.2 [EPA-HQ-OAR-2011-0512-0042, Excerpt 12] of Section 2 of API’s comment letter to EPA regarding the definition “intermittent bleed pneumatic devices.”

Response: Please see response to EPA-HQ-OAR-2011-0512-0029, Excerpt 11. EPA has modified the definition as recommended but is not providing examples in the preamble for reasons explained in the referenced response.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 12

Commenter Type: Industry - oil and gas

Comment: Revision: In the definition of “intermittent bleed pneumatic devices”, EPA clarified that the devices are used for “automatically” maintaining a process condition ..., and that these devices discharge “all or a portion of” the full volume of the actuator intermittently...

Comment: API supports this revision.

Response: Please see response to EPA-HQ-OAR-2011-0512-0029, Excerpt 11. EPA has finalized the definition as proposed.

Section 5 - Source Category Definitions (98.230)

Commenter Name: William W. Grygar II

Commenter Affiliation: Anadarko Petroleum Corporation

Document Control Number: EPA-HQ-OAR-2011-0512-0028

Comment Excerpt Number: 3

Commenter Type: Industry - oil and gas

Comment: • Anadarko notes that under §98.230(a)(2), dehydrators are still referenced in the onshore petroleum and natural gas production industry segment and maintains that dehydrators owned and operated by a third party should be excluded from applicability. Anadarko supports both API and AXPC's position on this concern.

• Anadarko supports EPA's proposed changes to the onshore natural gas transmission compression industry segment under §98.230(a)(4).

Response: Regarding §98.230(a)(2), EPA notes that the reporter has to determine whether or not equipment within their facility is subject to reporting depending on whether the reporter has common ownership or common control over the equipment. Please see preamble Section II.D.10 – Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Dehydrators owned and operated by third parties. Regarding the onshore natural gas transmission compression industry segment under §98.230(a)(4), EPA agrees with the commenter and has finalized this amendment, as proposed.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 32

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] § 98.230 Definition of the source category.

[highlighted text: NO CHANGES]

Response: EPA thanks the commenter for their remarks.

Section 5.1 - Onshore Petroleum and Natural Gas Production

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 13

Commenter Type: Industry - oil and gas

Comment: B. § 98.230 - Definition of source categories

“Onshore petroleum and natural gas production” - Chesapeake and AXPC support EPA’s proposal to use the term “single well-pad” in §§ 98.230, 98.232(c), and 98.238. However, this term should be used consistently throughout the rule. We note that the definition of “facility with respect to onshore petroleum and natural gas production” does not use the term “single well-pad.” This definition should be revised to include “single well-pad” for the purpose of consistency and clarity in order to avoid the implication that there is a difference between EPA’s use of well pad and “single well-pad.” Additionally, to clarify that “associated with a single well-pad” is a defined term, a cross-reference should be provided to 40 C.F.R. § 98.238 (“associated with a single well-pad”) in the definition of “onshore petroleum and natural gas production” in § 98.230.

Response: Please see preamble Section II.C – Summary of Final Amendments under the Petroleum and Natural Gas Systems Source Category, and Section II.D – Summary of Comments and Responses Submitted on the Petroleum and Natural Gas Systems Source Category for the response on the definition of “associated with a single well-pad.” EPA agrees with these clarifications and in this final rule, has made a change to § 98.238 to ensure that “associated with a single well-pad” is used consistently. Since the term is defined in 98.238, which is a section that applies to Subpart W only, EPA does not see a need for cross reference in 98.230.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 15

Commenter Type: Industry - oil and gas

Comment: Revision: EPA has modified the definition of Onshore Petroleum and Natural Gas Production.

Comment: API agrees with the proposed revisions and suggests one additional change to the definition. API requests removing the phrase: “auxiliary non-transportation related equipment” from the parenthetical list of portable non-self-propelled equipment because there is no emission methodology or reporting requirement for this equipment.

Response: EPA disagrees that auxiliary non-transportation related equipment should be removed from the list of portable non-self-propelled equipment, because this could be interpreted to include drilling rigs, workover rigs and hydraulic fracturing engine driven pumping units which are specifically required to report GHG emissions. EPA has provided methods for such equipment under 98.233(z), which reporters must comply with.

Section 5.2 - Onshore Natural Gas Processing

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 14

Commenter Type: Industry - oil and gas

Comment: “Onshore natural gas processing” - EPA has proposed revising the definition of onshore natural gas processing in the final Subpart W rule because it currently fails to distinguish between a boosting station, which EPA intended to exempt, and an "onshore natural gas transmission compression facility," which must report under the rule. 76 Fed. Reg. 56,027. EPA proposed revisions to this definition to address this problem. Specifically, EPA states: "We are proposing to strike the term 'this industry segment does not include reporting of emissions from gathering lines and boosting stations' because the edits proposed above clarify what 'onshore natural gas processing' means, and therefore it is unnecessary to discuss that which is excluded. Further, if we had decided to maintain the 'gathering lines and boosting' stations in the rule, EPA would have to propose and finalize a definition of the term 'gathering line and boosting' station, which EPA has previously noted we intend to consider in a future rulemaking (75 FR 74468)." Id.

AXPC and Chesapeake appreciate EPA’s clarification that onshore natural gas processing does not include emissions from gathering lines and boosting stations. However, some gathering line and boosting stations would still be required to report under this proposed definition. By including CO2 removal as an activity that must be reported by “processing” facilities, the proposed definition would include compressor stations with amine units. Under the proposed rule, these compressor stations would suddenly become subject to the Subpart W reporting obligations, whereas they are currently exempt from reporting given the express exemption for gathering lines and boosting stations provided in § 98.230(a)(3).

It would be arbitrary and capricious for EPA require reporting from certain gathering and boosting stations while others remain exempt. The reporting obligations for all gathering and boosting stations should be handled together in a comprehensive, forthcoming rulemaking, as EPA clearly stated it would address this source category. 76 Fed. Reg. 56,027 (citing 75 Fed. Reg. 74,468 (Nov. 30, 2010) (“EPA has decided not to include gathering lines and boosting stations as an emissions source in subpart W at this time [because EPA must conduct] further analysis to ensure an effective coverage of emissions from this source in order to inform future policy decisions.”)). Therefore, EPA should modify the rule to clarify that onshore natural gas processing is not intended to apply to boosting stations with amine units.

If EPA determines to arbitrarily impose a reporting requirement on boosting stations with amine units, it is not feasible for reporters to gather information for this equipment in 2011. Reporters were not aware of a potential reporting obligation for this equipment until this notice was published and will not have adequate time to install the necessary monitoring equipment and reporting systems to obtain this data in 2011. Therefore, if EPA does require boosting stations

with amine units to report their emissions under Subpart W, such units should not be obligated to report data from 2011 and should begin collecting data in 2012.

Response: Please see preamble Section II.C – Summary of Final Amendments under the Petroleum and Natural Gas Systems Source Category, for the response on the definition of natural gas processing. This definition has two parts which EPA is retaining in the final rule: “separation of non-methane gases from produced natural gas,” and “the threshold ... [of] 25 million standard cubic feet ... annual average throughput.” First, EPA notes that separation of non-methane gases is processing of natural gas according to Subpart W requirements. There are processes that are common between facilities that gather and boost natural gas and facilities that process gas. Hence, EPA has provided a 25 mmscf average daily throughput facility threshold to exclude non-fractionation facilities below that level from the natural gas processing segment. EPA has also determined that a limited number of facilities are over this threshold. Please see the Minimum Gas Processing Throughput memorandum, Petroleum and Natural Gas Systems (Subpart W) of the Greenhouse Gas Reporting Rule, Docket: EPA-HQ-OAR-2009-0923.

EPA disagrees that reporters were not aware of the reporting obligations. The November 2010 final rule clearly states that sulfur and carbon dioxide removal are considered part of the onshore natural gas processing segment. In addition, the November 2010 final rule also clearly provided the non-fractionator facility throughput threshold. Hence, the reporter obligations were clearly stated in the November 2010 final rule. Also as regards reporting of emissions for year 2011, please see the preamble for the Mandatory Reporting of Greenhouse Gases Rule 2011 Technical Corrections, Clarifying, Other Amendments to Certain Provisions, Section II.A.2, Subpart A – General Provisions: Summary of Comments and Responses, and preamble Section II.F – Summary of Comments and Responses Submitted on the Petroleum and Natural Gas Systems Source Category, for the response on a source category required to begin data collection in 2011. EPA notes that the BMM provision in the November 2011 final rule provide ample guidance on using data already available to report emissions for reporting year 2011. Hence, EPA does not deem the requirement for large (i.e. ≥ 25 million scf/day) gas plants with acid gas removal, as being an issue for reporting year 2011.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 16

Commenter Type: Industry - oil and gas

Comment: [Please refer to the original comment text posted in the docket] Revision: EPA has revised the definition of Onshore Natural Gas Processing.

Comment: API requests the following revisions shown in green font.

(3) Onshore natural gas processing. Natural gas processing [add (red): means the separation] [add (green): of] [delete (red): ofseparates and recovers] natural gas liquids (NGLs) [delete (red):

and/] or [delete (red): other] [delete (green): non-methane gases] [add (green): CO₂] [delete (red): and liquids] [add (red):from a stream of] produced natural gas[add (red): , or the separation of NGLs into one or more component mixtures. Separation includes] [delete (red): using equipment performing] one or more of the following [delete (red): processes]: [add (red): forced extraction of natural gas liquids,] [delete (green): sulfur and] [add (red): carbon dioxide removal,] [delete (red): oil and condensate removal, water removal, separation of natural gas liquids, sulfur and carbon dioxide removal,] fractionation of NGLs, or [delete (red): other processes, and also] the capture of CO₂ separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing [add (green): facility as facility is defined in §98.6.] [delete (green): plant] [delete (red): .facility, whether inside or outside the processing facility fence.] This [add (red): industry segment includes processing facilities] [delete (red):plants] [add (red): that fractionate gas liquids, and processing plants that do not fractionate gas liquids but have an annual average throughput of 25 MMscf per day or greater.] [delete (red): Source category does not include reporting of emissions from gathering lines and boosting stations. This source category includes: (i) All processing facilities that fractionate. (ii) All processing facilities that do not fractionate with annual average throughput of 25 MMscf per day or greater.]

[See original comment for track changes in different colors]

Replacing the reference to “non-methane gases” with “CO₂” specifically addresses GHG emissions from removing CO₂ from acid gas streams. Similarly, API requests removing the reference to sulfur removal, as sulfur is not a GHG nor does the removal of sulfur produce GHG emissions beyond what would occur from the removal of CO₂ from the acid gas stream.

API also requests that “natural gas processing plants” be revised back to “natural gas processing facilities” to maintain distinction between the Subpart W definition and the KKK definition. The definition of gas plant has specific meaning in other regulations that do not apply here.

API does not see any difficulty in the application of the term “facility” in the source category definitions provided for gas processing. API does not believe that using the terminology “facility” in this definition changes the reporting of other source categories that are located within the boundaries of a gas processing facility. EPA has already provided a work-around under 98.236(c).

The September 9, 2011 preamble indicates (page 56027) that EPA replaced “facility” with “plant” because “facility” has a specific meaning under 98.6 that is not intended here. However, the source category definition provided in 98.230 is broader than the “facility” definition in 98.6. In addition, the use of “facility” also takes on a specific meaning for onshore petroleum and natural gas production in Subpart W. Therefore, a specific meaning for “facility” with respect to onshore natural gas processing is not unique to gas processing under Subpart W.

Response: Please see preamble Section II.C – Summary of Final Amendments under the Petroleum and Natural Gas Systems Source Category, for the response on the definition of natural gas processing. This definition does not delete the general reference to “non-methane

gases,” does not delete the inclusion of sulfur as a non-methane gas to focus this aspect of the definition on only CO₂ removal, and does not change the term “plant” to “facility.” For future policy considerations, EPA is seeking GHG emissions information on large (>25 million scf/day) gas plants that operate processes other than just CO₂ removal, such as H₂S removal, because these two acid gases are typically both present in produced natural gas in varying concentrations, and it would be impractical to specify minimum concentrations of one or the other in defining a gas processing plant.

It is not appropriate to replace the term "plant" with "facility" as suggested by the commenter. Facility has a specific meaning in 40 CFR 98.6, and refers to "any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas...." The "facility" can include multiple source categories, covered by different subparts under part 98. For onshore natural gas processing specifically, the "facility" would likely include, at a minimum, subpart C (General Stationary Combustion) and subpart W (petroleum and natural gas systems). The gas processing "plant" is only one part of a larger "facility".

Section 5.3 - Onshore Natural Gas Transmission Compression

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 15

Commenter Type: Industry - oil and gas

Comment: “Onshore natural gas transmission compression” - AXPC and Chesapeake support and incorporate by reference the comments provided in W.3 [EPA-HQ-OAR-2011-0512-0042, Excerpt 17] of Section 2 of API’s comment letter to EPA regarding the definition “onshore natural gas transmission compression.”

Response: Please see response to EPA-HQ-OAR-2011-0512-0042, Excerpt 17.

Commenter Name: Jessica Stark

Commenter Affiliation: SLR International Corp

Document Control Number: EPA-HQ-OAR-2011-0512-0040

Comment Excerpt Number: 5

Commenter Type: Industry - oil and gas

Comment: Definition of ‘Transmission Pipeline’ and Definition of ‘Onshore Natural Gas Transmission Compression’ Industry Sector in 98.230(a)(4)

I would like to request that these two definitions be expanded to clarify the applicability to compressor stations. Many companies operate numerous compressor stations that range from one single compressor at a location on a pipeline to boost pressure up to larger stations with multiple compressors. The units operate to compress gas to serve different functions – from gas collection and field gathering to put gas into 6 to 8 inch pipelines, or to compress gas (their own produced gas as well as that of other companies) to transmit it through larger diameter 12 inch pipelines prior to sale to utilities or local distribution companies.

As currently written, it could be interpreted that any compressor station operating on a FERC-listed interstate or intrastate pipeline would be covered by the Transmission Compression industry sector. This is likely not EPA's intention. I would like to request clarifying language to indicate exactly the types of stations that are considered 'Transmission Compression.' This could be accomplished by the addition of delineating parameters such as stations compressing gas for transmission in 12 (or 16) inch or greater pipelines, just prior to sale to a Local Distribution Company or other end user. This would only cover the final compressor stations in the process and not the gathering and boosting stations that are located everywhere along the lines between the wells and the point of transfer to regional gas companies. In locations where there is no gas processing plant, there is no clear delineation between field gathering and transmission compression. The same company can act as gas producer, gas collector, and gas transmitter, so using the list of FERC pipelines has too broad of a scope. The rule should have clearly identifying parameters such as pipeline diameter, operating pressure, or a minimum compression capacity.

As an example, I am providing information on a representative compressor station operated by one of my clients. The station compresses gas collected by the company as well as other production companies in the region, and is one of their largest compressor stations. Many other stations have only one or two small compressors. At this station, the gas is dehydrated and compressed for transmission in a 12 inch diameter pipeline. Approximately 15 million cubic feet per day is compressed and transmitted. It is our opinion that the vent rates on the blowdown vents, isolation valves and rod packing vent lines on the compressors at this station would be so low they would be difficult to measure using the methods required by the rule. These are not very large units and the cost associated with performing these measurements does not seem to be worthwhile in terms of the accuracy of the magnitude of emissions measured. Emission factors (such as those presented for the individual vent types in the Technical Support Documents for Subpart W or those used for all compressor vents as allowed for Onshore Production compressors) would adequately represent emissions from smaller compressor units such as these.

[See original comment for table: Representative Compressor Station in West Virginia]

We request that the Transmission Compression category be defined using parameters that would clearly capture only the larger compressor stations in the industry due to the effort required to perform annual leak detection and vent measurement surveys, or that if the scope of the industry sector is so broad as to cover many small stations, that a size threshold be included to allow the use of emission factors to estimate compressor venting emissions.

Response: EPA disagrees with the commenter and is retaining the proposed definition of transmission pipeline in this final rule. Please see preamble Section II.C – Summary of Final Amendments under the Petroleum and Natural Gas Systems Source Category, for the response on the definition of onshore natural gas transmission compression. EPA notes that there is no ambiguity in the definition of a transmission pipeline. It is EPA’s intent that any compression station located on a transmission pipeline be designated as transmission station. Also, no combination of compressor size, pressure rating, pipeline diameter and compression ratio will uniquely separate compressors in these five segments of the industry. Finally, EPA notes that since the facility in the natural gas transmission segment is an individual compressor station, the 25,000 tonnes of CO_{2e} emissions reporting threshold, will exempt small compressor stations.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 17

Commenter Type: Industry - oil and gas

Comment: [Please refer to the original comment text posted in the docket] Revision: EPA has revised the definition of Onshore Natural Gas Transmission Compression.

Comment: API requests the following revisions shown in green font.

Onshore natural gas transmission compression. Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas [delete (red): at elevated pressure] from production fields[add (red): .] [delete (red): or] natural gas processing [add (green): facilities] [delete (green): plants] [delete (red): ,facilities] [add (red): or] [delete (red): in] [add (red): other] transmission [add (red): compressors through transmission] pipelines to natural gas distribution pipelines [add (red):, LNG storage facilities,] or into [add (red): underground] storage. In addition, transmission compressor station [delete (red): may] include[add (red): s] equipment for liquids separation [delete (red):, natural gas dehydration,] and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression [add (red): that is part of] [add (green): an] [delete (red): operated by natural gas processing facilities are included in the] onshore natural gas processing [add (green): facility (as facility is defined in §98.6)] [delete (green): plant] [add (green): is] [delete (green): are] [add (red): included in the onshore natural gas processing] segment and are excluded from this segment. [delete (red): This source category also does not include reporting of emissions from gathering lines and boosting stations – these sources are currently not covered by subpart W.]

[See original comment for track changes in different colors]

As discussed in comment W.2 [EPA-HQ-OAR-2011-0512-0042, Excerpt 16] above, API requests that “natural gas processing plants” be revised back to “natural gas processing facilities” to maintain distinction between the Subpart W

Response: Please see response to comment EPA-HQ-OAR-2011-0512-0040, Excerpt 5. In this final rule, EPA has adopted most of the text edits recommended here with exception of changing

the term “process plant” back to “process facility.” EPA is not changing the term “plant” to “facility”; please see response to EPA-HQ-OAR-2011-0512-0042, Excerpt 16 for further details.

Section 6 - Greenhouse Gases to Report (98.232)

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 10

Commenter Type: Trade Association

Comment: Reporting N₂O is inappropriate for vented emissions and equipment leaks unless the emissions are controlled with a combustion device. N₂O reporting is required by §98.232(n) and adding N₂O as a reportable GHG in §98.232(e) and (f) will cause confusion. This proposed revision should be deleted.

§98.232(e) and (f) list the vent and equipment leak sources that must be reported for natural gas transmission compression and for underground storage, respectively. Subpart W currently indicates that CO₂ and CH₄ should be reported and both constituents are in natural gas. The Proposed Rule adds N₂O to the list of GHGs to report. Adding this requirement preceding a list of vented sources and equipment leaks will cause unnecessary confusion. The proposed addition of N₂O should be deleted in the Final Rule.

Reporting N₂O is appropriate for combustion, (e.g., when vented or fugitive sources are routed to a flare or other combustion device). §98.233(n) provides the GHG estimation methods for vented and fugitive sources that are controlled via combustion and includes N₂O reporting. Since §98.232(n) addresses N₂O reporting for Subpart W transmission compression and underground storage sources that are combusted, it is not necessary to add N₂O to §98.232(e) or (f).

Response: EPA's intention in the November 2010 rule is that all industry segments that report flaring emissions include N₂O emissions in their reporting. In this final rule, EPA has clarified the requirement to report N₂O for all industry segments. Emissions sources with no N₂O emissions would report zero emissions. Please see preamble Section II.C – Final Amendments to the Petroleum and Natural Gas Systems Source Category, for the response on the Greenhouse Gases to Report.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 28

Commenter Type: Trade Association

Comment: Reference to §98.232(j) in §98.232(a) should be deleted because (j) has been deleted.

The Proposed Rule deletes §98.232 (j), which referred to criteria for flaring, and "reserves" that section. Section §98.232(a) includes a reference to section (j), "...emissions from each flare as specified in paragraph (j) of this section, ...". To reconcile with other revisions, the reference to §98.232(j) should be deleted.

Response: EPA agrees with the commenter. In this final rule, EPA has removed the reference to 40 CFR 98.232(j) and has replaced it with 40 CFR 98.232 (b) through (i) in 40 CFR 98.232(a).

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 34

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] § 98.232 GHGs to report.

[highlighted text: Add section (m) to clarify that operators can use DEFAULT values or company records for percent methane and CO₂ for vented and fugitive emissions from transmission and storage segments

Revise section (j) based on INGAA-EPA May 26 meeting discussion to clarify : (1) FLARE emissions are only reported if flares are listed for the segment in §98.232; (2) flare / vapor recovery efficiency should be applied when reporting emissions for ANY source that includes such control; and (3) if flares are not listed in §98.232 but flaring applies, the combustion emissions from the flare do NOT need to be reported]

(j) [delete: All applicable i] [add: Industry] segments [add: in §98.232(b) through (d) include flares as a listed source and] must report the CO₂, CH₄, and N₂O emissions from each flare.

(i) [add: Other industry segments in §98.232(e) through (i) should not report flare emissions but should consider flaring, vapor recovery, or other control when reporting emissions of CH₄ and CO₂ under §98.236 based on calculations in §98.233 that estimate uncontrolled emissions. The emissions reported under §98.236 should consider the reduction efficiency (e.g., flare efficiency). Equation W-19 in §98.233(n) can be used to calculate CH₄ emissions from a controlled emission source. Equation W-19 also applies for CO₂ emissions for a vapor recovery system. Equation W-20 applies for CO₂ emissions for combustion based control (flare, thermal oxidizer). The calculation approach should be documented under §98.3(g).] [comment bubble JMc1: Approach is to provide this “direction” once rather than in each 98.233 section, and reporting criteria based on May 26 INGAA meeting with EPA. With this addition, flare references in §98.233 sections for transmission are deleted (see below).]

[add: (m) In [comment bubble JMc2: To simplify, intent is to allow operators in transmission, etc to apply either a default composition or to use company records / gas analysis. Alternate would be to add this criteria within §98.233(u)(2) and revise equation citations for gas composition throughout §98.233 source calculation sections.] lieu of the requirements for natural gas composition specified in §98.233, the operator may alternately apply a gas composition in (1) or (2) when calculating emissions in §98.233:

(1) For sources in §98.232(e), (f), (g) and (i), default [comment bubble JMc3: Based on default assumed in DOE/EIA national inventory report – e.g., see “Documentation for Emissions of

Greenhouse Gases in the United States 2008”, DOE/EIA-0638 (2008), January 2011 Default would apply for transmission, underground storage, LNG storage, and distribution.]natural gas composition of 95 percent CH₄ and 1 percent CO₂ (by volume).

(2) For sources in §98.232(e) through (i), company gas records consistent with §98.233(u)(2).]

Response: Regarding adding section (m), EPA disagrees with the commenter. Please see the response to EPA-HQ-OAR-2011-0512-0029, Excerpt 43.

Regarding (j), EPA disagrees with the commenter, and in this final rule, EPA is removing the reference to 40 CFR 98.232(j) and has replaced it with 40 CFR 98.232 (b) through (i) in 40 CFR 98.232(a).

Regarding (i), emissions sources are to report the emissions sent to the flare under that emissions source type and not under the flares source. Please see section 98.233(n)(9) for further details.

Commenter Name: Pamela A. Lacey

Commenter Affiliation: American Gas Association (AGA)

Document Control Number: EPA-HQ-OAR-2011-0512-0032

Comment Excerpt Number: 12

Commenter Type: Trade Association

Comment: Section 98.232(i): The proposed amendments to 98.232(i) would change the numbering of the distribution emission sources and inadvertently omit pipeline main equipment leaks from 98.232(i). In the November 2010 final rule, section 98.232.(i)(4) listed “pipeline main equipment leaks”. In the September 2011 Proposal, EPA proposes to revise section 98.232(i)(4) to include “equipment leaks from vaults at below grade metering-regulating stations” but the agency proposes no further edits to the list. There are no proposed revisions to the first paragraph in section 98.233(r), which references section 98.232(i). As a result, the list in 98.233(r) will need to be revised to reflect these proposed changes.

Response: EPA thanks the commenter for pointing out this omission. This final rule includes a revision to 98.232(i) to restore the appropriate emissions sources.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 19

Commenter Type: Industry - oil and gas

Comment: Revision: 98.232(a) indicates “You must report CO₂, CH₄, and N₂O emissions from each industry segment specified in paragraph (b) through (i) of this section, CO₂, CH₄, and N₂O emissions from each flare as specified in paragraph (j) of this section, and stationary and portable combustion emissions as applicable as specified in paragraph (k) of this section” (emphasis added).

Comment: Paragraph (j) language was deleted and paragraph (j) is now [Reserved]. The reference to paragraph (j) in this section should be deleted. [Flare emissions will be covered in paragraphs (b) through (i).

Response: EPA agrees with the commenter. In this final rule, EPA has removed the reference to 40 CFR 98.232(j) and has replaced it with 40 CFR 98.232 (b) through (i) in 40 CFR 98.232(a).

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 20

Commenter Type: Industry - oil and gas

Comment: Revision: 98.232(c) EPA has added the word “single” prior to well-pad to designate the emission source types reported for onshore petroleum and natural gas production facilities.

Comment: API supports this revision and interprets this to apply to single well bore and multiple well bore well-pads.

Response: EPA agrees with the commenter. The well-pad can have a single wellhead or multiple wellheads on the same well-pad.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 21

Commenter Type: Industry - oil and gas

Comment: Revision: EPA has revised 98.232(c)(22) to specifically state that the methods in 98.233(z) must be used for emissions from stationary or portable fuel combustion equipment that is “located at an onshore petroleum and natural gas production facility as defined in 98.238.”

Comment: Previously this paragraph referenced combustion equipment at an onshore production well-pad. However, the reference for the definition of onshore petroleum and natural gas production facility in 98.238 is limited to “equipment on a well-pad or associated with a well-pad and CO2 EOR operations...” Therefore, this revision does not change the requirements of this paragraph.

In addition, API interprets “well drilling and completion equipment” and “workover equipment” to refer specifically to equipment used on a well pad. This is consistent with the proposed

definition of “associated with a single well pad” which links the emission sources associated with a single well-pad to the produced hydrocarbon stream from wells located on that well-pad.

Response: Regarding combustion equipment, EPA has clarified the intention of the requirement by clarifying the definition of facility with respect to onshore petroleum and natural gas production in 98.238. The reporter has to make a determination on how the requirements of 98.232(c)(22) and well drilling, completion and workover apply in the context of this clarification.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 22

Commenter Type: Industry - oil and gas

Comment: Revision: EPA added that N₂O emissions are required to be reported for the sources types under 98.232 (e), (f), (g), (h), and (i).

Comment: 98.232(d) is excluded in the regulatory language. This appears to be an oversight in the Federal Register version.

Response: EPA agrees with the commenter. In this final rule, EPA has updated the reference to 40 CFR 98.232 (b) through (i), which includes 98.232(d).

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 4

Commenter Type: Industry - oil and gas

Comment: D. Onshore Production Flares

In Table 2 of the preamble EPA recaps the status of its responses to issues raised in API’s petition for reconsideration, including, “Requirements for flare stack emission associated with onshore oil and gas production. API asserted that “[e]missions from flare stacks associated with onshore oil and gas production were not included in the Petroleum and Natural Gas production industry segment in the proposed rule * * * the inclusion of emissions from flare stacks associated with onshore oil and gas production is duplicative, burdensome, and a potential source of reporting inaccuracies”.

EPA contends that it has addressed this issue in Table 2 of the current proposal.

API Response:

EPA has not fully addressed this issue or the primary issue API stated in relation to this source type in the proposed technical corrections.

EPA's addition of Flare Stack Emissions as a discrete source type in 98.232 (c) (9) of the November 30, 2010 final rule represents a significant expansion of the rule requirements which was not included in the proposed rule and thus not able to be commented on prior to finalization. API understands and acknowledges that the proposed rule referred certain source types to 98.233 (n) for calculation of emissions from gas sent to flares from these specific source types. This has been discussed with EPA and communicated in written form previously and API accepts this coverage of flared gas which was proposed and then finalized.

The emissions calculation methodologies for dehydrator vents (233(e)), gas well venting during completions and workovers with and without hydraulic and non-hydraulic fracturing (98.233(g) and (h)), onshore production storage tanks (98.233(j)), well testing venting and flaring (98.233(l)), associated gas venting and flaring (98.233(m)), and centrifugal compressor venting (98.233(o)) each acknowledge that emissions may be sent to a flare. Each of these sections references the method in 98.233(n) as the means for calculating emissions from flares. However, nothing in the proposal indicated the potential inclusion of flare stacks as a discrete source type for onshore production in the final rule. In prior communications with EPA, API has noted the difficulties associated with coverage of "all flares" in the onshore production sector with no exclusions or de minimis levels or volumes. In these same communications API has noted that the specific source types which refer to the flaring methodology for calculation represent the vast majority of gas which is sent to flare in the onshore production sector and that including flare stacks as a discrete source type imposes significant burden without commensurate emissions coverage.

Although there are some minor flaring types which are not covered in the specific source types, such as flaring of small amounts of gas entrained in the drilling fluid on those occasions where gas enters the drilling fluid, these are small, infrequent, and very difficult to adequately capture and estimate volume. API and its members are not aware of any significant flaring sources which are not specifically covered in the other specific source types in the rule. Inclusion of flare stacks as a discrete source type for onshore production in 40 CFR 98.232 (c) (9) requires that operators put systems in place to capture every flare event regardless of how small, estimate volume, calculate emissions, and then report the voluminous information required by the rule. Given the very minor volumes of flared gas that are not already captured under the other source types specified in 98.232, inclusion of flares as a discrete source type simply does not make sense from an emissions coverage vs. burden and cost perspective.

Additionally, API has previously stated that it believes that the rule's requirements for calculation and reporting of emissions from flares are duplicative for onshore oil and natural gas operations. The rule does acknowledge the possibility of double counting flare emissions, and 98.233(n)(9) requires that "flare emissions determined under subparagraph (n) of this section must be corrected for flare emissions calculated and reported under other paragraphs of this section to avoid double counting of these emission."

API requests that EPA remove flare stacks as a source type for onshore production at 98.232(c)(9) since EPA has not properly proposed this addition and has not provided an explanation yet as to why flare stacks were added as a source type in the first place, except to state in a response to comments[Footnote 5: Comment Number: EPA-HQ-OAR-2009-0923-

1155-31; Response to Comments, Volume I, page 88] that “onshore production, offshore production and natural gas processing, must report the CO₂, CH₄, and N₂O combustion emissions from each flare.”

Response:

EPA has reviewed your comment and is unable to respond at this time. Your question relates to an issue or issues currently the subject of ongoing litigation. Please monitor the website for any additional guidance that may be available in the future.

[_http://www.epa.gov/climatechange/emissions/subpart/w.html](http://www.epa.gov/climatechange/emissions/subpart/w.html)

Commenter Name: Curtis J. Winner

Commenter Affiliation: New Mexico Gas Company (NMGC)

Document Control Number: EPA-HQ-OAR-2011-0512-0047

Comment Excerpt Number: 3

Commenter Type: Industry - oil and gas

Comment: The proposed amendments to 98.232.(i) changes the numbering of the distribution emission sources and ends up omitting pipeline main equipment leaks from 98.232(i). In the November 2010 final rule 98.232.i.4 was “pipeline main equipment leaks”. In the September 2011 revision, 98.232.i.4 is listed as “equipment leaks from vaults at below grade metering-regulating stations” with no further edits to the list. The first paragraph in section 98.233.r was not amended and references 98.232.(i) so the list in 98.233.r will need to be revised to reflect these proposed changes.

Response: EPA agrees with the commenter. In this final rule, EPA has revised the opening paragraph to 98.233(r) to include 98.232(i)(6) to reflect changes in the September 2011 proposal.

Section 7 - Calculating GHG Emissions (98.233) and Data Reporting Requirement (98.236)

Commenter Name:

Commenter Affiliation: Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2011-0512-0026

Comment Excerpt Number: 7

Commenter Type: Industry - other

Comment: EPA should standardize the mol fraction of CH₄ and CO₂ used for underground storage of natural gas in the various emission equations that are required to be used. For Pneumatic Device Venting - Equation W-1 uses 0.95 for CH₄ and 0.01 for CO₂ – Also, should the footnote in Equation W-1 refer to paragraph (u)(2) instead of (u)(2)(i)?

For Compressor Vents - Equation W-26 uses 0.95 for CH₄ and 0.01 for CO₂

For Equipment Leaks - Equation W-30 uses 0.974 for CH₄ and 0.01 for CO₂

For Population Count Fugitive Emissions - Equation W-31 uses 1 for CH₄ and 0.011 for CO₂
EPA should standardize on one mole fraction for CH₄ (0.95) and for CO₂ (0.01) in all of these equations involving natural gas calculations.

Response: EPA agrees with the commenter about standardizing the mole fraction of CH₄ and CO₂ for underground storage in Equations W-1, W-30, and W-31. In this final rule, for Equations W-1, W-30, and W-31, GHG_i for CH₄ = 0.975 and GHG_i for CO₂ = 1.1*10⁻² which are the compositions of methane and carbon dioxide in total hydrocarbon for transmission pipeline quality natural gas.

EPA is not accepting any comments on Equation W-26, because amendments to this equation were not proposed. Hence, this equation is outside the scope of this rule. EPA may consider your comment in future rulemakings. Additionally, your question relates to an issue or issues currently the subject of ongoing litigation. Please monitor the website for any additional guidance that may be available in the future.

<http://www.epa.gov/climatechange/emissions/subpart/w.html>

EPA disagrees with the commenter in regard to the citation (u)(2)(i) in parameter GHG_i in Equation W-1 being incorrect. For this equation, only onshore petroleum and natural gas production reporters are referred to paragraph (u) to determine the mole fractions of CH₄ and CO₂ in produced natural gas, and this is specifically addressed in (u)(2)(i). For reporters under other applicable industry segments, EPA is providing the mole fractions of CH₄ and CO₂ within the parameter definition. Hence, in this final rule, in Equation W-1, GHG_i refers to (u)(2)(i).

Commenter Name: Jeff Applekamp

Commenter Affiliation: Gas Processors Association

Document Control Number: EPA-HQ-OAR-2011-0512-0034

Comment Excerpt Number: 3

Commenter Type: Trade Association

Comment: On September 9, 2011, EPA proposed numerous technical amendments to Subpart W of the GHGRP for the following purposes: to respond to requests for reconsideration filed by industry groups, 76 Fed. Reg. 56012, “to ensure that the 2010 final rule is implemented as intended”, and “to address questions and issues raised by stakeholders since development of the proposal of the technical corrections rule.” 76 Fed. Reg. 56019. GPA strongly supports resolution of these technical matters, which will ensure consistency among GHGRP subparts and consistent application across reporting entities under the rule. GPA, through their members, has worked with API and API members on the development of comments on these proposed amendments and hereby incorporates by reference the comments filed by API on October 24, 2011, including comments that address technical matters not addressed in the September 9, 2011 proposal.

Response: EPA has carefully reviewed GPA and API comments and has responded to every unique comment submitted. In regard to GPA’s incorporation by reference of API comments, for further information, please see EPA responses to API’s comments in this docket.

Commenter Name: Richard Bye

Commenter Affiliation: Centerpoint Energy, Inc.

Document Control Number: EPA-HQ-OAR-2011-0512-0044

Comment Excerpt Number: 2

Commenter Type: Industry - oil and gas

Comment: CenterPoint Energy, Inc. supports the detailed technical comments filed in this docket of the American Gas Association (AGA), and the Interstate Natural Gas Association of America (INGAA). Thank you for your consideration of these comments.

Response: EPA has carefully reviewed INGAA’s and AGA’s comments and has responded to every unique comment submitted. In regard to Centerpoint Energy’s incorporation by reference of INGAA and AGA comments, for further information, please see EPA responses to INGAA’s and AGA’s comments in this docket.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 53

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] § 98.236 Data reporting requirements.

[highlighted text: CORRECTIONS ARE ADDED FOR CONSISTENCY WITH §98.233 REVISIONS AND UNDERSTANDING OF EPA’S INTENT ON DESIRED INFO FOR REPORTING]

In addition to the information required by §98.3(c), each annual report must contain reported emissions and related information as specified in this section.

(a) Report annual emissions separately for each of the industry segments listed in paragraphs (a)(1) through (8) of this section in metric tons CO₂e per year [delete: at standard conditions]. For each segment, report emissions from each source type §98.232(a) in the aggregate, unless specified otherwise. For example, an onshore natural gas production operation with multiple reciprocating compressors must report emissions from all reciprocating compressors as an aggregate number.

(c) For each aggregated source, unless otherwise specified, report activity data and emissions (in metric tons CO₂e per year [delete: at standard conditions]) for each aggregated source type as follows:

Response: EPA agrees with the commenter on removing “at standard conditions” from 40 CFR 98.236(a). However, in this final rule, EPA is making additional changes to this paragraph. Hence this issue does not arise anymore.

EPA is also modifying 40 CFR 98.236(c) to clarify the reporting of emissions from equipment in co-located facilities and the reporting of vented and flared emissions from the same source type. With this change, the text that the commenter commented on is not part of this final rule and is therefore not an issue.

Section 7.1 - Standard temperature and pressure

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 24

Commenter Type: Industry - oil and gas

Comment: Inconsistencies

Chesapeake and AXPC have concerns about inconsistencies in the text of the Subpart W rule.

(1) Standard Conditions

EPA has proposed changes to several equations in Subpart W impacting whether emissions are calculated at standard conditions or atmospheric conditions. AXPC and Cheapeake support

EPA's efforts to achieve consistency in the rule because doing so will reduce the burden associated with calculating facility emissions. Therefore, we support and incorporate by reference API's comments in W.8 [EPA-HQ-OAR-2011-0512-0042, Excerpt 24], W.10 [EPA-HQ-OAR-2011-0512-0042, Excerpt 26], W.11 [EPA-HQ-OAR-2011-0512-0042, Excerpt 27], W.14 [EPA-HQ-OAR-2011-0512-0042, Excerpt 30], W.15 [EPA-HQ-OAR-2011-0512-0042, Excerpt 31], W.20 [EPA-HQ-OAR-2011-0512-0042, Excerpt 36], W.24 [EPA-HQ-OAR-2011-0512-0042, Excerpt 40], W.28 [EPA-HQ-OAR-2011-0512-0042, Excerpt 44], W.29 [EPA-HQ-OAR-2011-0512-0042, Excerpt 45], W.30 [EPA-HQ-OAR-2011-0512-0042, Excerpt 46], W.36 [EPA-HQ-OAR-2011-0512-0042, Excerpt 52], and W.41 [EPA-HQ-OAR-2011-0512-0042, Excerpt 58] of Section 2 of its letter regarding corrections to address reporting emissions at standard, atmospheric and actual conditions.

Response: For the response to API's comment in W.8 of Section 2, please see the response to EPA-HQ-OAR-2011-0512-0042, Excerpt 24.

For the response to API's comment in W.10 of Section 2, please see the response to EPA-HQ-OAR-2011-0512-0042, Excerpt 26.

For the response to API's comment in W.11 of Section 2, please see the response to EPA-HQ-OAR-2011-0512-0042, Excerpt 27.

For the response to API's comment in W.14 of Section 2, please see the response to EPA-HQ-OAR-2011-0512-0042, Excerpt 30.

For the response to API's comment in W.15 of Section 2, please see the response to EPA-HQ-OAR-2011-0512-0042, Excerpt 31.

For the response to API's comment in W.20 of Section 2, please see the response to EPA-HQ-OAR-2011-0512-0042, Excerpt 36.

For the response to API's comment in W.24 of Section 2, please see the response to EPA-HQ-OAR-2011-0512-0042, Excerpt 40.

For the response to API's comment in W.28 of Section 2, please see the response to EPA-HQ-OAR-2011-0512-0042, Excerpt 44.

For the response to API's comment in W.29 of Section 2, please see the response to EPA-HQ-OAR-2011-0512-0042, Excerpt 45.

For the response to API's comment in W.30 of Section 2, please see the response to EPA-HQ-OAR-2011-0512-0042, Excerpt 46.

For the response to API's comment in W.36 of Section 2, please see the response to EPA-HQ-OAR-2011-0512-0042, Excerpt 52.

For the response to API's comment in W.41 of Section 2, please see the response to EPA-HQ-OAR-2011-0512-0042, Excerpt 58.

Section 7.2 - (t) (u) (v) Volumetric and mass conversion [W-33 to W36]

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 27

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] The rule inconsistently references and applies the gas volume and mass emission conversion calculations in §98.233(t) – (v) (e.g., see Comment 2 regarding natural gas composition). To clarify and standardize calculations and avoid unnecessary confusion and associated errors, the same GHG emissions calculation methodology and common engineering units should be used for all emission sources in §98.233(a) through (r).

This is a broader comment regarding revisions associated with converting engineering units. Subpart W clarity and readability would be greatly improved if there was more commonality across emission estimate sections. §98.233(a) through (r) provide methods for source-specific emission estimates, and §98.233(t) through (v) provide calculations to convert engineering units from volumetric emissions to standard volumes and mass of CO₂e emissions. Rule clarity would be greatly enhanced if the objective of calculations in sections (a) through (r) was to calculate emissions with a common endpoint for engineering units (i.e., volumetric emissions at actual or standard conditions). Then, consistently refer to (t), (u) and (v) to convert natural gas volumetric emissions to CO₂ and CH₄ volumetric and mass emissions. The lack of a standard format hinders implementation clarity and also results in confusing or conflicting requirements. For example, Comment 2 discusses revisions where conflicts remain regarding natural gas composition assumptions.

EPA may view this as a daunting task at this point in the process, but as Subpart W is incrementally (and repeatedly) revised, basic structural and organizational issues should be addressed. To implement this approach, only minor revisions would be needed in the equations and parameters in subsections (a) through (r) – and conflicting requirements such as natural gas composition assumptions would be clearly addressed. The revisions should follow several basic principles:

§98.233(a) – (r) should not prescribe whether volumetric natural gas measurements are at actual or standard conditions (i.e., temperature and pressure). Rather, if volumetric gas measurements are at actual conditions, the rule should reference §98.233(t) and equation W-33 to convert the gas volumes to standard temperature and pressure. Volumetric conversions are not needed if volumetric gas measurements are reported at standard conditions.

A specific natural gas composition (i.e., concentration of CH₄ and CO₂) should not be included in (a) – (r). Instead, §98.233(u) should always be referenced to determine the appropriate gas composition with equation W-35 referenced to calculate volumetric GHG emissions. An example of how this would be implemented is provided for reciprocating compressors based on suggested revisions to Equation W-26. (Note that this also relates to Comment 2 issues regarding

conflicting natural gas composition assumptions). Equation W-26 should calculate natural gas volumetric emissions and then §98.233(u) and equation W-35 should be referenced to calculate volumetric GHG emissions. Equation W-26 revisions would include:

“(6) Estimate annual emissions using the flow measurement and Equation W-26 of this section.

[See original comment for Equation W-26]

Where:

$E_{s,i,m}$ = Annual [delete: GHG i (either CH₄ or CO₂)] volumetric emissions [add: of natural gas] [delete: at standard conditions], in [add: standard] cubic feet [add: for the unique mode and vent source combination].

MT_m = Measured gas [add: volumetric] emissions in standard cubic feet per hour [add: for the unique mode and vent source combination].

T_m = Total time the compressor [add: package] is in the mode for which $E_{s,i,m}$ is being calculated, in the calendar year in hours.”

Calculations of mass emissions for each GHG should not be included in §98.233(a) – (r) equations and calculations. Instead, §98.233(v) and equation W-36 should be referenced to calculate GHG mass emissions. For example, for pneumatic devices Equation W-1 would not include "GHG _{i} " or Conv _{i} " terms but rather reference §98.233(u) and Equation W-35 to address natural gas composition and §98.233(v) and Equation W-36 to calculate emissions on a mass basis.

Response: EPA disagrees with the commenter. EPA acknowledges that some changes in the equations have resulted in incorrect references to 98.233(t), (u), and (v), which are fixed in this final rule. However, EPA notes that not all monitoring methods are similar in their calculation methods; some use emission factors, some actual measurements, some simulations, and others a blend of these methods. As a result the output from these calculations is a mix of emissions at actual and standard conditions. Therefore, the use of 98.233(t) is appropriate. Also, if the actual conditions for any of the equations are STP conditions then the use of 98.233(t) will not result in any error; please see response to EPA-HQ-OAR-2011-0512-0042, Excerpt 44 for further details.

In this final rule, 40 CFR 98.233 (a) through (r) accurately reference either 40 CFR 98.233 (t), (u), and (v), to convert natural gas or GHG volumetric emissions at actual conditions to standard conditions, natural gas volumetric emissions at standard conditions to GHG volumetric emissions at standard conditions, and GHG volumetric emissions at standard conditions to GHG mass emissions in carbon dioxide equivalent, respectively. Thereby, regardless of the end result of the Equations W-1 through W-32, all emission estimates are converted to GHG mass emissions in carbon dioxide equivalent.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 42

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] Volumetric emissions. Calculate volumetric emissions at standard conditions as specified in paragraphs (t)(1) or (2) of this section[add: , with actual pressure and temperature] determined by engineering estimate based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions [delete: by converting actual temperature and pressure of natural gas emissions to standard temperature and pressure of natural gas] using [add: actual natural gas emissions temperature and pressure, and] Equation W-33 [delete: of this section.

[See original comment for Eq. W-33]

Where:

$E_{s,n}$ = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet.

$E_{a,n}$ = Natural gas volumetric emissions at actual conditions in cubic feet.

T_s = Temperature at standard conditions (°F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (psia).

P_a = Absolute pressure at actual conditions (psia).

(2) Calculate GHG volumetric emissions at standard conditions [delete: by converting actual temperature and pressure of GHG emissions to standard temperature and pressure] using [add: actual GHG emissions temperature and pressure, and] Equation W-34 [delete: of this section].

[See original comment for Eq. W-34]

Where:

$E_{s,i}$ = GHG i volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet.

$E_{a,i}$ = GHG i volumetric emissions at actual conditions in cubic feet.

T_s = Temperature at standard conditions (°F).

Ta= Temperature at actual emission conditions (°F).

Ps= Absolute pressure at standard conditions (psia).

Pa= Absolute pressure at actual conditions (psia).

Response: EPA agrees with the commenter and is modifying 40 CFR 98.233 (t) accordingly, along with other amendments, in this final rule.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 43

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] GHG volumetric emissions. Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (u)(1) and (2) of this section[add: , with mole fraction of GHGs in the natural gas] determined by engineering estimate based on best available data unless otherwise specified.

(1) Estimate CH₄ and CO₂ emissions from natural gas emissions using Equation W-35 of this section.

[See original comment for Eq. W-35]

Where:

Es,i= GHG i (either CH₄ or CO₂) volumetric emissions at standard conditions in cubic feet.

Es,n= Natural gas volumetric emissions at standard conditions in cubic feet.

Mi= Mole fraction of GHGi in the natural gas.

(2) For Equation W-35 of this section, the mole fraction, Mi, shall be the annual average mole fraction for each facility, as specified in paragraphs (u)(2)(i) through (vii) of this section.

(i) GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities. If you have a continuous gas composition analyzer for produced natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then you must use your most recent gas composition based on available sample analysis of the field.

(ii) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer

overhead or dew point control for onshore natural gas processing facilities. If you have a continuous gas composition analyzer on feed natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in §98.234(b).

(iii) GHG mole fraction in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities [add: or the composition in §98.232(m)(1)].

(iv) GHG mole fraction in natural gas stored in underground natural gas storage facilities [add: or the composition in §98.232(m)(1)].

(v) GHG mole fraction in natural gas stored in LNG storage facilities [add: or the composition in §98.232(m)(1)].

(vi) GHG mole fraction in natural gas stored in LNG import and export facilities.

(vii) GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities [add: or the composition in §98.232(m)(1)].

(v) GHG mass emissions. Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions by converting the GHG volumetric emissions [add: at standard conditions] into mass emissions using Equation W-36 of this section.

[See original comment for Eq. W-36]

Where:

Mass s_i = GHG i (either CH₄[add: ,] [delete: or] CO₂ [delete: or N₂O]) mass emissions at standard conditions in metric tons CO₂e.

Es, i = GHG i (either CH₄[add: ,] [delete: or] CO₂ [delete: or N₂O]) volumetric emissions at standard conditions, in cubic feet.

ρ_i = Density of GHG i . Use 0.0538 kg/ft³ for CO₂ and N₂O, and 0.0196 kg/ft³ for CH₄ at 68 °F and 14.7 psia or 0.0530 kg/ft³ for CO₂ and N₂O, and 0.0193 kg/ft³ for CH₄ at 60 °F and 14.7 psia.

GWP = Global warming potential, 1 for CO₂, 21 for CH₄, and 310 for N₂O.

Response: EPA agrees with the commenter, and in this final rule, along with other amendments, EPA has modified 40 CFR 98.233 (u) introductory text and (v) accordingly.

In regard to the commenter's suggested changes to 40 CFR 98.233 (u)(2), EPA agrees with the provision of default values for methane and carbon dioxide. In this final rule, EPA is allowing the use of 95% methane and 1% carbon dioxide as default GHG mole fractions in natural gas for facilities in transmission compression, underground natural gas storage, LNG storage, LNG

import facilities, LNG export facilities if the export facility receives gas from transmission pipelines, and natural gas distribution. Please note that the use of 95% methane and 1% carbon dioxide as default GHG mole fractions only pertains to Subpart W and does not necessarily set agency precedent.

EPA disagrees with the commenter in regard to the reference to 98.233(m)(1) where the commenter suggested allowing for the use of company records. The November 2010 Final Rule allows the use of engineering estimate based on best available data, which includes company records among many other options, to determine the GHG mole fractions. Hence, EPA deems it unnecessary to specifically mention “company records” as a provision to determine the GHG mole fractions.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 49

Commenter Type: Industry - oil and gas

Comment: Revision: Under 98.233(u), EPA replaced field with sub-basin category. EPA clarified that the mole fraction of GHGs in the natural gas is determined by engineering estimate based on best available data unless otherwise specified. EPA also clarified that if you have a continuous gas composition analyzer, you must use an annual average of the values for determining the mole fraction. Otherwise, an annual average of the available sample analyses for the sub-basin category is used. EPA has also clarified the CH₄ and CO₂ compositions that should be used for the other industry sectors.

Comment: Several of the reporting categories that do not require reporting on a sub-basin basis direct you to 98.233(u)(2)(i) for GHG_i compositional analysis. EPA revised 98.233(u) to address issues with determining the appropriate gas composition. For production operations, EPA addressed the gas composition in terms of the sub-basin approach, as shown below. However, there is an inconsistency between 98.233(u)(2) and 98.233(u)(2)(i). 98.233(u)(2) refers to the average mole fraction for each sub-basin category or facility; while 98.233(u)(2)(i) requires the use of available analyses in each sub-basin category. The regulatory text is shown below:

(2) For Equation W–35 of this section, the mole fraction, M_i , shall be the annual average mole fraction for each sub-basin category or facility, as specified in paragraphs (u)(2)(i) through (vii) of this section.

(i) GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities. If you have a continuous gas composition analyzer for produced natural gas, you must use an annual average of these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then you must use an annual average gas composition based on available analyses in each of the sub-basin categories.

API requests that 98.233(u)(2)(i) allow for determining average gas composition analysis on

either a facility (basin) basis or sub-basin basis, whichever is more appropriate for the specific emission source category.

Response: EPA agrees with the amendments suggested by the commenter in 98.233(u)(2). In this final rule, EPA has clarified in 40 CFR 98.233 (u)(2) that gas mole fractions can be determined either at a sub-basin or facility level, as applicable to the emission source.

Section 7.3 - Emission factors tables

Commenter Name: Pamela A. Lacey

Commenter Affiliation: American Gas Association (AGA)

Document Control Number: EPA-HQ-OAR-2011-0512-0032

Comment Excerpt Number: 14

Commenter Type: Trade Association

Comment: Below Grade TD Stations: The proposed rule is not clear regarding how and whether to calculate emissions separately for below grade TD transfer stations and below grade metering-regulating stations. EPA does not provide an emission factor in Table W-7 for below grade TD transfer stations for calculating emissions in 98.233(r), although EPA does require emissions from below grade TD transfer stations to be reported separately under the proposed amendment to 98.236(c)(16)(.xvi). Conversely, in 98.233(r)(6)(i), below grade TD transfer stations are included with below grade metering-regulating stations suggesting they are to be calculated together and not separately. If EPA does want emissions from below grade TD transfer station to be calculated separately from metering-regulating stations, AGA suggests using the same emission factor for both below grade TD transfer stations and below grade metering-regulating stations.

Response: In this final rule, EPA is clarifying that below grade T-D transfer stations use the same emission factor as below grade metering-regulating stations. EPA is also requiring emissions to be reported for below grade T-D transfer stations separately from metering-regulating stations.

Commenter Name: Pamela A. Lacey

Commenter Affiliation: American Gas Association (AGA)

Document Control Number: EPA-HQ-OAR-2011-0512-0032

Comment Excerpt Number: 15

Commenter Type: Trade Association

Comment: Default Emission Factor for MR Stations at Companies with No TD Stations: A related question arises for a few companies that have no TD stations within the meaning of the Proposed Rule. Such companies will not have the option of leak surveying TD stations to develop a company-specific emission factor per metering-regulating run for their MR stations. The rule does not describe what these companies should do. A reasonable solution for this situation is to amend the rule to allow such companies to use the same default emission factor for

both above-ground and below-ground MR stations, based on inlet pressure. The equipment is essentially the same. The only difference is whether it is situated above or below ground.

Response: In this final rule, natural gas distribution reporters that do not own or operate T-D transfer stations must provide a count of above grade metering-regulating stations, but are not required to report emissions at these stations. EPA believes that the definition of T-D transfer station as finalized will capture almost all instances where a company transfers gas from a line at transmission pressure to a line operating at distribution pressure at an above ground facility.; please see response to EPA-HQ-OAR-2011-0512-0030, Excerpt 4 for further details. Hence, distribution companies that do not own or operate T-D transfer stations and only report activity data will not affect the overall quality of data used to inform future policy. If needed, EPA can use emission factors developed by other reporting entities in the region to estimate emissions from these metering-regulating stations.

Commenter Name: Pamela A. Lacey

Commenter Affiliation: American Gas Association (AGA)

Document Control Number: EPA-HQ-OAR-2011-0512-0032

Comment Excerpt Number: 7

Commenter Type: Trade Association

Comment: Use of GTI or Other Emission Factors for Meter-Regulating Stations

In AGA’s petition for reconsideration, we asked EPA to allow companies to use an updated emission factor for above ground metering and regulating stations based on the field testing performed recently by the Gas Technology Institute (GTI) at distribution facilities in the United States, rather than the default component leaker factors provided in Subpart W, which are based on data collected in Canada on facilities that are not subject to the same pipeline safety leak detection and repair requirements that apply to U.S. facilities. In the Proposal preamble, EPA states that

“although we are not proposing changes to the approach for applying emission factors to above ground metering-regulating stations in this action, we are seeking comment on alternative approaches, or data that may be used, for determining emissions factors for above ground metering –regulating stations. Based on comments received, EPA may consider future amendments to the rule.”

76 Fed. Reg. at 56,032.

We appreciate the agency’s willingness to consider other approaches. In the months since we submitted our petition for reconsideration, our members have been performing numerous leak surveys at their larger custody transfer stations. Even at these large facilities, they are finding the leak rates are extremely low. As described above, one of our members computed a company-specific, station-level emission factor of 0.64 metric tons (tonnes) per year per station, based on actual measured emissions. Using the default leaking component emission factors and adding these up for the average > 1 leaking component per station is likely to yield a somewhat

overstated per station emission factor, but we believe it will be good enough for all reasonable efforts at policy analysis and regulatory program design. AGA urges EPA to evaluate the data submitted for 2011 and 2012 station emissions, and use this data to calculate a default station-level emission factor for reporting emissions from both TD Stations and other metering-regulating stations in subsequent years. This will be a more robust data set than used in either the GTI or Canadian studies, and it will be up to date. Further, by applying the emission factor approach to TD stations as well as other metering-regulating stations, EPA can eliminate the burden of annual leak surveys, which is not justified when compared to the minimal emissions being found and reported at these facilities.

Response: EPA analyzed the report on field tests and measurements done by the Gas Technology Institute and determined that additional granularity in the data is required before any new distribution emission factors can be calculated. EPA found that although the GTI report collected a significant amount data on individual components and equipment, the data as presented, aggregated these sources together to create emissions factors by custody transfer, district regulator, or pressure limiting stations as a whole. In addition, the GTI sources do not map directly to the distribution segment sources as defined in Subpart W. To fully analyze the data, EPA determined it needs, amongst other details:

- (i) the descriptions of the stations where leak detection and measurement was conducted;
- (ii) the underlying data, including each emission measurement for each component; and
- (iii) a full description of each component.

Should this data become available, EPA may consider the information to develop new distribution emission factors.

EPA has retained the requirement for natural gas distribution reporters to conduct leak detection at T-D transfer stations. EPA determined that the use of leaker emissions factors (i.e. emission factors applied to components that are found to be leaking during a leak survey) will be a closer representation of actual emissions than a facility-level population emission factors. At this time, EPA deems this level of detail necessary to track changes in emissions from T-D transfer station and effectively inform policy.

Commenter Name: Pamela A. Lacey

Commenter Affiliation: American Gas Association (AGA)

Document Control Number: EPA-HQ-OAR-2011-0512-0032

Comment Excerpt Number: 8

Commenter Type: Trade Association

Comment: Emission Factors for Plastic Pipe

AGA is also concerned that the emission factors for distribution pipe – particularly for plastic pipe – vastly overstate actual emissions rates. As we describe in our petition for reconsideration, these old emission factors were developed over a decade ago by the Gas Research Institute (GRI) using data from testing a limited sample of equipment in work performed nearly 20 years ago.

GRI's study only included six locations. Although the study was supposed to identify locations with low leak rates, one of the six locations included in GRI's study was a faulty butt fusion on plastic pipe that was actively blowing gas and that had to be repaired immediately. This anomaly should have been omitted, but it was not. As a result, the GRI emission factor for plastic pipe – which EPA is using as the Subpart W default emission factor – overstates the actual emission rate for plastic pipe by over 300%. This is commonly known and understood, but the old plastic pipe emission factor is still being used because there is no updated emission factor available as yet.

However, this will soon change. GTI is performing field testing in 2011 and 2012 that will provide the data needed for an updated, more accurate emission factor for plastic pipe, based on a far more robust data set. GTI has presented its methodology to EPA's Natural Gas STAR staff along with the preliminary results of its study. We encourage EPA to evaluate the data when the study is complete, probably in fall 2012, and to initiate a proposed rule change to adopt the new, more accurate emission factor.

Response: EPA used the best publicly available data to develop emission factors for plastic pipelines. EPA supports studies conducted by all stakeholders to improve emission factors. EPA will review any new data that is made available and consider updating emission factor for plastic pipe in a future rulemaking.

Commenter Name: Ezra McCarthy

Commenter Affiliation: National Grid

Document Control Number: EPA-HQ-OAR-2011-0512-0046

Comment Excerpt Number: 3

Commenter Type: Industry - oil and gas

Comment: Emission Factors for Plastic Pipe

National Grid believes that the emission factors for distribution pipe – particularly for plastic pipe – vastly overstates actual emissions rates using old emission factors that were developed over a decade ago by the Gas Research Institute (GRI) using data from testing a limited sample of equipment in work performed nearly 20 years ago. GRI was only able to include six locations in its study and one of the six locations included in GRI's study was actively blowing gas, scenario not likely to exist without immediate attention in a distribution system. As a result, the GRI emission factor for plastic pipe – which EPA is using as the Subpart W default emission factor – overstates the actual emission rate for plastic pipe considerably. This is commonly known and understood, but the old plastic pipe emission factor is still being used because there is no updated emission factor available as yet.

GTI is performing field testing in 2011 and 2012 that will provide the data needed for an updated, more accurate emission factor for plastic pipe, based on a far more robust data set. We encourage EPA to evaluate the data when the study is complete, probably in fall 2012, and to initiate a proposed rule change to adopt the new, more accurate emission factor.

Response: Please see response to EPA-HQ-OAR-2011-0512-0032, Excerpt 8.

Commenter Name: Curtis J. Winner
Commenter Affiliation: New Mexico Gas Company (NMGC)
Document Control Number: EPA-HQ-OAR-2011-0512-0047
Comment Excerpt Number: 8
Commenter Type: Industry - oil and gas

Comment: In 98.236.c.15.ii.A EPA added 98.230(a)(8) to the list but did not include the appropriate Table, W-7, that goes with (a)(8).

The rule is confusing about how and whether to calculate emissions separately for below grade T-D transfer stations and below grade metering-regulating stations. EPA does not provide an emission factor in Table W-7 for below grade T-D transfer stations for calculating emissions in 98.233.r, although EPA does require emissions from below grade T-D transfer stations to be reported separately per the proposed amendment to 98.236.c.16.xvi. Conversely, in 98.233.r.6.i, below grade T-D transfer stations are included with below grade metering-regulating stations suggesting they are calculated together and not separately. If EPA does want emissions from below grade T-D transfer station to be calculated separately from metering-regulating stations, should the same emission factor be used for below grade T-D transfer stations and below grade metering-regulating stations?

Response: In this final rule, EPA is clarifying that below grade T-D transfer stations use the same emission factor as below grade metering-regulating stations. Also, as proposed in the September 2011 Proposal, EPA is finalizing the requirement for emissions to be reported for below grade T-D transfer stations separately from below grade metering-regulating stations.

Commenter Name: Lisa Beal
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2011-0512-0029
Comment Excerpt Number: 60
Commenter Type: Trade Association

Comment: TABLES – APPARENT ERROR IN TABLE W-4

There appears to be a heading in Table W-4 that is not appropriate. The third bold heading in the table states, “Leaker Emission Factors—Storage Station, Gas Service”. It appears that this heading should be deleted and the following line that present a component emission factor (“open ended line..... 0.03”) should be merged with the previous section under the second heading, “Population Emission Factors—Storage Wellheads, Gas Service”.

Response: EPA is not clear on the issue that the commenter has stated. First, the third line in the Table W-4 is “Population Emission Factors-Other Component, Gas Service” and not “Leaker Emission Factors—Storage Station, Gas Service” as stated by the commenter. Second, EPA did

not revise the emission factor for “open ended line”, hence, EPA has determined that no change is required for this comment.

Section 7.4 - Calculating Greenhouse Gas Emissions

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 26

Commenter Type: Trade Association

Comment: Onshore production wells can use default component counts when estimating equipment leaks from wellheads. The underground storage sector should be afforded the same flexibility and be allowed to use default component counts for storage wells.

Onshore production wells can use default component counts for wellheads based on information in Tables W-1B and W-1C. Default component counts are not allowed for storage wells.

Similar to production wells, an underground storage field may include many wells dispersed over a broad area. In addition, these wells are often identically designed and constructed, and will typically be low emitters. The underground storage sector should be afforded the same flexibility as production and be should be allowed to use default component counts for storage well emission estimates.

Rather than counting components at every wellhead, defaults based on engineering judgment should be allowed, with the methodology explained in the Monitoring Plan. For example, if a storage field contains many wells with similar design and construction, component counts from a subset of the wells could be used to define the default values for other wells. This methodology would be documented in the Monitoring Plan and would provide a reasonable estimate of storage well components and associated emissions. In fact, the component count uncertainty would be much lower than the emission factor uncertainty.

Response: EPA disagrees that underground natural gas storage reporters should be allowed to use average component counts for wellheads or engineering estimates. EPA allowed the use of average component count in onshore petroleum and natural gas production because of the large number of wells that several reporters will have to visit to conduct a thorough component count. Underground natural gas storage reporters may have geographically dispersed wells, but do not have as many wells as onshore petroleum and natural gas production reporters. Therefore, the burden is not comparable, and reporters must comply with the requirements of 40 CFR 98.233(q). Hence, this final rule has retained the monitoring requirements from the November 2010 final rule for underground storage reporters.

Section 7.4.1 - Calculating GHG Emissions (non equipment specific)

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 53

Commenter Type: Industry - oil and gas

Comment: These amendments include changes to many of the equations in Subpart W. For the equations that have been modified, EPA has added upper and lower bounds to most of the equations with a summation. However, Equation W-32 was modified in these amendments, but the summation limits are not defined. In addition, several other equations were not modified and do not include upper and lower limits on the summations: Equations W-7, W-13, W-23, W-24, W-27, W-28 and W-39. For clarification, API requests that EPA provide the proper notation for the summations in these equations.

Response: EPA agrees with the commenter on issues with Equations W-32, W-7, W-13, and W-39A (W-39 in The November 2010 Final Rule). In this final rule, EPA is removing the summation operator from Equation W-32 to make it mathematically accurate. Additionally, EPA is modifying Equations W-7, W-13, and W-39A to include upper and lower limits on the summations, among other amendments.

Regarding Equations W-23, W-24, W-27, and W-28, amendments to these equations were not proposed and hence, these equations are outside the scope of this rule. EPA may consider your comment in future rulemakings. Additionally, your question relates to an issue or issues currently the subject of ongoing litigation. Please monitor the website for any additional guidance that may be available in the future.

<http://www.epa.gov/climatechange/emissions/subpart/w.html>

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 9

Commenter Type: Industry - oil and gas

Comment: Gas Compressibility

On page 56031 of the September 9, 2011 preamble, EPA raised the issue of factors, such as compressibility, which could impact emissions from blowdowns. EPA states, “We have considered accounting for gas compressibility but have not proposed this because we believe that the effort in adjusting for a compressibility factor outweighs the benefits in terms of increased accuracy.”

EPA goes on to state, “EPA seeks comments on why such an allowance should be provided and

how to standardize this option so that those who choose to use it all do so in the same way.”

API Response:

API supports EPA’s position that accounting for gas compressibility is not important under typical conditions and thus not warranted for GHG reporting. There are various industry methodologies for compressibility correction factors for mixed gases, and no simple (consensus) approaches exist to mathematically describe how it varies with gas composition and other deviations from ideal gas behavior.

Response: EPA thanks the commenter for their remarks.

Section 7.4.2 - Data Reporting Requirements (non equipment specific)

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 2

Commenter Type: Industry - oil and gas

Comment: Unique name ID for specified units

EPA added requirements to report a unique name or ID number for each AGR unit, each glycol dehydrator, each blowdown vent stack, each wellhead gas-liquid separator, each flare stack, EOR injection pump blowdowns, and each transmission storage tank.

API Response:

API’s member companies insist strongly that the requirements to develop and report certain Subpart W affected equipment through the use of unique identifier information at the individual equipment level:

- were not contemplated or proposed in previous proposals,
- have not been subject to comment previously, and are unnecessarily onerous,
- add substantial costs that were not analyzed nor disclosed in the economic impact analysis,
- do not deliver benefits commensurate with the costs, and
- are contrary to the original scope and intent of the Greenhouse Gas Reporting Program (GHGRP) and its varying provisions for the different subparts as applicable to specific sectors.

This is particularly an issue for wellhead gas-liquid separators with oil throughput greater than or equal to 10 bbls per day. For this source type, EPA has added the requirement to “report the following by sub-basin category, unless otherwise specified” (emphasis added). 98.236(c)(8)

goes on to add reporting requirements under paragraphs (J), (K), (L), and (M) that are specified for each separator and not the aggregate of separators as in the existing rule language. These reporting requirements are contrary to EPA's previously stated goal of their intent to "reduce reporting burden." The introduction of these new reporting requirements for gas-liquid separators, which have no impact on the current emissions inputs or data quality, under the heading of "Technical Revisions" is clearly contradictory to industry's efforts to work with EPA to complete an accurate GHG inventory within a manageable reporting burden and resources.

The entire concept of basin level reporting for onshore petroleum and natural gas production was justified by EPA through its desire to achieve adequate coverage of the onshore production sector and its economic impact analysis and the concept of reducing burden by handling the vast number of sources as grouped source types rather than discrete emission sources. EPA should not include or imply individual tracking and reporting for separators that are currently reported as total counts or average emissions information. The requirement for creating unique identifiers for individual separators is inconsistent with aggregating equipment and emissions within a basin or sub-basin as currently required in the rule. This proposed change in effect eliminates the benefits from handling separators in the production sector at the sub-basin level, which API previously supported, and fundamentally changes API's acceptance of this approach.

For separators, the throughput, existence, and site-specific functionality (wells they service) can vary or change greatly depending on production scenarios throughout the year. Some sites have multiple separators that may change or be used differently throughout the year, so assigning a unique number on a specific separator and tracking for a whole year does not add clarity or value. API and its members strongly urge that EPA reconsider its proposal and remove this requirement upon promulgation.

For the other equipment types that EPA is proposing to require assigning a unique name or ID number (AGR units, glycol dehydrator, blowdown vent stacks, flare stacks, EOR injection pump blowdowns, and transmission storage tanks), the current level of reporting already relies on individual component counts and equipment inventories that apply to EPA specified calculations. Creating unique equipment identifiers neither adds to the level of accuracy of calculated emissions, nor does it provide information that is not already available through the currently reported individual equipment counts and reported CO₂ and CH₄ emissions totals that are already part of the GHGRP.

API further contends that the identifier data requested by EPA will not be usable at the individual equipment level due to the dynamic nature of the sector and the fact that the identifiers may be tied to well names or locations and hence be different every year due to frequent equipment movement, change-outs and replacements that routinely occur at Oil and Gas well sites. For example, flaring during drilling or completion operations uses either portable flares or open-ended pipe which is moved to new drilling/completion operations. A unique name or ID for the "flare" is meaningless in this situation.

This requirement would lead to the expenditure of unnecessary time and resources to create identifiers, which serve no other purpose than to specifically identify equipment that is already

called out and accounted for within the current GHGRP process.

Response: Firstly, it is important to note that the reporting of unique ID does not impose a new requirement for unit-level reporting. The 2010 final rule required that emissions be reported for EACH [emphasis added] AGR (98.236(c)(3)), each glycol dehydrator (98.236(c)(4)), each blowdown vent stack (98.236(c)(7)), each transmission storage tank (98.236(c)(9)), each flare (98.236(c)(12)), and each EOR injection pump (98.236(c)(17)). Therefore, under the 2010 final rule, facilities in practice would have to collect emissions for each piece of equipment, and then report separately for each piece of equipment. The clarification made by EPA was just to generate a link between a specific piece of equipment and its emissions.

Although EPA had intended for emissions be reported for each storage tank in the 2010 final rule, we can see how the lack of clarity in the reporting requirement for storage tank (98.236(c)(8)) which required emissions reporting for Calculation Methodology 1 and Calculation Methodology 2, could have been interpreted so as to not require separator specific reporting. In this final rule EPA is clarifying that all the reporting requirements for Calculation Methodologies 1 and 2 for onshore production storage tanks must be reported at a sub-basin category level, which is consistent with the sub-basin level change made to the onshore petroleum and natural gas production industry segment.

Based on this, we are finalizing, as proposed, reporting of unique name or ID for all segments, except for onshore production. EPA agrees that for the onshore production segment, a unique name or ID number may be difficult to assign for portable equipment that may move from one location to another. In this final rule, EPA is not requiring unique name or ID number in onshore production. EPA recognizes that removing this requirement for onshore production could potentially result in the loss of equipment-specific information that could be useful for future policy analysis and we may continue to evaluate this for future rulemaking. For further details on the unique ID issue, please see preamble Section II.C.3 - Final Amendments to the Petroleum and Natural Gas Systems Source Category – Major Changes Since Proposal – 2. Data Reporting Requirements; and Section II.D.3 –Response to Major Comments on the Petroleum and Natural Gas Systems Source Category.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 5

Commenter Type: Industry - oil and gas

Comment: Feasibility of Reporting 2011 Data under Amended Rule

On page 56020 of the preamble, EPA states, “for subpart W, reporters would be expected to calculate emissions and other relevant data for the reports that are submitted in 2012 using part 98, as amended by this rule, as finalized. We have determined that it is feasible for the sources to implement these changes for the 2011 reporting year since the proposed revisions primarily provide additional clarifications or flexibility regarding the existing regulatory requirements, generally do not affect the type of information that must be collected, and do not substantially

affect how emissions are calculated.”

API Response:

API and its members have been working with EPA staff over the past year to revise and correct a myriad of technical issues and mistakes that pervaded the Subpart W rule as promulgated on November 30, 2010. API and its members welcome most of the changes proposed by EPA and agree that the technical corrections in this proposed action are based to a large extent on technical issues raised by industry along with specific requests for reconsideration. API concurs that EPA’s final action on the ability to use best available monitoring methods (BAMM) for all of calendar year 2011 data [Footnote 6: On September 16, 2011, Administrator Jackson signed a rule that finalized amendments to the best available monitoring methods (BAMM) provisions in subpart W. <http://www.epa.gov/climatechange/emissions/subpart/w.html>] provides reporters the needed flexibility and time to implement these new requirements. However, there are still many issues in need of resolution, which is creating uncertainty for calendar year 2011 data collection and reporting. Some pertinent examples with specific comments and requests include:

- Expanded reporting requirements for gas-liquids separators – As indicated in Comment A above, EPA has significantly expanded the reporting requirements for each gas-liquid separator with oil throughput greater than or equal to 10 bbls per day.
- Completions and workovers with hydrofracing - For Methodology 1 data collection it would be best for EPA to specifically allow the use the data collected in 2012 for reporting for the 2-year period that includes the 2011 and 2012 calendar years. The rule allows the use of representative data for a period of 2-years, and this approach will be best for implementing the final sub-basin categories once promulgated.
- Liquids Unloading – The same considerations would apply for implementing the sub-basin categories for this source type. Here again API requests that EPA specifically allow the use of data collected in 2012 for the 2-year period of 2011 and 2012.
- Oil Production – EPA is yet to propose and seek comment on a sub-basin category approach for oil production. As addressed in comments W.25 [EPA-HQ-OAR-2011-0512-0042, Excerpt 41] and W.26 [EPA-HQ-OAR-2011-0512-0042, Excerpt 42] below, API proposes that oil production be classified as a fifth sub-basin category, in addition to the four sub-basins identified for gas production. Until this is incorporated into the rule, it remains another area of uncertainty that would require special considerations for 2011 reporting.
- Use of unique name or ID – This requirement has been introduced in this proposal under the banner of a technical revision, but as stated in Comment A above, it has far greater ramifications and potential burden for the regulated industry. If EPA were to finalize this requirement as proposed, it will be impossible in 2011 to:
 - implement a system of assigning unique names or IDs to the vast number of individual pieces of equipment;
 - implement a system to collect data for each piece of equipment; and
 - implement a system to track each piece of equipment.

Moreover, EPA itself recognizes in Table 2 of the September 9, 2011 preamble that several issues from API’s (and other organization’s) Petitions for Reconsideration were not yet addressed. Likewise, additional technical errors and recommended corrections are provided in

the Technical Comments Section below.

Resolution of all of these pending issues is essential to allowing reporters to provide EPA with high quality GHG emissions data. API and its members request that EPA take into account the lateness in the calendar year of promulgating all of the referenced changes, and allow additional flexibility when approving BMM requests beyond 2011.

Response: EPA agrees with the commenter with regards to reporting requirements for wellhead gas-liquid separators and is modifying this final rule accordingly. Regarding the comment on the requirement for a unique name or ID, in this final rule, EPA is not requiring unique name or ID for the onshore production segment. For more details on these two issues, please see response to EPA-HQ-OAR-2011-0512-0042, Excerpt 2.

EPA is allowing reporters to use 2012 data for reporting of emissions from well completions/workovers and well liquids unloading for reporting year 2011. For further details, please see preamble Section II.D.7 – Response to Major Comments on the Petroleum and Natural Gas Systems Source Category.

EPA added oil formations to the sub-basin category definition in 40 CFR 98.238 and clarified the reporting of sources under this formation for 2011. For the response on the Addition of Oil formation definition in the sub-basin category definition, please see preamble Section II.C - Final Amendments to the Petroleum and Natural Gas Systems Source Category - Major Changes Since Proposal – 3. Definitions; and Section II.D.9 – Response to Major Comments on the Petroleum and Natural Gas Systems Source Category.

As indicated in its September 9, 2001 proposal, EPA has granted only limited reconsideration of specific issues contained in various Petitions for Reconsideration and will consider the remaining issues at a later point in time. EPA points out that we are allowing the use of BMM as provided in the Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems: Revisions to Best Available Monitoring Method Provisions (76 FR 59533), where applicable.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 55

Commenter Type: Industry - oil and gas

Comment: Revision: EPA revised the reporting for offshore petroleum and natural gas to require reporting emissions individually for all source types listed in the most recent BOEMRE study. Previously, the rule required reporting as set forth by BOEMRE in 30 CFR 250.302 through 304.

Comment: For consistency with existing regulatory reporting requirements, API requests that EPA reverse the decision and reinstate reporting for offshore petroleum and natural gas production as set forth by BOEMRE in 30 CFR 250.302 through 304.

Response: EPA disagrees with the commenter. The BOEMRE data reporting is for activity data by platforms, not emissions estimates. The emissions estimates are provided by BOEMRE in a report subsequent to data collection from platforms. Therefore, the November 2010 final rule was unclear on what information needs to be reported. Hence, we are finalizing, as proposed, reporting of emissions by gas type and emission source type, as listed in the most recent BOEMRE study.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 68

Commenter Type: Industry - oil and gas

Comment: Revision: EPA has added a requirement to report average API gravity, average gas to oil ratio, and average low pressure separator pressure for each sub-basin category. On page 56034 of the September 9, 2011 preamble EPA contends that this information is already known to reporters, and it plans to use these facility sub-basin characteristics to characterize other emissions sources across different sub basins.

Comment: This information is not available or appropriate for broader applications to each of the sub-basin categories. For example, dry gas production areas, such as coal-bed methane, will not have API gravity or gas to oil ratios to report for a sub-basin.

API interprets this reporting requirement as applicable only to the oil production sub-basin category proposed for addition by API. Only this sub-basin category is consistent with the preamble language, which indicates that this information is readily available.

For the oil production sub-basin category, this requirement should only apply to separators with oil throughput greater than or equal to 10 barrels per day, as it is only for these operations where this information is available. API also interprets the requirement to report the low pressure separator pressure to refer only to the separator pressure in those instances where the separator oil composition is sampled and analyzed.

Response: EPA agrees that reporting of average API gravity, average gas to oil ratio, and average low pressure separator pressure only applies to oil formation sub-basin categories. Please see preamble Section II.D.2 – Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category, for the response on data reporting requirements of 98.236(e).

However, EPA disagrees that this requirement should only apply to separators with oil throughput greater than or equal to 10 barrels per day. As stated in this final rule, reporters must report average values for these requirements on a sub-basin category level, specifically oil formation sub-basin category, using best available estimates. These requirements are not to be reported on an equipment or emission source type level.

Section 7.5 - Natural Gas Pneumatic Device Venting

Commenter Name: William W. Grygar II

Commenter Affiliation: Anadarko Petroleum Corporation

Document Control Number: EPA-HQ-OAR-2011-0512-0028

Comment Excerpt Number: 5

Commenter Type: Industry - oil and gas

Comment: Under §98.233(a) and (c), EPA has allowed reporters to use the total number of hours that the devices/pumps were operational to estimate emissions, rather than the total hours in a year. Anadarko supports this change, but requests that a revision be made to clarify that the time used is an estimated average time for the basin; actual operating hours are extremely burdensome to collect and not readily tracked. An appropriate estimate of operating time of these devices and pumps is the well operating time, which is readily available.

Response: EPA agrees with the commenter. In this final rule, EPA is modifying the parameter T_t and T in Equations W-1 and W-2 respectively, to allow reporters to estimate the average number of hours in the operating year the devices (of type t)/pumps are operational. Additionally, EPA is providing 8760 hours as a default values for these parameters.

Commenter Name: William W. Grygar II

Commenter Affiliation: Anadarko Petroleum Corporation

Document Control Number: EPA-HQ-OAR-2011-0512-0028

Comment Excerpt Number: 6

Commenter Type: Industry - oil and gas

Comment: Anadarko supports the proposed addition under §98.233(a)(2) that the type of pneumatic device be determined using engineering estimates based on best available information.

Response: EPA thanks the commenter for their remarks.

Section 7.5.1 - Calculating GHG Emission [W-1]

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 12

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] Pneumatic controller operating hours: The Proposed Rule adds annual operating hours as a parameter in

Equation W-1. Operators should be allowed to assume 8760 operating hours, with actual hours used at the operator's discretion.

Equation W-1 in §98.233(a) calculates emissions from pneumatic controllers. The Proposed Rule revises the equation to add a new parameter "T", which is defined as, "The total number of hours in the operating year that the devices were operational." Previously, Equation W-1 assumed continuous operation for the entire year – i.e., 8760 annual operating hours. In addition to substituting "controllers" for "devices" per the previous comment, INGAA strongly recommends that Subpart W clearly indicate that 8760 hours can be assumed as a default value for "T". The proposed revision will have a minimal impact on inventory estimate accuracy, and in many cases operators have already set up reporting programs based on the 8760 operating hour assumption. EPA should not add unnecessary costs and complications by mandating that annual operating hours is defined for pneumatic controllers. INGAA recommends that Subpart W include the following revisions for the description of "T" in the list of variable that follows Equation W-1:

"T = Total [delete: number of] [add: annual operating] hours for [delete: in the operating year] the [add: controllers] [delete: devices were operational]. [add: 8760 annual operating hours can be used as a default assumption.]"

Response: EPA agrees with the commenter with regards to providing a default value of 8760 hours for parameter "T" in equation W-1 of 40 CFR 98.233(a). For additional changes to parameter "T_i" and "T" in Equations W-1 and W-2, please see the response to EPA-HQ-OAR-2011-0512-0028, Excerpt 5.

EPA disagrees with the commenter with regards to substituting "controllers" for "devices" in parameter "T". Please see the response to EPA-HQ-OAR-2011-0512-0029, Excerpt 11.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 3

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] INGAA supports Proposed Rule revisions that allow default or standard facility-wide concentrations for natural gas composition for the transmission compression and underground storage segments. However, the Proposed Rule still contains conflicts and inconsistencies that need to be resolved.

In Table 2 of the preamble, EPA indicates that the Proposed Rule addresses INGAA's request to allow operators in natural gas transmission and storage to use a default gas composition and consistently apply the assumed gas composition for all emission estimates. INGAA supports this objective, but conflicting requirements remain, and additional revisions are needed. In addition, refer to Comment 20 regarding general issues associated with emission estimates and the lack of clarity that results from inconsistent approaches for converting from volumetric emissions (i.e., volume of natural gas) to volume and mass of CH₄, CO₂ and CO_{2e} emissions.

INGAA requested that transmission, storage, and distribution operations be allowed to use either a default natural gas CH₄ and CO₂ composition, or a single assumption based on a facility gas analysis. Subpart W currently stipulates different assumptions for different sources within a facility. Proposed Rule revisions in §98.233(u)(2) address the intent of INGAA's request. However, §98.233 individual source sections still contain conflicts. To enhance rule clarity and simplicity, EPA should address this issue throughout Subpart W as recommended in Comment 20. INGAA's recommendations to address the issue for the natural gas transmission compression and underground storage segments within the applicable §98.233 subsections follow:

In §98.233(a), parameter GHG_i inappropriately references §98.233(u)(2)(i), which is for production. The parameter should be revised to reference the general section as follows (or alternatively, to reference (u)(2)(iii) and (iv) for transmission and storage, respectively):

"GHG_i = [delete: For onshore petroleum and natural gas production facilities, onshore natural gas transmission compression, and underground natural gas storage, c] [add: C]oncentration of GHG_i, CH₄, or CO₂, in natural gas as defined in paragraph (u)(2) [delete: (i)] of this section.

Response: EPA disagrees with the commenter with regards to the citation (u)(2)(i) in parameter GHG_i in Equation W-1 being incorrect. The emission factors for pneumatic devices for segments other than onshore production are in total hydrocarbon units. Hence, the blanket allowance of applying 95% methane and 1% carbon dioxide to a facility will be incorrect. In this final rule, for onshore production facilities, GHG_i refers to (u)(2)(i) and for onshore natural gas transmission compression and underground natural gas storage, GHG_i for CH₄ = 0.975 and GHG_i for CO₂ = 1.1*10⁻².

EPA disagrees with standardizing calculations as suggested in Comment 20 submitted by the commenter. Please see the response to EPA-HQ-OAR-2011-0512-0029, Excerpt 27.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 35

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket]
§ 98.233 Calculating GHG emissions.

[highlighted text: Clarifications in 98.33(a), (e), (i), (k), (o) and (p); minor changes to (q), (r), (t), (u), (v) for consistency]

...

(a) Natural gas pneumatic device venting.

[highlighted text: Clarify that best available information and engineering judgment can be used

to define high vs low bleed; also address definition (and provide examples) for intermittent devices [see revision to 98.6 and recommended paragraph for preamble with examples].]

Calculate CH₄ and CO₂ emissions from continuous high bleed, continuous low bleed, and intermittent bleed natural gas pneumatic devices using Equation W-1 of this section.

[See original comment for Eq. W-1]

Where:

Mass s_i = Annual total mass GHG emissions in metric tons CO₂e per year at standard conditions from a natural gas pneumatic device vent, for GHG i .

Count = Total number of continuous high bleed, continuous low bleed, or intermittent bleed natural gas pneumatic devices of each type as determined in paragraph (a)(1) of this section. [add: The count shall be based on best available information or engineering judgment with the approach described in the monitoring plan required under §98.3(g)(5) and does not require bleed rate measurement to define device type.]

EF = Population emission factors for natural gas pneumatic device venting listed in Tables W-1A, W-3, and W-4 of this subpart for onshore petroleum and natural gas production, onshore natural gas transmission compression, and underground natural gas storage facilities, respectively.

GHG _{i} = For onshore petroleum and natural gas production facilities, concentration of GHG i , CH₄ or CO₂, in produced natural gas; for facilities listed in §98.230(a)(3) through (a)(8), GHG _{i} equals 1 [add: or the gas composition allowed per §98.232(m).]

Convi = Conversion from standard cubic feet to metric tons CO₂e; 0.000410 for CH₄, and 0.00005357 for CO₂.

24 * 365 = Conversion to yearly emissions estimate.

...

Response: EPA agrees with the commenter with regards to clarifying the use of an engineering estimate based on best available data to determine the type of pneumatic device. In this final rule, EPA is adding clarification language in section 40 CFR 98.233(a)(3) and not in the definition of the parameter “Count” as suggested by the commenter.

EPA disagrees with the commenter with regards to changes in definition of parameter “GHG _{i} ”. Please see response to EPA-HQ-OAR-2011-0512-0029, Excerpt 3 for further details.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 9

Commenter Type: Trade Association

Comment: As discussed below in Comment 20, if common approaches are implemented for converting from natural gas volumetric emission estimates in §98.233(a) – (r) to CO₂ and CH₄ volumetric and mass emissions, these conflicts can be avoided. §98.233(i) and (k) provide examples of this approach.

Response: EPA disagrees with standardizing calculations as suggested in Comment 20 submitted by the commenter. Please see the response to EPA-HQ-OAR-2011-0512-0029, Excerpt 27.

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 16

Commenter Type: Industry - oil and gas

Comment: C. § 98.233 Calculating GHG Emissions

(1) Natural gas pneumatic device venting, § 98.233(a). The requirement to report emissions from pneumatic devices, 40 C.F.R. § 98.233(a), is vague in the final rule. Subpart W requires conducting a total count of pneumatic devices within three calendar years and classifying each device according to its bleed rate. EPA required conducting a count of pneumatic devices in order to reduce the burden on reporters, while still meeting the necessary data quality to inform EPA's policies. 75 Fed. Reg. 74,470 (Nov. 30, 2010).

Subpart W states that high-bleed pneumatic devices are those that vent continuously to the atmosphere at a rate in excess of 6 scf/hr, whereas low-bleed pneumatic devices are those that bleed at rates equal to or less than 6 scf/hr. However, the final rule does not clarify how industry must determine whether a device's bleed rate exceeds 6 scf/hr or not. Without explaining how to determine a device's bleed rate, it is unclear whether a reporter must rely on the manufacturer's bleed rate data, whether direct measurements are required at each individual pneumatic device, or if some other method should be used.

To rectify this problem, the proposed rule directs that all industry segments must "determine the type of pneumatic device using engineering estimates based on best available information." 76 Fed. Reg. 56,040. Chesapeake and AXPC support this proposed clarification because it provides the necessary explanation of how reporters are expected to determine what devices have high bleed rates versus low bleed rates, as is needed to comply with the rule.

Separately, EPA has proposed modifying Eq. W-1 and Eq. W-2 "to include a parameter 'T' that

estimates the total number of hours [pneumatic] devices were operational.” 76 Fed. Reg. 56,029. We support this proposal because it will increase accuracy in the emissions reported from leaking pneumatic devices and pumps.

Response: EPA thanks the commenter for their remarks. For additional changes to parameter “ T_i ” and “ T ” in Equations W-1 and W-2, please see the response to EPA-HQ-OAR-2011-0512-0028, Excerpt 5.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 24

Commenter Type: Industry - oil and gas

Comment: Revision: EPA added a time term to equation W-1 to account for the duration the device is operational for the reporting year. T is defined as “Total number of hours in the operating year the devices were operational.”

Comment: The term “ T ” should refer to an estimated average annual time for all the devices or allow the use of 8760 hours. An estimate of the time is consistent with the preamble language stating “EPA is also proposing to amend Equation W-1 to include a parameter ‘ T ’ that estimates the total number of hours the devices were operational” (emphasis added).

Further for this equation, the term “ $Mass_{s,i}$ ”, does not need the subscript “ s ”, and the definition does not need “at standard conditions” as mass does not change based on temperature and pressure. API also requests the term $Mass_{s,i}$ be revised to “mass per type of device” for the different pneumatic device types.

The term GHG_i refers to “onshore petroleum and natural gas production facilities” and references paragraph (u)(2)(i), which is defined as “sub-basin”. However, to be consistent with this equation and the methodology for compiling pneumatic device counts, GHG_i should be representative of all the wells in the basin with a particular device type and not aligned with a sub-basin. Revisions to 98.233(u)(2)(i) to address this are provided in comment W.33 [EPA-HQ-OAR-2011-0512-0042, Excerpt 49].

Response: EPA agrees with the commenter with regards to parameters “ T_i ” and “ $Mass_i$ ”. In this final rule, these parameters are being modified accordingly.

EPA agrees with the commenter with regards to parameter “ GHG_i ”. For the response about clarifying the use of 98.233(u)(2)(i) on either a facility (basin) basis or sub-basin basis, as per the specific emission source type, please see the response to EPA-HQ-OAR-2011-0512-0033, Excerpt 17.

Commenter Name: Karin Ritter
Commenter Affiliation: American Petroleum Institute (API)
Document Control Number: EPA-HQ-OAR-2011-0512-0042
Comment Excerpt Number: 25
Commenter Type: Industry - oil and gas

Comment: Revision: EPA added 98.233(a)(3), which states: “For all industry segments, determine the type of pneumatic device using engineering estimates based on best available information.

Comment: API supports this revision.

Response: EPA thanks the commenter for their remarks.

Commenter Name: Curtis J. Winner
Commenter Affiliation: New Mexico Gas Company (NMGC)
Document Control Number: EPA-HQ-OAR-2011-0512-0047
Comment Excerpt Number: 4
Commenter Type: Industry - oil and gas

Comment: Pneumatic Device Venting

NMGC supports EPA’s amendment to 98.233.a to allow the type of pneumatic devices to be determined using engineering estimation based on best available information.

Response: EPA thanks the commenter for their remarks.

Section 7.5.2 - Data Reporting Requirements

Commenter Name: Lisa Beal
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2011-0512-0029
Comment Excerpt Number: 13
Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] Pneumatic controller reporting in §98.236(c)(1) for transmission and storage sectors should simply require the pneumatic controller type by count. INGAA recommended rule text is provided.

In its June 2011 letter, INGAA recommended revisions to §98.237(c)(1) reporting requirements. It appears that EPA is trying to differentiate reporting obligations for other sectors where different options are available for obtaining pneumatic controller counts. If so, that delineation

should be defined in a separate subsection for the sector of interest. For natural gas transmission compression and underground storage, controller count by type and emissions reporting are all that is warranted. INGAA reiterates recommended rule text for §98.236(c)(1) provided in June 2011:

"(1) For natural gas pneumatic controllers devices (refer to Equation W–1 of §98.233), report the following:

(i) [delete: Actual c] [add: C]ount [delete: and estimated count separately] of natural gas pneumatic high bleed [add: controllers] [delete: devices as applicable].

(ii) [delete: Actual c] [add: C]ount [delete: and estimated count separately] of natural gas pneumatic low bleed [add: controllers] [delete: devices as applicable].

(iii) [delete: Actual c] [add: C]ount [delete: and estimated count separately] of natural gas pneumatic intermittent bleed [add: controllers] [delete: devices as applicable].

(iv) Report emissions collectively [add: for all pneumatic controllers]."

It appears that reference to "actual" or "estimated" counts is intended for the onshore production segment where requirements are phased in over multiple years. More straightforward criteria apply to transmission and storage, and reporting based on production criteria could cause confusion. If necessary, EPA should provide separate subsections in §98.236(c)(1) to clearly identify segment-specific criteria.

Response: EPA disagrees with the commenter with regards to changes to the data reporting requirements for natural gas pneumatic devices. Please see the response to EPA-HQ-OAR-2011-0512-0029, Excerpt 63 for further details.

EPA disagrees with the commenter on replacing “devices” with “controllers”. Please see the response to EPA-HQ-OAR-2011-0512-0029, Excerpt 11 for further details.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 63

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] § 98.236 Data reporting requirements.

(1) For natural gas pneumatic devices (refer to Equation W–1 of §98.233), report the following:

(i) [delete: Actual c] [comment bubble JMc11: Reference to “actual” deleted for consistency with language added in 98.233(a) regarding “best available info” for defining device type. In

addition, §98.233(a) criteria clearly identify differences allowed for device counts for different segments.] [add: C]ount [delete: and estimated count separately] of natural gas pneumatic high bleed devices [delete: as applicable].

(ii) [delete: Actual c] [add: C]ount [delete: and estimated count separately] of natural gas pneumatic low bleed devices [delete: as applicable].

(iii) [delete: Actual c] [add: C]ount [delete: and estimated count separately] of natural gas pneumatic intermittent bleed devices [delete: as applicable].

(iv) Report emissions collectively [add: for all pneumatic devices].

Response: EPA does not agree with the commenter with regards to changes to the data reporting requirements for natural gas pneumatic devices. In this final rule, EPA is finalizing the reporting of “actual” and “estimated” counts separately for different types of natural gas pneumatic devices, as applicable. The text “as applicable” implies that reporters must follow the requirement of “actual” versus “estimated” only if it is applicable to their facility, i.e., if they report under onshore petroleum and natural gas production consistent with 40 CFR 98.233(a)(1). Onshore production facilities are allowed to count their pneumatic devices over a three year period. Hence, for each year they may have an actual count and an estimated count, where an actual count is not available. For reporters with facilities where it is not applicable, i.e., if they report under onshore transmission compression and underground natural gas storage, reporters must report the actual count of each type of pneumatic device, consistent with 40 CFR 98.233(a)(2) and (a)(3). “Actual” count does not refer to the engineering estimate based on best available information.

EPA disagrees with the commenter with regards to reporting the emissions from all pneumatic devices collectively. The Calculation Methodology in 40 CFR 98.233(a) calculates CO₂ and CH₄ emissions from each type of pneumatic device at a facility level. Consistent with this Calculation Methodology, EPA is finalizing the reporting of CO₂ and CH₄ emissions from each type of pneumatic device at a facility level.

Section 7.6 - Natural Gas Driven Pneumatic Pump Venting

Section 7.6.1 - Calculating GHG Emission [W-2]

Commenter Name: Vince Alaimo

Commenter Affiliation: Marshall Miller & Associates Inc. on behalf of Consol Energy Inc.

Document Control Number: EPA-HQ-OAR-2011-0512-0036

Comment Excerpt Number: 4

Commenter Type: Trade Association

Comment: Natural Gas Driven Pneumatic Pump

•EPA is also proposing to amend Equation W-2, to include a parameter “T” that estimates the total number of hours the devices were operational. Previously, this equation assumed that all natural gas pneumatic devices were operational all year, which would overestimate the emissions where the pneumatic devices operate less than a full year. These amendments to Equation W-2 will more accurately reflect operating conditions for natural gas pneumatic device venting

Comment 3

In many cases the time the devices are operational is not recorded in which Consol Energy proposes a default value be allowed of 8260 hours.

Response: EPA disagrees with the commenter as no justification for the value of “8260 hours” is given. However, EPA assumes that the commenter intended for the default hours to be “8760” and not “8260” and is providing the option to use 8760 default hours of operation in Equation W-2.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 26

Commenter Type: Industry - oil and gas

Comment: Revision: EPA added a time term to equation W-2 to account for the duration the pneumatic pump is operational for the reporting year.

Comment: The terms defined for Equation W-2 include “ $24 * 365 =$ Conversion to yearly emissions estimate”. This term is no longer used in the equation and should be deleted from the list of terms.

The term “T” should refer to an estimated average annual time for all the pumps or allow the use of 8760 hours. An estimate of the time is consistent with the preamble language stating “We are proposing to amend Equation W-2 in 40 CFR 98.233(c), which is used for calculating GHG emissions from natural gas pneumatic pump venting, to include a parameter “T” that estimates the total amount of hours the pumps were operational” (emphasis added).

Further for this equation, the term “ $Mass_{s,i}$ ”, does not need the subscript “s”, and the definition does not need “at standard conditions” as mass does not change based on temperature and pressure.

The term GHG_i refers to “onshore petroleum and natural gas production facilities” and references paragraph (u)(2)(i), which is defined as “sub-basin”. However, to be consistent with this equation, GHG_i should be representative of all the wells in the basin with a pneumatic pump and not aligned with a sub-basin. Revisions to 98.233(u)(2)(i) to address this are provided in

comment W.33 [EPA-HQ-OAR-2011-0512-0042, Excerpt 49].

Response: EPA agrees that the “24*365” conversion in equation W-2 is no longer used or needed and is removing it from the list of terms. EPA also agrees that “Mass_i” does not need the subscript “s,” and it is removing it from the equation. Furthermore, EPA agrees that “T” in Equation W-2 should be an estimated average annual time, and the definition will be changed to reflect this. Finally, EPA agrees that pneumatic device emissions are to be estimated and reported at a facility level. Paragraph 98.233(u)(2)(i) is being revised to reflect the use of either the basin or sub-basin as applicable to the emissions source.

Section 7.7 - Acid Gas Removal Vents

Section 7.7.1 - Calculating GHG Emission [W-3, W-4]

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 27

Commenter Type: Industry - oil and gas

Comment: Revision: EPA has modified Equation W-4 for calculating CO₂ emissions from acid gas removal units. EPA notes in the preamble that the correction was needed because the original equation introduces an error that increases significantly when the amount of CO₂ in the gas increases.

Comment: The previous (original) equation contained a variable, alpha, to adjust the calculation based on whether the inlet gas or outlet gas flow rate was applied. Note, the definition of terms still lists the term alpha, although alpha is not used in the revised equation.

The proposed correction seems to introduce a larger error than the original equation if the inlet gas volume is applied. Testing the equations using the onshore production example facility from the Compendium (Section 8.1.1), results in the following:

Compendium Method 1,190 scf CO₂/yr

Original EPA Method: Applying inlet gas flow 1,183 scf CO₂/yr

Original EPA Method: Applying outlet gas flow 1,154 scf CO₂/yr

Revised EPA Method: Applying inlet gas flow 1,337 scf CO₂/yr

Revised EPA Method: Applying outlet gas flow 1,169 scf CO₂/yr

[The Compendium example is based on the following conditions: AGR inlet gas flow = 10,290 scf/yr, inlet gas CO₂ composition is 12%, AGR outlet gas flow rate = 8,997 scf/yr, outlet gas CO₂ composition is 0.5%.]

When the inlet volume of gas is used, the proposed corrected equation over estimates emissions by incorrectly increasing the volume of inlet gas. Based on API's analysis, it does not appear that the revision improves the quality of data when the inlet gas flow rate is applied.

API requests that EPA retain the previous equation, using the alpha term. As demonstrated in the table above, the revised equation actually introduces a larger error, particularly when the inlet gas flow rate is applied.

API also requests that the flow rate term "V" be defined in terms of standard conditions (60°F and 14.7 psia), consistent with the flow measurements available for amine units. In addition, the term E_{a,CO_2} should be revised to E_{s,CO_2} and be expressed in volumetric emissions at standard conditions (60°F and 14.7 psia). With this revision, paragraph (9) is no longer needed.

Response: EPA agrees that equation W-4, as published, is incorrect. EPA is proposing two new equations, W-4A and W-4B, to replace the current equation. These two new equations, used separately if either inlet or outlet gas flow is known, give the highest accuracy of any of the equations considered thus far. For further explanation, please see docket memo "Acid Gas Removal Vents – Engineering Calculation Revisions" located in the docket: EPA-HQ-OAR-2011-0512.

Commenter Name: Mike Hampton

Commenter Affiliation: SandRidge Midstream, Inc.

Document Control Number: EPA-HQ-OAR-2011-0512-0045

Comment Excerpt Number: 3

Commenter Type: Industry - oil and gas

Comment: Problems with the September 9, 2011 Proposed Rule Changes

The proposed changes to 40 CFR 98.233(d)(1) in the September 9, 2011 Federal Register require, for AGR vents with both continuous gas analyzer and continuous flow monitor, to calculate CO₂ emissions "by following the Tier 4 Calculation Methodology and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources)."

SandRidge believes this requirement to use 40 CFR Part 98 Subpart C Tier 4 methodology and all associated calculation, quality assurance, reporting, and recordkeeping requirements is inappropriate for several reasons, as discussed below.

1. AGR vents are not combustion sources. Subpart C was drafted and promulgated for combustion sources, and AGR vents exhausted to atmosphere are not combustion sources. The requirements for Tier 4 specifically address combustion sources and fuels, and as such, direct

application to cold, dry, non-combustion vents is not appropriate. Rather, development of Tier 4 type requirements should be proposed, reviewed, and finalized specifically for AGR vents, if needed, at a future date if an applicable rule requires specific AGR units to demonstrate compliance with a limit or an allowance.

2. QA/QC requirements in 40 CFR Part 60 apply to new or modified sources, not to existing sources. It is not appropriate to retroactively apply the stringent Part 60 QA/QC requirements (which include initial certification, annual relative accuracy test audits [RATA], quarterly cylinder gas audits, daily calibrations, and associated recordkeeping/reporting requirements) to existing monitoring equipment that was not designed or installed to meet such requirements. An owner or operator who becomes subject to 40 CFR Part 60 QA/QC requirements will design, purchase, and install such equipment specifically with the intent of meeting such requirements. It is not reasonable for the retroactive application of such stringent QA/QC requirements to apply simply because an owner or operator has existing monitoring equipment.

3. 40 CFR Part 98 Subpart C itself does not mandate Tier 4 methodology unless the stationary source is already subject to the QA/QC requirements of 40 CFR Part 75 or Part 60 [ref §98.33(b)(4)(ii)(F) and §98.33(b)(4)(iii)(C)]. Therefore, it is unreasonable and far-reaching for EPA to require these QA/QC requirements for AGR vents that are not already subject to the stringent QA/QC requirements of 40 CFR Part 75 or Part 60, simply because the vents have continuous monitoring equipment.

4. The proposed QA/QC requirements for AGR vents with monitoring equipment cause unreasonable and excessive expense applied unevenly across AGR vent owners. The fact that some AGR vent owners have monitoring equipment should not subject them to excessive burden and expense when there are other acceptable methods in 40 CFR Part 98 Subpart W that other AGR vent owners are allowed to use, even though the data quality of the other methods is less certain than with continuous gas analyzers/continuous flow monitors. In fact, if existing monitoring equipment that currently meets existing QA/QC requirements is unable to satisfy the stringent Part 60 requirements, the owner/operator would be forced to spend additional resources to replace the existing system, simply because they had an existing system. Operators that do not currently have continuous monitoring equipment would not be exposed to this requirement.

5. AGR vent owners and operators have no opportunity to comment on Tier 4 methodology in Subpart C. By proposing a reference to 40 CFR Part 98 Subpart C Tier 4 methodology that imposes significant new burdens on some AGR vent owners and operators, EPA has initiated rulemaking without the opportunity for stakeholder comments, because Subpart C is not open for comment. At the time Subpart C was open to comment, AGR owner/operators would not have had any need to comment on the rule.

Additionally, SandRidge believes that the proposed language in the September 9, 2011 federal register should be clarified to specify that Tier 4 methodology would only apply if the continuous gas analyzer and continuous flow monitor are sampling and recording data from the exhaust stack. Monitoring equipment on the feed to a combustion or process device (such as flare, engine, sulfur recovery unit, etc.) could not be appropriately subjected to RATA-type QA/QC for CO₂ emissions, because it is not a direct measurement of emissions.

Proposed Solution

Therefore, SandRidge proposes that 98.233(d) be changed as shown below, with proposed changes to the September 9, 2011 federal register shown in redline format.

“(d) Acid gas removal (AGR) vents. For AGR vent (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for C02 only (not CH4) vented directly to the atmosphere or through a flare, engine (e.g., permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant using any of the calculation methodologies described in paragraph (d) of this section, as applicable.

(1) Calculation Methodology 1. If you operate and maintain a CEMS [add: on an AGR exhaust Stack] that has both a C02 concentration monitor and volumetric flow rate monitor, you must calculate C02 emissions under this subpart by following the Tier 4 Calculation Methodology and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). [add: For existing continuous monitoring equipment on AGR vents, and for continuous monitoring equipment on non-combustion AGR vents, the calculation, quality assurance, reporting, and recordkeeping requirements of 98.33(a)(4) and 98.34(c) may alternatively be satisfied by following the calculation, quality assurance, reporting, and recordkeeping requirements in a permit or the recommendations of the manufacturer of the monitoring equipment or general industry practice.] If a C02 concentration monitor and volumetric flow rate monitor are not available, you may elect to install a C02 concentration monitor and a volumetric flow rate monitor that comply with all of the requirements specified for the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion). The calculation and reporting of CH4 and N20 emissions is not required as part of the Tier 4 requirements for AGRs.”

Response: EPA notes that CEMS stands for continuous emissions monitoring systems and hence cannot be confused for monitoring of feed gas to equipment. Therefore, EPA disagrees with the commenter on adding “on an AGR exhaust stack” to Calculation methodology 1. EPA agrees with the commenter that the stringent calibration and quality assurance required for combustion stack CEMS are not required for AGR vent stack CEMS. Hence, EPA is allowing reporters the use of “manufacturer’s instructions or industry standard practice” for calculations, quality assurance, reporting, and recordkeeping for CEMS as stated in 98.233(d)(1).

Section 7.8 - Dehydrator Vents

Section 7.8.1 - Calculating GHG Emission [W-5, W6]

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 28

Commenter Type: Industry - oil and gas

Comment: Revision: EPA added a definition for the “1000” term used in Equation W-5.

Comment: API requests the following revision to this definition: “1000 = Conversion of EF_i in thousand standard cubic feet to [add (red): standard] cubic feet.”

Response: EPA agrees that the word “standard” should be added to the conversion factor definition in Equation W-5. Accordingly, this change has been made in this final rule.

Section 7.9 - Well Venting for Liquids Unloading

Section 7.9.1 - Calculating GHG Emission [W-7 to W9]

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 18

Commenter Type: Industry - oil and gas

Comment: Well venting for liquids unloading, § 98.233(f). EPA has proposed revising the calculation methodologies for well venting for liquids unloading, § 98.233(f). We support and incorporate by reference the comments regarding Eq. W-8 and Eq. W-9 that were submitted by API on October 24, 2011 in Section 2 - W.14 [EPA-HQ-OAR-2011-0512-0042, Excerpt 30] and W.15 [EPA-HQ-OAR-2011-0512-0042, Excerpt 31] of its letter. See also Section A.7 supra.

Response: EPA thanks Chesapeake Energy Corporation and American Exploration & Production Council for their comments. Please refer to responses to EPA-HQ-OAR-2011-0512-0042, Excerpt 30, and EPA-HQ-OAR-2011-0512-0042, Excerpt 31.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 30

Commenter Type: Industry - oil and gas

Comment: Revision: EPA has modified the summation terms in Equation W-8 to account for the pressure and tubing diameter groupings.

Comments:

- API appreciates that EPA has corrected $E_{s,n}$ and SFR_q to be stated in standard conditions, not actual conditions.
- For clarity, the term CD_p in Equation W-8 should indicate that this is the internal diameter, which is consistent with the calculation approach.
- On page 54 of Appendix D in the Technical Support Document associated with these proposed amendment, EPA indicates that the pressure in Equation W-8 is the reservoir shut-in pressure. EPA comments that this information is not reliably available in public literature. API agrees with this assessment, but further would like to point out that reservoir shut-in pressure is not reliably available in operations either. The term SP_p should represent the surface pressure prior to venting, in pounds per square inch absolute (not atmosphere).
- In the list of defined terms for Equation W-8, the term $HR_{Q,PW}$ should be $HR_{q,p}$.
- EPA has clarified that the term WD_p is the distance between the lowest packer to the bottom of the well. It is unclear what value should be applied for WD_p for wells without packers.
- The amendments did not change 98.233(f)(2)(i) which references 98.233(t) to adjust the natural gas volumetric emissions at standard conditions. This adjustment double corrects the gas volume for pressure, which is already included in the 0.37×10^{-3} constant. API recommends removing the reference to §98.233(t) since SFR_q and $E_{s,n}$ are defined in terms of gas volumes at standard conditions (60 °F and 14.7 psia).

Response: EPA agrees that the term CD_p should be the “internal diameter” of the casing, the parameter $HR_{q,p}$ was listed incorrectly, and the reference to paragraph §98.233(t) should be removed. EPA agrees with API’s definition change to SP_w and in this final rule has updated Equation W-8 to reflect “pounds per square inch absolute” instead of “pounds per square inch atmosphere”.

In this final rule, EPA is allowing the use of surface pressure in Equation W-8 with certain stipulations; please see preamble section II.C. - Final Amendments to the Petroleum and Natural Gas Systems Source Category: Well Venting for Liquids Unloading for further details. Also, agrees that the definition for WD_p does not address wells without packers, and in this final rule, has revised the definition to make provision for wells without packers by restating the definition as “Well depth from either the top of the well or the lowest packer to the bottom of the well”. Finally, EPA agrees that shut-in pressure may not be known for all wells. Therefore, EPA is allowing the use of surface pressure or casing pressure either when the well is shut-in or just before liquids unloading.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 31

Commenter Type: Industry - oil and gas

Comment: Revision: EPA revised Equation W-9.

Comments:

- API appreciates that EPA has corrected $E_{s,n}$ and SFR_q to be stated in standard conditions, not actual conditions.
- For clarity, the term TD_p in Equation W-9 should indicate that this is the internal diameter, which is consistent with the calculation approach.
- The term SP_p should be the flowing wellhead pressure, not the sales line pressure which has no bearing for wells on compression. Using the sales line pressure in this situation will over-estimate emissions. SP_p should also be expressed as pounds per square inch absolute, (not atmosphere) which is gauge pressure + 14.7 psi and is consistent with the pressure adjustment included in the 0.37×10^{-3} constant.
- The amendments did not change 98.233(f)(3)(i) which references §8.233(t) to adjust the natural gas volumetric emissions at standard conditions. This adjustment double corrects the gas volume for pressure, which is already included in the 0.37×10^{-3} constant. API recommends removing the reference to §98.233(t) since SFR_q and $E_{s,n}$ are defined in terms of gas volumes at standard conditions (60 °F and 14.7 psia).
- API requests the use of Methodology 3 for wells without plunger lifts.

Response: EPA agrees that the term TD_p should be for “internal diameter” and that the reference to paragraph §98.233(t) should be removed; EPA is making these changes to this final rule. EPA disagrees that the sales line pressure should not be used; please see the response to EPA-HQ-OAR-2011-0147-0007, Excerpt 3. EPA is also clarifying that sales line pressure may be estimated using best available data; please see preamble section II.C. - Final Amendments to the Petroleum and Natural Gas Systems Source Category: Well Venting for Liquids Unloading for further discussion on this issue. EPA disagrees that Methodology 3 should be used for wells without plunger lifts. Equation W-8 and W-9 were specifically derived for wells without plunger lifts and wells with plunger lifts, respectively; please see docket memo “Change to Equation W-7 Well Liquids Unloading” located in the docket: EPA-HQ-OAR-2009-0923.

Section 7.9.2 - Data Reporting Requirements

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 29

Commenter Type: Industry - oil and gas

Comment: Revision: For Well Venting for Liquids Unloading, EPA is proposing a vent measurement for each unique well tubing diameter grouping and pressure grouping in each sub-basin category. Pressure groupings are defined in 98.238 as: = 25 psig; 25-60 psig; 60-110 psig, 110-200 psig; and > 200 psig. Tubing diameter groupings are defined in 98.238 as: = 1 inch; 1-2 inches; and = 2 inches. The average flow rate is calculated for each unique tubing diameter

grouping and pressure grouping in each sub-basin category by dividing the recorded total flow by the recorded time for a single liquid unloading with venting to the atmosphere. The revisions also state that for a new producing sub-basin category, an average flow rate is calculated beginning in the first year of production.

Comment: EPA has modified the terms used in Equation W-7 to address the groupings by tubing diameter and pressure. However, the emissions resulting from Equation W-7 are inconsistent with the reporting requirements under 98.236(c)(5). It appears, though it is not explicitly stated, that Equation W-7 is intended to result in emissions summed for the sub-basin, while the reporting requirements are for each well tubing diameter and pressure grouping. API interprets Equation W-7 to result in emissions aggregated for the sub-basin and requests that the reporting requirements be modified to be consistent.

The reporting requirements are further confused by combining the requirements for Methodologies 1, 2, and 3 all under the same paragraph of 98.236(c)(5). API requests that EPA specify separate reporting requirements for Methodology 1.

Methodology 1 indicates that the pressure groupings apply across each of the sub-basin category (conventional and unconventional) and tubing grouping. API has provided separate comments specifically addressing the pressure groupings under comment W.56 [EPA-HQ-OAR-2011-0512-0042, Excerpt 74].

As indicated in comment W.58 [EPA-HQ-OAR-2011-0512-0042, Excerpt 76], API proposes the use of two tubing diameter groupings, rather than the three proposed by EPA. In addition, while the pressure and tubing groupings only apply to Methodology 1, the reporting requirements under 98.236(c)(5) require reporting emissions for each tubing diameter and pressure grouping for Methodologies 2 and 3 as well. API requests that EPA remove the reporting requirements by pressure grouping for Methodologies 2 and 3 since these groupings do not apply to calculation Methodologies 2 and 3.

Response: EPA disagrees with the commenter that reporting for Methodology 1 should be only at a sub-basin level. The methodology requires estimation of emissions at a pressure grouping and sub-basin level. Hence, reporting at the same level of granularity is not an issue.

EPA agrees that the pressure groupings should not apply to Methodologies 2 and 3 and is revising the data reporting section accordingly to require reporting only at a sub-basin category level for these two methodologies. EPA disagrees that only two pressure groupings should be used. Please see response to EPA-HQ-OAR-2011-0512-0042, Excerpt 74, for further explanation.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 57

Commenter Type: Industry - oil and gas

Comment: Revision: For well venting for liquids unloading, EPA requires reporting for each well tubing diameter grouping and pressure grouping. For Methodology 1, EPA also requires reporting the casing diameter, depth, and pressure of each well selected to represent emissions in that tubing size and pressure combination.

Comment: 98.236(c)(5) requires reporting the casing diameter for Equations W-7, 8, and 9, although casing diameter is not used for Equations W-7 or W-9. Also, where Methodologies 2 and 3 are applied, tubing and pressure groupings are not used, so the reporting requirements for these methodologies should not reference the tubing and pressure groupings. API requests that these inconsistencies between the reporting requirements and calculation methodologies be removed.

Response: EPA agrees that pressure groupings and tubing diameter groupings combinations are not used in Calculation Methodology 2 or 3 under paragraph 98.233(f), and in this final rule has modified the data reporting requirements to not require this data when methodologies 2 and 3 are used. EPA agrees that the pressure groupings should not apply to Calculation Methodology 2 and 3, and in this final rule, has revised the data reporting section accordingly to require reporting only at a sub-basin category level for these two methodologies.

Section 7.10 - Gas Well Venting During Completions and Workovers from Hydraulic Fracturing

Commenter Name: William W. Grygar II

Commenter Affiliation: Anadarko Petroleum Corporation

Document Control Number: EPA-HQ-OAR-2011-0512-0028

Comment Excerpt Number: 7

Commenter Type: Industry - oil and gas

Comment:

- Under §98.233(g), reporters should have the option of using measured data on gas vented and/or flared, if available, for all wells hydraulically fractured during completions and workovers.
- Under §98.233(g)(1), the clarification should be made that the number of measurements are per each sub-basin category. Similarly, under §98.233(g)(1)(i), the regulatory text should read, "For well completion(s) and well workover(s) in each producing sub-basin category ... "

Response: EPA agrees with the commenter's recommendation to allow reporters to calculate emissions using metered volumes of the backflow subsequent to the hydraulic fracture; please see the response to EPA-HQ-OAR-2011-0512-0042, Excerpt 32, for further details.

EPA has clarified in the introductory text of 40 CFR 98.233 (g)(1) that the number of required measurements are the specified number of completions and workovers for either vertical or horizontal wells are performed in a sub-basin category.

Section 7.10.1 - Calculating GHG Emission [W10 to W12]

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 32

Commenter Type: Industry - oil and gas

Comment: Revision: EPA revised Equation W-10, but not as API had requested in our July 29, 2011 correspondence to EPA.

Comment: In an e-mail provided to EPA on July 29, 2011, API provided regulatory revisions to Equation W-10. API proposed to remove the subtraction of the SG term and define the “flow-back volume” term in Equation W-10 by limiting it only to the time span during which gas is actually vented to the atmosphere or flared. The SG_p term should be removed and FRM should be revised to reflect venting to the atmosphere. SG_p is not needed since T is defined as the hours vented. If a well is venting, then it is not recovering to sales.

These proposed revisions add clarity, simplify the calculation, and reflect the emissions characteristics of flow-back operations. Without the removal of the SG term, Equation W-10 has the potential to either lead to the calculation of a negative emissions value, or compare emissions values vented to the atmosphere to sales values that are produced against the back-pressure of a gathering or sales pipeline; these are two completely different operating scenarios. API’s proposed mark-ups to incorporate the changes for 98.233(g) are provided in Section 4 of these comments.

EPA has added language defining the number of measurements required based on the number of workovers/completions. API interprets this requirement to apply to the sub-basin. Clarification is needed that the number of measurements required is relative to a sub-basin or basin (facility) and well type combination and not total number of completions/workovers.

In addition, API requests the addition of a new equation that sums available measurements and eliminates the need for normalizing and tracking cumulative venting time. Some companies are planning to measure the venting associated with gas well completion and workovers with hydraulic fracturing. Equation W-10 does not allow the use the actual measurements. API has included this new equation in the proposed revisions provided in Section 4 below.

Response: EPA disagrees that the term SG_p should be removed from Equation W-10A. The parameter “FRM”, which is calculated using Equation W-12, has been amended to the ratio of backflow during well completions and workovers from hydraulic fracturing to the 30-day

production rate. Therefore, the backflow measurement is not only limited to the time the gas is vented to the atmosphere or flared, but also includes the time the gas is recovered for beneficial use. Consequently, subtracting “SG_p” in Equation W-10A, will not result in negative emissions. Instead, it will only take out the amount of gas that is recovered for beneficial use from the total amount of backflow for a specific well in a sub-basin and well-type combination.

EPA agrees with the commenter’s recommendation to allow reporters to calculate emissions using metered volumes of the backflow subsequent to the hydraulic fracture; therefore, in this final rule, EPA has added Equation W-10B. This equation can only be used if vented or flared backflow volumes for all well are measured in a sub-basin category and well-type combination.

In this final rule, EPA has clarified in the introductory text of 40 CFR 98.233 (g)(1) that the number of required measurements are if the specified number of completions and workovers for either vertical or horizontal wells are performed in a sub-basin category.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 33

Commenter Type: Industry - oil and gas

Comment: Revision: EPA has modified the definitions of terms associated with Equations W-11A and W-11B.

Comment: In Equations W-11A and W-11B. “A” is defined as m² instead of m², which API interprets to mean “meters squared”. However, cross sectional area of an orifice is usually reported in inches squared. API would prefer to define the term “A” as inches squared (in²) and the other terms in these equations in English units, consistent with industry practices.

Response: EPA agrees that the unit for “A” should be defined as “m²” and has changed it accordingly in this final rule. Equations W-11A and W-11B have been subjected to peer review and validation and can be found in engineering handbooks and textbooks. These equations, as they stand, require the use of metric units. Converting the units of parameters from English units to metric units for use in Equation W-11A and Equation W-11B does not place undue burden on reporters. Therefore, the units of Equations W-11A and W-11B have been retained in this final rule.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 34

Commenter Type: Industry - oil and gas

Comment: Revision: EPA has added Equation W-11C to determine whether the flow rate is sonic or subsonic. Flow is sonic if the value of R is greater than 2.

Comment: API appreciates the clarity provided by documenting the equation determining if the flow rate is sonic or sub-sonic. However, Methodology 2 does not acknowledge that a single completion or workover can alternate between sonic and sub-sonic flows. As API pointed out in a letter to EPA on May 13, 2011, flowback on any single completion will be partially supersonic and partially subsonic. Reporters cannot discern exactly when flowback falls into either category during a completion. Additionally, liquids and gases flow at different rates. As a completion progresses, the amount of liquids decreases and the amount of gases increases, which makes performing the calculations more difficult. EPA should replace this methodology with a single calculation for tracking pressure drop across the choke, with assumptions for choke flow and gas gravity. Such a calculation will be technically feasible and sufficient for policy purposes.

Response: EPA agrees that it is difficult to track flow that alternates between sonic or subsonic. In this final rule, EPA has allowed operators to use best engineering estimate based on best available data and Equation W-11C to determine whether the flow is predominantly sonic or sub-sonic.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 35

Commenter Type: Industry - oil and gas

Comment: Revision: EPA has added Equation W-12 to quantify a ratio of emissions to 30-days production

Comment: As provided to EPA in an e-mail on July 29, 2011 and also included is Appendix A to these comments, API had proposed the use of the first calendar month for developing a normalized production rate. API would agree to use 30-days of production as well. However, as noted in comment W-16 above, the key issue is that the time used in Equation W-10 should only reflect flowback time and should not include time when gas is sent to sales.

Response: EPA does not agree that gas sent to the flow line should not be included in the ratio calculated in Equation W-12; please see the response to EPA-HQ-OAR-2011-0512-0042, Excerpt 32.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 91

Commenter Type: Industry - oil and gas

Comment: [Please refer to the original comment text posted in the docket] The follow reiterates suggested regulatory revisions provided to EPA on July 29, 2011 addressing workover

and completions. The mark-ups shown are incorporated into the September 9, 2011 proposed regulatory amendments.

During a meeting with API on May 26, 2011, EPA had outlined an approach to extrapolate measured or quantified flow-back volumes for gas well completions and workovers across all workovers and completions in the sub-basin category. The following provides API's mark-ups to the September 9, 2011 proposed regulatory language to incorporate this approach. API's revisions for the flow-back volume normalization approach are indicated in blue text.

API's revisions include a modification to Equation W-10 that consists of removing the subtraction of the SG term. API is proposing to define the "FRM" term in Equation W-10 by limiting it only to the time span during which gas is actually vented to the atmosphere or flared. These proposed revisions add clarity, simplify the calculation, and reflect the emissions characteristics of flow-back operations. Without the removal of the SG term, Equation W-10 has the potential to either lead to the calculation of a negative emissions value, or compare emissions values vented to the atmosphere to sales values that are produced against the back-pressure of a gathering or sales pipeline; these are two completely different operating scenarios.

Please note that these proposed regulatory revisions do not yet address changes to Methodology 2 under §98.233(g). API is working to develop an alternative approach to Equations W-11 and W-12, but this is a difficult technical challenge. API intends to address this separately with EPA.

(g) Gas well venting during completions and workovers from hydraulic fracturing. Calculate CH₄, CO₂ and N₂O (when flared) annual emissions from gas well venting during completions involving hydraulic fracturing in wells and well workovers using Equation W-10[add (blue): A or W-10B] of this section. Both CH₄ and CO₂ volumetric and mass emissions shall be calculated from volumetric total gas emissions using calculations in paragraphs (u) and (v) of this section.

[See original comment for Eq. W-10A] (Eq. W-10A)

Where:

Es,n = Annual volumetric total gas emissions in cubic feet at standard conditions from gas well venting [add (blue): to the atmosphere or a flare] during completions or workovers following hydraulic fracturing for each sub-basin [add (blue): category] and well type combination [add (blue): (vertical or horizontal).]

Tp = Cumulative amount of time [add (blue): venting to the atmosphere or a flare post fracture stimulation before being routed to production. Reported] in hours of each well(p) completion or workover [delete (blue): venting] in a sub-basin and well type combination during the reporting year.

[add (blue): FRM = Ratio of venting to the atmosphere or flare to 30-day production rate] [delete (blue): Venting to 30-day production ratio] [add (blue): from Equation W-12.]

PRp = First 30-day average production flow rate [add (blue): after well completion or well workover operations have ended and the well has been routed to normal production]in standard

cubic feet per hour of each well (p), [delete (blue): under actual conditions, converted to standard conditions,] as required in paragraph (g)(1) of this section.

EnF = Volume of CO₂ or N₂ injected gas in cubic feet at standard conditions that was injected into the reservoir [add (blue): during the completion or workover] [delete (blue): an energized fracture job] for each well (p). If the fracture process did not inject gas into the reservoir, then EnF is 0. If injected gas is CO₂ then EnF is 0.

[delete (blue): SGp = Volume of natural gas in cubic feet at standard conditions that was recovered into a sales pipeline for well p as per paragraph (g)(3) of this section. If no gas was recovered for sales, SG is 0.]

[add (blue) or

[See original comment for Eq. W-10B] (Eq. W-10B)

Where

Es,n = Annual volumetric total gas emissions in cubic

feet at standard conditions from gas well venting to the atmosphere or a flare during completions or workovers following hydraulic fracturing for each sub-basin category and well type combination (vertical or horizontal).

EnF = Volume of CO₂ or N₂ injected gas in cubic feet at

standard conditions that was injected into the reservoir during an energized fracture job for each well (p). If the fracture process did not inject gas into the reservoir, then EnF is 0. If injected gas is CO₂ then EnF is 0.

FRM = Measured Volume of flow-back gas from completions or workovers for the time that gas is vented to the atmosphere or a flare, in cubic feet at standard conditions.

W = Number of wells completed or worked over using Hydraulic fracturing in a sub-basin.]

(1) The average flow rate for gas well venting to the atmosphere or to a flare during well completions and workovers from hydraulic fracturing shall be determined using either of the calculation methodologies described in this paragraph (g)(1) of this section. The number of measurements shall be determined as follows: One measurement for less than or equal to 25 completions/workovers; two measurements for 26 to 50 completions/workovers; three measurements for 51 to 100 completions/workovers; four measurements for 101 to 250 completions/workovers; and five measurements for greater than 250 completions/workovers.

(i) Calculation Methodology 1. For one well completion(s) in each gas producing sub-basin category and well type (horizontal or vertical) combination and for one well workover(s) in each gas producing sub-basin category and well type (horizontal or vertical) combination, a recording

flow meter (digital or analog) shall be installed on the vent line, ahead of a flare if used, to measure the backflow venting event according to methods set forth in §98.234(b).

(ii) Calculation Methodology 2. For one horizontal gas well completion and one vertical gas well completion in each gas producing sub-basin category and for one horizontal well workover and one vertical well workover in each gas producing sub-basin category, record the well flowing pressure upstream (and downstream in subsonic flow) of a well choke according to methods set forth in §98.234(b) to calculate intermittent well flow rate of gas during venting to the atmosphere or a flare. Calculate emissions using Equation W-11A of this section for subsonic flow or Equation W-11B of this section for sonic flow. Use equation W-11C of this section to determine whether flow is sonic or subsonic. If the value of R in Equation W-11C is greater than or equal to 2, then flow is sonic; otherwise, flow is subsonic:

[See original comment for Eq. W-11A] (Eq. W-11A)

Where:

FR = Average flow rate in cubic feet per hour, under subsonic flow conditions.

A = Cross sectional area of orifice ([add (blue): 2]).

P1 = Upstream pressure (psia).

Tu = Upstream temperature (degrees Kelvin).

P2 = Downstream pressure (psia).

3430 = Constant with units of m[add (blue): 2] / (sec[add (blue): 2] * K).

1.27*10⁵ = Conversion from m[add (blue): 3] / second to ft[add (blue): 3] / hour.

[See original comment for Eq. W-11B] (Eq. W-11B)

Where:

FR = Average flow rate in cubic feet per hour, under sonic flow conditions.

A = Cross sectional area of orifice (m[add (blue): 2]).

Tu = Upstream temperature (degrees Kelvin).

187.08 = Constant with units of m[add (blue): 2] / (sec[add (blue): 2] * K).

1.27*10⁵ = Conversion from m[add (blue): 3] / second to ft[add (blue): 3] / hour.

[See original comment for Eq. W-11C] (Eq. W-11C)

Where:

R = Pressure ratio

P1 = Pressure upstream of the restriction orifice in pounds per square inch absolute.

P2 = Pressure downstream of the restriction orifice in pounds per square inch absolute.

(iii) The emissions to 30-day production ratio is calculated using Equation W-12 of this section.

[See original comment for Eq. W-12] (Eq. W-12)

Where:

FRM = [add (blue): Ratio of venting to the atmosphere or flare] [delete (blue): Emissions] to 30-day production rat[delete (blue) eio].

FR_p = Measured flow rate from Calculation Methodology 1 or estimated flow rate from Calculation Methodology 2 in standard cubic feet per hour [add (blue): of venting to the atmosphere or flaring] for well(s) p for each sub-basin and well type [add (blue): (horizontal or vertical) combination.]

PR_p = First 30-day production rate in standard cubic feet per hour [add (blue): after well completion or well workover operations have ended and the well has been routed to normal production] for each well p that was measured in the sub-basin and well type combination (horizontal or vertical).

W = Number of wells [add (blue): sampled per the requirements of paragraph 98.233(g)(1)] [delete (blue): completed or worked over using hydraulic fracturing in a sub-basin and well type formation.]

(iv) The [add (blue): average] flow rates for horizontal and vertical wells are applied to all horizontal and vertical well completions in the gas producing sub-basin and well type combination and to all horizontal and vertical well workovers, respectively, in the gas producing sub-basin and well type combination for the total number of hours of venting [add (blue): to the atmosphere or a flare] of each of these wells.

(v) New [add (blue): average] flow rates for horizontal and vertical gas well completions and horizontal and vertical gas well workovers in each sub-basin category shall be calculated once every two years starting in the first calendar year of data collection.

(2) The volume of CO₂ or N₂ injected into the well reservoir during [add (blue): completion or workover] [delete (blue): energized hydraulic fractures] will be measured using an appropriate meter as described in 98.234(b) or using receipts of gas purchases that are used for the energized fracture job.

(i) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

[delete (blue): (3) The volume of recovered completion or workover gas sent to a sales line will be measured using existing company records. If data does not exist on sales gas, then an appropriate meter as described in 98.234(b) may be used.

(i) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]]

(3[delete (blue):4]) Both CH₄ and CO₂ volumetric and mass emissions shall be calculated from volumetric total emissions using calculations in paragraphs (u) and (v) of this section.

[delete (blue): (5) Determine if the well completion or workover from hydraulic fracturing recovered gas with purpose designed equipment that separates saleable gas from the backflow, and sent this gas to a sales line (e.g. reduced emissions completion).

(i) Use the factor SG in Equation W-10 of this

section, to adjust the emissions estimated in paragraphs (g)(1) through (g)(4) of this section by the magnitude of emissions captured using reduced emission completions as determined by engineering estimate based on best available data.

(ii) [Reserved]]

(4[delete (blue): 6]) Calculate annual emissions from gas well venting during well completions and workovers from hydraulic fracturing to flares as follows:

(i) Use the total gas well venting volume during well completions and workovers as determined in paragraph (g) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine gas well venting during well completions and workovers using hydraulic fracturing emissions from the flare. This adjustment to emissions from completions using flaring versus completions without flaring accounts for the conversion of CH₄ to CO₂ in the flare.

Response: EPA agrees with the commenter's recommendation to allow reporters to calculate emissions using metered volumes of the backflow subsequent to the hydraulic fracture; please see the response to EPA-HQ-OAR-2011-0512-0042, Excerpt 32 for further details.

EPA has combined the requirements of 40 CFR 98.233 (g)(3) and 40 CFR 98.233 (g)(5), because the requirements in both were duplicative. The requirements in 40 CFR 98.233 (g)(5) has been

deleted and paragraph 40 CFR 98.233 (g)(6), (g)(6)(i), and (g)(6)(ii) has been re-designated as 40 CFR 98.233 (g)(5), (g)(5)(i), and (g)(5)(ii).

EPA disagrees with the commenter's stance that the normalized backflow volumes (i.e. "FRM") multiplied by the 30-day production only accounts for the amount of gas that is vented to the atmosphere or flared. EPA disagrees with any rule text edits associated with the commenter's suggestion, including the deletion of SG_p. Please see the response to EPA-HQ-OAR-2011-0512-0042, Excerpt 32 for further details.

Section 7.10.2 - Data Reporting Requirements

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 58

Commenter Type: Industry - oil and gas

Comment: Revision: EPA requires reporting emissions by sub-basin and well type for well completions and workovers with hydraulic fracturing. EPA also requires reporting annual CO₂ and CH₄ emissions that resulted from gas venting directly to the atmosphere and that annual CO₂, N₂O, and CH₄ emissions resulted from flares,

Comment: For 98.236 (c)(6)(i)(B)&(D) API suggests that the average flow rate should be reported in "standard" cubic feet instead of cubic feet.

Response: EPA agrees that the average flow rates reported in 40 CFR 98.236 (c)(6)(i)(B) and 40 CFR 98.236 (c)(6)(i)(D) are at standard cubic feet. EPA in this final rule has amended these reporting requirements accordingly.

Section 7.11 - Gas Well Venting During Completions and Workovers Without Hydraulic Fracturing

Commenter Name: William W. Grygar II

Commenter Affiliation: Anadarko Petroleum Corporation

Document Control Number: EPA-HQ-OAR-2011-0512-0028

Comment Excerpt Number: 8

Commenter Type: Industry - oil and gas

Comment: Under §98.233(h), term Now should read "Number of workovers per sub-basin category not involving ... "

Response: EPA agrees with the commenter and in this final rule has revised the term N_{wo} to reflect accounting at a sub-basin level.

Section 7.11.1 - Calculating GHG Emission [W13]

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 36

Commenter Type: Industry - oil and gas

Comment: Revision: EPA has addressed gas volumes at standard conditions and the sub-basin category approach in revisions to the definition of terms for Equation W-13.

Comment: EPA has changed V_f and T_f to V_p and T_p , respectively in the definitions, but did not change the variable subscripts in the equation. Also, the term " V_v " is defined in terms of each blowdown " i ". However, the subscript " i " is not used in either Equation W-14A or W-14B. API believes " i " should be replaced with " p ".

Response: EPA agrees that the subscript " p " did not get updated in the parameter definitions for Equation W-13.

Parameter " V_v " has been redefined to " V " in Equation W-14A and W-14B. In Equation W-14B, all references to subscript " i " have been removed and replaced with subscript " p ". A definition for subscript " p " has been added.

Section 7.12 - Blowdown Vent Stack

Section 7.12.1 - Calculating GHG Emission [W14A, W-14B]

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 15

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] INGAA supports the addition of Equation W-14B, which estimates blowdown vent stack emissions by summing venting events for the year. However, minor errors need to be corrected.

INGAA requested that an additional calculation method be included in §98.233(i), and INGAA supports the addition of Equation W-14B. Minor errors in the new text need to be revised. For example, the reference to a "purge factor" should be deleted.

Methods prescribed in §98.233(i) are used to estimate natural gas emissions from blowdown events. Equation W-14A and associated reporting requirements apply to equipment where every blowdown event has the same physical volume, gas temperature, starting and ending pressure, and blowdown vent stack. The methods associated with this equation do not apply to normal operating practices at transmission and storage facilities. The physical volume of vented equipment depends on the locations of operational isolation valves and blowdown events do not typically have the same physical volume. Similarly, starting and ending pressures and temperatures typically vary for blowdown events. In addition, operations often dictate use of more than one vent stack (i.e., there is not a unique vent stack for each piece of equipment).

INGAA's June 2011 letter recommended the approach reflected in Equation W-14B to address these real-world considerations for estimating blowdown event emissions and to be consistent with typical blowdown data collection practices that are already in place. Equation W-14B accomplishes this by estimating annual facility blowdown emissions by summing emissions from individual events, with event emissions calculated from event-specific physical volume, temperature, and pressures. INGAA supports adding this equation to Subpart W, but there are minor corrections needed to the equation and description of Equation W-14B parameters. For example, although subtle, in the equation the subscript for "start" (i.e., pressure at start of event) should be a capital "S" rather than lower case "s" because the latter is used in the equation and throughout Subpart W to denote standard conditions. (In June 2011, INGAA recommended time zero and time final ("0" and "f" subscripts) in the equation and this avoids using a duplicative subscript). Based on EPA's subscripts, Equation W-14B should be revised (edits are not shown within the equation) and parameter definitions in Equation W-14B should be revised as follows:

[See original comment for Eq. W-14B]

Where:

$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.

N = Number of repetitive blowdowns [~~delete: for each unique volume~~] in [~~add: the~~] calendar year.

V_v [~~add: ,i~~] = Total [~~add: physical~~] volume of blowdown equipment chamber (including pipelines, compressors and vessels) between isolation valves in cubic feet for each blowdown "i."

[~~delete: C = Purge factor that is 1 if the equipment is not purged or zero if the equipment is purged using non-GHG gases.]~~

T_s = Temperature at standard conditions (°F).

T_a [~~add: ,i~~] = Temperature at actual conditions in the blowdown equipment chamber (°F) for each blowdown "i".

Ps = Absolute pressure at standard conditions (psia).

Pa,[delete: s] [add: S], [delete: p] [add: i] = Absolute pressure at actual conditions in the blowdown equipment chamber (psia) at the start of the blowdown “[delete: p] [add: i]”.

Pa,[delete: e] [add: E], [delete: p] [add: i] = Absolute pressure at actual conditions in the blowdown equipment chamber (psia) at the end of the blowdown “[delete: p] [add: i]”; 0 if blowdown volume is purged using non-GHG gases.

Response: EPA disagrees to the changes in definition of parameter N. EPA requires calculation and reporting of blowdown emissions by each unique physical volume; please see response to EPA-HQ-OAR-2011-0512-0029, Excerpt 16 for further details. In this final rule, all references to subscript “i” have been removed and replaced with subscript “p”. A definition for subscript “p” has also been added. EPA agrees to the clarification on subscripts designating the beginning and end of a blowdown and also agrees on the deletion of the purge factor. In this final rule, EPA has deleted the purge factor definition and has represented the pressure at the start of the blowdown as “P_{a,b,p},” standing for pressure at the beginning of the blowdown event.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 30

Commenter Type: Trade Association

Comment: Compressibility should be allowed in blowdown vent stack calculations at the operator's discretion.

EPA requests comment [76 FR 56031] on whether an allowance should be provided for considering compressibility in blowdown calculations. When calculating blowdown emissions for current operations, some natural gas operators include compressibility in calculations that generally follow Equation W-14B. This approach should be allowed, at the operators discretion, since it is an existing practice based on engineering principles and provides a more accurate estimate. This can be readily addressed in Subpart W by including compressibility as a parameter in equations W-14A and W-14B, and clearly indicating that the compressibility factor is assumed to be one unless the operator chooses to apply a compressibility factor.

Response: EPA does not consider the complexities in mandating a compressibility factor to be warranted for the purposes of informing future policy. EPA believes that the variability of allowing voluntary use of a compressibility factor, with a default value of 1 (one), would unnecessarily complicate comparison of reported blowdown data. Please see response to comment number EPA-HQ-OAR-2011-0512-0041, Excerpt 3.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 36

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket]

[highlighted text: Clarify ?exempt volumes; events to include (i.e., “significant” blowdowns for maintenance or safety), and add another calc (operator selects calc to use) where events are calculated and summed.]

Calculate CO₂ and CH₄ blowdown vent stack emissions from depressurizing equipment to the atmosphere [add: to reduce [comment bubble JMc4: Intent is to include “significant” blowdown events associated with shutdowns and maintenance activity.] system pressure for planned or emergency shutdowns or to take equipment out of service for maintenance] (excluding depressurizing to a flare, over-pressure relief, [delete: operating pressure control venting and] blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraph (e)(5) of this section) as follows:

- (1) Calculate the total volume (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) between isolation valves determined by engineering estimate based on best available data.
- (2) If the total [add: physical] volume between isolation valves is greater than or equal to 50 [delete: standard] cubic feet, retain logs of the number of blowdowns [delete: for each equipment type] (including but not limited to compressors, vessels, pipelines, headers, fractionators, and tanks). [delete: Blowdown] [add: Physical] volumes smaller than 50 [delete: standard] cubic feet are exempt from reporting under paragraph (i) of this section.
- (3) [add: The operator can elect to use either Equation W-14a or W-14b.] [comment bubble JMc5: Additional description can be included in the preamble: Equation W-14a (former Equation W-14) applies to an equipment type (i.e., group of equipment) where the estimate is based on the following physical and operating properties: the same unique blowdown chamber volume; the same blowdown chamber pressure and temperature; and, the same equipment purging practices (i.e., C = 0 or 1). Equation W-14b is appropriate if the blowdown pressure differential (start and end pressures) vary for different events and calculations for annual emissions are based on summing the calculated volume for events that occur throughout the year. For the latter, each event can be unique, so reporting requirements include total annual emissions and number of annual events.] Calculate [delete: the] total annual venting emissions for each equipment type using Equation W-14a [delete: of this section:] [add: or calculate total annual venting emissions using Equation W-14b. The operator can include corrections that address factors such as gas compressibility when completing the calculation.][comment bubble JMc6: This sentence is needed to allow operators to use existing vent records – e.g., similar equation used but longstanding calculation includes minor adjustments for factors such as compressibility. Without this sentence, some operators will have “two sets of books” for calculating vented emissions.]

[See original comment for equation (Eq. W-14a)]

Where:

$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.

N = Number of repetitive blowdowns for each equipment type of a unique volume in calendar year.

V_v = Total volume of blowdown equipment chambers (including pipelines, compressors and vessels) between isolation valves in cubic feet.

C = Purge factor that is 1 if the equipment is not purged or zero if the equipment is purged using non-GHG gases.

T_s = Temperature at standard conditions (°F).

T_a = Temperature at actual conditions in the blowdown equipment chamber (°F).

P_s = Absolute pressure at standard conditions (psia).

P_a = Absolute pressure at actual conditions in the blowdown equipment chamber (psia).

[See original comment for Eq.-W-14b]

[add: Where:

$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.

N = Number of blowdowns in the calendar year.

$V_{v,i}$ = Total volume of blowdown equipment chambers (including pipelines, compressors and vessels) in cubic feet.

T_s = Temperature at standard conditions (°F).

$T_{a,i}$ = Temperature at actual conditions (estimated) for event "i" in the blowdown chamber (°F).

P_s = Absolute pressure at standard conditions (psia).

$P_{a,0,i}$ = Absolute pressure at actual conditions at the start of event "i" in the blowdown chamber (psia).

$P_{a,f,i}$ = Absolute pressure of natural gas at actual conditions at the end of event "i" in the blowdown chamber (psia) ((if the equipment is purged using non-GHG gases then $P_{a,f,i} = 0$).]

(4) Calculate both CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas

emissions using calculations in paragraph (u) and (v) of this section. [add: This calculation can use the gas composition per §98.232(m).]

(5) Calculate total annual venting emissions for all blowdown vent stacks by adding all standard volumetric and mass emissions determined [delete: in] [add: from] Equation[add: s] W-14[add: a or W-14b] and paragraph (i)(4) of this section.

Response: EPA disagrees with the commenter. Exempt volumes already have enough clarity, and adding the word “significant” will not improve the clarity. Also, both equations result in a summed total of emissions for each unique physical volume. Please see response to EPA-HQ-OAR-2011-0512-0029, Excerpt 16 for further details. EPA agrees with the commenter on adding the word “physical” and removing “standard” where appropriate to the unique volume. EPA also agrees with the commenter and is removing any references to the words “equipment type”. A unique physical volume is a reference to one or more equipment collectively blowdown to the atmosphere and hence the term “equipment type” is unnecessary. EPA has made these changes in this final rule. EPA does not agree with the commenter on the issue of compressibility; please see response to comment number EPA-HQ-OAR-2011-0512-0041, Excerpt 3.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 4

Commenter Type: Trade Association

Comment: §98.233(i) appropriately refers to §98.233(u) and (v). This is the general methodology that INGAA recommends for all §98.233(a) – (r) subsections in Comment 20.

Response: EPA agrees with the commenter.

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 19

Commenter Type: Industry - oil and gas

Comment: (3) Blowdown vent stacks – § 98.233(i). We support and incorporate by reference the comments regarding reporting emissions from blowdown vent stacks submitted by API October 24, 2011 (Section 2 - W.21 [EPA-HQ-OAR-2011-0512-0042, Excerpt 37], W.22 [EPA-HQ-OAR-2011-0512-0042, Excerpt 38], W.23 [EPA-HQ-OAR-2011-0512-0042, Excerpt 39], and W.24 [EPA-HQ-OAR-2011-0512-0042, Excerpt 40]).

Response: Please see responses to EPA-HQ-OAR-2011-0512-0042, Excerpt 37, EPA-HQ-OAR-2011-0512-0042, Excerpt 38, EPA-HQ-OAR-2011-0512-0042, Excerpt 39, and EPA-HQ-

Commenter Name: Gregory L. Ryan
Commenter Affiliation: DTE Energy
Document Control Number: EPA-HQ-OAR-2011-0512-0041
Comment Excerpt Number: 3
Commenter Type: Industry - oil and gas

Comment: Calculating Natural Gas Venting Emissions from Blowdown Events

DTE Energy appreciates that the EPA is seeking comments on why a compressibility allowance should be provided in the equations used for calculating natural gas emissions from blowdowns [Equations W-14(a) & (b)]. We support the utilization of a compressibility correction factor in the calculation of blowdown volumes using AGA Report No. 8 to compute gas compressibility. Utilizing compressibility factors in the blowdown volume equation is consistent with required reporting of blowdown volumes to the Michigan Department of Environmental Quality as well as for financial and system balancing (Lost and Unaccounted For gas) purposes. Computing blowdown volumes using Equations W-14(a) or (b) in the proposed rule would add additional burden by requiring calculation and reporting of blowdown emissions in two separate ways to two separate environmental agencies.

A complete calculation of the quantity of gas to be blown down to atmosphere would include the internal volume of the chamber to be evacuated along with the pressure, temperature, and compressibility of the gas just prior to the blowdown event. The largest quantities of gas that are blown down are from long sections of pipelines that are taken out of service. Since pipelines are generally buried below the frost line in a given area, the coldest that the gas temperature would equilibrate to in the pipe is 32 degrees F. The impact that the temperature would have on the calculated blowdown quantity would be as large as 6% at 32 degrees F. Since most planned blowdown events occur during warmer seasons, the typical impact on the calculated quantity would likely be between 0% and 4%. Transmission system blowdowns could happen between 300 psig and 1,000 psig which correlate to compressibilities between 4% and 15 %.

EPA's equations W-14(a) and (b) require LDC's to monitor gas temperature in the blowdown equipment chamber, which is difficult to perform (See DTE Energy's Best Available Monitoring Method request, dated July 28, 2011). However, the equations completely disregard the likely more substantial impact of compressibility. It is DTE Energy's recommendation that EPA require compressibility to be included in the calculation of gas blowdowns. As an alternative, DTE Energy is recommending that each company be allowed the option to include compressibility in the blowdown volume calculation, and to identify if the company is reporting the numbers utilizing compressibility to eliminate the inconsistent reporting as described previously.

Response: EPA has considered the refinement of the blowdown equations with a compressibility factor, either voluntary with a default factor of 1 (one) or mandatory based on public literature, and decided that this improvement in accuracy does not warrant the extra

burden and creates a degree of uncertainty between reporters on how their reported blowdown values compare. Compressibility of pure light hydrocarbon substances is well known, but compressibility of mixtures is less well known and the composition of natural gas throughout the segments covered by Subpart W is highly variable. For the purposes of informing future policy, ideal gas law calculations are considered adequate. Hence, EPA is not requiring compressibility adjustment in this final rule.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Commenter Excerpt Number: 37

Commenter Type: Industry - oil and gas

Comment: Revision: EPA has clarified that emissions are to be calculated for blowdown vent stacks from depressurizing equipment to reduce system pressure for planned or emergency shutdowns or to take equipment out of service. EPA is proposing to delete “to atmosphere” because not every blowdown will result in the blowdown chamber being brought to atmospheric pressure. In addition, the preamble indicates that EPA is proposing to remove the exclusion of emergency events from blowdown vent stack emissions.

Comment: The preamble (page 56020) indicates that EPA intends to only “cover the type of blowdowns typically tracked by operators for planned maintenance or emergency situations.” The preamble goes on to state that these amendments propose to overturn the exclusion of emergency events proposed in the August 4, 2011 amendments because EPA has since learned that operators track emergency shutdowns.

API disagrees with this assessment. While it is true that emergency blowdowns at gas plants may be tracked, such releases are not tracked with the specificity required under 98.233(i). In addition, many of the emergency events are routed to a flare, in which case they would not be reportable under 98.233(i). Due to the unexpected occurrence of such events, it may not be possible to determine the actual volume of gas released.

Response: EPA disagrees with the commenter. First, EPA requires only emergency blowdowns with human or manned intervention to be tracked. Please see response to EPA-HQ-OAR-2011-0512-0029, Excerpt 14. Second, blowdowns of GHG emissions are to be reported under 98.233(i) and not 98.233(n). See 40 CFR 98.233(n)(10) for further details.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 38

Commenter Type: Industry - oil and gas

Comment: [Please refer to the original comment text posted in the docket] Revision: The

preamble (page 56020) indicates that EPA is providing reporters the option of tracking blowdowns by each occurrence for the same blowdown volume: “To enable facilities to retain their current tracking system, we are proposing to add an option for calculating emission by equipment type” (emphasis added). However, the regulatory language does not provide an option, but rather blends the two approaches. 98.233(i)(3) requires calculating the total emissions for each equipment type using either Equation W-14A or W-14B. While, the term “N” used in these equations is defined as the number of repetitive blowdowns for each unique volume in the calendar year.

Comment:

API suggests that EPA revise the definition of term “N” to present the option of using unique volume or equipment: “N= number of repetitive blowdowns for each unique [add (red): volume or equipment type] in calendar year.”

EPA should similarly revise the text under 98.233(i)(3): “Calculate the total annual venting emissions for each [add (red): unique volume or] equipment type ...”.

API also requests that EPA delete the words “and mass” under 98.233(i)(5). This correction is consistent with the calculation approach for blowdown vent stacks which result in volumetric emissions, not mass.

Response: In this final rule EPA has clarified 98.233(i) by using unique physical volume only to avoid any confusion; please see response to EPA-HQ-OAR-2011-0512-0029, Excerpt 36 for further details. In this final rule, EPA has deleted the paragraph under 98.233(i)(5), and hence the issue of “and mass” is no longer relevant.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 39

Commenter Type: Industry - oil and gas

Comment: Revision: EPA has added Equation W-14B, which appears to apply where equipment is only partially blown down.

Comment: API suggests that a statement be added to 98.233(i)(3) to indicate when Equation W-14B should be applied. In addition, the equation should include the same adjustment for purging the equipment as is used in Equation W-14A. The modified equation is provided below.

[See original comment for equation]

Response: EPA disagrees with the commenter. Equation W-14B can be used, as proposed and now finalized, regardless to which pressure the equipment is blown down. If the equipment is purged, an adjustment is provided in the definition of variable “ $P_{a,e,p}$ ” where the final pressure is

taken to be zero.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 40

Commenter Type: Industry - oil and gas

Comment: Revision: EPA revised 98.233(i)(5) to reference emissions determined under Equations W-14A and W-14B.

Comment: 98.233(i)(5) requires calculating the total annual venting emissions for all blowdown vent stacks “by adding all standard volumetric and mass emissions determined using

Equations W-14A and W-14B.” API requests the phrase “and mass” be deleted from this statement as neither Equations W-14A nor B result in mass emissions. Paragraph (5) should be placed before paragraph (4), which references 98.233(v) for the conversion of volumetric emissions to mass emissions.

Response: Please see responses to EPA-HQ-OAR-2011-0512-0042, excerpt 38.

Section 7.12.2 - Data Reporting Requirements

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 16

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] Reporting requirements for blowdown vent stacks must be revised to be consistent with emission estimates calculated using Equation W-14A and Equation W-14B of §98.233(i).

The reporting criteria in §98.236(c)(7) should be revised to reflect different requirements depending on whether Equation W-14A or W-14B is used. For example, a "unique volume" attribute may be considered a reportable data element when using Equation W-14A, but it is not applicable for Equation W-14B.

Reporting of blowdown events could be based on one of three approaches: (1) use equation W-14A for calculating all facility emissions if all blowdown events can be categorized by unique physical volume with invariant blowdown gas parameters, and events are always associated with a unique blowdown stack; (2) use equation W-14B to sum the emissions for all facility blowdown events; or (3) use Equation W-14A for calculating emissions from equipment that have a unique physical volume, invariant blowdown gas parameters, and are associated with a unique blowdown stack, and use equation W-14B to sum the emissions the remaining facility blowdown events (i.e., both equations are used during a year, depending on the type of event).

For natural gas transmission and storage operations, it is anticipated that option (2) will be commonly used based on Equation W-14B.

The Proposed Rule revision that requires reporting of a unique name or ID for each blowdown stack does not apply for emissions calculated using equation W-14B. During real-world operations, equipment gas releases are not always associated with a specific or unique stack. In addition, multiple equipment groupings could be vented through a single stack. Thus, unique blowdown vent stack reporting is not appropriate when using Equation W-14B.

Reporting requirements need to be revised to address the different methods for estimating blowdown vent stack emissions. INGAA recommends the following revisions to §98.236(c)(7):

“(7) For [delete: each] blowdown vent stack[add: s] [delete: (refer to Equation W-14 of §98.233)], report the following:

(i) [delete: Total number of blowdowns per unique volume type in calendar year.] [add: For blowdown vent stack emissions calculated using Equation W-14A, report the following for each blowdown vent stack:

(A) Total number of blowdowns per unique volume type in calendar year.

(B) Annual CO₂ and CH₄ emissions, expressed in metric tons CO₂e for each gas, for each unique volume type, at each blowdown stack.

(C) A unique name or ID number for the blowdown vent stack.]

(ii) [delete: Annual CO₂ and CH₄ emissions, expressed in metric tons CO₂e for each gas, for each unique volume type, at each blowdown stack.] [add: For blowdown vent stack emissions calculated using Equation W-14B, report the following:

(A) Total number of blowdowns in calendar year.

(B) Total annual CO₂ and CH₄ emissions, expressed in metric tons CO₂e for each gas.]

[delete: (iii) A unique name or ID number for the blowdown vent stack.”]

Response: EPA is clarifying that Equations W-14A and W-14B are equivalent, except that W-14B allows for accounting of variations in emission volume from multiple occurrences of blowdown from the same unique physical volume. EPA disagrees with the commenter in item (1) above that W-14A is used when “events are always associated with a unique blowdown stack”. Furthermore, EPA is allowing Equation W-14A or W-14B to be used for either multiple blowdowns of the same unique physical volume or one-time blowdowns of unique physical volumes.

Therefore, the summation in W-14B is over multiple occurrences of the same unique physical volume and not a summation over the entire facility (which was never stated in the September 2011 proposal). Therefore, EPA disagrees with items (2) and (3) in the comment. The “unique

physical volume” applies to a set of equipment, not different sets of equipment that may have the same calculated volume. In other words, if two or three compressors are virtually identical design and construction, and have the same unique physical volume between isolation valves within the accuracy of engineering estimation, and each is blown down multiple times per year, they are reported individually using either Equation W-14A if the actual volume of gas vented is approximately the same in starting and ending temperature and pressure, or Equation W-14B if the starting temperature and pressure change from blowdown to blowdown.

EPA agrees with the comments to exclude assigning a unique name or ID number for blowdown vent stacks, given there may be multiple choices and different amounts blowdown through different vents. Instead, EPA is taking the emphasis in this reporting requirement off the stack and applying it to the unique physical volume. In addition, EPA agrees that there are many unique physical volumes that are blowdown only once a year and is allowing for reporting of emissions from them as an aggregate at the facility level. Therefore, the unique name or ID should be associated with the unique physical volumes that are blown down multiple times in a reporting year, not the blowdown stack or vent, and not one-time blowdown unique physical volumes.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 54

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] (7) For [delete: each] blowdown vent stack[add: s] (refer to Equation W-14[add: a or W-14b] of §98.233), report the following:

(i) Total number of blowdowns per equipment type in calendar year [add: for Equation W-14a].

(ii) [add: Total number of blowdowns in calendar year for Equation W-14b.] [comment bubble JMc12: As noted in section 98.233(i), for facility blowdowns calculated using Eq W-14b, most or all events will include a unique volume, so tracking counts “per equipment type” is not appropriate]

[add: (iii)] Report emissions collectively [delete: per equipment type].

Response: EPA agrees with the text in the opening paragraph allowing for either use of Equation W-14A or Equation W-14B and in this final rule is clarifying the text accordingly. EPA agrees that reporting by “equipment type” is irrelevant in the context of “unique physical volume”. However, EPA disagrees with the commenter that the total number of occurrences should be reported only in the case of Equation W-14B. In this final rule, the number of occurrences for each unique physical volume that is blown down more than once a year must be reported.

For further details on reporting blowdown emissions, please see response to EPA-HQ-OAR-2011-0512-0029, Excerpt 16.

Section 7.13 - Onshore Production Storage Tanks

Commenter Name: William W. Grygar II

Commenter Affiliation: Anadarko Petroleum Corporation

Document Control Number: EPA-HQ-OAR-2011-0512-0028

Comment Excerpt Number: 9

Commenter Type: Industry - oil and gas

Comment: Under §98.233(j)(1)(Vii)(B) and (C), the sub-basin category definition is referenced in regards to separator oil composition. Oil sub-basin categories are also required under §98.233(m). The current definition of sub-basin category does not have any reference to oil wells. Anadarko supports API's recommendations on how best to define oil well sub-basin categories.

Response: EPA agrees with the commenter and in this final rule has added an oil formation to the sub-basin category definition. Please see preamble Section II.C – Final Amendments to the Petroleum and Natural Gas Systems Source Category – Major Changes Since Proposal and Section II.D.9 - Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Addition of oil formation type in the sub-basin category definition for further details.

Section 7.13.1 - Calculating GHG Emission [W-15, W-16]

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 20

Commenter Type: Industry - oil and gas

Comment: Onshore production tanks – § 98.233(j). EPA has proposed that reporters provide the annual total volumetric GHG emissions for storage tanks based on a representative sample for the sub-basin. Chesapeake and AXPC support this change, but EPA must also provide a definition for sub-basin as applied to oil wells. See Section A.8 supra.

Notably, the proposed revision to the rule does not remedy the primary problem with § 98.233(j) – knowing how long a dump valve has been stuck open. Subpart W states that the number of hours a dump valve is stuck open may be established through "maintenance or operations records." 75 Fed. Reg. at 74,497 (Nov. 30, 2010). If a company has no records to establish how

long a valve was open, it must assume it was open for the entire portion of the calendar year until the open valve was discovered and repaired. Id. However, doing so would grossly overstate the emissions from dump valves.

Onshore production companies typically have thousands of dump valves per reporting facility or basin that would require frequent monitoring and recordkeeping. One AXPC company alone has determined that it has over 6,700 separators. Another company has reported that it has approximately 8,000 separators. Each separator has one or two dump valves. Even if a field technician were obligated to begin recording the position of every dump valve during each visit to a site, not every dump valve can feasibly be checked on a daily basis. Many field technicians are assigned to routes that cover 30 to 100 different sites. The frequency that a field technician visits each site varies according to the extent of his or her route. Some field technicians whose routes don't cover as much territory are able to visit each site every few days, while those with larger routes are only able to visit each site around every two weeks. Therefore, even relying on records from scheduled site visits would likely overestimate the duration that a valve was stuck open, as it may be several days or weeks between scheduled site visits.

The assumption that dump valves stay stuck open for long periods of time disregards the reality that onshore production companies have an economic interest in minimizing losses of natural gas. As a result, most large companies closely monitor process data, typically on a daily basis from a remote location. If data shows conditions such as a sudden pressure drop, a low level in the separator, or an increase in the amount of fluid in the tank, a field technician will typically be sent to the site to investigate whether a dump valve was stuck open or if there is another operational problem. Such non-routine site visits are typically conducted within about 24-hours of the onset of irregular operational conditions. Furthermore, if companies detect that a certain valve model has a higher occurrence of sticking open, they will usually stop purchasing those types of valves in favor of those that malfunction less frequently.

However, it is not industry practice to require field technicians to maintain checklists indicating whether every dump valve at every site was operating properly. Rather, as operational problems arise, corrections are made in the field as a matter of routine business practices. Therefore, the present text imposes a very large manual recordkeeping obligation for a problem that rarely occurs and for which a timely response is triggered by ongoing monitoring.

One AXPC member has reviewed data for several of its fields and estimates that dump valves get stuck open approximately 1% of the time in a given year. Despite the infrequency of its dump valves getting stuck open, this operator would still need to develop a system to manage a massive number of forms documenting that dump valves are operating properly 99% of the time. A system would need to be developed to retain thousands of forms, which would be filled out at varying frequencies – every few days for wells that are visited regularly and up to every few weeks for others. All of these forms would need to be reviewed on a regular basis (at least weekly or monthly) by the appropriate personnel to:

- assess whether any valves had been stuck open,
- if so, review operational records/maintenance records/production data preceding the discovery of the stuck valve,

· calculate the emissions associated with the stuck valve, and document the emissions in a format that will facilitate annual reporting.

AXPC and Chesapeake object to this requirement because it imposes an unreasonable burden on reporters for no environmental benefit and because assuming a valve was stuck open for an extended period of time would create large inaccuracies in emission reporting. Furthermore, reporters were not provided with an opportunity to comment on this reporting obligation during the notice and comment period. EPA alleges that onshore production was provided notice of the dump valve monitoring requirement by the inclusion of a statement regarding tank emissions not being "represented by the equilibrium conditions of the liquid in a gas-liquid separator and calculated by E&P Tank. . . ." 75 Fed. Reg. at 18,640 (Apr. 12, 2010). This alleged notice did not refer to "dump valves" and was interpreted as referring to problems other than a stuck dump valve, such as a separator that is too small. For these reasons, we believe the requirement should be removed from the rule.

Response: EPA agrees with the comment regarding an oil sub-basin and has revised the definition for sub-basin in 40 CFR 98.238 to include an oil formation within the sub-basin category; please see the preamble Section II.C. -- Final Amendments to the Petroleum and Natural Gas Systems Source Category – Major Changes Since Proposal and Section II.D.9 - Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Addition of oil formation type in the sub-basin category definition for further details. EPA disagrees with the commenter on the accounting of emissions from leaky dump valves. EPA has provided the simplest monitoring method to account for these emissions. The commenter states that "As a result, most large companies closely monitor process data, typically on a daily basis from a remote location." Hence, EPA believes that this monitoring can be used to maintain a simple log of disruptions in dump valve functioning. Finally, the information that AXPC member collected is what EPA expects to account for malfunctioning dump valves. Therefore, EPA has retained the requirement to account for malfunctioning dump valves.

Commenter Name: Jessica Stark

Commenter Affiliation: SLR International Corp

Document Control Number: EPA-HQ-OAR-2011-0512-0040

Comment Excerpt Number: 4

Commenter Type: Industry - oil and gas

Comment: 98.233(j) Onshore Production Storage Tanks

I would like to request that Calculation Methodology 2 be modified to allow a representative sample of separator oil composition at separator temperature and pressure to be used to estimate dissolved gas concentrations for all wells in the same field (or sub-basin category if that is retained). The only alternative calculation method for oil or condensate flowing through a separator on the same well-pad as the producing well (with a throughput greater than 10 barrels per day) is Calculation Methodology 1, requiring modeling of each tank. One of my clients owns thousands of tanks located on well pads and would prefer the flexibility to calculate dissolved

gas emissions. The modeling exercise is too onerous. Requiring an oil sample from each on-pad separator with a throughput greater than 10 barrels per day is going to be very expensive and is not consistent with the other calculation methods in Subpart W allowing use of representative sample data under reasonably similar conditions. My client does not currently have any separator oil sample results. Separator sample results are not going to vary greatly within the same reservoir.

Response: EPA has considered this comment and concludes it is out of scope with the Technical Revisions to the Petroleum and Natural Gas Systems Category of the GHG Reporting Rule. The only proposed change made to Methodology 2 under 98.233(j) was the replacement of the term “field” with “sub-basin,” and therefore the commenter’s suggested alteration is out of scope.

Section 7.13.2 - Data Reporting Requirements

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 59

Commenter Type: Industry - oil and gas

Comment: Revision: 98.236(c)(8)(i)(J) requires reporting emissions for each wellhead gas-liquid separator or storage tank.

Comment: Previously, the rule required separate reporting for Methodologies 1 and 2, which did not imply separate reporting for each separator or tank. A basin can have well over 1000 separators. This is a significant expansion of the regulatory requirements introduced through these rule amendments as discussed in Section 1, Comment A [EPA-HQ-OAR-2011-0512-0042, Excerpt 2], above.

Response: In this final rule, EPA has amended the requirement to report emissions at a sub-basin level; please see the response to EPA-HQ-OAR-2011-0512-0042, Excerpt 2 for further details.

Section 7.14 - Transmission Storage Tanks

Section 7.14.1 - Calculating GHG Emission

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 5

Commenter Type: Trade Association

Comment: §98.233(k) appropriately refers to §98.233(u)(2)(iii).

Response: EPA thanks the commenter for their remarks.

Commenter Name: Curtis J. Winner

Commenter Affiliation: New Mexico Gas Company (NMGC)

Document Control Number: EPA-HQ-OAR-2011-0512-0047

Comment Excerpt Number: 5

Commenter Type: Industry - oil and gas

Comment: Transmission Storage Tanks

NMGC supports EPA's proposed revision of 98.233(k) to include the option of directly measuring the transmission storage tanks. This allows NMGC to measure emissions from storage tanks at compressor stations using equipment NMGC currently owns without purchasing additional equipment. This option is more cost effective for NMGC and obtains the same data as the current rule.

Response: EPA thanks the commenter for their remarks and is finalizing the requirements in this final rule.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 17

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] Transmission tanks:

10. INGAA supports Proposed Rule revisions in §98.233(k)(1) that add flexibility for transmission tank vent measurement. However, the proposed text requires minor revisions to improve clarity and consistency with the measurement methods.

INGAA supports options added to §98.233(k)(1) for detecting and measuring leaks. The revisions are based on INGAA recommendations, and the following revision is from the EPA redline version of the rule:

“(1) Monitor the tank vapor vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in §98.234(a)(1) [add: or by directly measuring the tank vent using a flow meter, calibrated bag, or high volume sampler according to methods in §98.234(b) through (d) for a duration of 5 minutes.] [delete: for a duration of 5 minutes.] Or you

may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in §98.234(a)(5)."

This text and associated text in (k)(2) requires a minor revision because a five minute sampling duration may not be appropriate for all methods. For example, a calibrated bag, which is a reasonable method, may fill in less than five minutes, so the specified duration is not appropriate. The five minute duration was originally included for optical imaging to ensure a sample time that captures a leaky dump valve rather than a release associated with a dump cycle, and five minutes is essentially an arbitrary choice. The other measurement approaches added to (k)(1) can identify the appropriate source (i.e., a leaky dump valve), but may accomplish this in a shorter time period. The text in (k)(1) that refers to "a 5 minute duration" should be revised to indicate, "a duration of 5 minutes or a duration adequate to demonstrate continuous leakage rather than a dump cycle release." In addition, related text in (k)(2)(i) appropriately refers to "continuous leakage" and the text, "...for five minutes..." is not necessary and should be deleted.

Response: EPA thanks the commenter for their remarks on flow meter, calibrated bag, and high volume sampler options. EPA agrees that the five minute measurement duration should not apply to measurements carried out by calibrated bags. Therefore, in this action EPA has modified the associated rule provisions accordingly.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 37

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] Transmission storage tanks.

[highlighted text: Correct reference to flaring in intro, add monitoring method flexibility, and delete reference to flaring calculation (broadly addressed in §98.232(j) and not needed in this section)]

For condensate storage tanks, either water or hydrocarbon, [delete: without vapor recovery or thermal control devices] in onshore natural gas transmission compression facilities calculate CH₄[delete: ,] [add: and] CO₂ [delete: and N₂O (when flared)] annual emissions from compressor scrubber dump valve leakage as follows:

(1) Monitor the tank vapor vent stack annually for emissions using an optical gas imaging instrument according to methods [delete: set forth] in §98.234(a)(1) [add: or by directly measuring the tank vent using a flow meter, calibrated bag, or high volume sampler according to methods in §98.234(b) through (d)] for a duration of 5 minutes. Or you may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods [delete: set forth] in §98.234(a)(5).

(2) If the tank vapors are continuous for 5 minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (k)(2) of this section to [add: estimate] [delete: quantify] emissions:

(i) Use a meter, such as a turbine meter, [add: calibrated bag, or high flow sampler] to estimate tank vapor volumes according to methods [delete: set forth] in §98.234(b) [add: through (d)]. If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapor vent stack. [add: If the vent is directly measured for five minutes under section (1) to detect continuous leakage, this serves as the measurement. If a leak of 3.1 SCF per hour or greater is measured, a leak is detected and must be reported.]

(ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in §98.234(a)(5).

(3) [delete: (iii)] [add: Calculate both CH₄ and CO₂ volumetric and mass emissions using calculations in (u) and (v) of this section, and using] [delete: Use] the appropriate gas composition in paragraph (u)(2)(iii) of this section [add: or the gas composition allowed in §98.232(m).]

(4) [delete: (3)] If the leaking dump valve(s) is repaired following leak detection, the annual emissions shall be calculated from the beginning of the calendar year to the time the valve(s) is repaired.

[delete: (4) Calculate emissions from storage tanks to flares as follows:

(i) Use the storage tank emissions volume and gas composition as determined in either paragraph (j)(1) of this section or with an acoustic leak detection device in paragraphs (k)(1) through (k)(3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine storage tank emissions from the flare.]

Response: EPA disagrees with the deletion of reference to 98.233(n) when emissions are sent to a flare. The reporter must either meter or use an acoustic device to estimate emissions that are going to a flare and report the emissions under 98.233(k).

EPA agrees with the commenter on the deletion of “thermal control devices” in the opening paragraph to 98.233(k) and has amended this final rule accordingly. EPA has reviewed the comment about the deletion of “without vapor recovery units” and disagrees with the deletion of this term. EPA’s intent is to cover transmission storage tanks without vapor recovery, as is stated in 98.233(k). EPA disagrees with the deletion of N₂O emissions. When emissions are sent to a flare, EPA requires reporters to use 98.233(n) to determine CH₄, CO₂ and N₂O emissions.

EPA thanks the commenter for their remarks on flow meter, calibrated bag, and high volume sampler options. For additional changes to measurement options, please see response to EPA-HQ-OAR-2011-0512-0029, Excerpt 17.

EPA disagrees with the commenter on the change suggested to 98.233(k)(2). Reporters are required to physically quantify leaks using methods in 98.233(k)(2), not estimate them. Reporters are required to measure and quantify leaks, if detected, using 98.233 (k)(2). 98.233 (k)(2) refers the reporter to 98.233 (k)(1) and appropriate sections in 98.234 to explain how they should estimate the emissions. Therefore it is not appropriate to use the term “estimate” in the rule language for 98.233 (k)(2).

EPA agrees with the commenter on allowing the 5 minute measurement in 98.233(k)(1) to be the necessary measurement in 98.233(k)(2)(i). However, EPA disagrees with the 3.1 scf per hour limit other than for acoustic leak detection devices; any leak measured must be reported.

EPA agrees with the commenter on adding references to (u) and (v) to 98.233(k)(2). EPA disagrees with the reference to 98.232(m); please see response EPA-HQ-OAR-2011-0512-0029, Excerpt 3 for further details.

EPA agrees that multiple transmission storage tanks may be connected to the same vent; therefore the tank may not be the monitored source. In this final rule, EPA is requiring the venting emissions from transmission storage tanks be monitored and reported per vent stack.

Section 7.14.2 - Data Reporting Requirements

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 18

Commenter Type: Trade Association

Comment: Reporting a unique name or ID for each transmission tank does not provide relevant information. EPA should eliminate the revision that adds this reporting requirement.

As noted in Comment 13, INGAA supports method and monitoring flexibility in the Proposed Rule. INGAA does not support a new reporting requirement proposed for transmission tanks. §98.236(c)(9)(iii) adds a requirement to report "a unique name or ID for the transmission storage tank." INGAA does not agree with this revision because it does not provide meaningful information. The tank is not the emission source or the monitored source. For example, multiple tanks are often tied into a single vent, and the vent, not the tank, will be monitored. In addition, providing a unique name or ID for the transmission storage tank may cause confusion with the tank ID under an existing SPCC plan. EPA should eliminate this requirement from the Final Rule.

Response: EPA agrees that there may be cases where multiple transmission storage tanks may be connected to the same vent. In this final action, EPA has amended the provisions in 40 CFR 98.233(k) and 98.236(c)(9) accordingly. Also finalized in this action is the requirement for reporters to assign a unique name or ID to for the vent stack that is being monitored according to

40 CFR 98.233(k). Please see preamble Section II.D.3 - Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Unique name or ID reporting requirements for further details.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 55

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] For transmission tank [delete: emissions identified using optical gas imaging instrument per §98.234(a) (refer to §98.233(k)), or acoustic leak detectionof] scrubber dump valves, report the following for each tank:

(i) Report emissions individually [add: for each tank].

(ii) [Reserved]

Response: EPA does not agree with the commenter. EPA agrees that additional clarification is needed when asking operators to “report emissions individually”, however, EPA is amending the requirement 40 CFR 98.234(c)(9)(i) and 40 CFR 98.234(c)(9)(iii) to have emissions reported per vent stack, please see EPA-HQ-OAR-2011-0512-0029, Excerpt 37 and preamble Section II.D.3 - Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Unique name or ID reporting requirements for further details. EPA disagrees with modifying paragraph 98.236(c)(9) since commenter’s suggestion of removing text adds no additional clarity to the data reporting requirements.

Section 7.15 - Well Testing Venting and Flaring

Section 7.15.1 - Calculating GHG Emission [W-17]

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 12

Commenter Type: Industry - oil and gas

Comment: EPA has requested comments regarding how to reduce the burden where companies verify that zero emissions are associated with this well testing venting and flaring, such as when a closed loop system is employed. Where a reporter deems that there are zero emissions to report under well testing venting and flaring, EPA should require no additional reporting under §

98.233(l) aside from indicating the source has zero emissions from well testing venting and flaring.

Response: EPA would like to clarify that the data reporting section (98.236) applies to emission sources that need to be monitored as per requirements in 98.233. If a well is tested using a closed loop system that does not result in either venting or flaring, then the reporter would report zero emissions.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 7

Commenter Type: Industry - oil and gas

Comment: Well testing venting and flaring

On page 56031 of the September 9, 2011 preamble, EPA is addressing well testing and venting and flaring. Among other things, EPA is considering, but has not yet proposed, using the production rate to estimate the volume of emissions from venting and testing gas wells that produce dry gas. EPA is soliciting comments on this suggested provision for gas wells.

API Response:

API agrees that production rate could be used as an estimate of gas flow rate.

Response: EPA agrees with the commenter and in this final rule has added a new equation (W-17B) to provide for testing on dry gas producing wells.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 8

Commenter Type: Industry - oil and gas

Comment: Emissions associated with well testing

On page 56031 of the September 9, 2011 preamble EPA states, "EPA has determined that during well testing, some states allow companies to flare sour gas for a maximum of 72 or 144 hours.

EPA has concluded that this approach would result in emissions from this source that should be reported under this rule. If, however, for some reason reporters do not have any emissions from this source (e.g., states do not allow venting or flaring from well testing), they would report zero emissions. Thus, EPA is retaining well testing venting and flaring in the rule.

EPA is seeking comment on how to reduce or eliminate burden in cases where companies verify that zero emissions are associated with this potential source, such as when a closed loop system is employed.

API Response:

Many of the source types specified for reporting under Subpart W may have zero emissions for reporting facilities, including no venting during well testing. These zero emissions should be reported consistently with zero emissions from other affected sources.

Response: Please see response to EPA-HQ-OAR-2011-0512-0033, Excerpt 12 for requirements on data reporting.

Section 7.15.2 - Data Reporting Requirements

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 60

Commenter Type: Industry - oil and gas

Comment: Revision: For well testing venting and flaring, EPA has added the requirements to report CO₂ and CH₄ emissions at the facility level, and CO₂, CH₄ and N₂O emissions at the facility level from flaring.

Comment: API supports this reporting at the facility level.

Response: EPA thanks the commenter for their remarks.

Section 7.16 - Associated Gas Venting and Flaring

Section 7.16.1 - Calculating GHG Emission [W-18]

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 42

Commenter Type: Industry - oil and gas

Comment: [Please refer to the original comment text posted in the docket] Revision: For associated gas venting and flaring, EPA has replaced field with sub-basin category for determining the separator oil composition and Reid vapor pressure.

Comment: API supports the revision for sub-basin. However, sub-basin here should apply to oil wells based on the “oil formation” sub-basin category proposed by API above. In addition, API interprets “associated gas” to mean natural gas produced with crude oil that is not recovered for sales due to the lack of infrastructure. This is consistent with a response EPA posted to the list of Frequently Asked Questions on Subpart W, which indicated “Section 98.233(m) only covers natural gas that is not recovered from the production operation.”

With the introduction of the sub-basin concept, it is now unclear what the geographic boundaries are for the volume term used in Equation W-18. The objective of the sub-basin approach is to reduce sampling burden. API requests that EPA clarify that the volume used in Equation W-18, and the resulting emissions from Equation W-18, represent the oil formation at the entire basin level. Paragraph (1) should be modified to state “If GOR from each well is not available, the GOR from a cluster of wells in the [add (red): basin] shall be used.” With these changes, the terms in Equation W-18 will be consistent with the reporting requirements under 98.236(c)(11)(iii) and (iv).

Response: EPA agrees that an oil well sub-basin category is needed and in this final rule, has made included the oil-formation type in the sub-basin category definition. Please see preamble Section II.C. – Final Amendments to the Petroleum and Natural Gas Systems Source Category – Major Changes Since Proposal and Section II.D.9 - Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Addition of oil formation type in the sub-basin category definition for further details.

EPA agrees with the FAQ response as it relates to “associated gas venting and flaring”.

EPA agrees conditionally that equation W-18 and the associated parameters need clarification. EPA agrees that the data reporting requirements ask for emissions summed on a facility level, and EPA has modified the equation accordingly. However, EPA disagrees that both GOR and volume should be used on a facility level to calculate emissions. GOR can vary widely within a basin, and therefore individual well GOR should be used. If this data isn’t available, paragraph 98.233(m)(1) provides an alternative method to determine GOR. This method allows the reporter to use the average GOR from a cluster of wells in the same sub-basin as a surrogate data for wells for which the GOR is unknown.

Section 7.16.2 - Data Reporting Requirements

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 61

Commenter Type: Industry - oil and gas

Comment: Revision: For associated gas venting, EPA has added the requirements to report CO₂ and CH₄ emissions at the facility level, and CO₂, CH₄ and N₂O emissions at the facility level from flaring.

Comment: API supports this reporting at the facility level.

Response: EPA thanks the commenter for their remarks.

Section 7.17 - Flare Stack Emissions

Section 7.17.1 - Calculating GHG Emission [W-19 to W-21]

Commenter Name:

Commenter Affiliation: Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2011-0512-0026

Comment Excerpt Number: 4

Commenter Type: Industry - other

Comment: EPA should clarify whether or not emissions from flares should be reported for sources in the underground storage of natural gas category.

Section 98.232(f) requires that the owner/operator calculate CO₂, CH₄, and N₂O emissions from the following sources:

1. Reciprocating compressor rod packing;
2. Centrifugal compressor venting;.
3. Natural gas pneumatic device venting; and
4. Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

Thus, section 98.232(f) does not require reporting emissions from flares. However, the introductory sentence to 98.232(f) does require reporting of N₂O emissions. Furthermore, Page 56028 of the Federal Register preamble contains a statement which says: “we are proposing to revise the introductory sentences to 40 CFR 98.232(e), (f), (g), (h), and (i) to clarify that N₂O emissions, which are the primary GHG emissions from flaring, are also required to be reported under these industry segments. Thus, the preamble and the introductory sentence suggest that emissions from an associated flare must be included in the calculations for underground natural gas storage.

Thus, it is unclear whether or not the flare emissions must be calculated for this source category, and if so, should the provisions contained in 98.233(n) for flares be followed?

Response: In this action, EPA has clarified that any emission source types for which there are methods in 98.233 where emissions are being sent to a flare, reporters must use provisions in 98.233(n) to estimate flare emissions and report the emissions under the same emission source, and not under flare category. For example, the centrifugal compressor emission source type

listed for Underground Storage of Natural Gas has a reference to paragraph 98.233(n) for emissions routed to a flare. The emissions from the centrifugal compressor venting routed to a flare must be calculated as outlined in 98.233(n), however, the emissions must be attributed to the source type where the gas originated (i.e. centrifugal compressor venting). EPA requires monitoring of emissions from the four sources listed under 98.232(f), but any emissions from those sources sent to a flare must be calculated as outlined in 98.233(n).

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 38

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] [highlighted text: §98.233(n) PROVIDED HERE FOR REFERENCE ONLY – NO CHANGES... “Efficiency” calcs in Equations W-19 and W-20 are shown here because these are referenced in proposed new section §98.232(j)(1) [see above] for calculating “reduction efficiency” from §98.233 sources.]

(n) Flare stack emissions. Calculate CO₂, CH₄, and N₂O emissions from a flare stack as follows:

(4) Calculate GHG volumetric emissions at actual conditions using Equations W–19, W–20, and W–21 of this section.

[See original comment for Eq. W-19, W-20, and W-21]

Where:

$E_{a,CH_4(un-combusted)}$ = Contribution of annual un-combusted CH₄ emissions from flare stack in cubic feet, under actual conditions.

$E_{a,CO_2(un-combusted)}$ = Contribution of annual un-combusted CO₂ emissions from flare stack in cubic feet, under actual conditions.

$E_{a,CO_2(combusted)}$ = Contribution of annual combusted CO₂ emissions from flare stack in cubic feet, under actual conditions.

V_a = Volume of gas sent to flare in cubic feet, during the year.

η = Fraction of gas combusted by a burning flare (default is 0.98). For gas sent to an unlit flare, η is zero.

X_{CH_4} = Mole fraction of CH₄ in gas to the flare.

X_{CO_2} = Mole fraction of CO₂ in gas to the flare.

Y_j = Mole fraction of gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes-plus).

R_j = Number of carbon atoms in the gas hydrocarbon constituent j : 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes-plus).

Response: EPA thanks the commenter for their remarks.

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 21

Commenter Type: Industry - oil and gas

Comment: Flare stack emissions – § 98.233(n). EPA has proposed a new equation to calculate combusted emissions, clarified that if a facility has CEMS the Tier 4 calculation methodology must be used, and verified that flare emissions reported in this part must be corrected for flare emissions calculated and reported under other paragraphs to avoid double counting. We support and incorporate by reference API’s comments W.27 [EPA-HQ-OAR-2011-0512-0042, Excerpt 43] and W.28 [EPA-HQ-OAR-2011-0512-0042, Excerpt 44] in Section 2 of its October 24, 2011 letter to EPA.

Response: Please see responses to EPA-HQ-OAR-2011-0512-0042, Excerpt 43 and EPA-HQ-OAR-2011-0512-0042, Excerpt 44.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 43

Commenter Type: Industry - oil and gas

Comment: Revision: For flare stack emissions, EPA added a provision for natural gas processing plants that solely fractionate a liquid stream. In this situation, the GHG mole percent in feed natural gas liquids is applied for all streams.

Comment: API’s understanding of the phrase “fractionating a liquids stream” means that the input to the plant is solely NGL.

Response: EPA agrees that fractionating a liquids stream means that the input to the plant is solely a hydrocarbon liquid stream.

Commenter Name: Karin Ritter
Commenter Affiliation: American Petroleum Institute (API)
Document Control Number: EPA-HQ-OAR-2011-0512-0042
Comment Excerpt Number: 44
Commenter Type: Industry - oil and gas

Comment: Revision: EPA added clarification that for source types in 98.233 that use Equations W-19 through W-21 for flare emissions, an estimate of emissions under actual conditions are to be used for the parameter V_a . The preamble (page 56032) states that “this is consistent with other proposed changes throughout this revision that clarify the use of actual versus standard conditions.

Comment: Industry’s common practice is to track all gas flow rates in standard cubic feet at 60 °F and 14.7 psia. The parameters V_a and E_a in Equations W-19 through W-21 should be defined in terms of standard cubic feet and use the subscript “s” to indicated standard conditions.

Response: EPA disagrees with the commenter. EPA’s understanding from this comment is that flow rate readout from the meter is for standard conditions of 60°F and 14.7 psia. As long as this flow rate readout has been appropriately converted to standard conditions, then this flow rate may be used in Equations W-19, W-20, and W-21. Currently paragraph 98.233(n)(5) refers reporters to paragraph 98.233(t) to convert emissions at actual conditions to standard conditions. Assuming the flow rate reading from the meter is at standard conditions of 60°F and 14.7 psia, then in that case when the emissions calculated by Equations W-19, W-20, or W-21 are converted to standard conditions by using paragraph 98.233(t) (either equation W-33 or W-34), then the actual condition emissions would essentially be multiplied by 1 (since the reporting conditions are standard conditions), and the standard condition emissions would be the same as the actual condition emissions. However, not all meters may measure at STP or at the same STP as required in the rule. Hence the change suggested by the commenter is unnecessary. Therefore, EPA is retaining the definition of V_a and E_a in equations W-19, W-20, and W-21 and the reference to paragraph 98.233(t).

Section 7.18 - Leak Detection and Leaker Emission Factors

Section 7.18.1 - Calculating GHG Emission [W-30]

Commenter Name:
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2011-0512-0026
Comment Excerpt Number: 3
Commenter Type: Industry - other

Comment: EPA should provide an option for the owner/operator to take credit in the equipment leak calculations if the owner/operator fixes a leaking component before the end of the year.

Equation W-30 requires the input of the total time (T) that a component was found leaking and

operational. If one leak detection survey is conducted, the owner/operator must assume the component was leaking for the entire calendar year. Dow's practice is generally to repair leaking components. Thus, Dow suggests that the owner/operator be provided an option to determine the number of hours that a component is leaking by taking the hours between January 1st and the time that a leaking component has been repaired. Such a change to the rule will allow for increased accuracy in the GHG emissions reporting, and will allow the owner/operator the ability to use the population emission factors for the period of time that a component is not leaking.

Response: In the November 2010 rule EPA did provide an option for reporters to conduct more than the one mandatory leak detection survey and account for leaks that are fixed. Hence, EPA disagrees with the commenter that there is no option in the rule to account for leaking components that have been repaired. To verify that leaking components have been repaired and are no longer leaking, a second, subsequent leak detection survey must be performed on the entire facility. For further details, please see response to EPA-HQ-OAR-2009-0923-1014, Excerpt 9 for further details, which we have below:

Comment Number: EPA-HQ-OAR-2009-0923-1014-9

Organization: Independent Oil and Gas Association of West Virginia **Commenter:** Charlie Burd

Comment Excerpt Text:

Fugitive Emissions Sources

Finally, Subpart W requires all covered facilities to perform comprehensive emissions surveys of their entire population of fugitive emissions on an annual basis. Should a leak be detected during this survey, the current calculation methodologies specified in the proposal require operators to assume that these fugitive emissions occur for the entire 365 days in the year. 75 Fed. Reg. at 18623. Those facilities required to estimate fugitive emissions based on population count (e.g., onshore production facilities) generally must make similar assumptions (i.e., that the emissions occurred for the total time that the specific source associated with the fugitive emissions was operating). See 40 C.F.R. § 98.233(r), 75 Fed. Reg. at 18643. Because this is not the case with regard to most fugitive emissions at most operations, these assumptions will result in a significant overestimation of actual emissions that will artificially inflate the inventory. Indeed, as USEPA acknowledges in the Preamble for Subpart W, "the petroleum and natural gas industry is already implementing voluntary fugitive emissions and repair programs" for detected fugitive emissions that will result in correction of leaks. *Id.* at 18623. Nevertheless, IOGA-WV shares USEPA's view that requiring more frequent emissions surveys would be both unduly burdensome and impractical in light of the marginal levels of emissions that would be captured in the inventory in light of the leak reductions and repairs that are undertaken pursuant to these programs. If anything, IOGA-WV believes that the burdens associated with undertaking a comprehensive annual emissions survey of these sources outweigh the benefits of including these comparatively de minimis emissions in the inventory.

Response: EPA disagrees that equipment leaks are a small portion of emissions from the petroleum and natural gas industry. Equipment leaks are a substantial percentage of emissions from upstream production; EPA conducted detailed analysis in order to determine sources to report in each segment of the industry. EPA does not agree that the burden associated with leak detection is not justified by the benefits. Please see Section III.E of the preamble to this final rule for a description of the benefits of the rule. EPA recognizes the commenter's concern that

assuming a leak duration of 365 days may overestimate emissions. Conversely, there will be leaks that start after a leak survey is conducted and therefore an underestimation may occur as well. Regardless, in this final rule, EPA allows reporters the option to perform subsequent facility-wide leak detection surveys and to adjust their emissions to account for components that are subsequently found to be leaking or not leaking, respectively. EPA emphasizes that adjustment of emissions is not allowed based on repair records alone. Reporters must assume that a leaking component has been leaking starting from the beginning of the calendar year. In addition, if only one leak detection survey is conducted during the calendar year, the reporter must assume that the duration of the leak is 365 days unless the leak is fixed and a subsequent official leak detection survey is conducted for an entire facility proving that the leak and others were repaired. A goal with leak detection is to get a facility wide snapshot of equipment leak emissions. If a reporter finds certain components leaking during a specific survey they are usually not addressed immediately. During the time leaks are being addressed, other leaks will appear which only subsequent facility wide leak detection surveys will ascertain.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 40

Commenter Type: Trade Association

Comment: [highlighted text: In (q) and (r), add references to gas composition; minor clarifications and corrections to (t) though (v)]

(q) Leak detection and leaker emission factors.

GHGi = For onshore natural gas processing facilities, concentration of GHGi, CH₄ or CO₂, in the total hydrocarbon of the feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8), GHGi equals 1 for CH₄ and 1.1×10^{-2} for CO₂[add: , or use the gas composition allowed in §98.232(m)].

Response: [Please refer to the original comment text posted in the docket.] EPA disagrees with the commenter. The emission factors in Table W-7 are in methane only and the reporter cannot use a 1% CO₂ composition on this emission factor as suggested by the commenter. Please see response to EPA-HQ-OAR-2011-0512-0029, Excerpt 3 and EPA-HQ-OAR-2011-0512-0029, Excerpt 43 for further details.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 7

Commenter Type: Trade Association

Comment: §98.233(q) includes different default values in the definition of GHG_i that follows Equation W-30. Section (u)(2) should be referenced rather than introducing different defaults.

Response: EPA disagrees that a reference to 98.233(u)(2) should be provided instead of the default compositions listed in the definition for GHG_i . Paragraph 98.233(u)(2) is for determining greenhouse gas compositions in whole gas streams. The emissions factors used in paragraph 98.233(q) are not whole gas emission factors, and are instead total hydrocarbon (THC) emission factors or methane emission factors. Hence, EPA is retaining the requirements in 98.233(q) as relates to composition in this final rule. Please see response to EPA-HQ-OAR-2011-0512-0029, Excerpt 3 for further details.

Commenter Name: Pamela A. Lacey

Commenter Affiliation: American Gas Association (AGA)

Document Control Number: EPA-HQ-OAR-2011-0512-0032

Comment Excerpt Number: 11

Commenter Type: Trade Association

Comment: AGA Supports Proposed Revisions to Equations W-30 and W-31, and W-32, but Seeks Additional Corrections

Equation W-30: As AGA and others have requested, EPA has proposed to clarify the summation operator in Equation W-30 to make it mathematically correct, and we appreciate this correction. 76 Fed. Reg. at 56,032. The agency has also proposed several revisions to use the new terms “transmission-distribution transfer stations” and “metering-regulating stations.” AGA supports these revisions. However, Equation W-30 is still confusing and requires additional revisions.

First, there appears to be a conflicting provisions in the definition of T_p in W-30.

The last two sentences are confusing. We suggest revising the text to say:

“If multiple leak detection surveys are conducted at a facility or TD station, assume that the component found to be leaking has been leaking since the previous survey (if not found in the previous survey) or the beginning of the entire calendar year (if it was found in the previous survey). For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year.”

Second, a typographical error appears in the proposed revision to Equation W-30, where the subscript “s” was omitted from EF. The definition for EF was not amended in the proposed rule, so the definition for EF is found in the November 2010 final rule version of Equation W-30 – where the term is listed as EFs. This should be corrected to avoid confusion.

Third, Equation W-30 is also confusing because the definition of $E_{s,i}$ in Equation W-30 is different from the definition for $E_{s,i}$ in W-32 even though they represent the same thing. To make it less confusing, the definition of $E_{s,i}$ in Equation W-30 should be changed to match the

definition in Equation W-32 which says “Annual volumetric GHG i emissions, CO₂ or CH₄ at standard conditions from all equipment leak sources at all above grade T-D transfer stations”.

Response: In regard to the definition of parameter “ T_p ” in Equation W-30, EPA agrees with the commenter and in this final rule, has made necessary clarifications to the text. In regard to the subscript “s” in parameter “EF”, EPA agrees with the commenter and in this final rule, has removed the subscript throughout the Equations W-30A and W-30B. In regard to parameter “ $E_{s,i}$ ”, EPA disagrees with the commenter. The parameter “ $E_{s,i}$ ” in Equation W-30 does not represent the same definition as parameter “ $E_{s,i}$ ” in Equation W-32. Please see response to EPA-HQ-OAR-2011-0512-0047, Excerpt 9 for further details.

Commenter Name: Curtis J. Winner

Commenter Affiliation: New Mexico Gas Company (NMGC)

Document Control Number: EPA-HQ-OAR-2011-0512-0047

Comment Excerpt Number: 6

Commenter Type: Industry - oil and gas

Comment: Leak Detection and Leaker Emission Factors

Although EPA has proposed revisions to Equation W-30 in 98.233.q, NMGC still feels it is difficult to determine what is being calculated in W-30. Is equation W-30, the sum of emissions from each component type (ie $E_{s,i}$ is emissions from just connectors) from all stations? Or is it the sum of emissions from all components (ie the sum of emissions from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators AND open-ended lines) from all transmission-distribution stations? It is confusing because of the use of the terms component and equipment leak source. Component is defined in the rule, but equipment leak source is not. EPA seems to be using these terms interchangeably and they seem to mean the same thing. For example, the term component is used both in T_p and in equation W-31 definition of Counts whereas equipment leak source is used in the definition of x and $E_{s,i}$ in equation W-30. In addition, although EPA amended the definition of x in equation W-30, it is still confusing. The definition of x in Equation W-30 should more closely match the language for $E_{s,i}$ in equation W-32. Some confusion could be eliminated if the definition of x was changed to “total number of equipment leak sources, at all above ground stations”. Or the definition of x in W-30 could be changed to say “total number of each component type”, not equipment leak source, since the term component is used in Tables W-2 through W-7.

When EPA revised Equation W-30 the subscript “s” was omitted from EF. The definition for EF was not amended in the proposed rule, so the definition for EF is found in the final rule and it is listed as EFs.

Response: EPA agrees with the commenter that the terms “component” and “emission source” were being interchangeably used that caused some confusion. In this final rule, EPA has clarified that the Equation W-30 (A and B) sums up at a facility level per “component type.” EPA has also clarified that the term “ x ” is the total count of each “component type”. Finally,

EPA has consistently removed the subscript from EF throughout Equations W-30 (A and B) and W-31.

Section 7.18.2 - Data Reporting Requirements

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 57

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] For each equipment leak sources that uses emission factors for estimating emissions (refer to §98.233(q) and (r)[add:]).

(i) For equipment leaks found in each leak survey (refer to §98.233(q)), report the following:

(A) Total count of leaks found in each complete survey listed by date of survey and each type of leak source for which there is a leaker emission factor in Tables W-2, W-3, W-4, W-5, W-6, and W-7 of this subpart.

(B) [delete: Concentration of CH₄ and CO₂ as described in Equation W-30 of §98.233.]

[delete: (C) Report] [add: Annual] CH₄ and CO₂ emissions (refer to Equation W-30 [delete: of §98.233]) collectively by equipment type.

(ii) For equipment leaks calculated using population counts and [add: emission] factors (refer to §98.233(r)), report the following:

(A) For source categories §98.230(a)(3), (a)(4), (a)(5), (a)(6), and (a)(7), total count for each type of leak source in Tables W-2, W-3, W-4, W-5, and W-6 of this subpart for which there is a population emission factor, listed by major heading and component type.

(B) For onshore production (refer to §98.230 paragraph (a)(2)), total count for each type of major equipment in Table W-1B and Table W-1C of this subpart, by field.

(C) [delete: Report] [add: Annual] CH₄ and CO₂ emissions (refer to Equation W-31 [delete: of §98.233]) collectively by equipment type.

Response: EPA agrees with the commenter in part. In this final rule, in paragraphs 98.236(c)(15)(i)(C) and (ii)(C), the word “annual” has been added. EPA disagrees with deleting paragraph 98.236(c)(15)(i)(B) and in this rule has instead clarified to read that only onshore natural gas processing facilities must report their CH₄ and CO₂ concentration ranges in the total hydrocarbon feed of natural gas. EPA also disagrees with deleting the reference to 98.233 in

paragraphs 98.236(c)(15)(i)(C) and (ii)(C), since it adds no additional clarity to what is requested.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 62

Commenter Type: Industry - oil and gas

Comment: Revision: EPA has added a reporting requirement for the range of CH₄ and CO₂ concentrations associated with equipment leaks in gas processing leak surveys. The rule cites Equation W-30. EPA also requires reporting CO₂ and CH₄ emissions by equipment type.

Comment: It is not clear what “range” of concentrations EPA is referring to. The concentrations of CH₄ and CO₂ are defined for each segment under Equation W-30; there are no ranges in concentration.

Response: EPA disagrees with the commenter that it is not clear what range of concentrations is asked for in 98.236(c)(15)(i)(B). First, that paragraph only applies to onshore natural gas processing facilities. All other facilities have default concentrations listed in the definition of GHG_i in paragraph 98.233(q). The only segment that doesn’t have a default composition is onshore natural gas processing, and instead instructs reporters to use the actual concentration of CH₄ and CO₂ in the total hydrocarbon of the feed natural gas. Therefore, this range in CH₄ and CO₂ concentrations for onshore natural gas processing is what is asked for in 98.236(c)(15)(i)(B).

Section 7.19 - Population Count and Emission Factors

Section 7.19.1 - Calculating GHG Emission [W-31, W-32]

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 41

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] Population count and emission factors.

GHG_i = For onshore petroleum and natural gas production facilities and onshore natural gas processing facilities, concentration of GHG_i, CH₄ or CO₂, in produced natural gas or feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8), GHG_i equals 1 for CH₄ and 1.1×10^{-2} for CO₂[add: , or use the gas composition allowed in §98.232(m)].

Response: EPA disagrees with the commenter. The default gas compositions for facilities listed in 98.230(a)(4) through (a)(8) are standard default ratios of CH₄ and CO₂ to total hydrocarbon content (THC) in pipeline quality gas. Since the emission factors used in Equation W-31 are on a THC or methane basis, these default CH₄ and CO₂ are sufficient for estimating GHG emissions. Hence, in this final rule, EPA has retained the requirements in 98.233(r) as relates to composition. Please see response to EPA-HQ-OAR-2011-0512-0029, Excerpt 3 for further details.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 8

Commenter Type: Trade Association

Comment: §98.233(r) includes different default values in the definition of GHG_i that follows Equation W-31. Section (u)(2) should be referenced rather than introducing different defaults.

Response: EPA disagrees that a reference to 98.233(u)(2) should be provided instead of the default compositions listed in the definition for GHG_i. Paragraph 98.233(u)(2) is for determining greenhouse gas compositions in whole gas streams. The emissions factors used in paragraph 98.233(r) are not whole gas emission factors, and are instead total hydrocarbon (THC) or methane emission factors. Therefore, a reference to 98.233(u)(2) would be inappropriate. The compositions provided in the definition of GHG_i for the facilities listed in 98.230(a)(4) through (a)(8) are standard default ratios of CH₄ and CO₂ to THC or methane for pipeline quality gas in the various sectors.

Commenter Name: Pamela A. Lacey

Commenter Affiliation: American Gas Association (AGA)

Document Control Number: EPA-HQ-OAR-2011-0512-0032

Comment Excerpt Number: 13

Commenter Type: Trade Association

Comment: Equation W-32 and §98.233(r)(2)(ii):

The preamble incorrectly states that the agency is proposing to amend Equation W-32 to yield an emission factor in cubic feet “per meter to be used in Equation W-31 for above ground metering-regulating stations.” See 76 Fed. Reg. at 56,033. We think you meant to say “per metering-regulating station.” If the emission factor in the Proposal is to apply to a count of meters, we would have a problem, because the emission factor is supposed to apply to some stations where there are no meters. Recall that the proposed term “metering-regulating station” is defined to include stations that have (1) a pressure regulator but not a meter; or (2) a meter but not a pressure regulator; or (3) both a meter and a regulator. See 76 Fed. Reg. at 56,050. Fortunately, the actual proposed rule language in Equation W-32 correctly directs LDCs to count the “[t]otal number of meter/regulator runs at all TD transfer stations.” 76 Fed. Reg. at 56,045. Proposed

section 98.233(e)(6)(ii) also correctly uses the term “meter/regulator runs.”

Define Meter/Regulator Run: AGA supports changing the emission factor so that it is based on a count of meter/regulator runs rather than a count of “meters.” However, we urge EPA to define this new term “meter/regulator run.” There is no definition in the proposed rule. We suggest the following definition:

“Meter/ regulator run means a series of components used in regulating pressure or metering natural gas or both.”

Response: EPA disagrees with the commenter that W-32 yields emission factors at a metering-regulating station. The September 2011 proposal rule text stating that the emission factor is at a meter/regulator run is correct and in this final rule, EPA has finalized the requirements. EPA has also added the definition for meter/regulator run.

Commenter Name: Pamela A. Lacey
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2011-0512-0032
Comment Excerpt Number: 17
Commenter Type: Trade Association

Comment: Additional Corrections for W-32 and Section 98.233(r):

EPA states in the preamble that the agency is proposing to eliminate the summation operator from Equation W-32. See 76 Fed. Reg. at 56.033. AGA supports this change. However, it appears that the agency inadvertently failed to remove this summation operator from Equation W-32 in the proposed rule. See 76 Fed. Reg. at 56,045. In this case, it appears the preamble is correct but the proposed rule is not. AGA requests that EPA remove the summation operator from Equation W-32 in section 98.,233(r), as the agency apparently intended. Our members have attempted to run calculations using the revised equations in the proposed rule, and they have found this equation is still confusing. Eliminating the summation operator will help remove that confusion.

Further, in the proposed amendments, EF from the equation is listed as EFi when it is defined. The subscript i is either omitted from the equation or added unnecessarily in the definition for EF.

Response: EPA agrees with the commenter and has removed the summation operator from Equation W-32. Additionally, EPA has removed the subscript “i” from parameter EF under Equation W-32.

Commenter Name: Grover R. Campbell and V. Bruce Thompson
Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 22

Commenter Type: Industry - oil and gas

Comment: Population count and emission factors – § 98.233(r). The preamble discussion of Eq. W-31 is inconsistent with the proposed caption to this equation. In the preamble, EPA stated that it was proposing to modify Eq. W-31 by including a reference to 40 C.F.R. § 98.233(u) and deleting the specified compositions for each industry segment. 76 Fed. Reg. 56,033. The caption provided to Eq. W-31 in the proposed regulatory text does not include this cross-reference. Rather, it lists specific compositions for each industry segment. Chesapeake and AXPC support the caption provided in the proposed regulatory text. We object to inserting a cross reference to 40 C.F.R. § 98.233(u)(2)(i) because doing so would impose a requirement for reporters to provide population count and emission factor information on a sub-basin basis. Gathering sub-basin level data for fugitive sources would provide little environmental benefit. We support and incorporate by reference API's comments in W.31 [EPA-HQ-OAR-2011-0512-0042, Excerpt 47] of Section 2 in its October 24, 2011 letter to EPA.

Response: EPA agrees with the commenter that a reference to paragraph 98.233(u) is unnecessary and is retaining the compositions for each industry segment in the parameter GHG_i . Please see response to EPA-HQ-OAR-2011-0512-0042, Excerpt 48 for more information.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 47

Commenter Type: Industry - oil and gas

Comment: Revision: EPA added guidance on how to determine the number of fugitive component sources in Equation W-31 for the different industry sectors. EPA provided CH₄ and CO₂ concentrations for GHG_i for some industry sectors.

Comment: The preamble on page 56033 states “In that same equation [Eq. W-31], we are proposing to revise the definition for GHG_i by referring to 40 CFR 98.233(u) and deleting the composition specified for each industry segment.” However, the regulatory text on page 56045 and the redline version for the definition of GHG_i in Eq. W-31 were not revised to reference 98.233(u) and still specify the composition for each industry segment. Also the compositions specified in the GHG_i definition were revised in the regulatory text.

Response: EPA agrees with the commenter that the rule and the preamble in the September 2011 proposal do not match for 98.233(r). EPA's intent was to specify the default compositions in W-31 for the parameter GHG_i . Accordingly in this final rule, EPA has listed the composition of GHGs in the THC or methane emission factors in the definition of GHG_i for Equation W-31.

Commenter Name: Karin Ritter
Commenter Affiliation: American Petroleum Institute (API)
Document Control Number: EPA-HQ-OAR-2011-0512-0042
Comment Excerpt Number: 48
Commenter Type: Industry - oil and gas

Comment: Revision: EPA clarified for component count Methodology 1 that the count of meters/piping is 1 per well pad.

Comment: API supports this revision.

Response: EPA agrees with the commenter and thanks them for their remarks.

Commenter Name: Curtis J. Winner
Commenter Affiliation: New Mexico Gas Company (NMGC)
Document Control Number: EPA-HQ-OAR-2011-0512-0047
Comment Excerpt Number: 7
Commenter Type: Industry - oil and gas

Comment: Population Count and Emission Factors

In Equation W-31, the revised definition for EFs in the proposed rule refers to an “EF for meter/regulating runs at above grade metering-regulating stations”. Did EPA intend for the emission factor to be for meter/regulator runs? NMGC’s understanding is we are using W-31 to calculate emissions from all above grade metering-regulating stations (including above grade TD transfer stations) using an EF generated from Equation W-32.

The proposed rule revises 98.233.r.6.ii, to calculate emissions from all above grade metering-regulating stations (including above grade T-D transfer stations) by applying the EF calculated in W-32 and the total count of meter/regulator runs at all above grade metering-regulating stations (inclusive of T-D transfer stations) to Equation W-31. Does this mean we need to count all meter/regulator runs at all metering-regulating stations and use this count as the Counts for equation W-31? A count of meter/regulator runs at all metering-regulating stations would be very time consuming and costly to do. NMGC would have to visit close to 1,000 stations to obtain this count and it would negate the reduced burden EPA included in the final rule of applying a company specific emission factor to a larger set of stations that do not need to be surveyed for leaks. Instead, Counts for calculating emission from all above grade metering-regulating stations (including above grade T-D transfer stations) should be the total count of metering-regulating stations (including T-D transfer stations).

In the proposed rule EPA uses a new term, meter/regulator run which is not defined. Does this mean all meter runs and all regulator runs need to be counted at each transmission-distribution transfer station where a leak survey is conducted? It should mean count meter and/or regulators since a meter can be on a regulator run. A meter on a regulator is just one run not two.

Response: EPA is clarifying in this final rule (as proposed in the September 2011 rule) that Equation W-32 should be used to develop a meter-regulator run emission factor using leak detection data from above grade T-D transfer stations as summed in Equation W-30B. This factor per meter/regulator run should then be used to estimate emissions from above grade metering-regulating stations in Equation W-31. EPA disagrees with the commenter that counting meter/regulator runs is burdensome. Natural gas distribution facilities can collect this information when such stations are visited by personnel for routine visits. EPA cannot require the use of metering-regulating stations, as the size of stations varies considerably and will introduce errors in emissions estimates. In this final rule, EPA has clarified that a meter on a regulator run is considered one run.

Commenter Name: Curtis J. Winner

Commenter Affiliation: New Mexico Gas Company (NMGC)

Document Control Number: EPA-HQ-OAR-2011-0512-0047

Comment Excerpt Number: 9

Commenter Type: Industry - oil and gas

Comment: NMGC appreciates that EPA corrected Equation W-32 to calculate hourly emissions. However, there are still errors with Equation W-32. In the proposed amendments, EF from the equation is listed as EF_i when it is defined. The subscript i is either omitted from the equation or added unnecessarily in the definition for EF. In addition, in the preamble to the proposed rule, page 56033, it says that the summation operator is removed in Equation W-32. This change is not reflected in the rule revisions to Equation W-32. Although the preamble states that the summation operator is removed because $E_{s,i}$ represents annual volumetric GHG $_i$ emissions at all T-D transfer stations, and its removal would clear up some of the confusion stated above for Leak Detection and Leaker Emission Factors, Equation W-30 is still confusing. It is confusing because the definition of $E_{s,i}$ in Equation W-30 is different from the definition for $E_{s,i}$ in W-32 even though they represent the same thing. To make it a little less confusing, the definition of $E_{s,i}$ in Equation W-30 should be changed to match the definition in Equation W-32 which says “Annual volumetric GHG $_i$ emissions, CO $_2$ or CH $_4$ at standard conditions from all equipment leak sources at all above grade T-D transfer stations”.

Response: EPA agrees with the commenter and in this final rule, has removed the summation from Equation W-32 to match the text provided in the preamble. Additionally, EPA has removed the subscript “ i ” from parameter “EF” under Equation W-32.

EPA does not agree with changing the definition of the parameter “ $E_{s,i}$ ” in Equation W-30 to match the definition of the parameter “ $E_{s,i}$ ” in Equation W-32. Equation W-30, and therefore the parameter “ $E_{s,i}$ ”, is applicable to other industrial segments as well. Changing it to be applicable to natural gas distribution only would make the parameter invalid for other industry segments.

Section 7.19.2 - Data Reporting Requirements

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 63

Commenter Type: Industry - oil and gas

Comment: Revision: For equipment leaks using population counts, EPA has replaced the field level reporting requirement with reporting at the sub-basin. EPA also requires reporting CO₂ and CH₄ emissions by equipment type.

Comment: API supports reporting for the sub-basin level. Although we recognize that reporting emissions by equipment type is consistent with the calculation methodologies, this reporting requirement adds burden without value. The requirements under 98.236(c)(15)(ii)(A) already requires the count of each type of leak source. Since emissions are based on this count and the emission factors provided in Tables W-2 through W-6, EPA already has the information required to determine the emissions for each equipment type. Therefore the request for this information from the reporters is redundant with information already available to EPA.

Response: EPA notes that the commenter has misread the requirements for reporting of equipment leaks from onshore production. 98.236(c)(15)(ii)(A) applies to non-onshore production industry segments only. For onshore production, only 98.236(c)(15)(ii)(B) applies, where reporters are required to report the count of major equipment, not the count of component. In this final rule, EPA has provided further clarifying language to this paragraph.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 64

Commenter Type: Industry - oil and gas

Comment: Revision: 98.236(c)(15)(ii)(A) – EPA is proposing a correction to not include onshore gas processing as this source category is not required to use population emission factors.

Comment: API supports this revision.

Response: EPA agrees with the commenter and thanks them for their remarks.

Section 7.2 - EOR Injection Pump Blowdown

Section 7.21.1 - Calculating GHG Emission [W-37]

Commenter Name: Darrell Shier

Commenter Affiliation: SCANA Corporation

Document Control Number: EPA-HQ-OAR-2011-0512-0030

Comment Excerpt Number: 3

Commenter Type: Industry - oil and gas

Comment: M&R Station Emission Calculations

We find the emission calculations in the Proposed Rule remain confusing, particularly for M&R stations. We offer two suggestions. First, Equations W-30 and W-32 both use a variable named "EF" but the definitions for EF are different in the two equations. One of these variables should be renamed.

Second, we find that the sequence in which the equations must be used (W-30 to W-32 to W-31) is confusing. The changes in the variable definitions for W-31 that are contained in paragraph 98.233(r)(6)(ii) are also confusing. We suggest that a new equation W-32b be created to solve this second concern.

Response: In this final rule, EPA is amending Equations W-30A (designated as Equation W-30 in the November 2010 Final rule), adding Equations W-30B, and revising the associated data reporting requirements. For further details on these changes, please see preamble Section II.C. – Final Amendments to the Petroleum and Natural Gas Systems Source Category – Major Changes Since Proposal.

EPA disagrees with the commenter's suggestion of renaming one the variable "EF" for one of the equations. For each equation, the definitions of the relevant parameters are stated below the equation and must only be used for that particular equation. Hence, the "EF" for Equation W-30 is different from the "EF" in Equation W-32.

The commenter does not provide any reasoning to explain why the sequence in which Equations W-30 (now W-30A) through W-32 and the changes in variable definitions for Equation W-31 are confusing. In this final rule, EPA clearly states that reporter must calculate emissions per component type per reporting facility using Equation W-30A (for industry segments 98.230(a)(3) to (a)(7)) and Equation W-30 B (for industry segment (a)(8)) if equipment leaks are detected for the applicable sources as listed in 98.233(q). Additionally, reporters must calculate the facility wide emission factor per meter/regulator run and component type in Equation W-32 using the total volumetric GHG emissions at standard conditions for all leaking components calculated in Equation W-30B and the count of meter/regulator runs located at above grade transmission-distribution transfer stations that were monitored over the years that constitute one complete cycle as per 98.233(q)(8)(i). Lastly, reporters must calculate emissions from all above grade metering-regulating stations (including above grade T-D transfer stations) by applying the emission factor calculated in Equation W-32 and the total count of meter/regulator runs at all above grade metering-regulating stations (inclusive of T-D transfer stations) to Equation W-31.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 65

Commenter Type: Industry - oil and gas

Comment: Revision: 98.236(c)(15)(ii)(b) requires reporting fugitive emissions for each type of major equipment by sub-basin category. However, Equation W-31, which is the calculation approach applied for fugitive emissions by population counts is applied at the facility (i.e. basin) level. Comment: The reporting requirements should align with the calculation method. The definitions for “Count” and “GHGi” Equation W-31 clearly refer to the facility. API requests that the reporting requirements be revised accordingly.

Response: EPA agrees with the commenter. EPA has amended this final rule to require reporting of major equipment type by facility for onshore production.

Section 7.22 - Onshore Petroleum and natural Gas Production and Natural Gas Distribution Combustion Emissions

Commenter Name: William W. Grygar II

Commenter Affiliation: Anadarko Petroleum Corporation

Document Control Number: EPA-HQ-OAR-2011-0512-0028

Comment Excerpt Number: 12

Commenter Type: Industry - oil and gas

Comment: Furthermore, Anadarko supports additional comments submitted by API, particularly regarding reporting requirements under §98.236. Anadarko also supports the recommendations made by AXPC, particularly regarding stationary and portable combustion requirements for the onshore production sector under §98.233(z).

Response: For the response to API’s comments regarding §98.236, please see the responses to EPA-HQ-OAR-2011-0512-0042, Excerpt 29; EPA-HQ-OAR-2011-0512-0042, Excerpt 57; EPA-HQ-OAR-2011-0512-0042, Excerpt 58; EPA-HQ-OAR-2011-0512-0042, Excerpt 59; EPA-HQ-OAR-2011-0512-0042, Excerpt 64; and EPA-HQ-OAR-2011-0512-0042, Excerpt 65. For the response to AXPC’s comments regarding §98.233(z), please see the response to comment EPA-HQ-OAR-2011-0512-0033, Excerpt 23.

Commenter Name: Pamela A. Lacey

Commenter Affiliation: American Gas Association (AGA)

Document Control Number: EPA-HQ-OAR-2011-0512-0032

Comment Excerpt Number: 10

Commenter Type: Trade Association

Comment: EPA Should Exclude Distribution Combustion from Subpart W

In addition to the exclusion for small IC engines, AGA urges EPA to exclude LDC combustion emissions entirely from Subpart W, because this needlessly duplicates the emissions already

reported by LDC's for their system operations under Subpart NN.

LDCs report the CO₂e emissions that result from their own combustion in distribution operations through Subpart NN. Meters feeding LDC buildings and combustion units are included in the gas sendout volumes reported under NN along with the associated combustion emissions.

In Subpart NN, section 98.406(b)(1) specifically prompts the LDC to report the "Annual volume in Mscf of natural gas received by the LDC at its city gate stations for redelivery on the LDC's distribution system, including for use by the LDC." Reporting these emissions twice – under both Subpart NN and W results in an overstatement of the carbon footprint for the natural gas value chain. Accordingly, we urge EPA to exclude natural gas distribution combustion emissions from Subpart W.

Response: EPA disagrees with the commenter that LDCs should be excluded from reporting combustion emissions. EPA notes that the Subpart NN requires the reporting of total natural gas delivered among other activity data; it does not collect information on natural gas consumed internally as fuel separately from the total sendout for the facility. Secondly, Subpart NN does not track the specific combustion equipment type in which natural gas is being consumed. EPA understands that the combustion volume of natural gas is being reported twice, and will ensure appropriate adjustments in the national mass balance of emissions. Hence, EPA has retained the requirement for LDCs to report combustion emissions. However, EPA has provided relief in terms of an equipment threshold for internal combustion emissions that are not compressor drivers; please see preamble Section II.C –Final Amendments to the Petroleum and Natural Gas Systems Source Category, and Section II.D.6 – Responses to Major Comments Submitted on the Petroleum and Natural Gas Systems Source Category for onshore production and distribution combustion emissions and equipment threshold for internal combustion engines.

Section 7.22.1 - Calculating GHG Emission [W-39, W-40]

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 23

Commenter Type: Industry - oil and gas

Comment: Onshore petroleum & natural gas production combustion emissions – § 98.233(z). In its December 17, 2010 amendments to the MRR, EPA modified the definition of "natural gas" provided in 40 C.F.R. § 98.6. Natural gas is now defined as: "a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane. Natural gas may be field quality or pipeline quality." 40 C.F.R. § 98.6. The December 17 technical amendments also modified Table C-1, which provides default CO₂ emission factors and high heat values for various types of fuel. Specifically, EPA removed the modifier "pipeline" from the description of "natural gas." 75 Fed. Reg. 79113, 79154 (Dec. 17, 2010). By making this change in Table C-1, EPA provided a

default high heat value and CO2 emission factor for the general term "natural gas" which includes both field gas and pipeline quality gas. Prior to this amendment, the CO2 emission factor and high heat value in Table C-1 could not be used for field gas. These changes impact the calculations required for the combustion emissions from onshore petroleum and natural gas production and natural gas distribution.

40 C.F.R. § 98.233(z) created different calculation methodologies for pipeline quality natural gas and field gas. To determine the emissions from combusting pipeline quality natural gas, Subpart W currently allows reporters to use the Tier 1 methodologies provided in Subpart C, which are based on the emission factors found in Table C-1. In contrast, to determine the emissions from combusting natural gas that is not of pipeline quality or that has a higher heating value of less than 950 Btu/scf, Subpart W does not allow reporters to use the Tier 1 methodologies and emission factors from Table C-1.

The rule creates an arbitrary distinction between pipeline quality gas and field gas, in addition to an inconsistency between the way terms are used in Subpart W and in Subpart C, resulting in different reporting obligations. Table C-1 lists the high heat value and CO2 emission factor for "natural gas," which is defined to include both pipeline quality and field quality natural gas. Therefore, Subpart W reporters should be directed to use the default emission factors in Table C-1 for both pipeline quality and field gas quality natural gas, regardless of the higher heating value, to ensure consistency in reporting emissions relating to natural gas combustion. This modification to Subpart W would be consistent with EPA's decision to remove the modifier "pipeline" from the description of "natural gas" in Table C-1. 75 Fed. Reg. 79113, 79154 (Dec. 17, 2010); see also 75 Fed. Reg. 79,106 ("we have decided to finalize the definition of natural gas without any specifications regarding minimum or maximum Btu values or a minimum methane content.").

AXPC and Chesapeake also restate our objection to the requirement to report emissions from the combustion of diesel fuels under § 98.233(z). Requiring the reporting of these diesel combustion emissions contradicts EPA's oft-stated need for accurate emission data from all sectors covered in the Reporting Rule. See, e.g., 75 Fed. Reg. 74,474 ("[T]he high level of public interest in the data collected, as well as its importance to future policy, warrants establishment of a high standard for data quality and consistency. . . ."); 75 Fed. Reg. 74,484 ("EPA plans to collect complete and accurate facility-level GHG emissions from the petroleum and natural gas industry. Accurate and timely information on GHG emissions is essential for informing future climate change policy decisions); 75 Fed. Reg. 74,467 ("facility" definition selected in part to avoid double-counting); 75 Fed. Reg. 74,498 (flare emissions "must be corrected for flare emissions calculated and reported under other paragraphs of this section to avoid double counting"). In its Response to Comments to the final Subpart W rule, EPA acknowledged that these same emissions are already reported under Subpart MM and double counting will result. RTC at 955-56. EPA accepts double counting in this instance, because "[a]lthough refineries will report total fuel supplied under Subpart MM, EPA will not know where the fuels are being combusted to inform any combustion equipment specific policy. . . ." RTC at 1600.

EPA's determination to require that such diesel emissions be reported under Subpart W is completely arbitrary; in the same rule, EPA demands exact measurement of very de minimis

emissions, while inviting inaccuracy by expressly requiring double-counting of emissions from the same sources. This irrational outcome should be addressed during this rulemaking process. Section 98.233(z) should not require the reporting of emissions from diesel-fired equipment.

To address both of these issues (the definition of natural gas and the double-counting of diesel combustion emissions), §§ 98.233(z)(1) and (2) should be rewritten as follows:

§ 98.233(z) Onshore petroleum and natural gas production and natural gas distribution combustion emissions. Calculate CO₂, CH₄, and N₂O combustion related emissions from stationary or portable equipment as follows:

(1) If the fuel combusted in the stationary or portable equipment is:

(i) Diesel fuel (i.e., distillate fuel oil No. 1, 2 or 4 or other diesel fuel), the emissions from the combustion of such fuel in stationary or portable equipment used for onshore petroleum and natural gas production are excluded from 40 CFR 98, subpart W;

(ii) listed in Table C–1 of subpart C of this part, except for diesel fuel, or is a blend of fuels listed in Table C–1, use the Tier 1 methodology described in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) [Reserved]

* * *

Response: EPA disagrees with the reporter on the use of Subpart C methods for fuel that is field gas, process vent gas, a blend of field gas and process vent gas, or natural gas less than 950 Btu per scf. EPA did not change this method as finalized in the November 2010 final rule. In the September 2011 proposal, EPA simplified the determination of fuel consumption and allowed for the use of company records. EPA also proposed a calculation method for CH₄ emissions and allowed the use of CEMS for combustion emissions monitoring. The change in the definition of natural gas for Subpart W has no bearing on the reporting of combustion emissions for onshore production and natural gas distribution. In this final rule, the requirement for the determination of composition of non-pipeline quality gas remains unchanged from the November 2010 rule.

EPA disagrees with the commenter on the reporting of diesel fuel combustion. Please see response to EPA-HQ-OAR-2009-0923-1042, Excerpt 26 for further details.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 50

Commenter Type: Industry - oil and gas

Comment: Revision: EPA has added clarifications on the requirements for combustion

emissions under 98.233(z). Natural gas that does not meet the definition of “pipeline quality” is required to use the same approach as used for the combustion of process vent gas or field gas. EPA has removed the requirement that a flow meter must be used if available.

Comments:

- A conversion term in Eq. W-40 is 1×10^3 , but the term in the definition is 1×10^{-3} .
- In 98.233(z)(1)(i), the first sentence should be corrected to read “...or a blend containing one or more fuels...” instead of “...or a blend containing one more fuels...”.
- 98.233(z)(2)(ii) is an example of a non-sub-basin reporting category directing you to 98.233(u)(2)(i) which requires sub-basin composition analysis. (See comment W.34 [EPA-HQ-OAR-2011-0512-0042, Excerpt 50]).
- In 98.233(z)(2)(i), EPA has added that you may use company records to determine the volume of fuel combusted in the unit during the reporting year. API fully supports this revision.

Response: EPA agrees with the commenter on Equation W-40 and has modified the conversion term appropriately in this final rule.

EPA agrees with the commenter on 98.233(z)(1)(i) and has added the “or” to the sentence as necessary in this final rule.

EPA agrees with the commenter on 98.233(z)(2)(ii). In this final rule, EPA has clarified that 98.233(u)(2)(i) is applicable at a facility or sub-basin level as per the requirements in the monitoring method for the particular emission source.

EPA agrees and thanks the commenter for the comment on 98.233(z)(2)(i) and has finalized the requirements in this final rule.

Section 7.22.2 - Data Reporting Requirements

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 66

Commenter Type: Industry - oil and gas

Comment: Revision: API interprets the type of units for external combustion sources >5 MMBtu/hr to refer to those listed under 98.30: boilers, incinerators, and process heaters.

Comment: EPA has revised the reporting requirements for external combustion sources >5 MMBtu/hr to require annual CO₂, CH₄ and N₂O emissions by type of unit.

Response: EPA notes that the reporters for onshore production combustion equipment must determine the type of equipment using 98.232(c)(22).

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 67

Commenter Type: Industry - oil and gas

Comment: Revision: API interprets the type of units for internal combustion sources to refer to those listed under 98.30: simple and combined-cycle combustion turbines, and engines.

Comment: EPA has revised the reporting requirements for internal combustion sources to require annual CO₂, CH₄ and N₂O emissions by type of unit.

Response: EPA notes that the reporters for onshore production combustion equipment must determine the type of equipment using 98.232(c)(22).

Section 7.22.3 - Onshore Production and Distribution Equipment Threshold for Internal Combustion Equipment

Commenter Name: Pamela A. Lacey

Commenter Affiliation: American Gas Association (AGA)

Document Control Number: EPA-HQ-OAR-2011-0512-0032

Comment Excerpt Number: 9

Commenter Type: Trade Association

Comment: AGA Supports a 1 million Btu/hour or 130 HP Threshold for Exempting Internal Combustion Engines

EPA, citing a lack of data, declined to include a 5 million Btu/hour threshold for exempting internal combustion (IC) engines even though the Agency had established a similar exemption level for external combustion engines, and even though both API and AGA had requested such an exemption in their respective petitions for reconsideration. However, the agency indicates that it collected data on IC engines used in production, and determined that a 130 horsepower level (double the largest size found) would exclude virtually all small IC engines, and would equate to about 1 million Btu/hour. EPA states in the preamble that it “is seeking comment on whether a 1 mm Btu/hour equipment threshold for IC engines that are not driven by natural gas is reasonable.” 76 Fed. Reg. at 56034. AGA supports exempting small stationary IC engines less than 1 million Btu/hour from the reporting requirements. This exemption threshold would work for the small IC engines used by our members in natural gas distribution systems, but only if the exemption also applies to IC engines that are driven by natural gas.

Attached are three pictures of a typical natural gas-powered generator set at a regulator station. (See Exhibits 1-3). [See original comment for Exhibits 1, 2, and 3]. LDCs typically place these at their larger regulator stations (including custody transfer stations, and T-D or Transmission to Transmission stations) for backup power in the event of a power outage. At stations where large pressure drops are occurring, the natural gas must be heated ahead of the pressure cut to keep the gas above freezing temperature downstream of the pressure cut. The boilers that preheat the gas actually burn natural gas but they need electricity to operate the controls and the pumps. In the event of a prolonged outage the IC engine generator sets are run to keep the heaters in operation.

Two specification sheets are also attached in Exhibit 4 for a typical 20 kW generator set and a larger 35 kW generator set. [See original comment for Exhibit 4]. As shown on the sheets the full load input of the 35 kW generator is 494 scf/hour or approximately 0.496 mmBtu/hour.

The IC engine generators are used for backup generation so they rarely run. Typically they are test fired once a year for 10 minutes to make sure they operate. For example, one of our members reported that they have three IC engines of this type that are all relatively new & have operated for the following number of hours during the years after installation: (1) their 35 kW unit is 4 years old and has operated 36.2 total hours; (2) a 20 kW unit is less than 2 yrs old and has operated for 9.3 hrs over that time; and (3) another 20 kW unit is new and has operated 5 hrs during its first year (all for testing). The member estimates that the engines operate about 6 hours per year on average, most of which occurs during quarterly test runs to make sure they work.

Subpart W calculations would yield estimated emissions of only 0.357 tonnes CO₂e per year from the three engines [Footnote 3: 35 kW IC engine @ 6 hrs = 2,964 scf/hour; 20 kW IC engine @ 6hrs = 1,790 scf/hour each X two engines; Total = 6,544 scf/hour of gas; Total CO₂e GHG = 0.357 metric tons]. And this overstates actual emissions, because the gas is not metered, so the member assumed for purposes of this calculation that the engines were operated under full load consumption, which was obviously not the case. For most of the hours of operation, the back-up engines were being tested and were operating at minimal load or no load at all. Exempting such engines from the reporting requirement would reduce burdens while maintaining a robust and accurate estimate of the greenhouse gas emissions from the distribution sector.

Response: EPA agrees with the commenter on adopting a 1 mmBtu/hr threshold for internal combustion equipment. However, this equipment threshold does not apply to compressor drivers. Please see preamble Section II.C – Final Amendments to the Petroleum and Natural Gas Systems Source Category, and Section II.D.6 – Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category for onshore production and distribution combustion emissions and equipment threshold for internal combustion engines. Given the requirements in this final rule, gas fired electricity generator sets with a rated heat capacity under 1 mmBtu/hour do not have to report emissions; however a count of such equipment, by type, has to be reported.

Commenter Name: Vince Alaimo

Commenter Affiliation: Marshall Miller & Associates Inc. on behalf of Consol Energy Inc.

Document Control Number: EPA-HQ-OAR-2011-0512-0036

Comment Excerpt Number: 9

Commenter Type: Industry - oil and gas

Comment: Onshore Production and Distribution Equipment Threshold for Internal Combustion Equipment

•EPA is proposing to use a 1mBtu threshold for the small internal combustion engines used for periodic maintenance and construction. This would remove all but the largest generator (130HP) from the reporting requirement.

In some cases the deck engine used for the drill is powered using the engine that propels the drill rig on the road. Consol Energy Inc. would like clarification if the GHG emissions from this engine are to be considered?

Response: In the scenario that the engine used to propel the rig is used to run the drill, the emissions do not have to be reported under Subpart W. Generally, if the power take-off for operating the truck mounted workover rig is the truck wheel drive engine (i.e. a transmission option to transfer the truck wheel drive shaft to powering the rig generator or wench or other rig equipment), this workover rig arrangement is “self propelled.” However, if the truck has a separate engine not connected to the drive wheels that powers the workover rig equipment, then it is a “non-self propelled equipment” and therefore you must report emissions from this equipment.

If the equipment is on a trailer where the trailer can technically be detached from the truck tractor, this equipment is considered portable equipment and required for reporting. Regardless of whether the trailered equipment is detached from a tractor or not, the equipment is considered portable and required for reporting, if the equipment itself is considered non-self propelled.

Commenter Name: Gregory L. Ryan

Commenter Affiliation: DTE Energy

Document Control Number: EPA-HQ-OAR-2011-0512-0041

Comment Excerpt Number: 4

Commenter Type: Industry - oil and gas

Comment: Threshold for internal combustion equipment in natural gas distribution

DTE Energy supports a 1 million BTU/hr or 130 HP threshold for exempting internal combustion engines in service in natural gas distribution systems. We support this exemption for all internal combustion engines, including those that combust natural gas.

Response: EPA agrees with the commenter on adopting a 1 mmBtu/hr threshold for internal combustion equipment. However, this equipment threshold does not apply to compressor drivers. For further details, please see response to EPA-HQ-OAR-2011-0512-0032, Excerpt 9.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 3

Commenter Type: Industry - oil and gas

Comment: Threshold for Internal Combustion Engines

On page 56034 of the preamble EPA solicits comments as to why emissions from specific internal combustion related equipment should not be reported, including the size of the equipment that should be excluded along with supporting data.

Specifically, EPA is seeking comments on the following:

- "...whether a 1 MMBtu/hr equipment threshold for internal combustion engines that are not driven by natural gas is reasonable."
- "...combustion-related emissions at compressors should not be excluded from reporting, regardless of size, and where EPA can find reliable estimates of natural gas consumption."
- "... why emissions from specific internal combustion related equipment should not be reported, including the size of the equipment that should be excluded along with supporting data."

API Response:

For the onshore petroleum and natural gas production segment, the current rule exempts external combustion equipment with a rated heat capacity < 5 MMBtu/hr from reporting GHG emissions regardless of fuel type.[Footnote 4: See 40 C.F.R. § 98.233(z)(3)] The rule simply requires reporters to report the type and number of each external fuel combustion unit. API has welcomed this exemption in the final rule as a means to reducing the reporting burden associated with the small quantity of emissions associated with these sources.

API has noted further that internal combustion equipment with a similar capacity of < 5 MMBtu/hr, regardless of fuel type, should be likewise exempted. The magnitude of emissions from the combustion of internal combustion devices of similar capacity would be no different than for the exempted external combustion devices.

Although API appreciates EPA's consideration of providing a limited exemption for reporting GHG emissions from small internal combustion engines not fueled with natural gas, API continues to insist that there is no justification for separate exemption thresholds for internal and external combustion equipment, no justification for limiting such an exemption to engines not fueled by natural gas, and that all combustion equipment, both internal and external, integral to production operations with a rated capacity of < 5 MMBtu/hr should be uniformly exempted from emissions reporting regardless of fuel type.

The reporting burden that EPA found not to be justified for small external combustion devices

remains unjustified for small internal combustion devices. API recommends that along with such an exemption, reporters would simply report the type and number of internal combustion units, regardless of fuel type, which are integral to production operations, in each of the following specified size categories: (a) those that are less than or equal to 125hp (<1MMBtu/hr); (b) those that are over 125hp but less than or equal to 375hp (1-3MMBtu/hr); and (c) those that are over 375hp but less than or equal to 625hp (3-5 MMBtu/hr). This is consistent with and provides more detailed information than the approach for the excluded external combustion devices, and would contribute to reducing the reporting burden. This information will enable EPA to estimate the natural gas consumption by these internal combustion engines and thus provide EPA with needed data for future policy development.

At the same time, API wants to reiterate here that the internal combustion engines addressed by this rule should be limited to those that are “integral to the extraction, processing, or movement of oil or natural gas”, including compressors. This would not include some of the types of engines referenced in the first paragraph on Page 56034 of the preamble to the September 9, 2011 proposed rule, and which are already exempt from emissions reporting based on the promulgated Subpart W requirements.

Response: EPA disagrees with the commenter on providing a 5 mmBtu per hour threshold for internal combustion equipment and also disagrees on applying an equipment threshold for natural gas driven internal combustion equipment, especially compressor drivers. Please see response to comment EPA-HQ-OAR-2011-0512-0032, Excerpt 9 for further details. To inform future policy, EPA requires the number of wellhead compressors, generally fueled with produced natural gas, in the size categories between 1 and 5 mmBtu/hour. EPA believes that most of the wellhead compressors in onshore production will fall under 5 mmBtu/hour, so extending the threshold would exempt virtually all such compressors from reporting. No commenter has provided EPA with data on the numbers and horsepower ranges of such internal combustion engines, as commenters did for external combustion devices. In addition, no reporter has provided any reference(s) to reliable source of data for natural gas consumption by such compressors. Finally, EPA cannot estimate natural gas consumption simply by using a count of equipment by heat rate, since the hours of operation are needed to perform such a calculation; and the ranges specified by the commenter are too large and will potentially result in estimates with large uncertainty.

Section 8 - Monitoring and QA/QC Requirements (98.234)

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 20

Commenter Type: Trade Association

Comment: INGAA supports revisions that provide additional clarity and flexibility for monitoring and measurement methods.

EPA has added monitoring and monitoring measurement flexibility in response to INGAA recommendations. INGAA supports revisions that provide additional flexibility for monitoring and measurement methods and associated recordkeeping. For example, the Proposed Rule indicates in §98.234(a) that video records are not required for optical imaging; and, provides additional flexibility in §98.233(k)(1) for measuring vented emissions from transmission tanks. Similarly, under §98.234(a)(5), INGAA supports the addition of acoustic stethoscope type devices to detect through valve leakage and recommends that the use of similar and commonly used devices such as open air attachments also be allowed.

The flexibility from these changes provides reasonable options that reduce burden while ensuring data quality objective are met. As discussed in Comment 12, an important monitoring option is not included in the Proposed Rule. Flexible approaches to acquire the necessary data should be consistently implemented throughout Subpart W, and this philosophy should be applied when addressing Comment 12 and Comment 14.

Response: EPA thanks the commenter for their remarks. EPA is unclear on what an “open air attachment” is, and therefore has no comment in that regard. For further details on the monitoring options suggested by the commenter in comments 12 and 14, please see the response to EPA-HQ-OAR-2011-0512-0029, Excerpt 19 and EPA-HQ-OAR-2011-0512-0029, Excerpt 21.

Section 8.1 - Methods

Commenter Name:

Commenter Affiliation: Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2011-0512-0026

Comment Excerpt Number: 5

Commenter Type: Industry - other

Comment: Dow supports EPA’s proposed rule that clarifies that video recordings for leak inspections are not required under Subpart W.

Proposed changes to Section 98.34(a)(1) clarify that video recordings of the fugitive emission

monitoring scans with the IR camera are not required under subpart W. Dow supports this clarification and believes that the proposal will increase the ability of the owner/operator to use the camera for the required annual check.

Response: EPA agrees and thanks the commenter for their remarks.

Commenter Name:

Commenter Affiliation: Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2011-0512-0026

Comment Excerpt Number: 6

Commenter Type: Industry - other

Comment: Dow seeks clarification on whether any of the options contained in 98.234(a) can be used to detect valve leak through or whether an acoustic device must be used for these determinations.

Dow's interpretation of the Monitoring and QA/QC requirements in 98.234(a) is that any of the options noted in Section 98.234(a)(1) through (5) can be used to detect through-valve leakage. If correct, Dow comments that EPA should slightly modify the beginning of section 98.234(a) to read as follows:

You may use one or more of the methods described as follows in this paragraph to conduct leak detection(s) of equipment leaks and through-valve leakage from all source types listed

Response: EPA has reviewed your comment and may consider it in future rulemakings. EPA notes that for monitoring transmission storage tanks as under 98.233(k), reporters must use the equipment listed in 98.233(k).

Section 8.1.1 - Optical Gas Imaging Instrument

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 19

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] Monitoring and measurement methods:

In a May 2011 meeting, EPA was receptive to an INGAA request to allow optical imaging to screen compressor vents subject to §98.233(o) and (p) to determine whether measurement is warranted. The Proposed Rule does not include this important revision.

As EPA has developed necessary revisions to Subpart W, INGAA has strived to provide input

and recommendations on rule content. To increase the flexibility of compressor vent measurement required under §98.233(o) and (p), INGAA has requested that Subpart W allow optical imaging as a method to pre-screen affected vents. With this approach, if emissions are not seen using optical imaging, the vent line would not require measurement. This issue was discussed at a May 2011 meeting and EPA was receptive. In response to EPA's request at the meeting, INGAA provided recommended rule redlines, including the following addition to §98.234(a):

[add: "An operator can elect to conduct annual optical gas imaging according to paragraph (i) or (ii) of this section to screen vents that require measurement under §98.233(o) and (p). Vent rate measurement is not required and the vent rate is recorded as zero if optical gas imaging does not detect vented gas."]

Unfortunately, EPA has not addressed this issue in the Proposed Rule. As discussed in Comment 1, this omission may be due to EPA's failure to address revisions to §98.233(o) and (p) in either the Proposed Rule or August 4 proposed revisions. Adding this flexibility can be easily accomplished through an addition to the monitoring section, §98.234(a), and appropriate reference to the new provisions in §98.233(o) and (p). INGAA's June 2011 recommended redlines provide example text.

Availability of this option should not be delayed as EPA considers other revisions to §98.233(o) and (p). INGAA hopes that this omission from the Proposed Rule is an oversight, and recommends that EPA incorporate the text above, or similar text, in the Final Rule so this option is available for use as soon as possible.

Response: EPA is not accepting any comments on 40 CFR 98.233 (o) and (p), because amendments to these sections were not proposed in this proposed rule or the August 4 proposed revisions and hence, these equations are outside the scope of this rule. EPA may consider your comment in future rulemakings.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 21

Commenter Type: Trade Association

Comment: For optical imaging, methods other than the EPA Alternative Work Practice (AWP) should be allowed.

INGAA reiterates previous comments and concerns expressed to EPA. For optical imaging, methods other than the EPA Alternative Work Practice (AWP) are necessary and should be allowed. EPA's attempt to apply select sections of the AWP is resulting in a derivative method that is untested and has not been validated. The derivative AWP in the Proposed Rule should not be mandated as the only method allowed.

§98.234(a)(1) specifies the use of an optical gas imaging instrument for fugitive emissions detection in accordance with 40 CFR part 60, Subpart A, §§ 60.18(i)(1) and (2) of the AWP for monitoring equipment leaks. This AWP was not developed for methane or GHG leaks and contains provisions and requirements that are inappropriate or too restrictive for natural gas transmission and storage component leak screening. The Proposed Rule adds criteria and revisions to the AWP, and INGAA reiterates that this should not be the only method allowed.

§98.234(a)(1) should be revised to include additional flexibility and allow use of other methods such as manufacturer procedures or industry standards which are more appropriate for methane detection from transmission and storage sources.

The Proposed Rule attempts to rely on select provisions from an AWP that was developed for the refining sector as a Method 21 alternative work practice. Since its adoption, the AWP has not been widely adopted by that industry. It is inappropriate to assume that an AWP that is not generally accepted in its intended sector provides the only viable method for methane detection from a different sector. It is also inappropriate to unilaterally mandate a derivative method that has not been peer-reviewed or validated for this application.

A basic tenet of test method development is that the component parts collectively comprise procedures that result in a method that has been evaluated, peer-reviewed, and validated. For the GHG reporting rule, methodology guidelines are marginally less rigorous in most cases, with industry practices and manufacturer procedures commonly allowed. This is appropriate for measurement associated with data gathering for a reporting rule that includes inherent uncertainties in the estimation methods. Yet, EPA is mandating a single method for optical imaging – but revising the published method without adequately supporting the premise that this is the only solution. The unilateral imposition of untested criteria is contrary to the process for developing acceptable methods. In a case where a single method is mandated and EPA dictates only one solution, it is imperative that the procedures have been validated and scrutinized, rather than unilaterally imposed without testing, evaluation, and validation. Rule flexibility is needed to accommodate manufacturer recommendations, future test methods and method enhancement, and possible adoption of AWP revisions to address method inadequacies, shortcomings, and criteria to adapt the method to other applications (i.e., other industrial sources, gases, etc.).

In the Proposed Rule, rather than addressing comments requesting flexibility for other methods, EPA unilaterally revises the AWP, and maintains that this is the only viable method. The AWP revisions have not been subjected to peer review or validation. INGAA is troubled by the precedent established by unilaterally implementing untested procedural changes to a method that has not been validated. Mandating selected provisions and revisions to an AWP that has not been successfully integrated into the mainstream practices for optical imaging is inappropriate. The failure to provide alternative options is remiss. In addition, mandating a single method for optical imaging is contrary to the general tenor of Subpart W, which commonly allows manufacturer procedures and industry standard procedures for measurements. EPA has not adequately justified or supported this position.

INGAA opposes the Proposed Rule mandate that identifies the "derivative" AWP as the only allowed method. EPA has not provided documentation that supports the efficacy of the proposed

AWP deviations, or assessed (and discounted) whether other viable alternatives are available. At a minimum, EPA should allow operators flexibility to document the procedures relied upon within site Monitoring Plans to ensure optical imaging performance.

INGAA refers EPA to previous INGAA comments submitted in response to Subpart W rule proposals and our June 2011 letter that provided recommended redlines. In addition, INGAA understands that optical camera vendors and users of the technology – i.e., the best experts available – are more than willing to provide alternative procedures and standards for optical imaging. If EPA retains a single method mandate, it should be subject to appropriate peer review and a refereed method validation process. INGAA strongly recommends revising §98.234(a)(1) to add flexibility. In addition to the AWP, manufacturer procedures and industry standard practices should be allowed.

Response: EPA disagrees with the commenter. First, EPA is not mandating the use of optical imaging cameras and the associated AWP requirements. EPA has provided reporters the option to use Method 21 compliant leak detection equipment. Reporters may, therefore, choose to use this option instead of using the optical imaging camera.

Second, the commenter is objecting to the “derivative” AWP without specifically identifying what feature(s) of the leak imaging cameras are not acceptable. EPA excluded from the AWP those features that are necessary in an enforceable leak repair program but are unnecessary for Subpart W purposes (e.g. the requirement to retain a video recording of all detected leaks). Because the LDAR regulation requires detection and repair of only components that are accessible to an operator standing on the ground or fixed platform using hand held instruments such as an organic vapor analyzer (OVA), the IR camera is not a necessary instrument. Operators decide which instrument is most cost effective for the regulatory requirement and IR camera with video recording of all detected leaks may not be more cost effective than OVA with no requirement of video recording. This choice by refinery and chemical plant operators complying with the LDAR regulation has no bearing on the collection of leak data to inform future policy in Subpart W. EPA notes that allowing manufacturer’s standards does not establish the sensitivity of the instrument the way AWP does for the detection of hydrocarbons, i.e. nothing precludes the optical imaging camera from being less sensitive than as needed by the AWP to detect hydrocarbon emissions. If the detection sensitivity 60 grams per hour is acceptable to the commenter, then this final rule clearly specifies this requirement in which there is no issue with the AWP requirements in Subpart W. Please see preamble Section II.C. –Final Amendments to the Petroleum and Natural Gas Systems Source Category, Monitoring and QA/QC Requirements for further details. Although AWP was developed for VOCs, EPA notes that the limited use of AWP, which is an established standard whether widely used or not, is sufficient for the purposes of Subpart W, as the detection of methane using an IR camera is indeed well tested and documented in the Journal of Air and Waste Management (paper 6560-50-P), in EPA’s Natural Gas STAR Program presentations by FLIR (http://www.epa.gov/gasstar/documents/workshops/okcity2009/chk_flir.pdf) showing the methane absorption spectrum overlapping the IR camera detection range, and the EPA ETV (Environmental Technology Verification) program which used methane for the IR camera calibration for detecting other chemicals (<http://www.epa.gov/nrmrl/std/etv/pubs/600r10160/600r10160vr.pdf>).” Finally, EPA notes that

the AWP requirements for Subpart W have been greatly simplified; please see preamble Section II.C. - Final Amendments to the Petroleum and Natural Gas Systems Source Category, Monitoring and QA/QC Requirements for further details.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 44

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] § 98.234 Monitoring and QA/QC requirements.

[highlighted text: REVISIONS TO ADD METHOD FLEXIBILITY AND TO ALLOW AN ALTERNATIVE TO AWP IN 60.18(i) THAT CAPTURES THE RELEVANT PERFORMANCE SPECS FOR DAILY QA/QC]

The GHG emissions data for petroleum and natural gas emissions sources must be quality assured as applicable as specified in this section. Offshore petroleum and natural gas production facilities shall adhere to the monitoring and QA/QC requirements as set forth in 30 CFR 250.

(a) You must use any of the methods described as follows in this paragraph to conduct leak detection(s) of equipment leaks and through-valve leakage from all source types listed in §98.233(k), (o), (p) and (q) that occur during a calendar year, except as provided in paragraph (a)(4) of this section.

(1) Optical gas imaging instrument. Use an optical gas imaging instrument for equipment leak detection in accordance with [add: (i) or (ii).]

[add: (i)] 40 CFR part 60, subpart A, §60.18(i)(1)[add: (i)] and (2) of the Alternative work practice for monitoring equipment leaks [add: with a detection sensitivity of 60 grams per hour]. Any emissions detected by the optical gas imaging instrument is a leak unless screened with Method 21 (40 CFR part 60, appendix A-7) monitoring, in which case 10,000 ppm or greater is designated a leak. [add: Video records per §60.18(i)(1)(ii) are not required.] [delete: In addition, you must operate the optical gas imaging instrument to image the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.]

[add: (ii) Operate the optical gas imaging instrument consistent with manufacturer operating procedures. The instrument must meet the specification in §60.18(i)(1)(i) and manufacturer procedures must include daily instrument check procedures similar to those in §60.18(i)(2) based on a detection sensitivity level of 60 grams methane per hour (equivalent to 3.1 SCFH) with a purity of no less than 98 percent by volume. Video records per §60.18(i)(1)(ii) are not required.

(iii) An operator can elect to conduct annual optical gas imaging according to paragraph (i) or (ii) of this section to screen vents that require measurement under §98.233(o) and (p). Vent rate

measurement is not required and the vent rate is recorded as zero if optical gas imaging does not detect vented gas.]

Response: EPA agrees with the commenter that a 60 grams per hour detection sensitivity be stated in the rule and that no video recording be required. Please see preamble section II.C. – Final Amendments to the Petroleum and Natural Gas Systems Source Category, Monitoring and QA/QC Requirements and the response to EPA-HQ-OAR-2011-0512-0029, Excerpt 21 for further details. Hence, in this final rule, EPA is finalizing these amendments in §98.234 (a)(1), and EPA does not consider it necessary to add separate items (i) and (ii), as suggested by the commenter. Additionally, EPA disagrees with the rule text amendments recommended by the commenter in (iii); please see the response to EPA-HQ-OAR-2011-0512-0029, Excerpt 19 for further details.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 47

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] Optical gas imaging instrument. An optical gas imaging instrument must be used for [delete: all source types] [add: components requiring a leak survey] that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

Response: In this final rule, EPA combined 40 CFR 98.234 (a)(4) with 40 CFR 98.234(a)(1) because both of these are applicable to optical gas imaging instruments. EPA is not implementing the change suggested by the commenter because it adds no additional clarity to the statement given the amendments in this final rule.

Section 8.1.2 - Method 21

Commenter Name:

Commenter Affiliation: Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2011-0512-0026

Comment Excerpt Number: 2

Commenter Type: Industry - other

Comment: EPA should clarify the rule text to clarify that Method 21 compliant instruments may be used to monitor inaccessible fugitive emission sources.

On Page 56034 of the Federal Register preamble, EPA explains that the language in 98.234(a)(2) is being amended to state that Method 21 compliant instruments may be used to monitor inaccessible emission sources. Dow supports this change as it does increase the flexibility in monitoring requirements and reduces the burden on industry without compromising data quality.

However, the proposed rule text in 98.234(a)(1) and (2) is confusing. For example, the last sentence in 98.234(a)(1) states that: “An optical gas imaging instrument must be used for all sources types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.” Then, the last sentence of 98.234(a)(2) seems to allow the owner/operator to use the alternative leak detection devices as described in paragraph (a)(1) or (a)(2) of this section, which includes Method 21.

Assuming the intent discussed in the preamble is correctly understood, Dow suggests that EPA clarify in both 98.234(a)(1) and (a)(2) that a Method 21 compliant instrument may be used to monitor inaccessible emission sources that are subject to the monitoring requirements.

Response: EPA agrees with your comment, and in this final rule is adding language indicating that an optical gas imaging instrument must be used for all source types that are inaccessible and cannot be safely monitored using Method 21 compliant leak detection equipment. Please see preamble section II.C. –Final Amendments to the Petroleum and Natural Gas Systems Source Category, Monitoring and QA/QC Requirements for further details.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 45

Commenter Type: Trade Association

Comment: Method 21. Use the equipment leak detection methods in 40 CFR part 60, appendix A–7, Method 21. If using Method 21 monitoring, if an instrument reading of 10,000 ppm or greater is measured, a leak is detected. Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. Owners or operators must use alternative leak detection devices as described in paragraph(a)(1) of this section to monitor inaccessible equipment leaks or vented emissions.

Response: EPA thanks the commenter for their remarks and notes that this rule text has been amended to allow for alternative leak detection devices as described in paragraph (a)(2) in addition to (a)(1). Please see response to EPA-HQ-OAR-2011-0512-0026, Excerpt 2 for further details.

Section 8.1.5 - Acoustic Leak Detection Device

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 48

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] Acoustic leak detection device. Use the acoustic leak detection device to detect through-valve leakage. When using the acoustic leak detection device to quantify the through-valve leakage, you must use the

instrument manufacturer's calculation methods to quantify the through-valve leak. When using the acoustic leak detection device, if a leak of 3.1 scf per hour or greater is calculated, a leak is detected. In addition, you must operate the acoustic leak detection device to monitor the source valves required by this subpart in accordance with the instrument manufacturer's operating parameters. [add: Acoustic devices that provide an audible leak signal but do not calculate a leak rate can be used to identify non-leakers with subsequent measurement required to calculate the rate if through-valve leakage is identified. Leaks are reported if a leak rate of 3.1 scf per hour or greater is measured.]

Response: EPA agrees with the commenter. However, EPA disagrees that the September 2011 proposal language needs to be revised, because the meaning of the proposed text is the same as the revised text provided by the commenter.

Section 8.2 - Use Flow Meters

Commenter Name: Mike Hampton

Commenter Affiliation: SandRidge Midstream, Inc.

Document Control Number: EPA-HQ-OAR-2011-0512-0045

Comment Excerpt Number: 2

Commenter Type: Industry - oil and gas

Comment: Operations Overview

One of the plants operated by SandRidge captures CO₂ for sale from an AGR vent stream composed of 95%+ CO₂, up to 5% methane and hydrocarbons, and trace nitrogen. If it cannot be sold, the stream is incinerated for VOC control, and as a last resort, if the incinerator (thermal oxidizer) is not available, the stream is vented to atmosphere.

The AGR vent stream to atmosphere has a continuous flow monitor and a separate continuous gas analyzer, which are quality assured per the air permit requirement and manufacturer recommendations or industry standard methods. The exhaust gas is predominantly dry CO₂, and the stack gas temperature is typically 10-20 degrees F.

SandRidge believes that the data generated from the existing monitoring equipment provides quality assured information that is the best data available for calculating emissions.

Response: EPA has described all the Calculation Methodologies under AGRs sufficiently. The commenter may use the data generated from its existing monitoring equipment as long as this data follows one of the methodologies accurately, keeping in mind the hierarchy of the Calculation Methodologies. From the information provided by the commenter, EPA believes that the reporter must use methodology 1 or 2 in 98.233(d) to estimate emissions from their AGR units. EPA has relaxed the calibration criteria for methodologies 1 and 2; please see response to EPA-HQ-OAR-2011-0512-0045, Excerpt 3 for further details.

Section 8.3 - Use Calibrated Bags

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 50

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures [add: and below the maximum temperature specified by the vent bag manufacturer] such that [delete: it] [add: the bag] is safe to handle[add: .] [delete: and can capture all the emissions, below the maximum temperature specified by the vent bag manufacturer, and] [add: The bag must be of sufficient size that] the entire emissions volume can be encompassed for measurement.

(1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.

(2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in §98.233(t).

(4) Estimate CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using the calculations in §98.233(u) and (v).

Response: EPA agrees with the commenter and EPA is modifying this final rule accordingly. EPA notes that the bag opening, and not the bag, must be of sufficient size such that the entire emissions volume can be encompassed for measurement till the calibrated bag is completely filled.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 51

Commenter Type: Industry - oil and gas

Comment: Revision: EPA added clarification to the requirements for using a calibrated bag that the temperature of the source to be measured must be below the maximum temperature specified by the manufacturer and that the bag must be of sufficient size that the entire volume can be encompassed for measurement.

Comment: API requests clarification on EPA's intent in stating "the bag must be of sufficient size that the entire volume can be encompassed for measurement." This could be interpreted to mean that the bag must fit over the entire source being measured. Alternatively, this could be interpreted to mean that the bag must be sized to capture the venting volume within a specific time, recognizing, however, that the calibrated bag cannot measure the entire volume.

Response: EPA is clarifying in this final rule that the entire volume of emissions must be tightly encompassed till the calibrated bag is filled.

Section 8.4 - Use High Volume Sampler

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 51

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] Use a high volume sampler to measure emissions within the capacity of the instrument.

(1) A technician following manufacturer instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a high volume sampler, including positioning the instrument for complete capture of the equipment leak without creating backpressure on the source.

(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

[add: (3) Estimate natural gas volumetric emissions at standard conditions using calculations in §98.233(t).]

[delete: 3][add: 4] Estimate CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using the calculations in §98.233(u) and (v).

[delete: 4][add: 5] Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH₄ by using calibrated gas samples and by following manufacturer's instructions for calibration.

Response: EPA agrees with the commenter in regard to adding a reference to 40 CFR 98.233(t) for monitoring and QA/QC requirements for high volume samplers. However, in this final rule,

EPA is adding this reference in 40 CFR 98.234(d)(3) and hence, a change to the designation of 40 CFR 98.234(d)(4) is not necessary.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 52

Commenter Type: Industry - oil and gas

Comment: Revision: EPA clarified that volumetric emissions from the high flow sampler must be at standard conditions using 98.233(t).

Comment: API supports this revision with standard conditions defined as 60 °F and 14.7 psia.

Response: EPA thanks the commenter for their remarks. EPA agrees with the commenter in regard to revising standard conditions as 60 °F and 14.7 psia. EPA is making the necessary changes in this final rule. Additionally, EPA is providing a ratio in 40 CFR 98.233(t)(3) for reporters who use 68°F for standard temperature to convert volumetric emissions from 68°F to 60°F.

Section 9 - Records that must be retained (98.237)

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 24

Commenter Type: Trade Association

Comment: 17. The proposed new recordkeeping requirement in §98.237(e) should be deleted because the Monitoring Plan addresses similar requirements and this revision adds unnecessary burden.

The Monitoring Plan required under Subpart A requires operators to document how data is collected and emission calculations are completed. The Proposed Rule adds new recordkeeping in §98.237(e), "The records required under §98.3(g)(2)(i) shall include an explanation of how company records, engineering estimation, or best available information are used to calculate each applicable parameter under this subpart."

This new requirement is duplicative, may cause confusion, and adds unnecessary recordkeeping burden. Since the Monitoring Plan addresses similar criteria, this addition to Subpart W is not needed and §98.237(e) should be deleted.

Response: EPA disagrees with the commenter that the recordkeeping requirements are duplicative and add unnecessary burden. The requirements in §98.3(g)(2)(i) were written to be generally applicable to all facilities. The recordkeeping requirement in §98.237(e) further clarifies this general requirement as it applies to subpart W, particularly with respect to the use of company records, engineering estimation or best available information. If this detailed information is already captured under a Monitoring Plan then it does not add burden to the reporter. It is important to note that, in §98.3(g)(2), EPA states only that records must be kept in an electronic or hard-copy format and recorded in a format that is suitable for expeditious inspection and review. If the Monitoring Plan meets all the requirements of 98.3(g) and 98.237, then this information may only have to be retained in one location.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 54

Commenter Type: Trade

Comment: [Please refer to the original comment text posted in the docket] § 98.237 Records that must be retained.

Monitoring Plans, as described in §98.3(g)(5), must be completed by April 1, 2011. In addition to the information required by §98.3(g), you must retain the following records:

(a) Dates on which measurements were conducted.

(b) Results of all emissions detected and measurements [add: except video records from optical imaging conducted according to §98.234(a)(1) or (4) are not required].

Response: EPA agrees with the commenter and has addressed the exclusion for keeping video records within §98.234(a)(1). Please see the response to EPA-HQ-OAR-2011-0512-0029, Excerpt 21 and Section II.C. - Final Amendments to the Petroleum and Natural Gas Systems Source Category: Monitoring and QA/QC Requirements of the Preamble for further details.

Section 10 - Definitions (98.238)

Section 10.1 - Associated With a Single Well-Pad

Commenter Name: William W. Grygar II

Commenter Affiliation: Anadarko Petroleum Corporation

Document Control Number: EPA-HQ-OAR-2011-0512-0028

Comment Excerpt Number: 10

Commenter Type: Industry - oil and gas

Comment: [Please refer to the original comment text posted in the docket] The definition for "associated with a single well-pad" provides confusion in the last sentence, "this does not include storage and condensate tanks that are located downstream of the point of combination." This sentence could be interpreted either to imply that storage and condensate tanks downstream of the point of combination are included or are not included. Anadarko believes EPA's intent is to include these sources, and recommends that the regulatory text be revised to state the following:

o With the exception of storage and condensate tanks, [add: t][delete: T]he association ends where the stream from a single well-pad is combined with streams from one or more additional single well-pads, where the point of combination is located off that single well-pad. [delete: This does not include storage and condensate tanks that are located downstream of the point of combination.]

Response: In this final rule, EPA is amending the proposed definition of associated with a single well-pad in 40 CFR 98.238 and deleting the text "[t]his does not include storage and condensate tanks that are located downstream of the point of combination." This revision clarifies that onshore production reporters do not report emissions from equipment that are not either on a single well-pad or associated with a single well-pad (as defined in 98.238). This same condition applies to storage and condensate tanks. However, under 98.233(j) onshore production reporters must report emissions from separators or tanks that are either on a single well-pad or associated with a single well-pad. EPA is making additional clarifications about reporting emissions under onshore production. For more details, please see preamble Section II.D.5 - Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Associated with a single well-pad.

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 2

Commenter Type: Industry - oil and gas

Comment: [Please refer to the original comment text posted in the docket] A. Definitions – § 98.238

(1) "Associated with a single well-pad" – EPA has proposed a new term to clarify what

equipment is associated with a single well-pad. The inclusion of this term is fundamental to enabling reporters to determine what equipment must report under Subpart W. The proposed definition is not entirely clear and must be further modified as follows:

Associated with a single well-pad means associated with the hydrocarbon stream as produced from one or more wells located on that single well-pad. [Add: With the exception of storage and condensate tanks,] [Delete: T] [Add: t] he association ends where the stream from a single well-pad is combined with streams from one or more additional single well-pads, where the point of combination is located off that single well-pad. [Delete: This does not include storage and condensate tanks that are located downstream of the point of combination.]

As proposed, the last sentence is ambiguous because “this” could either be interpreted as clarifying that tanks downstream of the combination point are or are not associated with a single well-pad. We believe that EPA meant the former. This definition must be modified to remedy this ambiguity.

Response: Please see response to EPA-HQ-OAR-2011-0512-0028, Excerpt 10.

Commenter Name: Vince Alaimo

Commenter Affiliation: Marshall Miller & Associates Inc. on behalf of Consol Energy Inc.

Document Control Number: EPA-HQ-OAR-2011-0512-0036

Comment Excerpt Number: 2

Commenter Type: Industry - oil and gas

Comment: Associated With a Single Well-Pad

EPA is proposing to add a definition for “associated with a single well-pad” to clearly demarcate the boundary of onshore production. EPA proposes that the association be defined by the hydrocarbon stream from a single wellpad. The association with a single wellpad ends where the stream from a single well-pad is combined with streams from one or more additional single well-pads, where the point of combination is located off that single well-pad. In addition, EPA is stating that this definition does not include storage and condensate tanks that are located downstream of the point of combination. For gas contained in crude oil or condensate flowing under pressure off a single well-pad to a gas liquid separator or tank, or comingled with flow from other well-pads, 40 CFR 98.233(j) requires reporting of the gas content that may be released from the oil or condensate in an atmospheric pressure fixed roof storage tank. EPA has determined that the conditions of the pressurized oil or condensate (i.e., gravity, pressure, temperature, flow rate) are commonly known by the well owner/operator, and the amount of gas that may be released from the oil or condensate with a pressure reduction.

In some remote areas the tie in with other wells may be miles from the well pad. As such Consol Energy Inc. proposes to limit the distance “associated with a well pad” to a maximum of ¼ mile from the actual wellpad.

Response: EPA disagrees with the commenter with regards to defining “associated with a single well-pad” with a distance limit of a maximum of ¼ mile from the actual wellpad, because distance is neither a reliable or consistent indicator of what is “associated with”. Instead, EPA is

finalizing, as proposed, that the association ends where the stream from a single well-pad is combined with streams from one or more additional single well-pads, where the point of combination is located off that single well-pad. This physical demarcation ensures more comparable treatment across reporters for the type of equipment and processes included in the onshore oil and gas production segment. For further information, please see response to EPA-HQ-OAR-2011-0512-0028, Excerpt 10.

Commenter Name: Yasmeen Sultana

Commenter Affiliation: ERM

Document Control Number: EPA-HQ-OAR-2011-0512-0039

Comment Excerpt Number: 1

Commenter Type: Other

Comment: Existing and proposed changes to Subpart W of the EPA GHG Reporting Rule do not adequately address typical onshore oil and gas production facilities in California. Much of California produces heavy oil, with many more shallow wells (most reservoirs are < 4,000 ft deep) in close proximity to each other. Most of the oil is produced with the aid of steam injection. It is not uncommon for an operator to have several thousand wells with associated, shared process equipment that is located where space is available. Please see Attachment 1. [See original comment for attachment].

From the initial introduction of the facility definition in the Subpart W Pre-publication Rule of 10 March 2010, EPA has proposed language changes several times that have impacted the applicability of equipment source types for onshore petroleum and natural gas facilities. EPA states that, "...the proposed amendments would not change the overall requirements, but improve clarity and consistency across the calculation, monitoring and data reporting requirements." However, it appears that EPA is trying to clarify applicability of certain equipment types based on both their geographical location (on a well pad) within an oil field and their location within a process (associated with a single well pad).

The latest proposed changes to the Subpart W regulation (8/19/2011) implies that only equipment used at onshore oil and gas production facilities that is on a single well pad, or associated with a single well pad is included in the reported calculated emissions under Subpart W. Depending on the interpreted definition, not all equipment types (for which a GHG calculation method has been provided) have the potential to be "associated with a single well pad" (i.e., hydrocarbon stream dependent): storage tanks; however, every equipment type has the potential to be on a single well pad.

Although EPA has clarified "associated with a single well pad," a clear definition of well pad does not exist in the current Subpart W regulation or any proposed revisions. This creates ambiguity in applicability of Subpart W to equipment in California's oil field operations where the process equipment (including combustion) is in close proximity to several wells but typically serves entire oil field's (and sometimes several fields') operations. Using the latest proposed language, the same type of equipment can be included into the facility at some locations and excluded at others, solely based on the physical location or location within the process stream; exclusive of the emissions potential.

This lack of clear definition has a big impact on stationary combustion emission sources. Except for some process heaters, none of the stationary combustion emission sources are “associated with a single well pad”; therefore, their inclusion and exclusion will depend solely on their geographical location, and if that location is interpreted as being on a well pad.

Stationary combustion emission sources that are determined to be on a well pad are part of the Subpart W Onshore petroleum and natural gas production Industrial Segment. Within Subpart W, combustion emission sources are required to be grouped by type of unit (assumed well drilling and completion equipment, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters). Combustion emission sources that are determined to be not on a well pad, are not part of the Subpart W Onshore petroleum and natural gas production Industrial Segment. Therefore, it is assumed that these sources, excluding portable equipment, would fall within the applicability of Subpart C, much like they were for 2010 calendar year emissions. Within Subpart C, combustion emissions are essentially grouped by fuel type. Fuel meters selected (often common pipe meters with several unit types), and in some cases installed, to measure shared fuel by fuel type for Subpart C reporting will not be adequate to measure fuel by type of unit. Stationary combustion emission sources that are interpreted to be on a well pad will require the purchase and installation of additional fuel meters to enable quantification and reporting by unit type as required by Subpart W. Operators drill several hundreds to thousands of wells every year and established down hole well patterns create congested surface locations. As a result, the applicability of Subpart W or C to existing combustion equipment depends on their location with respect to the newly drilled wells. Applicability and reporting “bucket” (Subpart C or Subpart W) has to be determined every time a new well is drilled. This requires rigorous additional monitoring of existing equipment and exhaustive applicability determinations creating unnecessary burden on operators with several thousand wells without increasing the amount or quality of reported emissions (emissions are reported either under Subpart C or Subpart W).

Recommendation: At this point there is no clear direction on how to identify equipment that is located on a single well pad. However, actions associated with these decisions needs to happen fast (especially for stationary combustion emissions report due for Subpart C reporting in March 2012) to ensure compliance with the EPA GHG reporting requirements. With this letter, we are requesting further clarification on the definition of a single well pad to enable applicability determinations for stationary combustion equipment. Operators would prefer a definition that does not change applicability of Subpart C versus Subpart W to combustion equipment every year. We have provided Attachment 1 to depict actual well sites and equipment configurations. [See original comment for attachment].

Given the timing of the initial data gathering and reporting activities, your prompt attention to this matter would be appreciated. The issues addressed above apply to many California oil and gas sources and therefore, publication of a clarification in the Federal Register is probably appropriate. However, any near term information you could provide would be greatly appreciated.

Response: EPA acknowledges the variations in well and equipment arrangements within onshore production. Although some equipment may be perceived as being in either the

production or gathering segment, it might be challenging to develop a demarcation that can capture all such nuances. Hence, the physical demarcation point is the most optimal method for the purposes of reporting GHG emissions. Therefore, EPA has chosen a physical point of demarcation, i.e. on a single well-pad or associated with a single well-pad, to separate the onshore production segment from the gathering and boosting segment of the oil and gas industry. The reference to “on a single well pad, or associated with a single well pad” was in the 2010 final rule and was not changed further in the proposed amendments. The proposal merely defined this term to provide the clarity that the commenter is seeking. Please see preamble Section II.D.5 - Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Associated with a single well-pad.

EPA disagrees with the comment on the definition of a “well-pad”. EPA defined a well-pad in the November 2010 final rule; please see the definition for “wellhead” in 40 CFR 98.6. Also note that EPA is amending the proposed definition of associated with a single well-pad in 40 CFR 98.238 to clarify the application to storage tanks; please see response to EPA-HQ-OAR-2011-0512-0028, Excerpt 10.

EPA disagrees with the comment that combustion sources on a well-pad will require the purchase and installation of fuel meters, as 40 CFR 98.233(z) allows the use of company records to determine the volume of fuel combusted. EPA disagrees with the comment that it is onerous to determine if combustion equipment is on a single well-pad or associated with a single well-pad. Further, if a piece of equipment is not on a well pad or associated with a well pad, and covered under subpart C, it is unlikely to trigger the threshold for reporting under subpart C alone. Hence, EPA has not changed the requirements for combustion equipment reporting for onshore production.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 70

Commenter Type: Industry - oil and gas

Comment: [Please refer to the original comment text posted in the docket] Revision: EPA added a new definition for “associated with a single well-pad”.

Comments: EPA needs to clarify what the word “This” is referring to in the beginning of the last sentence. API suggests the following revisions to the definition as shown in green font:

Associated with a single well-pad means associated with the hydrocarbon stream as produced from one or more wells located on that single well-pad. [add (green): For all equipment with the exception of storage and condensate tanks], the[add (green): exclusion for the] association ends where the stream from a single well-pad is combined with streams from one or more additional single wellpads, where the point of combination is located off that single well-pad. [delete (green): This does not includes storage and condensate tanks that are located downstream of the point of combination.]

API offers the diagrams provided in Section 3, which illustrate API’s understanding of the

proposed definition for “associated with a well-pad” and the proposed revised source category definition for onshore petroleum and natural gas production. API is providing this information to companies as a tool to guide industry to classify their emission sources for data collection and reporting, although we realize that it is too cumbersome to include in regulatory language.

Response: Please see response to EPA-HQ-OAR-2011-0512-0028, Excerpt 10.

Commenter Name: Karin Ritter

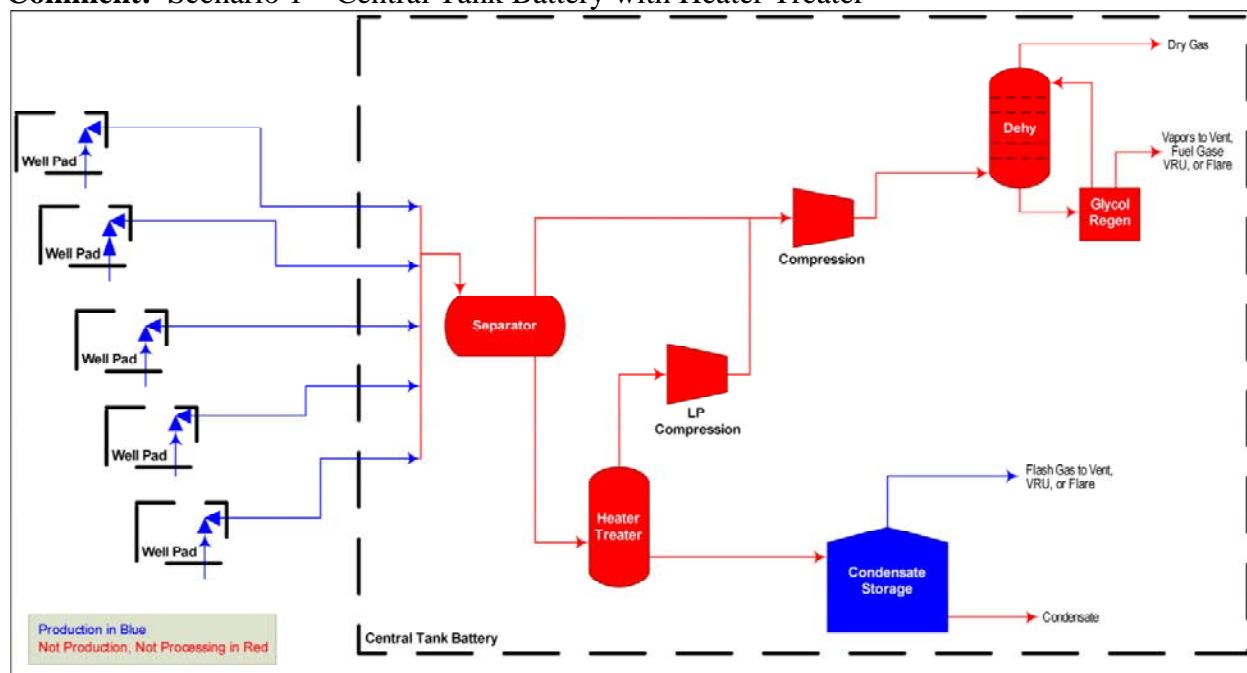
Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 80

Commenter Type: Industry - oil and gas

Comment: Scenario 1 – Central Tank Battery with Heater Treater



Response: In the commenter’s example Scenario 1, EPA agrees with the classifications, with the exception that “condensate storage” is not part of onshore production, because the input stream to the condensate storage tank is a combination of multiple streams from equipment associated with one or more additional single well-pads.

Commenter Name: Karin Ritter

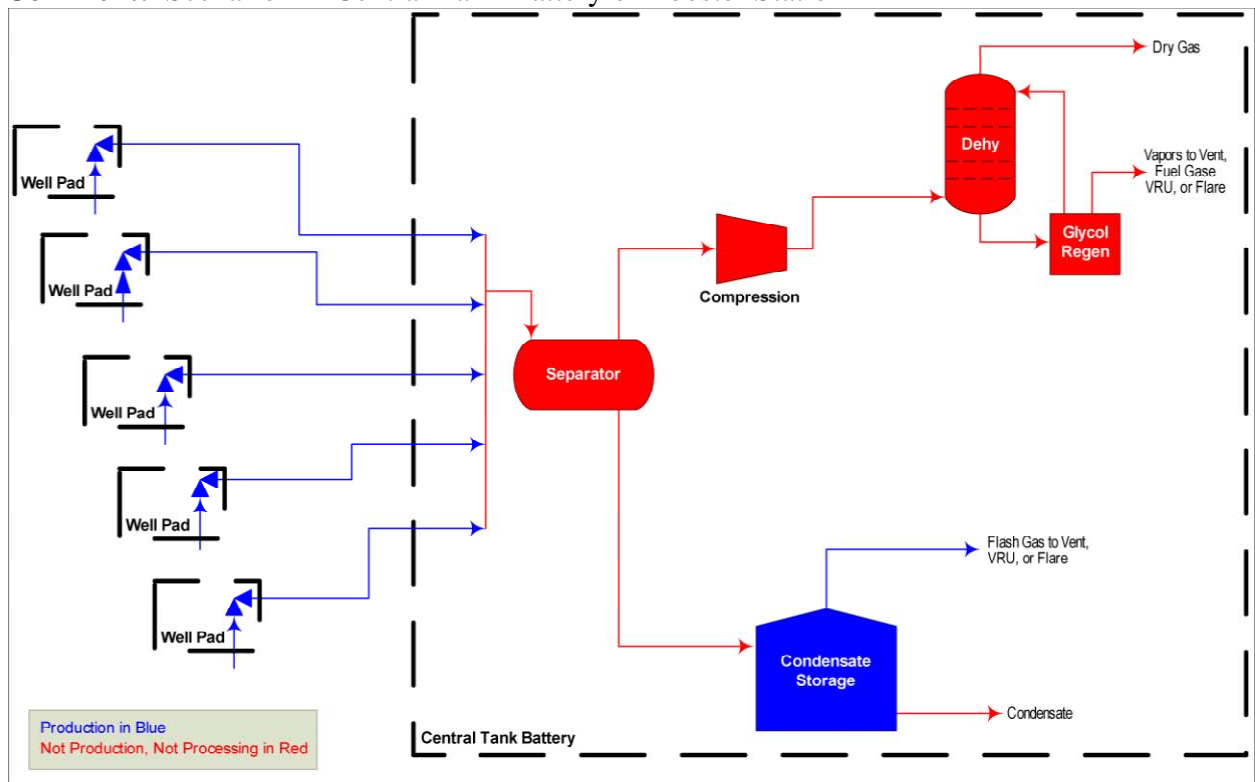
Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 81

Commenter Type: Industry - oil and gas

Comment: Scenario 2 – Central Tank Battery or Booster Station



Response: In the commenter’s example Scenario 2, EPA agrees with the classifications, with the exception that “condensate storage” is not part of onshore production, because the input stream to the condensate storage tank is a combination of multiple streams from equipment associated with one or more additional single well-pads.

Commenter Name: Karin Ritter

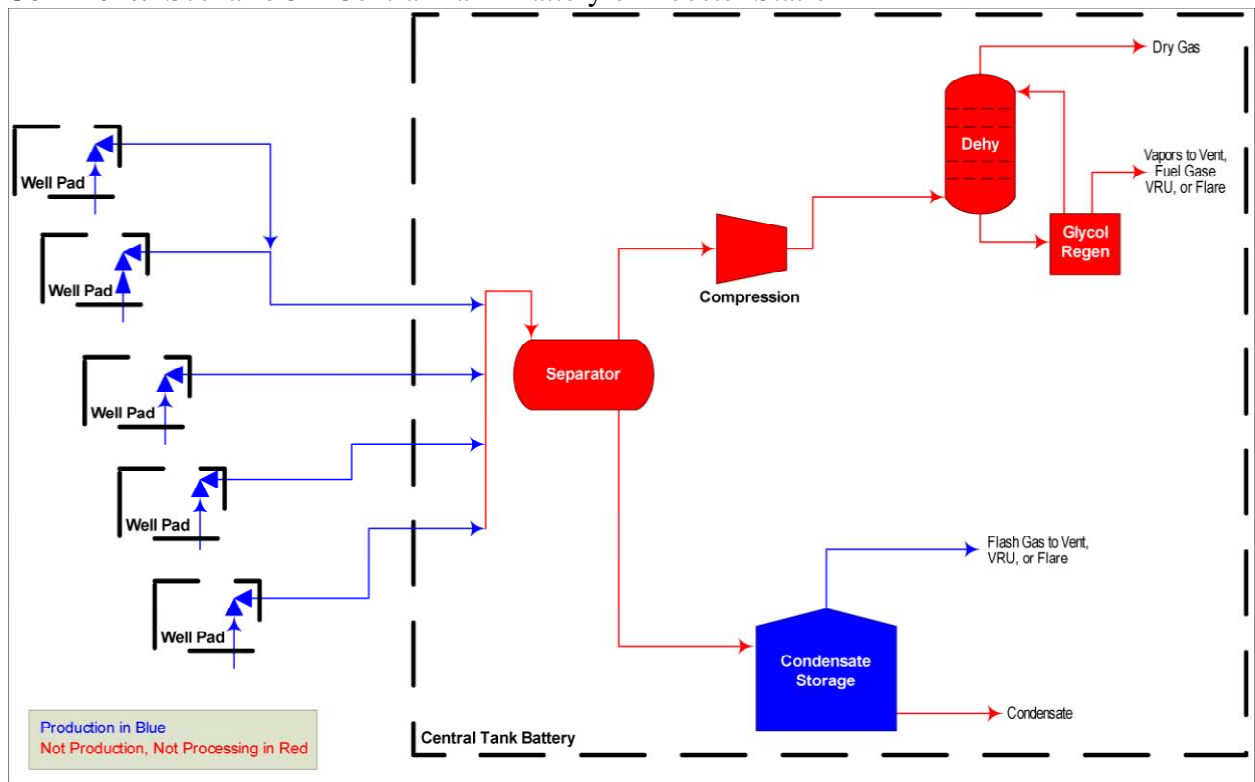
Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 82

Commenter Type: Industry - oil and gas

Comment: Scenario 3 – Central Tank Battery or Booster Station



Response: In the commenter’s example Scenario 3, EPA agrees with the classifications, with the exception that “condensate storage” is not part of onshore production, because the input stream to the condensate storage tank is a combination of multiple streams from equipment associated with one or more additional single well-pads.

Commenter Name: Karin Ritter

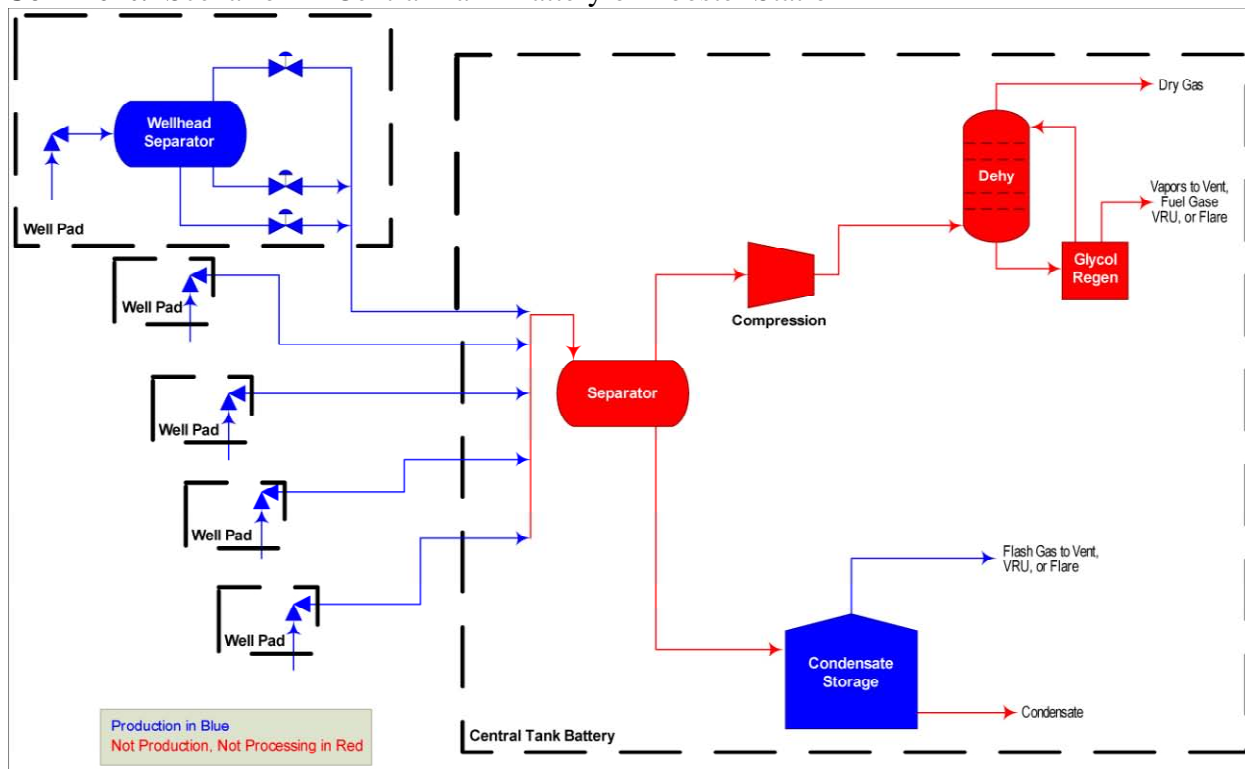
Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 83

Commenter Type: Industry - oil and gas

Comment: Scenario 4 – Central Tank Battery or Booster Station



Response: In the commenter’s example Scenario 4, EPA agrees with the classifications, with the exception that “condensate storage” is not part of onshore production, because the input stream to the condensate storage tank is a combination of multiple streams from equipment associated with one or more additional single well-pads.

Commenter Name: Karin Ritter

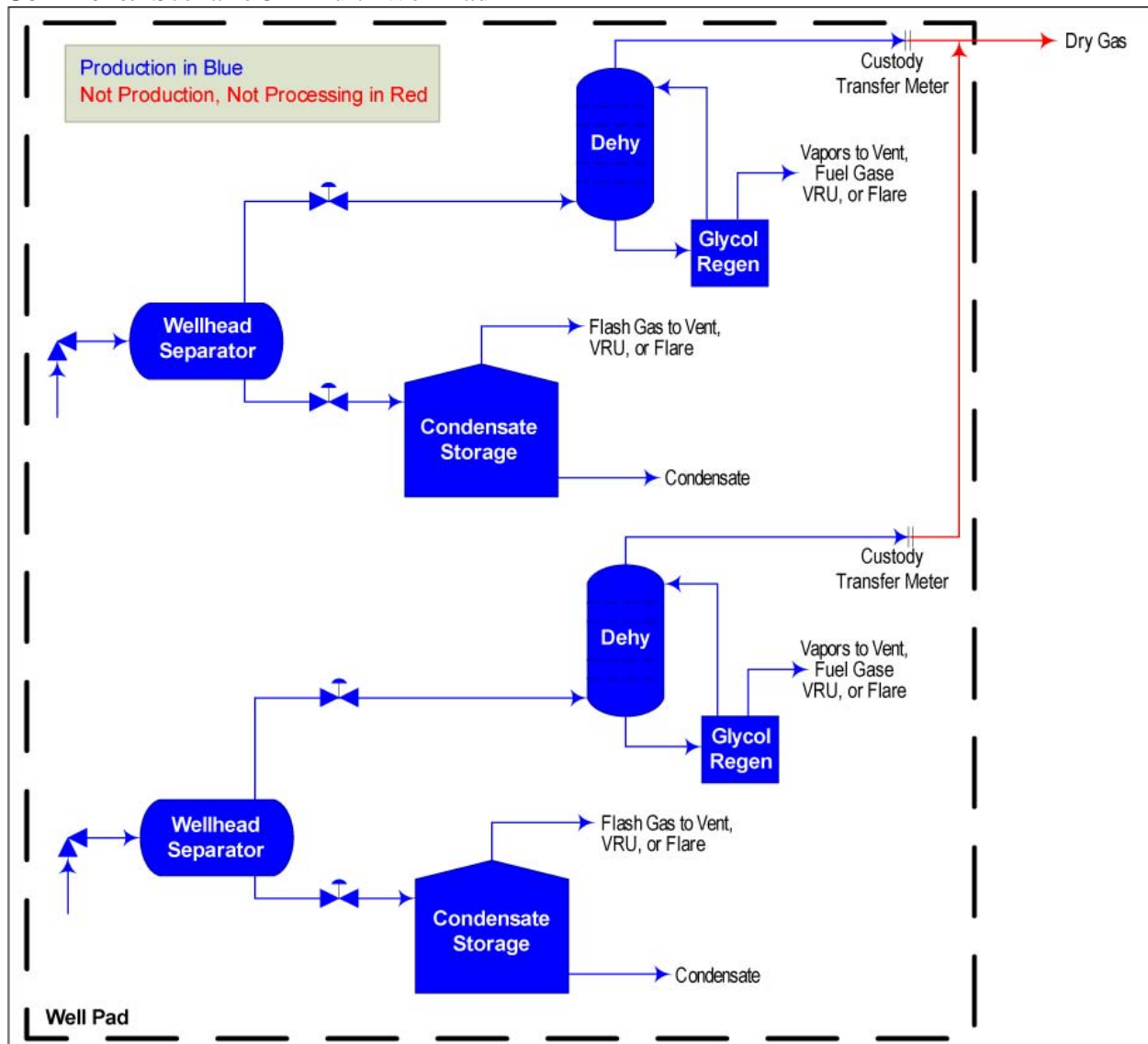
Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 84

Commenter Type: Industry - oil and gas

Comment: Scenario 5 – Multi-Well Pad



Response: In the commenter’s example Scenario 5, EPA conditionally agrees with the classifications. If the dry gas leaving the well-pad in Scenario 5 does not enter equipment(s) that is under common-control or common ownership of the reporter, then Scenario 5 is correct. However, if there is equipment(s) that is associated with a single well-pad in Scenario 5 and is under common-control or common ownership of the reporter, then that equipment(s) is a part of onshore production and the reporter must monitor and report emissions from such equipment(s).

Commenter Name: Karin Ritter

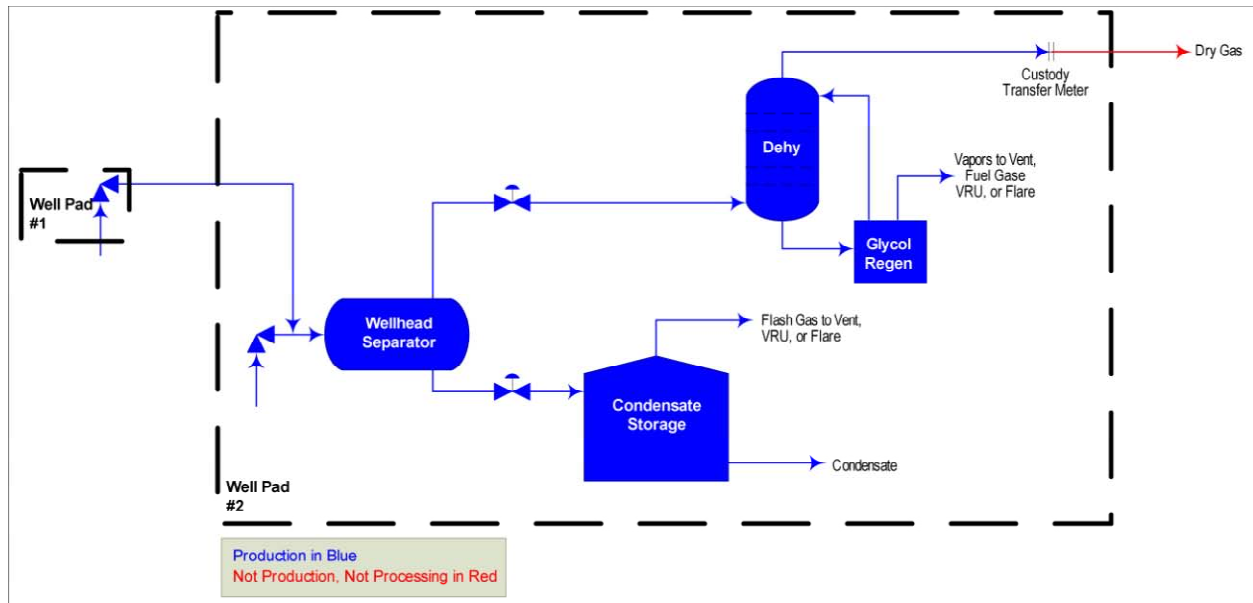
Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 85

Commenter Type: Industry - oil and gas

Comment: Scenario 6 – Remote Well Pad to Satellite Well Pad



Response: In the commenter’s example Scenario 6, EPA conditionally agrees with the classifications. If the dry gas leaving the well-pad in Scenario 6 does not enter equipment(s) that is under common-control or common ownership of the reporter, then Scenario 6 is correct. However, if there is equipment(s) that is associated with a single well-pad in Scenario 6 and is under common-control or common ownership of the reporter, then that equipment(s) is a part of onshore production and the reporter must monitor and report emissions from such equipment(s).

Commenter Name: Karin Ritter

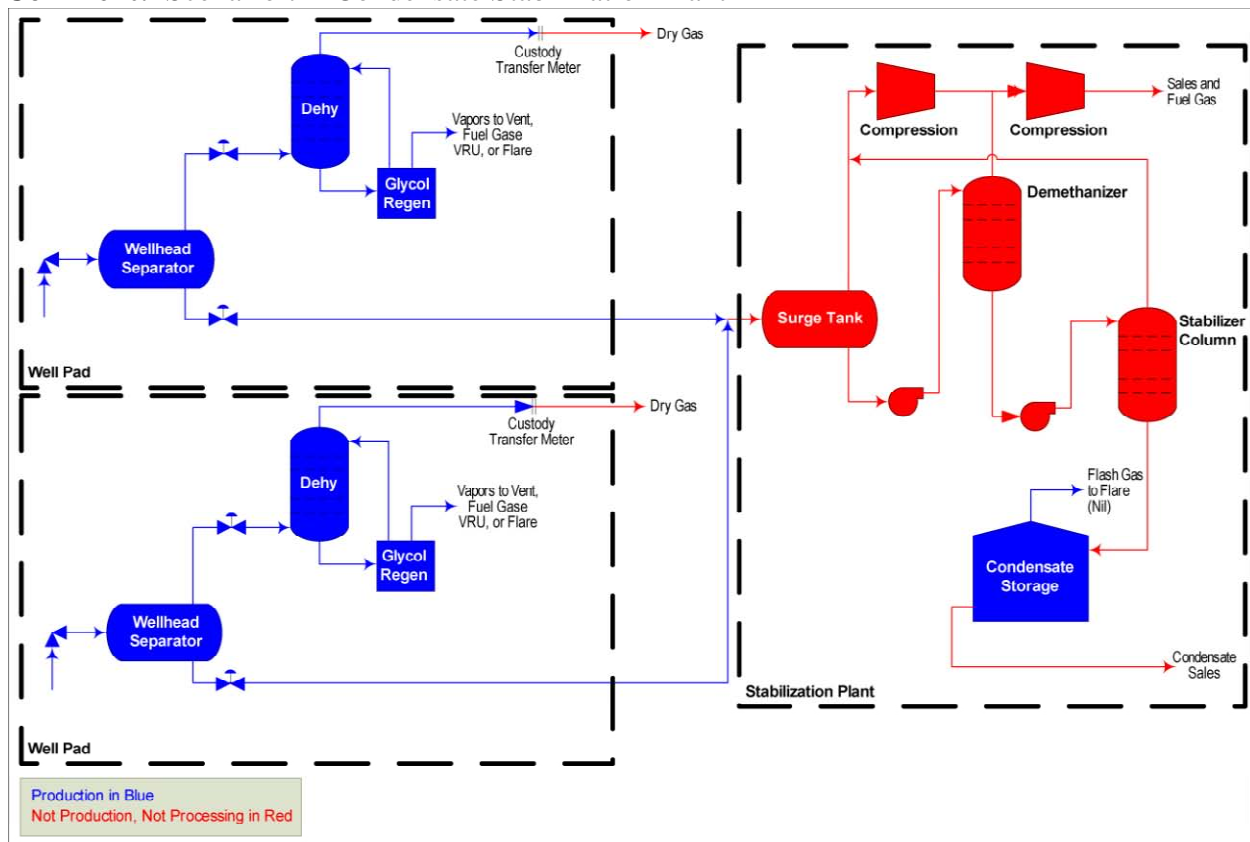
Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 86

Commenter Type: Industry - oil and gas

Comment: Scenario 7 – Condensate Stabilization Plant



Response: In the commenter’s example Scenario 7, EPA disagrees that the “stabilization plant” is not natural gas processing, because of the fractionation of hydrocarbon liquids into component mixtures. EPA also disagrees that “condensate storage” is part of onshore production. If the dry gas leaving the well-pad in Scenario 7 does not enter equipment(s) that is under common-control or common ownership of the reporter, then the designation of onshore production equipment in Scenario 7 is correct. However, if there is equipment(s) that is associated with a single well-pad in Scenario 7 and is under common-control or common ownership of the reporter then that equipment(s) is a part of onshore production and the reporter must monitor and report emissions from such equipment(s).

Commenter Name: Karin Ritter

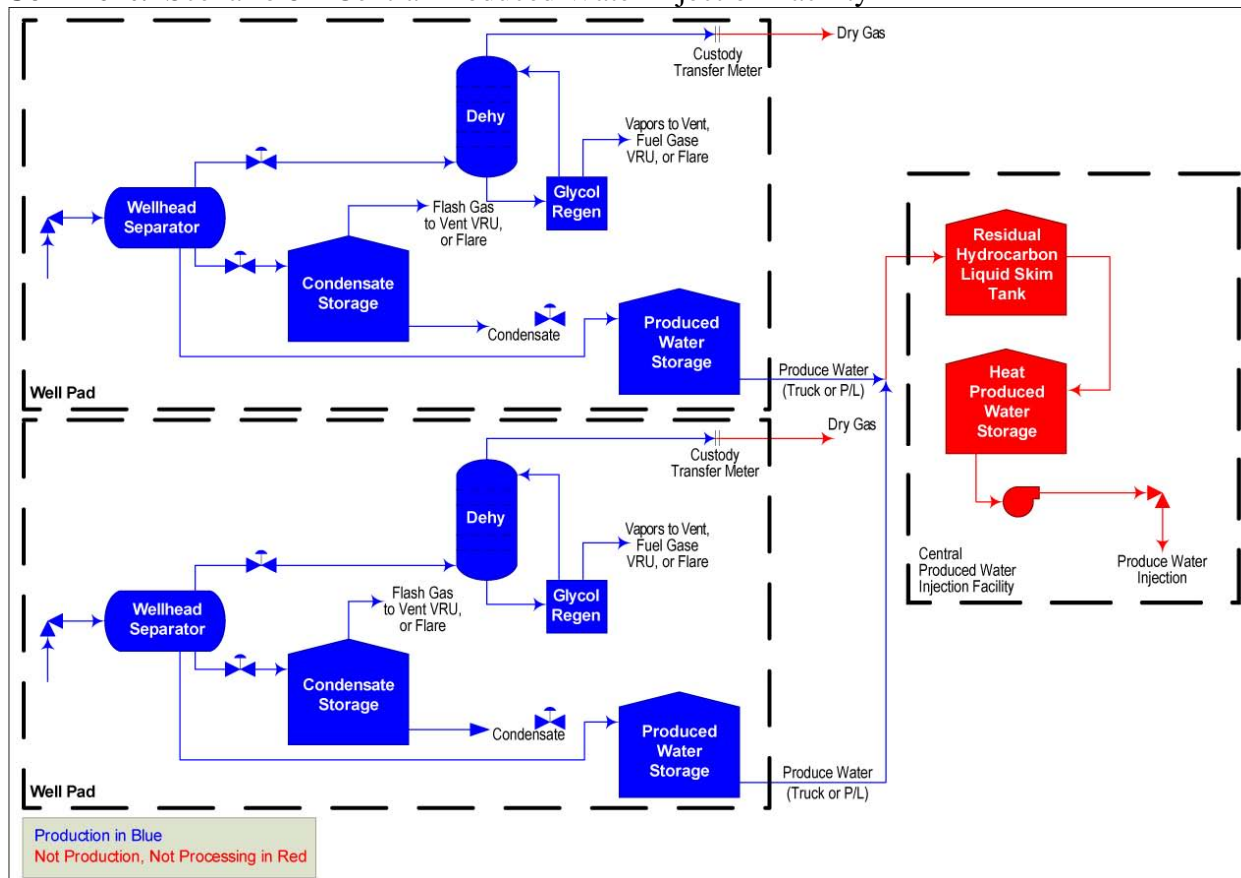
Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 87

Commenter Type: Industry - oil and gas

Comment: Scenario 8 – Central Produced Water Injection Facility



Response: In the commenter’s example Scenario 8, EPA conditionally agrees with the classifications. If the dry gas leaving the well-pad in Scenario 8 does not enter equipment(s) that is under common-control or common ownership of the reporter, then Scenario 8 is correct. However, if there is equipment(s) that is associated with a single well-pad in Scenario 8 and is under common-control or common ownership of the reporter, then that equipment(s) is a part of onshore production and the reporter must monitor and report emissions from such equipment(s).

Commenter Name: Karin Ritter

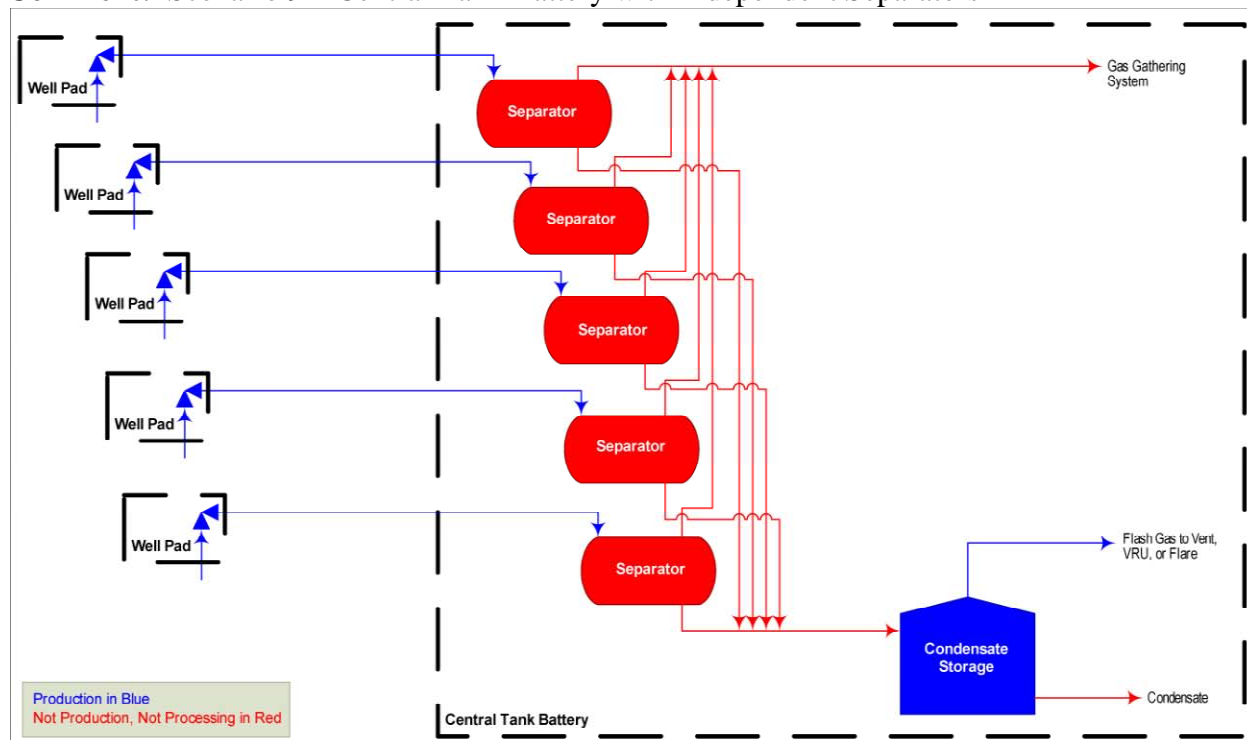
Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 88

Commenter Type: Industry - oil and gas

Comment: Scenario 9 – Central Tank Battery with Independent Separators



Response: In the commenter’s example Scenario 9, EPA disagrees that “separators” are not part of onshore production, because each separator is associated with a single well-pad. EPA also disagrees that “condensate storage” is part of onshore production, because the input stream to the condensate storage tank is a combination of multiple streams from equipment associated with one or more additional single well-pads.

Commenter Name: Karin Ritter

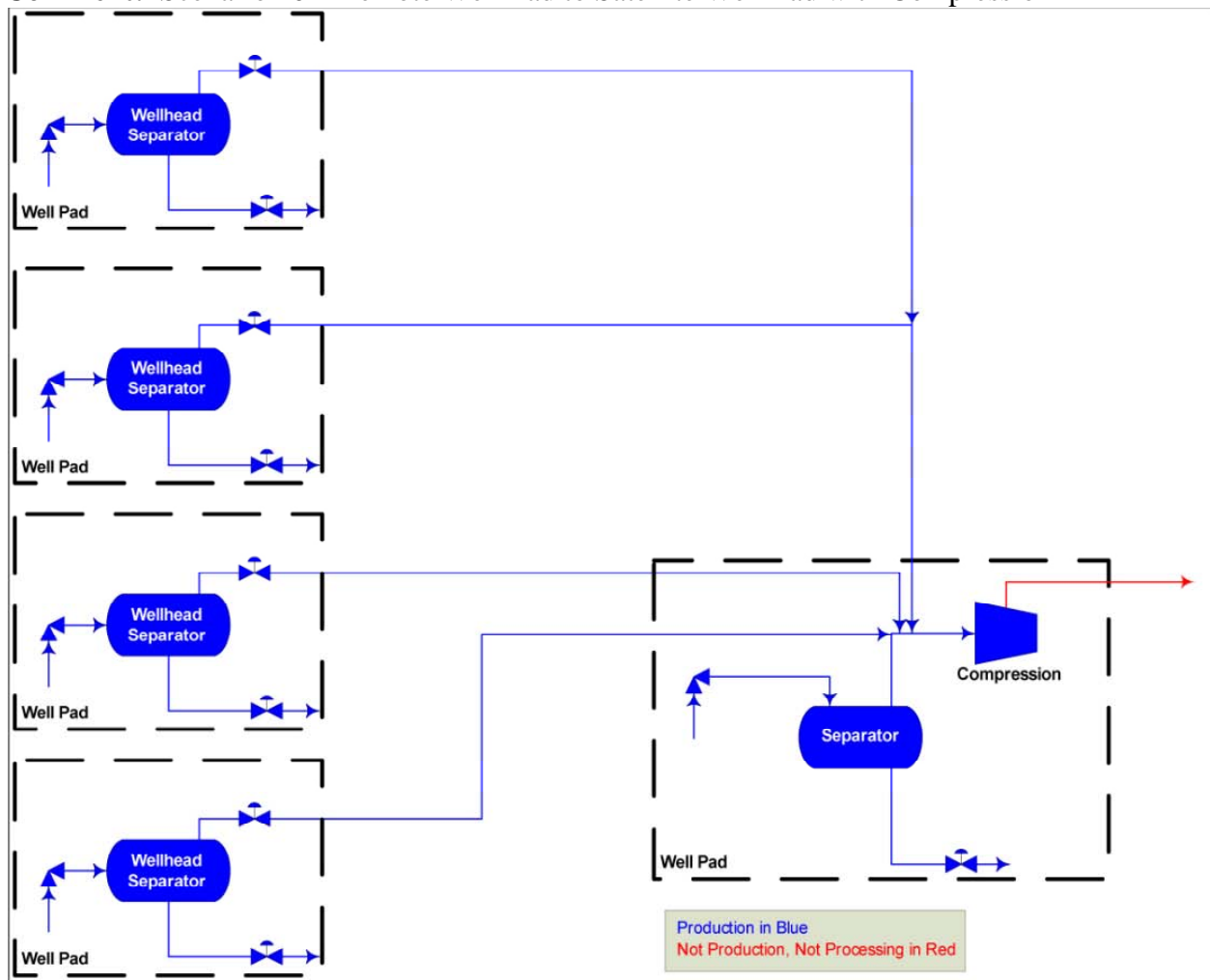
Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 89

Commenter Type: Industry - oil and gas

Comment: Scenario 10 – Remote Well Pad to Satellite Well Pad with Compression



Response: In the commenter’s example Scenario 10, EPA conditionally agrees with the classifications. If the dry gas leaving the well-pad in Scenario 10 does not enter equipment(s) that is under common-control or common ownership of the reporter, then Scenario 10 is correct. However, if there is equipment(s) that is associated with a single well-pad in Scenario 10 and is under common-control or common ownership of the reporter, then that equipment(s) is a part of onshore production and the reporter must monitor and report emissions from such equipment(s).

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 79

Commenter Type: Industry - oil and gas

Comment: Section 3: Production Configuration Diagrams

As referenced in Comment W.52 [EPA-HQ-OAR-2011-0512-0042, Excerpt 70], the following

diagrams illustrate API's understanding of the proposed definition for "associated with a well-pad" and the proposed revised source category definition for onshore petroleum and natural gas production. In these diagrams, blue shading indicates equipment "associated with a well-pad", and red shading indicates equipment that is not part of the onshore petroleum and natural gas source category nor part of the onshore natural gas processing source category. These diagrams were distributed to the API member companies as a tool to guide industry in classifying their emission sources for data collection and reporting.

[See original comment for Scenario, Well Pad Equipment, Facility Processes Table]

Response: For EPA's agreements and disagreements with the Production Configuration Diagrams submitted by the commenter, please see the responses to EPA-HQ-OAR-2011-0512-0042, Excerpt 80 through EPA-HQ-OAR-2011-0512-0042, Excerpt 89.

Section 10.3 - Facility With Respect to Natural Gas Distribution

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 56

Commenter Type: Industry - oil and gas

Comment: Revision: EPA added the following to the reporting requirements: "Report the information listed in this paragraph for each applicable source type. If a facility operates under more than one industry segment, each piece of equipment should be reported under its respective majority use segment..."

Comment: The use of "facility" here is confusing. It is not clear how a "facility" in the context of Subpart W can operate under more than one industry segment. Is this statement meant to address equipment rather than facilities? For example, a well located within a gas plant or residue compression adjacent to a gas plant, are two examples where specific equipment might be operated under more than one industry segment. API requests clarification on EPA's intention with this statement and guidance on how these two examples should be reported.

Response: There are situations in which more than one industry segment could be located in one facility. Where there is co-located or dual use equipment, reporters should consider the following when evaluating applicability:

- 1) As a first step the reporter must determine the emissions from all equipment listed in 98.232(c) for onshore petroleum and production. Per section 98.231(a) only sources listed in 98.232(c) need to be considered for threshold determination for onshore petroleum and natural gas production. 98.238 defines "facility" for the purposes of onshore petroleum and natural gas systems. Per the requirements of 98.3 each "facility" must submit a GHG report for all source categories at that "facility".
- 2) Note that while identifying onshore production emissions sources reporters have to determine whether the source is "on the well pad or associated with a well pad". The location of production wells within other facilities is inconsequential to this

determination. Sources on a single well pad or associated with a single well pad across the entire reporting basin have to be taken into consideration. If your emissions from onshore petroleum and natural gas production are equal to or greater than 25,000mtCO₂e, then onshore petroleum and natural gas production facilities report as a separate facility and include all emissions sources listed in 98.232(c).

3) Except for onshore petroleum and natural gas production and natural gas distribution, which have unique facility definitions, all other segments subject to subpart W are considered in the threshold determination for a single facility. You would also include emissions from other source categories at your facility (e.g., stationary combustion). If there are emissions sources that are dual purpose then the rule requires this piece of equipment to be reported under the majority use industry segment based on guidance provided in EPA-HQ-OAR-2009-0923-1024, Excerpt 14 of the Reporting Rule Subpart W – Petroleum and Natural Gas: EPA's Response to Public Comments.

4) For collocated industry segments, which cannot occur in the case of onshore petroleum and natural gas production and natural gas distribution due to the requirements in 98.231(a), EPA has provided guidance on emissions reporting in EPA-HQ-OAR-2009-0923-1024, Excerpt 14 of the Reporting Rule Subpart W – Petroleum and Natural Gas: EPA's Response to Public Comments.

Section 10.4 - Facility with Respect to Onshore Petroleum and Natural Gas Production

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 5

Commenter Type: Industry - oil and gas

Comment: “Facility with respect to onshore petroleum and natural gas production” – We generally support the modifications made to this definition; however, EPA should exclude from this definition dehydrators that are located on or associated with a single well-pad if the dehydrator is owned and operated by a third-party. In such cases, these dehydrators are owned and operated by a third-party company contracted by the well operator. The well operator does not control the dehydrator, may not handle it, and cannot conduct maintenance on the dehydrator even if it is located at the well site. In some cases, the well operator no longer owns the gas going through this equipment as there has already been a transfer of custody of the gas to the third-party. Therefore, such third-party owned and operated dehydrators are better classified as gathering and boosting equipment. Hence, third-party owned and operated dehydrators should be required to report under forthcoming regulations that will cover these activities. EPA should clarify that emissions from dehydrators owned and operated by third parties should not be reported under § 98.232(c)(1), (14), (22).

Response: The reporter has to determine whether or not equipment within their facility has to report depending on whether the reporter has common ownership or common control over the equipment. Please see preamble Section II.D.10 – Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Dehydrators owned and operated by third parties.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 71

Commenter Type: Industry - oil and gas

Comment: _Revision: EPA modified the definition for “facility” as shown:

Facility with respect to onshore petroleum and natural gas production for purposes of [add (red): reporting under] this subpart and for [add (red): the corresponding] subpart A [add (red): requirements] means all petroleum or natural gas equipment on a well- pad or associated with a well[add (red): -] pad and CO2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in §98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

Comments: API supports this revision.

Response: EPA thanks the commenter for their remarks. Additionally, in this final rule, EPA is adding the word “single” to the first sentence of this definition to clarify that the petroleum or natural gas equipment must be on a “single” well-pad or associated with a “single” well-pad.

Section 10.7 - Forced extraction of natural gas liquids

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 6

Commenter Type: Industry - oil and gas

Comment “Forced extraction of natural gas liquids” – Chesapeake and AXPC support EPA’s proposed definition for this term.

Response: EPA thanks the commenter for their remarks.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 72

Commenter Type: Industry - oil and gas

Comment: Revision: EPA added a new definition for “forced extraction”.

Forced extraction of natural gas liquids means removal of ethane or higher carbon number hydrocarbons existing in the vapor phase in natural gas, by removing ethane or heavier hydrocarbons derived from natural gas into natural gas liquids by means of a forced extraction process. Forced extraction processes include but are not limited to refrigeration, absorption (lean oil), cryogenic expander, and combinations of these processes. Forced extraction does not include in and of itself; natural gas dehydration, or the collection or gravity separation of water or hydrocarbon liquids from natural gas at ambient temperature or heated above ambient temperatures, or the condensation of water or hydrocarbon liquids through passive reduction in pressure or temperature, or portable dewpoint suppression skids.

Comment: API supports the addition of this definition

Response: EPA thanks the commenter for their remarks.

Section 10.9 - Horizontal well

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 73

Commenter Type: Industry - oil and gas

Comment: Revision: EPA added a new definition for “horizontal well”:

Horizontal well means a well bore that has a planned deviation from primarily vertical to a primarily horizontal inclination or declination tracking in parallel with and through the target formation.

Comment: API supports the addition of this definition.

Response: EPA thanks the commenter for their remarks.

Section 10.10 - Metering-regulating station

Commenter Name: Pamela A. Lacey

Commenter Affiliation: American Gas Association (AGA)

Document Control Number: EPA-HQ-OAR-2011-0512-0032

Comment Excerpt Number: 4

Commenter Type: Trade Association

Comment: The term “metering-regulating station” is also defined in revised §98.238. We believe this is the clearer term and should be used consistently instead of “meter-regulating station” as used in the TD station definition above. The Proposal defines the term metering-regulating station to mean:

“A station that meters the flowrate, regulates the pressure, or both, of natural gas in a natural gas distribution facility. This does not include customer meters, customer regulators, or farm taps.”

Exclusion of Farm Taps and Customer Meters and Regulators: AGA very much appreciates the exclusion of customer meters, regulators and farm taps. This will avoid sweeping millions of customer facilities into the reporting rule, thereby avoiding an untenable burden on LDC resources. We also appreciate the clarity of the definition. However, we believe the definition is unduly broad. We understand that the term Metering-regulating station includes stations that have just a meter but no regulator, stations that have just a pressure regulator but no meter, and stations that have both a meter and a regulator. It is still our understanding however, that equipment that the LDC does not own or operate would not be included because this equipment is not part of the LDC distribution “facility.”

Response: In this final rule, EPA is amending the term “meter-regulating station” to “metering-regulating station” to make it consistent with the definition. The commenter has not provided any technical reason as to why the definition for metering-regulating station is broad and how this places undue burden on reporters. The commenter’s understanding that stations with only meters, only regulators, or both meters and regulators are considered metering-regulating stations is correct as per the requirements of this final rule. EPA notes that the reporters only have to conduct leak detection at T-D transfer stations and apply a meter/regulator run factor to metering-regulating stations. Hence, there is no burden to monitor metering-regulating stations other than to determine a count of such facilities.

Natural gas distribution reporters must determine whether equipment, which is not owned or operated, is under common ownership or common control. Emissions from sources that are under common ownership or common control of the reporter must be reported.

Section 10.11 - Pressure grouping

Commenter Name: William W. Grygar II

Commenter Affiliation: Anadarko Petroleum Corporation

Document Control Number: EPA-HQ-OAR-2011-0512-0028

Comment Excerpt Number: 11

Commenter Type: Industry - oil and gas

Comment: For the liquids unloading emissions calculations EPA provides a definition of pressure groupings. The exact pressure to use; however, is not defined. Downhole pressure is not available; however tubing and gas-line pressure are readily available data sets that may be used for this calculation.

Response: In this final rule, EPA is clarifying that reporters may use shut-in pressure, surface pressure, or casing pressure. If casing pressure is not available for each well then the operator may determine the casing pressure by multiplying the tubing pressure of each with a ratio of casing pressure to tubing pressure from a well in the same sub-basin where the casing pressure is known. The tubing pressure must be measured during gas flow to a flow line. The shut-in pressure, surface pressure, or casing pressure must be determined just prior to liquids unloading, when the well production is impeded by liquids loading or closed to the flow line by surface valves.

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 8

Commenter Type: Industry - oil and gas

Comment: Pressure groupings – The proposed definition for pressure groupings is silent regarding where reporters must measure the pressure. This definition must clarify whether reporters must use the surface pressure or the reservoir shut-in pressure. See also API’s comment W.56 [EPA-HQ-OAR-2011-0512-0042, Excerpt 74] in Section 2 of its October 24, 2011 letter to EPA.

Response: In this final rule, EPA is clarifying that shut-in pressure, surface pressure, or casing pressure may be used in estimating emissions from well liquids unloading. Please see response to EPA-HQ-OAR-2011-0512-0028, Excerpt 11.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 74

Commenter Type: Industry - oil and gas

Comment: Revision: EPA added a new definition for “pressure groupings”:

Pressure groupings are defined as follows: less than or equal to 25 psig; greater than 25 psig and less than or equal to 60 psig; greater than 60 psig and less than or equal to 110 psig; greater than 110 psig and less than or equal to 200 psig; and greater than 200 psig.

Comments:

- As noted in comment (EPA-HQ-OAR-2011-0512-0042, Excerpt 74), the pressure groupings only apply to Methodology 1 for the liquids unloading emission source.

- Also as noted in comment (EPA-HQ-OAR-2011-0512-0042, Excerpt 74), above, Methodology 1 indicates that the pressure groupings apply across each of the sub-basin category (conventional and unconventional) and tubing grouping. This is inconsistent with previous discussions with EPA, where pressure grouping were discussed only in the context of conventional wells. API requests that the regulatory language clarify that pressure groupings are only applicable to conventional wells.

- In discussions with EPA and an e-mail sent on June 22, 2011, API proposed two pressure groupings for Conventional formations based on flowing wellhead pressure. API requests that the pressure groupings be limited to two pressure groupings as originally proposed by the API. Based on the pressure regimes EPA included in this amendment, the two recommended pressure groupings would be < 110 psig and > 110 psig. Requiring five pressure groupings for three tubing diameter groupings and four formation types per county is excessive considering the logistics involved with capturing calibrated metered vent rates. Two pressure groupings will still provide EPA with the desired representative data and sufficient data granularity for future policy development. API recognizes that there may be some concerns regarding the range of the two proposed pressure groupings and would propose that the pressure of the representative metered vent rates be within $\pm 10\%$ of the average pressure of the range (S P / well count) to address this issue.

- EPA does not define what pressure is to be used for the pressure groupings. API interprets the pressure groupings to be based on the surface pressure. As EPA indicated in Appendix D of the Technical Support Document associated with these proposed amendments, reservoir shut-in pressure is not available in the public domain. API agrees with this assessment, and as indicated in Comment W.14 reservoir shut-in pressure is not reliably available in operations either.

Response: EPA notes that the language in the rule sufficiently indicates that the pressure grouping applies only to the gas well liquids unloading monitoring method. Hence, EPA is not making any changes to this effect in final rule. EPA agrees that the pressure grouping and sub-basin category should apply only to Method 1. However, for methods 2 and 3, the data reporting is required at a sub-basin level. For further details, please see the preamble Section II.D.1 – Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Pressure groupings.

EPA has deleted the term conventional and unconventional from the definition of sub-basin category, since it has different connotations in the industry. As regards the pressure grouping, since they apply to only one emission source, i.e. gas well liquids unloading, reporters have to apply the pressure grouping to any sub-basin category where gas well liquid unloading occurs, if they are using Calculation Methodology 1 in 40 CFR 98.233(f).

Regarding the suggestion to limit the number of pressure groupings to two; as discussed in the proposed rule, EPA analyzed different numbers of pressure groupings and selected the optimal number of pressure groupings that resulted in minimal error while managing burden. The EPA error estimates were developed using the mean pressure value within each range. EPA estimates that using five pressure groupings would result in a possible national average error of approximately 30% from all wells that report for the well liquids unloading emissions source.

The API suggestion to decrease the pressure groupings to two would result in a possible national average error increase to approximately 65%. For background on the analysis, please see “2011 Technical Revisions to the Petroleum and Natural Gas Systems Category of the GHG Reporting Rule: Summary of questions raised on Subpart W” docket number EPA-HQ-OAR-2011-0512-0015 and “Sub-Basin Entity Pressure Range Analysis” docket number EPA-HQ-OAR-2011-0016, and preamble Section II.C – Final Amendments to the Petroleum and Natural Gas Systems Source Category – Well Venting for Liquids Unloading and Section II.D.1 – Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Pressure groupings. Hence, EPA has retained the five pressure ranges for Monitoring method 1 for well venting from liquids unloading in this final rule. Reporters are to estimate emissions from one well with a unique tubing diameter grouping and pressure grouping combination in a sub-basin, and apply that value to all wells with that tubing diameter grouping and pressure grouping in that same sub-basin. Additionally, EPA has provided alternative calculation methodologies that do not require any measurement to calculate the total emissions for well venting for liquids unloading with or without plunger lifts in Equations W-9 and W-8.

In this final rule, EPA is clarifying that shut-in pressure, surface pressure, or casing pressure may be used in estimating emissions from well liquids unloading. Please see response to EPA-HQ-OAR-2011-0512-0028, Excerpt 11.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 95

Commenter Type: Industry - oil and gas

Comment: National Gas Well Counts

EPA posted several supporting documents to Docket EPA–HQ–OAR–2011–0512 on August 18, 2011. The file, “Sub-basin Well Counts by Group Type 2010”, includes a listing of gas wells by state, county, formation type, pressure grouping, and reservoir name from the 2010 HPDI© data listing. API has reviewed this information and found that the gas well counts from this file (355,082 gas wells for 2010) are significantly less than the 2009 gas well counts available from EIA (493,100 from http://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm).

In addition, API found that all of Southwest Wyoming wells are listed as Conventional <25 psi when these are actually almost 100% tight sand and run with surface pressures of between 200 and 600 psi. This raises concerns with the HPDI data posted by EPA.

API therefore questions whether these discrepancies are:

- artifacts of the query used to pull the data;
- indications that the HPDI database does not have the proper data in their database and EPA assumed blank is zero (<25) for pressure and blank is conventional/other for formation type; or

- indications that data are simply not available in any of the databases.

API requests additional information on the well counts contained in the HPDI data listing, including an explanation of any algorithms and assumptions used in classifying wells, as well as an explanation for the differences between the HPDI gas well totals and gas well counts reported by EIA.

Response: EPA provided the mapping of sub-basin categories in the docket as guidance to reporters. The sub-basin categories were developed using the HPDI© database, which is a commercially available data base that is compiled of specific data on onshore producers. The data within the HPDI © database is developed using data gathered from States by oil and gas operators. EPA in developing the sub-basin categories has made best engineering judgment on certain data elements where data were not available in HPDI©. However, EPA reiterates that the listing which maps sub-basin categories that was provided in the docket has been provided as guidance only. The responsibility for determining the correct sub-basin category listing using the criteria outlined in 40 CFR part 98, Subpart W ultimately lies with the Subpart W reporter.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 74

Commenter Type: Industry - oil and gas

Comment: Revision: EPA added a new definition for “pressure groupings”:

Pressure groupings are defined as follows: less than or equal to 25 psig; greater than 25 psig and less than or equal to 60 psig; greater than 60 psig and less than or equal to 110 psig; greater than 110 psig and less than or equal to 200 psig; and greater than 200 psig.

Comments:

- As noted in comment W.13 [EPA-HQ-OAR-2011-0512-0042, Excerpt 29], the pressure groupings only apply to Methodology 1 for the liquids unloading emission source.
- Also as noted in comment W.13 [EPA-HQ-OAR-2011-0512-0042, Excerpt 29], above, Methodology 1 indicates that the pressure groupings apply across each of the sub-basin category (conventional and unconventional) and tubing grouping. This is inconsistent with previous discussions with EPA, where pressure grouping were discussed only in the context of conventional wells. API requests that the regulatory language clarify that pressure groupings are only applicable to conventional wells.
- In discussions with EPA and an e-mail sent on June 22, 2011, API proposed two pressure groupings for Conventional formations based on flowing wellhead pressure. API requests that the pressure groupings be limited to two pressure groupings as originally proposed by the API. Based on the pressure regimes EPA included in this amendment, the two recommended pressure

groupings would be < 110 psig and > 110 psig. Requiring five pressure groupings for three tubing diameter groupings and four formation types per county is excessive considering the logistics involved with capturing calibrated metered vent rates. Two pressure groupings will still provide EPA with the desired representative data and sufficient data granularity for future policy development. API recognizes that there may be some concerns regarding the range of the two proposed pressure groupings and would propose that the pressure of the representative metered vent rates be within $\pm 10\%$ of the average pressure of the range (S P / well count) to address this issue.

- EPA does not define what pressure is to be used for the pressure groupings. API interprets the pressure groupings to be based on the surface pressure. As EPA indicated in Appendix D of the Technical Support Document associated with these proposed amendments, reservoir shut-in pressure is not available in the public domain. API agrees with this assessment, and as indicated in Comment W.14 [EPA-HQ-OAR-2011-0512-0042, Excerpt 30] reservoir shut-in pressure is not reliably available in operations either.

Response: EPA notes that the language in the rule sufficiently indicates that the pressure grouping applies only to the gas well liquids unloading monitoring method. Hence, EPA is not making any changes to this effect in final rule. EPA agrees that the pressure grouping and sub-basin category should apply only to Method 1. However, for methods 2 and 3, the data reporting is required at a sub-basin level. For further details, please see the preamble Section II.D.1 – Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Pressure groupings.

EPA has deleted the term conventional and unconventional from the definition of sub-basin category, since it has different connotations in the industry. As regards the pressure grouping, since they apply to only one emission source, i.e. gas well liquids unloading, reporters have to apply the pressure grouping to any sub-basin category where gas well liquid unloading occurs, if they are using Calculation Methodology 1 in 40 CFR 98.233(f).

Regarding the suggestion to limit the number of pressure groupings to two; as discussed in the proposed rule, EPA analyzed different numbers of pressure groupings and selected the optimal number of pressure groupings that resulted in minimal error while managing burden. The EPA error estimates were developed using the mean pressure value within each range. EPA estimates that using five pressure groupings would result in a possible national average error of approximately 30% from all wells that report for the well liquids unloading emissions source. The API suggestion to decrease the pressure groupings to two would result in a possible national average error increase to approximately 65%. For background on the analysis, please see “2011 Technical Revisions to the Petroleum and Natural Gas Systems Category of the GHG Reporting Rule: Summary of questions raised on Subpart W” docket number EPA-HQ-OAR-2011-0512, Excerpt15 and “Sub-Basin Entity Pressure Range Analysis” docket number EPA-HQ-OAR-2011-0016, and preamble Section II.C – Final Amendments to the Petroleum and Natural Gas Systems Source Category – Well Venting for Liquids Unloading and Section II.D.1 – Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Pressure groupings. Hence, EPA has retained the five pressure ranges for Monitoring method 1 for well venting from liquids unloading in this final rule. Reporters are to estimate emissions from one well with a unique tubing diameter grouping and pressure grouping combination in a sub-basin,

and apply that value to all wells with that tubing diameter grouping and pressure grouping in that same sub-basin. Additionally, EPA has provided alternative calculation methodologies that do not require any measurement to calculate the total emissions for well venting for liquids unloading with or without plunger lifts in Equations W-9 and W-8.

In this final rule, EPA is clarifying that shut-in pressure, surface pressure, or casing pressure may be used in estimating emissions from well liquids unloading. Please see response to EPA-HQ-OAR-2011-0512-0028, Excerpt 11.

Section 10.12 - Sub-basin category

Commenter Name: Vince Alaimo

Commenter Affiliation: Marshall Miller & Associates Inc. on behalf of Consol Energy Inc.

Document Control Number: EPA-HQ-OAR-2011-0512-0036

Comment Excerpt Number: 3

Commenter Type: Industry - oil and gas

Comment: Sub-Basin Field designation

EPA still believes they are correct by using EIA Field Code Master List for field designation; however, they are proposing an alternative method using the County and the distinction of the type of hydrocarbon formation. The various hydrocarbon formations can be grouped into four categories: conventional, coal bed methane, tight formations, and shale. BUT for liquid unloading EPA is also proposing a measurement plan that uses some operational criteria to generate more than one sample per sub-basin category for specific emissions sources. EPA is proposing the use of pressure ranges for liquids unloading measurements, because the volume of gas released during an unloading is related to the wellhead pressure. For example, reporters would take one measurement per pressure range within a sub-basin category. An example of pressure ranges is 0–25 psig, > 25–60 psig, > 60–110 psig, > 110–200 psig, and 200 psig and above.

COMMENT 2

Consol Energy Inc. would like to see this category reduced to two or three pressure ranges per sub-basin. Companies with thousands of wells could have a very large number of wells per sub-basin. Two categories would reduce the burden of additional measurements required. Consol Energy Inc. proposes reporting wells above 110 psig and below.

Response: EPA disagrees with reducing the number of pressure groups to two or three; please see the response to EPA-HQ-OAR-2011-0512-0042, Excerpt 74 for further details.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 75

Commenter Type: Industry - oil and gas

Comment:[Please refer to the original comment text posted in the docket]

Revision: EPA added a new definition for “sub-basin category”.

Comments: API requests the following revisions, shown in green font:

Sub-basin category, for onshore natural gas production, means a subdivision of a basin into the unique combination of wells with the surface coordinates within the boundaries of an individual county and subsurface completion in one or more of each of the following [add (green): five] [delete (green): four] formation types: [add (green): oil, conventional gas, shale gas, coal seam, or other tight reservoir rock. The distinction between conventional gas and tight gas reservoirs shall be [delete (green): as] [add (green): designated as:] [delete (green): by 18 C.F.R. 270.305:] conventional with >0.1 millidarcy permeability, and unconventional tight with =0.1 millidarcy permeability. [add (green): Permeability for a reservoir type shall be determined by engineering estimate.] [delete (green): Unconventional formation types are either shale, coal seam, or other tight reservoir rock.] Wells producing from more than one [delete (green): unconventional] formation type shall be classified into only one type based on the formation with the most contribution to production as determined by engineering knowledge. [delete (green): Unconventional wells producing in two or more formation types of “shale and coal seam”, “shale and other tight”, or “shale, coal seam, and other tight”; are considered shale. In addition, unconventional wells producing in “coal seam and other tight” formations are considered coal.]

- API requests the revisions noted above. Deleting “unconventional” in the third sentence clarifies how to distinguish between wells that produce from co-mingled conventional and unconventional formations (the previous language did not address this situation). In addition, the last two sentences appear contradictory. API prefers to assign formation types by the highest contribution to production based on engineering knowledge.
- In the preamble (page 56026 middle column), EPA indicates “In the event that there is more than one formation, then the reporters would use the most specific designation.” This seems to imply that only one formation type is assigned per county. Whereas the rule language assigns the formation type by well, with only one designation to each well. API prefers the approach described in the preamble and requests additional clarification in the rule language if EPA’s intent is for reporters to assign only one formation type per county. If the intent is for reporters to assign only one formation type per county, then EPA would need to clarify what is meant by “most specific designation”.
- The revisions above address API’s concern that a sub-basin category for oil production was not previously defined.

Response: In this final rule, EPA has deleted the term conventional and unconventional from the definition of sub-basin category, since it has different connotations in the industry. EPA is allowing engineering estimate to determine the permeability of the reservoir type in this final

rule. It was not EPA's intent to place additional burden on reporters by having them measure formation permeability.

EPA does not agree with assigning one formation type to each county. The statement cited by the commenter is not referring to assigning a formation type to each county. Instead, the intent of the preamble text was that wells, which are producing from more than one formation type, must be associated with the formation that contributes most to its production. This is clearly stated in the definition of sub-basin category in 98.238. EPA is not changing the sub-basin category definition to have reporters assign a single formation type to a county and this was never the intent. A single county can have multiple different types of formations each with its own characteristic. Assigning a single formation to a count would not provide the level of data clarity and formation differentiation necessary for future policy considerations.

EPA agrees with the comment regarding an oil sub-basin and in this final rule has revised the definition for sub-basin in 40 CFR 98.238 to include an oil formation within the sub-basin category; please see the preamble Section II.C. – Final Amendments to the Petroleum and Natural Gas Systems Source Category – Major Changes Since Proposal and Section II.D.9 - Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Addition of oil formation type in the sub-basin category definition, for further details.

Section 10.13 - Transmission-distribution transfer station

Commenter Name: Darrell Shier

Commenter Affiliation: SCANA Corporation

Document Control Number: EPA-HQ-OAR-2011-0512-0030

Comment Excerpt Number: 2

Commenter Type: Industry - oil and gas

Comment: Metering-Regulating Station Sampling

The Final Rule requires that leak surveys be conducted at all metering-regulating (M&R) stations classified as "custody transfer city gate stations." We agree that this definition has problems, because it attempts to capture ownership change (custody transfer) and pressure change (city gate) within the same definition. Those two classes of stations do not necessarily overlap.

The Proposed Rule discards those qualifying terms and instead requires surveys at all transmission distribution stations. While this definition is perhaps more clear, the number of stations that must be surveyed is greatly increased, thus putting an undue burden on LDCs. We respectfully disagree with the EPA's statement that "the proposed revisions primarily provide additional clarifications or flexibility regarding the existing regulatory requirements, [and] generally do not affect the type of information that must be collected" For example, under the Final Rule, PSNC would be required to leak survey 18 M&R stations in its entire system. This is the number of "custody transfer" M&R stations within the PSNC system. Under the Proposed Rule, the number of transmission-distribution stations that must be surveyed increases to more

than 450. Our SCE&G subsidiary would experience a similarly impossible number to survey in 2011. A survey of this magnitude cannot possibly be conducted with but a few months remaining in the year.

Furthermore, we believe that a survey of this size will not yield significantly better information than a smaller survey. If it is EPA's goal to have a statistically sound number of M&R stations surveyed, then it is appropriate to use other factors to reduce the number of stations surveyed. We suggest two possible ways to limit the surveyed subset of stations:

1. Survey only those stations that flow a significant amount of gas at any point during the year. This flow range could be based on actual gas measurements or determined by flow models based on actual system conditions. This method is attractive because it would remove from the subset all M&R stations that serve only handfuls of customers. For example, if only stations that had modeled flows of 200 cubic feet per hour (cfh) or more were included in the PSNC survey, the surveyed subset would be cut to 68 stations from 450 stations.

2. Survey a defined percentage of M&R stations. For example, 10% of all M&R stations might be included in the survey, perhaps subject to a minimum and maximum number of stations. This method might be attractive because the 10% of surveyed stations could include stations of all sizes and types, thus creating a more representative emission factor to apply to the whole universe of stations.

We suggest that the inlet pressure to the M&R station not be used as a threshold for subset selection. A large number of PSNC's and SCE&G's M&R stations serve a small number of customers -as few as three per station. Some of those small stations have inlet pressures as high as 800 psi and would be included any subset based on inlet pressure.

Response: In this final rule, EPA is finalizing the definition of transmission-distribution (T-D) transfer station, as proposed. EPA has determined that custody of gas is not necessarily transferred from a transmission company to a distribution company through a pressure drop (i.e. custody may be transferred through a transmission pipeline owned by a transmission company to a transmission pipeline owned by a natural gas distribution company). In this final rule, EPA requires reporters to conduct leak detection at specific stations where gas is regulated and not necessarily where custody is transferred. EPA understands that pressure drops occur in several locations throughout a distribution system, but only requires reporters to do leak detection at stations where gas is taken from the transmission pipeline and put into a distribution pipeline at a lower pressure. Therefore, EPA is finalizing the definition of T-D transfer station to more clearly distinguish the stations where reporters must do leak detection.

Regarding the commenter suggestion (1) of excluding some smaller stations from leak detection requirements, EPA disagrees with the commenter that surveying only large stations will represent the entire population and that size of the station should impact whether leaks are surveyed or not. Hence, EPA requires monitoring of all T-D transfer stations. However, EPA is providing the option for natural gas distribution companies to conduct leak detection at their T-D transfer stations over multiple years, not exceeding five years. This is similar to option 2 suggested by the commenter, however, the reporter has to monitor a minimum of 20% as opposed to the commenter suggested 10% of the T-D transfer stations each year. For further

details on why EPA is not including a threshold (below which reporter do not have to conduct leak detection) for T-D transfer stations, and how EPA is reducing burden on natural gas distribution reporters that must conduct leak detection at T-D transfer stations, please see preamble Section II.D.4 – Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Transmission-distribution transfer station reporting.

Commenter Name: Paul Pike

Commenter Affiliation: Ameren Corporation

Document Control Number: EPA-HQ-OAR-2011-0512-0031

Comment Excerpt Number: 2

Commenter Type: Industry - other

Comment: Ameren appreciates EPA's effort to propose revisions to what is subject to the annual component leak surveys, the Proposal increases the type and number of stations that would be subject to the annual leak survey requirement under, and that this would apply retroactively to the beginning of 2011, even though the Technical Revisions are not expected to be issued in final form until December 2011. We made a determination regarding which stations we would leak survey under the existing Subpart W rule, and by December 2011 it will be too late to re-do the Subpart W leak survey program. It will be important that the agency make clear in the final rule and preamble that it is allowing local distribution companies to deal with this situation by submitting the leak surveys we have conducted and/or apply an emission factor to a count of stations under the Best Available Monitoring Methods provisions.

Response: In this final rule, EPA is providing the option for natural gas distribution companies to conduct leak detection at their T-D transfer stations over multiple years, not exceeding five years. Please see preamble Section II.D.4 – Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Transmission-distribution transfer station reporting and the response to EPA-HQ-OAR-2011-0512-0030, Excerpt 2.

With regards to reporting of emissions for year 2011, EPA notes that the BMM provisions in the Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems: Revisions to Best Available Monitoring Method Provisions (76 FR 59533) and the November 2011 final rule provide ample guidance on using data already available to report emissions for reporting year 2011. If you already made a determination regarding which stations to leak survey under the 2010 final Subpart W rule, you can use those measurements as your best available monitoring method for the 2011 reporting year. Hence, EPA does not deem the requirement for T-D transfer stations as being an issue for reporting year 2011.

Commenter Name: Paul Pike

Commenter Affiliation: Ameren Corporation

Document Control Number: EPA-HQ-OAR-2011-0512-0031

Comment Excerpt Number: 3

Commenter Type: Industry - other

Comment: Under the Proposal, EPA is replacing the term "custody transfer city gate station" with the term Transmission-distribution (TD) transfer station". This replacement will sweep in many more stations into the resource-intensive on site leak survey requirement than appear to be covered under the current rule. Survey data from larger stations should be sufficient to develop an emission factor that can be applied to smaller stations. We urge EPA to impose the leak survey requirement only on TD Stations with a design rate of 4 million standard cubic feet per hour (scf/hr). This level will focus the leak surveys on a manageable number of stations.

Response: In this final rule, EPA is finalizing the definition of T-D stations and associated monitoring and reporting requirements and providing the option for natural gas distribution companies to conduct leak detection at their T-D transfer stations over multiple years, not exceeding five years. Please see preamble Section II.D.4 – Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Transmission-distribution transfer station reporting and the response to EPA-HQ-OAR-2011-0512-0030, Excerpt 2. Please see response to EPA-HQ-OAR-2011-0512-0031, Excerpt 2 about the ability to use BMM for the 2011 reporting year.

Commenter Name: Pamela A. Lacey

Commenter Affiliation: American Gas Association (AGA)

Document Control Number: EPA-HQ-OAR-2011-0512-0032

Comment Excerpt Number: 2

Commenter Type: Trade Association

Comment: I. New Definition of Stations Subject to Annual Leak Surveys: BMM Essential to Deal with Retroactive Application to 2011

While AGA appreciates EPA's effort to provide clear definitions of what is or is not subject to the annual component leak surveys, we are very concerned about the dramatic shift in the type and number of stations that would be subject to the annual leak survey requirement under the Proposal. We are further concerned that these new requirements would apply retroactively to the beginning of 2011, even though the Technical Revisions are not expected to be issued in final form until December 2011. Obviously, natural gas local distribution companies (LDCs) have had to make their best guess this year regarding which stations they should leak survey under the existing Subpart W rule, and in December 2011 they will not be able to turn the clock back to January 2011 and re-do their Subpart W leak survey program. We understand that the agency is suggesting that LDCs will be allowed to deal with this dilemma by submitting the leak surveys they have conducted and/or apply an emission factor to a count of stations under the Best Available Monitoring Methods (BMM) provisions. See 76 Fed. Reg. at 56,032. It will be important to make this clear in the final rule and preamble.

Response: In this final rule, EPA is finalizing, as proposed, the definition of T-D stations and associated monitoring and reporting requirements and providing the option for natural gas distribution companies to conduct leak detection at their T-D transfer stations over multiple years, not exceeding five years. Please see preamble Section II.D.4 – Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Transmission-

distribution transfer station reporting and response to comments EPA-HQ-OAR-2011-0512-30, Excerpt 2 and EPA-HQ-OAR-2011-0512-0031, Excerpt 2.

Commenter Name: Pamela A. Lacey
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2011-0512-0032
Comment Excerpt Number: 3
Commenter Type: Trade Association

Comment: AGA Appreciates Clear Definition of TD Stations, But Urges EPA to Exclude Stations Below 4.0 Million SCF/hr From Annual On-Site Surveys

Aside from the retroactive timing, we are also concerned about the overly broad scope of the new leak survey requirement in the Proposal. The current rule requires annual on-site surveys of components at “custody transfer city gate stations.” As explained in our March 2, 2011 petition for reconsideration, this term has proved subject to conflicting interpretations, especially when combined with other provisions of the rule that focus on components in meter runs, and the provision in the rule stating that the LDC’s distribution “facility” include only equipment operated by the LDC. Our members were confused as to which stations would be subject to the survey requirement. The best consensus guess was to leak survey meter run components at stations where an upstream pipeline or local producer transfers custody of natural gas to the LDC, and where the LDC operates a meter.

EPA is now proposing to replace the term “custody transfer city gate station” with the term “Transmission-distribution (TD) transfer station” defined in proposed revised section 98.238 to mean:

“a meter-regulating station where a local distribution company takes part or all of the natural gas from a transmission pipeline and puts it into a distribution pipeline.

Response: In this final rule, EPA is finalizing, as proposed, the definition of T-D stations and associated monitoring and reporting requirements and providing the option for natural gas distribution companies to conduct leak detection at their T-D transfer stations over multiple years, not exceeding five years. Additionally, EPA disagrees with the commenter with regards to including a threshold for the T-D transfer stations. Please see preamble Section II.D.4 – Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Transmission-distribution transfer station reporting and response to comments EPA-HQ-OAR-2011-0512-30, Excerpt 2 and EPA-HQ-OAR-2011-0512-0031, Excerpt 2.

Commenter Name: Pamela A. Lacey
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2011-0512-0032
Comment Excerpt Number: 6
Commenter Type: Trade Association

Comment: It is Essential to Reduce the Number of TD Stations Requiring On-Site Surveys: AGA appreciates EPA's request for comment on whether the agency should establish a threshold for imposing the annual leak survey requirement that would exclude smaller stations. See 76 Fed. Reg. at 56036. It will be very important to establish a workable exemption threshold to avoid sweeping in many more stations into the resource-intensive on site leak survey requirement than appear to be covered under the current rule. There is no environmental reason not to set such reasonable requirements. Survey data from larger stations will be sufficient to develop an emission factor that can be applied to smaller stations. Our members have found in their Subpart W work this year that even their large custody transfer stations have less than one leaking component per station on average. Surveying smaller stations is a waste of resources that could be better used elsewhere.

AGA surveyed its members in October 2011 regarding the number of TD stations they have that would be affected by the Proposal. We received responses from 42 of our larger member LDCs. The 42 responding companies reported they have a total of 20,781 stations that appear to fall within the Proposal's definition of TD Station. If no threshold were established, an average of 483 TD stations per company would have to be visited each year by a trained crew of utility employees or consultants for an annual Subpart W survey. The burden is uneven, and would fall much more heavily on some companies than on others simply based on their configuration. Several companies reported they have between 1,000 and 4,770 TD stations that would have to be surveyed every year under the Proposal. This could easily impose a cost burden of several million dollars per company each year.

This burden is completely out of proportion to the quantity of CO₂e that would be estimated and reported from these stations. One of our member companies hired a consultant this year to perform leak surveys using a FLIR GasFind IR camera and a Bacharach HiFlow Sampler to measure the actual volume of any leaks found.

The company surveyed 162 custody transfer stations in 2011. Out of 32,400 components measured, they found only 18 leaking components for an average of 0.1 leaking components per custody transfer station. The total component leak rate was 0.06%, and the total amount of greenhouse gas emissions actually measured from those leaking components amounted to 104 tonnes CO₂e per year from all the 162 stations – assuming the components leaked at this rate for the entire year.

In fact, this is an overestimate, because most of the leaking components were tightened with a wrench and fixed on the spot.

The resulting emission factor for the company's custody transfer stations is 0.64 tonnes per year per station.

The company estimates over 2,700 TD stations would be subject to the annual survey requirement under the Proposal. Leak surveying those 2,700 TD stations would cost around \$3 million. Using the above emission factor, one can estimate the total emissions from the 2,700 stations would equal 1,728 tonnes per year. So in effect, the Proposal would require this company – and many others – to expend about \$1,736 per tonne of CO₂e just to estimate and report – not to reduce emissions. This is about fifty times the level of control costs that would be

imposed on those same emissions by a comprehensive and aggressive GHG control program [Footnote 1: Many analysts project that \$30 per tonne CO₂e would be enough to stabilize climate change in the long run.].

Another way to look at this requirement is to compare the minimal cost and effort to estimate and report emissions from miles of pipeline – which just requires multiplying the miles of pipe times an emission factor. And yet pipeline emissions contribute the largest percentage of emissions from distribution systems, simply because there are so many miles of pipe. For example, the same company calculates emissions from its distribution pipelines by multiplying its 71,000 miles of distribution mains and 3.5 million miles of service lines by the appropriate default emission factor (for plastic pipe, cast iron, and steel). This simple spreadsheet calculation yields an estimate of 431,153 tonnes per year (tpy) CO₂e. This effort costs about \$2,000 at most, including the time to build the spreadsheet, collect the mileage data, and have a supervising engineer review the result [Footnote 2: This conservatively assumes using the services of a junior engineer for 24 hours at \$75/hour, and two hours of review by a senior engineer at \$100/hour, which is probably a lot more time than it actually took to calculate. The going rates for engineers may vary somewhat in different parts of the country.]. Thus, the cost to estimate and report the 431,153 tpy CO₂e from distribution pipelines is approximately \$0.005/Tonne CO₂e calculated. This is a far cry from the \$1,736 per tonne of CO₂e for surveying TD Station components.

Given what we have learned this year about the extremely low incidence of leaking components and the cost for conducting component leak surveys, it would make far more sense to impose the annual survey requirement on the largest stations and allow an emissions estimate for other TD stations using a station-level emission factor and population count.

Based on AGA's survey, we urge EPA to impose the leak survey requirement only on TD Stations with a design rate of 4 million standard cubic feet per hour (scf/hr).

This level would focus the leak surveys on a manageable number of stations. Most of our members have surveyed about 10 - 50 custody transfer stations this year. A threshold of 4 million scf/hr would capture about six TD stations on average per company. For the 42 members responding to the survey, this threshold would include 270 TD stations in the survey requirement and exclude 16,524 TD stations. In the alternative, at a 2.5 million scf/hr level, the survey requirement would apply to about 13 TD stations per company on average. For the 42 members responding to the survey, a threshold of 2.5 million scf/hr would include 568 TD stations and exclude 16,226 TD stations. AGA would prefer the 4 million scf/hr threshold, as this would yield more than enough data to develop an emission factor for other TD stations, and the effort involved would be more in line with the truly minimal emissions from this type of source.

Response: In this final rule, EPA is finalizing, as proposed, the definition of T-D stations and associated monitoring and reporting requirements and providing the option for natural gas distribution companies to conduct leak detection at their T-D transfer stations over multiple years, not exceeding five years. Additionally, EPA disagrees with the commenter with regards to including a threshold for the T-D transfer stations. Please see preamble Section II.D.4 – Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category:

Transmission-distribution transfer station reporting and response to comments EPA-HQ-OAR-2011-0512-30, Excerpt 2 and EPA-HQ-OAR-2011-0512-0031, Excerpt 2.

EPA does not have sufficient information to comment on the low leak rates found at the stations monitored by the company that conducted a survey at 162 stations. However, EPA does not expect to find significant leaks at custody transfer stations where gas is transferred from a transmission pipeline owned by a transmission company to a transmission pipeline owned by a natural gas distribution company. Typically, such stations are equipped with only a meter without any gas regulation. The leaks that are of interest to EPA are at T-D transfer stations where pressure is stepped down from a transmission pipeline to a distribution pipeline.

EPA disagrees with the cost estimate provided by the commenter. First, EPA does not require leak measurement to estimate emissions in Subpart W. Reporters need only conduct leak detection and use an emission factor to estimate emissions. Second, EPA has determined through experience in the Natural Gas Star Program that leak detection at a typical T-D transfer station takes about 15-30 minutes using a camera and 30-60 minutes using an OVA/ TVA. Third, commenters to the August 2011 rule proposal indicated that natural gas distribution companies already own and operate leak detection equipment. Finally, the Department of Transportation requires periodic inspection of certain stations, potentially providing reporters with an opportunity to align their survey schedules to meet both requirements on the same trip, although the DOT regulations are not duplicative of the Greenhouse Gas Reporting program. For further details, please see Preamble Section II.D.4 - Responses to Major Comments on the Petroleum and Natural Gas Systems Source Category: Transmission-distribution transfer station reporting. Hence, EPA does not agree that it will cost reporters approximately \$1,100 per T-D transfer station for leak detection only. For further details on EPA's cost estimates, please see Technical Support Document to the November 2010 final rule and Volume 10 of the Mandatory Greenhouse Gas Reporting Rule Subpart W – Petroleum and Natural Gas: EPA's Response to Public Comments.

EPA does not have, nor has the commenter provided, sufficient information on emissions from T-D transfer stations. Further, it is not clear that the estimates provided by the commenter are from T-D transfer stations. EPA does not agree with the costs to monitor these stations. Hence, EPA disagrees with the cost effectiveness estimate developed by the commenter.

Commenter Name: Eldon Lindt

Commenter Affiliation: Xcel Energy, Inc.

Document Control Number: EPA-HQ-OAR-2011-0512-0035

Comment Excerpt Number: 2

Commenter Type: Industry - oil and gas

Comment: Xcel Energy's operating companies provide gas to 1.9 million natural gas customer and is therefore required to report under EPA's Subpart W. Xcel Energy is in agreement with the American Gas Association's (AGA) comments submitted on October 24, 2011, related to exclusion of leak surveying for transmission-distribution (TD) stations below 4.0 million standard cubic feet/hour. Imposing a threshold for leak surveying allows local distribution

companies to focus efforts on the larger TD stations. The threshold also ensures that reporting is not unduly burdensome on industry.

Response: Please see response to comment EPA-HQ-OAR-2011-0512-32, Excerpt 6.

Commenter Name: Gregory L. Ryan

Commenter Affiliation: DTE Energy

Document Control Number: EPA-HQ-OAR-2011-0512-0041

Comment Excerpt Number: 2

Commenter Type: Industry - oil and gas

Comment: DTE Energy is a member of the American Gas Association (AGA) and Interstate Natural Gas Association of America (INGAA) and endorses the comments filed by each in this docket.

II. Definition of Transfer-Distribution Stations and Threshold for Excluding T-D Stations from Annual On-Site Surveys

DTE Energy supports AGA's comments regarding the replacement of the term "custody transfer city gate station" with "transmission-distribution (T-D) station". While EPA's proposed definition for T-D stations is clear, we would prefer that EPA utilize the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) definition of a "transmission line" in Section 98.238 of the proposed rule in order to be consistent with EPA's use of the PHMSA definition of "distribution line" in the proposed rule.

We also support AGA's request for a natural gas design flow rate threshold that would exempt smaller T-D stations from the requirements to perform annual leak surveys. If the EPA rule required leak surveys at T-D stations with a design flow rate of 4 million standard cubic feet per hour (scf/hr), as recommended by AGA, MichCon would be required to conduct leak surveys at 11 T-D stations, and use these results to develop an emission factor to apply to 222 T-D stations with design flow rates less than 4 million scf/hr. Applying this threshold would greatly reduce the burden of conducting leak surveys at these facilities that account for a very small component of the GHG leaks from the natural gas distribution sector.

In addition, we support AGA's understanding that equipment that the Local Distribution Company (LDC) does not own or operate (e.g. a transmission company's meter) at a T-D station would not be included in the leak survey. In other words, only equipment owned by the LDC would be used to calculate the emission factor for metering-regulating (M-R) stations and T-D stations below the design flow rate threshold, if a threshold is included in the final rule. The final rule should clarify this assumption that T-D station components not owned by an LDC should not be included in the leak survey.

Response: EPA disagrees with the commenter's suggestion to use the PHMSA definition of a transmission pipeline. The commenter has not provided any technical reasons on why PHMSA is better suited for the transmission pipeline definition. EPA has determined that transmission companies best understand the definition of transmission pipeline as aligned to the FERC

designation. Hence, EPA has retained the definition of a transmission pipeline as proposed in the September 2011 proposal. In this final rule, EPA is finalizing the definition of transmission-distribution transfer station and associated monitoring and reporting requirements and providing the option for natural gas distribution companies to conduct leak detection at their T-D transfer stations over multiple years, not exceeding five years. Please see response to comment EPA-HQ-OAR-2011-0512-32, Excerpt 6.

Emissions from sources at T-D transfer stations that are under common ownership or common control of the reporter must be reported by the reporter. For further discussion on common ownership and common control issues, please see preamble Section II.D.10 – Summary of Comments and Responses Submitted on the Petroleum and Natural Gas Systems Source Category: Dehydrators owned and operated by third parties.

Commenter Name: Ezra McCarthy

Commenter Affiliation: National Grid

Document Control Number: EPA-HQ-OAR-2011-0512-0046

Comment Excerpt Number: 2

Commenter Type: Industry - oil and gas

Comment: New Definition of Stations Subject to Annual Leak Surveys

National Grid notes that EPA, in the preamble, believes it is feasible to implement the technical changes to the 2011 reporting year. National Grid is very concerned about the dramatic shift in the type and number of stations that would be subject to the annual leak survey requirement under the Proposal, and that this would apply retroactively to the beginning of 2011, even though the Technical Revisions are not expected to be issued in final form until December 2011. The new T-D Station definition changes the stations to be surveyed significantly from the existing rule where only custody transfer stations are to be surveyed. National Grid has had to make its own determination of applicable survey locations and has conducted many surveys as part of our plan, based on our interpretation of the existing rule (published November 30, 2010). In December 2011 we will not be able to redo surveys at other locations. We understand that the agency is suggesting that LDCs will be allowed to deal with this dilemma by submitting the leak surveys they have conducted and/or apply an emission factor to a count of stations under the Best Available Monitoring Methods (BAMM) provisions. We would appreciate this emphasized in the final rule in December 2011.

Definition of T-D Stations

Under the proposed technical revisions, EPA is now replacing the term “custody transfer city gate station” with the term “Transmission-Distribution (TD) transfer station” defined in proposed revised section §98.238 to mean

“a meter-regulating station where a local distribution company takes part or all of the natural gas from a transmission pipeline and puts it into a distribution pipeline.

This definition changes the stations National Grid would survey considerably. Using the existing

rule we are surveying only our equipment at 102 Custody Transfer Stations, where we take custody of gas from transmission companies and they own the meters. Generally at these stations both inlet and outlet pipelines are at transmission pipeline pressures and the gas pressure is regulated down to distribution pressure further down the system chain. Using the new definition National Grid would now have to survey roughly 300 stations where the transmission pipeline pressure at the inlet to distribution pipeline pressure at the outlet scenario exists. Given the small amount of emissions we are finding at Custody Transfer Stations, expanding the number of survey locations seems an unnecessary cost burden that does not improve the robustness of GHG data. Please refer to the example provided in the AGA comments to see an example how few emissions are being observed at Custody Transfer Stations and how small those are in comparison to fugitive emissions from distribution mains and services

Establishing a TD Stations Survey Threshold:

National Grid appreciates EPA's request for comment on whether the agency should establish a threshold for imposing the annual leak survey requirement that would exclude smaller stations. It will be very important to establish a workable exemption threshold to avoid surveying more TD stations than what is necessary to estimate emission in a statistically significant manner. Survey data from larger stations will be sufficient to develop an emission factor that can be applied to smaller stations. Surveying smaller stations is a waste of resources that could be better used elsewhere.

Based on an AGA's survey and National Grid's own station characteristics, we urge EPA to impose the leak survey requirement only on TD Stations with a design rate of 4 million standard cubic feet per hour (scf/hr). This level will focus the leak surveys on a manageable number of stations. A threshold of 4 million scf/hr would capture about 15 TD stations from our company. In the alternative, at a 2.5 million scf/hr level, the survey requirement would apply to about 36 TD stations. National Grid would prefer the 4 million scf/hr threshold, as this would yield more than enough data to develop an emission factor for other TD stations, and the effort involved would be more in line with the truly minimal emissions from this type of source.

Response: Please see response to comment EPA-HQ-OAR-2011-0512-0032, Excerpt 6.

Commenter Name: Curtis J. Winner

Commenter Affiliation: New Mexico Gas Company (NMGC)

Document Control Number: EPA-HQ-OAR-2011-0512-0047

Comment Excerpt Number: 2

Commenter Type: Industry - oil and gas

Comment: Source Category Definitions

The proposed amendments to the natural gas distribution industry segment definition changes the locations that NMGC will conduct leak surveys in 2012 compared with 2011. The current rule requires leak surveys at above ground custody transfer city gate stations which mean only locations where there is custody transfer of natural gas. EPA's new definitions of meter-

regulating and transmission-distribution transfer stations, do not depend on custody transfer. This means that the stations that NMGC surveyed in 2011 will be totally different from those that must be surveyed in 2012. Per EPA's proposed new definition NMGC will be required to survey approximately 600 more stations in 2012 compared with 2011. In 2011 NMGC will survey approximately 50 stations. This will substantially increase our burden and costs to comply with SP W of the mandatory reporting rule in 2012. NMGC suggests adding a threshold which would exempt some T-D transfer stations from requiring a leak survey. NMGC supports AGA's proposed threshold of 4 million scf per hour.

Response: The amendments in this final rule apply to the 2011 reporting years. Regarding reporting of emissions for reporting year 2011, EPA does require reporters to re-conduct leak detection at stations for reporting year 2011. Please see response to comment EPA-HQ-OAR-2011-0512-0032, Excerpt 6.

Section 10.14 - Transmission pipeline

Commenter Name: Darrell Shier

Commenter Affiliation: SCANA Corporation

Document Control Number: EPA-HQ-OAR-2011-0512-0030

Comment Excerpt Number: 4

Commenter Type: Industry - oil and gas

Comment: Definition of a Transmission Pipeline

The Proposed Rule defines a transmission-distribution transfer station as a "a meter regulating station where a local distribution company takes part or all of the natural gas from a transmission pipeline and puts it into a distribution pipeline," see 76 Fed. Reg. at 56,050 (to be codified at 40 C.F.R. 98.238), and imposes certain requirements on transmission distribution transfer stations, see 76 Fed. Reg. at 56,039 (to be codified at 40 C.F.R. 98.232(i)(1)) (emphasis added) (reporting requirement) and 76 Fed. Reg. at 56,045 (to be codified at 40 C.F.R. 98.233(0)(8))(leak detection). The Proposed Rule defines "distribution pipeline" as "a pipeline that is designated as such by the Pipeline and Hazardous Material Safety Administration (PHMSA) 49 C.F.R. 192.3," and it defines "transmission pipeline" as "a Federal Energy Regulatory Commission rate-regulated Interstate pipeline, a state rate-regulated Intrastate pipeline, or a pipeline that falls under the 'Hinshaw Exemption'" Id.

Attachment 1 presents a hypothetical for which we are requesting guidance on how to apply the Proposed Rule's definition of a transmission-distribution transfer station. In the attached hypothetical, an LDC takes natural gas from a FERC rate-regulated Interstate pipeline (the red "Line A" in Attachment 1) at Points 1 and 2. Point 1 is a meter regulating station where the LDC takes the natural gas from the transmission pipeline and puts the natural gas into the LDC's own pipeline (the blue "Line B") which is designated as a distribution line under 49 C.F.R. 192.3. As

such, it appears that, under the Proposed Rule's definition of "transmission distribution transfer station" in 40 C.F.R. 98.238, the LDC would be subject to any requirements applicable to transmission-distribution transfer stations at Point 1.

Point 2 is a meter regulating station where the LDC takes natural gas from the transmission line (Line A) and puts it into its own pipeline ("Line C"). However, Part 1 of Line C (the orange portion in Attachment 1) is not considered to be a distribution line under 49 CFR 192.3. Thus, under the Proposed Rule's definition of "transmission distribution transfer station" of 40 C.F.R. 98.238, it appears that the LDC would not be subject to any requirements applicable to transmission-distribution transfer stations at Point 2 because the LDC is not putting the natural gas into a distribution line (as defined by the Proposed Rule) at this point.

At Point 3, however, the application of the Proposed Rule is less clear. Point 3 is a meter regulating station where the LDC takes natural gas from Part 1 of its own Line C (the orange portion in Attachment 1) and puts it into Part 2 of its own Line C (the green portion in Attachment 1). Part 2 of Line C is designated as a distribution line under 49 C.F.R. 192.3. However, to determine whether Point 3 is a transmission-distribution transfer station, one must determine whether Part 1 of Line C (the orange portion) is a transmission line under the Proposed Rule. Part 1 of Line C is classified as a transmission line by PHMSA under 49 CFR 192.3 because it operates at a hoop stress of 20 percent or more of SMYS, but the Proposed Rule does not incorporate the PHMSA definition of transmission line into the Proposed Rule's definition of "transmission pipeline." Rather, the Proposed Rule attempts to "define transmission pipeline using a widely accepted designation for what is a transmission pipeline," 76 Fed. Reg. at 56,027, i.e., "a Federal Energy Regulatory Commission rate-regulated Interstate pipeline, a state rate-regulated Intrastate pipeline, or a pipeline that falls under the 'Hinshaw Exemption'" See 76 Fed. Reg. at 56,039 (to be codified at 40 C.F.R. 98.238); see also *id.* at 56,036 (discussing "interstate transmission pipelines" and "intrastate transmission pipelines.").

Part 1 of Line C does not fit into any of the definitions of "transmission pipeline" in the Proposed Rule. It is not a FERC rate-regulated Interstate Pipeline; it is not a Hinshaw Pipeline; and it is not considered to be an Intrastate pipeline in the natural gas industry because the term "Intrastate pipeline" refers to a transmission pipeline, see 76 Fed. Reg. at 56,036 (stating that "transmission pipelines are clearly designated as such by ... individual States for intrastate transmission pipelines"). Because Part 1 of Line C is owned and operated by a state rate-regulated LDC and is used to deliver natural gas to end users, the natural gas industry and the State would not consider Part 1 of Line C to be a transmission pipeline but rather would consider it to be a distribution pipeline. As we have already noted, however, Part 1 of Line C does not meet the Proposed Rule's definition of a distribution pipeline because PHMSA classifies it as a transmission line for purposes of its safety regulations. In short Part 1 of Line C does not appear to fit the Proposed Rule's definitions for either a distribution pipeline or a transmission pipeline.

As such, we believe the Proposed Rule does not address whether lines which are owned and operated by an LDC in the delivery of natural gas to end users and which do not meet PHMSA's definition of a "distribution line" should be classified as "distribution pipelines" or "transmission pipelines" for purposes of the Proposed Rule. However, we also do not believe that it was EPA's intent for neither Point 2 nor Point 3 to be considered a transmission-distribution transfer station.

We would appreciate clarification in the Final Rule on which point--Point 2 or Point 3--should be considered a transmission-distribution transfer station in the above-described hypothetical.

Response: Based on the definition of T-D transfer station in this final rule, EPA agrees with the commenter's classification of Point 1 as T-D transfer station, because gas is taken from a transmission pipeline and put into a distribution pipeline.

EPA disagrees with the commenter that Part 1 of Line C in the hypothetical example is not subject to requirements of Subpart W. While the complete "fact pattern" in the hypothetical is not fully defined, we submit that the segment between Point 2 and Point 3 falls within the transmission pipeline definition in the September 2011 proposal, and as finalized in this final rule includes the "Hinshaw Exemption." Line C is not an interstate transmission pipeline regulated by FERC. However, Part 1 of Line C as defined in the hypothetical conforms to the definition of a transmission pipeline under the rule since it is consistent with the Hinshaw Exemption as described by the United States Court of Appeals of the Sixth Circuit (226 F.3d 777 (6th Cir. 2000));

A Hinshaw pipeline is a natural gas pipeline that receives all of its out-of-state gas from persons "within or at the boundary of a [s]tate if all the natural gas so received is ultimately consumed" within the state in which it is received. 15 U.S.C. § 717(c).

Since Part 1 of Line C is a transmission pipeline according to Subpart W, Point 3 is the T-D transfer station that the facility has to monitor by conducting leak detection. In addition, EPA notes that since Line C is a transmission pipeline according to Subpart W, all requirements associated with facilities in 98.230(a)(4) apply to Line C.

Commenter Name: Pamela A. Lacey

Commenter Affiliation: American Gas Association (AGA)

Document Control Number: EPA-HQ-OAR-2011-0512-0032

Comment Excerpt Number: 5

Commenter Type: Trade Association

Comment: Transmission vs. Distribution Pipelines: The TD station definition depends on a clear understanding of what is a "transmission pipeline" vs. what is a "distribution pipeline." We appreciate EPA's willingness to define "distribution pipeline" by reference to the definition of "distribution line" used in 49 C.F.R. Part 192, the regulations for natural gas pipeline safety

promulgated by the Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA). Our members can clearly identify what is a distribution main using this definition. PHMSA defines a distribution line as a pipeline that is not a “transmission line” or a “gathering line” – as defined by the PHMSA regulations. See 49 C.F.R. §192.3. The EPA Proposal refers to the definition of transmission pipeline used by the Federal Energy Regulatory Commission (FERC) and state utility commission regulations rather than PHMSA’s definition.

We understand that this definition of “transmission pipeline” will be easier for producers and processors to use in order to determine what is a gathering line and not a “transmission pipeline” for purposes of Subpart W. They are more familiar with the FERC or state rate regulation definition. In response to their concerns, the Proposal would define “transmission pipeline” as:

A Federal Energy Regulatory Commission rate-regulated Interstate pipeline, a state rate-regulated Intrastate pipeline, or a pipeline that falls under the “Hinshaw Exemption” as referenced in ...the Natural Gas Act...”

AGA supports EPA’s proposed definitions of “distribution pipeline” and “transmission pipeline” as these definitions will help companies clearly and easily determine whether equipment falls within the production, processing, transmission or distribution sectors.

Response: EPA thanks the commenter for their remarks.

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 10

Commenter Type: Industry - oil and gas

Comment:

[Please refer to the original comment text posted in the docket] (9) “Transmission pipeline” – Chesapeake and AXPC support EPA’s modified definition for transmission pipeline but EPA should further modify the definition as follows:

Transmission pipeline means a Federal Energy Regulatory Commission rate-regulated Interstate pipeline, a state rate regulated Intrastate pipeline, or a pipeline that falls under the “Hinshaw Exemption” as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717-717(w)(1994) [Add:, except that a pipeline is not a transmission pipeline if it moves natural gas to a natural gas processing facility. All pipelines upstream of FERC regulated, state regulated, or Hinshaw pipelines are considered gathering pipelines.]

The definition as proposed is overbroad and will cover pipelines that are not “transmission pipelines.” Precision is needed in this definition in order to clearly draw the distinction between pipelines that are covered by Subpart W and those that are part of gathering systems, which EPA has indicated will be covered in a future rulemaking.

Response: EPA disagrees that further clarification is required to segregate gathering lines in the definition for transmission pipelines. The Subpart W definition of transmission pipeline includes only pipelines that are rate-regulated by FERC or the State, or are considered transmission pipeline according to the “Hinshaw Exemption”. In this final rule, pipelines, such as gathering facilities that are exempt from rate regulation under the Natural Gas Act, do not fall in any one of three categories are not covered as transmission pipelines. Finally, the amendments recommended by the commenter attempts to define a gathering pipeline. EPA will consider this definition in a possible future rulemaking, but does not consider it necessary at this time.

Commenter Name: Eldon Lindt

Commenter Affiliation: Xcel Energy, Inc.

Document Control Number: EPA-HQ-OAR-2011-0512-0035

Comment Excerpt Number: 3

Commenter Type: Industry - oil and gas

Comment: In addition, Xcel Energy supports AGA's discussion on the conflicting definitions of pipelines that are neither transmission nor distribution as proposed in the rule. To completely avoid uncertainty and confusion surrounding the definition of transmission and distribution pipelines, Xcel Energy urges EPA to adopt the Pipeline and Hazardous Material Safety Administration (PHMSA) definition for distribution pipeline and the PHMSA definition for transmission pipeline. At the very least, Xcel Energy echoes AGA's request for clarification on how to report pipelines that are neither PHMSA distribution pipelines nor FERC transmission pipeline.

Response: EPA disagrees with the commenter’s suggestion to use the PHMSA definition of a transmission pipeline; please see the response to EPA-HQ-OAR-2011-0512-0041, Excerpt2.

Section 10.15 - Tubing diameter groupings

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 76

Commenter Type: Industry - oil and gas

Comment:

Revision: EPA added a new definition for “tubing diameter groupings”: Tubing diameter groupings are defined as follows: less than or equal to 1 inch; greater than 1 inch and less than 2 inch; and greater than or equal to 2 inch.

Comment: API supports this grouping concept. However, tubing diameters for completions are not commonly less than 1 inch. API suggests that two categories of tubing diameter be used based on the most common tubing sizes used in completions: = 2 3/8" nominal diameter and > 2 3/8" nominal diameter.

Response: EPA thanks the commenter for their remarks on the grouping concept. EPA does not agree with changing the number of tubing diameter ranges to only 2. EPA is retaining the lowest tubing diameter range (less than or equal to 1 inch) to characterize emissions from wells employing smaller tubing diameters that avoid liquid buildup by increasing the velocity of flow through a smaller cross-sectional area. EPA agrees with the commenter's suggestion to change the upper and lower limit of the remaining two ranges to 2.375 inches. EPA has also clarified in the definition that the ranges apply specifically to the outer diameter of the well tubing. In this final rule, both of these changes have been made.

Section 10.17 - Vertical well

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 77

Commenter Type: Industry - oil and gas

Comment:

Revision: EPA added a new definition for "vertical well":

Vertical well means a well bore that is primarily vertical but has some unintentional deviation or one or more intentional deviations to enter one or more subsurface targets that are off-set horizontally from the surface location, intercepting the targets either vertically or at an angle.

Comment: API supports the addition of this definition

Response: EPA thanks the commenter for their remarks.

Section 10.18 - Well testing venting and flaring

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 11

Commenter Type: Industry - oil and gas

Comment: “Well testing venting and flaring” – The current regulatory text in § 98.233(l) is unclear regarding what activities constitute “well testing.” To address this problem, EPA has proposed a new definition in § 98.238 for “well testing venting and flaring.” Chesapeake and AXPC support this new definition.

Response: In this final rule, EPA has clarified the definition of well testing venting and flaring by deleting the text “(i.e., the well testing) through a choke (an orifice restriction)” and adding the phrase “for regulatory, commercial, or technical purposes”; please see the response to EPA-HQ-OAR-2011-0512-0042, Excerpt78 for further details.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 78

Commenter Type: Industry - oil and gas

Comment: [Please refer to the original comment text posted in the docket] Revision: EPA added a new definition for “well testing venting and flaring”:

Well testing venting and flaring means venting and/or flaring of natural gas at the time the production rate of a well is determined [add (green): for regulatory purposes] [delete (green): (i.e., the well testing) through a choke (an orifice restriction).] If well testing is conducted immediately after well completion or workover, then it is considered part of well completion or workover.

Comment: API suggests the revisions shown above in green font to make the definition technically correct. API supports the clarification that well testing conducted after a well completion or workover, is considered part of the completion or workover.

Response: EPA does not agree with the commenter’s addition of “for regulatory purposes” to the definition of well testing venting and flaring. EPA requires reporters to determine emissions from all well testing activities, which result in vented or flared emissions, regardless of the purpose of the activity. The only exception is well tests conducted after completions and workovers, which are part of well completions or workover completions with or without hydraulic fracturing. Thus, in this final rule, EPA has clarified the definition by adding “for regulatory, commercial, or technical purposes.”

EPA agrees with the deletion of “(i.e., the well testing) through a choke (an orifice restriction)” from the definition of well testing venting and flaring. Not all well testing activities are conducted through a choke. For example, depleted gas wells with liquids loading problems are not tested through a choke. Hence, in this final rule, EPA has clarified the definition by deleting “(i.e., the well testing) through a choke (an orifice restriction).”

Section 12 - Outside Scope

Section 12.3 - Other

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 46

Commenter Type: Trade Association

Comment: (3) Infrared laser beam illuminated instrument. Use an infrared laser beam illuminated instrument for equipment leak detection. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with Method 21 monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the infrared laser beam illuminated instrument to detect the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

Response: EPA thanks the commenter for their remarks.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 49

Commenter Type: Trade Association

Comment: (b) You must operate and calibrate all flow meters, composition analyzers and pressure gauges used to measure quantities reported in §98.233 according to the procedures in §98.3(i) and the procedures in paragraph (b) of this section. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

Response: EPA thanks the commenter for their remarks.

Commenter Name: T. Cook

Commenter Affiliation:

Document Control Number: EPA-HQ-OAR-2011-0512-0027

Comment Excerpt Number: 1

Commenter Type: Private Citizen

Comment: Environmental Protection Agency (EPA),

I am writing this letter in regards to the proposed Greenhouse Gas Emissions Regulation. We all realize the importance to protect and preserve our environment, however, at this time; it would be counterproductive to enforce this regulation due to the negative impact it would have on the United States economy. It is estimated that while over 1.4 Million jobs (daily caller) would be lost from this regulation's enactment, at the same time, an outrageous 21 Billion dollars (nwdailymarker) of taxpayer money would be needed to fund the manpower additions to the EPA. Not only are American's losing 1.4 million fellow taxpayer that could help us pay your salaries, but now we are wasting 21 billion that could go to our nation's debt.

This is not the right time for this proposed regulation. Let's get out of debt before we continue spending on things that are not absolute necessities.

Thank you for your time,

Toby Cook

References:

<http://www.nwdailymarker.com/2011/09/goplabs-obama%E2%80%99s-proposed-environmental-regs-mean-millions-more-u-s-jobs-lost/>

<http://dailycaller.com/2011/09/26/epa-regulations-would-require-230000-new-employees-21-billion/>

<http://www.citizen.org/Page.aspx?pid=2628>

<http://www.epa.gov/compliance/civil/index.html>

Response: The subject of national debt is outside of the scope of the specific amendments proposed for public comment in the Federal Register notice of September 9, 2011, therefore no rule changes were made as a result of this comment.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 2

Commenter Type: Trade Association

Comment: 1. EPA has not addressed previous INGAA comments and recommendations, especially clarifications and revisions for compressor venting emission estimates. In addition, some proposed revisions intended to address INGAA comments are insufficient and additional revisions are needed.

As discussed in INGAA's comments below, and, more importantly, as reflected in ongoing discussions with EPA regarding Subpart W, there are significant Subpart W implementation

concerns due to unclear or conflicting requirements.

Previous INGAA comments (e.g., comments on the 2009 and 2010 proposed rules; comments on the August 4 proposed revisions) discuss these issues. In addition, following a May 26, 2011 meeting with EPA and at EPA's request, on June 6, 2011 INGAA provided a document to EPA with recommended redlines to Subpart W. The proposed redlines addressed items discussed with EPA regarding rule clarity (e.g., estimation methods and associated reporting in §98.233 and §98.237) and conflicts (e.g., conflicting requirements for CO₂ and CH₄ content of natural gas and use of a default assumption for pipeline quality natural gas).

Neither the Proposed Rule nor the August 4 proposed revisions address these key issues. As indicated in Table 2 of the Proposed Rule preamble and discussed in comments below, it appears that EPA intended to address some INGAA recommendations. However, in some cases the proposed revisions do not effectively address INGAA recommendations or additional revisions are needed to improve rule clarity. For example, Comment 2 discusses additional revisions that are needed to eliminate conflicting requirements when implementing a default natural gas composition for calculating emissions from the transmission and storage sectors.

As INGAA members implement Subpart W, many questions remain about reporting requirements and regulatory intent. INGAA has voiced these concerns on the record through its comments and letters to EPA. It is imperative that Subpart W is revised and clarified in response to INGAA recommendations so operators can effectively and efficiently address rule requirements and ensure compliance. The INGAA recommended Subpart W redlines provided in June 2011 are provided as Attachment 2. In addition, INGAA plans to revisit these redlines to assess whether additional comments are warranted. This effort is needed because INGAA developed the recommended redlines over approximately one week in response to EPA's request and deadline. As indicated in ongoing communications with EPA, INGAA looks forward to continued engagement until these items are resolved. Recent Subpart W revisions that provide reporting flexibility for 2011 expire at the end of the year. Thus, it is imperative that remaining issues are expeditiously resolved so the reporting requirements are clear at the start of the 2012 reporting year.

Response: The subject of compressor emissions estimates is outside of the scope of the specific amendments proposed for public comment in the Federal Register notice of September 9, 2011, therefore no rule changes were made as a result of this comment. EPA may consider these issues at a later date.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 22

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket] Missing data

provisions in §98.235 should be revised to provide more flexibility.

In meetings with INGAA, EPA has indicated that §98.235 missing data provisions may provide an avenue to address reporting issues that arise in future years that may otherwise require resolution through a request for Best Available Monitoring Methods (BAMM). Despite EPA's claims, INGAA believes that §98.235 is far too restrictive to serve as a means to address out-year issues that hinder an operator's ability to fulfill Subpart W obligations. One scenario discussed with EPA is the case where a facility is not subject to Subpart W, but becomes subject late in a future year due to an unexpected event at the facility that increases emissions above the reporting threshold. If this occurs late in the calendar year, the company may not be able to acquire necessary data or complete required measurements. INGAA believes that the BAMM process would be needed in this situation. EPA indicated that missing data provisions may provide another option. However, §98.235 very narrowly defines where missing data provisions apply and INGAA does not believe it serves the purpose intimated by EPA unless revised.

For example, §98.235 limits missing data provisions to instances where, "...data are lost or an error occurs during annual emissions estimation or measurements...". The scenario described, where facility status changes late in the year, does not meet the common meaning of "lost data" or an "error during estimation or measurement." Revisions are needed to improve the utility of the missing data provisions.

To provide the additional flexibility necessary to serve scenarios such as those discussed with EPA, INGAA recommends revising §98.235 as follows:

"A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost, or an error occurs during annual emissions estimation or measurements, [add: or an unanticipated circumstance precludes data collection or measurement,] you must repeat [add: or conduct] the estimation or measurement activity for those sources as soon as possible, including in the subsequent calendar year if missing data are not discovered until after December 31 of the year in which data are collected, until valid data for reporting is obtained. [delete: Data developed and/or collected in a subsequent calendar year to substitute for missing data cannot be used for that subsequent year's emissions estimation.] Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or measurements for the current year of data collection[add: , with the exception of cases where a facility becomes newly affected under this subpart in a particular year and it is not reasonably feasible to collect information or conduct measurements until the subsequent year. In this case, the first year reporting can be based on data collected in the subsequent year. ..."]

If EPA is concerned that these revisions may be abused or misused, recordkeeping and/or reporting criteria could be added that require documenting the basis for using the missing data provisions in response to unanticipated circumstances.

Response: The subject of compressor emissions estimates is outside of the scope of the specific amendments proposed for public comment in the Federal Register notice of September 9, 2011,

therefore no rule changes were made as a result of this comment. EPA may consider these issues at a later date.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 39

Commenter Type: Trade Association

Comment:[Please refer to the original comment text posted in the docket]
[highlighted text: Sections (o) and (p) for compressor emissions include significant revisions based on recent discussions with EPA on intended requirements for calculating and reporting compressor vent emissions. In addition, revisions were completed so that the format / structure of the two sections is analogous.]

(o) Centrifugal compressor venting. Calculate CH₄[delete: ,] [add: and] CO₂ [add: and] N₂O (when flared)] emissions from both wet seal and dry seal centrifugal compressor vents as follows:

(1) [add: Centrifugal compressor package operating status includes two reportable modes: operating and not operating de-pressurized. Centrifugal compressor package vent sources are wet seal oil degassing vents, unit isolation valve vents, and blowdown valve vents.] For each centrifugal compressor [add: package] covered by §98.232 (d)(2), (e)(2), (f)(2), (g)(2), and (h)(2) you must conduct an annual measurement in the [delete: operating] mode in which it is found [add: during the annual measurement]. Measure emissions from [add: each unique mode and vent source combination in (i) through (iii) of this section applicable to the as-found mode.] [delete: all vents (including emissions manifolded to common vents) including wet seal oil degassing vents, unit isolation valve vents, and blowdown valve vents).] [add: Measurement from a single compressor package can] [delete: (]include[add: e] [delete: ing] emissions [add: from unique vent sources] manifolded to common vent[delete: s)]. Record emissions from the following vent [add: sources] [delete: types] in the specified [delete: compressor] mode[delete: s] during the annual measurement.

(i) Operating mode, blowdown valve leakage through the blowdown vent, [add: for both] wet seal and dry seal compressors.

(ii) Operating mode, wet seal oil degassing vents.

(iii) Not operating depressurized mode, unit isolation valve leakage through open blowdown vent, without blind flanges, [add: for both] wet seal and dry seal compressors.

(A) For the not operating depressurized mode, each compressor [add: package] must be measured at least once in any three consecutive calendar years. If a compressor [add: package] is not operated and has blind flanges in place throughout the 3 year period, measurement is not

required in this mode. [delete: If [comment bubble JMc7: Sentence is redundant and not needed.]the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.]

(2) [add: Measure emissions from each vent including emissions manifolded to a common vents from a single vent source (] [delete: For] wet seal oil degassing vents, [delete: determine vapor volumes sent to an atmospheric vent or flare], [add: unit isolation valves, or blowdown valve vents) for a single compressor package] using [add: any of the methods in (o)(2)(i) though (iv) of this section. Vents may be screened annually using an optical imaging instrument according to methods in §98.234(a)(1) and if emissions are not present, then measurement per §98.234(b) is not required and emissions are estimated as zero.]

[add: (i) A] [delete: a] temporary meter such as a vane anemometer or permanent flow meter [add: such as an orifice meter] according to 98.234(b) [delete: of this section. If [comment bubble JMc8: Sentence is not needed because operator clearly has the option to use a temporary or permanent meter.] you do not have a permanent flow meter, you may install a permanent flow meter on the wet seal oil degassing tank vent.]

[delete: (3) For blowdown valve leakage and unit isolation valve leakage to open ended vents, you can use one of the following methods:]

[add: (ii)] Calibrated bagging [delete: or high volume sampler] according to methods set forth in §98.234(c) [delete: and §98.234(d), respectively].

[add: (iii)] High volume sampler according to methods set forth in §98.234(d),]

[add: (iv)] For through valve leakage, such as isolation valves [add: on not operating depressurized compressor packages and blowdown valves on pressurized compressor packages,] you may use an acoustic leak detection device according to methods set forth in §98.234(a). [delete: If you do not have a flow meter, you may install a port for insertion of a temporary meter, or a permanent flow meter, on the vents.]

([delete: 4][add: 3]) [comment bubble JMc9: NOTE: Calculation and reporting requirements would likely be clearer to reader if Eqn W-24 (i.e., Section 5) was introduced first, which would then provide a more logical flow through the estimates. INGAA did not make this change to avoid section “restructuring” in these edits, but recommends that EPA re-order the sections] [add: For each unique mode and vent source combination for which vent gas emission measurements were conducted during the reporting year, e] [delete: E]stimate annual emissions [add: for each centrifugal compressor package] using the flow measurement and Equation W–22 of this section.

[See original comment for Eq. W-22]

Where:

$E_{s,i,m}$ = Annual GHG_i (either CH₄ or CO₂) volumetric emissions [delete: at standard conditions], in [add: standard] cubic feet [add: for the unique mode and vent source combination].

MT_m = Measured gas [add: volumetric] emissions in standard cubic feet per hour [add: for the unique mode and vent source combination].

T_m = Total time the compressor [add: package] is in the mode for which $E_{s,i,m}$ is being calculated, in the calendar year in hours.

M [delete: i,m] = Mole fraction of GHG_i in the vent gas; use the appropriate gas compositions in paragraph (u)(2) of this section [add: or according to §98.232(m)].

[delete: B_m = Fraction of operating time that the vent gas is sent to vapor recovery or fuel gas as determined by keeping logs of the number of operating hours for the vapor recovery system and the time that vent gas is directed to the fuel gas system or sales.]

([delete: 5][add: 4]) [add: For each unique mode and vent source combination for which vent gas emission measurements were not conducted during the reporting year, c] [delete: C] calculate annual emissions from each centrifugal compressor package using Equation W-23 of this section.

[See original comment for Eq. W-23]

Where:

$E_{s,i,[add: m]}$ = Annual [add: GHG_i (either CH₄ or CO₂)] [delete: total] volumetric [delete: GHG] emissions [delete: at standard conditions] from each centrifugal compressor [add: package] in [add: standard] cubic feet [add: for the unique mode and vent source combination].

EF_m = [add: For each unique mode and vent source combination,] [delete: R][add: r] reporter emission factor [delete: for each mode m], in [add: standard] cubic feet per hour, from Equation W-24 [delete: of this section] as calculated in paragraph [add: 5][delete: 6].

T_m = Total time [add: the compressor package is in the mode for which $E_{s,i,m}$ is being calculated, in the calendar year] [delete: in hours per year the compressor was in each mode, as listed in paragraph (o)(1)(i) through (o)(1)(iii)].

GHG_i = For onshore natural gas processing facilities, concentration of GHG_i, CH₄ or CO₂, in produced natural gas or feed natural gas; for other facilities listed in §98.230(a)(4) through (a)(8), GHG_i equals 1 [add: or use the gas composition allowed in §98.232(m)].

[add: (5)] You shall use [add: all of] the [add: volumetric gas] flow measurements [add: (MT_m)] for each unique mode and vent source combination () [delete: of] operating mode wet seal oil degassing vent, operating mode blowdown valve vent[add: ,] and not operating depressurized mode isolation valve vent[add:) to develop] [delete: for all the] reporter[delete: 's] [add:

emission factors that are mode and vent source-specific. Use Equation W-24] to develop the [delete: following] emission factors [delete: using Equation W-24 of this section] for each emission source and mode as listed in paragraph (o)(1)(i) through (o)(1)(iii).

[See original comment for Eq. W-24]

Where:

EF_m = Reporter emission factors for [add: centrifugal] compressor [add: packages] [delete: in the] [add: for a unique] [delete: three] modes [delete: m] [add: and vent source combination] as listed in paragraph[add: s] (o)(1)(i) through (o)(1)(iii)) [add: of this section,] in [add: standard] cubic feet [add: of natural gas] per hour.

MT_m = [add: All] [delete: F][add: f]low [delete: M] [add: m]easurements from [delete: all] centrifugal compressor [add: packages for a unique mode and vent source combination as listed] in [add: paragraphs] (o)(1)(i) through (o)(1)(iii) of this section[add: ,] in [add: standard] cubic feet [add: of natural gas] per hour.

Count_m = Total number of [add: centrifugal] compressors [add: packages] measured [add: in the respective unique mode and vent source combination].

m = [add: Three unique] [delete: Compressor] mode [add: and vent source combinations] as listed in paragraph (o)(1)(i) through (o)(1)(iii).

(i) [add: For each of the unique mode and vent source combinations in §98.233(o)(1)(i) through (iii),] [delete: The] emission factors must be calculated annually. You must use all measurements from the current calendar year and the preceding [add: one (after the second annual measurement) or] two calendar years, totaling three consecutive calendar years of measurements in paragraph (o)([add: 5] [delete: 6]) of this section [add: for year three and beyond. The emission factor is used for calculating compressor package emissions from the unique mode and vent source combinations not measured in a particular year.]

(ii) [Reserved]

([add: 6] [delete: 7]) Onshore petroleum and natural gas production shall calculate emissions from [add: wet seal] centrifugal compressor [add: packages] [delete: wet seal oil degassing vents] as follows:

[See original comment for Eq. W-25]

Where:

Es,_i = Annual total volumetric GHG emissions [add: at standard conditions] from [add: wet seal] centrifugal compressor [add: packages] [delete: wet seals] in [add: standard] cubic feet.

Count = Total number of [add: wet seal] centrifugal compressors [add: packages] for the

reporter.

EF_i = Emission factor for GHG_i. Use 12.2 million standard cubic feet per year per compressor [add: package] for CH₄ and 538 thousand standard cubic feet per year per compressor [add: package] for CO₂ at 68 °F and 14.7 psia or 12 million standard cubic feet per year per compressor [add: package] for CH₄ and 530 thousand standard cubic feet per year per compressor [add: package] for CO₂ at 60 °F and 14.7 psia.

([add: 7][delete: 8]) [add: Estimate] [delete: Calculate both] CH₄ and CO₂ mass emissions from volumetric emissions using [add: the] calculations in paragraph (v) of this section.

[delete: (9) Calculate emissions from seal oil degassing vent vapors to flares as follows:

(i) Use the seal oil degassing vent vapor volume and gas composition as determined in paragraphs (o)(5) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine degassing vent vapor emissions from the flare.]

(p) Reciprocating compressor venting. Calculate CH₄ and CO₂ emissions from all reciprocating compressor vents as follows.

[add: (1) Reciprocating compressor package operating status includes three modes: operating, standby pressurized, and not operating de-pressurized. Reciprocating compressor package vent sources are] reciprocating rod packing vents, unit isolation valve vents, and blowdown valve vents. For each reciprocating compressor [add: package] covered in §98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1) you must conduct an annual measurement [delete: for each compressor] in the mode in which it is found during the annual measurement, except as specified in paragraph (p)([add: 7] [delete: 9]) of this section. Measure emissions from [add: each unique mode and vent source combination in (i) through (iv) of this section applicable to the as-found mode.] [delete: (including emissions manifolded to common vents) reciprocating rod packing vents, unit isolation valve vents, and blowdown valve vents).] [add: Measurement from a single compressor package can include emissions from unique vent sources manifolded to common vents.] Record emissions from the following vent [add: sources][delete: types] in the specified [delete: compressor] modes during the annual measurement [delete: as follows]:
[add: (i)][delete: (1)] Operating [delete: or standby pressurized] mode[delete: ,] blowdown vent leakage through the blowdown vent stack.

[add: (ii)] Operating mode, reciprocating rod packing emissions.

[add: (iii)] [delete: (2)] [add: Standby pressurized mode blowdown vent leakage through the blowdown vent stack.]

[add: (iv)] [delete: (3)] Not operating depressurized mode, unit isolation valve leakage through the blowdown vent stack, without blind flanges.

[add: (A)] [delete: (i)] For the not operating depressurized mode, each compressor [add: package] must be measured at least once in any three consecutive calendar years [delete: if this mode is not found in the annual measurement]. If a compressor [add: package] is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. [delete: If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.]

[add: (B)] [delete: (ii)] [Reserved]

[add: (2)] [delete: (4)] If reciprocating rod packing and blowdown vent are connected to an open-ended vent line[add: ,] [delete: use one of the following two methods to calculate emissions][add: .] [delete: (i) M] [add: m]easure emissions from [add: each] [delete: all] vents [delete: (]including emissions manifolded to [add: a] common vents [add: from a single vent source (] [delete: including] rod packing, unit isolation valves, [delete: and] [add: or] blowdown [add: valve] vents[add:)] for a single compressor package)[delete:)] using [delete: either] [add: any of the methods in (p)(2)(i) though (iv) of this section. Vents may be screened annually using an optical imaging instrument according to methods in §98.234(a)(1) and if emissions are not present, then measurement per §98.234(b) is not required and emissions are estimated as zero.]

[delete: calibrated bagging or high volume sampler according to methods set forth in §98.234(c) and §98.234(d), respectively.

(ii) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent including rod packing vents, unit isolation valve leakage through blowdown vents according to methods set forth in §98.234(b). If you do not have a permanent flow meter, you may install a port for insertion of a temporary meter or a permanent flow meter on the vents.]

[add: (i) A temporary meter such as a vane anemometer or a permanent meter such as an orifice meter according to methods set forth in §98.234(b).

(ii) Calibrated bagging according to methods set forth in §98.234(c).

(iii) High volume sampler according to methods set forth in §98.234(d).]

[add: (iv)] For through-valve leakage [delete: to open ended vents], such as unit isolation valves on not operating depressurized compressors [add: packages] and blowdown valves on pressurized compressors [add: packages], you may use an acoustic detection device according to methods set forth in §98.234(a).

[add: (3)][delete: (5)] If reciprocating rod packing is not equipped with a vent line use the following method to calculate emissions:

(i) You must use the methods described in §98.234(a) to conduct annual leak detection of equipment leaks from the packing case into an open distance piece, or from the compressor crank

case breather cap or other vent with a closed distance piece.

(ii) Measure emissions found in paragraph (p)[add: (3)][delete: (5)](i) of this section using an appropriate meter, or calibrated bag, or high volume sampler according to methods set forth in §98.234(b), (c), and (d), respectively.

[add: (4)][delete: (6)] [comment bubble JMc10: NOTE: Calculation and reporting requirements would likely be clearer to reader if Eqn W-28 (i.e., Section 6) was introduced first, which would then provide a more logical flow through the estimates. INGAA did not make this change to avoid section “restructuring” in these edits, but recommends that EPA re-order the sections.] [add: For each unique mode and vent source combination for which vent gas emission measurements were conducted during the reporting year,] [delete: E]estimate annual emissions [add: for each reciprocating compressor package] using the flow measurement and Equation W-26 of this section.

[See original comment for Eq. W-26]

Where:

$E_{s,i,m}$ = Annual GHG i (either CH₄ or CO₂) volumetric emissions [delete: at standard conditions], in [add: standard] cubic feet [add: for the unique mode and vent source combination].

MT_m = Measured gas [add: volumetric] emissions in standard cubic feet per hour [add: for the unique mode and vent source combination].

T_m = Total time the compressor [add: package] is in the mode for which $E_{s,i,m}$ is being calculated, in the calendar year in hours.

$M_{i,m}$ = Mole fraction of GHG i in [add: the vent] gas; use the appropriate gas compositions in paragraph (u)(2) of this section [add: or according to §98.232(m)].

[add: (5)][delete: (7)] [add: For each unique mode and vent source combination for which vent gas emission measurements were not conducted during the reporting year,] [delete: C][add: c]calculate annual emissions from each reciprocating compressor [add: package] using Equation W-27 of this section.

[See original comment for Eq. W-27]

Where:

$E_{s,i,[add: m]}$ = Annual [add: GHG i (either CH₄ or CO₂)] [delete: total] volumetric [delete: GHG] emissions [delete: at standard conditions] from each reciprocating compressor [add: package] in [add: standard] cubic feet [add: for the unique mode and vent source combination].

E_{Fm} = [add: For each unique mode and vent source combination,] [delete: R][add: r]reporter

emission factor [~~for each mode, m,~~] in [add: standard] cubic feet per hour, from Equation W-28 [~~of this section~~] as calculated in paragraph (p)(~~7~~)[add: 6][~~(i)~~] of this section.

T_m = Total time [add: the compressor package is in the mode for which E_{s,m} is being calculated, in the calendar year] [~~in hours per year the compressor was in mode, m, as listed in paragraph (p)(1) through (p)(3).~~]

GHG_i = For onshore natural gas processing facilities, concentration of GHG i, CH₄ or CO₂, in produced natural gas or feed natural gas; for other facilities listed in §98.230(a)(4) through (a)(8), GHG_i equals 1 [~~.]~~ [add: or gas composition allowed per §98.232(m)].

[~~m = Compressor mode as listed in paragraph (p)(1) through (p)(3).~~]

(~~6~~)[~~i~~] You shall use [add: all of] the [add: volumetric gas] flow [~~meter readings from~~] measurements [add: (MT_m) for each unique mode and vent source combination (~~of~~) operating [add: mode] [~~and standby pressurized~~] blowdown vent, [add: operating mode reciprocating rod packing] vents, [add: standby pressurized mode blowdown vent, and] not operating depressurized isolation valve vent[add:)] [~~for all the reporter's compressor modes not measured in the calendar year~~] to develop [~~the following~~] [add: reporter] emission factors [add: that are mode and vent source-specific]. [~~u~~][add: U][~~s~~][add: e]ing Equation W-28 [~~of this section for~~] [add: to develop the emission factors] for each [add: emission source and] mode as listed in paragraph (p)(1)[add: (i)] through (p)(~~3~~)[add: 1)(iv)].

[See original comment for Eq. W-28]

Where:

E_{Fm} = Reporter emission factors for [add: reciprocating] compressor [add: packages] [~~in the~~] [add: for a unique] [~~three~~] mode[~~s, m,~~] [add: and vent source combination as listed in paragraphs (p)(1)(i) through (p)(1)(iv) of this section,] in [add: standard] cubic feet [add: of natural gas] per hour.

MT_m = [add: All flow measurements] [~~Meter readings~~] from [~~all~~] reciprocating compressor [add: packages for a unique] [~~vents in each and mode, m,~~] [add: and vent source combination as] [~~identified~~] [add: listed] in [add: paragraphs (p)(1)(i) through (p)(1)(iv) of this section], in [add: standard] cubic feet [add: of natural gas] per hour.

Count_m = Total number of [add: reciprocating] compressors [add: packages] measured [~~in each mode, m~~] [add: in the respective unique mode and vent source combination].

m = [add: Four unique] [~~Compressor~~] mode [add: and vent source combinations] as listed in paragraphs (p)(1)(i) through (p)(~~3~~)[add: 1)(iv)].

[~~(A) You must combine emissions for blowdown vents, measured in the operating and~~]

standby pressurized modes.]

([add: i][delete: B]) [add: For each of the unique mode and vent source combinations in §98.233(p)(1)(i) through (iv),] [delete: The] emission factors must be calculated annually. You must use all measurements from the current calendar year and the preceding [add: one (after the second annual measurement) or] two calendar years, totaling three consecutive calendar years of measurements [add: in paragraph (p)(6) of this section for year three and beyond. The emission factor is used for calculating compressor package emissions from the unique mode and vent source combinations not measured in a particular year].

(ii) [Reserved]

[delete: (8) Determine if the reciprocating compressor vent vapors are sent to a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (p)(7) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) [Reserved]]

[add: (7)][delete: (9)] Onshore petroleum and natural gas production shall calculate emissions from reciprocating compressors [add: packages] as follows:

[See original comment for Eq. W-29]

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from reciprocating compressors in [add: standard] cubic feet.

Count = Total number of reciprocating compressors [add: packages] for the reporter.

E_{Fi} = Emission factor for GHG i . Use 9.63 thousand standard cubic feet per year per compressor [add: package] for CH₄ and 0.535 thousand standard cubic feet per year per compressor [add: package] for CO₂ at 68 °F and 14.7 psia or 9.48 thousand standard cubic feet per year per compressor [add: package] for CH₄ and 0.527 thousand standard cubic feet per year per compressor [add: package] for CO₂ at 60 °F and 14.7 psia.

[add: (8)][delete: (10)] Estimate CH₄ and CO₂ [delete: volumetric and] mass emissions from volumetric [delete: natural gas] emissions using the calculations in paragraph[delete: s (u) and] (v) of this section.

Response: No rule change has been made as a result of this comment. The subject of compressor emissions estimates is outside of the scope of the specific amendments proposed for

public comment in the Federal Register notice of September 9, 2011. EPA may consider these issues at a later date.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 52

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket]

§ 98.235 Procedures for estimating missing data.

[highlighted text: [INITIAL SUGGESTION OF TEXT TO BROADEN ?ACCESS? TO MISSING DATA PROVISIONS]]

A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, [add: or an unanticipated circumstance prevents a measurement or leak survey,] you must repeat [add: or conduct] the estimation or measurement activity for those sources as soon as possible, including in the subsequent calendar year if missing data are not discovered until after December 31 of the year in which data are collected, until valid data for reporting is obtained. Data developed and/or collected in a subsequent calendar year to substitute for missing data cannot be used for that subsequent year's emissions estimation. Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or measurements for the current year of data collection. For missing data which are continuously monitored or measured, (for example flow meters), or for missing temperature or pressure data that are required under § 98.236, the reporter may use best available data for use in emissions determinations. The reporter must record and report the basis for the best available data in these cases.

Response: No rule change has been made as a result of this comment. The subject of missing data provisions is outside of the scope of the specific amendments proposed for public comment in the Federal Register notice of September 9, 2011. EPA may consider this issue at a later date.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 56

Commenter Type: Trade Association

Comment:

[Please refer to the original comment text posted in the docket]

(13) For each centrifugal compressor [add: packages]:

(i) For [add: each wet seal centrifugal] compressors [add: package] [delete: with wet seals]in operati[add: ng][delete: onal] mode [delete: (refer to Equations W-22 through W-24 of §98.233)], report the following [delete: for each degassing vent]:

(A) Number of wet seals connected to the degassing vent.

(B) Fraction of [add: wet seal oil degassing] vent gas recovered for fuel or sales or flared.

(C) [delete: Annual throughput in million scf, use an engineering calculation based on best available data.]

(D) Type of meters used for making measurements.

(E) Reporter emission factor for wet seal oil degassing vents in cubic feet per hour (refer to Equation W-24 of §98.233).

(F) Total time the compressor driver is operating in hours.]

[delete: (G) Report] [add: Annual wet] seal oil degassing vent emissions [add: in metric tons of CH₄ and metric tons of CO₂] [delete: Report seal oil degassing vent emissions for compressors measured (refer to Equation W-22 of §98.233) and for compressors not measured (refer to Equation W-23 and Equation W-24 of §98.233)].

(ii) For [add: each] wet [delete: and] [add: or] dry seal centrifugal compressors [add: package] in operating mode[delete: , (refer to Equations W-22 through W-24 of §98.233),] report the following:

(A) Total time in hours the compressor [add: package] is in operating mode.

(B) [delete: Reporter emission factor for blowdown vents in cubic feet per hour (refer to Equation W-24 of §98.233).]

[delete: (C) Report] [add: B][delete: b]lowdown vent emissions [add: in metric tons of CH₄ and metric tons of CO₂] [delete: when in operating mode (refer to Equation W-23 and Equation W-24 of §98.233)].

[add: (C) Annual throughput in million scf, use an engineering calculation based on best available data.]

(iii) For [add: each] wet [delete: and] [add: or] dry seal centrifugal compressors [add: package] in not operating depressurized mode [delete: (refer to Equations W-22 through W-24 of §98.233)], report the following:

(A) Total time in hours the compressor [add: package] is in [delete: shutdown,] [add: not operating] depressurized mode.

(B) [delete: Reporter emission factor for isolation valve emissions in shutdown, depressurized mode in cubic feet per hour (refer to Equation W-24 of §98.233).]

[delete: (C) Report the i][add: I]solation valve leakage emissions in not operating depressurized mode in [delete: cubic feet] [add: metric tons of CH₄] [delete: per hour] [add: and metric tons of CO₂] [delete: (refer to Equation W–23 and Equation W–24 of §98.233)].

(iv) For each [add: centrifugal] compressor [add: package,] [delete: R][add: r]eport total annual compressor emissions from all modes of operation [delete: (refer to Equation W–24 of §98.233)].

(v) [add: Report the following:

(A) Reporter emission factor for wet seal oil degassing vents in operating mode in standard cubic feet of natural gas per hour (refer to Equation W–24 of §98.233).]

(B) Reporter emission factor for blowdown vents in operating mode in standard cubic feet of natural gas per hour (refer to Equation W–24 of §98.233).

[add: (C) Reporter emission factor for isolation valve emissions in not operating depressurized mode in cubic feet of natural gas per hour (refer to Equation W–24 of §98.233).]

(v[add: i]) For centrifugal compressors in onshore petroleum and natural gas production (refer to Equation W–25 of

§ 98.233), report the following:

(A) Count of compressors [add: packages].

(B) Report emissions (refer to Equation W–25 of § 98.233) collectively.

(14) For reciprocating compressor [add: packages]:

(i) For [add: each] reciprocating compressors [add: package] [delete: rod packing emissions with or without a vent] in operating mode, report the following:

(A) Annual throughput in million scf, use an engineering calculation based on best available data.

(B) Total time in hours the reciprocating compressor [add: package] is in operating mode.

(C) [delete: Report] [add: Annual] rod packing emissions [add: in metric tons of CH₄ and metric tons of CO₂] [delete: for compressors measured (refer to Equation W–26 of §98.233) and for compressors not measured (refer to Equation W–27 and Equation W–28 of §98.233)].

[add: (D) Annual blowdown vent emissions in metric tons of CH₄ and metric tons of CO₂.]

(ii) For [add: each] reciprocating compressors [add: package] [delete: blowdown vents not manifold to rod packing vents], in [delete: operating and] standby pressurized mode [delete:

(refer to Equations W–26 through W–28 of §98.233)], report the following:

(A) Total time in hours the compressor is in standby, pressurized mode.

(B) [delete: Reporter emission factor for blowdown vents in cubic feet per hour (refer to §98.233, Equation W–28).]

[delete: (C) Report] [add: Annual] blowdown vent emissions [add: in metric tons of CH₄ and metric tons of CO₂] [delete: when in operating and standby pressurized modes (refer to Equation W–27 and Equation W–28 of §98.233)].

(iii) For [add: each] reciprocating compressors [add: package] in not operating depressurized mode [delete: (refer to Equations W–26 through W–28 of §98.233)], report the following:

(A) Total time the compressor [add: package] is in not operating depressurized mode.

(B) [delete: Reporter emission factor for isolation valve emissions in not operating depressurized mode in cubic feet per hour (refer to Equation W–28 of §98.233).]

[delete: (C) Report the] [add: Annual] isolation valve leakage emissions [add: in metric tons of CH₄ and metric tons of CO₂] [delete: in not operating depressurized mode.]

(iv) For each reciprocating compressor [add: package], [delete: R][add: r]eport total annual [delete: compressor] emissions from all modes of operation [delete: (refer to Equation W–27 and Equation W–28 of §98.233)].

(vi) [add: Report the following:

(A) Reporter emission factor for rod packing vents in operating mode in standard cubic feet of natural gas per hour (refer to Equation W–28 of §98.233).

(B) Reporter emission factor for blowdown vents in operating mode in standard cubic feet of natural gas per hour (refer to Equation W–28 of §98.233).

(C) Reporter emission factor for blowdown vents in standby pressurized mode in standard cubic feet of natural gas per hour (refer to Equation W–28 of §98.233).

(D) Reporter emission factor for isolation valve emissions in not operating depressurized mode in cubic feet of natural gas per hour (refer to Equation W–28 of §98.233).]

(v[add: ii]) For reciprocating compressors in onshore petroleum and natural gas production (refer to Equation W–29 of §98.233), report the following:

(A) Count of compressor[delete: s] [add: packages.]

(B) Report emissions collectively.

Response: No rule change has been made as a result of this comment. The subject of compressor emissions estimates is outside of the scope of the specific amendments proposed for public comment in the Federal Register notice of September 9, 2011. EPA may consider this issue at a later date.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 59

Commenter Type: Trade Association

Comment: [Please refer to the original comment text posted in the docket]
§ 98.238 Definitions.

Except as provided in this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Compressor means any machine for raising the pressure of a natural gas or CO₂ by drawing in low pressure natural gas or CO₂ and discharging significantly higher pressure natural gas or CO₂.

[add: Compressor package means one or more compressors with a single drive, including separable, integral, and multi-stage compressor designs.]

Response: No rule change has been made as a result of this comment. The subject of compressor definitions is outside of the scope of the specific amendments proposed for public comment in the Federal Register notice of September 9, 2011. EPA may consider this issue at a later date.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0512-0029

Comment Excerpt Number: 6

Commenter Type: Trade Association

Comment:

[Please refer to the original comment text posted in the docket]§98.233(o) and (p) include conflicts. For centrifugal compressors, §98.233(u) is referenced following Equation W-22, but following Equation W-23 GHG_i is defined as "1". The reference to "1" should be deleted and §98.232(u)(2) should be referenced. The analogous conflict occurs for reciprocating compressors following equations W-26 and W-27. §98.233(p)(10) also includes another reference to subsection (u). Consistent regulatory text referencing (u)(2) should be used in §98.233(o) and (p).

Response: No rule change has been made as a result of this comment. The subject of compressor emissions estimates is outside of the scope of the specific amendments proposed for

public comment in the Federal Register notice of September 9, 2011. EPA may consider this issue at a later date.

Commenter Name: Grover R. Campbell and V. Bruce Thompson

Commenter Affiliation: Chesapeake Energy Corporation and American Exploration & Production Council (AXPC)

Document Control Number: EPA-HQ-OAR-2011-0512-0033

Comment Excerpt Number: 25

Commenter Type: Industry - oil and gas

Comment: (2) Approval Criteria

Chesapeake and AXPC would like to note an inconsistency in the recently finalized Subpart W Best Available Monitoring Methods (BAMM) approval criteria. 76 Fed. Reg. 59533 (Sept. 27, 2011). The final rule states the following regarding BAMM:

· “Owners and operators that submit both a timely notice of intent and extension request consistent with 98.234(f)(8)(ii) can automatically use BAMM through June 30, 2012. . . regardless of whether the best available monitoring methods request is ultimately approved.” 40 C.F.R. § 98.234(f)(8)(i):

· “To obtain approval to use best available monitoring methods after December 31, 2011” a BAMM extension request must demonstrate “to the Administrator’s satisfaction that the owner or operator faces unique or unusual circumstances” 40 C.F.R. § 98.234(f)(8)(iii).

These two statements are at best confusing and perhaps inconsistent. On the one hand, the rule indicates that BAMM is available automatically after 2011 based on the timely submission of both a notice of intent and an extension request. 40 C.F.R. § 98.234(f)(8)(i). But on the other hand, the rule indicates EPA approval under the unique or unusual circumstance criteria is required for all BAMM after December 31, 2011. 40 C.F.R. § 98.234(f)(8)(iii).

During the BAMM comment period, Chesapeake and AXPC suggested that 40 C.F.R. § 98.234(f)(8)(iii) be modified to state that the approval criteria applies to BAMM “other than BAMM that is allowed automatically through” June 30, 2012. This modification would have made it clear that there are two methods to obtain BAMM for January – June 2012: automatic BAMM is available to reporters that submit both a timely notice of intent and a BAMM extension request and EPA-approved BAMM is available to reporters that do not submit both a timely notice of intent and BAMM extension request.

Unfortunately, the final BAMM rule now expressly links the EPA approval requirement to the period when automatic BAMM is available. The now-modified 40 C.F.R. § 98.234(f)(8)(iii) requires EPA approval “to use best available monitoring methods after December 31, 2011.” So rather than exclude reporters from obtaining EPA approval to receive automatic BAMM from January – June 2012, the final BAMM rule expressly requires this approval. Chesapeake and AXPC recommend that EPA modify this language to clarify that EPA approval is not necessary where a reporter fulfills the criteria to obtain automatic BAMM.

Response: No rule change has been made as a result of this comment. The subject of Best Available Monitoring Methods (BAMM) approval criteria was addressed in the rulemaking finalizes Sept. 27, 2011 and is outside of the scope of the specific amendments proposed for public comment in the Federal Register notice of September 9, 2011.

Commenter Name: Rachel Buckbee

Commenter Affiliation: BP Exploration Alaska Inc. (BPXA)

Document Control Number: EPA-HQ-OAR-2011-0512-0037

Comment Excerpt Number: 2

Commenter Type: Industry - oil and gas

Comment:[Please refer to the original comment text posted in the docket]Centrifugal Compressor Venting - Paragraph (o) and Reciprocating Compressor Venting - Paragraph (p)

Although changes were not proposed to these paragraphs, BPXA believes that EPA should allow companies to petition EPA directly via a specific exemption process where direct measurement of a vent is deemed unsafe and unable to be completed. Where there is other data on similar machines in a grouping, substitution of test data should be able to be approved by EPA on a case by case basis.

Centrifugal Compressor Venting - Paragraph (o)

BPXA requests an alternative flow rate estimation methodology for measuring wet seal oil degassing vents to flare. This proposed methodology would greatly reduce the burden to report these emissions while maintaining the level of accuracy the EPA desires. BPXA has a unique wet seal oil system design for their compressors (diagram below). [See original comment for Typical BPXA North Slope Wet Seal Oil System diagram].

Most wet seal degassing systems send the sour seal oil (with process gas entrained) to the degassing tank which may vent to flare or atmosphere. BPXA has a modified system, where the sour seal oil goes into an intermediate stage of separation (a sour seal oil trap) before it goes to the degassing tank. This is where the majority (estimated >98%) of the gas is knocked out of the seal oil and the degassing tank removes the remaining entrained gas with an electric heater. The gas outlet of the sour seal oil trap has a restriction orifice which provides backpressure on the system to keep the sour seal oil trap operating near the sour seal oil feed pressure. Some facilities recover the gas off of the sour seal oil trap while others vent it to the flare system. Where this gas goes to flare, BPXA interprets that this flow rate to flare must be measured and reported. As this flare system typically operates at very low pressures (5-10 psig) and the sour seal oil traps operate at significantly higher pressures (ranging from 100-1000 psig), this causes the flow through the restriction orifice to be choked. (Note: choked flow typically occurs when the downstream pressure is less than half the upstream pressure). As the flow through the restriction orifice is choked, it can be easily estimated using standard industry calculations. These calculations will be as accurate as installing a meter.

BPXA proposes the following language (in green) be considered for addition to Subpart W to clarify the applicability of compliance requirements for compressors with sour seal oil trap systems:

98.233(o)(2) For wet seal oil degassing vents determine the vapor volumes sent to an atmospheric vent of flare, using a temporary meter such as a vane anemometer or permanent flow meter according to 98.234(b) of this section. If you do not have a permanent flow meter, you may install a permanent flow meter on the wet seal oil degassing tank vent. [highlighted text in green: If the sour seal oil system has an intermediate stage of separation before the degassing tank, a choked flow orifice gas flow engineering calculation may be used to estimate the flow rate to the flare under the following conditions: (1) A restriction orifice is installed on the gas outlet of the intermediate separator gas outlet, (2) the operating pressure of the intermediate stage of separation is two times the operating pressure of the flare system.]

Response: No rule change has been made as a result of this comment. The subject of compressor emissions estimates is outside of the scope of the specific amendments proposed for public comment in the Federal Register notice of September 9, 2011. Please see the Revisions to Best Available Monitoring Method Provisions for further details
<http://www.gpo.gov/fdsys/pkg/FR-2011-09-27/pdf/2011-24362.pdf>.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 45

Commenter Type: Industry - oil and gas

Comment: Revision: For centrifugal compressor venting, EPA modified the definition of the term MTm in Equation W-24 to clarify that the flow measurements are in standard cubic feet per hour.

Comment: API supports the use of flowrate in standard cubic feet at industry's standard conditions of 60 °F and 14.7 psia.

Response: No rule change has been made as a result of this comment. The subject of compressor emissions estimates is outside of the scope of the specific amendments proposed for public comment in the Federal Register notice of September 9, 2011.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0512-0042

Comment Excerpt Number: 46

Commenter Type: Industry - oil and gas

Comment: Revision: For reciprocating compressor venting, EPA modified the definition of the

term MTm in Equation W-28 to clarify that the flow measurements are in standard cubic feet per hour.

Comment: API supports the use of flowrate in standard cubic feet at industry's standard conditions of 60 °F and 14.7 psia.

Response: No rule change has been made as a result of this comment. The subject of compressor emissions estimates is outside of the scope of the specific amendments proposed for public comment in the Federal Register notice of September 9, 2011.

Commenter Name: J. Dillard

Commenter Affiliation: City of Los Angeles

Document Control Number: EPA-HQ-OAR-2011-0512-0043

Comment Excerpt Number: 1

Commenter Type: Private Citizen

Comment: See Attachment

ATTACHMENT:

Comments to EPA-HQ-OAR-2011-0512 Mandatory Reporting of Greenhouse Gases:

Petroleum and Natural Gas Systems due 10.24.2011

Joyce Dillard

to:

GHG Reporting Rule Oil and Natural Gas

10/24/2011 08:00 PM

Hide Details

From: Joyce Dillard <dillardjoyce@yahoo.com>

To: GHG Reporting Rule Oil and Natural Gas@EPA

Please respond to Joyce Dillard <dillardjoyce@yahoo.com>

Comments to EPA-HQ-OAR-2011-0512 Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems due 10.24.2011

To comment generally on the proposed amendments which include calculation methods, amending data reporting requirements clarifying terms and definitions, and technical corrections in Petroleum and Natural Gas Systems and are concerned “only on the issues specifically identified in this proposal for the identified subparts,” we ask that you consider that these systems are not necessarily in remote areas but in the context of densely populated areas.

We, in the City of Los Angeles, parts of Los Angeles County and parts of Orange County have these systems in our backyards. The City of Los Angeles is so densely populated and has diminished and non-reliable Fire and Emergency Services due to budget cuts.

Not all wells are mapped since records were destroyed in those early boom years in Los Angeles where wells were prolific everywhere. We do have leakage and we do have subsidence.

Even if oil was found, say when constructing a building, it may be that there are no records of this find. We have found this out from conversations former construction employees who remember finds, but we can find no records of a well-current or abandoned.

The emissions problem from methane and affiliated gases are part of our air quality problem and water quality problem.

Also, because of earthquake faults, we may be subject to more carbon sequestration projects. We have a Class V Experimental Project in the Terminal Annex Renewable Energy Project now. Specific identification is important to us. We are home to many Petroleum Production Facilities.

There is leakage of Natural Gas Systems in densely populated areas. Those who are watchdogs are having extreme difficulty in obtaining cooperation and compliance from the parties who own this Natural Gas Systems and the governing bodies over the situation.

We ask that identification used we aid us in identifying vent wells, as they are part of the pollution problems. We are trying to avoid explosions and the loss of life.

So, in essence, we ask that you consider the Public Health and Safety as you review these amended rules.

Thank you for your consideration.

Joyce Dillard

P.O. Box 31377

Los Angeles, CA 90031

Response: EPA thanks the commenter for their remarks. EPA will make emissions data collected under the Mandatory Greenhouse Gas reporting rule available to the public.

December 2011

**Responses to Public Comments Pertaining to Subpart W from the 2011 Technical
Corrections, Clarifying, Other Amendments to Certain Provisions of the Greenhouse Gas
Reporting Rule**

Section 7 - Calculating Greenhouse Gas Emissions (non-equipment specific)

Section 7.1 - Standard temperature and pressure

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0147-0016

Comment Excerpt Number: 18

Commenter Type: Industry – oil and gas

Comment: Revisions: EPA added a conversion factor multiplier of 1000 to Equation W-15.

Comment: API supports this correction. However, API requests that the emission factors be replaced with the following, derived for industry standard conditions of 60 °F and 14.7 psia

- Crude EF for CH₄ at 60 °F = 4.2 Mscf CH₄/separator
- Crude EF for CO₂ at 60 °F = 2.9 Mscf CO₂/separator
- Condensate EF for CH₄ at 60 °F = 17.2 Mscf CH₄/separator
- Condensate EF for CO₂ at 60 °F = 2.9 Mscf CO₂/separator

Response: EPA agrees with the commenter's request to provide the emission factors in Equation W-10 at 60°F and 14.7 psi; for further details, please see the response to EPA-HQ-OAR-2011-0147-0016, Excerpt 1.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0147-0016

Comment Excerpt Number: 1

Commenter Type: Industry – oil and gas

Comment: Technical Corrections, Clarifying and Other Amendments to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule

Inconsistent Use of Standard Conditions

No revisions were made in Subparts A or W to allow for the consistent use of industry standard conditions (60 °F and 14.7 psia). Even with the August 4, 2011 proposed technical amendments, there are numerous inconsistencies in the standard conditions applied in Subpart W. The following table summarizes the different temperatures used for standard conditions in Subpart W.

Table 1. Summary of Standard Conditions Used in Subpart W.

Equations W-1 and W-2

Standard Conditions: 50.6 °F and 14.7 psia (derivation is provided in comment W.1 [EPA-HQ-OAR-2011-0147-0016, Excerpt 9], below)

Equation W-3

Standard Conditions: Equation indicates that the resulting volumetric emissions are at actual conditions, though the metered vent rate is likely to be at standard conditions, which for industry would correspond to 60 °F and 14.7 psia

§98.233(d)(4)

Standard Conditions: AmineCalc uses industry standard conditions of 60 °F and 14.7 psia

Equation W-4

Standard Conditions: Equation indicates that the resulting volumetric emissions are at actual conditions, though inlet and outlet flow rate are likely tracked at standard conditions, which for industry would correspond to 60 °F and 14.7 psia

§98.233(e)(1)

Standard Conditions: GlyCalc uses industry standard conditions of 60 °F and 14.7 psia

Equation W-5

Standard Conditions: Provides emission factors for both standard temperatures of 60 °F and 68 °F

Equation W-6

Standard Conditions: Equation indicates that the resulting volumetric emissions are at standard conditions, which for industry would correspond to 60 °F and 14.7 psia

Equation W-7

Standard Conditions: Equation indicates that the resulting volumetric emissions are at actual conditions, though flow rates are likely tracked at standard conditions, which for industry would correspond to 60 °F and 14.7 psia

Equations W-8 and W-9

Standard Conditions: Equation indicates that the resulting volumetric emissions are at actual conditions, though the pressure correction results in standard conditions of 14.7 psia. The equations do not include a temperature correction.

Equation W-10

Standard Conditions: Equation indicates that the resulting volumetric emissions are at standard conditions, which for industry would correspond to 60 °F and 14.7 psia

Equations W-11 and W-12

Standard Conditions: Equation results in volumetric emissions at actual conditions

Equation W-13

Standard Conditions: Equation indicates that the resulting volumetric emissions are at actual conditions. (API recognizes the equation is corrected to standard conditions in the September 9, 2011 amendments.) The emission factor is based on standard conditions at 60 °F and 14.7 psia

Equation W-14

Standard Conditions: Equation indicates that the resulting volumetric emissions are at standard conditions, which for industry would correspond to 60 °F and 14.7 psia

§98.233(j)(1)

Standard Conditions: E&P Tanks uses the standard conditions associated with the input gas analysis, which for industry would correspond to 60 °F and 14.7 psia

§98.233(j)(2)-(4)

Standard Conditions: Calculation methodologies will result in volumetric emissions at standard conditions, which for industry would correspond to 60 °F and 14.7 psia

Equation W-15

Standard Conditions: Calculation methodologies will result in volumetric emissions at standard conditions. Emission factors are based on standard conditions at 68 °F and 14.7 psia. Comment W.10 [EPA-HQ-OAR-2011-0147-0016, Excerpt 18] below provides the emission factors for industry standard conditions of 60 °F and 14.7 psia

Equation W-16

Standard Conditions: Calculation methodologies will result in volumetric emissions at standard conditions, which for industry would correspond to 60 °F and 14.7 psia

Equations W-17 and W-18

Standard Conditions: Equations indicate that the resulting volumetric emissions are at actual conditions, however the GOR is typically reported at industry standard conditions of 60 °F and 14.7 psia

Equations W-19 and W-20

Standard Conditions: Equations indicate that the resulting volumetric emissions are at actual conditions

Equations W-22 through W-24

Standard Conditions: Equations indicate that the resulting volumetric emissions are at standard conditions, which for industry would correspond to 60 °F and 14.7 psia

Equation W-25

Standard Conditions: Calculation methodologies will result in volumetric emissions at standard conditions. Emission factors are provided for both standard temperatures of 68 °F and 60 °F

Equations W-26 and W-27

Standard Conditions: Equations indicate that the resulting volumetric emissions are at standard conditions, which for industry would correspond to 60 °F and 14.7 psia

Equation W-29

Standard Conditions: Calculation will result in volumetric emissions at standard conditions.

Emission factors are provided for both standard temperatures of 68 °F and 60 °F

Equations W-30 and W-31

Standard Conditions: Calculations will result in volumetric emissions at standard conditions. Some of the emission factors in Table W-2, W-3, W-4, W-5, W-6 and W-7 are provided for standard conditions of 68 °F and 14.7 psia. Table 2 at the end of this document provides the emission factors for 60 °F and 14.7 psia based on a correction factor of 519.67/527.67.

Equation W-32

Standard Conditions: Equations indicate that the resulting volumetric emissions are at standard conditions, which for industry would correspond to 60 °F and 14.7 psia

Equations W-33 and W-34

Standard Conditions: Converts actual volumetric emissions to standard conditions, which for industry would correspond to 60 °F and 14.7 psia

Equation W-35

Standard Conditions: Equation indicates that the resulting volumetric emissions are at standard conditions, which for industry would correspond to 60 °F and 14.7 psia

Equation W-36

Standard Conditions: Calculation will result in volumetric emissions at standard conditions. Density factors are provided for both standard temperatures of 68 °F and 60 °F

Equations W-37, W-38, and W-40

Standard Conditions: Equations result in mass emissions

Equation W-39

Standard Conditions: Equation indicates the resulting volumetric emissions are at actual conditions, though gas volumes are likely tracked at standard conditions, which for industry would correspond to 60 °F and 14.7 psia

API strongly insists that EPA should allow the use of industry standard conditions of 60 °F and 14.7 psia for all Subpart W equations used to quantify and report volumetric emissions for individual sources. This would reduce the potential for error in tracking standard volumes for the regulatory program that differ from those usually tracked for industry operations. If EPA needs the volumetric data at 68 °F for EPA's purposes, API requests that reporters should be allowed to make a single final conversion (under §98.233(t)) in which they would convert volumetric emissions from 60 °F to 68 °F by using the ratio of 527.67/519.67 as the applicable temperature correction. Providing consistency in the application of industry standard conditions for the source-specific calculations will reduce burden, increase consistency, and improve data quality while ultimately once the emissions are converted to a metric tons basis, the mass emissions reported to EPA would be identical.

Response: EPA agrees with commenter's request to change standard conditions to 60°F and 14.7 psi, which conforms to industry standard conditions. EPA has determined that changing the

standard condition will reduce the burden of reporting but will not affect the quality of data received through this program. Emission factors, throughput thresholds, and conversion factors currently in Subpart W have been changed to 60°F and 14.7 psi in this final rule. EPA has also modified 98.233 (t) by fixing the standard conditions at 60°F and 14.7 psi in Equation W-33 or Equation W-34. Finally, reporters that are already complying with standard conditions as provided in Subpart A (68°F and 14.7 psi), can use a final conversion of 519.67/527.67 to convert emissions from 68°F to 60°F.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0147-0016

Comment Excerpt Number: 20

Commenter Type: Industry – oil and gas

Comment: Revision: EPA revised the density factors for CO₂ and CH₄ used in Equation W-36. Comment: API supports this revision. However, based on our general comment on standard conditions, API suggests that the density factors are only needed for standard conditions of 60 °F and 14.7 psia if all emission source calculations are carried out at industry standard conditions.

Response: EPA agrees with commenter’s request to change the density factors to 60°F and 14.7 psi and has revised this final rule accordingly; for further details please see the response to EPA-HQ-OAR-2011-0147-0016, Excerpt 1.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0147-0016

Comment Excerpt Number: 23

Commenter Type: Industry – oil and gas

Comment: Also, Equations 39 A&B are shown in actual volume terms in both the August 4 and the September 9 amendments. As discussed above, API requests restating these equations in terms of industry standard conditions (60 °F and 14.7 psia).

Response: EPA agrees with the commenter’s request to change Equation 39 A and B standard conditions to 60°F and 14.7 psi and has revised this final rule accordingly; for further details please see the response to EPA-HQ-OAR-2011-0147-0016, Excerpt 1.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0147-0016

Comment Excerpt Number: 31

Commenter Type: Industry – oil and gas

Comment: Table 2. Revised Fugitive Emission Factors

The emission factors provided below are corrected to standard conditions of 60 °F and 14.7 psia. Note, the table below only corrects those emission factors which were provided at 68 °F and 14.7 psia in the reporting rule. Factors not listed below or not addressed in the comments above are believed to be provided at standard conditions of 60 °F and 14.7 psia in the reporting rule.

Table W-1. Onshore Petroleum and Natural Gas Production – Eastern U.S.

Component: Connector; Scf/hour/component: 0.003
Component: Open-ended Line; Scf/hour/component: 0.061
Component: Pressure Relief Valve; Scf/hour/component: 0.040

Table W-1. Onshore Petroleum and Natural Gas Production – Western U.S.

Component: Connector; Scf/hour/component: 0.121
Component: Open-ended Line; Scf/hour/component: 0.031
Component: Pressure Relief Valve; Scf/hour/component: 0.193

Table W-2. Onshore Natural Gas Processing and Table W-3. Onshore Natural Gas Transmission Leaker Emission Factors – Compressor Components, Gas Service

Component: Valve; Scf/hour/component: 14.84
Component: Connector; Scf/hour/component: 5.59
Component: Open-ended Line; Scf/hour/component: 17.27
Component: Pressure Relief Valve; Scf/hour/component: 39.66
Component: Meter; Scf/hour/component: 19.33

Table W-2. Onshore Natural Gas Processing and Table W-3. Onshore Natural Gas Transmission Leaker Emission Factors – Non-Compressor Components, Gas Service

Component: Valve; Scf/hour/component: 6.42
Component: Connector; Scf/hour/component: 5.71
Component: Open-ended Line; Scf/hour/component: 11.27
Component: Pressure Relief Valve; Scf/hour/component: 2.01
Component: Meter; Scf/hour/component: 2.93

Table W-4. Underground Natural Gas Storage Leaker Emission Factors – Storage Station, Gas Service

Component: Valve; Scf/hour/component: 14.84
Component: Connector; Scf/hour/component: 5.59
Component: Open-ended Line; Scf/hour/component: 17.27
Component: Pressure Relief Valve; Scf/hour/component: 39.66
Component: Meter; Scf/hour/component: 19.33

Table W-5. LNG Storage and Table W-6. LNG Import and Export Equipment Leaker Emission Factors – LNG Storage Components and LNG Terminals Components, LNG Service

Component: Valve; Scf/hour/component: 1.19
Component: Pump Seal; Scf/hour/component: 4.00
Component: Connector; Scf/hour/component: 0.34

Component: Other; Scf/hour/component: 1.77

Table W-5. LNG Storage and Table W-6. LNG Import and Export Equipment Leaker Emission Factors – LNG Storage and LNG Terminals Compressors, Gas Service
Component: Vapor Recovery Compressor; Scf/hour/component: 4.16

Table W-7. Natural Gas Distribution Leaker Emission Factors – Above Grade M&R at City Gate Stations Components, Gas Service

Component: Block Valve; Scf/hour/component: 0.557

Component: Control Valve; Scf/hour/component: 9.34

Component: Pressure Relief Valve; Scf/hour/component: 0.270

Component: Orifice Meter; Scf/hour/component: 0.212

Component: Regulator; Scf/hour/component: 0.772

Component: Open-ended Line; Scf/hour/component: 26.13

Response: EPA agrees with the commenter's request to provide the emission factors at 60°F and 14.7 psi and has revised this final rule accordingly; for further details please see the response to EPA-HQ-OAR-2011-0147-0016, Excerpt 1.

Section 7.2 - (t) (u) (v) Volumetric and mass conversion [W-33 to W36]

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0147-0029

Comment Excerpt Number: 5

Commenter Type: Trade Association

Comment: INGAA supports revisions that allow use of default natural gas CO₂ and CH₄ compositions for T&S pneumatic device emission estimates. Additional rule revisions are necessary to allow a consistent default gas composition for all T&S source estimates.

In previous communications and comments, INGAA has requested that a single gas composition for natural gas CH₄ and CO₂ content should be allowed for estimating emissions from all sources at a T&S facility. In addition, default compositions should be allowed for T&S. The Proposed Rule revises §98.233(a) to require natural gas composition of 95.2% CH₄ and 1% CO₂ for calculating vented emissions from T&S pneumatic devices. This is an improvement over the current version of Subpart W which requires that 100% is assumed for both constituents. However, the Proposed Rule (and September 9 proposed revisions) does not achieve the objective of allowing a common standard assumption for all sources and a common default composition of 95% and 1%. The September 9 proposed revisions offer additional changes that improve the rule, but the desired outcome is still not achieved because references to gas quality remain within source-specific subsections and introduce conflicts.

Rather than requiring different assumptions for gas composition, a single value should be allowed for all sources. This results in a logical approach where ALL sources at a facility assume

the same gas composition rather than using different assumptions for different sources. In addition, for T&S sources, operators should be allowed to use a default of 95% CH₄ and 1% CO₂ or a common value for the facility based on a gas analysis. To best achieve this outcome, it appears that §98.233 should be revised so that individual subsections (e.g., §§98.233(a), (i), (k), (o), (p), and (q) for the transmission compression segment) do not specify gas quality within the section. Instead, all of the subsections should consistently refer to §98.233(u). Then, §98.233(u) can identify the appropriate criteria for each segment. For T&S segments, §98.233(u) should indicate that operators can apply a default of 95% CH₄ and 1% CO₂ or use a value based on facility measured data (i.e., best available data). The September 9 proposed revisions provide appropriate §98.233(u) revisions but conflicts still exist within source-specific estimation methods in other §98.233 subsections. Additional details can be found in previous INGAA communications with EPA regarding inconsistent and conflicting Subpart W gas composition requirements which are incorporated herein by reference.

Response: It is EPA's intention that any facility that handles transmission quality gas may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas. This may include the following industry segments: Onshore natural gas processing, Onshore natural gas transmission compression, Underground natural gas storage, Liquefied Natural Gas (LNG) storage, and LNG import and export equipment, and Natural gas distribution

To make this clear, in this final rule, EPA has updated the following two sections to refer to the applicable sections within §98.233(u)(2) that refer to these default values: §98.233(a) Natural Gas Pneumatic Device Venting and §98.233(i) Blowdown Vent Stacks.

EPA has not updated the following two sections to refer to 98.233(u)(2): (k) Transmission Storage Tanks and (q) Leak Detection and Leaker Emissions. Further clarification of §98.233(k) Transmission Storage Tanks is not necessary as the applicable section within §98.233(u)(2) that refers to the default values is already appropriately referenced in the November 30, 2010 final rule in §98.233 (k)(2)(iii). §98.233(q) Leak Detection and Leaker Emission Factors does use the above-mentioned default factors, however, while 98.233 (a) and (i) and (k) refer to total gas, 98.233 (q) refers to total hydrocarbons. The above-mentioned default factors of 95% and 1% were used to back-calculate to get the correct percentages for total hydrocarbons, and these percentages are correctly referenced in the September 9, 2011 Proposal.

EPA has also not updated the following two sections 98.233(o) Centrifugal Compressor Venting and (p) Reciprocating Compressors. The September 9, 2011 Proposed Rule did not propose changes to either of these sections. At this time EPA is not granting reconsideration of other issues raised, but will consider those issues at a later time.

Section 7.3 - Emission Factors Table

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0147-0016

Comment Excerpt Number: 28

Commenter Type: Industry – oil and gas

Comment: Revision: EPA has revised the pneumatic device emission factors for transmission compression and natural gas storage.

Comment: Based on API's Compendium and a review of the TSD for Subpart W, EPA is applying the "low-bleed" pneumatic device emission factor from production to a "low continuous bleed" device category in the transmission and storage sectors. EPA's revision to the emission factor is correcting an error in converting the factor from a CH₄ basis to a natural gas basis. EPA's revised emission factor is correct for standard conditions of 68 °F. However, as stated above, API requests that EPA provide the emission factor of 1.39 scf/pneumatic controller for industry standard conditions of 60 °F.

Similarly, API reviewed EPA's proposed correction to the "intermittent bleed" and "high continuous bleed" pneumatic devices in the transmission sector. The basis for EPA's emission factor is an average value provided in the API Compendium for pneumatic devices in the transmission and storage sectors. EPA's revision to the emission factor is correcting an error in converting the factor from a CH₄ basis to a natural gas basis. EPA's revised emission factor is correct for standard conditions of 68 °F. However, as stated above, API requests that EPA provide the emission factor of 19.8 scf/pneumatic controller for industry standard conditions of 60 °F.

Response: EPA agrees with the commenter's request to provide the emission factors for pneumatic devices at 60°F and 14.7 psi and has revised this final rule accordingly; for further details please see the response to EPA-HQ-OAR-2011-0147-0016, Excerpt 1. In this final rule, EPA has updated the pneumatic device emission factor in Table W-3 and Table W-4; please see the response to EPA-HQ-OAR-2011-0147-0029, Excerpt 7.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0147-0016

Comment Excerpt Number: 29

Commenter Type: Industry – oil and gas

Comment: API notes that EPA has not proposed revisions to the pneumatic emission factors for the production sector. API had previously pointed out an error in the emission factors provided in Table W-1A. Below, API provides a corrected derivation for these emission factors:

Pneumatic Device Emission Factor Correction

API Question (Response Tracker 4844-40)

The derivation provided in the Technical Support Document (TSD) for the high bleed, low bleed, and intermittent bleed pneumatic device emission factors provided in Table W-1A introduces an error. Footnote 3. U.S. Environmental Protection Agency (EPA). Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry, Background Technical Support Document, U.S. EPA, Climate Change Division, Washington, DC.

<http://www.epa.gov/climatechange/emissions/downloads10/Subpart-W_TSD.pdf>] The

derivation incorrectly divides by the CH₄ weight fraction (e.g. D=0.788). The correct values are provided in the API Compendium (Table 5-15; based on scf/day of natural gas at 60 °F).

EPA Response (January 28, 2011): The emission factors in Table W-1A are correct. The emission factors in Table 5-15 of the API compendium are Methane (CH₄) emission factors, where as the emission factors in Table W-1A are Whole Gas emission factors.

API Follow-up:

It appears EPA misunderstood the emission factors they have cited from the API Compendium. Table 5-15 of the 2009 API Compendium provides emission factors for pneumatic devices in two sets of units. The first column cites emission factors from the original reference in the same units as the original reference. The original reference for the emission factors of interest is the data set used to develop the emission estimates provided in Volume 12 of the GRI/EPA 1996 study and the derivation provided in Table B-14 of the API Compendium. [Footnote 4 Shires, T.M. and M.R. Harrison. Methane Emissions from the Natural Gas Industry, Volume 12: Pneumatic Devices, Final Report, GRI-94/0257.29 and EPA-600/R-96-0801, Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

http://www.epa.gov/gasstar/documents/emissions_report/12_pneumatic.pdf] As shown in both Compendium Tables 5-15 (Column labeled “Emission Factor, Original Units) and B-14 (Column labeled “Bleed Rate (scf/day)), the units are in scf of gas per device. The emission factors are then converted to tonnes CH₄/device-yr in the far right-hand column of Table 5-15 and the bottom row of Table B-14.

The TSD incorrectly labels the emission factor units as scfd CH₄/device and then divides by the CH₄ mole% in an attempt to convert the emission factor to a total gas basis. This erroneously increases the emission factors. The TSD calculations should be corrected to show the following:

"High Continuous Bleed Pneumatic Device Vents" Methodology

37.9 scf/hour/component EF = (**705.7 From Compendium Table B-14** [scfd CH₄/pneumatic devices, high bleed]) * (B) / (D) / (E)

OR

37.9 scf/hour/component EF = (896 [scfd gasCH₄/pneumatic devices, high bleed]) * (B) / (~~D~~) / (E)

At industry standard conditions of 60 °F, the emission factor is 37.3 scfh/device

Conversions:

B: $1.015 = (68+459.67)/(60+459.67)$ = conversion from 60°F to 68°F [API suggests removing this conversion and requests that the emission factors be provided at industry standard conditions of 60 °F.]

D: 78.8% – production quality of natural gas (% methane), taken from Table B-14 of the 2009 API Compendium [This should be shown as 0.788, as used in the equation.]

E: 24 hours/day

Low Continuous Bleed Pneumatic Device Vents” Methodology

1.41 scf/hour/component EF = (**26.3 From Compendium Table B-14** [scfd CH₄/pneumatic devices, low bleed]) * (B) / (D) / (E)

OR

1.41 scf/hour/component EF = (33.4 [scfd ~~gas~~CH₄/pneumatic devices, low bleed]) * (B) / (~~D~~) / (E)

At industry standard conditions of 60 °F, the emission factor is 1.39 scfh/device

Conversions:

B: $1.015 = (68+459.67)/(60+459.67)$ = conversion from 60°F to 68°F [API suggests removing this conversion and requests that the emission factors be provided at industry standard conditions of 60 °F.]

D: 78.8% – production quality of natural gas (% methane) [This should be shown as 0.788, as used in the equation.]

E: 24 hours/day

“Intermittent Bleed Pneumatic Device Vents” Methodology

13.7 scf/hour/component EF = (323 **From GRI/EPA CH₄ Study, Vol. 12, Table 4-6**[scfd ~~gas~~CH₄/pneumatic devices, low bleed]) * (B) / (~~D~~) / (E)

At industry standard conditions of 60 °F, the emission factor is 13.5 scfh/device

Conversions:

B: $1.015 = (68+459.67)/(60+459.67)$ = conversion from 60°F to 68°F [API suggests removing this conversion and requests that the emission factors be provided at industry standard conditions of 60 °F.]

~~D: 78.8% – production quality of natural gas (% methane)⁴⁴~~

E: 24 hours/day

The corrected emission factors, derived above for industry standard conditions of 60 °F and 14.7 psia, are summarized below.

- High Continuous Bleed Pneumatic Device Vents= 37.3 scfh/device
- Low Continuous Bleed Pneumatic Device Vents= 1.39 scfh/device
- Intermittent Bleed Pneumatic Device Vents = 13.5 scfh/device

Response: EPA agrees with the commenter’s correction of the emission factors for high continuous bleed, low continuous bleed, and intermittent bleed pneumatic device vents in Table W-1A. In this final rule, EPA has appropriately updated the factors as recommended by the commenter.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0147-0016

Comment Excerpt Number: 30

Commenter Type: Industry – oil and gas

Comment: API had also noted in previous correspondence to EPA an error in the CH₄ emission factors applied to fugitive population counts in heavy crude service. API requests that these revision be included in amendments to Subpart W.

CH₄ Composition for Heavy Crude Service Emission Factors

API Question (Response Tracker 4844-41)

The derivation provided in the Technical Support Document (TSD) for heavy crude service population emission factors applies the wrong composition. API 4615, Table 16 indicates the vapor phase CH₄ composition associated with heavy crude is 0.942 weight fraction, not the 0.612 weight fraction that the TSD uses for the density conversion.

EPA Response: EPA used the averaged methane gas composition from produced gas based on API collected data, as noted on p. 12 of the document Estimates of Methane Emission from US Oil Industry (which further references API Publication No. 4638). This is the data that EPA uses in their standard calculations and is used as the basis for the National Inventory.

API Follow-up:

EPA's response above conflicts with the TSD. Based on API Publication 4615 (also cited in Compendium Table C-6), the vapor phase CH₄ content of light crude is 61.3 wt%, while for heavy crude it is 94.2 wt%.

In the TSD (page 125), under "Population Emission Factors – All Components, Heavy Crude Service Methodology", EPA indicates "*Average emissions factors by facility type were taken from API's Emission Factors for Oil and Gas Production Operations. [Footnote 5 API. Emission Factors for Oil and Gas Production Operations. API Publication Number 4615. page ES-3, Table ES-4, January 1995.] Hydrocarbon liquids less than 20°API are considered "heavy crude." The methane content of associated natural gas with onshore light (sic) crude is **94.2%** from the same study.*" (emphasis added). The statement above uses the term "light crude" when it should be "heavy crude" which corresponds to the methane weight percent shown.

As detailed above, the TSD references the correct methane content for heavy crude; however, the composition used for the density calculations, shown on page 126 of the TSD, does not correspond with that of heavy crude methane composition.

*F: 0.072 gas density lb/scf – assumes a gas composition of **61.2% methane**, 20% ethane, 10% propane, 5% butane, and 3.8% pentanes+*

Notably, the term "F" used for the density of heavy crude in the emission factor derivation is the identical to that used for the density of light crude in the derivation of the population emission factors. Since the vapor phase compositions are different for light crude and heavy crude, the density values should not be the same. EPA should calculate separate densities corresponding to light crude and heavy crude, based on the weight percent methane contents cited by EPA in the TSD. These densities should be applied as the "F" terms for the emission factors shown on pages 125 and 126 of the TSD.

The correct density calculation for the vapor phase associated with light crude service is provided below using the composition from the TSD.

Compound: Methane ;Weight %: 61.2; Molecular Weight: 16.04

Compound: Ethane ;Weight %: 20; Molecular Weight: 30.07

Compound: Propane ;Weight %: 10; Molecular Weight: 44.10

Compound: Butanes ;Weight %: 5; Molecular Weight: 58.12
Compound: Pentanes ;Weight %: 3.8; Molecular Weight: 72.15

Applying Compendium Equation 3-9, the molecular weight of the gas is calculated as shown:

[See original comment for equation 3-9 on page 19]

The gas density is calculated by dividing the molecular weight of the vapor by the ideal gas molar volume. Compendium Table 3-3 provides commonly used molar volume conversion factors: 379.3 scf/lb-mole at 60°F and 385.3 scf/lb-mole at 68°F.

Using these values results in the following light crude vapor phase density

[See original comment for light crude vapor phase density (a) and (b) on page 19]

The density for heavy crude vapor phase, when accounting for its higher CH₄ content, would be somewhat lower than the density for light crude vapor phase. The TSD (page 113) provides a CH₄ density of 0.04246 lb/scf for leakers emission factors in heavy crude service. This value should be applied to the population-based fugitive emission factors for heavy crude service. The use of the incorrect density reduces the population emission factors by 25% for components in light crude service and by 40% for components in heavy crude service.

The corrected population emission factors for components in heavy crude service are provided below. Note, the emission factors are shown for standard conditions of 60 °F and 14.7 psia.

Component: Valve; Scf/hour/component: 0.00064
Component: Flange; Scf/hour/component: 0.0011
Component: Connector (other) ; Scf/hour/component: 0.00039
Component: Open-ended line; Scf/hour/component: 0.0076
Component: Other; Scf/hour/component: 0.0034

Response: EPA has reviewed your comment and may consider it in future rulemakings.

Section 7.5 - Natural Gas Pneumatic Device Venting

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0147-0029

Comment Excerpt Number: 6

Commenter Type: Trade Association

Comment: The T&S emission factors for natural gas pneumatic device venting are inappropriate and emission factors more representative of current equipment and operations should be determined.

The Proposed Rule updates emission factors for T&S pneumatic devices, and there are several issues that will affect emission estimate accuracy. Emission factors based on more recent and representative emissions data should be used for Subpart W estimates of emission from natural gas pneumatic devices. At a minimum and as detailed below, the Tier 2 emission factor in Tables W-3 and W-4 (i.e., 20.1 scf THC/device-hr) should be replaced by the Tier 3 emission factors for high continuous bleed pneumatic devices (i.e., 57.7 scf NG/device-hr) and intermittent bleed pneumatic devices (i.e., 2.51 scf NG/device-hr). In addition, these emission factors are based on very limited data that is approximately 20 years old. Assessing more recent data to arrive at emission factors more indicative of current operations is appropriate. Additional discussion follows on three topics.

Response: EPA does agree with the use of “tier 3” emission factor for intermittent bleed devices but does not agree with the use of “tier 3” emission factors for continuous bleed devices. EPA used best available public data to develop the pneumatic device emission factors in this final rule. For further details on these issues please see the response to EPA-HQ-OAR-2011-0147-0029, Excerpt 7.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0147-0029

Comment Excerpt Number: 7

Commenter Type: Trade Association

Comment: Separate emission factors are warranted for high-bleed and intermittent-bleed devices. In Table W-3 and Table W-4 of Subpart W, the same emission factor is applied to high continuous bleed pneumatic device vents and intermittent bleed pneumatic device vents. The Subpart W Technical Support Document (TSD) indicates the emission factor is from the GRI Methane Emissions from the Natural Gas Industry” study. This study and other reference documents provide different emission factor “tiers”. The Subpart W factor is a “Tier 2” emission factor derived from the “Tier 3” continuous and intermittent bleed emission factors (shown in Table 1 below), and the estimated relative populations of each device type. Tier 2 emission factors are appropriate when pneumatic device counts do not distinguish between continuous bleed and intermittent bleed devices, but Subpart W requires separate counts of continuous bleed and intermittent bleed devices (i.e., Tier 3 activity data). Thus, Tier 3 intermittent device emission factors from the GRI study would appear more appropriate.

Table 1 lists the Tier 3 and Tier 2 emission factors from the GRI study. For intermittent bleed devices, separate Tier 3 emission factors for turbine valve operators and pneumatic/hydraulic valve operators could be used or a weighted average Tier 3 intermittent bleed emission factor (i.e., 2.51 scf NG/hr) could be used as shown in Table 1.

Table 1. Pneumatic Device Emission Factors for Transmission and Storage

Emission Source: Gas-driven continuous bleed pneumatic devices

Emission Factor* Tier: 3
Emission Factor* scf NGA/ device-yr: 505,000
Emission Factor* scf NGA/ device-hr : 57.7
Reference Tier D

Emission Source: Turbine valve operator (Intermittent bleed)
Emission Factor* Tier: 3
Emission Factor* scf NGA/ device-yr: 68,600
Emission Factor* scf NGA/ device-hr : 7.84
Reference Tier D

Emission Source: Pneumatic/hydraulic valve operator (Intermittent)
Emission Factor* Tier: 3
Emission Factor* scf NGA/ device-yr: 5,710
Emission Factor* scf NGA/ device-hr : 0.652
Reference Tier D

Emission Source: Intermittent bleed pneumatic device
Emission Factor* Tier: 3B
Emission Factor* scf NGA/ device-yr: 22,000
Emission Factor* scf NGA/ device-hr : 2.51
Reference Tier D

Emission Source: Gas-operated pneumatic devices
Emission Factor* Tier: 2C
Emission Factor* scf NGA/ device-yr: 176,000
Emission Factor* scf NGA/ device-hr : 20.1
Reference Tier D

* Emission factors reported to three significant figures for consistency with Subpart W.
A. Based on standard temperature of 68°F and standard pressure of 14.73 psi
B. Weighted average of Tier 3 emission factors for intermittent bleed devices
C. Weighted average of Tier 3 emission factors for continuous bleed and intermittent bleed devices
D. Emission factors based on data collected for the 1996 GRI/EPA Study. These emission factors are also included in the INGAA GHG Guidelines, API Compendium, GRI GHGCalc™, and the U.S. Inventory of Greenhouse Gas Emissions and Sinks.

In addition, these emission factors are based on a small emissions data set that was collected in the early 1990's. Thus, these emission factors may not be representative of pneumatic devices currently used in the natural gas T&S segments and of questionable accuracy when developing emission estimates. This issue is of particular concern for the intermittent bleed device emission factors, which may not reflect integration of current generation “no bleed or low bleed” devices.

The emission factor engineering units should be revised. The Proposed Rule units for the emission factors are “scf THC/device-hr.” The emission factor units should be “scf

NG/devicehr” based on the data used to develop the emission factors. NG (natural gas) is the appropriate basis for the engineering units and THC (total hydrocarbons) is not appropriate or equivalent nomenclature. For example, analysis on a THC basis would typically be expressed as methane equivalents for natural gas and provides a different result unless the gas is 100% methane.

The low bleed emission factor is based on data from a different industry segment. The Subpart W emission factor for continuous low-bleed pneumatic devices is from Table 5-15 from the API Compendium. The data used to develop this emission factor are included in Appendix B.5 of the API Compendium, and these data originate from the 1996 GRI/EPA Study. A review of these data shows: (1) the emission factor is based on a total of seven devices. Six of the devices are from a single Oil Battery measured for a 1992 Canadian Petroleum Association (CPA) study; and (2) the devices are from the production segment rather than natural gas transmission or storage operations. The very limited data set, age of the data (20 years), and production segment operations suggest this emission factor may not represent emissions from low-bleed pneumatic devices currently in use for natural gas transmission and storage operations.

Response: Regarding the suggestion to include “tier 3” emission factor for intermittent bleed device EPA agrees with commenter’s suggestion; therefore, EPA has provided separate emission factors for turbine valve operators and pneumatic/hydraulic valve operators. The weighted average intermittent bleed device emission factor can be used in cases where the pneumatic device does not fall under either of the new intermittent pneumatic device categories. Regarding the suggestion to provide a single “tier 3” emission factor for both continuous high-bleed and low-bleed emission factors, EPA does not agree. EPA requires data that segregates continuous high-bleed devices from continuous low-bleed devices. This level of detail is required to inform future policy.

Regarding the commenter’s conversion of the factors to standard cubic feet of natural gas, EPA does not agree. Reporters are to use the total hydrocarbon emission factors and convert these to CH₄ and CO₂ (default values as listed under 98.233(u)(2)(i) may be used for the conversion). EPA used best available public data to develop the pneumatic device emission factors in this final rule. All other alternatives considered were either less recent or more prone to erroneous calculations than the data EPA used. If and when new data become available, EPA will consider the need to update the emissions factors. Moreover, EPA developed the emission factors with the intent of minimizing the reporting burden on reporters. Where used in this final rule, population emission factors are the least burdensome method for reporters, while sustaining the necessary quality of data.

Section 7.5.1 - Calculating GHG Emission [W-1]

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0147-0016

Comment Excerpt Number: 9

Commenter Type: Industry – oil and gas

Comment: Revision: EPA revised the GHGi definition for Equation W-1.

Comment: API supports the clarification provided for GHGi in Equation W-1. However, EPA did not correct the constant in this equation and Equation W-2. As API commented in December 2010, the conversion from standard cubic feet to metric tons used in Equations W-1 and W-2 is based on 50.6 °F. Applying the Ideal Gas Law, the correct conversion factors at industry standard conditions should be:

- CH4 at 60 °F = 4.03E-4

- CO2 at 60 °F = 5.26E-5

In Subpart Y, EPA provides molar volume conversion factors for two set of standard conditions: “MVC = Molar volume conversion factor at standard conditions, as defined in §98.6. Use 849.5 scf per kg mole if you select 68 °F as standard temperature and 836.6 scf per kg mole if you select 60 °F as standard temperature”. Based on the MVC for 60 °F, the conversion factor for CH4 should be:

$(\text{kg mol}/836.6 \text{ scf}) \times (16.04 \text{ kg CH}_4/\text{kg mo}) \times (\text{tonne CH}_4/1000 \text{ kg CH}_4) \times (21 \text{ tonne CO}_2\text{e}/\text{tonne CH}_4) = 0.000403 \text{ tonne CO}_2\text{e}/\text{scf}$

Using the conversion factor provided for Equation W-1, we were able to back-calculate the molar volume conversion factor associated with the value, as shown:

$(0.000410 \text{ tonne CO}_2\text{e}/\text{scf}) \times (\text{tonne CH}_4/21 \text{ tonne CO}_2\text{e}) \times (1000 \text{ kg CH}_4/\text{tonne CH}_4) \times \text{kgmole HC}_4/16.04 \text{ kg CH}_4) = 0.0012172 \text{ kgmole CH}_4/\text{scf}$

The inverse of this value = 821.56 scf/kgmole CH4. The temperature associated with this conversion factor can be calculated using the Ideal Gas Law:

$MVC1/MVC2 = T1/T2$

$821.56/849.5 = (T1 + 459.7)/(69 + 459.7)$

$T1 = 50.6^\circ \text{ F}$

This clearly demonstrates an error in the derivation of the conversion factors provided for both CH4 and CO2. API requests that EPA correct the conversion factor to correspond to industry standard conditions of 60 °F and 14.7 psia. Based on the general comment above on standard conditions, a conversion factor for 68 °F and 14.7 psia is not needed. This conversion would take place under §98.233(t), based on API’s recommendations.

Response: EPA agrees that the factor should be determined at industry standard conditions; please see the response to EPA-HQ-OAR-2011-0147-0016, Excerpt 1. EPA also agrees that factor $Conv_i$ in Equation W-1 and W-2 was not calculated at standard condition and has updated factor $Conv_i$ in Equation W-1 and W-2 in this final rule.

Commenter Name: Pamela Lacey
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2011-0147-0028
Comment Excerpt Number: 3
Commenter Type: Industry – oil and gas

Comment: Clarification that Pneumatic Device Venting in W-1 Does not Apply to Natural Gas Distribution: AGA appreciates the proposed clarification that the definition of GHG1 in section 98.233(a), Equation W-1, are to be reported only for certain listed sectors of the natural gas industry, and that natural gas distribution is not on the list. We thought this was your intent, but it was not clear from the existing rule. See 76 Fed. Reg. at 47,398.

Response: EPA agrees that this was our intent.

Section 7.7 - Acid Gas Removal

Section 7.7.1 - Calculating GHG Emission [W-3, W-4]

Commenter Name: William Grygar
Commenter Affiliation: Anadarko Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2011-0147-0014
Comment Excerpt Number: 4
Commenter Type: Industry – oil and gas

Comment: Under Subpart W EPA proposes to require the use of Methodology 2 for acid gas removal units if the owner or operator has a meter installed on the vent, allowing the use of Methodologies 3 and 4 only when there is no vent meter. This revision requires the calibration requirements under §98.3(i) if a meter is present. In some instances an operational meter may be installed on a vent for basic process and safety information, and requiring a facility to maintain these meters under the requirements of §98.3(i) is overly arduous. Anadarko supports the continued use of Methodologies 3 and 4 where a previously quality-assured meter meeting the requirements of the GHGR is not already in place.

Response: EPA has finalized, as proposed, the requirement that if CEMS is not available, but a vent meter is installed, it must be used to quantify GHG emissions from acid gas removal vents. If the meter cannot provide the required quality expectation in 98.3(i) despite calibration, the operator may calibrate the meter according to manufacturer's instructions and use this measurement for determining vent emissions.

Commenter Name: Karin Ritter
Commenter Affiliation: American Petroleum Institute (API)
Document Control Number: EPA-HQ-OAR-2011-0147-0016
Comment Excerpt Number: 10

Commenter Type: Industry – oil and gas

Comment: Revision: For Acid Gas Unit Methodology 2, EPA proposes to require the use of Methodology 2 if you have a meter. If a facility has a vent meter but no CEMS available for determining the CO₂ emissions from AGR units, then they would use Calculation Methodology 2; and if a facility has neither a CEMS nor a vent meter, they have the option of using either Calculation Methodology 3 or 4.

Comment: This revision poses a problem. A company may have a meter installed on the acid gas unit for process information or flow indication. Such meters were not intended to provide the level of quality required by §98.3(i). API requests the continued use of Methodologies 3 or 4 even where a flow meter is installed and there is no CEMS.

Response: EPA agrees with the commenter regarding the use of available vent meters on AGR vents; please see the response to EPA-HQ-OAR-2011-0147-0014, Excerpt 4.

Section 7.8 - Dehydrator Vents

Section 7.8.1 - Calculating GHG Emission [W-5, W6]

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0147-0016

Comment Excerpt Number: 11

Commenter Type: Industry – oil and gas

Comment: Revisions: EPA revised several references for dehydrator emissions under §98.233(e) and clarified that the annual average daily throughput is used to assess if the flow is less than 0.4 million cubic feet per day.

Comment: API supports the corrected references. API requests one additional revision to the clarification of the annual average daily throughput. The flow rate should be examined based on 0.4 million **standard (at 60 °F and 14.7 psia)** cubic feet of gas per day. This is consistent with the terms defined in Equation W-5.

Response: EPA has taken into consideration the suggestion to change STP conditions and has revised this final rule to this STP condition of 60°F. Hence dehydrator daily throughput threshold should be determined at STP conditions to 60°F and 14.7 psia.

Section 7.9 - Well Venting for Liquids Unloading

Commenter Name: Amy Hendershot

Commenter Affiliation: Marshall Miller & Associates, Inc

Document Control Number: EPA-HQ-OAR-2011-0147-0007

Comment Excerpt Number: 3

Commenter Type: Industry – oil and gas

Comment: Discussion on plunger lift –

“Plunger travel is normally provided by formation gas stored in the casing annulus during a shut-in period. As the well is opened and the tubing pressure allowed to decrease, the stored casing gas moves around the end of the tubing and pushes the plunger to the surface. This intermittent operation is repeated several times per day.”

In essence, the well shuts itself in and the casing pressure builds to a pre-set point. At that time, the valve that shut in the gas flow from the tubing re-opens. The casing pressure pushes the plunger up the tubing string to unload the liquids that accumulated. The EPA uses sales line pressure. In some cases, the pressures may be the same, however, not always.

Response: EPA does not agree with the suggestion to change sales line pressure (SP_w , now renamed SP_p defined as “flow-line” pressure) to casing pressure. If a well venting to the atmosphere with the aid of a plunger lift is operated properly, either manually or with automated controls, a small amount of high pressure casing gas may slip past the plunger and through the liquids load being pushed up the tubing, so the gas being vented at the surface is the gas in the tubing string above the liquid load and plunger. This gas begins at flow-line pressure just before opening the surface vent, and quickly reduces to atmospheric pressure allowing the higher pressure gas in the casing to push the plunger and liquids up the tubing. EPA’s method for calculating well venting for liquids unloading with plunger lifts is not attempting to quantify the casing gas at all. The liquid accumulation in the tubing string suppresses gas flow to the sales line, which gradually shuts in the well causing gas in the formation to replenish the “cone” of low pressure gas surrounding the well perforations, raising the casing gas pressure to near shut-in pressure. Thus, EPA agrees with the commenter that the casing pressure is what pushes the plunger up the tubing string. In the first term of Equation W-9, EPA is attempting to quantify the gas in the tubing, above the liquid column, and released when the plunger lift travels up the tubing string. This gas is not at the same pressure as the casing pressure, which the commenter noted. Thus, EPA does not agree that casing pressure should be used instead of sales line pressure when a plunger lift is employed.

Section 7.9.1 - Calculating GHG Emission [W-7 to W9]

Commenter Name: Amy Hendershot

Commenter Affiliation: Marshall Miller & Associates, Inc

Document Control Number: EPA-HQ-OAR-2011-0147-0007

Comment Excerpt Number: 2

Commenter Type: Industry – oil and gas

Comment: § 98.233 Calculating GHG emissions.

(f) * * *

(3) Calculation Methodology 3.

The proposed correction to equation W-9 appears to have been just a copy of the revised equation W- 8. TD_w is outlined in the details of this revised equation but is not included.

Also in this same equation, the pressure requirement is for sales line pressure (SP_w). We believe this should instead be using casing pressure.

Response: Regarding the comment about the missing term TD_w in Equation W-9, first in the September 9, 2011 proposal and subsequently finalized in this final rule, EPA has corrected equation W-9 to include the TD_w term, now renamed TD_p. Regarding the comment that sales line pressure (SP_w) should be replaced by casing pressure, EPA does not agree. Please see EPA's response to comment number EPA-HQ-OAR-2011-0147-0007, Excerpt 3.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0147-0016

Comment Excerpt Number: 19

Commenter Type: Industry – oil and gas

Comment: Revision: EPA has proposed corrections to Equation W-8.

Comment: The revisions do not fully correct Equation W-8. API provides the following corrections for both the terminology associated with Equation W-7 and for Equation W-8.

For Equation W-7:

- Ea,n should be defined in terms of standard conditions: Ea_n = Annual natural gas emissions at ~~actual conditions~~ in **standard** cubic feet.
- Similarly, FR_{h,t} should be defined in terms of standard conditions: FR_{h,t} = Average flow rate in **standard** cubic feet per hour of the measured well venting for the duration of the liquids unloading, under actual conditions as determined in paragraph (f)(1)(i) of this section.
- §98.233(f)(1)(ii) should be deleted.

Equation W-8 should be replaced with the following:

[See original comment for revised equation W-8 on page 11]

Where: ~~Esa~~_n = Annual natural gas emissions ~~at actual conditions~~ in **standard** cubic feet/year.

W = Number of wells with well venting for liquids unloading at the facility.

$0.37 \times 10^{-3} = \{3.14 (\pi)/4\} / \{14.7 * 144\}$ (psia converted to pounds per square feet).

CDW = Casing diameter for each well, in inches.

WDW = Well depth to first producing horizon for each well, in feet.

SPW = ~~Shut in~~ **Surface** pressure **prior to venting** for each well, in pounds square inch ~~atmosphere~~**absolute** (psia).

VW = Number of vents per year per well. (Note, the second summation was changed from V to VW in the revised equation above to reflect this term.)

SFRW = Average sales flow rate of each gas well in cubic feet per hour.

HRV,W = Hours that each well was left open to the atmosphere during each unloading event.

1.0 = Hours for average well to blowdown casing volume at shut-in pressure.

ZV,W = If HRV,W is less than 1.0 then

ZV,W is equal to 0. If HRV,W is greater than or equal to 1.0 then ZV,W is equal to 1.

- In the equation above, API requests that the SP_p term represent surface pressure prior to venting, in pounds per square inch absolute. As EPA had defined SP_p , the shut-in pressure is interpreted to refer to the bottom-hole or casing pressure, which is not readily available.

- EPA uses “pounds per square inch atmosphere”, while the correct terminology is “pounds per square inch absolute” which is gauge pressure + 14.7 psi and is consistent with the pressure adjustment included in the 0.37×10^{-3} constant.

- §98.233(f)(2)(i) references §98.233(t) to adjust the natural gas volumetric emissions at standard conditions. This adjustment double corrects the gas volume for pressure, which is already included in the 0.37×10^{-3} constant. API notes that the August 19 amendments remove the reference to §98.233(t) and define SFRW in terms of gas volumes at standard conditions (60 °F and 14.7 psia). As indicated above, the term $E_{a,n}$ should also be defined in terms of gas volumes at standard conditions (60 °F and 14.7 psia).

Response: In this final rule, EPA has implemented industry’s request to change standard conditions to 60°F and 14.7 psi, which conforms to industry standard conditions. Please see EPA response to comment number EPA-HQ-OAR-2011-0147-0016, Excerpt 1. Regarding the two comments about equation W-7: 1) that meter reading $FR_{h,t}$ in most cases could be under the new STP condition at 60°F and 14.7 psia, and 2) that $E_{a,n}$ should be defined in terms of standard conditions, EPA notes that a reporter could be using meters set at STP at 68°F, in which case the emissions would have to be converted to the new STP standard. Therefore, instead of making changes to equation W-7, in §98.233(t), EPA has provided STP conversion from actual to standard (60°F).

Regarding the five suggested changes to equation W-8, EPA’s responses are below:

Regarding the first suggestion to make the following replacements: “ **$E_{a,n}$ = Annual natural gas emissions at actual conditions in standard cubic feet/year**”, as stated in the response above regarding a similar comment about equation W-7, in this rule EPA has implemented industry’s request to change standard conditions to 60°F and 14.7 psi, which conforms to industry standard conditions. Again, please see EPA response to comment number EPA-HQ-OAR-2011-0147-0016, Excerpt 1. However, EPA notes that a reporter could be using meters set at STP at 68°F, in which case the emissions would have to be converted to the new STP standard. Therefore, instead of making changes to equation W-8, in §98.233(t), EPA has provided conversion from 68°F to 60°F.

Regarding the following three comments and suggestions: 1) to make the following Equation W-8 replacements: “ **$SPW = \text{Shut-in Surface pressure prior to venting}$ for each well, in pounds square inch ~~atmosphere~~**absolute** (psia)”;**

2) “EPA uses “pounds per square inch atmosphere”;

and 3) In the equation above, API requests that the SP_p term represent surface pressure prior to venting, in pounds per square inch absolute. As EPA had defined SP_p , the shut-in pressure is

interpreted to refer to the bottom-hole or casing pressure, which is not readily available, while the correct terminology is “pounds per square inch absolute,” which is gauge pressure plus 14.7 psi and is consistent with the pressure adjustment included in the 0.37×10^{-3} constant”; EPA agrees with API’s definition change to SP_w and in this final rule has updated Equation 8 to reflect “pounds per square inch absolute” instead of “pounds per square inch atmosphere”. Also, in the final rule, EPA is allowing the use of surface pressure in Equation W-8 with certain stipulations; please see preamble section II.C. - Final Amendments to the Petroleum and Natural Gas Systems Source Category: Well Venting for Liquids Unloading for further details.

Regarding the comment: “§98.233(f)(2)(i) references §98.233(t) to adjust the natural gas volumetric emissions at standard conditions. This adjustment double corrects the gas volume for pressure, which is already included in the 0.37×10^{-3} constant. API notes that the August 19 amendments remove the reference to §98.233(t) and define SFR_w in terms of gas volumes at standard conditions (60°F and 14.7 psia). As indicated above, the term $E_{a,n}$ should also be defined in terms of gas volumes at standard conditions (60°F and 14.7 psia).”, EPA has eliminated the double correction for pressure in the 98.233 (f)(2) by eliminating the reference to 98.233 (t) in 98.233(f)(2)(i) in this final rule.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0147-0016

Comment Excerpt Number: 14

Commenter Type: Industry – oil and gas

Comment: Revision: EPA has proposed corrections to Equation W-9.

Comment API recognizes that EPA has inadvertently replicated Equation W-8 as Equation W-9 in the August 4, 2011 revisions, but has updated the equation in the September 9, 2011 revisions. API will comment on the September 9 amendment separately.

API provides the following corrected version of Equation W-9:

[See original comment for corrected version of equation W-9 on page 12]

Where: $E_{a,n}$ = Annual natural gas emissions in **standard** cubic feet/year.

W = Number of wells with well venting for liquids unloading at the facility.

$0.37 \times 10^{-3} = \{3.14 (\pi)/4\} / \{14.7 * 144\}$ (psia converted to pounds per square feet).

TDW = Tubing diameter for each well, in inches.

WDW = Tubing depth to plunger bumper for each well, in feet.

~~SPW = Sales line~~ **Surface** pressure for each well, in pounds per square inch **atmospheric absolute** (psia).

~~NVW~~ = Number of vents per year per well.

SFRW = Average sales flow rate of each gas well in **standard** cubic feet per hour.

HRV,W = Hours that each well was left open to the atmosphere during each unloading event.

0.5 = Hours for average well to blowdown tubing volume at sales line pressure.

ZV,W = If HRV,W is less than 0.5 then ZV,W is equal to 0. If HRV,W is greater than or equal to 0.5 then ZV,W is equal to 1.

- API requests that EPA modify the equation to apply the surface pressure. The use of the sales line pressure has no bearing for wells on compression. Using the sales line pressure in this situation will over-estimate emissions.

- EPA uses “pounds per square inch atmosphere”, while the correct terminology is “pounds per square inch absolute” which is gauge pressure + 14.7 psi and is consistent with the pressure adjustment included in the 0.37×10^{-3} constant.

- §98.233(f)(3)(i) references §8.233(t) to adjust the natural gas volumetric emissions at standard conditions. This adjustment double corrects the gas volume for pressure, which is already included in the 0.37×10^{-3} constant. API recommends removing the reference to §98.233(t) and defining SFRW and $E_{a,n}$ in terms of gas volumes at standard conditions (60 °F and 14.7 psia), as shown above.

- API requests the use of Methodology 3 for wells without plunger lifts. Methodology 3 specifies that it can be used only for tubing wells with plunger lifts. However, there are several instances in the field where one would have tubing wells without plunger lifts. In those instances there is no other methodology provided to calculate emissions.

Response: Regarding the comment: “EPA uses “pounds per square inch atmosphere”, while the correct terminology is “pounds per square inch absolute” which is gauge pressure + 14.7 psi and is consistent with the pressure adjustment included in the 0.37×10^{-3} constant.” And the request to change the definition to SP_w , in this final rule, EPA has changed the definition of SP_w from “pounds per square inch atmosphere” to “pounds per square inch absolute”.

Regarding the request and comment: “EPA modify the equation to apply the surface pressure. The use of the sales line pressure has no bearing for wells on compression. Using the sales line pressure in this situation will over-estimate emissions.” EPA is not allowing reporters to use surface pressure in Equation W-9 but is allowing the use of engineering estimate to determine sales line pressure when not known; please see preamble section II.C. - Final Amendments to the Petroleum and Natural Gas Systems Source Category: Well Venting for Liquids Unloading for further discussion on this issue.

Regarding the comment: “§98.233(f)(3)(i) references §8.233(t) to adjust the natural gas volumetric emissions at standard conditions. This adjustment double corrects the gas volume for pressure, which is already included in the 0.37×10^{-3} constant. API recommends removing the reference to §98.233(t) and defining SFRW and $E_{a,n}$ in terms of gas volumes at standard conditions (60°F and 14.7 psia), as shown above.”, EPA has eliminated the double correction for pressure in the 98.233(f)(3) by eliminating the reference to 98.233(t) in 98.233(f)(3)(i).

Regarding the comment: “API requests the use of Methodology 3 for wells without plunger lifts. Methodology 3 specifies that it can be used only for tubing wells with plunger lifts. However, there are several instances in the field where one would have tubing wells without plunger lifts.

In those instances there is no other methodology provided to calculate emissions.”, EPA has provided a detailed explanation for the use of casing diameter instead of tubing diameter in Calculation Methodology 2, even if the well has a tubing string and does not have a plunger lift. Please refer to the technical memo titled, “Change to Equation W-7: Time to Vent Gas” located in the Petroleum and Natural Gas Systems (Subpart W) of the Greenhouse Gas Reporting Rule docket (EPA-HQ-OAR-2009-0923).

Section 7.10 - Gas Well Venting During Completions and Workovers from Hydraulic Fracturing

Commenter Name: Amy Hendershot

Commenter Affiliation: Marshall Miller & Associates, Inc

Document Control Number: EPA-HQ-OAR-2011-0147-0015

Comment Excerpt Number: 2

Commenter Type: Industry – oil and gas

Comment: Field Code and Producing Horizon

The field code where each well is located is required for several of the sections of Subpart W to determine representative emissions from representative fields and producing horizons, specifically Section (g) Gas well venting during completions and workovers with hydraulic fracturing. In everyday practice, this field name is not typically referenced and it would be very difficult to identify for each well. In an attempt to comply with the rule, a map of several wells was overlaid with the EIA Field Code Master List GIS layer. It became abundantly clear that this requirement will be very burdensome with which to comply: there is no vertical vector (depth) within the EIA Field Codes and, as such, there is no way to determine from the EIA Master List which producing horizon each field references and thus to which field a well (or portions of a well if it has multiple horizons) belongs. Also, the current EIA Field Code List does not include fields for approximately 10% of the wells that were reviewed because of the relative age of the some of the fields.

Response: EPA addressed the concern with EIA field designation by proposing the use of sub-basin category in the September 9, 2011 rule proposal. In this final rule, EPA has retained the sub-basin category designation to monitor and report emissions from specific source types. Please see section 98.238 for a definition of sub-basin category and preamble section I.E. – How Do These Amendments Apply to 2012 Reports? for further details.

Section 7.10.1 - Calculating GHG Emission [W10 to W12]

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0147-0016

Comment Excerpt Number: 24

Commenter Type: Industry – oil and gas

Comment: Revision: Under §98.236(c)(6)(ii)(B), EPA clarified that the total count of workovers in the calendar year should be reported for those that flare gas or vent to the atmosphere.

Comment: API supports this revision. However, API requests similar clarification be added to the definition of the term “N” in Equation W-13 to reflect that the number of workovers in the equation reflect those that flare gas or vent gas to the atmosphere.

Response: EPA thanks the commenter for their remarks. EPA agrees with the change to the definition of “N” (now defined as “N_{wo}”) and EPA has modified this final rule accordingly.

Section 7.10.2 - Data Reporting Requirements

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0147-0016

Comment Excerpt Number: 25

Commenter Type: Industry – oil and gas

Comment: API also notes that there is an inconsistency between the preamble and the revised regulatory text. The preamble (page 47400, 1st column, under “Other Technical Corrections”) states: “EPA is proposing to clarify in 40 CFR §98.236(c)(6)(ii)(B) that only the number of workovers with hydraulic fracturing that vent gas to the atmosphere or flare gas needs to be reported . The current rule language could suggest you must report on the total number of workovers per year, including those that don’t involve hydraulic fracture and those that do not vent gas to the atmosphere.”

The text in the preamble is inconsistent with the regulatory text since §98.236(c)(6)(i)(A-H) are the reporting requirements for completions/workovers with hydraulic fracturing; and §98.236(c)(6)(ii)(A-D) are the reporting requirements for completions/workovers without hydraulic fracturing. Despite the text in the preamble the revisions in the regulatory text were made under §98.236(c)(6)(ii)(B), where for workover and completions without hydraulic fracturing EPA has changed from “Total count of workover in calendar year” to “Total count of workovers in calendar year that flare gas or vent gas to the atmosphere”.

API requests EPA to clarify this inconsistency, and as noted above, it supports the revision as reflected in the regulatory language. However, we wanted to point out this inconsistency and confirm that EPA’s intent is reflected in the revision to the regulatory language under §98.236(c)(6)(ii).

Response: EPA agrees and therefore EPA has finalized this requirement in §98.236(c)(6)(ii)(B).

Section 7.11 - Gas Well Venting During Completions and Workovers Without Hydraulic Fracturing

Section 7.11.1 - Calculating GHG Emission [W13]

Commenter Name: Amy Hendershot
Commenter Affiliation: Marshall Miller & Associates, Inc
Document Control Number: EPA-HQ-OAR-2011-0147-0008
Comment Excerpt Number: 2
Commenter Type: Industry – oil and gas

Comment: § 98.233 Calculating GHG emissions.
(h) * * *

The definitions of the variables within Equation W-13 in section (h) has been revised. The original rule indicated we were solving for $E_{a,n}$ but the revised definition (the equation was not revised) indicates “ $E_{s,n}$ = Annual natural gas emissions in standard cubic feet from a gas well...” Which should it be? $E_{a,n}$ or $E_{s,n}$?

Response: In this final rule EPA has revised the output of equation W-13 to $E_{s,n}$, which is emissions in standard cubic feet. This follows the clarification of the input terms EF_{wo} and V_p as being in standard cubic feet.

Commenter Name: Karin Ritter
Commenter Affiliation: American Petroleum Institute (API)
Document Control Number: EPA-HQ-OAR-2011-0147-0016
Comment Excerpt Number: 15
Commenter Type: Industry – oil and gas

Comment: Revision: EPA has revised the emission factor for non-hydraulic fracture well workover venting from 2,454 scf CH₄/workover to 3,114 scf gas/workover.
Comment: API has reviewed this correction and confirmed that EPA is adjusting the emission factor of 2,454 scf CH₄/workover to a natural gas basis, based on 78.8 mol% CH₄. This conversion does result in 3,114 scf natural gas/workover, as shown below, where standard conditions are 60 °F and 14.7 psia.

[See original comment for equation on page 13]

Response: In this final rule, at the suggestion of industry, EPA has adopted consistent use of industry standard conditions (60°F and 14.7 psia). Please see comment number EPA-HQ-OAR-2011-0147-0016, Excerpt 1. Accordingly, EPA has updated the final rule, including revising the

emission factor for non-hydraulic fracture well workover venting from 2,454 scf CH₄/workover to 3,114 scf natural gas/workover.

Section 7.12 - Blowdown Vent Stack

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0147-0029

Comment Excerpt Number: 3

Commenter Type: Trade Association

Comment: INGAA supports the proposed revision to the definition of "blowdown vent stack" in §98.6 but additional clarification is required regarding blowdown vent reporting.

The definition of "blowdown vent stack" is revised to clarify that emissions from emergency events are not included. INGAA supports this revision. However, when considered along with §98.233(i), additional clarification on blowdown vent emissions reporting is required, especially when considering additional revisions proposed by EPA in the September 9 proposed revisions. INGAA will provide additional comment when responding to the September 9 proposal, but the issue relates to clearly indicating which type of blowdown events are to be reported under §98.233(i). This requires a clear definition in §98.6, as well as consistent and clear text in §98.233(i), including introductory text explaining which types of blowdowns are included and excluded. Currently, and based on revisions proposed in the September 9 proposed revisions, §98.233(i) is not clear.

Response: EPA acknowledges that the provision regarding emergency equipment blowdown is different between the August 4, 2011 and September 9, 2011 proposals. The proposed technical corrections published on August 4, 2011 (76 FR 47392) reflected clarifications determined to be necessary based on questions and issues raised on the GHG Reporting Program hotline in the first half of 2011. Subsequent to development of the August "2011 Technical Corrections, Clarifying and Other Amendments" proposed rule, EPA learned that some of the technical amendments proposed there did not fully correct the technical errors or were not fully reflective of industry practice, as understood by EPA at the time of that proposal. Therefore, EPA further clarified the proposed requirements in its September 9, 2011 proposal. Because of the close relationship between the August 4, 2011 and September 9, 2011 proposals, and the need to consider the comments in total before finalizing the respective requirements, EPA decided not to finalize the technical corrections to subpart W when finalizing the August "2011 Technical Corrections, Clarifying and Other Amendments" final rule.

As suggested, in this final rule, EPA has added additional clarification on blowdown vent stacks reporting. Please see preamble section II.C. - Final Amendments to the Petroleum and Natural Gas Systems Source Category: Blowdown Vent Stacks, which clarifies that the following blowdowns are covered: the types of blowdowns typically tracked by operators for emergency shutdowns resulting from human intervention or when taking equipment out of service for maintenance; and not automated releases that do not require human intervention, such as valve

releases designed to keep equipment under safe operating mode. Please see section 98.233(i), which has been amended to clarify the types of blowdowns that must be reported and the types of blowdowns that are not required to be reported.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0147-0029

Comment Excerpt Number: 4

Commenter Type: Trade Association

Comment: INGAA supports §98.233(i) revisions clarifying that physical volumes less than 50 cubic feet are exempt from reporting, but additional revisions are needed to consistently apply appropriate terminology.

§98.233(i) revisions clarify that the exempt volume is a "physical" volume of 50 cubic feet (rather than a volume of 50 standard cubic feet). INGAA supports this revision. However, the term "physical volume" needs to be consistently used and terminology related to "standard" conditions should not be used when referring to physical volumes. The Proposed Rule still uses the term standard cubic feet when identifying volumes exempt from blowdown reporting. In §98.233(i), the term "physical" should be consistently used and "standard" should be deleted. The Proposed Rule revisions along with additional recommendations are provided here:

“If the total physical [EPA proposed revision] volume between isolation valves is greater than or equal to 50 standard [EPA proposed revision]cubic feet, retain logs of the number of blowdowns for each equipment type (including but not limited to compressors, vessels, pipelines, headers, fractionators, and tanks). Physical Blowdown [ADDITIONAL REVISION RECOMMENDED] volumes smaller than 50 standard [ADDITIONAL REVISION RECOMMENDED]cubic feet are exempt from reporting under paragraph (i) of this section.”

Response: EPA thanks the commenter for pointing out the inconsistency and has clarified 40 CFR 98.233(i) to remove the term “standard”.

Section 7.12.2 - Data Reporting Requirements

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2011-0147-0029

Comment Excerpt Number: 8

Commenter Type: Trade Association

Comment: Reporting Requirements: §98.236(c)(7)(i) reporting for blowdown vents should be revised. In addition, to complement the Proposed Rule and the September 9 proposed revisions, EPA will need to revise the recently adopted criteria in Subpart A Table A-7 regarding data elements where reporting is deferred until 2015.

§98.236(c)(7)(i) reporting for blowdowns includes the number of blowdowns "per unique volume type". As indicated by INGAA recommendations (see EPA-HQ-OAR-2011-0512-0013), an alternative equation is needed (i.e., summing the annual blowdown volumes by event). With that approach, only the total volume should be reported. "Unique volume type" is a misnomer for determining compressor station blowdown emissions because most events will be associated with a unique circumstance and repetitive blowdown of the same volume is not the norm. The reporting section for blowdown vents should be revised to include reporting associated with the current equation (which is revised to Equation W-14A in the September 9 proposed revisions) and separate criteria for blowdown emissions calculated by summing individual events (i.e., see approach associated with Equation W-14B in the September 9 proposed technical corrections). INGAA will provide additional details in October comments on the second proposal.

In addition, EPA will need to propose additional corrections to Subpart A to reconcile ongoing revisions in Subpart W with the recently adopted, "Change to the Reporting Date for Certain Data Elements Required Under the Mandatory Reporting of Greenhouse Gases Rule" (see 76 FR 53057 to 53071). That rule was published in the Federal Register on August 25, 2011 and identifies data elements used for Subpart W emission estimation calculations where reporting is deferred until March 31, 2015. The pending technical revisions to Subpart W will result in anomalies and additional data elements for Subpart A, Table A-7. EPA needs to adopt changes expediently so that 2012 reporting obligations are clearly defined in Table A-7 and reflect the pending technical corrections to Subpart W.

Response: With respect to revisions to Subpart A Table A-7 deferrals and additional corrections to Subpart A, EPA is addressing these changes, and will be publishing an updated list of data elements in an upcoming rulemaking.

In regard to the first comment about the need to revise the reporting section to include separate criteria for blowdown emissions calculated by summing individual events, EPA agrees that the data reporting requirements for blowdown vent stacks should accurately represent the calculation methodologies in 98.233(i). In this final rule, EPA is amending Equations W-14A and W-14B and the associated data reporting requirements for blowdown vent stacks. For further details, please see the response to EPA-HQ-OAR-2011-0512-0029, Excerpt 16.

Section 7.13 - Onshore Production Storage Tanks

Section 7.13.1 - Calculating GHG Emission [W-15, W-16]

Commenter Name: Amy Hendershot

Commenter Affiliation: Marshall Miller & Associates, Inc

Document Control Number: EPA-HQ-OAR-2011-0147-0007

Comment Excerpt Number: 4

Commenter Type: Industry – oil and gas

Comment: § 98.233 Calculating GHG emissions.

(j) * * *
(8) * * *

MM&A has found issues with the original as well as the revised equation W-16. The units do not work out properly, and there seems to be a flaw in the logic. Please see attached PDF for details.

Response: EPA agrees with the commenter. Please see the response to EPA-HQ-OAR-2011-0147-0007, Excerpt 6 for further information.

Commenter Name: Amy Hendershot
Commenter Affiliation: Marshall Miller & Associates, Inc
Document Control Number: EPA-HQ-OAR-2011-0147-0007
Comment Excerpt Number: 6
Commenter Type: Industry – oil and gas

Comment: W-16 (j)(8) onshore production storage tanks and occurrences of well pad gas-liquid separator liquid dump valves not closing during calendar year

[See original comment for handwritten equations]

$$Es_{1i} = (CFN * EN/8760 * TN) + (EN * (8760 - TN))$$
$$ft^3/hr = (No \text{ unites} * ft^3/year / 8760 \text{ hr/year} * hr/hr) + (ft^3/year * (8760 \text{ hrs/year} - hrs/hr))$$
$$= ft^3/yr + (ft^3 * hr/yr^2) \text{ units not the same cannot sum here} \Rightarrow \text{something off with eq. W-16.}$$

Es_{1i} – Total volumetric GHG emissions @ STP from each storage tank
CFN = Correction Factor: 3.87 \Rightarrow crude oil production for time period TN
5.37 \Rightarrow gas condensate production for the period TN
1.0 = periods when dump value is closed

TN = Total time dump valve is not closing properly during calendar year (hrs/yr)
Estimate by Maintenance/Ops records
When record shows open, it is assumed open since last record. If next record shows closed, it is assumed closed from that time forward until next reading or, if no reading, through the end of calendar year.

EN = storage tank emissions as calculated in j(1), j(2) and j(4) \Rightarrow all having well head separators (ft³/year)

Assume closed all year \Rightarrow TN = 0 hrs/year and that units aren't as issue

$$Es_{1i} = (1 EN/8760 0 + (EN (8760 - 0))$$
$$= 0 + [EN - 8760]$$
$$= 8760 EN \Rightarrow \text{But if closed all year there should be no emissions}$$

This again seems to show something is off with the Eq. W-16

Response: EPA agrees with the issue in Equation W-16 and has corrected the problem in this final rule. The units of E_n are standard cubic feet per year; therefore the conversion from hours to year is necessary in the second part of Equation W-16. EPA has included a divisor of 8760 to the part of the Equation after the summation point ($E_n(8760-T_n)$), which will resolve the issue highlighted in the equation.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0147-0016

Comment Excerpt Number: 17

Commenter Type: Industry – oil and gas

Comment: Revision: Under §98.233(j), EPA has clarified that the annual average daily throughput is used to assess if the separator oil flow is less or more than 10 barrels per day.
Comment: API supports this clarification.

Response: EPA has finalized, as proposed, the clarification to §98.233(j).

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0147-0016

Comment Excerpt Number: 19

Commenter Type: Industry – oil and gas

Comment: Revision: In Equation W-16, EPA added a correction to the first part of the equation to convert the time aspect of the emission factor from an annual basis to an hourly basis.
Comment: The proposed revisions did not correct the units in the second part of the equation. The correct equation should be:

[See original comment for equation on page 14]

Response: EPA agrees with the correction presented in the comment and made the necessary correction in this final rule; please see response to EPA-HQ-OAR-2011-0147-0007, Excerpt 6 for further details.

Section 7.25 - Onshore Petroleum and Natural Gas Production and Natural Gas Distribution Combustion Emissions

Section 7.25.1 - Calculating GHG Emission [W-39, W-40]

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2011-0147-0016

Comment Excerpt Number: 21

Commenter Type: Industry – oil and gas

Comment: Revision: EPA revised Equation W-39 to account for CO₂ present in the combusted gas, to apply a combustion efficiency, and to separately quantify CH₄ emissions from combustion.

Comment: For determining the combustion efficiency, EPA, API supports the use of engineering estimate. In addition, API requests the option of using a combustion efficiency of 99.5%, as referenced in the footnotes of AP-42 Tables 3.2-1, 3.2-1, and 3.2-2.

Response: EPA agrees with the commenter's suggestion to use a default combustion efficiency of 99.5% in Equation W-39A and Equation W-39B for internal combustion devices only and has made appropriate changes in this final rule. This default combustion efficiency will not apply to external combustion devices that must report under 98.233(z).

Commenter Name: Pamela Lacey

Commenter Affiliation: American Gas Association (AGA)

Document Control Number: EPA-HQ-OAR-2011-0147-0028

Comment Excerpt Number: 4

Commenter Type: Industry – oil and gas

Comment: Combustion Emissions from Natural Gas Distribution Operations: It will be helpful to have additional clarification regarding how to calculate combustion emissions for natural gas distribution facilities, particularly methane combustion emissions. Our members were confused by the existing rule that did not describe how to determine methane emissions from fuel combustion. See 76 Fed. Reg. at 47,399.

Response: In the September 9, 2011 proposal, EPA proposed adding Equation W-39B to calculate methane emissions from combustion equipment. EPA has finalized this equation in this final rule.

