KINDER MORGAN
ENERGY PARTNERS, L.P.

June 8, 2009

U.S. Environmental Protection Agency
EPA Docket Center (EPA/DC)
Mailcode 6102T
Attention: Docket ID No. EPA-HQ-OAR-2008-0508
1200 Pennsylvania Avenue, NW
Washington, D.C. 20460

Re: **Comments Regarding the Proposed Rule, Mandatory Reporting of Greenhouse Gases (Proposed Rule) dated April 10, 2009 (74 FR 16,448) Docket ID No. EPA–HQ–OAR–2008–0508**

Dear Docket Clerk:

Kinder Morgan Energy Partners, L.P. (Kinder Morgan) thanks the Environmental Protection Agency (EPA) for the opportunity to comment on the Proposed Rule on Mandatory Reporting of Greenhouse Gases (Proposed Rule). Kinder Morgan appreciates the challenges of crafting such a rule, and offers these comments in a constructive spirit and with the intention of improving the Proposed Rule to ensure that it achieves its intended goals and yields useful data at a reasonable cost.

Introduction

Kinder Morgan is a leading energy, transportation and storage company in North America. Kinder Morgan is comprised of four primary business segments in the United States– CO_2, Natural Gas Pipelines, Products Pipelines, and Terminals. Kinder Morgan owns an interest in or operates more than 35,000 miles of pipelines and 170 terminals. Our pipelines primarily transport natural gas, gasoline, crude oil, and CO_2, and our terminals store petroleum products and chemicals and handle bulk materials like coal and petroleum coke. Kinder Morgan also owns interests in CO_2 production wells. Kinder Morgan's services and technology contribute to the nation's energy security, economic growth and environmental protection.

Comment Structure and Summary

I. **Overview of Kinder Morgan's Operations**

II. **Guiding Principles for the Proposed Rule**
   - Provides our suggestions as to how the guiding principles behind the Proposed Rule should inform its content.

III. **General Comments on the Proposed Rule**

- ➢ Timing of Implementation – Kinder Morgan seeks deferral of the rule for at least one year. Kinder Morgan believes such a deferral will result in the collection of better data. If EPA insists on maintaining the January 1, 2010 date, then EPA should allow its alternative "best available data" approach for data collected for the 2010 monitoring year.
- ➢ Timing of Reporting – To avoid conflicts with reporting requirements under many existing federal environmental laws, the March 30 annual reporting deadline should be moved to June 30.
- ➢ "Once in, always in" Reporting Rule – Kinder Morgan recommends that facilities that are below the reporting threshold for two years continuously should no longer be subject to reporting requirements. The proposed "once in, always in" rule would discourage emission reductions and impose reporting costs on facilities that EPA has determined are not significant enough to warrant reporting.
- ➢ Designated Representative – Kinder Morgan recommends that the new owner of a facility incur legal liability only for actions taken by a designated representative after the change in ownership.
- ➢ State-Level Implementation – Kinder Morgan supports EPA's decision to preserve an exclusive role for itself with respect to implementing the reporting requirements of the Proposed Rule.

IV. Kinder Morgan Key Concerns

- ➢ Subpart PP—Suppliers of Carbon Dioxide

  Kinder Morgan believes that EPA's treatment of CO_2 production wells under Subpart PP, Suppliers of Carbon Dioxide is unwarranted. EPA "propose[s] that all CO_2 production wells owned by a single owner or operator in a given Dome report the mass of CO_2 extracted and/or transferred off site."[1] Production of natural CO_2 is not an emission source and is therefore not an appropriate point for reporting. The technical support document (TSD) specifically presumes that CO_2 produced and delivered downstream, such as to an EOR project, is ultimately emitted.[2] That is not accurate. Kinder Morgan believes that EPA should instead collect data on actual CO_2 emissions above the 25,000 ton threshold if and where they occur rather than assume CO_2 that is produced is eventually emitted somewhere else.
- ➢ Subpart W—Fugitive Emissions From Oil and Natural Gas Systems

  Kinder Morgan is concerned with the lack of a screening method to determine the applicability of the Subpart W reporting requirement. Without such a screening method, a prudent operator would have to carry out a full measurement program at every facility, year in and year out, to determine whether the 25,000 tons CO2-e per year threshold is met. Kinder Morgan provides several suggested screening methods for applicability. Kinder Morgan is also concerned with EPA's treatment of fugitive emissions under Subpart W, Oil and Natural Gas Systems. Kinder Morgan disagrees with EPA's definition of "fugitive emission" and proposed detection and measurement methods. Determining and measuring fugitives the way EPA proposes would actually reduce data quality and do so at unjustifiably higher costs. Kinder Morgan offers several alternatives for EPA's

[1] Mandatory Reporting of Greenhouse Gases, 74 Fed. Reg. 16,448, 16,585 (proposed Apr. 10, 2009).

[2] EPA, Technical Support Document for CO_2 Supply at 7.

consideration, such as a volume balance approach and an alternative monitoring program based on representative direct measurement, that will better serve the goals of the reporting rule and allow greater flexibility for improved future technologies.

- Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids
  EPA's treatment of natural gas processing facilities under subpart NN (1) double counts NGLs; (2) overstates NGL combustion; and (3) may create an improper presumptive point of regulation. For these reasons, Kinder Morgan urges EPA to reconsider the "upstream" reporting approach. Kinder Morgan recommends reporting of fractionated NGLs for known end-uses only and not bulk, unfractionated NGLs. Such an approach would prevent double reporting, provide full reporting of NGLs, and provide EPA with a more accurate understanding of the contribution that NGLs make to nationwide GHG emissions.
- Subparts MM—Suppliers of Petroleum Products
  Kinder Morgan engages in substantial blending activities at its terminals and is a registered oxygenate blender under 40 C.F.R. § 80. Kinder Morgan requests confirmation that the Proposed Rule excludes these activities from reporting requirements as stated in the Preamble. Kinder Morgan also seeks to clarify the definitions of "importer" and "exporter" in the proposed 40 C.F.R. § 98.390 to ensure that blenders and transport service providers are excluded.
- Subpart KK—Suppliers of Coal
  Kinder Morgan's system includes several terminals where coal is offloaded, stored and reloaded for subsequent shipment. The Proposed Rule requires coal mines to report production and relies on the Mine Safety and Health Act's (MSHA) definition of "coal mine." Kinder Morgan is concerned that using the MSHA definition of coal mine is overly expansive, and should be clarified to exclude post-mining activities such as those in which Kinder Morgan is involved.

Kinder Morgan appreciates EPA's consideration of these comments and is willing to provide any additional support or information.

Sincerely,

K. Dang

Kim Dang
Chief Financial Officer
Kinder Morgan Energy Partners, L.P.

Attachment: Kinder Morgan Comments RE: Docket No. EPA-HQ-OAR-2008-0508, Mandatory Reporting of Greenhouse Gases (Proposed Rule) dated April 10, 2009 (74 FR 16448)

cc: Dina Kruger
Bill Irving
Babora Jemelkova
Roger Fernandez
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COMMENTS ON THE PROPOSED RULE FOR MANDATORY REPORTING OF GREENHOUSE GASES

Proposed Addition to Code of Federal Regulations Title 40, Part 98

74 Fed. Reg. 16,448 (Apr. 10, 2009)

Submitted by:
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Submitted to:
Docket ID No. EPA-HQ-OAR-2008-0508
U.S. Environmental Protection Agency
EPA Docket Center
Mailcode: 6102T
1200 Pennsylvania Avenue, NW
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June 9, 2009

I. Overview of Kinder Morgan's Operations

A. Kinder Morgan CO_2 Business

Kinder Morgan is the leading transporter and marketer of CO_2 in North America. Kinder Morgan delivers approximately 1.3 billion cubic feet (Bcf/d) per day of naturally occurring CO_2 through about 1,300 miles of pipelines. Kinder Morgan is a leading provider of CO_2 for enhanced oil recovery (EOR) projects in North America. CO_2 transport and EOR operations contribute to solving the climate change challenge because they are the technological foundation upon which current carbon capture and sequestration (CCS) efforts rest. In addition to CO_2 pipelines and oil producing fields, this business segment owns significant interests in and operates CO_2 source fields, natural gas processing plants, and a crude oil pipeline.

B. Kinder Morgan Natural Gas Pipelines

Kinder Morgan is one of the largest natural gas transporters and storage operators in the United States. Kinder Morgan transports up to 18 Bcf/d of natural gas through approximately 24,000 miles of gas pipelines in the Rocky Mountains, the Midwest and Texas.

C. Kinder Morgan Products Pipelines

Kinder Morgan is the largest independent transporter of refined petroleum products in North America. Kinder Morgan transports over 2 million barrels per day of gasoline, jet fuel, diesel, natural gas liquids, and other fuels through more than 8,000 miles of pipelines. Kinder Morgan also has approximately 50 liquids terminals in this business segment that store fuels and offer blending services for ethanol and other products.

D. Kinder Morgan Terminals Business

Kinder Morgan is the largest independent terminal operator in North America. Kinder Morgan has more than 170 terminals that store petroleum products and chemicals, and handle bulk materials such as coal, petroleum coke and steel products. Key assets in our terminals business include large liquids facilities that store refined petroleum products and alternative fuels in New York Harbor, the Houston Ship Channel and southern California. Kinder Morgan also has bulk terminal operations that handle such materials as coal in the Southeast, petcoke along the Gulf Coast and steel products in the Midwest. Our facilities have approximately 100 million barrels of liquids capacity and handle about 100 million tons of materials annually.

II. Guiding Principles for the Proposed Rule

Kinder Morgan understands that EPA's key goals are to:

- Obtain data that is of sufficient quality to inform a range of future climate change policies and regulations.
- Balance the rule coverage to maximize the amount of emissions reported while excluding small emitters.
- Create reporting requirements that are consistent with existing GHG reporting programs by using existing GHG emission estimation and reporting methodologies to reduce reporting burden, where feasible.[3]

Kinder Morgan agrees that the rule coverage must be balanced, but it has concerns with several of EPA's assumptions in designing its "upstream" reporting requirements. For example, Kinder Morgan does not think that CO_2 extracted for EOR operations, almost none of which is emitted to the atmosphere, should be reported as if it were a potential source of emissions like coal, petroleum, or some industrial GHGs. EPA's assumption that industrial GHGs or fossil fuels are "almost always"[4] used in a way that results in emissions to the atmosphere is simply not valid for CO_2, and would cause Kinder Morgan to vastly overstate the GHG emissions resulting from its CO_2 / EOR operations. EPA also wrongly requires reporting of the GHG content of all natural gas liquids (NGLs) supplied by domestic gas processors, because a large proportion of these products are not used as fuel but as industrial inputs for plastics, carpeting and other products.

Kinder Morgan also agrees with EPA that reporting requirements should be consistent with GHG reporting programs by using existing GHG emission estimation and reporting methodologies to reduce reporting burden, where feasible. However, this principle is not always realized in the Proposed Rule. For estimation of fugitive emissions from oil and natural gas systems, for example, existing practice calls for the use of emission factors or volume balances.

III. General Comments on the Proposed Rule

A. Timing of Implementation and Reporting

EPA's proposal to begin monitoring GHG emissions on January 1, 2010 and require the first annual report to be submitted by March 31, 2011 is likely to lead to poor data collection in general and poses severe logistical problems for Kinder Morgan. While there may be a tremendous amount of pressure to finalize GHG reporting rules, it is more important to ensure that the data collected is accurate and useful. Collecting bad data could lead to faulty conclusions and misdirected policies. From Kinder Morgan's perspective, the proposed monitoring and reporting in several areas goes significantly beyond existing requirements and business practices. Almost every aspect of the human

[3] Mandatory Reporting of Greenhouse Gases, 74 Fed. Reg. 16,448, 16,456 (Apr. 10, 2009).
[4] *Id.*

and physical infrastructure needed for Kinder Morgan to implement the Proposed Rule remains undeveloped as of mid-2009. While this challenge is true across the different Kinder Morgan business units, it is most evident with regard to Part W because the Proposed Rule does not provide simplified or well-defined methods through which fugitive GHG emissions can be calculated from readily available data. These concerns are discussed in more detail below.

The Proposed Rule requires the annual emission report to be filed by the end of the first quarter. Kinder Morgan supports deferring the annual deadline for emissions reporting until June 30, which marks the end of the second calendar quarter. A June 30 deadline would be more consistent with existing state GHG reporting programs, many of which do not require the submission of data until the second quarter of the year.[5] States adopted this deadline with the understanding that it takes time to collect, organize, assure and control quality, correct, and analyze emission data and required metadata, as well as prepare inventories in a format suitable for submission. In addition, stationary sources are already obligated to submit several data-intensive reports to various agencies, including EPA, in the first quarter of the year. These include Title V semiannual monitoring reports and annual certifications under the Clean Air Act; quarterly deviation reports under the Clean Air Act; Discharge Monitoring Reports under the Clean Water Act; and Tier II reports under the Emergency Preparedness and Community Right-to-Know Act. A June 30 second-quarter submission deadline would provide a more reasonable amount of time and help prevent GHG reporting obligations from interfering with these existing reporting requirements.

Suggested change regarding annual deadline

40 C.F.R. § 98.3(b). *Schedule.* Unless otherwise specified in subparts B through PP, you must submit an annual GHG emissions report no later than ~~March 31~~ *June 30* of each calendar year for GHG emissions in the previous calendar year.
(1) For existing facilities that commenced operation before January 1, ~~2010~~ *2011*, you must report emissions for calendar year ~~2010~~ 2011 and each subsequent calendar year.
(2) For new facilities that commence operation on or after January 1, ~~2010~~ *2011*....[remaining text of subparagraph is unchanged]
(3) For any facility or supplier that becomes subject to this rule because of a physical or operational change that is made after January 1, ~~2010~~ *2011*....[remaining text of subparagraph is unchanged].

If EPA insists on maintaining the proposed dates of January 1, 2010, for monitoring and March 31, 2011, as the deadline for the first annual report submission, then Kinder Morgan believes that EPA's alternative "best available data" approach[6] would be preferable to the proposed timetable. The alternative "best available data" approach,

[5] For example, June 30 is the submission deadline for the General Reporting Protocol of the Climate Registry, which has been accepted in 42 states and the District of Columbia. The Climate Registry, General Reporting Protocol v.1.1 at 8 (2008), *available at* http://www.theclimateregistry.org/downloads/GRP.pdf.
[6] 74 Fed. Reg. at 16,471.

however, has several drawbacks. This approach would yield uncertain and inconsistent data for facilities where there is considerable disagreement over what constitutes "best available data." GHG emission estimates based on "best available data" will not be comparable to figures for 2011 and subsequent years, making that data of limited use to EPA. Efforts to gather "best available data" for the 2010 monitoring year would divert time and resources that could better be applied to preparing personnel, equipment, and data management systems for emissions monitoring in 2011. Ultimately, EPA's regulatory efforts would be best served by allowing all sectors, and especially the gas transmission sector on which it is imposing significant new monitoring obligations, an additional year to provide for a smooth transition to GHG monitoring.

B. Once In, Always In

Kinder Morgan strongly supports amending the Proposed Rule to allow reporting facilities that fall below the emissions threshold for two consecutive years to discontinue reporting until and unless the facility emissions exceed the reporting threshold. As EPA recognizes, the proposed "once in, always in" rule creates disincentives for emission reductions, and imposes reporting costs on facilities that EPA has determined are not significant enough to warrant reporting.[7] "Once in, always in" is particularly problematic for facilities that are idled, inactivated, or dismantled. Moreover, the data collection benefit that EPA attributes to the "once in, always in" rule – that it is "important . . . to be able to track trends in emissions and understand factors that influence emission levels"[8] – is unconvincing. In most sectors, the factors that drive GHG emissions are well-understood and, in any event, a two-year exclusion rule would still provide EPA with an abundance of detailed data from which to draw policy conclusions.

Suggested change to once in/always in

40 C.F.R. § 98.2(g)*(1)* Once a facility or supplier is subject to the requirements of this part, the owners and operators of the facility or supply operation must continue for each year thereafter to comply with all requirements of this part, ~~including the requirement to submit GHG emission reports, even if the facility or supplier does not meet the applicability requirements in paragraph (a) of this section in a future year~~ *unless the condition in subparagraph (2) of this paragraph is satisfied. If the condition in subparagraph (2) is satisfied, the facility or supplier may discontinue reporting emissions as provided in this part. However, the facility or supplier shall reevaluate applicability as provided in paragraph (f) of this section.* [Final sentence of original text moved to subparagraph (3) below].
(2) A facility or supplier subject to the reporting requirements of this part may discontinue reporting if the facility or supplier fails to meet the applicability requirements of paragraph (a) of this section in two consecutive monitoring years. If reporting is discontinued pursuant to this subparagraph, the designated representative for the facility or supplier shall provide an appropriate notice accompanying its final report to EPA.
(3) If a GHG emission source in a future year through change of ownership....

[7] *Id.* at 16,470.
[8] *Id.*

C. Liability for Acts of Prior Designated Representative

Kinder Morgan is deeply concerned by the implication in the proposed 40 C.F.R. § 98.4(h) that a new owner of a facility could incur legal liability for actions that the Designated Representative undertook under *previous* ownership. EPA should clarify that the liability of a new owner only extends to actions of the Designated Representative made after the change in ownership and after the point when the Designated Representative becomes an employee of the new owner. The previous owner should remain liable for statements made by its Designated Representative during its period of operation and ownership. Indeed, EPA's new pilot project under its audit policy recognizes that new owners are not responsible for compliance prior to their ownership.[9] The clarifying language that Kinder Morgan suggests below is also consistent with existing permit requirements under the Clean Air Act and the Clean Water Act, which require owners and operators to be responsible for their actions and hold the permit during their period of ownership or operation but not thereafter. In any industry where facilities change corporate ownership, lack of clarity on this point could unintentionally create significant legal risks.

Suggested change to owners and operators obligations.

40 C.F.R. § 98.4(h)*(1) Changes in owners and operators.* In the event a new owner or operator is not included in the list of owners and operators in the certificate of representation under this section, such new owner or operator shall be deemed to be subject to and bound by *statements or actions of the designated representative made after the new owner or operator commenced ownership or operation. Such statements or actions shall include* the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative, as if the new owner or operator were included in such list. . . .
(2) Liability. Notwithstanding any other provision of this subpart, no new owner or operator of a facility shall be held liable for any certificate, representation, action, inaction or submission of a designated representative made before the new owner obtained title to the reporting facility or before the new operator began operating the reporting facility.

D. State-Level Implementation of the Proposed Rule Would Unnecessarily Increase the Cost and Complexity of Compliance

Kinder Morgan strongly supports EPA's decision to preserve an exclusive role for itself with respect to implementing reporting requirements under the Proposed Rule. Delegation of authority to the states under Section 114(b) of the Clean Air Act would have no conceivable advantage over the centralized data collection approach reflected in the Proposed Rule. Delegation of authority to states could result in inconsistent data

[9] Interim Approach to Applying the Audit Policy to New Owners, 73 Fed. Reg. 44,991, 44,995 (Aug. 1, 2008).

collection and increased compliance risks. State-level implementation would inevitably increase the complexity (and cost) of compliance with the Reporting Rule, because reporting tools and requirements would be likely to differ from state to state. In addition, some states that operate their own emission reporting programs have had difficulty implementing reliable electronic reporting tools, and have experienced frequent service outages and data format compatibility restrictions. As EPA recognizes in the Preamble to the Proposed Rule, exclusive EPA authority over data collection and enforcement is the option most likely to contain the cost of compliance, preserve the quality of data, and ensure rapid dissemination of GHG emission reports.[10]

IV. Kinder Morgan Key Concerns

A. Subpart PP—Suppliers of Carbon Dioxide

Kinder Morgan's comments related to Subpart PP include the following components: summary, background on Kinder Morgan's operations pertaining to Subpart PP, discussion of the issue, Kinder Morgan's recommendation, and a primer on CO_2 source, pipeline, and EOR operations.

1. Summary

Under Subpart PP of the Proposed Rule, CO_2 production wells are included as Suppliers of Carbon Dioxide[11] and are required to report the mass of CO_2 extracted from production wells[12]. Transportation and distribution of CO_2 and the injection and processing of CO_2 for enhanced oil and gas recovery (EOR) are excluded from the Suppliers of CO_2 source category and from the reporting requirement.[13] Kinder Morgan does not believe that CO_2 production data will provide EPA with useful information, and urges EPA to instead collect data on actual CO_2 emissions where they occur above the 25,000 tons CO_2-e per year emission threshold.

2. Background on Kinder Morgan's CO_2 Operations

Kinder Morgan, with other co-owners, extracts over 1 billion cubic feet of CO_2 per day from natural deposits at the McElmo Dome and Doe Canyon wells in Colorado, and transports the gas via pipeline to be injected into oil fields in Texas. Kinder Morgan's CO_2 division is one of the nation's largest suppliers and transporters of CO_2 for use in EOR operations and is a world leader in developing and implementing this important technology. Through its 1,300 plus mile CO_2 pipeline system, the largest CO_2 network in the world, Kinder Morgan's CO_2 division presently supplies a critical and growing industry in the mid-continent region. Furthermore, Kinder Morgan has become one of

[10] *Id.* at 16,594.
[11] 74 Fed. Reg. 16448, 16725 (Proposed 40 CFR § 98.420(a)).
[12] 74 Fed. Reg. 16448, 16725 (Proposed 40 CFR § 98.422).
[13] 74 Fed. Reg. 16448, 16725 (Proposed 40 CFR § 98.420(a)).

the largest independent oil producers in the U.S., mainly due its use of CO_2 injection and EOR.

Kinder Morgan is committed to continuing to work with EPA to further our understanding of the potential for the permanent geologic sequestration of CO_2, including through the study of CO_2 sequestration at EOR sites. In addition to enhancing national energy security and promoting economic growth, CO_2 transport and EOR operations can contribute to solving the climate change challenge. CO_2 transport and EOR operations are the technological foundation upon which current CCS efforts rest. Industry experience with CO_2 transport and EOR continues to provide valuable insights concerning carbon sequestration techniques, pipeline performance standards, safety issues, subsurface geological issues and protection of drinking water.

Kinder Morgan's CO_2 division has shared its expertise with both public and private partners, including several DOE Regional Sequestration Partnerships (such as WestCarb and the Southwest Partnership), the University of Texas Bureau of Economic Geology (UTBEG), and the privately funded U.S. Gulf Coast Carbon Center, in order to help further develop this technology. Recognizing the vital role carbon sequestration may play in the future, Kinder Morgan continues to provide funding, assets and human resources for a variety of CCS efforts throughout North America.

3. Discussion of the issue

As noted in the Preamble to the Proposed Rule, CO_2 used in most industrial applications will eventually be released into the atmosphere. In contrast, the vast majority of CO_2 that is produced from natural sources and used for EOR is not emitted. [14] During the EOR operation, the CO_2 is recycled, with minimal losses resulting from facility events such as maintenance blowdowns and upset conditions. EOR is a closed loop system and when the EOR project is no longer economic to operate, wells and equipment are shut in leaving the CO_2 permanently in the formation (*i.e.*, geologically sequestered). In our experience there have been rare occasions where CO_2 from a retired EOR project may be produced and delivered to an adjacent or nearby EOR project, but again the end point remains the same, in the ground. Accordingly, CO_2 source production is not and should not be presumed to be emitted.

Kinder Morgan understands that EPA relied on the Intergovernmental Panel on Climate Change (IPCC) protocol/reporting convention to justify its reporting requirement for CO_2 production. Under that protocol, it is assumed that everything produced is emitted if there is a lack of reliable downstream information. Kinder Morgan maintains that EPA does not need to rely on this default rule in the case of CO_2/EOR operations, because

[14] Around 98% of the CO_2 Kinder Morgan produces is used in domestic EOR operations. The remaining 2% is currently sold to distributors who resell the product to oil field service companies that use it primarily in hydraulic fracturing/well stimulation and small EOR pilot projects (delivered to their customers by tank trucks, typically).

there is reliable evidence that less than ½ of 1% of CO_2 from production wells is ultimately emitted during the entire process of extraction, compression, pipeline transportation, and delivery to EOR injection wells.

In addition, after an extensive review of available data, the IPCC concluded that "[o]bservations from engineered and natural analogues as well as models suggest that the fraction (of CO_2) retained in appropriately selected and managed geological reservoirs is very likely to exceed 99% over 100 years and is likely to exceed 99% over 1000 years. For well-selected, designed and managed geological storage sites, the vast majority of the CO_2 will gradually be immobilized by various trapping mechanisms and, in that case, could be retained for up to millions of years."[15] As explained in more detail below, by their very nature, EOR fields are well-selected, designed, and managed such that CO_2 is reliably retained in the given geologic formation both during active operation of the EOR field and after EOR operations have ceased.

It is for these reasons that Kinder Morgan disagrees with EPA's interpretation of retention rate at EOR sites. In the Preamble of the Proposed Rule, EPA referenced a study of CO_2 retention rates at EOR operations in the Permian Basin, and noted that reported retention rates ranged from 38 to 100%, with an average of 71%.[16] It is important to understand that most of the "retention rates" being reported in this study were from ongoing EOR operations. During an EOR operation, the amount of CO_2 "retained" by a reservoir, as the term is used by petroleum engineers, is the amount of CO_2 that is not recovered with the oil for recycling and reuse for further oil extraction. This quantity has no relationship to the amount of CO_2 that will be retained by the geologic formation once the EOR operation is concluded and the reservoir is capped. The study notes that the amount retained "is the estimated total amount of CO_2 that does not return to the surface once injected, thus is not recycled. Essentially 100% of the purchased CO_2 is still in the system. Practically, 100% of the fluid will be stored in the reservoir unless a reservoir blowdown is instigated."[17] This analysis is consistent with the IPCC conclusions discussed above.

Therefore, KM believes that EPA should instead collect data on actual CO_2 emissions above the 25,000 tons CO_2-e per year threshold at facilities if and where they occur, rather than assume CO_2 that is produced from a source well is eventually emitted somewhere else.

[15] INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, CARBON DIOXIDE CAPTURE AND STORAGE 14 (Bert Metz et al. eds., 2005).
[16] 74 Fed. Reg. 16448, 16584.
[17] Reid Grigg, *Long-Term CO_2 Storage: Using Petroleum Industry Experience*, *in* 2 CARBON DIOXIDE CAPTURE FOR STORAGE IN DEEP GEOLOGIC FORMATIONS 853, 860 (D.C. Thomas & S.M. Benson, eds. 2005).

4. Recommendation: EPA should monitor emissions, not production of CO_2

Because most or all of the CO_2 produced from a natural source for purposes of EOR is geologically sequestered, the amount of CO_2 produced for this purpose does not provide EPA with useful information about actual emissions. In such situations—when the use of a product does not generally result in emissions—upstream emissions estimates based upon production are unhelpful, and do not fit within EPA's mandate from Congress to measure upstream emissions only as appropriate.

Kinder Morgan therefore suggests that EPA change the definition of the Suppliers of Carbon Dioxide source category to exclude CO_2 produced from natural sources for the purpose of EOR, except for those facilities where actual emissions to the atmosphere exceed the 25,000 ton per year reporting threshold.

If EPA is not willing to exclude CO_2 produced for use in EOR from reporting requirements, Kinder Morgan urges EPA to make it abundantly clear in the Final Rule that CO_2 reported as *produced* is not an *emission*, because most or all of this CO_2 will never be emitted to the atmosphere.

Kinder Morgan also suggests that the Proposed Rule be modified to include a *de minimis* provision for CO_2/EOR systems to avoid imposing excessive reporting costs on minor emission points, much the same as the fugitive natural gas emissions (as outlined later). The surface equipment at a CO_2/EOR operation is generally the same as that along the natural gas system, including engines, turbines, vents, flares, and fugitive components, such as flanges, pumps, valves, etc. There are thousands of fugitive component parts.

Kinder Morgan therefore suggests that EPA require CO_2 *emission* reporting with a *de minimis* exception for negligible emission sources, by making the following changes to Subpart PP:

Suggested Revisions to Proposed Subpart PP.

Subpart PP—~~Suppliers of~~ Carbon Dioxide *Systems*

§ 98.420 Definition of the source category.

(a) The carbon dioxide (CO_2) ~~supplier~~ systems source category consists of the following:

(1) Production process units that capture a CO_2 stream for purposes of supplying CO_2 for commercial applications. Capture refers to the separation and removal of CO_2 from a manufacturing process; fuel combustion source; or a waste, wastewater, or water treatment process.

(2) ~~Facilities with CO2 production wells.~~ *Enhanced oil and gas recovery (EOR) systems that consist of the following*

(i) *CO_2 production facilities with actual emissions to the atmosphere greater than 25,000 tons of CO_2 per year.*

(ii) CO_2 *transmission compression facilities with actual emissions to the atmosphere greater than 25,000 tons of CO_2 per year.*

(iii)Enhanced oil and gas recovery (EOR) facilities with actual emissions to the

atmosphere greater than 25,000 tons of CO_2 per year.

(3) Importers or exporters of bulk CO_2.

(b) This source category does not include the following:

(1) Geologic sequestration (long term storage) of CO_2.

(2) ~~Injection and subsequent production and/or processing of CO_2 for enhanced oil and gas recovery.~~ .

(32) Above ground storage of CO_2.

(43) Transportation or distribution of CO_2 via pipelines, vessels, motor carriers, or other means.

(54) ~~Purification, compression, or processing of CO_2.~~ CO_2 imported or exported in equipment.

~~(6)~~

(c) Any source listed in § 98.420(a) shall not be required to report under Subpart W.

§ 98.421 Reporting threshold.

~~Any supplier of CO_2 who~~ *You must report GHG emissions from your CO_2 systems if your facility* meets the requirements of § 98.2(a)(4) *or the facility emits 25,000 metric tons CO_2e or more per year* ~~must report GHG emissions~~.

§ 98.422 GHGs to report.

You must report the mass of carbon dioxide captured from production process units, *CO_2 and CH4 emissions in metric tons per year from EOR facilities,* ~~the mass of carbon dioxide extracted from carbon dioxide production wells,~~ and the mass of carbon dioxide imported and exported regardless of the degree of impurities in the carbon dioxide stream.

§ 98.423 Calculating GHG emissions.

(a) Facilities with production process units must calculate quarterly the total mass of carbon dioxide in a carbon dioxide stream in metric tons captured, prior to any subsequent purification, processing, or compressing, based on multiplying the mass flow by the composition data, according to Equation PP-1 of this section. Mass flow and composition data measurements are made in accordance with § 98.424.

$$CO_2 = \sum_{p=1}^{4} Q * C_{CO_2} \text{ (Eq. PP-1)}$$

Where:

CO_2 = CO_2 mass emission (metric tons per year).

C_{CO2} = Quarterly average CO_2 concentration in flow (wt. % CO_2).

Q = Quarterly mass flow rate (metric tons per quarter).

(b) ~~CO_2 production well facilities must calculate quarterly the total mass of carbon dioxide in a carbon dioxide stream from wells in metric tons, prior to any subsequent purification, processing, or compressing, based on multiplying the mass flow by the composition data, according to Equation PP-1. Mass flow and composition data measurements are made in accordance with § 98.424.~~ *EOR systems must calculate quarterly the total mass of carbon dioxide (CO_2) and methane (CH_4) emitted from the following sources:*

(1) Combustion devices (as defined in § 98.30).

(2) Vent stacks, acid gas removal vent stacks, blowdown vent stacks, and dehydrator vent stacks.

(3) Component emissions.

(c) *EOR systems must estimate emissions using either an annual direct measurement, as specified in § 98.424, or an engineering estimation method specified in this section. You may use the engineering estimation method only for sources for which a method is specified in this section.*

(1) You may use engineering estimation methods described in § 98.33 to calculate emissions from combustion devices.

(2) A combination of engineering estimation described in this section and direct measurement described in § 98.424 shall be used to calculate emissions from flare stacks. Calculate GHG volumetric fugitive and flare emissions at actual conditions using Equation PP–3 of this section:

$$Va,i = Vp * Ci * Mv * Mw \qquad \textbf{(Eq. PP-3)}$$

Where:

Va,i = Emissions of GHG $_i$ from a vent.

Vp = Volume of process gas sent to the vent determined from § 98.424(b)(C) or Eq. PP-2b

Ci = weight percent of GHG $_i$ in the process gas determined from § 98.424(b)(C).

Mv =process gas molar volume determined from § 98.424(b)(C).

Mw = process gas molecular weight determined from § 98.424(b)(C).

(3) You may use engineering estimation methods described in this section to calculate emissions from components. Emission estimates should be based on actual component counts and the emission factors listed in Table PP-1 using Equation PP–4 of this section:

$$Ex,i = Nx * Fx * Ci * t \qquad \textbf{(Eq. PP-4)}$$

Where:

Ex,i = Fugitive emissions of GHG $_i$ for "x" component type.

Nx = Number of "x" components in the process

Fx = Emission factor for component type "x" from Table PP-1

Ci = weight percent of GHG $_i$ in the process material.

t = number of hours the equipment operated in that quarter

***Table PP-1.** Oil and Gas Production Operations Fugitive Emission Factors*

Equipment	***Emission Factor (lb/hr·component)***
Valve	*0.00992*
Flange/Connector	*0.000860*
Compressor	*0.0194*
Relief Valve	*0.0194*

(d) Importers or exporters of a carbon dioxide stream must calculate quarterly the total mass of carbon dioxide imported or exported in metric tons, based on multiplying the mass flow by the composition data, according to Equation PP-1. Mass flow and composition data measurements are made in accordance with § 98.424. The quantities of CO_2 imported or exported in equipment, such as fire extinguishers, need not be calculated or reported.

§ 98.424 Monitoring and QA/QC requirements.

(a) Facilities with production process units that capture a carbon dioxide stream must measure on a quarterly basis using a mass flow meter the mass flow of the CO_2 stream captured. If production process units do not have mass flow meters installed to measure the mass flow of the CO_2 stream captured, measurements shall be based on the mass flow of gas transferred off site using a mass flow meter. In either case, sampling also must be conducted on at least a quarterly basis to determine the composition of the captured or transferred CO_2 stream.

(b) ~~Carbon dioxide production well facilities must measure on a quarterly basis the mass flow of the~~ ~~CO_2~~ ~~stream extracted using a mass flow meter. If the~~ ~~CO_2~~ ~~production wells do not have mass flow meters installed to measure the mass flow of the~~ ~~CO_2~~ ~~stream extracted, measurements shall be based on mass flow~~

~~of gas transferred off site using a mass flow meter. In either case, sampling must be conducted on at least a quarterly basis to determine the composition of the extracted or transferred carbon dioxide.~~ *EOR systems must meet the following monitoring and QA/QC requirements. Appropriate standards methods in § 98.7 for vent stack and component emissions are to be implemented as necessary.*

(1) Monitoring and QA/QC requirements in § 98.34 for combustion sources.

(2) Parameters for calculating emissions from vents:

(i) Insert flow velocity measuring device (such as hot wire anemometer, ultrasonic flowmeter, or pitot tube) directly upstream of the vent to determine the velocity of gas sent to vent.

(ii) Sample representative gas to the vent stack every quarter to evaluate the composition of GHGs present in the stream, the gas molar volume, and molecular weight. Record the average of the most recent four gas composition analyses, which shall be conducted using ASTM D1945–03 (incorporated by reference, see § 98.7).

(3) Parameters for calculating emissions from components:

(i) Determine the quantity of each component type that is active each quarter. Keep records of the times when any portion of the process is empty and cleaned of all process material as that time should be excluded from emission calculations.

(c) Importers or exporters of bulk CO_2 must measure on a quarterly basis the mass flow of the CO_2 stream imported or exported using a mass flow meter and must conduct sampling on at least a quarterly basis to determine the composition of the imported or exported CO_2 stream. If the importer of a CO_2 stream does not have mass flow meters installed to measure the mass flow of gas imported, the measurements shall be based on the mass flow of the imported CO_2 stream transferred off site or used in on-site processes, as measured by mass flow meters. If an exporter of a CO_2 stream does not have mass flow meters installed to measure the mass flow exported, the measurements shall be based on the mass flow of the CO_2 stream received for export, as measured by mass flow meters. In all cases, sampling on at least a quarterly basis also must be conducted to determine the composition of the CO_2 stream.

(d) Mass flow meter calibrations must be NIST traceable.

(e) Methods to measure the composition of the carbon dioxide captured, extracted, transferred, imported, or exported must conform to applicable chemical analytical standards. Acceptable methods include U.S. Food and Drug Administration food-grade specifications for carbon dioxide (see 21 CFR 184.1250) and ASTM standard E-1745-95 (2005).

§ 98.425 Procedures for estimating missing data.

(a) Missing quarterly monitoring data on mass flow of CO_2 streams captured, ~~extracted,~~ imported, or exported shall be substituted with the greater of the following values:

(1) Quarterly CO_2 mass flow of gas transferred off site measured during the current reporting year.

(2) Quarterly or annual average values of the monitored CO_2 mass flow from the past calendar year.

(b) Missing monitoring data on the mass flow of the CO_2 stream transferred off site shall be substituted with the quarterly or annual average values from off site transfers from the past calendar year.

(c) Missing data on composition of the CO_2 stream captured, ~~extracted,~~ *used in EOR systems,* ~~transferred,~~ imported, or exported may be substituted for with quarterly or annual average values from the past calendar year.

(d) For the procedures in § 98.423 and § 98.424, best available estimates shall be used to substitute for missing data. Where the missing data is in the nature of a lost or erroneous direct measurement, the average of the previous two direct measurements for the component shall be deemed the best available estimate. Where the missing data can be obtained from public records or widely accepted references (e.g., ambient temperature), those records or references shall be used to supply the best available estimate. In all cases, the method used to derive substitute data shall be documented by the owner or operator and reported to the Administrator.

§ 98.426 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information.

(a) Each facility with production process units ~~or CO_2 production wells~~ must report the following information:

(1) Total annual mass in metric tons and the weighted average composition of the CO_2 stream captured, or transferred in either gas, liquid, or solid forms.

(2) Annual quantities in metric tons transferred to the following end use applications by end-use, if known:

(i) Food and beverage.
(ii) Industrial and municipal water/wastewater treatment.
(iii) Metal fabrication, including welding and cutting.
(iv) Greenhouse uses for plant growth.
(v) Fumigants (e.g., grain storage) and herbicides.
(vi) Pulp and paper.
(vii) Cleaning and solvent use.
(viii) Fire fighting.
(ix) Transportation and storage of explosives.
(x) Enhanced oil and natural gas recovery.
(xi) Long-term storage (sequestration).
(xii) Research and development.

(b) CO_2 importers and exporters must report the information in paragraphs (a)(1) and (a)(2) at the corporate level.

§ 98.427 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (c) of this section.

(a) The owner or operator of a facility containing production process units must retain quarterly records of captured and transferred CO_2 streams and composition.

(b) ~~The owner or operator of a carbon dioxide production well facility must maintain quarterly records of the mass flow of the extracted and transferred CO_2 stream and composition.~~ *The owner or operator of an EOR systems must maintain records of the dates on which measurements were conducted, the results of all emission measurements, calibration reports for measurement instruments used, and inputs and outputs of calculations or emissions computer model runs used for engineering estimation of emissions.*

(c) Importers or exporters of CO_2 must retain quarterly records of the mass flow and composition of CO_2 streams imported or exported.

§ 98.428 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Consistent with these changes to Subpart PP, we also suggest these additional edits:

Sec. 98.2 Do I need to report?

(a)(4)(vi)(A) ~~All producers of carbon dioxide.~~ *Enhanced oil and gas recovery (EOR) systems with emissions greater than 25,000 tons of CO_2 per year.*

98.6 – Add Definition

Enhanced oil and gas recovery facilities are engaged in the recovery of oil or gas from a reservoir by maintaining or enhancing reservoir pressure and increasing mobility by injecting carbon dioxide. Enhanced oil and gas recovery facilities also encompass the purification, compression, and processing of recycled carbon dioxide.

CO_2 transmission compression facility means any permanent combination of compressors that moves CO_2 at increased pressure in transmission pipelines.

5. Data Reporting Requirements in § 98.426

EPA has proposed requiring facilities producing CO_2 from production wells to report CO_2 production quantities at the corporate level rather than for each individual well.[18] While Kinder Morgan does not support the reporting of CO_2 production, Kinder Morgan agrees with the proposed owner level framework because domes or groups of wells are generally under the control of a single operator.

The Proposed Rule excludes fugitive emissions from CO_2 transportation, injection and storage. EPA states that although fugitive emissions are excluded under the current rule, EPA believes that it would be useful to obtain such data in order to evaluate the effectiveness of CCS as an emission mitigation option. As described above, Kinder Morgan believes reporting requirements should focus on actual emissions above 25,000 tons per year at a facility.

The Proposed Rule also excludes emissions from geologic sequestration sites, but welcomes comment on a potential method for reporting for sequestration sites. Kinder Morgan believes that scientific research has demonstrated that these sites do not produce emissions, and therefore should not be subject to reporting requirements unless and until they actually exist and exceed the 25,000 tons per year threshold.

Kinder Morgan also maintains that there is no justifiable reason for treating CO_2 differently from other upstream energy sources, especially since CO_2 is not burned; rather, it is used as a product in EOR. For example, production of natural gas and oil are excluded on the basis that downstream reporting will provide adequate data for EPA's purposes.

6. A Primer on CO_2 Source, Pipeline, and EOR Operations

In support of our prior comments and in the event that EPA staff are not familiar with these operations, Kinder Morgan provides the following summary of CO2 source, pipeline and EOR operations. The use of CO_2 to enhance oil recovery operations helps maximize domestic oil production, thereby providing greater U.S. energy security and invaluable national security benefits. Domestic EOR operations using CO_2 currently displace approximately 250,000 b/d of imported oil and are expected to provide approximately 25% of U.S. oil production by 2030, according to the AEO 2008 forecast.

In Kinder Morgan's operations, CO_2 is produced out of wellheads and into a pipeline network called a gathering system. The gathering system gathers the CO_2 and delivers it to a central facility where water is removed and the CO_2 is compressed from a lower pressure to a pressure high enough to be efficiently transported long distances. The CO_2 is transported above the critical pressure (dense phase) so that liquid and vapor CO_2 are not co-existing.

[18] 74 Fed. Reg. 16448, 16584-85; 74 Fed. Reg. 16448, 16726 (Proposed 40 CFR § 98.426(a)).

Measurement of the CO_2 is done as the CO_2 enters the transmission system at high pressure. Orifice meters are used to measure all of the CO_2 delivered from the production fields to the transmission pipelines. According to the Pipeline Rules of Thumb Handbook, orifice measurement of CO_2 has an accuracy of +/- 0.75%. Contracts in the CO_2 Industry have a required measurement accuracy of +/- 2.0%. It is important to note that given the compressibility of CO_2, very minor inaccuracies in the temperature assumptions can cause measurement differences (positive and negative) that are commonly in these ranges and therefore it should not be assumed that meter or calculation loss/gain is necessarily an emission.

When the CO_2 reaches the EOR site, it is injected into an oil field where it mixes with the oil and facilitates extraction. This is a closed loop system described in the following steps:

> (1) CO_2 is injected under high pressure into the oil bearing formation, pushing the oil out of the field and decreasing its viscosity by mixing with it;
> (2) CO_2 and the oil are extracted from the formation via the oil wells;
> (3) the oil and CO_2 are separated and the CO_2 is dehydrated and returned to the injection wells for reinjection.

During the production, transportation, and use of CO_2 at EOR sites, the surface equipment used is virtually identical to the equipment used in natural gas distribution systems (*e.g.*, pipes, components, compressors, etc.) – and therefore any fugitive emissions can be determined. In these systems, equipment blowdown (generally for maintenance work) is responsible for a significant portion of fugitive emissions, and the quantity of emissions can be reliably calculated using engineering estimates using simple volumetric, temperature, and pressure calculations. Because leaking CO_2 is harder to detect than methane and the technologies proposed in Subpart W for detection and measurement are not appropriate or accurate for CO_2 systems, engineering estimates are more accurate, representative, and complete. Another potential source of emissions is upsets, such as those caused by power outages at the EOR site, and these emissions can also readily be determined with engineering estimates. Losses from the closed loop system are monitored closely because the CO_2 is valuable. In addition, Kinder Morgan places a high value on its operational excellence program, emphasizing asset integrity and operational performance, assuring that production wells and injection wells are routinely monitored and tested for integrity, and providing assurance that they are not sources of emissions.

Utilizing the latest technology, including profile logs, tracers, and other surveillance techniques, Kinder Morgan carefully monitors injected CO_2 in an EOR site because it, and the entrained hydrocarbons, are valuable commodities to the company.[19] Extensive

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[19] For further information on monitoring technologies, please see U.S. DEPARTMENT OF ENERGY & NATIONAL ENERGY TECHNOLOGY LABORATORY, CO2 EOR TECHNOLOGY (2006), http://www.netl.doe.gov/technologies/oil-gas/publications/brochures/CO2Brochure_Mar2006.pdf, and NATIONAL ENERGY TECHNOLOGY LABORATORY, MONITORING, VERIFICATION, AND ACCOUNTING OF CO2

geologic surveys (and periodic additional testing) provide assurance that CO_2 injected in EOR fields is geologically confined. The CO_2 injection process at an EOR site continues until oil extraction becomes uneconomical. At that point, wells are capped and the CO_2 is sequestered in the reservoir. At this post-operational stage, the project goes from being an EOR activity to serving as a carbon capture and sequestration (CCS) site.

Kinder Morgan is an industry leader in developing and employing leading edge technologies, working hand in hand with universities and their scientists. The geologic formations into which CO_2 is injected for EOR projects are by their very nature secure geologic traps that should be capable of storing CO_2 for millions of years. Evidence suggests that CO_2 injected via EOR wells in compliance with the UIC regulations does not leak into the surrounding groundwater,[20] let alone the atmosphere. The Department of Energy's National Energy Technology Laboratory, the U.S. Regional Sequestration Partnerships, State geologic surveys, the U.S. Geologic Survey, and various State Energy Commissions are all engaged in efforts to develop and deploy the infrastructure and technology needed to safely and permanently sequester CO_2 underground.

B. Subpart W—Fugitive Emissions From Oil and Natural Gas Systems

Kinder Morgan's business reach and practices place it in a unique position to offer comments on EPA's proposed Subpart W, which would require the monitoring of fugitive GHG emissions from oil and natural gas systems. Kinder Morgan estimates that it owns or operates approximately 175 facilities that would be affected by the current language of Subpart W.

Detection and control of fugitive emissions has always been an important business priority for Kinder Morgan. Kinder Morgan considers product emitted to the atmosphere to represent an economic cost to be minimized or cost effectively eliminated. Accordingly, Kinder Morgan aggressively controls fugitive emissions through systematic accounting and control of lost and unaccounted for gas. Kinder Morgan routinely surveys for fugitive emissions and has significant experience with infrared cameras and acoustic leak detection methods. Kinder Morgan's fugitive efforts include participation in EPA's Natural Gas Star Program. Kinder Morgan has also been an active participant in EPA's effort to review currently available fugitive emission factors.

Kinder Morgan is concerned that the proposed Subpart W relies on untested new methods for direct measurement of fugitive emissions from millions of trivial components of oil and natural gas systems, rather than allowing the use of emission factors, volume balance

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STORED IN DEEP GEOLOGIC FORMATIONS (2009), http://www.netl.doe.gov/technologies/carbon_seq/refshelf/MVA_Document.pdf.

[20] Rebecca Smyth et al., *Assessing Risk to Fresh Water Resources from Long Term CO_2 Injection – Laboratory and Field Studies*, 1 ENERGY PROCEDIA 1957 (2009). International Energy Agency Greenhouse Gas Petroleum Technology Research Center, Weyburn CO_2 Monitoring and Storage Project Summary Report 2000-2004 (M. Wilson & M. Monea, eds., 2004).

quantification or focused monitoring of the most critical fugitive emissions points based upon established techniques. EPA's proposed direct measurement methods would impose a high and disproportionate compliance cost on the industry, while yielding data that could be inferior (as outlined later) to that obtained through traditional methods. Kinder Morgan thus urges EPA to consider alternatives presented below and in the comments submitted on this Proposed Rule by the Interstate Natural Gas Association of America (INGAA) as better ways to satisfy the Agency's need for accurate data while targeting the key components.

The comments below:

(1) Propose potential alternative screening approaches to determine whether the reporting threshold has been met;

(2) Elaborate on the deficiencies in EPA's proposed direct measurement method;

(3) Describe an alternative measurement approach proposed by the INGAA, an alternative method using volume balance quantification, and provide alternative regulatory language; and

(4) Offer technical comments on specific aspects of Subpart W.

1. Potential Alternative Methods to Determine if the Reporting Threshold Has Been Met

Kinder Morgan strongly supports the 25,000 ton CO_2-e per year emission threshold that would generally trigger reporting obligations under the Proposed Rule. However, the proposed method for determining whether a facility meets the threshold would require facilities covered by Subpart W to make detailed, prescribed measurements regardless of actual emissions.

These measurement requirements would vastly increase the cost of Subpart W relative to EPA's estimates, and would negate the administrative and cost advantages that EPA sought to achieve by selecting a 25,000 ton CO_2-e threshold. Also, the Proposed Rule requires reevaluation of applicability with repeated measurement of the facility's emissions under Subpart W if the facility undergoes any physical or operational changes that could cause its emissions to exceed the reporting threshold.[21] Because EPA estimated the costs of the Proposed Rule on a per entity basis and then multiplied those costs only by the number of entities affected at the 25,000 ton CO_2-e threshold, EPA's cost estimate significantly underestimates the level of effort required to comply with Subpart W.

These requirements would place a severe burden on natural gas systems, especially interstate pipelines. For instance, there are on average approximately 10,000 components at a Kinder Morgan compressor station. There are around 175 compressor stations in the Kinder Morgan system. Based on the Proposed Rule, Kinder Morgan would have to conduct 1.75 million measurements annually beginning as early as January 1, 2010.

[21] 74 Fed. Reg. at 16,613 (to be codified at 40 C.F.R. § 98.2(f)).

Kinder Morgan maintains that natural gas transmission systems represent particularly appropriate candidates for a capacity-based threshold or "simplified emission calculation tool" that would allow natural gas facility operators to easily determine whether Subpart W's reporting requirements apply. Recognizing that EPA has requested comment on the need for such tools,[22] Kinder Morgan offers several suggested methods for determining whether the reporting threshold has been met. However, if EPA were to accept INGAA's alternative measurement methodology (described below and endorsed by Kinder Morgan), a capacity threshold or simplified emission calculation tool would not be required.

a. Volume Balance Approach

Under this approach, if a facility has adequate instrumentation, the amount of gas leaving the facility or combusted for energy would be subtracted from the amount of gas entering the facility. The difference would be assumed to have been lost to the atmosphere, and would serve as an estimate of fugitive emissions for purposes of determining if the reporting threshold has been met. A "margin of safety" could be incorporated to account for measurement inaccuracy. This approach could be used by facilities with sufficient measurement equipment as determined by a Professional Engineer.

b. Existing Emission Estimation Techniques

Under this approach, the most current emission factors available, either from the 1992 GRI study or EPA's existing project to update these emission factors, would be applied to the facility to estimate fugitive emissions for purposes of determining if the facility met the 25,000 ton CO_2-e threshold. Again, a margin of safety could be incorporated here to protect against the possibility of a "false negative" reporting determination.

c. Subpart W Engineering Estimates for Vented Emissions, and Existing Emission Factors to Estimate Other Fugitive Emissions

This approach would essentially be an "abbreviated" Subpart W measurement – the Subpart W engineering estimation methods would be applied to vented sources, and the remaining fugitive sources would be determined using the most current emission factors available to determine whether the reporting threshold had been met. The advantage is that engineering estimates and emission factors are more practicable than direct measurement, and the engineering estimates would only need to be used on a limited number of vented sources. However, this method would be more burdensome than a "pure" emission factor approach or a volume balance.

[22] *Id.* at 16,470 "EPA requests comment on the need for developing simplified emissions calculation tools for certain source categories to assist potential reporters in determining applicability. These simplified calculation tools would provide conservatively high emission estimates as an aid in identifying facilities that could be subject to the rule."

d. Capacity, Size, or Component Count Threshold

EPA could develop a "rule of thumb" to be applied to compressor stations below a certain level of gas throughput, a certain physical size, or certain component count (or any combination of these factors) that would be deemed to have emissions below the 25,000 ton CO_2-e threshold (similar to the heat input rate of 30 mmBTU/hr that serves as a cutoff for stationary combustion units). This method would be clear and straightforward.

e. "Best Available Data"

This approach would allow reporting entities to use their own internal estimates, models, or measurement data to estimate emissions for the purpose of determining whether reporting is triggered.

f. Self-Determination

The Proposed Rule could simply not provide a method for determining whether reporting has been triggered, allowing each firm to use its sound scientific or engineering judgment and judge for itself how much risk of erroneous non-reporting to shoulder.

2. EPA's Proposed Direct Measurement Method Would Yield Inaccurate and Inconsistent Results at High Cost

a. EPA's Proposed Direct Measurement Method Would Yield Inaccurate or Misleading Results

Once a determination has been made that the facility emissions exceed the 25,000 ton CO_2-e per year emission threshold, more accurate data is necessary. The direct measurement methods proposed by EPA would provide only an incomplete "snapshot" of fugitive emissions at any given time, and are unlikely to provide a more accurate picture of emissions than a volume balance or emission factor model. As EPA is aware, the proposed Subpart W specifies twenty-four categories of oil and natural gas fugitive sources which must undergo annual fugitive emissions detection.[23] Reporting entities would be allowed to use engineering estimation to calculate fugitive emissions for only nine of those source categories,[24] and would be required to use direct measurement for the remaining fifteen categories.[25] These measurements would have to be obtained manually by trained technicians, who would apply the highly constraining prescribed measurement methodologies to each physically accessible component.

This direct measurement requirement creates significant inaccuracies and may provide a false perception of precision in measurement of inherently variable and difficult to

[23] *Id.* at 16,676 (to be codified at 40 C.F.R. § 98.232(a)).
[24] *Id.* (to be codified at 40 C.F.R. § 98.233(b), (c)).
[25] *Id.* at 16,678-79 (to be codified at 40 C.F.R. § 98.234(c), (f)-(h)).

characterize emissions. First, as EPA noted in the Preamble and in its annual GHG inventory,[26] non-vented fugitive emissions are notoriously variable even at the level of individual components, and depend on the pressure of gas within the system, the operational status of the components, and other operating conditions. Annual direct measurement of system components cannot capture this range of variables, and is thus unlikely to give an accurate estimate of annual emissions. Second, EPA's proposed method only permits the estimation of emissions from components that can be safely accessed by a technician from the ground or from a stationary platform.[27] Because the configuration of system components varies widely among oil and natural gas facilities, EPA's method implies that a different selection of fugitive sources would be measured at each reporting facility. As a result, direct measurements are unlikely to yield a complete or consistent picture of emissions at any facility. Lastly, as EPA acknowledges in the Preamble to the Proposed Rule, direct measurement is difficult to coordinate with ongoing leak detection and repair programs at oil and natural gas facilities.[28]

b. Direct Measurement in 2010 is Not Feasible

Like other owners and operators of natural gas transmission facilities, Kinder Morgan does not possess (1) the necessary equipment to carry out leak detection and measurement on the scale required; (2) trained personnel to operate that equipment; (3) data management systems to collect, archive, interpret and transmit emissions information; or (4) quality control procedures to ensure the integrity and completeness of emissions information. Contractors competent to perform the necessary detection and measurements are also in short supply, and likely to remain so for at least one to two years. The time required to properly train contractors and personnel cannot be overlooked, especially since some of EPA's proposed measurement methods – such as the use of high-volume samplers and infrared remote fugitive emission detection instruments – can only be mastered through experience. In light of these logistical challenges, Kinder Morgan strongly recommends that EPA consider an alternative to direct measurement.

c. Direct Measurement is Costly

EPA's proposed method of direct measurement would impose significant and disproportionate costs on the oil and natural gas sector – costs that, as described above, are unjustified in light of the marginal quality of data likely to be generated. EPA's estimate of the first year labor and capital costs of the Proposed Rule indicates that the 1,375 entities expected to report under Subpart W would incur $32.5 million in compliance costs.[29] The total costs will be higher in practice, because – absent a simplified applicability determination method – all natural gas processing, transmission compression, and storage facilities would have to undertake measurement on an ongoing

[26] Inventory of U.S. GHG Emissions and Sinks: 1990-2007, at 3-41; 74 Fed. Reg. at 16,535.
[27] 74 Fed. Reg. at 16,680 (to be codified at 40 C.F.R. § 98.234(k)).
[28] *Id.* at 16,535.
[29] *Id.* at 16,597.

basis in order to determine whether their fugitive emissions exceed the reporting threshold of 25,000 tons CO_2-e per year. As EPA's estimates reveal, these costs would exceed those of any other sector affected by the Proposed Rule. Subpart W would account for 19% of the total compliance cost of the Proposed Rule and 43% of the total capital cost, even though oil and natural gas systems only represent a 3% share of nationwide downstream emissions.[30]

According to the Regulatory Impact Analysis prepared by EPA, the average first-year cost of complying with Subpart W would be approximately \$21,415 per facility, with ongoing compliance costs of approximately \$18,325 per facility.[31] On a per ton basis, reporting under Subpart W costs \$0.25 per ton the first year and \$0.22 per ton in subsequent years.[32] For Kinder Morgan, which operates 175 facilities potentially subject to Subpart W, these average costs would translate to a total compliance cost of roughly \$3.5 million per year. By any measure, then, Subpart W is a costly rule whose burdens are disproportionate to the relative importance of oil and natural gas fugitive emissions in the overall national GHG inventory. Such costs are difficult to justify when alternative approaches could provide estimates of fugitive emissions that would be of equal or greater accuracy and at lower cost.

d. EPA's Proposed Direct Measurement Methods are Untested and Overly Prescriptive

EPA's proposed direct measurement methods have not been refereed by measurement and standard-setting organizations such as ASTM, AGA or ASME, have never before been required of American oil and natural gas facilities, and to Kinder Morgan's knowledge, have never been implemented as part of a foreign regulatory program. As discussed below, EPA's protocols are not only untested, they are also overly prescriptive and create a risk of inappropriate application and imprecise measurement results.

3. *The INGAA Company-Specific Emission Factor Approach and Volume Balance Quantification Both Represent Superior Alternatives to the Proposed Direct Measurement Methods*

a. Kinder Morgan Favors an Updated Emission Factor Approach

As an alternative to EPA's approach, Kinder Morgan favors the use of up-to-date company-specific emission factors developed by annual monitoring to estimate fugitive emissions. In particular, the emission factor approach described by INGAA in its

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[30] *Id.*, Table VIII-1.

[31] Regulatory Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions Proposed Rule (GHG Reporting), 4-68, Tables 4-38 and 39 (Mar. 2009), http://www.epa.gov/climatechange/emissions/downloads/GHG_RIA.pdf.

[32] *Id.* at 5-5, Table 5-2.

comments to the Proposed Rule would address many of the shortcomings associated with direct measurement of fugitive emissions.

The basic elements of this alternative, which are also described in the comments submitted by INGAA, are as follows:

- Owners or operators of oil and natural gas facilities would focus on specific key components and sources that have been shown in numerous industry studies to account for over 80% of GHG emissions.
- Owners or operators of oil and natural gas facilities would conduct a direct measurement at a randomly selected, statistically representative sample of their facilities subject to Subpart W rather than all 24 source categories identified in the proposed 40 C.F.R. § 98.232(a).
- Operating conditions will be recorded and accounted for (*e.g.*, standby and operational).
- Data would be used to develop company-specific emission factors.
- Fugitive emission estimates for other facilities owned by the same company would be determined by applying these up-to-date company-specific emission factors.
- Each year, a new sample of facilities would be selected for direct measurement, and updated emission factors developed.

Kinder Morgan's suggested changes to Subpart W to allow for the above Updated Emission Factor Approach are attached as Appendix A.

This Updated Emission Factor Approach alternative would reduce the cost and impracticality of direct measurement by limiting the number of facilities and components that would need to be tested. At the same time, this alternative would result in updated company-specific emission factors, based on current field data that would give an accurate, representative and complete picture of fugitive emissions from the most important source categories at the company's facilities. This alternative would reflect current and evolving practices and innovative techniques within the industry and would also help address the key implementation hurdle related to the limited pool of experienced technicians and contractors available to conduct measurements.

Unlike EPA's proposed direct measurement method, emission factors in general are a well-understood and widely used method of estimating GHG emissions from oil and natural gas systems. Component-specific emission factors have long provided the basis for EPA's estimates of oil and natural gas fugitive emissions in the GHG Inventories provided to the Secretariat of the United Nations Framework Convention on Climate Change (UNFCCC).[33] The Intergovernmental Panel on Climate Change (IPCC) recognizes emission factors as a "good practice" method for estimation of fugitive

[33] Inventory of US GHG Emissions, 3-40 to 41.

emissions from the oil and natural gas sector.[34] In addition, state initiatives such as California's mandatory GHG reporting program[35] recognize the use of emission factors to calculate GHG fugitive emissions from facilities such as oil refineries.

In the Preamble to the Proposed Rule[36] and the accompanying Technical Support Document for oil and natural gas systems,[37] EPA rejects the use of emission factors because the most recent available emission factors for oil and natural gas facilities date from a 1992 study by the Gas Research Institute (GRI) and EPA. EPA correctly points out that the GRI study was based on limited field data, and reported emission factors for equipment models that are no longer in use. INGAA's alternative addresses this criticism by providing a way to update company-specific emission factors through intensive monitoring of major emitting components at randomly sampled facilities. The shortcomings of the GRI emission factors do not justify EPA's adoption of an untested, costly, and inappropriately applied methodology for calculating fugitive emissions.

b. Kinder Morgan Also Endorses Volume Balances as an Alternative Estimation Method, Where Feasible

As a second alternative to the proposed direct measurement approach, Kinder Morgan urges EPA to provide the option of using a volume balance to estimate fugitive emissions at smaller facilities. As with the use of volume balance for purposes of determining applicability, under this approach if a facility is sufficiently instrumented, the amount of gas leaving the facility or combusted for energy would be subtracted from the amount of gas entering the facility. The difference would be assumed to have been lost to the atmosphere, and would serve as a calculation of fugitive emissions.

The volume balance approach carries many of the advantages associated with emission factor models. Rather than provide a "snapshot" of emission patterns at an arbitrary point in time, a volume balance provides a continuous profile of fugitive emissions throughout the monitoring year under a variety of operating conditions. Thus, a volume balance is more capable of accounting for the variability of fugitive emissions than EPA's proposed direct measurement methods. In addition, a volume balance is capable of capturing emissions from components that are currently omitted from the proposed Subpart W due to practical or physical constraints – such as emissions from components that are not safely within the reach of an instrument operator.

Volume balances are also attractive because they are a practical use of readily available data. Thus, for those facilities with sufficient instrumentation, the volume balance approach would alleviate the implementation issues discussed earlier in these comments.

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[34] 2006 IPCC Guidelines for National Greenhouse Gas Inventories, 4.46, http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_4_Ch4_Fugitive_Emissions.pdf.

[35] California Air Resources Board, Instructional Guidance for Mandatory GHG Emissions Reporting 10-27 to 10-29 (2008), *available at* http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-guid/10_PetroRefine.pdf.

[36] 74 Fed. Reg. at 16,535.

[37] Fugitive Emissions Reporting From the Petroleum and Natural Gas Industry, Background Technical Support Document at 40.

Kinder Morgan understands that EPA has concerns relating to the uncertainty of meter readings and the relative volume of fugitives compared to total pipeline throughput. Kinder Morgan believes that these problems can be minimized by restricting the use of volume balance approaches to smaller facilities using metering technologies deemed to be adequate by a professional engineer (PE) specializing in measurement.

4. Technical Comments on Subpart W

Kinder Morgan also offers these additional technical comments on specific aspects of Subpart W. In general, Kinder Morgan believes that measurement methods should be flexible and draw on engineering judgment. EPA's approach to prescribing measurement methods errs by (1) drawing on measurement methods that have not been refereed or approved by standard-setting organizations; (2) enshrining those methods in the text of the rule itself, thereby impeding the use of innovative measurement methods that may arise; and (3) prescribing a rigid hierarchy of methods for every system component, rather than relying on the judgment of measurement engineers to determine the most appropriate method.

a. EPA Should Use Consensus or Refereed Measurement Protocols

Kinder Morgan is concerned with EPA's proposed detection and measurement[38] protocols for each of the source categories listed in the proposed 40 C.F.R. § 98.232(a), and publishing those protocols directly in the Proposed Rule. These protocols have not benefited from the rigorous testing and expert review required by major standard-setting organizations such as ASTM, ASME, and the American Gas Association (AGA). As a result, the Proposed Rule creates a risk that the various testing methods in the proposed 40 C.F.R. § 98.234 will not give accurate results or be applied consistently. Indeed, many of the protocols in the Proposed Rule are not adequately specified and are likely to generate unreliable data.[39] EPA's approach will also hinder the adoption of more advanced measurement techniques, because a new rulemaking will be required if EPA ever chooses to revise the protocols in the Proposed Rule. Indeed, § 98.234 of the

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[38] In our proposed revisions to Subpart W, we have standardized the use of the terms "monitoring," "measurement" and "detection." Using these words interchangeably in multiple places could cause ambiguity in the rule.

[39] To list a few examples, the infrared detection protocol requires the operator to inspect the emissions source from "multiple angles" without "visual obstructions" and in "favorable conditions," without elaborating on the correct procedure for doing so. 74 Fed. Reg. at 16,679 (to be codified at 40 C.F.R. § 98.234(d)(2), (4)). The high volume sampler measurement protocol requires that the equipment be operated by a "trained technician" who is "conversant" with sampling techniques, but does not specify what operating procedures and measurement methodologies the technician would be expected to know. In addition, the protocol directs the technician to use "anti-static wraps or other aids" to if the high volume sampler is not able to completely capture all emissions from the source, but does not specify how such leakage is to be detected or how these aids are to be used. *Id.* (to be codified at 40 C.F.R. § 98.234(f)). Similarly, the calibrated bag protocol states that the operator must "obtain consistent results" when measuring the amount of time required to fill the bag, but does not provide a benchmark for consistency. *Id.* (to be codified at 40 C.F.R. § 98.234(g)(5)).

Proposed Rule omits many prominent techniques and approaches for leak detection, such as acoustic or ultrasonic devices and soap bubble solution.

A better approach would be for EPA to engage industry leaders and at least one of the major standard-setting organizations to develop consensus protocols for detection and direct measurement of fugitive emissions. The agency has wisely chosen to defer to such consensus standards in other sections of the Proposed Rule, and should seek to do the same in Subpart W. Consensus standards would provide assurance that the direct measurement protocols required in the Rule reflect the state of the art and are being applied in a consistent matter that is uniformly understood within the industry. If necessary, EPA should defer the effective date of the Final Rule to allow for the development of such standards.

These methods would not have to be written directly into the final Rule, but could instead be provided in a guidance document that could be easily revised in step with field experience and advances in measurement technology. Kinder Morgan is willing to be a constructive partner in developing such standards.

b. EPA Should Allow Operators to Exercise Judgment as to Measurement Methods and QA/QC Procedures

Although EPA should defer to consensus standards that govern the proper execution of fugitive detection and measurement techniques, Kinder Morgan also believes that the Proposed Rule should provide more flexibility as to the choice of technique for any given component. Currently, the proposed 40 C.F.R. § 98.234 calls on instrument operators to preferentially use high volume samplers to measure fugitive emissions, with other methods – such as anemometers, calibrated bags, or flow meters – to be used only as a second resort.[40] This rigid hierarchy of techniques ignores the considerable variations in component design and location from facility to facility. In our experience, no one instrument or technique is clearly superior in all situations. Kinder Morgan therefore recommends that the Final Rule permit technicians to use judgment as to which measurement instrument is most appropriate for the component at hand.

In addition, the proposed rule specifies methods to be used in §98.7 or vendor defined calibration procedures for quality assurance and quality control. Within the natural gas industry, flow measurement quality control and quality assurance procedures have been developed. Industry standards are in place for ensuring metering QA/QC. The proposed rule should be revised to allow the use of accepted operator-defined practices for fuel flow meter calibration and other QA/QC measures.

c. Flaring Emissions

Emissions from flares are not traditionally considered "fugitive" emissions and are more appropriately characterized as emissions from a "stationary fuel combustion source,"

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[40] *Id.* at 16,678-79 (to be codified at 40 C.F.R. § 98.234(c)).

analogous to the removal of a waste substance. Therefore, Kinder Morgan recommends that EPA amend § 98.30(a) in Subpart C to expressly include flares as stationary combustion devices. Similarly, Kinder Morgan's proposed revisions to Subparts W and PP delete references to flares to avoid inconsistency, confusion and double reporting.

> *Suggested change to Subpart C regarding flaring.*
>
> 40 C.F.R. § 98.30(a). Stationary fuel combustion sources…removing combustible matter. Stationary fuel combustion sources include, but are not limited to, boilers, combustion turbines, engines, incinerators, *flares*, and process heaters.

Should EPA choose to keep flares under Subpart W, the agency should amend § 98.234 to require annual sampling and composition analysis of gas sent to flare stacks. The Proposed Rule currently requires quarterly sampling, which is excessive given the extremely stable composition of pipeline-quality gas.[41] Indeed, Kinder Morgan's current policies call for gas composition analysis only once every five years. In addition, Kinder Morgan recommends that methods for sampling not be specified in the Final Rule, and that EPA instead accept approved industry practices for determining gas composition and volume of gas sent to the flare.

> *Suggested change to Subpart W regarding flaring.*
>
> 40 C.F.R. § 98.234(j)(1)(iii). Sample representative gas to the flare stack or compressor wet seal degassing vent ~~every quarter~~ *once during the year* to evaluate the composition of GHGs present in the stream.

d. Engineering Estimation Should Be Permitted for Storage Tanks

EPA's prescribed method for estimating fugitive emissions from storage tanks[42] is likely to be impractical for many operators of natural gas facilities. Kinder Morgan, for example, owns more than 1000 storage tanks, many of which are have a capacity of less than 90 barrels and are not even filled and emptied each year (in other words, these tanks are small and have low throughput). Because these tanks are not likely to be a significant source of fugitive emissions, EPA should either exclude them from the monitoring requirement, or allow reporting entities to use a pure engineering estimation. Such approaches are permitted for the reporting of emissions from storage tanks by EPA and every state for HAP emission reporting. Exclusion of modeling approaches would be especially appropriate for smaller storage tanks.

Kinder Morgan recommends including a tier based approach for monitoring and reporting tank emissions based on tank capacity. Condensate and produced water storage

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[41] *Id.* at 16,680 (to be codified at 40 C.F.R. § 98.234(j)(1)). By contrast, CO_2 produced at natural domes exhibits considerable variability on composition. Hence, Kinder Morgan's proposed revisions to Subpart PP, discussed above, would require quarterly sampling and analysis of CO_2 used in EOR operations.

[42] *Id.* at 16,680 (to be codified at 40 C.F.R. § 98.234(j)(2)).

tanks used in the natural gas sector are typically small in capacity (210 barrels or less). EPA rules such as NSPS Subpart Kb regulate tanks greater than a certain capacity (75 cubic meters, or approximately 470 barrels). Also, many state air quality programs do not currently permit tanks due to capacity. Kinder Morgan recommends using 90 barrels or less as a threshold for exclusion from Subpart W measurement and reporting. This size threshold is more conservative than EPA's NSPS standard, but would still eliminate many storage tanks that are truly *de minimis* in terms of fugitive emissions. For larger tanks with a capacity exceeding 90 barrels, Kinder Morgan recommends a tiered monitoring and reporting approach. Condensate and produced water tanks between 90 barrels and 210 barrels should require a "Tier 1" approach calling for simulation software such as EPA Tanks and E&P Tanks. Tanks over 210 barrels should utilize a Tier 2 approach including direct measurement as outlined in Kinder Morgan's proposed changes, which are attached as Appendix A.

e. Only Major Emitting Components Should be Monitored

Kinder Morgan supports the general approach adopted in the proposed 40 C.F.R. § 98.232(a) of specifying particular components whose fugitive emissions must be measured. As EPA is aware, an oil or natural gas facility can easily contain 20,000 to 30,000 sources of fugitive emissions.[43] Therefore, focusing measurement efforts on particular components of greatest interest is essential for implementing a cost-effective and timely reporting program. However, the list in section 98.232(a) contains several "catchall" categories that fail to provide needed focus. For example, items (9), (10), (21), and (24) imply that reporting entities need to measure emissions from "all components" of compressor stations, storage stations, and LNG import/export and storage facilities, no matter how small or numerous those components might be. EPA should eliminate these "catchall" categories, and ensure that the list in section 98.232(a) provides much-needed guidance as to which components within a given facility must be monitored.

In addition, the list in section 98.232(a) contains a number of specific components which, based on industry experience with leak detection and repair (LDAR) programs and component-specific emission factors, are negligible sources of fugitive emissions. Elsewhere in the Proposed Rule, EPA has recognized that small and numerous sources of GHG emissions are appropriate to exclude from reporting or direct measurement requirements, because inclusion of such sources would increase administrative complexity and cost without substantially improving EPA's understanding of GHG emission patterns.[44] A similar principle should apply to the monitoring of fugitive

[43] Kinder Morgan's own inventory of fourteen compressor stations located in Illinois found an average of 11,348 potentially measurable components per facility. One facility was found to have nearly 50,000 such components.

[44] *See* 74 Fed. Reg. at 16,473 (Stating that "EPA recognizes the potential burden of reporting emissions for smaller sources" and noting that the Proposed Rule provides simplified emission estimate procedures for smaller sources, where appropriate); *Id.* at 16,469 ("In order to ensure that the reporting of GHG emissions from all source categories within a facility's boundaries is not unduly burdensome, EPA has proposed flexibility in two ways. First . . . EPA has proposed methods only for source categories that typically

emissions within a facility. Limiting the list of components in section 98.232(a) to those known to be typically responsible for the greatest proportion of fugitive emissions would greatly reduce the burden of reporting, while capturing much of the emissions information EPA seeks under the Proposed Rule. Kinder Morgan recommends that monitoring be required only for the following component categories, which are typically responsible for 80 % of compressor station emissions:

Transmission and Storage Key Components and Sources	
KEY COMPONENT / SOURCE	**EMISSION MONITORING METHOD**
LEAKING EQUIPMENT COMPONENTS	
Compressor Unit Block Valve Vent	Direct Measurement
Compressor Unit Blowdown Valve Vent	Direct Measurement
Compressor Unit Pressure Relief Valve Vent	Direct Measurement
Reciprocating Compressor Seals	Direct Measurement
Centrifugal Compressor Seals	Direct Measurement
VENTED SOURCES	
Compressor Unit Blowdown Events	Engineering Estimation
Station Blowdown Events	Engineering Estimation
Engine Starter Events	Engineering Estimation

f. A Tiered Approach Would Be Appropriate For This Sector

In conjunction with, or as an alternative to, the narrowed list of component categories, the EPA should consider designating a minimum size of component within each category that would trigger a monitoring obligation. Such a tiered threshold would further assist regulatory entities in focusing their monitoring efforts on those components that are most responsible for fugitive emissions from oil and natural gas systems.

g. Missing Data Procedures Should Be Supplied

The proposed § 98.235 indicates that measurements must be repeated if test results are lost or in error. Although EPA understandably wishes to minimize instances of missing data, the large number of direct measurements that Subpart W would require would inevitably create a significant possibility of human or instrument error. Moreover, in many cases, reasonable methods for substituting missing data exist: ambient temperatures, for example, can be estimated using public records, and component-specific measurements can be estimated by averaging previous measurements. Given these facts, it is unreasonable for EPA to completely foreclose any recourse to best available estimates when missing data occurs. Kinder Morgan suggests the following language to allow reasonable use of estimation methods as a substitute for missing data:

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contribute a relatively significant amount to a facility's total GHG emissions . . . . Second, for small facilities, EPA has proposed simplified emission estimation methods where feasible.")

Suggested change regarding missing data.

§ 98.235. Procedures for estimating missing data.

~~There are no missing data procedures for this source category. A complete record of all measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions measurements, you must repeat the measurement activity for those sources until a valid measurement is obtained.~~

For the procedures in § 98.233 and § 98.234, best available estimates shall be used to substitute for missing data. Where the missing data is in the nature of a lost or erroneous direct measurement, the average of the previous two direct measurements for the component shall be deemed the best available estimate. Where the missing data can be obtained from public records or widely accepted references (e.g., ambient temperature), those records or references shall be used to supply the best available estimate. In all cases, the method used to derive substitute data shall be documented by the owner or operator and reported to the Administrator.

h. Additional Consensus Standards Used in the Gas Industry

The proposed 40 C.F.R. § 98.7 omits many measurement standards that are commonly used and widely accepted in the natural gas industry. Kinder Morgan urges EPA to reference these standards where appropriate.

- AGA Report No. 3 – Orifice Metering of Natural Gas Part 1: General Equations & Uncertainty Guidelines (1990)
- AGA Report No. 3 – Orifice Metering of Natural Gas Part 2: Specification and Installation Requirements (2000)
- AGA Report No. 3 – Orifice Metering of Natural Gas Part 3: Natural Gas Applications (1992)
- AGA Report No. 3 – Orifice Metering of Natural Gas Part 4: Background, Development Implementation Procedure (1992)
- AGA Report No. 5 – Natural Gas Energy Measurement
- AGA Report No. 7 – Measurement of Natural Gas by Turbine Meter (2006)
- AGA Report No. 8 – Compressibility Factor of Natural Gas and Related Hydrocarbon Gases (1994)
- AGA Report No. 9 – Measurement of Gas by Multipath Ultrasonic Meters (2007)
- AGA Report No. 10 – Speed of Sound in Natural Gas and Other Related Hydrocarbon Gases American Gas Association
- AGA Report No. 11 – Measurement of Natural Gas by Coriolis Meter (2003)
- ANSI B109.3 – Rotary-Type Gas Displacement Meters (2000)
- GPA 2145-09 – Table of Physical Properties for Hydrocarbons and Other Compounds of Interest to the Natural Gas Industry
- GPA 2172-09 – Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer

- GPA 2261-00 – Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography
- API 21.1 – Manual of Petroleum Measurement Standards Chapter 21 - Flow Measurement Using Electronic Metering Systems Section 1 - Electronic Gas Measurement[45]

In addition, Kinder Morgan recommends that a streamlined process for approving additional fuel rate measurement methods as they become available for use be incorporated in into the Final Rule.

i. Recommended Definition Amendments Pertinent to Subpart W

Kinder Morgan's alternative Subpart W rule language is attached as Appendix A. In the event that EPA does not accept this alternative approach, Kinder Morgan recommends the following additions or changes to definitions relevant to Subpart W.

The definition in Section 98.6 of "Natural gas driven pneumatic valve bleed devices fugitive emissions" should be changed to "Continuous Natural gas driven pneumatic valve bleed devices fugitive emissions" and amended follows:

Continuous Natural gas driven pneumatic valve bleed devices fugitive emissions means the continuous ~~or intermittent~~ release of natural gas from automatic process control loops including the natural gas pressure signal flowing from a process measurement instrument (e.g. liquid level, pressure, temperature) to a process control instrument which activates a process control valve actuator.

Kinder Morgan installs non-continuous natural gas driven pneumatic bleed devices where appropriate to minimize gas loss. Emissions from non-continuous devices are minimal because they only bleed during certain operational changes which typically occur rarely. Additionally, it is difficult to determine the amount of time a non-continuous bleed device operates.

In addition to this change regarding pneumatic valve bleed devices, Kinder Morgan recommends that the Final Rule include the following change in Section 98.233(d)(3)(i)(B):

(B) Maintain a log of the number of times the pneumatic device was actuated throughout the reporting period *or estimate the number of times the device was actuated.*

The definition in Section 98.6 of "Storage tank" should be changed as follows:
Storage tank means other vessel that is designed to contain an accumulation of ~~crude oil~~, *organic hydrocarbon* condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of non-earthen materials (*e.g.*, wood, concrete, steel,

[45] The Proposed Rule references an "ASTM Standard E-1745-95" which, to Kinder Morgan's knowledge, does not in fact exist. This reference should be omitted or corrected as necessary in the Final Rule.

plastic) that provide structural support. *Vessels containing lube oil for onsite usage are excluded from the definition of storage tanks.*

The term "Direct measurement device" should be added as follows:
Direct measurement device means any accepted candidate methods with the capability to capture and measure fugitive emissions. Accepted candidate methods include but are not limited to acoustic devices, high flow sampler, calibrated bags, hot wire anemometers, pitot tubes, anubars, turbine meters, orifice plates, etc.

C. Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids

Before natural gas can be transported it must be purified. The natural gas liquids (NGL) removed from natural gas, which include ethane, propane, butane, isobutane, and natural gasoline, are sold separately and have a variety of different uses including enhancing oil recovery in oil wells, providing raw materials for oil refineries or petrochemical plants, and as sources of energy. Once NGLs have been removed from the natural gas stream, they must be broken down into their base components to be useful. That is, the mixed stream of different NGLs must be separated out. The process used to accomplish this task is called fractionation. Fractionation is the separation of a mixture of hydrocarbons into individual products based on difference in boiling point and/or relative solubility. Fractionation occurs through distillation, the process of separating materials by successively heating to vaporize a portion and then cooling to liquefy a part of the vapor. According to the most recent industry survey, there are 308 processing facilities in the U.S. that exclusively produce "raw mix" or bulk NGLs for further separation, with a total production of approximately 314 million barrels per year (47% of U.S. NGL production).[46]

Kinder Morgan is engaged in transporting and processing NGLs. Kinder Morgan transports NGLs over two pipelines. First, our Cochin pipeline system consists of an approximately 1,900-mile pipeline operating between Fort Saskatchewan, Alberta and Windsor, Ontario. Even though the pipeline begins and ends in Canada, along the way it traverses through and has terminals within the United States. Second, our Cypress pipeline is also an interstate carrier of NGLs originating at storage facilities in Mont Belvieu, Texas and extending 104 miles east to a major petrochemical producer in the Lake Charles, Louisiana area. Kinder Morgan owns several plants that process NGLs. As explained in more detail below, some of these NGLs are fractionated into individual products (*e.g.*, propane, butane, ethane, and isobutane) and sold in local markets, while other "raw mix" or bulk NGLs are processed and sent to other fractionators for further separation.

The Proposed Rule's treatment of natural gas liquids (NGL) suppliers would dramatically overstate GHG emissions attributable to NGL consumption. EPA's approach to NGLs produced by domestic processors would also "double-count" the upstream emissions attributable to these products. As Kinder Morgan understands the Proposed Rule,

[46] Gas Processing Survey, Oil & Gas Journal, June 23, 2008.

Subpart NN would require domestic natural gas processors to specifically report emissions associated with the complete combustion of certain individual NGL products (propane, butane, ethane, and isobutane) as well as "bulk NGLs" (referring to undifferentiated mixtures of NGLs, excluding lease condensate). However, as in the petroleum products industry, domestic natural gas processors often produce semi-refined, *intermediate* NGL products (including bulk NGLs and "raw mix") that are delivered to other processors and fractionators for further processing and separation.

The magnitude of the double-counting that would occur under the proposed Subpart NN is significant. As described above, there are 308 processing facilities in the U.S. that exclusively produce "raw mix" or bulk NGLs for further separation.[47] These intermediate products have no market or use other than further separation. Rather, this product is sold to fractionators who separate the product into its constituent parts. It is these fractionators, rather than the producers of the raw make or Y-grade, bulk NGLs who handle all the final commercial deliveries of NGL products and there are significantly fewer fractionators than NGL producers

Without a change to the reporting of intermediate products, the Proposed Rule would count emissions from the same unit of production multiple times as it proceeds down the natural gas processing chain. Kinder Morgan urges EPA to avoid this unnecessary multiple-counting by eliminating reporting of bulk NGLs, and placing the reporting requirement on fractionators. Fractionators separate NGLs into their individual components, and are in the best position to know which NGLs will ultimately be combusted based on physical deliveries to their customers. Within the NGL supply chain, fractionators are the facilities most comparable to refiners (which bear the obligation of reporting upstream petroleum product emissions under the proposed Subpart MM) and LDCs (which bear the obligation of reporting upstream natural gas emissions under the proposed Subpart NN). There are approximately 144 fractionators in the U.S.[48] This smaller number of fractionators compared to NGL producers also makes the reporting requirement less burdensome.

Kinder Morgan also understands that the Proposed Rule would require domestic natural gas processing facilities to report CO_2 emissions that would result from complete combustion of all NGLs produced at those facilities.[49] In addition, importers of petroleum products would be required to report CO_2 emissions that would result from complete combustion of all NGLs introduced to the United States.[50] However, as EPA recognizes in its TSD for Natural Gas Suppliers, an overwhelming proportion of NGLs produced or imported in the United States are not used as fuels – indeed, data from the American Petroleum Institute indicates that from 2000 to 2007, between 69.2% and

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[47] Gas Processing Survey, Oil & Gas Journal, June 23, 2008.
[48] Gas Processing Survey, Oil & Gas Journal, June 23, 2008.
[49] 74 Fed. Reg. at 16,720 (to be codified at 40 C.F.R. § 98.402(a)).
[50] *Id.* at 16,715 (to be codified at 40 C.F.R. § 98.390(c)).

75.3% of all NGLs sold each year were used for *non*-fuel purposes.[51] As EPA also recognizes, processors are usually not in a position to know the ultimate use or disposition of the NGLs they supply. The same is generally true of importers.

Given these facts, Kinder Morgan urges EPA to reconsider the "upstream" reporting approach it has adopted for NGLs, and instead place the reporting requirement on major entities which purchase or distribute NGLs for known, *combustive* end-uses. Fractionators are the most appropriate domestic reporting entity for this purpose, since fractionators often know the end-use associated with their products.[52] Such an approach would provide EPA with a more accurate understanding of the contribution that NGLs make to nationwide GHG emissions. These combustion NGLs would likely also be reported by the combustor.

Lastly, although Kinder Morgan understands that the Proposed Rule does not incorporate GHG mitigation requirements, Kinder Morgan is also concerned that the structure of Subparts MM and NN may influence future cap-and-trade or carbon tax programs. Natural gas processors and fractionators do not customarily hold title to all of the products they process. Rather, these facilities commonly provide a processing service for other companies that do own the products. As a result, processors and fractionators are bound by contractual obligations that would limit their ability to pass on the costs of allowances or carbon taxes to their customers. Thus, any future compliance obligation relating to upstream emissions from NGLs or natural gas should fall on the actual owners of these fossil fuels, rather than on facilities that merely process the fuels for a fee.

Kinder Morgan's recommended revisions to Subpart NN and to the Proposed Rule's definition of NGLs include natural gasoline (as well as excluding bulk NGLs). Natural gasoline consists of heavier fractions of natural gas liquid, about 38% of which ultimately sees use as a chemical feedstock and the rest of which is sold to petroleum refineries for further blending with gasoline. Although reporting of natural gasoline production may introduce some double-counting (since natural gasoline would presumably be counted as an input by refiners reporting under Subpart MM), Kinder Morgan has included natural gasoline in the list of fractionated NGLs for consistency with how commercial NGLs are classified.

Suggested change regarding NGLs.

40 C.F.R. § 98.402(a) Natural gas processing plants *that fractionate NGLs* must report the CO_2 emissions that would result from the complete combustion or oxidation of the annual quantity of propane, butane, ethane, isobutane, and ~~bulk NGLs~~ natural gasoline sold or delivered for use off site. *Fractionated NGLs that are still subject to further processing prior to use (e.g., refinery), or are for a non-combustion end-use may be excluded.*

[51] Environmental Protection Agency, Technical Support Document: the Natural Gas Distribution and Natural Gas Processing Sectors at 11 (2009).

[52] For example, ethane produced by fractionators is usually delivered as an input for the production of plastics, where it does not result in GHG emissions to the atmosphere.

40 CFR § 98.6 – Definitions

Natural gasoline means a mixture consisting mostly of pentanes and heavier hydrocarbons, extracted from natural gas, that meets vapor pressure, end-point, and other specifications for natural gasoline set by the Gas Processors Association.

D. Subpart MM – Suppliers of Petroleum Products

EPA should clarify the scope of the Subpart MM reporting requirements for importers and exporters of petroleum products. Kinder Morgan has identified three specific points of confusion in the scope of Subpart MM. First, the Preamble to the Proposed Rule clearly states that blenders of petroleum products would not be required to report upstream emissions associated with their production.[53] Kinder Morgan agrees with EPA's rationale for excluding blenders, terminals, pipelines, and transmix processors from reporting. However, the definitions of "importer" and "exporter" in the proposed 40 C.F.R. § 98.390 expressly include blenders. Kinder Morgan requests that EPA clearly revise the final Rule to exclude blenders from the Subpart MM reporting requirements.

In addition, the Preamble to the Proposed Rule and the proposed 40 C.F.R. § 98.390 state that only importers and exporters of petroleum products need report under Subpart MM. However, Subpart MM also requires covered importers and exporters to report imports and exports of natural gas-derived NGL products. It is not clear whether this reporting requirement only applies to importers and exporters engaged in the petroleum product supply chain, as section 98.390 implies, or whether *any* entity that imports and exports NGLs would be required to report. Since shippers using Kinder Morgan's international pipelines may be subject to this provision, Kinder Morgan requests that the final rule clarify this point.

Lastly, Kinder Morgan's review of the proposed 40 C.F.R. § 98.6 concluded that the definitions of "importer" and "exporter" would only encompass entities that own or hold title to imported and exported products. Kinder Morgan requests that EPA confirm in the final Rule that entities that merely transport products, without holding title or paying customs duties, do not have a reporting obligation. In addition, the proposed definition of an "importer" closely parallels the definition provided in U.S. Customs and Border Protection (CBP) regulations. In order to avoid confusion as to who must report under the exporter/importer provisions of the Proposed Rule, Kinder Morgan recommends that EPA clarify the Rule by more explicitly linking its definition to entities that are already considered importers of record or exporters of record (Principal Parties in Interest) in CBP regulations. If an entity is not currently regarded as an importer or exporter of record for purposes of U.S. Customs, then it can be confident it will have no further obligations under the Reporting Rule. Similarly, entities that already deal with Customs would know for certain that they were also subject to the Rule.

[53] 74 Fed. Reg. at 16,569-70.

Suggested change regarding importer/exporter and blender.

40 C.F.R. § 98.6. *Importer shall have the same meaning provided in 19 C.F.R. § 101.1, and* means ~~any person, company, or organization of record that for any reason brings a product into the United States from a foreign country. An importer includes~~ the person, ~~company, or organization~~ primarily liable for the payment of any duties on the merchandise, or an authorized agent acting on his behalf. *An importer excludes transportation, transfer, blending, and terminal service providers, such as railroads, barge companies, or terminals that do not hold title to the product or otherwise have any ownership of the product.*

The term also includes, as appropriate ~~The importer may be~~:

(1) The consignee, *or*
(2) The importer of record, *or*
(3) The actual owner *of the merchandise, if an actual owner's declaration and superseding bond has been filed in accordance with 19 C.F.R. § 141.20; or*
(4) The transferee *of the merchandise*, if the right to *with*draw merchandise in a bonded warehouse has been transferred *in accordance with subpart C of part 144 of 19 C.F.R.*.

40 C.F.R. § 98.6. *Exporter shall have the same meaning provided in 15 C.F.R. § 30.4(a)(1), and means the person in the United States that receives the primary benefit, monetary or otherwise, of the transaction. Generally that person is the U.S. seller, manufacturer, order party, or foreign entity. An exporter excludes transportation, transfer, blending, and terminal service providers , such as railroads, barge companies, or terminals that do not hold title to the product or otherwise have any ownership of the product.* ~~Exporter means any person, company or organization of record that contracts to transfer a product from the United States to another country or that transfers products to an affiliate in another country, excluding transfers to United States military bases and ships for on-board use.~~

40 C.F.R. § 98.390. This source category consists of petroleum refineries and importers and exporters of petroleum products. … (c) Importer has the same meaning given in § 98.6 and includes any ~~blender or~~ refiner of refined or semi-refined petroleum products. (d) Exporter has the same meaning given in § 98.6 and includes any ~~blender or~~ refiner of refined or semi-refined petroleum products.

In general, the requirements for NGL reporting would be easier to comprehend if they were gathered together under one subpart, rather than duplicated within Subparts MM and NN. Doing so would minimize the risk of confusion and inadvertent regulatory violations.

Suggested clarification regarding NGLs in Subparts MM and NN.

Subpart MM – delete all references to reporting of NGLs in both the text and tables, except for NGLs used as a feedstock by domestic petroleum refiners. Remove Table MM-2.
Subpart NN – Revise Definition of Source Category:

40 C.F.R. § 98.400 This supplier category consists of natural gas processing plants, ~~and~~ local natural gas distribution companies, and importers and exporters of natural gas liquids (NGLs)…. [insert after paragraph (b)] (c) Importers and exporters are defined at 40 C.F.R. § 98.6. A blender shall be considered an importer or exporter if it otherwise satisfies the aforementioned definition.

E. Subpart KK—Supplies of Coal

1. Section 98.370 Definition of the source category

Under the Proposed Rule, coal suppliers would be required to report the GHG emissions associated with the coal they supply. Coal suppliers include coal mines, defined as: "any active U.S. coal mine engaged in the production of coal within the U.S. during the calendar year regardless of the rank of coal produced, e.g., bituminous, sub-bituminous, lignite, anthracite. *Any coal mine categorized as an active coal mine by MSHA is included*."[54]

The Federal Mine Safety and Health Act of 1977 (MSHA) uses a very broad definition of coal mine that in some cases has incorporated coal terminals that are off-site from coal mining locations. According to the Preamble of the Proposed Rule, however, EPA does not intend to require coal preparation plants, which Kinder Morgan presumes includes coal terminals, to report the emissions associated with the coal these facilities handle. Kinder Morgan therefore requests that EPA clarify the definition of "coal mine" used in the Proposed Rule by explicitly excluding coal terminals engaged in post-coal mining activities from the definition of coal mine.

Kinder Morgan operates approximately fifteen coal terminals around the United States. At these terminals coal comes in from mines or international shipments and may be dried, blended, or stored before being loaded for shipping to the final customer. Kinder Morgan does not take ownership of the coal at these facilities, but simply serves as an intermediary transport hub between the coal origin and the final consumer.

[54] 74 Fed. Reg. at 16,711 (to be codified at 40 C.F.R. § 98.370(b)) (emphasis added).

2. *Background on MSHA jurisdiction over coal terminals and implications for the Proposed Rule*

The MSHA has jurisdiction over coal mines as defined by the Federal Mine Safety and Health Act of 1977 (Mine Act), 30 U.S.C. § 802(h)(1), which includes "facilities . . . used in . . . the work of preparing coal" as coal mines. "Work of preparing the coal" is defined broadly as "the breaking, crushing, sizing, cleaning, washing, drying, mixing, storing, and loading of bituminous coal, lignite, or anthracite, and such other work of preparing such coal as is usually done by the operator of the coal mine."[55] Relying on the Mine Act's definition of a coal mine as a facility that mixes, stores, and loads coal, the Federal Mine Safety and Health Review Commission and federal courts have determined that some coal terminals qualify as "coal mines" subject to MSHA jurisdiction.[56] Therefore by referencing coal mines categorized as active mines by the MSHA, the definition of a coal mine used in the Proposed Rule would inadvertently require some coal terminals to report the greenhouse gas emissions associated with the coal moving through the terminals.

However, the Preamble of the Proposed Rule clearly states that EPA does not intend for "coal preparation plants" located offsite from mines to be required to report the emissions associated with the coal processed by these facilities. EPA explains, "We are not requiring offsite coal preparation plants to report under this subpart (KK) because the potential CO_2 emissions from coal supplied by these facilities are already accounted for by reported data from coal mines, coal importers, and waste coal reclaimers."[57]

Kinder Morgan agrees that coal terminals and other post-coal mining activities that do not involve holding title to the coal and are merely providing services such as transportation, transfer and storage, should be excluded from the rule to avoid double counting. The language of the Final Rule should be clarified to reflect more accurately EPA's intent and logic. Kinder Morgan suggests that EPA specifically exclude coal terminals from the definition of coal mines.

Suggested change regarding coal mines under Subpart KK.

Edit Section 98.370(b) as follows:

"Coal mine means . . . . Any coal mine categorized as an active coal mine by

[55] 30 U.S.C. § 802(i).

[56] *See, e.g., Kinder Morgan Operating, L.P. v. Chao*, 2003 U.S. App. LEXIS 20972 (6th Cir. 2003); *RNS Servs. v. Sec'y of Labor, MSHA*, 115 F.3d 182 (3d Cir. 1997); Mineral Coal Sales, Inc., 7 FMSHRC 615, 620 (1985). To determine whether or not a coal terminal is a "coal mine" under the Mine Act courts have considered factors such as whether the coal terminal was the final consumer of the coal, whether any coal preparation activities conducted at the terminal were usually performed by a mine operator or the final consumer, whether the actions taken were to facilitate the loading business or to meet customers' or market specification, whether the coal has been sold, and whether MSHA has exercised jurisdiction over the entity that handled the coal before or after the relevant entity. Kinder Morgan Operating L.P., 23 FMSHRC 1288, 1292-97 (2001).

[57] 74 Fed. Reg. at 16,565.

> MSHA is included, *except that the source category does not include post-coal mining activities.*"

The Proposed Rule defines "post-coal mining activities" as "the storage, processing, and transport of extracted coal."[58] With this change, coal terminals would be excluded from reporting requirements, as EPA intended. These proposed changes to the definition of "importer" or "exporter," also help clarify when emission reporting requirements should apply to coal terminals and are consistent with EPA's intent to avoid double counting in this Subpart.

V. Conclusion

Kinder Morgan appreciates EPA's consideration of these comments. In addition to these comments, Kinder Morgan shares the concerns and generally agrees with the recommendations of the Interstate Natural Gas Association of America (INGAA).

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[58] *Id.* at 16,625 (to be codified at 40 C.F.R. § 98.6). The Rule also provides that with regards to reporting requirements for actual CO_2 and CH_4 emissions, "underground coal mines" do not include post-coal mining activities. *Id.* at 16,696 (to be codified at 40 C.F.R. § 98.320).

Appendix A

Kinder Morgan's Suggested Changes to Subpart W Compared to Proposed Rule

Subpart W—Oil and Natural Gas Systems
§ 98.230 Definition of the source category.
This source category consists of the following facilities:

(a) Offshore petroleum and natural gas production facilities.
(b) Onshore natural gas processing facilities.
(c) Onshore natural gas transmission compression facilities.
(d) Underground natural gas storage facilities.
(e) Liquefied natural gas storage facilities.
(f) Liquefied natural gas import and export facilities.

§ 98.231 Reporting threshold.
You must report GHG emissions from oil and natural gas systems if your facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.232 GHGs to report.

(a) You must report CO2 and CH4 emissions in metric tons per year from *the key components* ~~sources~~ specified in § 98.232(a)(1) through (~~2~~*11*) at offshore petroleum and natural gas production facilities, onshore natural gas processing facilities, onshore natural gas transmission compression facilities, underground natural gas storage facilities, liquefied natural gas storage facilities and liquefied natural gas import and export facilities.

~~(1) Acid gas removal (AGR) vent stacks.~~

~~(2)~~ *(1) Compressor Unit Block Valve Vents*
~~(3)~~ *(2) Compressor Unit Blowdown Valve Vents*

~~(4)~~ *(3) Compressor Unit Pressure Relief Valve Vents.*

~~(5) Compressor fugitive emissions.~~

~~(6)~~ *(4) Reciprocating Compressor Seals.*

~~(7) Dehydrator vent stacks.~~

~~(8) Flare stacks.~~

~~(9) Liquefied natural gas import and export facilities fugitive emissions.~~

~~(10) Liquefied natural gas storage facilities fugitive emissions.~~

~~(11)~~ *(5) Centrifugal Compressor Seals*

~~(12)~~ *(6) Compressor Unit Blowdown Events*

~~(13)~~ *(7) Station Blowdown Events*

~~(14)~~ *(8) Engine Startup Events*

~~(15) Offshore platform pipeline fugitive emissions~~.

~~(16)~~ *(9) Dehydrator Vent Stacks*

~~(17)~~ *(10) Acid Gas Removal Vent Stacks*

~~(18) Platform fugitive emissions.~~

~~(19) Processing facility fugitive emissions.~~

~~(20)~~ *(11) Storage Tanks*

~~(21) Storage station fugitive emissions.~~

~~(22) Storage tanks.~~

~~(23) Storage wellhead fugitive emissions.~~

~~(24) Transmission station fugitive emissions.~~

(b) *Except as provided in this subpart, y*ou must report the CO2, CH4, and N2O emissions for stationary combustion sources, by following the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart C of this part.

§ 98.233 Calculating GHG emissions.

(a) Estimate emissions using either an annual direct measurement *according to your company specific sampling plan and procedures*, as specified in § 98.234, or an engineering estimation method specified in this section. You may use the engineering estimation method only for sources for which a method is specified in this section.

(b) You may use engineering estimation methods described in this section to calculate emissions from the following fugitive emissions sources *listed in § 98.232(a)*:

(1) Acid gas removal vent stacks.

(2) ~~Natural gas driven pneumatic pumps.~~ *Compressor Unit Blowdown Events*

(3) ~~Natural gas driven pneumatic manual valve actuator devices~~. *Station Blowdown Events*

(4) ~~Natural gas driven pneumatic valve bleed devices.~~ *Engine Startup Events*

~~(5) Blowdown vent stacks.~~

~~(6)~~ *(5)* Dehydrator vent stacks.

(c) A combination of engineering estimation described in this section and direct measurement described in § 98.234 shall be used to calculate emissions from *storage tanks* ~~the following fugitive emission sources~~:

(1) ~~Flare stacks.~~

(2) ~~Storage tanks.~~

(3) ~~Compressor wet seal degassing vents.~~

(d) You must use the methods described in § 98.234 (d) ~~or (e)~~ to conduct annual ~~leak detection~~ *direct measurement* of fugitive emissions from ~~all~~ *the following* sources listed in § 98.232(a): ~~If fugitive emissions are detected, engineering estimation methods may be used for sources listed in paragraphs (b) and (c) of this section. If engineering estimation is used, emissions must be calculated using the appropriate method from paragraphs (d)(1) through (9) of this section:~~

(1) Compressor Unit Block Valve Vents
(2) Compressor Unit Blowdown Valve Vents
(3) Compressor Unit Pressure Relief Valve Vents
(4) Reciprocating Compressor Seals
(5) Centrifugal Compressor Seals

(e) If engineering estimation is used, emissions must be calculated using the appropriate method from paragraphs (e)(1) through (5) of this section:

~~§ 98.233 (d)(2)-(4), (7) and (9) are deleted~~

(1) Acid gas removal vent stacks. Calculate acid gas removal vent stack fugitive emissions using simulation software packages, such as ASPEN™ or AMINECalc™, *or any standard simulation software. If the acid gas removal unit is capturing CO_2 and transferring it off site, then refer to subpart OO of this part for calculating transferred*

CO_2. ~~-Any standard simulation software may be used provided it accounts for the following parameters:~~

~~(i) Natural gas feed temperature, pressure, and flow rate.~~

~~(ii) Acid gas content of feed natural gas.~~

~~(iii) Acid gas content of outlet natural gas.~~

~~(iv) Unit operating hours, excluding downtime for maintenance or standby.~~

~~(v) Exit temperature of natural gas.~~

~~(vi) Solvent pressure, temperature, circulation rate and weight.~~

~~(vii) If the acid gas removal unit is capturing CO2 and transferring it off site, then refer to subpart OO of this part for calculating transferred CO2.~~

(~~5~~2) Blowdown vent stacks. Calculate fugitive emissions from blowdown vent stacks as follows:
(i) Calculate the total volume (including, but not limited to pipelines and vessels) between isolation valves (Vv in Equation W-1 of this subpart).
(ii) Retain logs of the number of blowdowns for each equipment type.
(iii) Calculate the total annual fugitive emissions using the following Equation W-~~4~~*I* of this section:

$$E_{a,n} = N * V_v$$

(Eq. W- ~~4~~*I*)
Where:
Ea,n = Natural gas fugitive emissions at ambient conditions from blowdowns.
N = Number of blowdowns for the equipment in reporting year.
Vv = Total volume of blowdown equipment chambers (including, but not limited to, pipelines and vessels) between isolation valves.
(iv) Calculate natural gas volumetric fugitive emissions at standard conditions using calculations in paragraph (e) of this section.
(v) Calculate both CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.

(~~6~~3) Dehydrator vent stacks. Calculate fugitive emissions from a dehydrator vent stack using simulation software packages, such as GLYCalc™ or any standard simulation software.

(4) Natural gas engine startup events. Calculate fugitive emissions from engines equipped with natural gas starters as follows:
(i) Log the number of starting events

(ii) Determine the amount of natural gas emitted during each start using an engineering estimate or actual measurement.
(iii) Calculate both CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.
(iv) Calculate the total annual fugitive emissions using the following Equation W-2 of this section

$$E_{a,n} = N * V_v$$

(Eq. W-2)
Where:
$E_{a,n}$ = Natural gas fugitive emissions at ambient conditions from natural gas starter events.
N = Number of starter events for the equipment in reporting year.
V_v = Total volume of natural gas emitted during each starter event

(~~8~~5) Storage tanks. Calculate fugitive emissions from a storage tank ~~as follows:~~ *according to this paragraph:*
(i) For storage tanks of all sizes, the total annual hydrocarbon vapor fugitive emissions may be estimated using Equation W–3 of this section:

$$E_{a,h} = Q \times ER$$

(Eq. W-3)
Where:
$E_{a,h}$ = Hydrocarbon vapor fugitive emissions at actual conditions.
Q = Storage tank total annual throughput.
ER = Measured hydrocarbon vapor emissions rate per throughput

(ii) Estimate hydrocarbon vapor volumetric fugitive emissions at standard conditions using calculations in paragraph (e) of this section.

(iii) Estimate CH_4 and CO_2 volumetric fugitive emissions from volumetric hydrocarbon fugitive emissions using Equation W-4 of this section.

$$E_{s,i} = E_{s,h} * M_i$$

(Eq. W-4)

Where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric fugitive emissions at standard conditions.
$E_{s,h}$ = Hydrocarbon vapor volumetric fugitive emissions at standard conditions.

M_i = Mole percent of a particular GHG i in the hydrocarbon vapors; hydrocarbon vapor analysis shall be conducted in accordance with §98.7.

(iv) Estimate CH_4 and CO_2 mass fugitive emissions from GHG volumetric fugitive emissions using calculations in paragraph (g) of this section

(v) The storage tank measurements described in this section shall be conducted in the first reporting year. Subsequent reporting periods may estimate storage tank emissions by substituting the storage tank annual throughput (Q) during the reporting year of interest into Equation W-3, using the most recent measurement data required under this section. However, the tank measurements required by this section must be conducted at least once every 3 years .

(vi) For storage tanks with a capacity of 210 barrels or less, or less than 10,000 barrels of throughput, instead of the method described in §98.233(d)(5)(i), emissions may be estimated using simulation software packages such as ASPEN™ or E&P TANK®, or using the Vasquez-Beggs equation, as presented in this paragraph.

Vasquez-Beggs equation: First, estimate the dissolved gas specific gravity at 100 pounds per square inch gauge (psig) using the following formula:

$$SG_X = SG_i \times \left[1.0 + 0.00005912 \times API \times T_i \times Log\left(\frac{P_i + 14.7}{114.7} \right) \right]$$

Where:

SG_X = *Dissolved gas gravity at 100 psig.*

SG_i = *Dissolved gas gravity at initial conditions, where air = 1. A suggested default value for SG_i is 0.90 (OK DEQ, 2004).*

API = *API gravity of liquid hydrocarbon at final condition.*

T_i = *Temperature of initial conditions in separator (°F).*

P_i = *Pressure of initial conditions of separator or other immediately upstream vessel (psig).*

Estimate the CH_4 tank emissions using the following formula:

$$CH_4 = C_1 \times SG_X \times (P_i + 14.7)^{C_2} \times \exp\left(\frac{C_3 \times API}{T_i + 460} \right) \times Q \times MF_{CH4} \frac{16}{MVC} \times 0.001$$

Where:

CH_4 = *Annual methane emissions from the storage tank.*

SG_X = *Dissolved gas gravity, adjusted to 100 psig (as calculated above).*

P_i = *Pressure in separator or other immediately upstream vessel (psig).*

API = *API gravity of stock tank oil at 60°F.*

T_i = *Temperature in separator (°F).*

Q = *Storage tank total annual throughput, barrels.*

MF_{CH4} = *Mole fraction of CH_4 in the vent gas from the storage tank from facility measurements or process knowledge (kg-mole CH_4/kg-mole gas); use 0.27 as a default if measurement data are not available.*

16 = *Molecular weight of CH_4 (kg/kg-mole).*

MVC = *Molar volume conversion factor (~~849.5~~ 836.2 scf/kg-mole).*

0.001 = *Conversion factor (metric ton/kg).*

C_1, C_2, C_3 = *Constants based on the API gravity of the liquid as defined below.*

For $G_{oil} \leq 30°API$: $C_1 = 0.0362$; $C_2 = 1.0937$; and $C_3 = 25.724$
For $G_{oil} > 30°API$: $C_1 = 0.0178$; $C_2 = 1.187$; and $C_3 = 23.931$

(vii) Storage tanks with a capacity of 90 barrels or less, or less than 5,000 barrels of throughput are excluded from the reporting required in §98.232.

(6) Key component fugitive emissions. Annual emissions for each key component shall be calculated by applying the appropriate company-specific emissions data to the time each compressor unit is in the given operating mode.
(i) In lieu of direct measurement of key components, facilities with sufficient instrumentation, as determined by a professional engineer specializing in measurement, may use a volume balance calculation to determine facility fugitive emissions. To determine the volume balance calculation, the amount of gas leaving the facility or combusted for energy shall be subtracted from the amount of gas entering the facility. The difference would be assumed to have been lost to the atmosphere, and would serve as a calculation of fugitive emissions.
(ii) For key components where direct measurement was conducted, the company-specific emissions data shall be used to calculate CH_4 and CO_2 using equations W-5 and W-6:

$$Emissions_i\, CH_4\,(tons) = [Emission\ Factor_i\,(mscf\ ng)_{pressurized\ op} \times Hours_{pressurized\ op} + Emission\ Factor_i\,(mscf\ ng)_{pressurized\ idle} \times Hours_{pressurized\ idle} + Emission\ Factor_i\ (mscfng)_{unpressurized} \times Hours_{unpressurized}]/8760 \times 1{,}000\ (scf / mscf) \times \frac{CH_4\ mole\,\%}{100} \times \frac{1}{379.3\ (scf/lbmole)} \times \times MW_{CH_4}\,(lb\ CH_4/lbmole\ CH_4) \times \frac{1\ ton}{2{,}000\ lb} \times Component\ Count$$

Equation W-5

$$Emissions_i\, CO_2\,(tons) = [Emission\ Factor_i\,(mscf\ ng)_{pressurized\ op} \times Hours_{pressurized\ op} + + Emission\ Factor_i\,(mscf\ ng)_{pressurized\ idle} \times Hours_{pressurized\ idle} + Emission_i\ Factor\ (mscfng)_{unpressurized} \times \times Hours_{unpressurized}]\,/\,8760 \times 1{,}000\ \ (scf / mscf) \times \frac{CO_2\ mole\,\%}{100} \times \frac{1}{379.3\ (scf/lbmole)} \times \times MW_{CO_2}\,(lb\ CO_2/lbmole\ CO_2) \times \frac{1\ ton}{2{,}000\ lb} \times Component\ Count$$

Equation W-6

(7) Fugitive emissions shall be calculated and reported as a sum of emissions from the associated key components.

~~(2) Natural gas driven pneumatic pump. Calculate fugitive emissions from a natural gas driven pneumatic pump as follows:~~

~~(i) Calculate fugitive emissions using manufacturer data.~~

~~(A) Obtain from the manufacturer specific pump model natural gas emission per unit volume of liquid pumped at operating pressures.~~

~~(B) Maintain a log of the amount of liquid pumped annually from individual pumps.~~

~~(C) Calculate the natural gas fugitive emissions for each pump using Equation W-1 of this section.~~

$$\cancel{E_{s,n} = F_s * V \qquad \text{(Eq. W-1)}}$$

~~Where:~~
~~$E_{s,n}$ = Natural gas fugitive emissions at standard conditions.~~
~~F_s = Natural gas driven pneumatic pump gas emission in "emission per volume of liquid pumped at discharge pressure" units at standard conditions, as provided by the manufacturer.~~
~~V = Volume of liquid pumped annually.~~

~~(D) Both CH_4 and CO_2 volumetric and mass fugitive emissions shall be calculated from volumetric natural gas fugitive emissions using calculations in paragraphs (f e) and (g f) of this section.~~

~~(ii) If manufacturer data for Fs are not available, follow the method in § 98.234 (i)(1).~~

~~(3) Natural gas driven pneumatic manual valve actuator devices. Calculate fugitive emissions from a natural gas driven pneumatic manual valve actuator device as follows:~~

~~(i) Calculate fugitive emissions using manufacturer data.~~

~~(A) Obtain from the manufacturer specific pneumatic device model natural gas emission per actuation.~~

~~(B) Maintain a log of the number of times the pneumatic device was actuated throughout the reporting period,~~

~~(C) Calculate the natural gas fugitive emissions for each manual valve actuator using Equation W-2 of this section.~~

$$\cancel{E_{s,n} = A_s * N \qquad \text{(Eq. W-2)}}$$

~~Where:~~
~~$E_{s,n}$ = Natural gas fugitive emissions at standard conditions.~~

~~A_s = Natural gas driven pneumatic valve actuator natural gas emission in ''emission per actuation'' units at standard conditions, as provided by the manufacturer.~~
~~N = Number of times the pneumatic device was actuated in a way that vented natural gas to the atmosphere through the reporting period.~~

~~(D) Calculate both CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.~~

~~(ii) Follow the method in § 98.234(i)(2) if manufacturer data are not available.~~

~~(4) Natural gas driven pneumatic valve bleed devices. Calculate fugitive emissions from a natural gas driven pneumatic valve bleed device as follows:~~

~~(i) Calculate fugitive emissions using manufacturer data.~~

~~(A) Obtain from the manufacturer specific pneumatic device model natural gas bleed rate during normal operation.~~

~~(B) Calculate the natural gas fugitive emissions for each valve bleed device using Equation W–3 of this section.~~

$$\cancel{E_{s,n} = B_s * T \qquad \text{(Eq. W-3)}}$$

~~Where:~~
~~$E_{s,n}$ = Natural gas fugitive emissions at standard conditions.~~
~~B_s = Natural gas driven pneumatic device bleed rate in ''emission per unit time'' units at standard conditions, as provided by the manufacturer.~~
~~T = Amount of time the pneumatic device has been operational through the reporting period.~~

~~(C) Calculate both CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.~~

~~(ii) Follow the method in § 98.234(i)(3) if manufacturer data are not available.~~

~~(5) (4) Blowdown vent stacks. Calculate fugitive emissions from blowdown vent stacks as follows:~~

~~(i) Calculate the total volume (including, but not limited to pipelines and vessels) between isolation valves (V_v in Equation W–4 of this subpart).~~

~~(ii) Retain logs of the number of blowdowns for each equipment type.~~

~~(iii) Calculate the total annual fugitive emissions using the following Equation W–4 of this section:~~

$$\cancel{E_{a,n} = N * V_v \qquad \text{(Eq. W-4)}}$$

~~Where:~~

~~$E_{a,n}$ = Natural gas fugitive emissions at ambient conditions from blowdowns.~~
~~N = Number of blowdowns for the equipment in reporting year.~~
~~V_v = Total volume of blowdown equipment chambers (including, but not limited to, pipelines and vessels) between isolation valves.~~

~~(iv) Calculate natural gas volumetric fugitive emissions at standard conditions using calculations in paragraph (e) of this section.~~

~~(v) Calculate both CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.~~

~~(6) Dehydrator vent stacks. Calculate fugitive emissions from a dehydrator vent stack using a simulation software packages, such as GLYCalc™. Any standard simulation software may be used provided it accounts for the following parameters:~~

~~(i) Feed natural gas flow rate.~~

~~(ii) Feed natural gas water content.~~

~~(iii) Outlet natural gas water content.~~

~~(iv) Absorbent circulation pump type (natural gas pneumatic/air pneumatic/ electric).~~

~~(v) Absorbent circulation rate.~~

~~(vi) Absorbent type: Including, but not limited to, triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).~~

~~(vii) Use of stripping natural gas.~~
~~(viii) Use of flash tank separator (and disposition of recovered gas).~~
~~(ix) Hours operated.~~

~~(x) Wet natural gas temperature, pressure, and composition.~~

~~(7) Flare stacks. Calculate fugitive emissions from a flare stack as follows:~~

~~(i) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 95 percent for non-steam aspirated flares and 98 percent for steam aspirated or air injected flares.~~

~~(ii) Calculate volume of natural gas sent to flare from velocity measurement in § 98.234(j) using manufacturer's manual for the specific meter used to measure velocity.~~

~~(iii) Calculate GHG volumetric fugitive emissions at actual conditions using Equation W-5 of this section:~~

$$\cancel{E_{a,i} = V_a * (1-\eta) * X_i + (1-K) * \eta * V_a * Y_j * R_{j,i}} \qquad \cancel{\text{(Eq. W-5)}}$$

~~Where:~~

~~$E_{a,i}$ = Annual fugitive emissions from flare stack.~~
~~V_a = Volume of natural gas sent to flare stack determined from § 98.234(j)(1)~~
~~η = Percent of natural gas combusted by flare (default is 95 percent for non-steam aspirated flares and 98 percent for steam aspirated or air injected flares).~~
~~X_i = Concentration of GHG i in the flare gas determined from § 98.234(j)(1)~~
~~Y_j = Concentration of natural gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes plus).~~
~~$R_{j,i}$ = Number of carbon atoms in the natural gas hydrocarbon constituent j; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and pentanes plus).~~
~~K = "1" when GHG i is CH_4 and "0" when GHG i is CO_2~~
~~(iv) Calculate GHG volumetric fugitive emissions at standard conditions using Equation W-6 of this section.~~

$$\cancel{E_{s,i} = \frac{E_{a,i} * (460 + T_s) * P_a}{(460 + T_a) * P_s}} \qquad \cancel{\text{(Eq. W-6)}}$$

~~Where:~~

~~$E_{s,i}$ = Natural gas volumetric fugitive emissions at standard temperature and pressure (STP) conditions.~~
~~$E_{a,i}$ = Natural gas volumetric fugitive emissions at actual conditions.~~
~~T_s = Temperature at standard conditions (°F).~~
~~T_a = Temperature at actual emission conditions (°F).~~
~~P_s = Absolute pressure at standard conditions (inches of H_g).~~
~~P_a = Absolute pressure at ambient conditions (inches of H_g).~~

~~(v) Calculate both CH_4 and CO_2 mass fugitive emissions from volumetric CH_4 and CO_2 fugitive emmisions usuing calculations in paragraph (g) of this section.~~

~~(8) Storage tanks. Calculate fugitive emissions from a storage tank as follows:~~
~~(i) Calculate the total annual hydrocarbon vapor fugitive emissions using Equation W-7 of this section:~~

$$\cancel{E_{a,h} = Q * ER} \qquad \cancel{\text{(Eq. W-7)}}$$

~~Where:~~

~~$E_{a,h}$ = Hydrocarbon vapor fugitive emissions at actual conditions.~~

~~Q = Storage tank total annual throughput.~~
~~ER = Measured hydrocarbon vapor emissions rate per throughput (e.g. cubic feet/barrel) determined from § 98.234(j)(2).~~
~~(ii) Estimate hydrocarbon vapor volumetric fugitive emissions at standard conditions using calculations in paragraph (e) of this section.~~
~~(iii) Estimate CH_4 and CO_2 volumetric fugitive emissions from volumetric hydrocarbon fugitive emissions using Equation W-8 of this section.~~

$$\cancel{E_{s,i} = E_{s,h} * M_i} \qquad \cancel{\text{(Eq. W-8)}}$$

~~Where:~~

~~$E_{s,i}$ = GHG i (either CH_4 and CO_2) volumetric fugitive emissions at standard conditions.~~
~~$E_{s,h}$ = Hydrocarbon vapor volumetric fugitive emissions at standard conditions.~~
~~M_i = Mole percent of a particular GHG, in the hydrocarbon vapors; hydrocarbon vapor analysis shall be conducted in accordance with ASTM D1945-03.~~

~~(iv) Estimate CH_4 and CO_2 mass fugitive emissions from GHG volumetric fugitive emissions using calculations in paragraph (g) of this section.~~

~~(9) Compressor wet seal degassing vents. Calculate fugitive emissions from compressor wet seal degassing vents as follows:~~

~~(i) Calculate volume of natural gas sent to vent from velocity measurement in § 98.234(j) using manufacturer's manual for the specific meter used to measure velocity.~~

~~(ii) Calculate natural gas volumetric fugitive emissions at standard conditions using calculations in paragraph (e) of this section.~~

~~(iii) Calculate both CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.~~

~~(e)~~ (f) Calculate natural gas volumetric fugitive emissions at standard conditions by converting ambient temperature and pressure of natural gas fugitive emissions to standard temperature and pressure natural using Equation W–~~9~~ 7 of this section.

$$E_{s,n} = \frac{E_{a,n} * (460 + T_s) * P_a}{(460 + T_a) * P_s} \qquad \text{(Eq. W-}\cancel{9}\text{ 7)}$$

Where:
$E_{s,n}$ = Natural gas volumetric fugitive emissions at standard temperature and pressure (STP) conditions.

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

T_s = Temperature at standard conditions (°F).

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

P_s = Absolute pressure at standard conditions (inches of Hg).

P_a = Absolute pressure at ambient conditions (inches of Hg).

~~(f)~~ (g) Calculate GHG volumetric fugitive emissions at standard conditions as specified in paragraphs (~~f~~ g)(1) and (2) of this section.

(1) Estimate CH_4 and CO_2 fugitive emissions from natural gas fugitive emissions using Equation W–~~10~~ *8* of this section.

$$E_{s,i} = E_{s,n} * M_i \qquad \text{(Eq. W-}\cancel{10}\ 8\text{)}$$

Where:
$E_{s,i}$ = GHG i (either CH_4 and CO_2) volumetric fugitive emissions at standard conditions.
$E_{s,n}$ = Natural gas volumetric fugitive emissions at standard conditions.
M_i = Mole percent of GHG i in the natural gas.

(2) For Equation W–~~10~~ *8* of this section, the mole percent, M_i, shall be the annual average mole percent for each facility, as specified in paragraphs (~~f~~ g)(2)(i) through (vi) of this section.

(i) GHG mole percent in produced natural gas for offshore petroleum and natural gas production facilities.

(ii) GHG mole percent in feed natural gas for all fugitive emissions sources upstream of the de-methanizer and GHG mole percent in facility specific residue gas to transmission pipeline systems for all fugitive emissions sources downstream of the de-methanizer for onshore natural gas processing facilities.

(iii) GHG mole percent in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.

(iv) GHG mole percent in natural gas stored in underground natural gas storage facilities.

(v) GHG mole percent in natural gas stored in LNG storage facilities.

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

~~(g)~~ *(h)* Calculate GHG mass fugitive emissions at standard conditions by converting the GHG volumetric fugitive emissions into mass fugitive emissions using Equation W–~~11~~ *9* of this section.

$$Mass_{s,i} = E_{s,i} * \rho_i \qquad \text{(Eq. W-}\cancel{11}\ 9\text{)}$$

Where:

$Mass_{s,i}$ = GHG i (either CH_4 and CO_2) mass fugitive emissions at standard conditions.
$E_{s,i}$ = GHG i (either CH_4 and CO_2) volumetric fugitive emissions at standard conditions.
ρ_i = Density of GHG i;1.87 kg/m^3 for CO_2 and 0.68 kg/m^3 for CH_4.

§ 98.234 Monitoring, *Measurement* and QA/QC requirements.

(a) You shall develop a company specific plan and procedure to determine company-specific emissions data to be utilized for reporting greenhouse gas emissions for key fugitive and vented components as specified in § 98.233(d).
(1) Conduct direct measurement, as specified in § 98.234(f), of key components listed in § 98.233(d) annually at a randomly selected, statistically representative sample of the full population of the company's §98.230 source category facilities.
(2) Random sampling of facilities. The company shall maintain a list of §98.230 source category facilities. The company shall assign a number to each facility, and then randomly select at least 20% of the numbers. These randomly selected facilities form the basis for the company's facilities to be monitored during the year. The total population of the company's facilities in a given year must account for any facilities acquired or divested during the reporting year.
(i) In the first reporting year a random sample of at least 20% of the company's full population of total facilities shall be subject to direct measurement of fugitive emissions at key components listed in §98.233(d). The results of the direct measurement will be used to develop company specific emissions data.
(ii) In each subsequent year, at least 20% of the facilities must be selected for monitoring under §98.234(a)(1) using the method in §98.234(a)(2) and include facilities that were not sampled during the previous five years such that 100% of the facilities are monitored during a given five year period, unless a waiver is granted under §98.234(a)(2)(iii).
(iii) A company may petition the Administrator for a facility sampling size less than the 20% prescribed in §98.234(a)(1) if the applicant can demonstrate to the satisfaction of the Administrator that the emissions data monitored are statistically representative of the emission sources at the facilities. Such a request must be made in writing and approved by the Administrator before a smaller facility sampling size can be used.
(iv) After the first 5 reporting years, or once all of the company's facilities have been measured, you shall continue to conduct random sampling at 20% of the total number of company facilities. You may petition the Administrator under §98.234(a)(2)(iii) to use the developed company-specific emissions data to report fugitive emissions in lieu of direct measurement.
(v) Provide on-site equipment component counts of key components listed in § 98.232(d) at all reported facilities in the first year of reporting. Equipment component counts may be developed utilizing engineering estimates. For a facility required to report fugitive emissions starting January 1, 201[1]~~0~~, if all component counts needed to calculate CO_2 mass emissions have not been completed, the operator shall estimate components based

on the sampled facility component counts. For those facilities reporting estimated component counts, the operator shall provide on-site equipment counts of key components by June 30, 201[2]~~1~~.

(b) You shall develop company-specific emissions data per key component type from the direct measurement conducted according to the procedures in § 98.234(a). Emissions data shall be measured in units of thousands of cubic feet (mcf) of natural gas. The emissions data shall be used to calculate fugitive emissions during the first year of reporting on a company-wide basis.

(1) The developed company-specific emissions data shall be updated annually to incorporate the new emissions data from sampled facilities.

(2) Company-specific emissions data shall be calculated using the median of the representative data points sampled as part of the company sampling plan and procedures. The company-specific emissions data will be used to calculate fugitive emissions for each facility.

(c) You shall measure all key components in the operating condition found at the time of the measurement. Representative data for each operating mode as described in this paragraph shall be developed. The hours in each mode must be logged. This may be determined using engineering estimates, best available data, or the company's policies for each operating area or facility and equipment.

(1) Pressurized and running – compressor is being utilized by compressing gas at system operating conditions.

(2) Idle and pressurized – compressor is offline but line pressure in the unit is maintained.

(3) Depressurized – source is not in operation and unit is blown down, but the station side of the suction and discharge valves are at line pressure.

(d) Direct measurement. You must conduct annual direct measurement of fugitive emissions as defined in §98.6 from all key components listed in §98.233(d) in the operating mode found at the time of measurement.

(1) Use and calibrate direct measurement devices in accordance with industry practices and/or manufacturer instructions.

(2) Owner or operator shall develop and document the procedures used to measure fugitive emissions including by not limited to measurement methods, instrument calibration, data handling, and data QA/QC .

(3) Component fugitive emissions sources that are not safely accessible within the operator's arm's reach from the ground or stationary platforms are excluded from the requirements of this section.

(e) Determine annual emissions assuming that the fugitive emissions were continuous from the beginning of the reporting period or last recorded zero measurement in the current reporting period and continuing until the fugitive emissions is repaired.

~~(a) You must use the methods described in paragraphs (d) or (e) in this section to conduct annual leak detection of fugitive emissions from all sources listed in § 98.232(a), whether in operation or on standby. If fugitive emissions are detected for sources listed in paragraph (b) of this section, you must use the measurement methods described in~~

~~paragraph(e) of this section to measure emissions from each source with fugitive emissions.~~

~~(b) You shall use detection instruments described in paragraphs (d) and (e) of this section to monitor the following fugitive emissions:~~

~~(1) Centrifugal compressor dry seals fugitive emissions.~~

~~(2) Centrifugal compressor wet seals fugitive emissions.~~

~~(3) Compressor fugitive emissions.~~

~~(4) LNG import and export facility fugitive emissions.~~

~~(5) LNG storage station fugitive emissions.~~

~~(6) Non-pneumatic pumps fugitive emissions.~~

~~(7) Open-ended lines (OELs) fugitive emissions.~~

~~(8) Pump seals fugitive emissions.~~

~~(9) Offshore platform pipeline fugitive emissions.~~

~~(10) Platform fugitive emissions.~~

~~(11) Processing facility fugitive emissions.~~

~~(12) Reciprocating compressor rod packing fugitive emissions.~~

~~(13) Storage station fugitive emissions.~~

~~(14) Transmission station fugitive emissions.~~

~~(15) Storage wellhead fugitive emissions.~~

~~(c) You shall use a high volume sampler, described in paragraph (f) of this section, to measure fugitive emissions from the sources detected in § 98.234(b), except as provided in paragraphs (c)(1) and (2) of this section:~~

~~(1) Where high volume samplers cannot capture all of the fugitive emissions, you shall use calibrated bags described in paragraph (g) of this section or meters described in paragraph~~

~~(h) of this section to measure the following fugitive emissions:~~

~~(i) Open-ended lines (OELs).~~

~~(ii) Centrifugal compressor dry seals fugitive emissions.~~

~~(iii) Centrifugal compressor wet seals fugitive emissions.~~

~~(iv) Compressor fugitive emissions.~~

~~(v) Pump seals fugitive emissions.~~

~~(vi) Reciprocating compressor rod packing fugitive emissions.~~

~~(vii) Flare stacks and storage tanks, except that you shall use meters in combination with engineering estimation methods to calculate fugitive emissions.~~

~~(2) Use hot wire anemometer to calculate fugitive emissions from centrifugal compressor wet seal degassing vents and flares where it is unsafe or too high a flow rate to use calibrated bags.~~

~~(d) Infrared Remote Fugitive Emissions Detection.~~

~~(1) Use infrared fugitive emissions detection instruments that can identify *emitting* specific equipment sources as emitting. Such instruments must have the capability to trace a fugitive emission back to the specific point where it escapes the process and enters the atmosphere.~~

~~(2) If you are using instruments that visually display an image of fugitive emissions, you shall inspect the emissions source from multiple angles or locations until the entire source has been viewed without visual obstructions at least once annually.~~

~~(3) If you are using any other infrared detection instruments, such as those based on infrared laser reflection, you shall monitor all potential emission points at least once annually.~~

~~(4) Perform fugitive emissions detection under favorable conditions, including but not limited to during daylight hours, in the absence of precipitation, in the absence of high wind, and, for active laser devices, in front of appropriate reflective backgrounds within the detection range of the instrument.~~

~~(5) Use fugitive emissions detection and measurement instrument manuals to determine optimal operating conditions.~~

~~(e) Use organic vapor analyzers (OVAs) and toxic vapor analyzers (TVAs) for all fugitive emissions detection that are safely accessible at close-range.~~

~~(1) Check each potential emissions source, all joints, connections, and other potential paths to the atmosphere for emissions.~~

~~(2) Evaluate the lag time between the instrument sensing and alerting caused by the residence time of a sample in the probe shall be evaluated; upon alert, the instrument shall be slowly retraced over the source to pinpoint the location of fugitive emissions.~~

~~(3) Use Method 21 of 40 CFR part 60, appendix A-7, Determination of Volatile Organic Compound Leaks to calibrate OVAs and TVAs.~~

~~(a) If fugitive emissions are detected for sources listed in this paragraph you must use the measurement methods described in paragraph (b) of this section to measure emissions from each source with fugitive emissions.~~
~~(1) Centrifugal compressor dry seals fugitive emissions.~~
~~(2) Centrifugal compressor wet seals fugitive emissions.~~
~~(3) Non-pneumatic pumps fugitive emissions.~~
~~(4) Open-ended lines (OELs) fugitive emissions.~~
~~(5) Pump seals fugitive emissions.~~
~~(6) Reciprocating compressor rod packing fugitive emissions.~~
~~(b) You shall use a direct measurement device, defined in 98.6, to measure fugitive emissions from the sources detected in §98.235(a).~~
~~(c) Estimate natural gas volumetric emissions at standard conditions using calculations in §98.233(e).~~
~~(d) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in §98.233(e) and (f).~~

~~(c) Use and calibrate direct measurement devices in accordance with industry practices and/or manufacturer instructions.~~
~~(d) Owner or operator shall develop and document the procedures used to detect and measure fugitive emissions including by not limited to detection methods, calibration and QA/QC.~~

~~(f) Use a high volume sampler to measure only cold and steady emissions within the capacity of the instrument.~~

~~(1) A trained technician shall conduct measurements. The technician shall be~~

~~conversant with all operating procedures and measurement methodologies relevant to using a high volume sampler, including, but not limited to, positioning the instrument for complete capture of the fugitive emissions 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 you shall use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.~~

~~(3) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(f) and (g).~~

~~(4) 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.~~

~~(g) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and the entire fugitive emissions volume can be captured 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.~~

~~(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(e).~~

~~(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(f) and (g).~~

~~(5) Obtain consistent results when measuring the time it takes to fill the bag with fugitive emissions.~~

~~(h) Channel all emissions from a single source directly through the meter when using metering (e.g., rotameters, turbine meters, and others).~~

~~(1) Use an appropriately sized meter so that the flow does not exceed the full range of the meter in the course of measurement and conversely has sufficient momentum for the meter to register continuously in the course of measurement.~~

~~(2) Estimate natural gas volumetric fugitive emissions at standard conditions using calculations in § 98.233(f).~~

~~(3) Estimate CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in § 98.233(f) and (g).~~

~~(4) Calibrate the meter using either one of the two methods provided as follows:~~

~~(i) Develop calibration curves by following the manufacturer's instruction.~~

~~(ii) Weigh the amount of gas that flows through the meter into or out of a container during the calibration procedure using a master weigh scale (approved by National Institute of Standards and Technology (NIST) or calibrated using standards traceable by NIST). Determine correction factors for the flow meter according to the manufacturer's instructions. Record deviations from the correct reading at several flow rates. Plot the data points, comparing the flowmeter output to the actual flowrate as determined by the master weigh scale and use the difference as a correction factor.~~

~~(i) Where engineering estimation as described in § 98.233 is not possible, use direct measurement methods as follows:~~

~~(1) If manufacturer data on pneumatic pump natural gas emission are not available, conduct a one-time measurement to determine natural gas emission per unit volume of liquid pumped using a calibrated bag for each pneumatic pump, when it is pumping liquids. Determine the volume of liquid being pumped from the manufacturer's manual to provide the amount of natural gas emitted per unit of liquid pumped.~~

~~(i) Record natural gas conditions (temperature and pressure) and convert natural gas emission per unit volume of liquid pumped at actual conditions into natural gas emission per pumping cycle at standard conditions using Equation W–9 of § 98.233.~~

~~(ii) Calculate annual fugitive emissions from the pump using Equation W–1, by replacing the manufacturer's data on emission (variable Fs) in the Equation with the standard conditions natural gas emission calculated in § 98.234(i)(1)(i).~~

~~(iii) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas fugitive emissions using the calculations in § 98.233(f) and (g).~~

~~(2) If manufacturer data on pneumatic manual valve actuator device natural gas emission are not available, conduct a one-time measurement to determine natural gas emission per actuation using a calibrated bag for each pneumatic device per actuation.~~

~~(i) Record natural gas conditions (temperature and pressure) and convert natural gas emission at actual conditions into natural gas emission per actuation at standard conditions using Equation W–9 of this subpart.~~

~~(ii) Calculate annual fugitive emissions from the pneumatic device using Equation W-2 of this section, by replacing the manufacturer's data on emission (variable As) in the Equation with the standard conditions natural gas emission calculated in § 98.234(i)(2)(i).~~
~~(iii) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas fugitive emissions using the calculations in § 98.233(f) and (g).~~

~~(3) If manufacturer data on natural gas driven pneumatic valve bleed rate is not available, conduct a one-time measurement to determine natural gas bleed rate using a high volume sampler or calibrated bag or meter for each pneumatic device.~~

~~(i) Record natural gas conditions (temperature and pressure) to convert natural gas bleed rate at actual conditions into natural gas bleed rate at standard conditions using Equation W-9 of this subpart.~~

~~(ii) Calculate annual fugitive emissions from the pneumatic device using Equation W-3 of this subpart, by replacing the manufacturer's data on bleed rate (variable B) in the equation with the standard conditions bleed rate calculated in § 98.234(i)(3)(i).~~

~~(iii) Estimate CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in § 98.233(f) and (g).~~

~~(j) Parameters for calculating emissions from flare stacks, compressor wet seal degassing vents, and storage tanks.~~

~~(1) Estimate fugitive emissions from flare stacks and compressor wet seal degassing vents as follows:~~

~~(i) Insert flow velocity measuring device (such as hot wire anemometer or pitot tube) directly upstream of the flare stack or compressor wet seal degassing vent to determine the velocity of gas sent to flare or vent.~~

~~(ii) Record actual temperature and pressure conditions of the gas sent to flare or vent.~~

~~(iii) Sample representative gas to the flare stack or compressor wet seal degassing vent every quarter to evaluate the composition of GHGs present in the stream. Record the average of the most recent four gas composition analyses, which shall be conducted using standards ASTM D1945-03 (incorporated by reference, see § 98.7).~~

~~(2) Estimate fugitive emissions from storage tanks as follows:~~

~~(i) Measure the hydrocarbon vapor emissions from storage tanks using a flow meter described in paragraph (h) of this section for a test period that is representative of the normal operating conditions of the storage tank throughout the year and which includes a complete cycle of accumulation of hydrocarbon liquids and pumping out of hydrocarbon liquids from the storage tank.~~

~~(ii) Record the net (related to working loss) and gross (related to flashing loss) input of the storage tank during the test period.~~
~~(iii) Record temperature and pressure of hydrocarbon vapors emitted during the test period.~~

~~(iv) Collect a sample of hydrocarbon vapors for composition analysis~~

~~(k) Component fugitive emissions sources that are not safely accessible within the operator's arm's reach from the ground or stationary platforms are excluded from the requirements of this section.~~

~~(l) Determine annual emissions assuming that the fugitive emissions were continuous from the beginning of the reporting period or last recorded zero detection in the current reporting period and continuing until the fugitive emissions is repaired.~~

§ 98.235 Procedures for estimating missing data.
~~There are no missing data procedures for this source category. A complete record of all measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions measurements, you must repeat the measurement activity for those sources until a valid measurement is obtained.~~
For the procedures in 98.233 and 98.234, best available estimates shall be used to substitute for missing data. Where the missing data is in the nature of a lost or erroneous direct measurement, the average of the previous two direct measurements for the component shall be deemed the best available estimate. Where the missing data can be obtained from public records or widely accepted references (e.g., ambient temperature), those records or references shall be used to supply the best available estimate. In all cases, the method used to derive substitute data shall be documented by the owner or operator and reported to EPA.

§ 98.236 Data reporting requirements.
In addition to the information required by § 98.3(c), each annual report must report emissions data as specified in this section.

(a) Annual emissions reported separately for each of the operations listed in paragraphs (a)(1) through (6) of this section. Within each operation, emissions from each source type must be reported in the aggregate. ~~For example, an underground natural gas storage facility with multiple reciprocating compressors must report emissions from all reciprocating compressors as an aggregate number.~~

(1) Offshore petroleum and natural gas production facilities.

(2) Onshore natural gas processing facilities.

(3) Onshore natural gas transmission compression facilities.

(4) Underground natural gas storage facilities.

(5) Liquefied natural gas storage facilities.

(6) Liquefied natural gas import and export facilities.

~~(b) Emissions reported separately for standby equipment.~~

~~(c)~~ (b) Emissions calculated for these sources shall assume no CO_2 capture and transfer off site.

~~(d)~~ (c) Activity data for each aggregated source type level for which emissions are being reported.

~~(e)~~ (d) Engineering estimate of total component count.

~~(f)~~ (e) Total number of compressors and average operating hours per year for compressors for each operation listed in paragraphs (a)(1) through (6) of this section.

~~(g) Minimum, maximum and average throughput for each operation listed in paragraphs (a)(1) through (6) of this section.~~

~~(h) Specification of the type of any control device used, including flares, for any source type listed in 98.232(a).~~

~~(i)~~ (f) For offshore petroleum and natural gas production facilities, the number of connected wells, and whether they are producing oil, gas, or both.

~~(j)~~ (g) ~~Detection and~~ Measurement instruments used.

§ 98.237 Records that must be retained.
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, whether quantification was made pursuant to § 98.234(k) and measurements.

(c) Calibration *and QA/QC* reports for detection and measurement instruments used.

(d) Inputs and outputs of calculations or emissions computer model runs used for engineering estimation of emissions.

(e) Random sampling plan and procedure.

(f) Leak detection and measurement procedures

§ 98.238 Definitions.
All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

***Kinder Morgan recommends the following definition changes in Section 98.6.*

Storage tanks: means other vessel that is designed to contain an accumulation of ~~crude oil,~~ *organic hydrocarbon* condensates, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of nonearthen materials (e.g., wood, concrete, steel, plastic) that provide structural support. *Vessels containing lube oil for onsite usage are excluded from the definition of storage tanks.*

Add "Direct Measurement Device": Any accepted candidate methods with the capability to capture and measure fugitive emissions. Accepted candidate methods include but are not limited to acoustic devices, high flow sampler, calibrated bags, hot wire anemometers, pitot tubes, anubars, turbine meters, orifice plates, etc.

Kinder Morgan's Suggested Changes to Subpart W

Subpart W—Oil and Natural Gas Systems

§98.230 Definition of the source category.
This source category consists of the following facilities:
(a) Offshore petroleum and natural gas production facilities.
(b) Onshore natural gas processing facilities.
(c) Onshore natural gas transmission compression facilities.
(d) Underground natural gas storage facilities.
(e) Liquefied natural gas storage facilities.
(f) Liquefied natural gas import and export facilities.

§98.231 Reporting threshold.
You must report GHG emissions from oil and natural gas systems if your facility meets the requirements of either §98.2(a)(1) or (2).

§98.232 GHGs to report.
(a) You must report CO_2 and CH_4 emissions in metric tons per year from the key components specified in (1) through (11) at offshore petroleum and natural gas production facilities, onshore natural gas processing facilities, onshore natural gas transmission compression facilities, underground natural gas storage facilities, liquefied natural gas storage facilities and liquefied natural gas import and export facilities.
(1) Compressor Unit Block Valve Vents
(2) Compressor Unit Blowdown Valve Vents
(3) Compressor Unit Pressure Relief Valve Vents
(4) Reciprocating Compressor Seals
(5) Centrifugal Compressor Seals
(6) Compressor Unit Blowdown Events
(7) Station Blowdown Events
(8) Engine Startup Events
(9) Dehydrator Vent Stacks
(10) Acid Gas Removal (AGR) Vent Stacks
(11) Storage Tanks
(b) Except as provided in this subpart, you must report the CO_2, CH_4, and N_2O emissions for stationary combustion sources, by following the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart C of this part.

§98.233 Calculating GHG emissions.
(a) Estimate emissions using either an annual direct measurement according to your company specific sampling plan and procedures, as specified in §98.234, or an engineering estimation method specified in this section. You may use the engineering estimation method only for sources for which a method is specified in this section.

(b) You may use engineering estimation methods described in this section to calculate emissions from the following fugitive emissions sources listed in §98.232(a):
(1) Compressor Unit Blowdown Events
(2) Station Blowdown Events
(3) Engine Startup Events
(4) Dehydrator Vent Stacks
(5) Acid Gas Removal (AGR) Vent Stacks
(c) A combination of engineering estimation described in this section and direct measurement described in §98.234 shall be used to calculate emissions from storage tanks.
(d) You must use the methods described in §98.234(d) to conduct annual direct measurement of fugitive emissions from the following sources listed in §98.232(a):
(1) Compressor Unit Block Valve Vents
(2) Compressor Unit Blowdown Valve Vents
(3) Compressor Unit Pressure Relief Valve Vents
(4) Reciprocating Compressor Seals
(5) Centrifugal Compressor Seals
(e) If engineering estimation is used, emissions must be calculated using the appropriate method from paragraphs (e)(1) through (5) of this section:
(1) Acid gas removal vent stacks. Calculate acid gas removal vent stack fugitive emissions using simulation software packages, such as ASPEN™ or AMINECalc™, or any standard simulation software. If the acid gas removal unit is capturing CO_2 and transferring it off site, then refer to subpart OO of this part for calculating transferred CO_2.
(2) Blowdown vent stacks. Calculate fugitive emissions from blowdown vent stacks as follows:
(i) Calculate the total volume (including, but not limited to pipelines and vessels) between isolation valves (Vv in Equation W-1 of this subpart).
(ii) Retain logs of the number of blowdowns for each equipment type.
(iii) Calculate the total annual fugitive emissions using the following Equation W-1 of this section:

$$E_{a,n} = N * V_v$$

(Eq. W-1)
Where:
Ea,n = Natural gas fugitive emissions at ambient conditions from blowdowns.
N = Number of blowdowns for the equipment in reporting year.
Vv = Total volume of blowdown equipment chambers (including, but not limited to, pipelines and vessels) between isolation valves.
(iv) Calculate natural gas volumetric fugitive emissions at standard conditions using calculations in paragraph (e) of this section.
(v) Calculate both CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.
(3) Dehydrator vent stacks. Calculate fugitive emissions from a dehydrator vent stack using simulation software packages, such as GLYCalc™ or any standard simulation software.

(4) Natural gas engine startup events. Calculate fugitive emissions from engines equipped with natural gas starters as follows:
(i) Log the number of starting events
(ii) Determine the amount of natural gas emitted during each start using an engineering estimate or actual measurement.
(iii) Calculate both CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.
(iv) Calculate the total annual fugitive emissions using the following Equation W-2 of this section

$$E_{a,n} = N * V_v$$

(Eq. W-2)
Where:
Ea,n = Natural gas fugitive emissions at ambient conditions from natural gas startup events.
N = Number of startup events for the equipment in reporting year.
Vv = Total volume of natural gas emitted during each startup event
(5) Storage tanks. Calculate fugitive emissions from a storage tank according to this paragraph..
(i) For storage tanks of all sizes, the total annual hydrocarbon vapor fugitive emissions may be estimated using Equation W–3 of this section:

$$E_{a,h} = Q \times ER$$

(Eq. W-3)
Where:
Ea,h = Hydrocarbon vapor fugitive emissions at actual conditions.
Q = Storage tank total annual throughput.
ER = Measured hydrocarbon vapor emissions rate per throughput

(ii) Estimate hydrocarbon vapor volumetric fugitive emissions at standard conditions using calculations in paragraph (e) of this section.

(iii) Estimate CH_4 and CO_2 volumetric fugitive emissions from volumetric hydrocarbon fugitive emissions using Equation W-4 of this section.

$$E_{s,i} = E_{s,h} * M_i$$

(Eq. W-4)

Where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric fugitive emissions at standard conditions.
$E_{s,h}$ = Hydrocarbon vapor volumetric fugitive emissions at standard conditions.

Mi = Mole percent of a particular GHG i in the hydrocarbon vapors; hydrocarbon vapor analysis shall be conducted in accordance with §98.7.

(iv) Estimate CH_4 and CO_2 mass fugitive emissions from GHG volumetric fugitive emissions using calculations in paragraph (g) of this section

(v) The storage tank measurements described in this section shall be conducted in the first reporting year. Subsequent reporting periods may estimate storage tank emissions by substituting the storage tank annual throughput (Q) during the reporting year of interest into Equation W-3, using the most recent measurement data required under this section. However, the tank measurements required by this section must be conducted at least once every 3 years .

(vi) For storage tanks with a capacity of 210 barrels or less, or less than 10,000 barrels of throughput, instead of the method described in §98.233(d)(5)(i), emissions may be estimated using simulation software packages such as ASPEN™ or E&P TANK®, or using the Vasquez-Beggs equation, as presented in this paragraph.

Vasquez-Beggs equation: First, estimate the dissolved gas specific gravity at 100 pounds per square inch gauge (psig) using the following formula:

$$SG_X = SG_i \times \left[1.0 + 0.00005912 \times API \times T_i \times Log\left(\frac{P_i + 14.7}{114.7}\right)\right]$$

Where:

SG_X = Dissolved gas gravity at 100 psig.

SG_i = Dissolved gas gravity at initial conditions, where air = 1. A suggested default value for SG_i is 0.90 (OK DEQ, 2004).

API = API gravity of liquid hydrocarbon at final condition.

T_i = Temperature of initial conditions in separator (°F).

P_i = Pressure of initial conditions of separator or other immediately upstream vessel (psig).

Estimate the CH_4 tank emissions using the following formula:

$$CH_4 = C_1 \times SG_X \times (P_i + 14.7)^{C_2} \times \exp\left(\frac{C_3 \times API}{T_i + 460}\right) \times Q \times MF_{CH4} \frac{16}{MVC} \times 0.001$$

Where:

CH_4 = Annual methane emissions from the storage tank.

SG_X = Dissolved gas gravity, adjusted to 100 psig (as calculated above).

P_i = Pressure in separator or other immediately upstream vessel (psig).

API = API gravity of stock tank oil at 60°F.

T_i = Temperature in separator (°F).

Q = Storage tank total annual throughput, barrels.

MF_{CH4} = Mole fraction of CH_4 in the vent gas from the storage tank from facility measurements or process knowledge (kg-mole CH_4/kg-mole gas); use 0.27 as a default if measurement data are not available.

16 = Molecular weight of CH_4 (kg/kg-mole).
MVC = Molar volume conversion factor (~~849.5~~ 836.2 scf/kg-mole).
0.001 = Conversion factor (metric ton/kg).
C_1, C_2,C_3 = Constants based on the API gravity of the liquid as defined below.

For $G_{oil} \leq 30°API$: $C_1 = 0.0362$; $C_2 = 1.0937$; and $C_3 = 25.724$
For $G_{oil} > 30°API$: $C_1 = 0.0178$; $C_2 = 1.187$; and $C_3 = 23.931$

(vii) Storage tanks with a capacity of 90 barrels or less, or less than 5,000 barrels of throughput are excluded from the reporting required in §98.232.
(6) Key component fugitive emissions. Annual emissions for each key component shall be calculated by applying the appropriate company-specific emissions data to the time each compressor unit is in the given operating mode.
(i) In lieu of direct measurement of key components, facilities with sufficient instrumentation, as determined by a professional engineer specializing in measurement, may use a volume balance calculation to determine facility fugitive emissions. To determine the volume balance calculation, the amount of gas leaving the facility or combusted for energy shall be subtracted from the amount of gas entering the facility. The difference would be assumed to have been lost to the atmosphere, and would serve as a calculation of fugitive emissions.
(ii) For key components where direct measurement was conducted, the company-specific emissions data shall be used to calculate CH_4 and CO_2 using equations W-5 and W-6:

$$\begin{aligned}&Emissions_i\ CH_4\,(tons) = [Emission\ \ Factor_i\,(mscf\ \ ng)_{pressurized\ op} \times Hours_{pressurized\ op} + \\ &Emission\ \ Factor_i\,(mscf\ \ ng)_{pressurized\ idle} \times Hours_{pressurized\ idle} + Emission\ \ Factor_i\ (mscfng)_{unpressurized} \\ &\times Hours_{unpressurized}\,]/8760 \times 1{,}000\ (scf\,/\,mscf) \times \frac{CH_4\ mole\,\%}{100} \times \frac{1}{379.3\ (scf\,/lbmole)} \times \\ &\times MW_{CH_4}\ (lb\ CH_4/lbmole\ CH_4) \times \frac{1\ ton}{2{,}000\ lb} \times Component\ \ Count\end{aligned}$$

Equation W-5

$$\begin{aligned}&Emissions_i\ CO_2\,(tons) = [Emission\,Factor_i\,(mscf\ \ ng)_{pressurized\ op} \times Hours_{pressurized\ op} + \\ &+ Emission\,Factor_i\,(mscf\ \ ng)_{pressurized\ idle} \times Hours_{pressurized\ idle} + Emission_i\ \ Factor\ \ (mscfng)_{unpressurized} \times \\ &\times Hours_{unpressurized}\,]\,/\,8760 \times 1{,}000\ \ (scf\,/\,mscf) \times \frac{CO_2\ mole\,\%}{100} \times \frac{1}{379.3\ (scf\,/lbmole)} \times \\ &\times MW_{CO_2}\ (lb\ CO_2/lbmole\ CO_2) \times \frac{1\ ton}{2{,}000\ lb} \times Component\ \ Count\end{aligned}$$

Equation W-6

(8) Fugitive emissions shall be calculated and reported as a sum of emissions from the associated key components.

(e) Calculate natural gas volumetric fugitive emissions at standard conditions by converting ambient temperature and pressure of natural gas fugitive emissions to standard temperature and pressure natural using Equation W-7 of this section.

$$E_{s,n} = \frac{E_{a,n} * (460 + T_s) * P_a}{(460 + T_a) * P_s}$$

(Eq. W-7)

Where:

Es,n = Natural gas volumetric fugitive emissions at standard temperature and pressure (STP) conditions.

Ea,n = Natural gas volumetric fugitive emissions at actual conditions.

Ts = Temperature at standard conditions (oF).

Ta = Temperature at actual emission conditions (oF).

Ps = Absolute pressure at standard conditions (inches of Hg).

Pa = Absolute pressure at ambient conditions (inchesof Hg).

(f) Calculate GHG volumetric fugitive emissions at standard conditions as specified in paragraphs (f)(1) and (2) of this section.

(1) Estimate CH_4 and CO_2 fugitive emissions from natural gas fugitive emissions using Equation W-8 of this section.

$$E_{s,i} = E_{s,n} * M_i$$

(Eq. W-8)

Where:

Es,i = GHG i (either CH_4 or CO_2) volumetric fugitive emissions at standard conditions.

Es,n = Natural gas volumetric fugitive emissions at standard conditions.

Mi = Mole percent of GHG i in the natural gas.

(2) For Equation W-8 of this section, the mole percent, Mi, shall be the annual average mole percent for each facility, as specified in paragraphs (f)(2)(i) through (vi) of this section.

(i) GHG mole percent in produced natural gas for offshore petroleum and natural gas production facilities. (ii) GHG mole percent in feed natural gas for all fugitive emissions sources upstream of the de-methanizer and GHG mole percent in facility specific residue gas to transmission pipeline systems for all fugitive emissions sources downstream of the de-methanizer for onshore natural gas processing facilities.

(iii) GHG mole percent in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities. (iv) GHG mole percent in natural gas stored in underground natural gas storage facilities. (v) GHG mole percent in natural gas stored in LNG storage facilities.

(iv) GHG mole percent in natural gas stored in LNG import and export facilities.

(g) Calculate GHG mass fugitive emissions at standard conditions by converting the GHG volumetric fugitive emissions into mass fugitive emissions using Equation W-9 of this section.

$$Mass_{s,i} = E_{s,i} * \rho_i$$

(Eq. W-9)

Where:

$Mass_{s,i}$ = GHG i (either CH_4 or CO_2) mass fugitive emissions at standard conditions.
$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric fugitive emissions at standard conditions.
i = Density of GHG i ; 1.87 kg/m3 for CO_2 and 0.68 kg/m3 for CH_4.

§98.234 Monitoring, Measurement, and QA/QC requirements.

(a) You shall develop a company specific plan and procedure to determine company-specific emissions data to be utilized for reporting greenhouse gas emissions for key components as specified in §98.233(d).

(1) Conduct direct measurement, as specified in §98.234(f), of key components listed in §98.233(d) annually at a randomly selected, statistically representative sample of the full population of the company's §98.230 source category facilities.

(2) Random sampling of facilities. The company shall maintain a list of §98.230 source category facilities. The company shall assign a number to each facility, and then randomly select at least 20% of the numbers. These randomly selected facilities form the basis for the company's facilities to be monitored during the year. The total population of the company's facilities in a given year must account for any facilities acquired or divested during the reporting year.

(i) In the first reporting year a random sample of at least 20% of the company's full population of total facilities shall be subject to direct measurement of fugitive emissions at key components listed in §98.233(d). The results of the direct measurement will be used to develop company specific emissions data.

(ii) In each subsequent year, at least 20% of the facilities must be selected for monitoring under §98.234(a)(1) using the method in §98.234(a)(2) and include facilities that were not sampled during the previous five years such that 100% of the facilities are monitored during a given five year period, unless a waiver is granted under §98.234(a)(2)(iii).

(iii) A company may petition the Administrator for a facility sampling size less than the 20% prescribed in §98.234(a)(1) if the applicant can demonstrate to the satisfaction of the Administrator that the emissions data monitored are statistically representative of the emission sources at the facilities. Such a request must be made in writing and approved by the Administrator before a smaller facility sampling size can be used.

(iv) After the first 5 reporting years, or once all of the company's facilities have been measured, you shall continue to conduct random sampling at 20% of the total number of company facilities. You may petition the Administrator under §98.234(a)(2)(iii)to use the developed company-specific emissions data to report fugitive emissions in lieu of direct measurement.

(v) Provide on-site equipment component counts of key components listed in §98.233(d) at all reported facilities in the first year of reporting. Equipment component counts may be developed utilizing engineering estimates. For a facility required to report fugitive emissions starting January 1, 201[1], if all component counts needed to calculate CO_2 mass emissions have not been completed, the operator shall estimate components based on the sampled facility component counts. For those facilities reporting estimated component counts, the operator shall provide on-site equipment counts of key components by June 30, 201[2].

(b) You shall develop company-specific emissions data per key component type from the direct measurement conducted according to the procedures in §98.234(a). Emissions data shall be measured in units of thousands of cubic feet (mcf) of natural gas. The emissions data shall be used to calculate fugitive emissions during the first year of reporting on a company-wide basis.

(1) The developed company-specific emissions data shall be updated annually to incorporate the new emissions data from sampled facilities.

(2) Company-specific emissions data shall be calculated using the median of the representative data points sampled as part of the company sampling plan and procedures. The company-specific emissions data will be used to calculate fugitive emissions for each facility.

(c) You shall measure all key components in the operating condition found at the time of the measurement. Representative data for each operating mode as described in this paragraph shall be developed. The hours in each mode must be logged. This may be determined using engineering estimates, best available data, or the company's policies for each operating area or facility and equipment.

(1) Pressurized and running – compressor is being utilized by compressing gas at system operating conditions.

(2) Idle and pressurized – compressor is offline but line pressure in the unit is maintained.

(3) Depressurized – source is not in operation and unit is blown down, but the station side of the suction and discharge valves are at line pressure.

(d) Direct measurement. You must conduct annual direct measurement of fugitive emissions as defined in §98.6 from all key components listed in §98.233(d) in the operating mode found at the time of measurement.

(1) Use and calibrate direct measurement devices in accordance with industry practices and/or manufacturer instructions.

(2) Owner or operator shall develop and document the procedures used to measure fugitive emissions including by not limited to measurement methods, instrument calibration, data handling, and data QA/QC .

(3) Component fugitive emissions sources that are not safely accessible within the operator's arm's reach from the ground or stationary platforms are excluded from the requirements of this section.

(e) Determine annual emissions assuming that the fugitive emissions were continuous from the beginning of the reporting period or last recorded zero measurement in the current reporting period and continuing until the fugitive emissions is repaired.

§98.235 Procedures for estimating missing data.

For the procedures in 98.233 and 98.234, best available estimates shall be used to substitute for missing data. Where the missing data is in the nature of a lost or erroneous direct measurement, the average of the previous two direct measurements for the component shall be deemed the best available estimate. Where the missing data can be obtained from public records or widely accepted references (e.g., ambient temperature), those records or references shall be used to supply the best available estimate. In all cases, the method used to derive substitute data shall be documented by the owner or operator and reported to EPA.

§98.236 Data reporting requirements.
In addition to the information required by §98.3(c), each annual report must report emissions data as specified in this section.
(a) Annual emissions reported separately for each of the operations listed in paragraphs (a)(1) through (6) of this section. Within each operation, emissions from each source type must be reported in the aggregate.
(1) Offshore petroleum and natural gas production facilities.
(2) Onshore natural gas processing facilities.
(3) Onshore natural gas transmission compression facilities.
(4) Underground natural gas storage facilities.
(5) Liquefied natural gas storage facilities.
(6) Liquefied natural gas import and export facilities.
(b) Emissions calculated for these sources shall assume no CO_2 capture and transfer off site.
(c) Activity data for each aggregated source type level for which emissions are being reported.
(d) Engineering estimate of total component count.
(e) Total number of compressors and average operating hours per operating mode per year for compressors for each operation listed in paragraphs (a)(1) through (6) of this section.
(f) For offshore petroleum and natural gas production facilities, the number of connected wells, and whether they are producing oil, gas, or both.
(g) Measurement instruments used.

§98.237 Records that must be retained.
In addition to the information required by §98.3(g), you must retain the following records:
(a) Dates on which measurements were conducted.
(b) All measurements and calculations.
(c) Calibration and QA/QC reports for measurement instruments used.
(d) Inputs and outputs of calculations or emissions computer model runs used for engineering estimation of emissions.
(e) Random sampling plan and procedure.
(f) Measurement procedures

§98.238 Definitions.
All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

***Kinder Morgan recommends amending two definitions in Section 98.6.*

Storage tanks: means other vessel that is designed to contain an accumulation of organic hydrocarbon condensates, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of nonearthen materials (*e.g.*, wood, concrete, steel, plastic) that provide structural support. Vessels containing lube oil for onsite usage are excluded from the definition of storage tanks.

Add "Direct Measurement Device": Any accepted candidate methods with the capability to capture and measure fugitive emissions. Accepted candidate methods include but are not limited to acoustic devices, high flow sampler, calibrated bags, hot wire anemometers, pitot tubes, anubars, turbine meters, orifice plates, etc.