GREENHOUSE GAS EMISSIONS REPORTING FROM THE PETROLEUM AND NATURAL GAS INDUSTRY

BACKGROUND TECHNICAL SUPPORT DOCUMENT

U.S. ENVIRONMENTAL PROTECTION AGENCY
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1. Segments in the Petroleum and Natural Gas Industry

The U.S. petroleum and natural gas industry encompasses the production of raw gas and crude oil from wells to the delivery of processed gas and petroleum products to consumers. These segments use energy and emit greenhouse gases (GHG). It is convenient to view the industry in the following discrete segments:

- Petroleum Industry – petroleum production, petroleum transportation, petroleum refining, petroleum storage terminals, and
- Natural Gas Industry –natural gas production, natural gas gathering and boosting (natural gas gathering and boosting are not included in this rulemaking), natural gas processing, natural gas transmission and underground storage, liquefied natural gas (LNG) import and export terminals, and natural gas distribution.

Each industry segment uses common processes and equipment in its facilities, most of which emit GHG. Each of these industry segments is described in further detail below.

a. Petroleum Industry

Petroleum Production. Petroleum or crude oil is produced from underground geologic formations. In some cases, natural gas is also produced from oil production wells; this gas is called associated natural gas. Production may require pumps or compressors for the injection of liquids or gas into the well to maintain production pressure. The produced crude oil is typically separated from water and gas, injected with chemicals, heated, and temporarily stored. GHG emissions from crude oil production result from combustion-related activities, and equipment leaks and vented emissions. Equipment counts and GHG-emitting practices are related to the number of producing crude oil wells and their production rates.

As petroleum production matures in a field, the natural reservoir pressure is not sufficient to bring the petroleum to the surface. In such cases, enhanced oil recovery (EOR) techniques are used to extract oil that otherwise can not be produced using only reservoir pressure. In the United States, there are three predominant types of EOR operations currently used; thermal EOR, gas injection EOR, and chemical injection EOR. Thermal EOR is carried out by injecting steam into the reservoir to reduce the viscosity of heavy petroleum to allow the flow of the petroleum in the reservoir and up the production well. Gas injection EOR involves injecting of gases, such as natural gas, nitrogen, or carbon dioxide (CO_2), to decrease the viscosity of the petroleum and push it towards and up the producing well. Chemical injection EOR is carried out by injecting surfactants or polymers to improve the flow of petroleum and/or enhance a water flood in the reservoir. Emissions sources from EOR operations are similar to those in conventional petroleum production fields. However, additional emissions occur when CO_2 is used for recovery. This specific EOR operation requires pumps to inject supercritical CO_2 into the reservoir while compressors maintain the recycled CO_2's supercritical state. Venting from these two emissions sources is a major source of emissions.

Petroleum Transportation. The crude oil stored at production sites is either pumped into crude oil transportation pipelines or loaded onto tankers and/or rail freight. Along the supply chain crude oil may be stored several times in tanks. These operational practices and storage tanks release mainly process GHG emissions. Emissions are related to the amount of crude oil transported and the transportation mode.

Petroleum Refining Crude oil is delivered to refineries where it is temporarily stored before being fractionated by distillation and treated. The fractions are reformed or cracked and then blended into consumer petroleum products such as gasoline, diesel, aviation fuel, kerosene, fuel oil, and asphalt. These processes are energy intensive. Equipment counts and GHG gas emitting practices are related to the number and complexity of refineries. Subpart Y of the GHG reporting rule (40 CFR Part 98) published in the Federal Register on October 30, 2009, addresses refineries and hence is not discussed further in this document.

Petroleum products are then transported via trucks, rail cars, and barges across the supply chain network to terminals and finally to end users.

b. Natural Gas Industry

Natural Gas Production In natural gas production, wells are used to withdraw raw gas from underground formations. Wells must be drilled to access the underground formations, and often require natural gas well completion procedures or other practices that vent gas from the well depending on the underground formation. The produced raw gas commonly requires treatment in the form of separation of gas/liquids, heating, chemical injection, and dehydration before being compressed and injected into gathering lines. Combustion emissions, equipment leaks, and vented emissions arise from the wells themselves, gathering pipelines, and all well-site natural gas treatment processes and related equipment and control devices. Determining emissions, equipment counts, and frequency of GHG emitting practices is related to the number of producing wellheads and the amount of produced natural gas. Further details are provided on the individual sources of GHG emissions in Appendix A.

Natural Gas Processing In the processing facility, natural gas liquids and various other constituents from the raw gas are separated, resulting in "pipeline quality" gas that is compressed and injected into the transmission pipelines. These separation processes include acid gas removal, dehydration, and fractionation. Most equipment and practices have associated GHG equipment leaks, energy consumption-related combustion GHG emissions, and/or process control related GHG vented emissions. Equipment counts and frequency of GHG emitting practices are related to the number and size of gas processing facilities. Further details are provided on the individual sources of GHG emissions in Appendix A.

Natural Gas Transmission and Storage Natural gas transmission involves high pressure, large diameter pipelines that transport natural gas from petroleum and natural gas production sites and natural gas processing facilities to natural gas distribution pipelines or large volume customers such as power plants or chemical plants. Compressor station facilities containing large reciprocating and / or centrifugal compressors, move the gas throughout the U.S. transmission pipeline system. Equipment counts and frequency of GHG emitting practices are related to the number and size of compressor stations and the length of transmission pipelines.

Natural gas is also injected and stored in underground formations, or stored as LNG in above ground storage tanks during periods of low demand (e.g., spring or fall), and then withdrawn, processed, and distributed during periods of high demand (e.g., winter and summer). Compressors, pumps, and dehydrators are the primary contributors to emissions from these underground and LNG storage facilities. Equipment counts and GHG emitting practices are related to the number of storage stations.

Imported and exported LNG also requires transportation and storage. These processes are similar to LNG storage and require compression and cooling processes. GHG emissions in this segment are related to the number of LNG import and export terminals and LNG storage facilities. Further details are provided on the individual sources of GHG emissions for all of transmission and storage in Appendix A.

Natural Gas Distribution Natural gas distribution pipelines take high-pressure gas from the transmission pipelines at "city gate" stations, reduce and regulate the pressure, and distribute the gas through primarily underground mains and service lines to individual end users. There are also underground regulating vaults between distribution mains and service lines. GHG emissions from distribution systems are related to the pipelines, regulating stations and vaults, and customer/residential meters. Equipment counts and GHG emitting practices can be related to the number of regulating stations and the length of pipelines. Further details are provided on the individual sources of GHG emissions in Appendix A.

2. Types of Emissions Sources and GHGs

The three main GHGs that are relevant to the petroleum and natural gas industry are methane (CH_4), carbon dioxide CO_2, and nitrous oxide (N_2O). All three gases were taken into account when developing the threshold analysis.

Emissions from sources in the petroleum and gas industry can be classified into one of two types:

Combustion-related emissions

> Combustion-related emissions result from the use of petroleum-derived fuels and natural gas as fuel in equipment (e.g., heaters, engines, furnaces, etc.) in the petroleum and gas industry. CO_2 is the predominant combustion-related emission; however, because combustion equipment is less than 100 percent efficient, CH_4 and other unburned hydrocarbons are emitted. N_2O results from both fuel-bound nitrogen and nitrogen from atmospheric air. For methodologies to quantify GHG emissions from combustion, please refer to Subpart C of the GHG reporting rule

(40 CFR Part 98), except for GHG emissions from flaring, onshore production stationary and portable combustion GHG emissions, and combustion emissions from stationary equipment involved in natural gas distribution. For methodologies to quantify combustion emissions from flaring, onshore production stationary and portable equipment, and combustion emissions from stationary equipment involved in natural gas distribution, please refer to Subpart W.

Equipment leaks and vented emissions

The Intergovernmental Panel on Climate Change (IPCC) and the Inventory of U.S. GHG Emissions and Sinks[1] (henceforth referred to as the U.S. GHG Inventory) define fugitive emissions to be both intentional and unintentional emissions from systems that extract, process, and deliver fossil fuels. Intentional emissions are emissions designed into the equipment or system. For example, reciprocating compressor rod packing has a certain level of emissions by design, e.g., there is a clearance provided between the packing and the compressor rod for free movement of the rod that results in emissions. Also, by design, vent stacks in petroleum and natural gas production, natural gas processing, and petroleum refining facilities release natural gas to the atmosphere. Unintentional emissions result from wear and tear or damage to the equipment. For example, valves result in emissions due to wear and tear from continuous use over a period of time. Also, pipelines damaged during maintenance operations or corrosion result in unintentional emissions.

IPCC's definition is not intuitive since fugitive in itself means unintentional. Therefore, this document henceforth distinguishes between fugitive emissions (referred to as equipment leaks in the final subpart W) and vented emissions.

Equipment leaks are those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Vented emissions are intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

3. GHG Emissions from the Petroleum and Natural Gas Industry

The U.S. GHG Inventory provides estimates of equipment leaks and vented CH_4 and CO_2 emissions from all segments of the petroleum and natural gas industry. These estimates are based mostly on emissions factors available from two major studies conducted by EPA/Gas

[1] U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006, (April 2008), USEPA #430-R-08-005

Research Institute (EPA/GRI)[2] for the natural gas segment and EPA/Radian[3] for the petroleum segment. These studies were conducted in the early and late 1990s respectively.

Petroleum Segment

According to the 2006 U.S. GHG Inventory, EPA estimates that crude oil production operations accounted for over 97 percent of total CH_4 emissions from the petroleum industry. Crude oil transportation activities accounted for less than one half of a percent of total CH_4 emissions from the oil industry. Crude oil refining processes accounted for slightly over two percent of total CH_4 emissions from the petroleum industry because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the petroleum refineries. The 2006 U.S. GHG Inventory for Petroleum Systems currently estimates CO_2 emissions from only crude oil production operations. Research is underway to include other larger sources of CO_2 emissions in future inventories.

Natural Gas Segment

Emissions from natural gas production accounted for approximately 66 percent of CH_4 emissions and about 25 percent of non-energy CO_2 emissions from the natural gas industry in 2006. Processing facilities accounted for about 6 percent of CH_4 emissions and approximately 74 percent of non-energy CO_2 emissions from the natural gas industry. CH_4 emissions from the natural gas transmission and storage segment accounted for approximately 17 percent of emissions, while CO_2 emissions from natural gas transmission and storage accounted for less than one percent of the non-energy CO_2 emissions from the natural gas industry. Natural gas distribution segment emissions, which account for approximately 10 percent of CH_4 emissions from natural gas systems and less than one percent of non-energy CO_2 emissions, result mainly from equipment leaks from gate stations and pipelines.

Updates to Certain Emissions Sources

The EPA/GRI study used the best available data and somewhat restricted knowledge of industry practices at the time to provide estimates of emissions from each source in the various segments of the natural gas industry. In addition, this study was conducted at a time when CH_4 emissions were not a significant concern in the discussion about GHG emissions. Over the years, new data and increased knowledge of industry operations and practices have highlighted the fact that emissions estimates from the EPA/GRI study are outdated and potentially understated for some emissions sources. The following emissions sources are believed to be significantly underestimated in the U.S. GHG Inventory: well venting for liquids unloading; gas well venting during well completions; gas well venting during well workovers; crude oil and condensate storage tanks; centrifugal compressor wet seal degassing venting; scrubber dump valves; onshore combustion; and flaring.

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[2] EPA/GRI (1996) *Methane Emissions from the Natural Gas Industry*. Prepared by Harrison, M., T. Shires, J. Wessels, and R. Cowgill, eds., Radian International LLC for National Risk Management Research Laboratory, Air Pollution Prevention and Control Division, Research Triangle Park, NC. EPA-600/R-96-080a.

[3] EPA (1996) *Methane Emissions from the U.S. Petroleum Industry (Draft)*. Prepared by Radian. U.S. Environmental Protection Agency. June 1996.

The understatement of emissions in the U.S. GHG Inventory were revised using publicly available information for all sources and included in the analysis, except crude oil and condensate storage tanks and flares, and scrubber dump valves.[4] The revised estimates for storage tanks are available in "Analysis of Tank Emissions", found in the EPA-HQ-OAR-2009-0923-0002 docket, but the revised emissions have not been included in this analysis (See Appendix C for further details). For further discussion on the inclusion of scrubber dump valves in this rulemaking please see the analysis "Scrubber Dump Valves" in EPA-HQ-OAR-2009-0923 docket. EPA has limited publicly available information to accurately revise estimates on a national level for flaring and scrubber dump valves. For onshore combustion emissions, EPA used emissions estimates from the GHG inventory which are based on EIA data which EPA believes to be underestimated. Refer to section 4(c)(iii) of the TSD for further details. This is explained further below. Appendix B provides a detailed discussion on how new estimates were developed for each of the four underestimated sources. Table 1 provides a comparison of emissions factors as available from the EPA/GRI study and as revised in this document. Table 2 provides a comparison of emissions from each segment of the natural gas industry as available in the U.S. GHG Inventory and as calculated based on the revised estimates for the four underestimated sources.

Table 1: Comparison of Emissions Factors from Four Updated Emissions Sources

Emissions Source Name	EPA/GRI Emissions Factor	Revised Emissions Factor	Units
1) Well venting for liquids unloading	1.02	11	CH_4 – metric tons/year-well
2) Gas well venting during completions			
Conventional well completions	0.02	0.71	CH_4 – metric tons/year-completion
Unconventional well completions	0.02	177	CH_4 – metric tons/year-completion
3) Gas well venting during well workovers			
Conventional well workovers	0.05	0.05	CH_4 – metric tons/year-workover
Unconventional well workovers	0.05	177	CH_4 – metric tons/year-workover
4) Centrifugal compressor wet seal degassing venting	0	233	CH_4 – metric tons/year-compressor

1. Conversion factor: 0.01926 metric tons = 1 Mcf

[4] EPA did consider the data available from two new studies, TCEQ (2009) and TERC (2009). However, it was found that the data available from the two studies raise several questions regarding the magnitude of emissions from tanks and hence were not found appropriate for any further analysis until the issues are satisfactorily understood and/ or resolved by the authors and covered parties.

Table 2: Comparison of Process Emissions from each Segment of the Natural Gas and Petroleum Industries

Segment Name	U.S. GHG Inventory[1] Estimate for Year 2006 ($MMTCO_2e$)	Revised Estimate for Year 2006 ($MMTCO_2e$)
Production[2]	90.2	198.0
Processing	35.9	39.5
Transmission and Storage	48.4	52.6
Distribution	27.3	27.3

1. U.S. EPA (2008) *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006.*

2.Production includes equipment leaks and vented emissions from both the natural gas and petroleum sectors' onshore and offshore facilities.

After revising the U.S. GHG Inventory emissions estimates for the sources listed in Table 1, total equipment leak and vented CH_4 and CO_2 emissions from the petroleum and natural gas industry were 317 million metric tons of CO_2 equivalent ($MMTCO_2e$) in 2006. Of this total, the natural gas industry emitted 261 $MMTCO_2e$ of CH_4 and 28.50 $MMTCO_2e$ of CO_2 in 2006. Total CH_4 and CO_2 emissions from the petroleum industry in 2006 were 27.74 $MMTCO_2e$ and 0.29 $MMTCO_2e$ respectively.

4. Methodology for Selection of Industry Segments and Emissions Sources Feasible for Inclusion in a GHG Reporting Rule

It is important to develop criteria to help identify GHG emissions sources in the petroleum and natural gas industry most likely to be of interest to policymakers. To identify sources for inclusion in a GHG reporting rule, two preliminary steps were taken; 1) review existing regulations to identify emissions sources already being regulated, and 2) review existing programs and guidance documents to identify a comprehensive list of emissions sources for potential inclusion in the proposed rule.

The first step in determining emissions sources to be included in a GHG reporting rule was to review existing regulations that the industry is subject to. Reviewing existing reporting requirements highlighted those sources that are currently subject to regulation for other pollutants and may be good candidates for addressing GHG emissions. The second step was to establish a comprehensive list of emissions sources from the various existing programs and guidance documents on GHG emissions reporting. This provided an exhaustive list of emissions sources for the purposes of this analysis and avoided the exclusion of any emissions sources already being monitored for reporting under other program(s). Both of these steps are described below.

a. Review of Existing Regulations

The first step was to understand existing regulations and consider adapting elements of the existing regulations to a reporting rule for GHG emissions. When the Mandatory Reporting Rule development process began, there were three emissions reporting regulations and six emissions reduction regulations in place for the petroleum and natural gas industry, including one voluntary reporting program included in the Code of Federal Regulations. This table also includes EPA's final GHG reporting rule, which requires certain petroleum and gas facilities to report their combustion-related emissions. Table 3 provides a summary of each of these nine reporting and reduction regulations.

Table 3: Summary of Regulations Related to the Petroleum and Natural Gas Industry

Regulation	Type	Point/ Area/ Major/ Mobile Source	Gases Covered	Segment and Sources
EPA 40 CFR Part 98 Final Rule: Mandatory Reporting of Greenhouse Gases	Mandatory Emissions Reporting	Point, Area, Biogenic	CO_2, CH_4, N_2O, HFCs, PFCs, , SF_6, NF_3, and HFE	Annual reporting of GHG emissions from direct emitters (including petroleum and natural gas systems) and suppliers of industrial GHGs in the United States.
EPA 40 CFR Part 51 – Consolidated Emissions Reporting	Emissions Reporting	Point, Area, Mobile,	VOCs, NOx, CO, NH_3, PM_{10}, $PM_{2.5}$	All segments of the petroleum and natural gas industry
DOE 10 CFR Part 300 – Voluntary GHG Reporting	Voluntary GHG Reporting	Point, Area, Mobile	CO_2, CH_4, N_2O, HFCs, PFCs, , SF_6, and CFCs	All segments of the petroleum and natural gas industry
EPA 40 CFR Part 60, Subpart KKK	NSPS[2]	Point	VOCs	Onshore processing plants; sources include compressor stations, dehydration units, sweetening units, underground storage tanks, field gas gathering systems, or liquefied natural gas units located in the plant
EPA 40 CFR Part 60, Subpart LLL	NSPS[2]	Point	SO_2	Onshore processing plants; Sweetening units, and sweetening units followed by a sulfur recovery unit
EPA 40 CFR Part 63, NESHAP[1], Subpart HHH	MACT[3]	Point (Glycol dehydrators, natural gas transmission and storage facilities)	HAPs	Glycol dehydrators

EPA 40 CFR Part 63, NESHAP[1], Subpart HH	MACT[3]	Major and Area (petroleum and natural gas production, up to and including processing plants)	HAPs	Point Source - Glycol dehydrators and tanks in petroleum and natural gas production; equipment leaks at gas processing plants Area Source - Triethylene glycol (TEG) dehydrators in petroleum and natural gas production
EPA 40 CFR Part 63, NESHAP[1], –Subpart YYYY	MACT[3]	Major and Area (Stationary Combustion Turbine)	HAPs	All segments of the petroleum and natural gas industry
EPA 40 CFR Part 63, NESHAP[1], Subpart ZZZZ	MACT[3]	Major and Area (Reciprocating Internal Combustion Engines)	HAPs	All segments of the petroleum and natural gas industry
Notes: [1]National Emission Standards for Hazardous Air Pollutants [2]New Source Performance Standard [3]Maximum Allowable Control Technology				

Table 3, indicates that only DOE 10 CFR Part 300 includes the monitoring or reporting of CH_4 emissions from the petroleum and natural gas industry. However, this program is a voluntary reporting program and is not expected to have a comprehensive coverage of CH_4 emissions. Although some of the sources included in the other regulations lead to CH_4 emissions, these emissions are not reported. The MACT regulated sources are subject to Part 70 permits which require the reporting of all major HAP emission sources, but not GHGs. GHG emissions from petroleum and natural gas operations are not systematically monitored and reported; therefore these regulations and programs cannot serve as the foundation for a GHG emissions reporting rule.

b. Review of Existing Programs and Studies

The second step was to review existing monitoring and reporting programs to identify all emissions sources that are already monitored under these programs. When the Mandatory Reporting Rule development process began, six reporting programs and six guidance documents were reviewed. Table 4 summarizes this review, highlighting monitoring points identified by the programs and guidance documents.

Table 4 shows that the different monitoring programs and guidance documents reflect the points of monitoring identified in the U.S. GHG Inventory, which are consistent with the range of sources covered in the 2006 IPCC Guidelines. Therefore, the U.S. GHG Inventory was used to provide the initial list of emissions sources for determining the emissions sources that can be potentially included in the rule.

The preliminary review provided a potential list of sources, but did not yield any definitive indication on the emissions sources that were most suitable for potential inclusion in a reporting program. A systematic assessment of emissions sources in the petroleum and natural gas industry was then undertaken to identify the specific emissions sources (e.g., equipment or component) for inclusion in a GHG reporting rule.

Table 4: Summary of Program and Guidance Documents on GHG Emissions Monitoring and Reporting

Reporting Program/Guidance	Source Category (or Fuel)	Coverage (Gases or Fuels)	Points of Monitoring	Monitoring Methods and/or GHG Calculation Methods*
2006 IPCC Guidelines for National GHG Inventory, Volume 2, Chapter 4	Petroleum and Gas – all segments	CH_4, non-combustion CO_2 and other GHG gases	Oil and natural gas systems fugitive equipment leaks, evaporation losses, venting, flaring, and accidental releases; and all other fugitive emissions at oil and natural gas production, transportation, processing, refining, and distribution facilities from equipment leaks, storage losses, pipeline breaks, well blowouts, land farms, gas migration to the surface around the outside of wellhead casing, surface casing vent bows, biogenic gas formation from tailings ponds and any other gas or vapor releases not specifically accounted for as venting or flaring	Accounting/ reporting methodologies and guidelines Companies choose a base year for which verifiable emissions data are available. The base year emissions are used as an historic control against which the company's emissions are tracked over time. This ensures data consistency over time. Direct measurement of GHG emissions by monitoring concentration and flow rate can also be conducted. IPCC methodologies are broken down into the following categories: - Tier I calculation-based methodologies for estimating emissions involve the calculation of emissions based on activity data and default industry segment emission factors - Tier II calculation-based methodologies for estimating emissions involve the calculation of emissions based on activity data and country-specific industry segment emission factors or by performing a mass balance using country-specific oil and/or gas production information Tier III calculation-based methodologies for estimating emissions involve "rigorous bottom-up assessment by primary type of source (e.g. evaporation losses, equipment leaks) at the individual facility level with appropriate accounting of contributions from temporary and minor field or well-site installations. The calculation of emissions is based on activity data and facility-specific emission factors
AGA - Greenhouse Gas Emissions Estimation Methodologies, Procedures, and Guidelines	Gas – Distribution	CH_4, non-combustion CO_2 and other GHG gases	Segment-level counts, equipment discharges (i.e. valves, open-ended lines, vent stacks), and segment	Equipment or segment emissions rates and engineering calculations Tier I, II (IPCC) - facility level emissions rates

for the Natural Gas Distribution Sector			capacities, facility counts and capacities	Tier III (IPCC) - equipment emissions rates for intentional emissions, process level emissions rates, and process/equipment level emissions rate
API - Compendium of GHG Emissions Estimation Methodologies for the Oil and Gas Industry	Gas and Petroleum – all segments	CH_4, non-combustion CO_2	Equipment discharges (e.g. valves, open-ended lines, vent stacks), vent stacks for equipment types, tank PRV/vents, and facility input	Equipment or segment emissions rates and engineering calculations Tier II (IPCC) - facility level emissions rates Tier III (IPCC) - equipment emissions rates for intentional emissions, process level emissions rates, tank level emissions rates, and process/equipment level emissions rate (BY SEGMENT)
California Climate Action Registry General Reporting Protocol, March 2007	All legal entities (e.g. corporations, institutions, and organizations) registered in California, including petroleum and gas – all segments	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in indirect and direct emission of GHG gases for the entity	Provides references for use in making fugitive calculations The CCAR does not specify methodology to calculate fugitive emissions
California Mandatory GHG Reporting Program	Petroleum – Refineries	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in CH_4 and CO_2 fugitive emissions for petroleum refineries	Continuous monitoring methodologies and equipment or process emissions rates CO_2 process emissions can be determined by continuous emissions monitoring systems. Methods for calculating fugitive emissions and emissions from flares and other control devices are also available
DOE Voluntary Reporting of Greenhouse Gases Program (1605(b))	Petroleum and Gas- All Segments	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in direct and indirect emissions of GHG gases for the corporation or organization	Direct, site-specific measurements of emissions or all mass balance factors Mass-balance approach, using measured activity data and emission factors that are publicly documented and widely reviewed and adopted by a public agency, a standards-setting organization or an industry group Mass-balance approach, using measured activity data and other emission factors

				Mass balance approach using estimated activity data and default emissions factors.
EU ETS 1st and 2nd Reporting Period	Petroleum – Refining	Non-combustion CO_2	Hydrogen production	Engineering calculations Operators may calculate emissions using a mass-balance approach
INGAA - GHG Emissions Estimation Guidelines for Natural Gas Transmission and Storage, Volume 1	Gas - Transmission/Storage	CH_4, non-combustion CO_2	Segment-level counts, equipment discharges (i.e. valves, open-ended lines, vent stacks), and segment capacities, facility counts and capacities	Equipment or segment emissions rates Tier I (IPCC)- segment level emissions rates from intentional and unintentional releases Tier II - equipment level emissions rates for intentional releases Tier II (IPCC) – facility and equipment level emissions rates for unintentional leaks Engineering calculation methodologies for: - Pig traps - Overhauls - Flaring
IPIECA - Petroleum Industry Guidelines for Reporting GHG Emissions	Petroleum and Gas – all segments	CH_4, non-combustion CO_2 and other GHG gases	Refers to API Compendium points of monitoring: Equipment discharges (e.g. valves, open-ended lines, vent stacks), vent stacks for equipment types, tank PRV/vents, and facility input	Tiers I, II, and III (IPCC) definitions and reporting methods for all fugitive and vented GHG emissions in the oil and gas industry
New Mexico GHG Mandatory Emissions Inventory	Petroleum refineries	CO_2 reporting starts 2008 , CH_4 reporting starts 2010	Equipment discharges (e.g. valves, pump seals, connectors, and flanges)	- 2009 reporting procedures will be made available in 10/2008

The Climate Registry (General Reporting Protocol for the Voluntary Reporting Program), 2007	All legal entities (e.g. corporations, institutions, and organizations) including petroleum and gas – all segments	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in emission of GHG gases for the entity	Continuous monitoring methodologies and equipment or process emissions rates Measurement-based methodology monitor gas flow (continuous, flow meter) and test methane concentration in the flue gas. Calculation-based methodologies involve the calculation of emissions based on activity data and emission factors
Western Regional Air Partnership (WRAP)	Petroleum and Gas – all segments	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in emission of GHG gases for the entity	Provides quantification methods for all sources from all sectors of the petroleum and gas industry considered in the rule. Quantification methods are typically engineering equation; however, parameters for the equations in several cases require measurement of flow rates, such as from well venting
World Resources Institute/ World Business Council for Sustainable Development GHG Protocol Corporate Standard, Revised Edition 2003	Organizations with operations that result in GHG (GHG) emissions e.g. corporations (primarily), universities, NGOs, and government agencies. This includes the oil and gas industry	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in direct and indirect emission of GHG gases for the corporation or organization	Provides continuous monitoring methodologies and equipment or process emissions rates Companies need to choose a base year for which verifiable emissions data are available and specify their reasons for choosing the year. "The base year emissions are used as an historic datum against which the company's emissions are tracked over time. Emissions in the base year should be recalculated to reflect a change in the structure of the company, or to reflect a change in the accounting methodology used. This ensures data consistency over time." Direct measurement of GHG emissions by monitoring concentration and flow rate can be conducted. Calculation-based methodologies for estimating emissions involve the calculation of emissions based on activity data and emission factors

i. EPA 2007 Cooperative Agreement with University of Texas (UT) Austin to Update GRI/ EPA Study Estimated Emission Factors

In the past decade, there has been growing interest in better understanding CH_4 emissions sources from the petroleum and natural gas industry. As mentioned above, the seminal study, upon which much of the current knowledge on CH_4 emission factors is based, is *Methane Emissions from the Natural Gas Industry (GRI/EPA 1996).* In the United States, the GRI/EPA Study serves as the basis for most CH_4 estimates from natural gas systems in EPA's *Inventory of U.S. GHG Emissions and Sinks*, EPA's Natural Gas STAR Program, Methane to Markets International Program, State Inventories, the American Petroleum Institute (API) Compendium, a transmission and distribution protocol by the Interstate Natural Gas Association of America (INGAA), as well as all of the organizations that reference these documents and programs in their individual work. The GRI/EPA Study was also evaluated for its relevance for a separate effort to develop a transmission and distribution GHG accounting protocol by the California Climate Action Registry. Internationally, the GRI/EPA Study is the source for many of the emission factors included in the Intergovernmental Panel on Climate Change Guidelines for National Greenhouse Gas Inventories.

Although the GRI/EPA Study has been the cornerstone for estimating CH_4 emissions from the natural gas industry to date, the data on which the study is based are now over a decade and a half old and in some cases (e.g., wells, compressors), not always reflective of current conditions in the United States. In recognition of the fact that existing methane emission factors were becoming quickly outdated, in 2007 EPA funded a 4-year cooperative agreement with UT Austin to support research and, as appropriate, measurement studies to update selected CH_4 emission factors from the 1996 GRI study. The cooperative agreement identified a small set of 11 priority sources in different industry segments on which to focus emission factor development. With the limited budget available, as of mid-2010, the project has begun work on updating emission factors for reciprocating and centrifugal compressors only. Specifically, the project team has initiated preliminary measurement studies at compressor stations at natural gas transmission and storage facilities owned by two companies. Now approaching its final year, the project team is currently evaluating the most efficient use of the remaining resources; specifically whether to undertake additional measurements on transmission and storage facilities to gain the most robust data set possible, or to use remaining funds on another source of emissions in the production, processing, transmission, or distribution segments.

The UT Austin cooperative agreement was initiated to develop representative national emission factors- it was not designed, like the GHG reporting rule, to comprehensively collect actual GHG emissions data to support a range of future climate policies. To meet the goals of the reporting rule, for larger sources, such as compressors, it is critical that EPA collect actual emissions data in order to understand trends and also connect emissions to specific equipment and types of operations. For example, if there is a trend regarding the maintenance of rod packing over time, this information would not be obtained through a static data set based on national compressor-level emission factors. .

Further, the limited budget available for the UT Austin study will not allow for emissions information from a large number of sources; the GHG reporting rule will be collecting comprehensive actual emissions data and other relevant information from major sources across the United States petroleum and natural gas industry for all U.S. facilities over 25,000 mtCO2e. In addition, the GHG reporting rule will collect applicable information (e.g., equipment component counts and operational data) needed to verify the reported GHG data and support future climate policy analysis.

c. Selection of Emissions Sources for Reporting

When identifying emissions sources for inclusion in a GHG reporting rule, two questions need addressing. The first is defining a facility. In other words, what physically constitutes a facility? The second is determining which sources of emissions should a facility report? Including or excluding sources from a GHG reporting rule without knowing the definition of a facility is difficult. Therefore, both the facility definition and emissions source inclusion (or exclusion) were reviewed to arrive at a conclusion.

i. Facility Definition Characterization

Typically, the various regulations under the Clean Air Act (CAA) define a facility as a group of emissions sources all located in a contiguous area and under the common control of the same person (or persons). This definition can be easily applied to offshore petroleum and natural production, onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, and LNG import and export equipment since the operations are all located in a clearly defined boundary. However, as discussed further below, this definition does not as directly lend itself to all industry segments, such as onshore petroleum and natural gas production, natural gas distribution, and petroleum transportation sectors.

Onshore petroleum and natural gas production operations can be very diverse in arrangement. Sometimes crude oil and natural gas producing wellheads are far apart with individual equipment at each wellhead. Alternatively, several wells in close proximity may be connected to common pieces of equipment. Whether wells are connected to common equipment or individual equipment depends on factors such as distance between wells, production rate, and ownership and royalty payment. New well drilling techniques such as horizontal and directional drilling allow for multiple wellheads to be located at a single location (or pad) from where they are drilled to connect to different zones in the same reservoir. Therefore, the conventional facility definition of a “contiguous area” under a common owner/ operator cannot be easily applied to the onshore petroleum and natural gas production industry segment. Refer to Section 4(c)(iv) in the TSD for a more detailed discussion of the facility definition for onshore petroleum and natural gas production.

An alternative to a physical facility definition is the use of a corporate level reporter definition. In such a case the corporation that owns or operates petroleum and natural gas production operations could be required to report. Here the threshold for reporting could require that an individual corporation sum up GHG emissions from all the fields it is operating in and determine if its total emissions surpass the threshold. See Appendix D for further discussion of this issue.

In the natural gas distribution segment the meters and regulators in the distribution segment are primarily located at small stations or underground vaults distributed over large urban or suburban regions. Individually defining each station or vault as a facility is impractical owing to the size and expected magnitude of emissions from single stations. However, a logical grouping of distribution equipment exists at the regulated local distribution company level. The precedent for reporting at this type of facility already exists under the Pipeline and Hazardous Materials Safety Administration (PHMSA) requirements under CFR Title 49 Section 191.11. Refer to Section 4(c)(iv) of the TSD for a more detailed discussion of the definition for natural gas distribution. As explained in the Response to Comments, the PHMSA regulations primarily relate to pipeline safety provisions, and are unrelated to information EPA seeks to collect under this rule.

ii. Selection of Potential Emissions Sources for Reporting

Given that there are over 100 emissions sources[1] in the petroleum and natural gas industry, it is important to target sources which contribute significantly to the total national emissions for the industry. This avoids an excessive reporting burden on the industry, but at the same time enables maximum coverage for emissions reporting. The selection of emissions sources for potential inclusion in the proposed rulemaking was conducted in three steps.

Step 1: Characterize Emissions Sources

The U.S. GHG Inventory was used as the complete list of sources under consideration for inclusion in a reporting rule. The U.S. GHG Inventory was also used to provide all relevant emissions source characteristics such as type, number of sources across industry segments, geographic location, emissions per unit of output, total national emissions from each emissions source, and frequency of emissions. Also, information included in the U.S. GHG Inventory and the Natural Gas STAR Program technical studies were used to identify the different monitoring methods that are considered the best for each emissions source. If there are several monitoring methods for the same source, with equivalent capabilities, then the one with lower economic burden was considered in the analysis.

Step 2: Identify Selection Criteria and Develop Decision Tree for Selection

There are several factors that impact the decision on whether an emissions source should be included for reporting. A discussion of the factors follows below.

- *Significant Contribution to U.S. GHG Inventory* – Emissions sources that contribute significant emissions can be considered for potential inclusion in the rule, since they increase the coverage of emissions reporting. Typically, in petroleum and natural gas facilities, 80 percent or more of the facility emissions are reported to be from approximately 10 percent of the emissions sources. This is a good benchmark to ensure the adequate coverage of emissions while reducing the number of emissions sources required for reporting thus, keeping the reporting burden to a minimum. Emissions sources in each segment of the natural gas and petroleum industry can be sorted into two main categories: (1) top sources contributing to 80 percent of the emissions from the segment, and (2) the remaining sources contributing to the remaining 20 percent of the emissions from that particular segment. This can be easily achieved by determining the emissions contribution of each emissions source to the segment it belongs to, listing the emissions sources in a descending order, and identifying all the sources at the top that contribute to 80 percent of the emissions. Appendix A provides a listing of all emissions sources in the U.S. GHG Inventory and a breakdown of the top emissions sources by industry segment.

- *Type of Emissions* – The magnitude of emissions per unit or piece of equipment typically depends on the type of emissions. Vented emissions per unit source are usually much higher than equipment leak emissions from a unit source. For example, emissions from compressor blowdown venting for one compressor are much higher than equipment leak emissions from any one unit component source on the compressor. The burden from covering emissions reporting from each unit source (i.e. dollar per ton of emissions reported) is typically much lower in the case of venting sources in comparison to equipment leak emission sources when the same monitoring method is used. Therefore, vented sources could be treated separately from equipment leak sources for assessment of monitoring requirements.

- *Best Practice Monitoring Method(s)* – Depending on the types of monitoring methods typically used, a source may or may not be a potential for emissions reporting. There are four types of monitoring methods as follows:

    - Continuous monitoring – refers to cases where technologies are available that continuously monitor either the emissions from a source or a related parameter that can be used in estimating emissions. For example, continuous monitoring meters can determine the flow rate and in line analyzers can determine the composition of emissions from a process vent.
    - Periodic monitoring – refers to monitoring at periodic intervals to determine emissions from sources. For example, leak detection and measurement equipment can be used on a recurring basis to identify and measure an emissions rate from equipment.
    - Engineering calculations – refers to estimation of emissions using engineering parameters. For example, emissions from a vessel emergency release can be estimated by calculating the volume of the emitting vessel.
    - Emissions factors – refers to utilizing an existing emissions rate for a given source and multiplying it by the relevant activity data to estimate emissions. For example, emissions per equipment unit per year can be multiplied by the number of pieces of equipment in a facility to estimate annual emissions from that equipment for the facility.

- *Accessibility of emissions sources* – Not all emissions sources are directly accessible physically for emissions detection and/or measurement. For example, connectors on pipelines, pressure relief valves on equipment, and vents on storage tanks may be out of direct physical reach and could require the use of bucket trucks or scaffolding to access them. In such cases requiring emissions detection and measurement may not always be feasible such as with leak detection equipment that requires the operator to be in close physical proximity to the equipment. Also, such requirements could pose health and safety hazards or lead to large cost burden. The accessibility of emissions sources was considered when addressing monitoring requirements and determining the type of leak detection equipment allowed under Subpart W.

- *Geographical dispersion of emissions sources* – The cost burden for detecting and measuring emissions will largely depend on the distance between various sources. Monitoring methods will have to be chosen considering the dispersion of emissions sources.

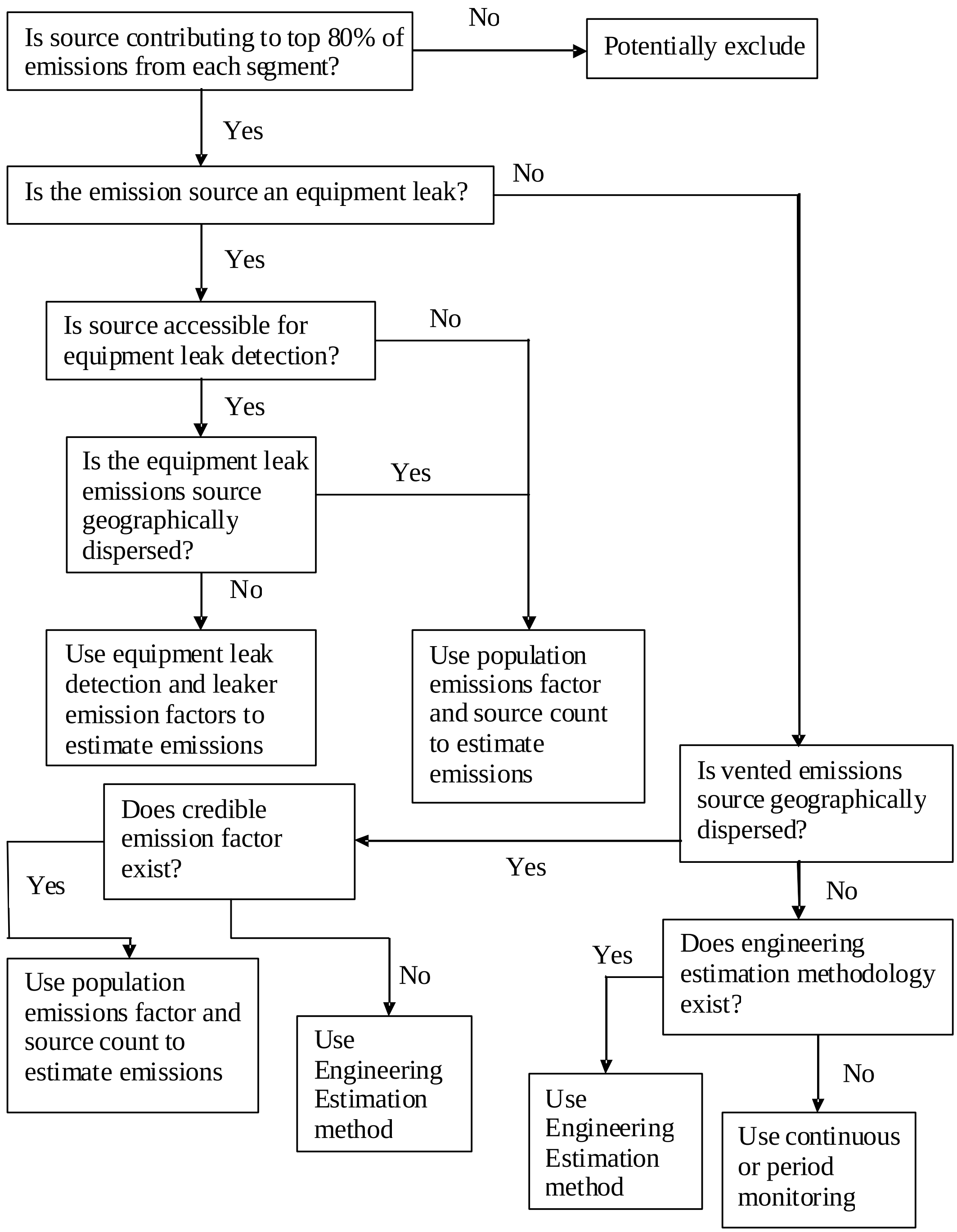
- *Applicability of Population or Leaker Emission factors* – When the total emissions from all leaking sources of the same type are divided by the total count of that source type then the resultant factor is referred to as population emissions factor. When the total emissions from all leaking sources of the same type are divided by the total count of leaking sources for that source type then the resultant factor is referred to as leaker emissions factor. For example, in an emissions detection and measurement study, if 10 out of 100 valves in the facility are found leaking then:

    - the total emissions from the 10 valves divided by 100 is referred to as population emissions factor
    - the total emissions from the 10 valves divided by 10 is referred to as leaker emissions factor

  Requiring emissions leak detection and application of a corresponding emissions factor results in lower reporting burden as compared to conducting actual measurements. Furthermore, the use of leaker emissions factors provides an estimate of "actual" emissions as opposed to the use of population emissions factor where the emissions from each facility can only be a "potential" of emissions.

Based on the criteria outlined above, a decision process was developed to identify the potential sources that could be included in the reporting rule. **Error! Reference source not found.** shows the resulting decision tree that includes these criteria and supported the decision-making process. The decision process provided in **Error! Reference source not found.** was applied to each emissions source in the natural gas segment of the U.S. GHG Inventory. The onshore petroleum production segment has emissions sources that either are equivalent to their counterparts in the natural gas onshore production segment or fall in the 20 percent exclusion category. Only CH_4 emissions from the petroleum segment were taken into consideration for this exercise given that, for most sources, non-combustion CO_2 emissions from the petroleum segment are negligible in comparison to CH_4 emissions from the same sources. The exception to these are flares and acid gas recovery units in EOR operations that have large CO2 emission, but EPA does not have any emissions estimates for these source (see Section 3 and (4)(c)(iv) of the TSD). Appendix A summarizes the results of this analysis and provides guidance on the feasibility of each of the monitoring options discussed previously.

Figure 1: Decision Process for Emissions Source Selection



iii. Address Sources with Large Uncertainties

As described in Section 3 of the TSD, the petroleum and natural gas industry inventories are primarily based on the EPA/GRI 1996 Study, however the emissions for several sources in the EPA/GRI study do not correctly reflect today's operational practices. In some cases, comprehensive and sufficient information is not publicly available to revise the national Inventory estimates. In cases where public data are available, it is often incomplete and does not represent the industry at a national level.

Over the years, new data and increased knowledge of industry operations and practices have highlighted the fact that emissions estimates for certain sources are understated in the US Inventory

- Condensate and petroleum storage tanks
- Natural gas well workovers
- Natural gas well completions
- Natural gas well liquid unloading
- Centrifugal compressor wet seals
- Flares
- Scrubber dump valve emissions through tanks
- Onshore combustion emissions

The decision tree was not necessarily ideal for the sources listed above because they are known to be underestimated in current inventories. Therefore, after careful evaluation, EPA determined that these are significant emission sources that should be included in a comprehensive petroleum and natural gas systems GHG reporting rule. The following emissions sources are believed to be significantly underestimated in the U.S. GHG Inventory: well venting for liquids unloading; gas well venting during well completions; gas well venting during well workovers; crude oil and condensate storage tanks; centrifugal compressor wet seal degassing venting; scrubber dump valves; onshore combustion; and flaring. Refer to Appendix B for a detailed discussion on how new estimates were developed for each of the underestimated sources; natural gas well workovers, natural gas well completions, and natural gas well blowdowns. For centrifugal wet seals, EPA used an emission factor from a presentation given at the 24th World Gas Conference.[5]

In addition, the U.S. GHG Inventory includes reasonable estimation of CH_4 and CO_2 combustion emissions from natural gas engines and turbines (except in onshore production), as well as petroleum refineries. Emissions from these sources were not considered further here because methods for calculating and reporting emissions from these sources are addressed in the background technical support documents for Stationary Combustion

[5] The Bylin, Carey (EPA) study reported wet seal degassing emission measurements from 48 centrifugal compressors. Five centrifugal compressors were found not emitting while, the remaining 43 emitted 14,860 thousand cubic meters per year. Twenty-three cubic feet per minute was determined by dividing the 14,860 by the 43 centrifugal compressors. Bylin, Carey (EPA), et. al (2009) *Methane's Role in Promoting Sustainable Development in Oil and Natural Gas Industry*. <presented at 24th World Gas Conference>

described in Subpart C and Petroleum Refineries described in Subpart Y of the of the final GHG reporting rule (40 CFR Part 98) respectively.

Onshore Combustion Emissions:
The EPA estimates onshore production combustions emissions in its national GHG inventory. However, there are two challenges with the way these data are collected that make it difficult to use this data to support potential future climate policies. First, combustion-related emissions are reported in the national inventory at a fairly high level of aggregation, making it difficult to discern facility-level emissions. Second, there are concerns that this aggregate estimate is underestimating the total emissions from this source. The National Inventory of U.S. GHG Emissions and Sinks uses the "lease and plant" fuel consumption data as reported by the Energy Information Administration (EIA) as activity data to apply an emissions factor to estimate emissions. However, EIA estimates the lease and plant volume using data available from individual petroleum and natural gas producing States. The States in turn require only the voluntary reporting of this data from petroleum and natural gas producing operators raising questions as to whether the national data are complete. In addition, this estimate may not include all of the combustion emissions resulting from contracted and/ or portable combustion equipment. Given the high level of aggregation of this data and the potential omissions of some fuel consumption in onshore production in the National Inventory, this source type would be valuable to include in the rule for a more complete picture of facility-related emissions from onshore production facilities.

iv. Identify Industry Segments to be Included

Based on the understanding of facility definitions for each segment of the petroleum and natural gas industry and the identification of potential sources for inclusion in a GHG reporting rule, the industry segments could be defined as follows:

> *Onshore Petroleum and Natural Gas Production Segment* – Onshore petroleum and natural gas production is an important segment for inclusion in a GHG reporting program, due to its relatively large share of emissions. However, in order to include this segment, it is important to clearly articulate how to define the facility and identify who is the reporter. Onshore production operations are a challenge for emissions reporting using the conventional facility definition of a "contiguous area" under a common owner/ operator. EPA evaluated possible options for defining a facility for onshore petroleum and natural gas production in order to ensure that the reporting delineation is clear, to avoid double counting, and ensure appropriate emissions coverage. One potential option considered was to define a facility for this segment as all petroleum or natural gas equipment on a well pad or associated with a well pad and CO_2 EOR operations that are under common ownership or common control and that are located in a single hydrocarbon basin as defined in 40 CRF Part 98.238. This includes leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility. In this case, the operator would be the

company or corporation holding the required permit for drilling or operating. If the petroleum and natural gas wells operate without a drilling or operating permit, the person or entity that pays the state or federal business income taxes may also be considered the owner or operator. Operational boundaries and basin demarcations are clearly defined and are widely known, and reporting at this level would provide the necessary coverage of GHG emissions to inform policy. This facility definition for onshore petroleum and natural gas production will result in 85% GHG emissions coverage of this industry segment.

EPA reviewed other possible alternatives to define a production facility such as at the field level. In such cases, the company (or corporation) operating in the field would report emissions. EPA analyzed this option and found that such a field level definition would result in a larger number of reporters and in lower emissions coverage than basin level reporting, since fields are typically a segment of a basin.

In addition to basin and field level reporting, one additional alternative is identifying a facility as an individual well pad, including all stationary and portable equipment operating in conjunction with that well, including drilling rigs with their ancillary equipment, gas/liquid separators, compressors, gas dehydrators, crude petroleum heater-treaters, gas powered pneumatic instruments and pumps, electrical generators, steam boilers and crude oil and gas liquids stock tanks. In reviewing this option, EPA found that defining a facility as a single wellhead would significantly increase the number of reporters to a program, lower emissions coverage, and potentially raise implementation issues. For a complete discussion of the threshold analysis and estimated emissions coverage for each of the onshore petroleum and natural gas production facility options considered, refer to Section 5 of the TSD.

- *Offshore Petroleum and Natural Gas Production Segment* – All of the production activities offshore take place on platforms. These platforms can be grouped into two main categories; wellhead platforms and processing platforms. Wellhead platforms consist of crude oil and/ or natural gas producing wellheads that are connected to processing platforms or send the hydrocarbons onshore. Processing platforms consist of wellheads as well as processing equipment such as separators and dehydrators, in addition to compressors. All platforms are within a confined area and can be distinctly identified as a facility. Since all sources are within a small area on and around the platform, all sources of emissions on or associated with offshore platforms could be monitored and reported.

- *Onshore Natural Gas Processing Segment* –Processing plants process the gas received from production and/ or gathering or boosting segments to remove hydrogen sulfide (H_2S) and/ or CO_2 from the natural gas, if any, separate the higher molecular weight hydrocarbons (ethane, propane, butane, pentanes, etc.) from the natural gas and compress the natural gas to be injected into the onshore natural gas transmission segment. Natural gas processing facilities have a well defined boundary within which all processes take place. All emissions sources in processing facilities could be monitored and included in a GHG reporting rule.

- *Onshore Natural Gas Transmission Compression* – Transmission compressor stations are the largest source of emissions on transmission pipelines and meet the conventional definition of a facility. Given the relatively large share of emissions from the compressor station, as compared to the pipeline segments between transmission compressor stations, the station may be the most logical place to capture emissions from this segment.

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- *Underground Natural Gas Storage, LNG Storage, and LNG Import and Export Segments* – All operations in an underground natural gas storage facility (except wellheads), LNG storage facility, and LNG import and export facilities are confined within defined boundaries. In the case of underground natural gas storage facilities, the wellheads are within short distances of the main compressor station such that it is feasible to monitor them along with the stations themselves. All three segments could be included in a GHG reporting rule.

- *Natural Gas Distribution Segment* – The distribution segment metering and regulator above ground stations and below ground vaults are identifiable as facilities. However, the magnitude of emissions from a single station or vault may not be significant, which would result in minimal coverage of emissions from this segment. Multiple stations or vaults collectively contribute to a significant share of emissions from the natural gas industry nationally, but they may not be considered one facility because they are not contiguous and there is no logical grouping unless the entire system is considered.

  Another option for including distribution sector is adapting the facility definition from Subpart NN, Suppliers of Natural Gas and Natural Gas Liquids, of the MRR which defines a local distribution company (LDC) as a facility. In this case, the definition of natural gas distribution would be the distribution pipelines, metering and regulator stations and vaults that are operated by a Local Distribution Company (LDC) that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system This facility definition provides clear reporting delineation because the equipment that they operate is clearly known, the ownership is clear to one company, and reporting at this level is consistent with the final MRR as well as other existing data reporting mechanisms. Additionally, this aggregation of equipment will include all the significant sources of emissions from the segment.

- *Petroleum Transportation Segment* – All the sources in the petroleum transportation segment were excluded as a result of the decision process. Hence, this segment may not be amenable to inclusion in a reporting program.

5. Options for Reporting Threshold

For each segment in the petroleum and natural gas industry identified above as amenable to a reporting program, four thresholds were considered for emissions reporting as applicable to an individual facility; 1,000 metric tons of CO_2 equivalent ($MtCO_2e$) per year, 10,000 $MtCO_2e$, 25,000 $MtCO_2e$, and 100,000 $MtCO_2e$. A threshold analysis was then conducted on each segment to determine which level of threshold was most suitable for each industry segment. CH_4, CO_2, and N_2O emissions from each segment were included in the threshold analysis.

a. Threshold Analysis

For each segment, a threshold analysis was conducted to determine how many of the facilities in the segment exceed the various reporting thresholds, and the total emissions from these impacted facilities. This analysis was conducted considering equipment leak and vented CH_4 and CO_2 emissions, and incremental combustion CH_4, CO_2, and N_2O emissions. Incremental combustion emissions are those combustion emissions from facilities not already reported under Subpart C of the 40 CFR Part 98, but are required to be reported because the combined process emissions from Subpar W plus combustion emissions exceed the 25,000 metric tons CO_2e reporting threshold. The equipment leak and vented emissions estimates available from the U.S. GHG Inventory were used in the analysis. However, the emissions estimates for four sources, well venting for liquids unloading, gas well venting during well completions, gas well venting during well workovers, and centrifugal compressor wet seal degassing venting from the U.S. GHG Inventory were replaced with revised estimates developed as described in Appendix B. Centrifugal compressor emissions were revised using centrifugal compressor activity data from the U.S. Inventory and an emission factor from the 24th World Gas Conference[5]. Incremental combustion emissions were estimated using gas engine methane emissions factors available from the GRI study, back calculating the natural gas consumptions in engines, and finally applying a CO_2 emissions factor to the natural gas consumed as fuel. Nitrous Oxide emissions were also calculated similarly. In the case of offshore petroleum and natural gas production platforms combustion emissions are already available from the GOADS 2000 study analysis and hence were directly used for the threshold analysis. It must be noted that the threshold analysis for 40 CFR Part 98, Subpart W includes all equipment leak and vented emissions, but only incremental combustion emissions. Due to these reasons the total emissions from the threshold analysis does not necessarily match the U.S. GHG Inventory for all segments of the petroleum and natural gas industry. A detailed discussion on the threshold analysis is available in Appendix C.

The general rationale for selecting a reporting threshold could be to identify a level at which the incremental emissions reporting between thresholds is the highest for the lowest incremental increase in number of facilities reporting between the same thresholds. This would ensure maximum emissions reporting coverage with minimal burden on the industry. For example, for onshore production the emissions reporting coverage is 74 percent and the corresponding reporting facilities coverage is 2 percent for a threshold of 100,000 $MtCO_2e$ per year. The incremental emissions and facilities coverage is 11 and 2 percent (85 percent minus 74 percent and 4 percent minus 2 percent), respectively, for a 25,000 $MtCO_2e$ per year threshold. However, at the next reporting threshold level of 10,000 $MtCO_2e$ per year the incremental emissions and entities coverage is 6 and 5 percent, respectively. It can be seen that the incremental coverage of emissions decreases but the coverage of facilities increases.

Table 5 provides the details of the threshold analysis at all threshold levels for the different segments in the petroleum and gas industry. It must be noted that the threshold analysis estimates of emissions in this table are slightly different from the estimate of emissions in the April 2010 proposal. The slight decrease in reported emissions of 4 percent for the entire oil and gas sector resulted from data and calculation corrections in the transmission and LNG storage segments and use of different well property databases in onshore production (HPDI® in the final, as opposed to LASSER® in the April 2010 proposal). The same note applies to Table 7 below.

Table 5: Threshold Analysis for the Petroleum and Gas Industry Segments

Source Category	Threshold Level	Total National Emissions	Number of Facilities	Emissions Covered				Facilities Covered	
				Process Emissions ($MtCO_2e$/year)	Combustion CO_2 Emissions (Mt/year)	Total Emissions (tons $mtCO_2e$/yr)	Percent	Number	Percent
Onshore Natural Gas Production Facilities (Basin)	100,000	265,349,383	22,510	136,547,535	60,732,073	197,279,608	74%	385	2%
	25,000	265,349,383	22,510	152,395,746	73,695,453	226,091,199	85%	981	4%
	10,000	265,349,383	22,510	158,499,897	82,061,519	240,561,416	91%	1,929	9%
	1,000	265,349,383	22,510	165,212,244	96,180,842	261,393,085	99%	8,169	36%
Offshore Petroleum and Natural Gas Production Facilities	100,000	11,261,305	3,235	3,217,228	25,161	3,242,389	29%	4	0.12%
	25,000	11,261,305	3,235	4,619,175	500,229	5,119,405	45%	58	1.79%
	10,000	11,261,305	3,235	5,515,419	1,596,144	7,111,563	63%	184	5.69%
	1,000	11,261,305	3,235	6,907,812	3,646,076	10,553,889	94%	1,192	36.85%
Onshore Natural Gas Processing Facilities	100,000	33,984,015	566	24,846,992	27,792	24,874,783	73%	130	23%
	25,000	33,984,015	566	29,551,689	1,677,382	31,229,071	92%	289	51%
	10,000	33,984,015	566	30,725,532	2,257,443	32,982,975	97%	396	70%
	1,000	33,984,015	566	31,652,484	2,331,531	33,984,015	100%	566	100%
Onshore Natural Gas Transmission Facilities	100,000	47,935,158	1,944	24,197,401	7,834	24,205,235	50%	433	22%
	25,000	47,935,158	1,944	36,154,061	6,155,313	42,309,374	88%	1,145	59%
	10,000	47,935,158	1,944	37,593,627	9,118,603	46,712,230	97%	1,443	74%
	1,000	47,935,158	1,944	37,993,603	9,934,474	47,928,077	100%	1,695	87%
Underground Natural Gas Storage Facilities	100,000	9,730,625	397	3,557,040	0	3,557,040	37%	36	9%
	25,000	9,730,625	397	6,585,276	1,276,239	7,861,516	81%	133	34%
	10,000	9,730,625	397	7,299,582	1,685,936	8,985,518	92%	200	50%
	1,000	9,730,625	397	7,762,600	1,951,505	9,714,105	100%	347	87%
LNG Storage Facilities	100,000	2,113,601	157	596,154	25,956	622,110	29%	4	3%
	25,000	2,113,601	157	1,524,652	188,552	1,713,205	81%	33	21%
		2,113,601	157	1,626,435	204,297	1,830,731	87%	41	26%
	1,000	2,113,601	157	1,862,200	252,895	2,115,095	100%	54	34%
LNG Import Facilities[1]	100,000	315,888	5	314,803	0	314,803	100%	4	80%
	25,000	315,888	5	314,803	0	314,803	100%	4	80%
	10,000	315,888	5	314,803	0	314,803	100%	4	80%
	1,000	315,888	5	315,048	840	315,888	100%	5	100%
Natural Gas Distribution Facilities	100,000	25,258,347	1,427	18,470,457	0	18,470,457	73%	66	5%
	25,000	25,258,347	1,427	22,741,042	0	22,741,042	90%	143	10%
	10,000	25,258,347	1,427	23,733,488	0	23,733,488	94%	203	14%
	1,000	25,258,347	1,427	24,983,115	0	24,983,115	99%	594	42%

1. The only LNG export facility in Alaska has not been included in this analysis.

Note: Totals may not add exactly due to rounding. Equipment leak and vented emissions in the threshold analysis are a sum of facility level emissions for each segment. Hence the total equipment leak and vented emissions from each segment may not match the U.S. GHG Inventory.

As discussed above, alternative definitions of facility for onshore petroleum and natural gas production could be considered. One alternative option is applying the threshold at the field level. Table 7 provides the results of the threshold analysis for a field level facility definition. The results of this analysis show that at a 25,000 metric ton CO_2e threshold, 1,157 facilities would be covered and only 57 percent of national emissions. If the threshold were decreased to 1,000 metric tons CO_2e, over 80 percent of national emissions would be covered but the number of reporters would increase to over 22,000.

Table 7. Emissions coverage and number of reporting entities for field level facility definition

Threshold Level[2]	Emissions Covered		Facilities Covered	
	Metric tons CO_2e/year	Percent	Number	Percent
100,000	110,437,470	42%	306	0%
25,000	150,297,681	57%	1,157	2%
10,000	171,902,688	65%	2,549	4%
1,000	219,121,375	83%	22,459	33%

A third alternative for a facility definition was individual well pads as facilities for onshore petroleum and natural gas production segment. Four different scenarios were also considered below for applying thresholds at individual well pads.

- Case 1 (highest well pad emissions): Drilling and completion of an unconventional gas well early in the year with the well producing the remainder of the year with a full complement of common, higher process emissions equipment on the well pad including a compressor, glycol dehydrator, gas pneumatic controllers, and condensate tank without vapor recovery. We assumed that unconventional well completion does not employ "Reduced Emissions Completion" practices.

- Case 2 (second highest well pad emissions): Drilling and completion of a conventional gas well early in the year with the well producing the remainder of the year with a full complement of common, higher process emissions equipment on the well pad including a compressor, glycol dehydrator, gas pneumatic controllers, and condensate tank without vapor recovery.

- Case 3 (third highest well pad emissions): Drilling and completion of a conventional oil well early in the year with the well producing the remainder of the year with a full complement of common, higher process emissions equipment on the well pad including an associated gas compressor, glycol dehydrator, gas pneumatic controllers, chemical injection pump, an oil heater-treater, and a crude oil stock tank without vapor recovery.

- Case 4 (fourth highest well pad emissions): Production at an associate gas and oil well (no drilling) with a compressor, dehydrator, gas pneumatics, oil heater/treater and oil stock tank without vapor recovery.

Table 8 below illustrates the average emissions for each scenario and the number of facilities that have emissions equal to or greater than that average. For example, in case 1, average emissions are 4,927 tons CO_2e/well pad. A threshold would have to be set as low as appropriately 5,000 tons CO_2e/well pad to capture even 6% of emissions from onshore petroleum and gas production. For the other cases, the threshold would have to be set lower than the thresholds considered for other sectors of the GHG reporting rule to capture even relatively small percentages of total emissions. In all cases, the number of reporters is higher than would be affected under the field or basin level options.

Table 8: Alternate Well-head Facility Definitions

	Case 1	Case 2	Case 3	Case 4
Average emissions (tons CO_2e / well pad)	4,927	700	700	370
Number of Reporters	3,349	38,949	66,762	166,690
Covered Emissions (metric tons CO2e)	16,498,228	40,943,092	50,572,248	87,516,080
Percent Coverage	6%	16%	19%	33%

The petroleum and natural gas industry may be somewhat unique when calculating facility emissions to be applied against a threshold for reporting. Subpart C in the GHG reporting rule excluded the calculation and reporting of emissions from portable equipment. This was one option considered for the petroleum and natural gas industry. However, given that portable equipment is so central to many of the operations in the petroleum and natural gas industry and such a large contributor to emissions for the industry, particularly for onshore petroleum and natural gas production, portable equipment emissions are an important source of emissions for inclusion a reporting rule. If these emissions were excluded from the threshold calculation, EPA estimates that a large number of facilities would fall below the threshold, preventing the collection of significant data from the industry that would be beneficial to the development of future climate policies and programs. Please see "Portable Combustion Emissions" memo under rulemaking docket EPA-HQ-OAR-2009-0923.

Another issue that concerns onshore petroleum and natural gas production is the number of equipment operating contractors that support the well operators. It is typical to find production well operators contracting out the majority of their process equipment from separation, dehydration, and tanks, up to gathering and boosting and transport. Hence requiring well operators to report only emissions from equipment they own or directly operate could lead to a significant reduction in emissions coverage. Accordingly, the final rule provides that emissions from such equipment must be reported whether from equipment contracted to, leased from, owned or run by a third party. For a more full discussion of this issue, see Vol. 9, Response to Legal Issues on Mandatory Greenhouse Gas Reporting Rule Subpart W – Petroleum and Natural Gas.

6. Monitoring Method Options

a. Review of Existing Relevant Reporting Programs/ Methodologies

To determine applicability of the different monitoring methods available, existing programs and guidance documents were reviewed. Table 4 shows a listing of the existing programs and guidance documents that were reviewed. All of the program and guidance documents provide direction on estimating CH_4 and/ or CO_2 emissions. All documents, in general, provide emissions rate (emissions factors) that can be used to estimate emissions and in some cases refer to continuous emissions monitoring.

b. Potential Monitoring Methods

Depending on the particular source to be monitored in a facility, several of the currently available monitoring methods for estimating emissions could be used.

i. Equipment Leak Detection

Traditional equipment leak detection technologies like the Toxic Vapor Analyzer (TVA) and the Organic Vapor Analyzer (OVA) are appropriate for use in small facilities with few pieces of equipment. However, comprehensive leak detection in large facilities can be cumbersome, time consuming, and in many cases costly. But new infrared remote equipment leak detection technologies are currently being used in the United States and internationally to efficiently detect leaks across large facilities. Considering these factors, one of the following two technologies can be used to detect leaks in facilities depending on suitability;

Infrared Remote Equipment Leak Detectors

Hydrocarbons in natural gas emissions absorb infrared light. The infrared remote equipment leak detectors use this property to detect leakages in systems. There are two main types of detectors; a) those that scan the an area to produce images of equipment leaks from a source (passive instruments), and b) those that point or aim an IR beam towards a potential source to indicate presence of equipment leaks (active instruments).

An IR camera scans a given area and converts it into a moving image of the area while distinctly identifying the location where infrared light has been absorbed, i.e. the equipment leak source. The camera can actually "see" equipment leaks. The advantages of IR cameras are that they are easy to use, very efficient in that they can detect multiple leaks at the same time, and can be used to do a comprehensive survey of a facility. The main disadvantage of an IR camera is that it may involve substantial upfront capital investment depending on the features that are made available. Therefore, these cameras are most applicable in facilities with large number of equipment and multiple potential leak sources or when purchased at the corporate level, and then shared among the facilities, thereby lowering costs.

Aiming devices are based on infrared laser reflection, which is tuned to detect the interaction of CH_4 and other organic compounds with infrared light in a wavelength range where CH_4 has strong absorption bands, but do not visually display an image of the equipment leaks. Such devices do not have screens to view equipment leaks, but pin point the location of the emissions with a visual guide (such as a visible pointer laser) combined with an audible alarm when CH_4 is detected. These devices are considerably less expensive than the camera and also can detect equipment leaks from a distance (i.e. the instrument need not be in close proximity to the emissions). More time is required for screening, however, since each equipment (or component) has to be pointed at to determine if it is leaking. Also, if there are multiple leaks in the pathway of the IR beam then it may not accurately detect the right source of emissions.

Method For IR instruments that visually display an image of equipment leaks, the background of the emissions has to be appropriate for emissions to be detectable. Therefore, the operator should inspect the emissions source from multiple angles or locations until the entire source has been viewed without visual obstructions to identify all emissions. For other IR detection instruments, such as those based on IR laser reflection, instruments would have to monitor potential emissions sources along all joints and connection points where a potential path to the atmosphere exists. For example, a flange can potentially have leaks along its circumference and such surfaces will have to be monitored completely by tracing the instrument along each surface.

Calibration The minimum detectable quantity of equipment leaks using an IR instrument depends on a number of factors including manufacturer, viewing distance, wind speed, gas composition, ambient temperature, gas temperature, and type of background behind the equipment leaks. For best survey results, equipment leak detection can be performed under favorable conditions, such as 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. The EPA Alternative Work Practice (AWP) requires optical imaging devices to detect a minimum flow rate, specified in Title 40 CFR Part 65 Section 7, before each use. The AWP specifies instructions for determining the minimum detectable flow rate, the purity of the calibration gas, and the allowed viewing distance. Equipment leak detection and measurement instrument manuals can also be used to determine optimal operating conditions to help ensure best results.

Toxic Vapor Analyzer (or Organic Vapor Analyzer)
TVAs and OVAs consist of a flame ionization detector that is used to detect the presence of hydrocarbons and measure the concentration of equipment leaks. It consists of a probe that is moved close to and around the potential emissions source and an emissions detection results in a positive reading on the instrument monitoring scale. The concentration can be used in conjunction with correlation equations to determine the leak rate. However, concentration is not a true measure of an emission's magnitude. Therefore concentration data from TVAs and OVAs, for the purposes of the rule, may be best suited for screening purposes only. The advantage of these instruments is that they have lower costs than IR cameras and several facilities conducting Leak Detection and Repair (LDAR) programs might already have these instruments, thereby reducing capital investment burden. But these instruments screen very slowly given that each potential emissions source has to be individually and thoroughly circumscribed less than 1 centimeter from the potentially leaking joints or seals.

Method TVAs and OVAs can be used for all equipment leak detection that is safely accessible at close-range. For each potential emissions source, all joints, connections, and other potential paths to the atmosphere would be monitored for emissions. Due to residence time of a sample in the probe, there is a lag between when an emission is captured and the operator is alerted. To pinpoint the source of the equipment leak, upon alert the instrument can be slowly retraced over the source until the exact location is found.

Calibration Method 21 guidance can be used to calibrate the TVA or OVA using guidelines from *Determination of Volatile Organic Compound Leaks* Sections 3, 6, and 7.

Acoustic Leak Detectors

Acoustic leak detectors are simple devices that filter out the low frequency vibrations and noise of heavy machinery operating and sense and measure the decibel reading of high frequency vibrations and noise of fluids leaking through small cracks or openings. Fluid flow through open valves has little difference in sonic generated noise between the inlet and outlet of a valve, or the valve body itself. Similarly tightly closed valves have little difference in sonic noise measured on the inlet, outlet or valve body. Valves which are not tightly closed (i.e. a crevice or deformation of the valve plug and seat) will generate a high frequency noise depending on the valve type and size, the pressure drop across the closed valve, and the fluid density. This frequency can be measured in decibels and correlated with through valve leakage rate.

Method

The instrument operator places the "stethoscope" like probe on the valve body or valve flange in one or more of the recommended locations, and observes the decibel reading displayed on the instrument digital signal indicator. This reading is documented in the field, along with the valve identification (valve number or location descriptor). The type of fluid, its density, and the system pressure upstream and downstream of the closed valve are also recorded to be entered along with the valve type (ball, plug, gate, pressure relief, etc) and nominal size) into an Excel spreadsheet supplied by the valve manufacturer. The through valve leakage rate is calculated by correlation algorithms developed by the instrument manufacturer.

Calibration

Calibration requirements are as provided by the manufacturer, depending on the type of acoustic detector.

ii. Emissions Measurement

A. Direct Measurement

Three types of technologies can be used where appropriate to measure or quantify the magnitude of emissions.

High Volume Sampler

A high volume sampler consists of a simple fixed rate induced flow sampling system to capture the emissions and measure its volume. The emissions and the air surrounding the emissions source are drawn into the instrument using a sampling hose. The instrument measures the flow rate of the captured volume of air and emissions mixture. A separate sample of the ambient air is taken by the instrument to correct for the volume of ambient air that is captured along with the emissions.

High volume samplers have moderate costs and have a potential capacity for measuring up to 30 leaking components per hour with high precision at 0.02 percent methane. This allows for reduced labor costs and survey times while maintaining precise results. For this reason, high volume samplers are considered the preferred and most cost-effective direct measurement option for emissions within their maximum range. However, large component emissions and many vent emissions are above the high volume sampler capacity and therefore warrant the use of other measurement instruments.

Method A high volume sampler is typically used to measure only emissions for which the instrument can intake the entire emissions from a single source. To ensure proper use of the instrument, a trained technician can conduct the measurements. The technician will have to be conversant with all operating procedures and measurement methodologies relevant to using a high volume sampler, such as positioning the instrument for complete capture of the emissions without creating backpressure on the source. 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 anti-static wraps or other aids can be used to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual. The attachments help capture the emissions from different points on the source allowing the measurement of the emission by the high volume sampler.

Calibration The instrument can be calibrated at 2.5% and 100% CH_4 by using calibrated gas samples and by following the manufacturer's instructions for calibration.

Meters

Several types of meters measure natural gas flows and can be used for measurement of emissions from sources where the volume of emissions are large like in vent stacks.

Rotameter **–** A rotameter consists of a tapered calibrated transparent tube and a floating bob inside to measure emissions. To measure emissions a rotameter is placed over an emissions source (typically vents and open ended lines) and the emissions pass through the tube. As the emissions move through the tube it raises the floating bob to indicate the magnitude of emissions on the calibrated scale. Rotameters are most advantageous to use in cases where the emissions are very large. The disadvantage though is that it can only be used on leaks where the entire emissions can be captured and directed through the rotameter.

Turbine Meter –To measure emissions a turbine meter is placed over an emissions source and the emissions pass through the tube. As the emissions move through the tube it spins the turbine; the rate at which the turbine spins indicates the magnitude of emissions. Like rotameters, turbine meters are most advantageous to use in cases where emissions are very large. The disadvantage is that it can only be used on emissions that can be entirely captured and directed through the meter.

Hotwire Anemometer – Hotwire anemometers measure emissions velocity by noting the heat conducted away by the emissions. The core of the anemometer is an exposed hot wire either heated up by a constant current or maintained at a constant temperature. In either case, the heat lost to emissions by convection is a function of the emissions velocity. Hotwire anemometers are best for measuring vents and open ended lines of known cross-sectional area and do not require complete capture of emissions. Hot wire anemometers have low levels of accuracy since they measure velocity that is converted into mass emissions rate.

Pitot Tube Flow Meter – A simple pitot tube is a right angled tube open at one end and closed at the other. The closed end is connected to a transducer to measure pressure of the inflowing emissions. The open end is aligned parallel to the direction of emissions flow. Emissions are directed into the tube so that the pressure required to bring the air inside the tube to stagnation is measured. The difference in pressure between the interior of the pitot tube and the surrounding air is measured and converted to an emissions rate. Pitot tube flow meters can be used when the cross-sectional area of an emitting vent or open ended line is known, or when the entire emission can be directed into the tube. The pitot tube flow meter measures pressure differential that is converted to mass emissions rate. The pitot tube detects the flow velocity at only one point along the flowstream, hence the placement of the pitot tube inside the pipe where the flow is to be measured is critical to determine a representative flow volume, and not a location-specific flow volume, which can give erroneous results. It has relatively low accuracy compared to most flow meters, due to the low pressure drop measured. This also makes it vulnerable to fluctuations from turbulence changes in the flow stream. Although inaccurate compared to most meters, the pitot tube is one of the least expensive flow meters available.

Vane Anemometer – A vane anemometer channels the emissions over a rotating vane that in turn rotates a fan to measure the velocity of emissions. The number of revolutions of the fan are detected and measured and converted to a flow velocity. Using the cross section of flow of the emissions, the volumetric flow rate of emissions can be estimated. A vane anemometer is best used for lines that have known cross-sectional areas. The disadvantage is if the flow direction of the emissions changes with respect to the axis of rotation of the vanes, it can result in errors in velocity and flow rate estimation.

Method To ensure accurate measurements when using metering (e.g. rotameters, turbine meters, and others), all emissions from a single source will have to be channeled directly through the meter. An appropriately sized meter can be used to prevent the flow from exceeding the full range of the meter and conversely to have sufficient momentum for the meter to register continuously in the course of measurement.

Calibration The meters can be calibrated using either one of the two methods provided below:

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

(B) 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 the National Institute of Standards and Technology (NIST) or calibrated using standards traceable by NIST) that has a very high degree of accuracy. 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, compare the flow meter output to the actual flow rate as determined by the master weigh scale and use the difference as a correction factor.

(C) The Final GHG Reporting Program provides guidance on calibration for meters in section §98.3(i).

Calibrated Bagging

A calibrated bag (also known as a vent bag) made of anti-static material is used to enclose an emissions source to completely capture all the leaking gas. The time required to fill the bag with emissions is measured using a stop watch. The volume of the bag and time required to fill it is used to determine the mass rate of emissions. Calibrated bags have a very high accuracy, since all the emissions are captured in the measurement.

Calibrated bags are the lowest cost measurement technique, and can measure up to 30 leaking components in an hour, but may require two operators (one to deploy the bag, the other to measure time inflation). It is a suitable technique for emission sources that are within a safe temperature range and can be safely accessed. The speed of measurement is highly dependent on the emissions rate and the results are susceptible to human error in enclosing the emission source and taking the measurement data, leading to lower precision and accuracy. For those sources outside the capacity of high volume samplers and within the limitations of bagging, this would be a second best choice for quantification.

Method Calibrated bags can be used only where the emissions are at near-atmospheric pressures and the entire emissions volume can be captured for measurement. Using these bags on high pressure vent stacks can be dangerous. For conducting measurement the bag is physically held in place by a trained technician, enclosing the emissions source, to capture the entire emissions and record the time required to completely fill the bag. Three measurements of the time required to fill the bag can be conducted to estimate the emissions rates. The average of the three rates will provide a more accurate measurement than a single measurement.

Calibration To ensure accurate results, a technician can be trained to obtain consistent results when measuring the time it takes to fill the bag with emissions.

All of the emissions measurement instruments discussed above measure the flow rate of the natural gas emissions. In order to convert the natural gas emissions into CO_2 and CH_4 emissions, speciation factors determined from natural gas composition analysis must be applied. Another key issue is that all measurement technologies discussed require physical access to the emissions source in order to quantify emissions.

B. Engineering Estimation and Emission Factors

For several emissions sources, there are viable alternatives to physical measurement for calculating emissions. For example, emissions to the atmosphere due to emergency conditions from vessels or other equipment and engineered emissions from equipment like pneumatic devices can be estimated or quantified using engineering calculations. This is referred to as engineering estimation. Emission factors can be considered for nearly every source where emissions data is available, however, they usually have high uncertainties. Emissions factors may be appropriate for frequent, geographically sparse emission sources such as pneumatic devices. Several sources are outlined below along with relevant engineering estimation methods that can be used to estimate GHG gas emissions from each source.

1. Natural Gas Driven Pneumatic Pumps

Leaks from natural gas driven pneumatic pumps can be calculated using data obtained from the manufacturer for natural gas emissions per unit volume of liquid pumped at operating pressures. This information is available from the pump manufacturer in their manuals. Operators can maintain a log of the amount of liquids pumped annually for individual pneumatic pumps and use Equation 1 below for calculating emissions:

$$E_{s,n} = F_s * V$$ **Equation 1**

where,

$E_{s,n}$	=	Annual natural gas emissions at standard conditions in cubic feet per year
F_s	=	Natural gas driven pneumatic pump gas emission in “emission per volume of liquid pumped at operating pressure” in scf/gallon at standard conditions, as provided by the manufacturer
V	=	Volume of liquid pumped annually in gallons/year

If manufacturer data for a specific pump is not available, then data for a similar pump model of the same size and operational characteristics can be used to estimate emissions. As an alternative to manufacturer data on pneumatic pump natural gas emissions, the operator can conduct a one-time measurement to determine natural gas emissions per unit volume of liquid pumped using a calibrated bag for each pneumatic pump, when it is pumping liquids.

Due to the geographically isolated nature of pneumatic pumps, if manufacturer data is not readily available or would result in high burden to obtain the data, pneumatic pump emissions can also be quantified using published emission factors. The use of emission factors is less burdensome than collecting manufacturer data from each pneumatic pump but can be inaccurate due to limited data and variable pump design. However, the resulting information can still be useful for the purposes of informing policy because it will provide updated activity data on the number and type of pneumatic pumps in operation. See Appendix G for a discussion of population emission factors for pneumatic pumps and see Section (6)(d) of the TSD for how to calculate emissions from population factors. Emissions from natural gas driven pneumatic pumps can be calculated using an emissions factor as follows;

$$Mass_{s,i} = Count * EF * GHG_i * Conv_i * 24 * 365$$ **Equation 2**

where,

$Mass_{s,i}$	=	Annual total mass GHG emissions in metric tons per year at standard conditions from all natural gas driven pneumatic pumps at the facility, for GHG_i
$Count$	=	Total number of natural gas driven pneumatic pumps at the facility

EF	=	Population emission factors for natural gas driven pneumatic pumps listed in Appendix G for onshore petroleum and natural gas production, onshore natural gas transmission, and underground natural gas storage facilities, respectively
GHG_i	=	for onshore petroleum and natural gas production facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas; for other facilities GHG_i equals 1
$Conv_i$	=	conversion from standard cubic feet to metric tons CO_2e; 0.000410 for CH_4, and 0.00005357 for CO_2
24 * 365	=	conversion to yearly emissions estimate

2. Natural Gas Driven Pneumatic Manual Valve Actuators

Emissions from natural gas driven pneumatic manual valve actuators can be calculated using data obtained from the manufacturer for natural gas emissions per actuation. Operators can maintain a log of the number of manual actuations annually for individual pneumatic devices and use Equation 3 below:

$$E_{s,n} = A_s * N \qquad \textbf{Equation 3}$$

where,

$E_{s,n}$	=	natural gas emissions at standard conditions
A_s	=	natural gas driven pneumatic valve actuator natural gas emissions in “emissions per actuation” units at standard conditions, as provided by the manufacturer.
N	=	Number of times the pneumatic device was actuated through the reporting period

As an alternative to manufacturer data, the operator could conduct a one-time measurement to determine natural gas emissions per actuation using a calibrated bag for each pneumatic device.

3. Natural Gas Driven Pneumatic Bleed Devices

Pneumatic devices typically fall in three categories; low bleed devices, high bleed devices, and intermittent bleed devices. Low bleed devices are devices that bleed less than 6 scf of natural gas per hour. High bleed devices are devices that bleed more than 6 scf of natural gas per hour.[6,7] Intermittent bleed devices are snap-acting or throttling devices that discharge the full volume of the actuator intermittently when control action is necessary, but do not bleed continuously. Given the vast difference in bleed rates, low bleed devices contribute to a

[6] "Opportunities to Reduce Anthropogenic Methane Emissions in the United States," EPA 430-R-93-012, October 1993
[7] PG&E (Pacific Gas and Electric). 1990. Unaccounted for Gas Project Summary Volume, PG&E Research and Development; San Ramon, CA: GRI-90/0067.1

small portion of the total emissions from pneumatic devices nationally. Therefore, it may be feasible to provide an emissions factor approach for low bleed pneumatic devices to reduce burden. The following are two different options for determining emissions from low bleed, high bleed, and intermittent pneumatic devices.

Emissions from a natural gas pneumatic high bleed device venting can be calculated using a specific pneumatic device model natural gas bleed rate during normal operation as available from the manufacturer. If manufacturer data for a specific device is not available then data for a similar size and operation device can potentially be used to estimate emissions. The natural gas emissions for each bleed device can be calculated as follows;

$$E_{s,n} = B_s * T \qquad \textbf{Equation 4}$$

where,

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

B_s = Natural gas driven pneumatic device bleed rate volume at standard conditions in cubic feet per minute, as provided by the manufacturer

T = Amount of time in minutes that the pneumatic device has been operational through the reporting period

Due to the geographically isolated nature of pneumatic devices, if manufacturer data is not readily available or would result in high burden to obtain the data, pneumatic device emissions can also be quantified using published emission factors. The use of emission factors is less burdensome than collecting manufacturer data from each device, but can be inaccurate due to limited data and variable design. However, the resulting information can still be useful for the purposes of informing policy because it will provide updated activity data on the number and type of pneumatic pumps in operation. See Appendix G for a discussion of population emission factors for pneumatic devices and see Section (6)(d) of the TSD for how to calculate emissions from population factors. Emissions from natural gas pneumatic low bleed device venting can be calculated using emissions factor as follows;

$$Mass_{s,i} = Count * EF * GHG_i * Conv_i * 24 * 365 \qquad \textbf{Equation 5}$$

where,

$Mass_{s,i}$ = Annual total mass GHG emissions in metric tons per year at standard conditions from all natural gas pneumatic low bleed device venting at the facility, for GHG i

$Count$ = Total number of natural gas pneumatic low bleed devices at the facility

EF = Population emission factors for natural gas pneumatic low bleed device venting listed in Appendix G for onshore petroleum and natural gas production, onshore natural gas transmission, and underground natural gas storage facilities, respectively

GHG_i = for onshore petroleum and natural gas production facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas; for other facilities GHG_i equals 1

$Conv_i$ = conversion from standard cubic feet to metric tons CO_2e; 0.000410 for CH_4, and 0.00005357 for CO_2

24 * 365 = conversion to yearly emissions estimate

4. Acid Gas Removal (AGR) Vent Stacks

AGR vents consist of both CO_2 and CH_4 emissions. CO_2 emissions from AGR units can be reliably estimated using continuous emissions monitoring (CEMS) systems, mass balance approach, or one of the standard simulation software packages. CH_4 emissions can only be estimated using simulation software packages. It must be noted, however, that CH_4 emissions from AGR vents are insignificant, 0.06 percent of the total volume of CO_2 and CH_4 emissions. The mass balance approach has the advantage of being usable in systems that use membrane, molecular sieves, or absorbents other than amines; simulation software packages currently do not provide an option for these types of technologies.

Some facilities may have CEMS installed on their AGR unit vent stacks. In such a case, if the CEMS can reliably measure CO_2 volumes then the measurements from CEMS can sufficiently inform on the CO_2 emissions from AGR units. Alternatively, if the vent stack has a meter on it then the CO_2 emissions can be estimated using this metered vent stack gas volume and the percent CO_2 in the vent stack gas.

Operators can calculate emissions from acid gas removal vent stacks using simulation software packages, such as ASPEN™ or AMINECalc™. Different software packages might use different calculations and input parameters to determine emissions from an acid gas removal unit. However, there are some parameters that directly impact the accuracy of emissions calculation. Therefore, any standard simulation software could be used assuming it accounts for the following operational parameters:

- Natural gas feed temperature, pressure, and flow rate;
- Acid gas content of feed natural gas;
- Acid gas content of outlet natural gas;
- Unit operating hours, excluding downtime for maintenance or standby;
- Emissions control method(s), if any, and associated reduction of emissions;
- Exit temperature of natural gas; and
- Solvent pressure, temperature, circulation rate, and weight.

CO_2 emissions from AGR unit vent stacks can also be calculated using mass balance approach from the throughput of the AGR unit and gas composition as follows;

$$E_{a,CO2} = \left(V + \alpha * \left(V * \left(Vol_I - Vol_O\right)\right)\right) * \left(Vol_I - Vol_O\right) \qquad \textbf{Equation 6}$$

where,

$E_{a,CO2}$	=	Annual volumetric CO2 emissions at actual condition, in cubic feet per year.
V	=	Total annual volume of natural gas flow into or out of the AGR unit in cubic feet per year at actual condition as determined using methods specified in paragraph (d)(5) of this section of the TSD.
α	=	Factor is 1 if the outlet stream flow is measured. Factor is 0 if the inlet stream flow is measured.
Vol_I	=	Volume fraction of CO2 content in natural gas into the AGR unit as determined in paragraph (d)(7) of this section.
Vol_O	=	Volume fraction of CO2 content in natural gas out of the AGR unit as determined in paragraph (d)(8) of this section of the TSD.

Sometimes AGR units have a continuous gas analyzer in which case they can be used to determine Vol_I and Vol_O.

There are gas processing plants that capture CO_2 for EOR or carbon sequestration projects. In such cases, the emissions E_{CO2} can be adjusted downward to account for the percentage of total emissions captured.

5. Blowdown Vent Stacks

Emissions from blowdown vent stacks can be calculated using the total physical volume between isolation valves (including all natural gas-containing pipelines and vessels) and logs of the number of blowdowns for each piece of equipment using Equation 7 below:

$$E_{s,n} = N * \left(V_v \left(\frac{(459.67 + T_s)P_a}{(459.67 + T_a)P_s} \right) - V_v * C \right) \qquad \textbf{Equation 7}$$

where,

Es,n	=	*Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.*
N	=	*Number of repetitive blowdowns for each equipment type of a unique volume in calendar year.*
Vv	=	*Total volume of blowdown equipment chambers (including pipelines, compressors and vessels) between isolation valves in cubic feet.*
C	=	*Purge factor that is 1 if the equipment is not purged or zero if the equipment is purged using non-GHG gases.*

Ts	=	*Temperature at standard conditions (^oF).*
Ta	=	*Temperature at actual conditions in the blowdown equipment chamber (^oF).*
Ps	=	*Absolute pressure at standard conditions (psia).*
Pa	=	*Absolute pressure at actual conditions in the blowdown equipment chamber (psia).*

6. Dehydrator Vent

There are two predominant types of technologies that are used to dehydrate natural gas. The first type is the most prevalent and uses liquid tri-ethylene glycol for dehydration, typically referred to as glycol dehydrators. The second type of dehydrators use solid desiccants to extract water from natural gas. For glycol dehydrators, when contacted with natural gas for dehydration, the glycol absorbs some amount of natural gas, which is released as emissions during its regeneration. Standard simulation software packages that use some form of equilibrium analysis can estimate emissions from such liquid glycol type dehydrators. On the other hand, in desiccant dehydrators the solid desiccant itself does not absorb any significant quantities of natural gas. But emissions result when the desiccant dehydrator is opened to the atmosphere for the regeneration of the desiccant, which results in the release of natural gas trapped in the desiccant dehydrator vessel. Hence, for desiccant dehydrators standard simulation software packages cannot be used. However, calculative methods can be used to determine emissions from solid desiccant type dehydrators. The two monitoring methods for the two different types for dehydrators are as below.

Emissions from a dehydrator vents can be calculated using a simulation software package, such as GLYCalc™. There may be several other simulation packages, such as Aspen HYSYS, that can also estimate emissions from glycol dehydrators. However, GLYCalc™ is the most widely used software and referenced by several State and Federal agencies in their programs and regulations. Different software packages might use different calculations and input parameters to determine emissions from dehydration systems. However, there are some parameters that directly impact the accuracy of emissions calculation. Therefore, any standard simulation software could be used provided it accounts for the following operational parameters:

- Feed natural gas flow rate;
- Feed natural gas water content;
- Outlet natural gas water content;
- Absorbent circulation pump type(natural gas pneumatic/ air pneumatic/ electric);
- Absorbent circulation rate;
- Absorbent type: including, but not limited to, triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG);
- Use of stripping natural gas;
- Use of flash tank separator (and disposition of recovered gas);
- Hours operated; and
- Wet natural gas temperature, pressure, and composition.

For dehydrators that use desiccant emissions can be calculated from the amount of gas vented from the vessel every time it is depressurized for the desiccant refilling process using Equation 8 below:

$$E_{s,n} = \frac{(H * D^2 * P * P_2 * \%G * 365 days / yr)}{(4 * P_1 * T * 1{,}000 cf / Mcf * 100)}$$ **Equation 8**

where,

$E_{s,n}$	=	Annual natural gas emissions at standard conditions
H	=	Height of the dehydrator vessel (ft)
D_v	=	Inside diameter of the vessel (ft)
P_1	=	Atmospheric pressure (psia)
P_2	=	Pressure of the gas (psia)
P	=	pi (3.14)
$G_{\%}$	=	Percent of packed vessel volume that is gas
T	=	Time between refilling (days)
100	=	*Conversion of %G to fraction.*

Some dehydrator vented emissions are sent to a flare. Annual emissions from dehydrator vents sent to flares can be calculated using the methodology under Section 8 of the TSD for flares. Alternatively, a simple combustion efficiency factors, such as 98 percent, can be used in conjunction with a CO_2 emissions factor for natural gas to estimate emissions from glycol dehydrator vents to flare stack.

7. EOR injection pump blowdown.

EOR operations use pumps to inject supercritical phase CO_2 into reservoirs. For maintenance, these pumps may be blown down to release all the supercritical phase CO_2. The volume of CO_2 released to during such blow down practices can be calculated using the total volume between isolation valves (including, but not limited to, pipelines, compressors and vessels).The emissions can be calculated using Equation 9 below.

$$Mass_{c,i} = N * V_v * R_c * GHG_i * 10^{-3}$$ **Equation 9**

where,

$Mass_{c,i}$	=	Annual EOR injection gas venting emissions in metric tons at critical conditions "c" from blowdowns.

N = Number of blowdowns for the equipment in calendar year.

V_v = Total volume in cubic meters of blowdown equipment chambers (including, but not limited to, pipelines, compressors and vessels between isolation valves.

R_c = Density of critical phase EOR injection gas in kg/m^3. Use an appropriate standard method published by a consensus-based standards organization to determine density of super critical EOR injection gas.

GHG_i = mass fraction of GHG*i* in critical phase injection gas

C. Emission Factors

The EPA/ GRI and EPA/Radian studies provide emissions factors for almost all the emissions sources in the petroleum and natural gas industry. These can potentially be used to estimate emissions for reporting under the rule. However, the emissions factors are not appropriate for all the emissions sources. The emissions factors were developed more than a decade ago when the industry practices were much different from now. In some cases, the emissions factors were developed using limited sample data and knowledge about the industry's operations (e.g., wells, compressors). While the available emission factors alone may not be appropriate for GHG reporting, certain emission factors may be sufficient, under certain circumstances, to calculate and characterize GHG emissions. Also, the introduction of many emissions reduction technologies are not reflected in the emissions factor estimates. However, the two studies provide raw emission data that in conjunction with newer publically available data (e.g., Clearstone 2006 study) could be used for developing emission factors for certain sources. Refer to Section 4(c)(ii), 6(c), and Appendix F and G of the TSD for a complete discussion of the use of emission factors in the reporting rule.

D. Combination of Direct Measurement and Engineering Estimation

Emissions from several sources can be estimated using a combination of direct measurement and engineering estimation. Direct measurement can provide either a snapshot of the emissions in time or information on parameters that can be used for using a calculative method to estimate emissions. Following are options for using such a combination of monitoring methods to estimate emissions.

8. Flare stacks

Flares typically burn two types of hydrocarbon streams; continuous and intermittent. Continuous streams result from vented emissions from equipment such as glycol dehydrators and storage tanks. Intermittent streams result from such sources as emergency releases from equipment blowdown. It must be noted that most of these streams, continuous or intermittent, can be covered using monitoring methods already provided on an individual emissions source level.

Flare emissions whether from continuous or intermittent streams can be monitored using one of the following monitoring methods

Method 1:

Many facilities, such as in the processing sector, may already have a continuous flow monitor on the flare. In such cases, the measured flow rates can be used when the monitor is operational, to calculate the total flare volumes for the calendar year.

Method 2:

Another option is to require the estimation of all streams of hydrocarbons going to the flare at an individual emissions source level. Here engineering calculation and other methods described for different sources in this Section of the TSD can be used to estimates of volume flare gas

Method 3:

When the flare stream is mostly continuous, a flow velocity measuring device (such as hot wire anemometer, pitot tube, or vane anemometer) can be inserted directly upstream of the flare stack to determine the velocity of gas sent to flare. The GHG volumetric emissions at actual conditions can then be calculated as follows.

$$E_{a,CH4}(un-combusted) = V_a * (1-\eta) * X_{CH4}$$ **Equation 10**

$$E_{a,CO2}(un-combusted) = V_a * X_{CO2}$$ **Equation 11**

$$E_{a,CO2}(combusted) = \sum_j \eta * V_a * Y_j * R_j$$ **Equation 12**

$$E_{a,i} = E_{a,CO2}(combusted) + E_{a,i}(un-combusted)$$ **Equation 13**

where,

$E_{a,i}(un\text{-}combusted)$	=	Contribution of annual un-combusted emissions from flare stack in cubic feet, under ambient conditions, for both CH_4 and CO_2 as described in Equation 10 and Equation 11.
$E_{a,CO2}(combusted)$	=	Contribution of annual emissions of CO_2 from combustion from flare stack, in cubic feet, under ambient conditions
$E_{a,i}(total)$	=	Total annual emissions from flare stack in cubic feet, under ambient conditions
V_a	=	Volume of natural gas sent to flare in cubic feet, during the year

η	=	Percent of natural gas combusted by flare (default is 98 percent)
X_i	=	Concentration of GHG_i in gas to the flare; where i = CO_2 or CH_4.
Y_j	=	Concentration of natural gas hydrocarbon constituents *j* (such as methane, ethane, propane, butane, and pentanes plus).
R_j	=	Number of carbon atoms in the natural gas hydrocarbon constituent *j*; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus)

In some cases the facility may have a continuous gas composition analyzer on the flare. Here the compositions from the analyzer can be used in calculating emissions. If an analyzer is not present then a sample of the gas to the flare stack can be taken every quarter to evaluate the composition of GHGs present in the stream. The natural gas composition analyses can be conducted using ASTM D1945-03. It must be noted that for processing plants there are two distinct streams of natural gas with significant differences in composition. The natural gas stream upstream of the de-methanizer can be expected to have higher C2+ components as opposed to the residue stream downstream of the de-methanizer. In addition, the CO_2 content in natural gas can change significantly after acid gas removal. Finally, processing plants may send pure streams of separated hydrocarbons such as ethane, propane, butane, iso-butane, or pentanes plus to the flare during an emergency shutdown of any particular equipment. Such variations in hydrocarbon streams being sent to the flare would have to be accounted for in the monitoring methodology.

9. Compressor wet seal degassing vents

In several compressors, the wet seal degassing vents emit flash gas from degassed oil straight into or close to the compressor engine exhaust vent stack. The temperatures at the degassing vent exit are very high due to the proximity to the engine exhaust vent stack. In such cases, emissions can be estimated using a flow velocity measuring device (such as hot wire anemometer, pitot tube) or a flow rate measurement device such as vane anemometer, which can be inserted directly upstream of the degassing unit vent exit to determine the velocity or flow rate of gas sent to the vent. If a velocity measuring device is used then the volume of natural gas sent to vent can be calculated from the velocity measurement using the manufacturer manual for conversion. Annual emissions can be estimated using meter flow measurement as follows:

$$E_{a,i} = MT * T * M_i * (1 - B) \qquad \textbf{Equation 14}$$

where,

$E_{a,i}$	=	Annual GHG_i (either CH_4 or CO_2) volumetric emissions at ambient conditions

MT = Meter reading of gas emissions per unit time

T = Total time the compressor associated with the wet seal(s) is operational in the calendar year

M_i = Mole percent of GHG_i in the degassing vent gas

B = percentage of centrifugal compressor wet seal degassing vent gas sent to vapor recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapor recovery system or recycle to fuel gas system

A sample representative of the gas to the degassing vent can be taken every quarter to evaluate the composition of GHGs present in the stream using ASTM D1945-03. Some facilities may send their degassing vent vapors to a flare or to fuel use. The monitoring method will have to account for this.

10. Reciprocating compressor rod packing venting

There are three primary considerations for emissions from rod packing on reciprocating compressors. First, the rod packing case may or may not be connected to an open ended line or vent. Second, the rod packing may leak through the nose gasket in addition to the emissions directed to the vent. And third, the emissions from rod packing will vary depending on the mode of operation of the reciprocating compressor – running, standby and pressurized, or standby and de-pressurized.

If the rod packing case is connected to an open ended line or vent then emissions from the rod packing case can be estimated using bagging or high volume sampler. Alternatively, a temporary meter such as vane anemometer or permanent meter such as orifice meter can be used to measure emissions from rod packing vents.

If the rod packing case is open to the atmosphere then the emissions from the rod packing case will be mingled with the emissions from the nose gasket. The emissions from an open rod packing case usually will migrate to the distance piece (dog house), and if the distance piece is enclosed then this emissions will migrate to the engine crank case, before being emitted to the atmosphere. There are two possible options to monitor these emissions. The first option is to use an emissions factor for rod packing along with a population count. The second option is to require equipment leak detection and measurement to determine the exact location and volume of emission.

Typically, rod packing emissions vary with the mode of operation of the compressor. The emissions are highest when the compressor is operating and lower when they are in standby pressurized mode. When the compressor is standby de-pressurized there might be some migration of natural gas from the unit isolation valve through the rod packing. But rod packing emissions from leaking unit isolation valves is for the most part negligible because unit isolation valves leak primarily through the blowdown vent stack. Hence to correctly characterize annual emissions from rod packing, estimation of emissions at two compressor modes, operating and standby pressurized, may be required.

11. Compressor isolation valve and blowdown valve

Blowdown valves on a compressor are used to depressurize and release all of the natural gas in the compressor chambers when the compressor is taken offline. These blowdown valves, however, can leak in some cases when the compressor is in operating or standby pressurized modes. Isolation valves are used to isolate the compressor chambers from the pipeline that connects the natural gas flow into and out of the compressor. These isolation valves can leak when the compressor is take offline. Both the blowndown valve and isolation valve are typically connected to the blowdown vent system. The emissions from leaks in an isolation valve or blowdown valve can be detected and measured using detection and measurement methods as discussed in Sections (6)(b)(i) and (6)(b)(ii)(A) of the TSD.

12. Storage tanks

Emissions from storage tanks can be estimated using one of the following four methods.

Method 1:

In the case of storage tanks, emissions rates are not constant; and thus, a one-time measurement may not provide accurate emissions rates for the entire reporting period. To accurately estimate emissions from storage tanks, it is necessary to conduct multiple measurements during a cycle of operation that is representative of the tank operations through the year. Equation 15 below can be used to calculate GHG emissions:

$$E_{a,h} = Q \times ER \qquad \textbf{Equation 15}$$

where,

$E_{a,h}$ = hydrocarbon vapor emissions at ambient conditions, in cubic meters

Q = storage tank total annual throughput, in barrels

ER = measured hydrocarbon vapor emissions rate per throughput (e.g. meter/barrel)

ER can be estimating using the following procedure:

- The hydrocarbon vapor emissions from storage tanks can be measured using a flow meter 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.
- The throughput of the storage tank during the test period can be recorded.

- The temperature and pressure of hydrocarbon vapors emitted during the test period can be recorded.
- A sample of hydrocarbon vapors can be collected for composition analysis.

Method 2:

A second method is to use simulation software such as E&P Tank (GEO-RVP) to estimate vented emissions from storage tanks. Therefore, any standard simulation software could be used assuming it accounts for the following operational parameters:

- Feed liquid flow rate to tank;
- Feed liquid API gravity;
- Feed liquid composition or characteristics;
- Upstream (typically a separator) pressure;
- Upstream (typically a separator) temperature;
- Tank or ambient pressure; and
- Tank or ambient temperature;
- Sales oil API gravity;
- Sales oil production rate;
- Sales oil Reid vapor pressure;

Method 3:

A third method to estimating emissions from storage tanks is to use the Peng-Robinson equation directly instead of using a simulation software. The Peng-Robinson equation is the basis behind most of the simulation softwares and therefore will result in estimates similar to *Method 2* above.

$$p = \frac{RT}{V_m - b} - \frac{a\alpha}{V_m^2 + 2bV_m - b^2}$$ **Equation 16**

where:

p = Absolute pressure
R = Universal gas constant
T = Absolute temperature
V_m = Molar volume = $\frac{0.45724R^2T_c^2}{p_c}$ = $\frac{0.7780RT_c}{p_c}$

α = $\left(1 + \left(0.37464 + 1.54226\omega - 0.26992\omega^2\right)\left(1 - \sqrt{\frac{T}{T_c}}\right)\right)^2$

where:

Ω = Acentric factor of the species
Tc = Critical temperature

Pc = Critical pressure

Method 4:
A conservative method to estimate GHG emissions from flashing in storage tanks is to take a sample of liquids at the low pressure separator (i.e. the last separator before the liquids enter the storage tank) and then assume that all the CH_4 and CO_2 dissolved in this sample is released to the atmosphere.

Method 5:

A fifth method for storage tank vented emissions quantification is use of the Vasquez-Beggs equation. This correlation equation provides an estimate of the gas-to-oil ratio for flashing tank vapors; however, it does not provide the GHG of the vapors, so composition analysis of tank vapors is still required. Equation 17 demonstrates the use of this correlation equation:

$$GOR = A \times G_{fg} \times \left(P_{sep} + 14.7\right) \times \exp\left(\frac{C \times G_{oil}}{T_{sep} + 460}\right)$$ **Equation 17**

where,

GOR = ratio of flash gas production to standard stock tank barrels of oil produced, in standard cubic feet/barrel (barrels corrected to 60°F)

G_{fg} = Specific gravity of the tank flash gas, where air = 1. A suggested default value for G_{fg} is 1.22

G_{oil} = API gravity of stock tank oil at 60°F

P_{sep} = Pressure in separator (or other vessel directly upstream), in pounds per square inch gauge

T_{sep} = Temperature in separator (or other vessel directly upstream of the tank), °F

A = 0.0362 for G_{oil} </= 30°API, or 0.0178 for G_{oil} > 30°API

B = 1.0937 for G_{oil} </= 30°API, or 1.187 for G_{oil} > 30°API

C = 25.724 for G_{oil} </= 30°API, or 23.931 for G_{oil} > 30°API

Sometimes one or more emissions source vents may be connected to the storage tank. In such cases the emissions from these sources will be commingled with the emissions from the storage tank. In addition, two phase separators directly upstream of the storage tank may not have a vortex breaker. This can lead to channeling of natural gas from the separator to the storage tank. All these multiple scenarios mean that only Method 1 could potentially capture such miscellaneous sources connected to the storage tank. If, however, Method 1 is performed at a time when say the separator is not vortexing then even Method 1 may not capture the emissions from the miscellaneous emissions sources connected to the storage tank. Hence there is no single method that can identify these variations in storage tank emissions that represent multiple sources. These data are available from two recent studies provided by the Texas Commission on Environmental Quality (2009) and the Texas Environment Research Consortium (2009) that highlight this fact. A potential option to correct such scenarios where other emissions sources are connected to the storage tank or if the separator is vortexing is to use multipliers on emissions estimated from Methods 1 and 2 above. Two such potential multipliers are as below,

(i) The emissions for sales oil less than 45 API gravity can be multiplied by 3.87

(ii) The emissions for sales oil equal to or greater than 45 API gravity can be multiplied by 5.37

Details on the development of these multipliers are available in Appendix E.

Dump Valve Emissions Estimation

Storage tank vented emissions quantification could include the emissions that result from a gas-liquids separator liquid dump valve malfunction. Liquid dump or scrubber dump valves open periodically to reduce the accumulation of liquids in the separator. Scrubber dump valves can get stuck open due to debris preventing it from closing properly. In such a case, natural gas from the separator is lost through the dump valve ultimately passing through the storage tank's atmospheric vent. Equation 18, below, can be used to account for storage tank emissions with improperly closed scrubber dump valves.

$$E_{s,i} = (CF_n \times E_n \times T_n) + (E_n \times (8760 - T_n)) \qquad \textbf{Equation 18}$$

where,

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each storage tank in cubic feet.

E_n = Storage tank emissions as determined in calculation methods 1, 2, or 5 (with wellhead separators) of this section of the TSD during time T_n in cubic feet per hour.

T_n = Total time the dump valve is not closing properly in the calendar year in hours. T_n is estimated by maintenance or operations records (records) such that when a record shows the valve to be open improperly, it is assumed the valve was open for the entire time period preceding the record starting at either the beginning of the calendar year or the previous record showing it closed properly within the calendar year. If a subsequent record shows it is closing properly, then assume from that time forward the valve closed properly until either the next record of it not closing properly or, if there is no subsequent record, the end of the calendar year.

CF_n = Correction factor for tank emissions for time period T_n is 3.87 for sales oil less than 45 API gravity. Correction factor for tank emissions for time period Tn is 5.37 for sales oil equal to or greater than 45 API gravity. Correction factor for tank emissions for time period T_n is 1.0 for periods when the dump valve is closed.

E_t = Storage tank emissions as determined in calculation methods 1, 2, or 3 of this section of the TSD at maintenance or operations during the time the dump valve is closing properly (ie.8760-T_n) in cubic feet per hour.

Transmission Storage Tanks:

Storage tanks in the onshore natural gas transmission segment typically store the condensate from the scrubbing of pipeline quality gas. The volume of condensate is typically low in comparison to the volumes of hydrocarbon liquids stored in the upstream segments of the industry. Hence the emissions from condensate itself in the transmission segment are insignificant. However, scrubber dump valves often get stuck due to debris in the condensate and can remain open resulting in natural gas loss via the open dump valve. If the scrubber dump valve is stuck and leaking natural gas to the tank then the emissions will be visibly significant and will not subside to inconspicuous volumes. If the scrubber dump valve functions normally and shuts completely after the condensate has been dumped then the storage tank emissions should subside and taper off to insignificant quantities; this will happen because once the condensate has flashed the dissolved natural gas there will not be significant emissions from the storage tank. If persistent and significant emissions are detected then a measurement of those emissions may be required using a temporary meter or ultrasonic devices that can detect and measure the emissions in a non-invasive way.

Storage tank vapors captured using vapor recovery systems or sent to flares will have to be accounted for in the above methods.

13. Well testing venting and flaring

During well testing the well usually is flowing freely and the produced hydrocarbons are typically vented and/ or flared. A gas to oil ratio is often determined when conducting well testing. This information can be reliably used to estimate emissions from well testing venting using Equation 19 below:

$$E_{s,n} = GOR * FR * D \qquad \textbf{Equation 19}$$

where,

$E_{s,n}$	=	Annual volumetric natural gas emissions from well testing in cubic feet under actual conditions
GOR	=	Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities
FR	=	Flow rate in barrels of oil per day for the well being tested
D	=	Number of days during the year the well is tested

When well testing emissions are sent to a flare then the emissions estimated above should be adjusted to reflect the combustion emissions.

14. Associated gas venting and flaring

Often times when onshore petroleum production fields are located in a remote location, the associated gas produced is sent to a vent or flare. This is because the associated natural gas is stranded gas, meaning that it is not economical to send the usually low volumes to the market via a pipeline system. Also, gas from producing wells may sometimes be routed to a vent or a flare due to system upset conditions or for maintenance of field equipment. In such cases the emissions can be estimated using the volume of oil produced and the corresponding gas to oil ratio as following;

Vented associated natural gas emissions can be estimated using Equation 20 below:

$$E_{a,n} = GOR * V$$ **Equation 20**

where,

$E_{a,n}$	=	Annual volumetric natural gas emissions from associated gas venting under actual conditions, in cubic feet
GOR	=	Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities
V	=	Total volume of oil produced in barrels in the calendar year.

When well testing emissions are sent to a flare then the emissions estimated above will have to be adjusted to reflect the combustion emissions.

15. Hydrocarbon liquids dissolved CO_2

Onshore petroleum production that uses EOR with CO_2 injection results in the production of petroleum that has significant amounts of CO_2 dissolved in it. This CO_2 is usually separated from the liquid petroleum component, and re-injected in a closed loop system (although this CO_2 might be eventually recovered when the EOR operation at the site is closed). However, the liquid portion of petroleum still contains dissolved CO_2, since separation usually takes place at higher than ambient pressure. Most of this CO_2 is then released in a storage tank where the CO_2 flashes out of the liquid hydrocarbons. But even after this stage some amount of CO_2 remains entrapped in the liquid hydrocarbons and is lost to the atmosphere during the transportation and processing phases.

The amount of CO_2 retained in hydrocarbon liquids after flashing in tanks can be determined by taking quarterly samples to account for retention of CO_2 in hydrocarbon liquids immediately downstream of the storage tank. The emissions from this hydrocarbon dissolved CO2 can be estimated using Equation 21 below:

$$Mass_{s,\,CO2} = S_{hl} * V_{hl}$$ **Equation 21**

where,

$Mass_{s,\,CO2}$	=	Annual CO_2 emissions from CO_2 retained in hydrocarbon liquids beyond tankage, in metric tons.
S_{hl}	=	Amount of CO_2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.

V_{hl}	=	Total volume of hydrocarbon liquids produced in barrels in the calendar year.

16. Produced water dissolved CO_2

EOR operations may use water injection techniques to pressurize the reservoir and drive the hydrocarbons containing CO_2 through the reservoir and up the production well. This water, like the liquid petroleum, contains dissolved CO_2, since CO_2 readily dissolves in water. This produced water is re-circulated for injection into the reservoir. However, often it may be sent through tankage to avoid a two phase flow of CO_2 and water through the injection pumps. In such cases the CO_2 dissolved in the water is flashed to the atmosphere in the storage tank.

These emissions can be determined similar to hydrocarbon dissolved CO_2 by sampling the water on a periodic basis. To determine retention of CO_2 in produced water immediately downstream of the separator where hydrocarbon liquids and produced water are separated the following equation can be used.

$$Mass_{s,\,CO2} = S_{pw} * V_{pw} \qquad \textbf{Equation 22}$$

where,

$Mass_{s,\,CO2}$	=	Annual CO_2 emissions from CO_2 retained in produced water beyond tankage, metric tons.
S_{pw}	=	Amount of CO_2 retained in produced water in metric tons per barrel, under standard conditions.
V_{pw}	=	Total volume of produced water produced in barrels in the calendar year.

EOR operations that route produced water from separation directly to re-injection into the hydrocarbon reservoir in a closed loop system without any leakage to the atmosphere could be exempted from reporting.

17. Well venting for liquids unloading

There are three potential methods to estimate well venting emissions from liquids unloading. Method 1 requires installation of a flow meter temporarily for developing an emissions factor. Method 2 requires a transient pressure spike engineering analysis across the vent pipe during one well unloading event. Method 3 uses an engineering calculation method that uses the well's physical parameters to estimate emissions. Each of the three options is discussed below.

Method 1:

For each unique well tubing diameter and producing horizon/formation combination in each gas producing field where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, a recording flow meter can be installed on the vent line used to vent gas from the well (e.g. on the vent line off the separator or a storage tank). An emissions factor can be estimated as an average flow rate per minute of venting calculated for each unique tubing diameter and producing horizon/formation combination in each producing field. The emission factor can be applied to all wells in the field that have the same tubing diameter and producing horizon/formation combination, multiplied by the number of minutes of venting of all wells of the same tubing diameter and producing horizon/formation combination in that field. A new factor can be determined periodically to track field declining formation pressure and flow potential.

Method 2:

For each unique well tubing diameter and producing horizon/formation combination in each gas producing field where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, an engineering analysis of the transient pressure spike across the vent line for well unloading events can be conducted. An emissions factor as an average flow rate per minute of venting can then be calculated through such an analysis. This emissions factor can be applied to all wells in the field that have the same tubing diameter and producing horizon/formation combination, multiplied by the number of minutes of venting all wells of the same tubing diameter and producing horizon/formation combination in that field. A new emission factor can be determined periodically to track field declining formation pressure and flow potential. Emissions from well venting for liquids unloading can be calculated using Equation 23 below:

$$E_{s,n} = T * X * EF \qquad \textbf{Equation 23}$$

where,

$E_{s,n}$ = Annual natural gas emissions at standard conditions

T = Amount of time of well venting

X = Concentration of GHG *i* in gas vented.

EF = Emission factor developed using the transient pressure spike

For wells that have a plunger lift installed on a timer or programmable logic controller that vent to the atmosphere and automatically closes the vent valve when the plunger is received at the well head, an equation calculating the volume of gas in the tubing string calculated at sales pipeline pressure can be used. This equation is unique for each category of wells with the same well depth and tubing size. The emissions factor can be estimated by multiplying the tubing cross-sectional area by the tubing string length from wellhead to the bottom resting location of the plunger, corrected for sales line pressure and average gas flowing temperature.

Method 3:

The Natural Gas STAR Lessons Learned – Installing Plunger Lift Systems in Gas Wells (available at <http://epa.gov/gasstar/documents/ll_plungerlift.pdf>) provides an engineering estimation method in its Appendix. This method uses physical characteristics of the well that are usually well known. Using this method, emissions from well venting for liquids unloading can be calculated using Equation 24 below:

$$E_{a,n} = \{(0.37\times10^{-3}) * CD^2 * WD * SP * V\} + \{SFR*(HR-T)*Z\} \qquad \textbf{Equation 24}$$

where,

$E_{s,n}$	=	Annual natural gas emissions at actual conditions, in cubic feet/year
0.37×10^{-3}	=	*{pi(3.14)/4}/{(14.7*144) psia converted to pounds per square feet}*
CD	=	Casing diameter (inches)
WD	=	Well depth (feet)
SP	=	Shut-in pressure (psig)
V	=	Number of vents per year
SFR	=	Average sales flow rate of gas well in cubic feet per hour
HR	=	Hours that the well was left open to the atmosphere during unloading
T	=	1 hour for average well to blowdown casing volume at shut-in pressure for wells without plunger lift assist; 0.5 hour for average well to blowdown tubing volume at sales line pressure when using plunger lift assist.
Z	=	If HR is less than 1.0 then Z is equal to 0. If HR is greater than or equal to 1.0 then Z is equal to 1.

For details on the time taken to blowdown a casing and tubing to unload a well, see “Change to Rule Equation W-7: Time to Vent the Casing Gas from Well Liquids Unloading” in the rulemaking docket (EPA-HQ-OAR-2009-0923)

18. Gas well venting during well completions and workovers

There are two methods to estimate emissions from gas well venting during well completions and workovers. Method 1 requires the installation of a recording flow meter on the vent line to the atmosphere or to a flare. Method 2 is an engineering calculation for flow based on the pressure drop across the well choke for subsonic and sonic flow. Method 3 uses the production of the well to determine emissions.

Method 1:

A recording flow meter can be installed on the vent line to the atmosphere or to a flare during each well completion or workover event. This one time reading can be extrapolated to yearly emissions based on the time taken for completion or workover and the number of times the well is worked over (if more than once per year). Such emissions factors can be developed for representative wells in a field on a yearly basis. During periods when gas is combusted in a flare, the carbon dioxide quantity can be determined from the gas composition with an adjustment for combustion efficiency. This method can also be used when phase separation equipment is used and requires the installation of a recording flow meter on the vent line to the atmosphere or to a flare.

Emissions from gas well venting during well completions and workovers can be calculated using Equation 25 below:

$$E_{a,n} = T * FR - EnF - SG \qquad \textbf{Equation 25}$$

where,

$E_{a,n}$	=	Annual natural gas vented emissions at ambient conditions in cubic feet
T	=	Cumulative amount of time in hours of well venting during the reporting period
FR	=	Flow rate in cubic feet per hour, under ambient conditions
EnF	=	Volume of CO_2 or N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job. If the fracture process did not inject gas into the reservoir, then EnF is 0. If injected gas is CO_2 then EnF is 0.
SG	=	Volume of natural gas in cubic feet at standard conditions that was recovered into a sales pipeline. If no gas was recovered for sales, SG is 0.

Method 2:

Using pressures measured upstream and downstream of the well choke, the average flow rate across the choke can be calculated. Using engineering judgment and the total time that flow across the choke is occurring, the total volume to the atmosphere or a flare during the back-flow period can be estimated. This one time reading can be extrapolated to yearly emissions based on the time taken for completion or workover and the number of times the well is worked over (if more than once per year). Such emissions factors can be developed for representative wells in a field on a yearly basis.

Emissions from gas well venting during well completions and workovers can be calculated using Equation 26 for subsonic flow and Equation 27 for sonic flow below:

$$FR = 1.27 * 10^5 * A * \sqrt{3430 * T_u * \left[\left(\frac{P_2}{P_1} \right)^{1.515} - \left(\frac{P_2}{P_1} \right)^{1.758} \right]} \qquad \textbf{Equation 26}$$

where,

FR	=	Average flow rate in cubic feet per hour, under subsonic flow conditions.
A	=	Cross sectional area of orifice (m^2).
P_1	=	Upstream pressure (psia).
T_u	=	Upstream temperature (degrees Kelvin).
P_2	=	Downstream pressure (psia).
3430	=	Constant with units of $m^2/(sec^2 * K)$.
$1.27*10^5$	=	Conversion from m^3/second to ft^3/hour.

$$FR = 1.27 * 10^5 * A * \sqrt{187.08 * T_u}$$ **Equation 27**

where,

FR	=	Average flow rate in cubic feet per hour, under sonic flow conditions.
A	=	Cross sectional area of orifice (m^2).
T_u	=	Upstream temperature (degrees Kelvin).
187.08	=	Constant with units of $m^2/(sec^2 * K)$.
$1.27*10^5$	=	Conversion from m^3/second to ft^3/hour.

Method 3:

A quick and least burdensome method to determine emissions from well venting during completions and workovers is to use the daily gas production rate to estimate emissions using Equation 28 below:

$$E_{a,n} = \sum_f V_f * T_f$$ **Equation 28**

where,

$E_{a,n}$	=	Annual natural gas emissions in cubic feet at actual conditions from gas well venting during well completions and workovers without hydraulic fracturing.
f	=	Total number of well completions without hydraulic fracturing in a field.
V_f	=	Average daily gas production rate in cubic feet per hour of each well completion without hydraulic fracturing. This is the total annual gas production volume divided by total number of hours the wells produced to the sales line. For completed wells that have not established a production rate, you may use the average flow rate from the first 30 days of production. In the event that the well is completed less than 30 days from the end of the calendar year, the first 30 days of the production straddling the current and following calendar years shall be used.

T_f = Time each well completion without hydraulic fracturing was venting in hours during the year.

19. Onshore production combustion emissions

The combustion process is well understood in terms of GHG emissions. The use of emissions factors is reliable if the quantity and type of fuel combustion is known. The alternative is to use combustion emissions stack monitors, which are cost prohibitive and may not be considered appropriate for onshore production. Onshore production segment does not meter its fuel, since most of the equipment in the field is located upstream of the lease meter. However, requiring meters at every single well site to measure fuel volume is not feasible in terms of cost. Hence, the use of heat rating of the equipment along with the hours of operations is the most feasible approach to estimate the amount of fuel consumed. Using the emissions factors approach, GHG emissions from combustion equipment can be estimated using broadly two methods; fuel specific emissions factors and equipment specific fuel factors. Fuel specific emissions factors are related to a particular type of fuel in use and do not take into account the type of equipment (e.g. whether internal or external combustion equipment). The advantage of this type of approach is that if the fuel volume for a facility is known then there is no need to identify the particular equipment that is combusting it. The disadvantage in this method though is that it does not take into account the differing levels of efficiency between different types of equipment. On the other hand, equipment specific emissions factors take into account the efficiency levels of each equipment type corresponding with the type of fuel it combusts. However, the disadvantage of using equipment specific emissions factors is that fuel consumption has to be known at an equipment level. Both fuel specific and equipment specific emissions factors are available form the API Compendium and EPA AP-42 documents.

20. Natural gas distribution combustion emissions

The combustion emissions from natural gas distribution result mainly from inline gas heaters, small compressors, etc. Heaters are used to prevent natural gas dropping below the dew point (where liquids, mainly water, might condense) or to maintain the temperature of gas let-down in pressure from high pressure transmission pipelines to low pressure distribution gate station metering systems. The Joule-Thompson effect causes gas temperature to drop when the gas is suddenly expanded across a valve or orifice. Thus, transmission pressure gas at, for example 1000 psig and ambient temperature of 70°F can drop well below freezing when depressurized to 100 psig. This gas may be heated to a temperature above so-called “dry” gas dew point or a range consistent with distribution gate station meter calibrations. These are usually small sources of emissions and may not contribute significantly to the total emissions from the distribution segment. However, some natural gas distribution systems operate compressor stations that are similar in size and operations to the natural gas transmission or gas storage systems. These compressor stations may have significant emissions and could be captured under combustion emissions reporting.

c. Leak detection and leaker emission factors

For leaks from standard components such as connectors, valves, meters, etc. emissions can be estimated by conducting an equipment leak detection program and applying a leaker emissions factor to those sources found to be emitting. This option may be considered over direct measurement (e.g., high flow sampler) to avoid the capital cost in measurement equipment and labor hours to conduct measurement. Estimating emissions using leaker emission factors is more accurate than population factors because leaker factors are applied to leaks once they are identified. Since equipment leaks occur randomly within a population of components, determining the number of actual leaking component improves the emissions estimate. Equation 29, below, can be used for this purpose.

$$E_{s,i} = GHG_i * \sum_x EF_X * T_x \qquad \textbf{Equation 29}$$

where,

$E_{s,i}$	=	Annual total volumetric GHG emissions at standard conditions from each equipment leak source in cubic feet.
x	=	Total number of this type of emissions source found to be leaking during T_x.
EF_E	=	Leaker emission factor for specific sources
GHG_i	=	For onshore petroleum and natural gas production facilities and onshore natural gas processing facilities,, concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; other segments GHG_i equals 1 for CH_4 and 1.1×10^{-2} for CO_2.
T_x	=	The total time the component was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey or the beginning of the calendar year. For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year.

Leaker emissions factors are available for specific sources for onshore natural gas processing facilities, onshore natural gas transmission compression facilities, underground natural gas storage facilities, liquefied natural gas storage facilities, liquefied natural gas import and export facilities, and natural gas distribution facilities. These leaker emissions factors and a discussion on their development are available in Appendix F.

d. Population Count and Emission Factors.

For equipment leaks that are geographically dispersed or where the cost burden is an issue, emissions can be estimated using the population count of emissions sources and a corresponding population emissions factor. This option may be considered over direct measurement to avoid the cost of purchasing a high volume sampler, screening device, and the labor hours to use both. Such an option may be most feasible for emissions sources with gas content greater than 10 percent CH_4 plus CO_2 by weight since otherwise the emissions factors may overestimate overall GHG emissions. The disadvantage of using population factors is that it will only provide an estimate of potential emissions, not actual emissions. It will also not provide any trends in changes in emissions over time, since the only variable is equipment/ component count, which in most operations does not change significantly. Hence, petroleum and natural gas operators who are voluntarily reducing emissions by conducting periodic leak detection and repair will end up reporting more emissions than is actually occurring in their operations. Emissions from all sources listed in this paragraph of this section can be calculated using Equation 30.

$$E_{s,i} = Count * EF * GHG_i * T \qquad \textbf{Equation 30}$$

where,

$E_{s,i}$	=	Annual total volumetric GHG emissions at standard conditions from each equipment leak source category
Count	=	Total number of this type of emission source at the facility
EF	=	Population emission factor for specific sources listed in Appendix F.
GHG_i	=	for onshore petroleum and natural gas production facilities and onshore natural gas processing facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities GHG_i equals 1
T	=	Total time the specific source associated with the equipment leak was operational in the reporting period, in hours

Population emissions factors are available for specific sources for onshore 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, liquefied natural gas import and export facilities, and natural gas distribution facilities. These population emissions factors and a discussion on their references are available in Appendix G.

e. Method 21

This is the authorized method for detecting volatile organic carbon (VOC) emissions under Title 40 CFR. The method specifies the performance of a portable VOC emission detection instrument with a probe not exceeding one fourth inch outside diameter, used to slowly circumscribe the entire component interface where a leak could occur. The probe must be maintained in close proximity to (but not touching) the interface; otherwise it could be damaged by rotating shafts or plugged with ingested lubricants or greases. In most cases, it can be no more than 1 centimeter away from the leak interface. Method 21 does not specify leak definitions; they are defined within specific subparts of the Title 40 CFR. Method 21 also allows certain alternative equipment leak detection methods, such as soap solutions (where the leaking source is below the boiling point and above the freezing point of the soap solution, does not have areas open to the atmosphere that the soap solution cannot bridge, and does not have signs of liquid leakage). Method 21 does not specify any emissions mass or volumetric quantification methods, but only specifies an emissions concentration expressed in parts per million of combustible hydrocarbons in the air stream of the instrument probe. This leak detection data has been used by state emission inventories with "leaker" factors developed by the Synthetic Organic Chemicals Manufacturing Industry (SOCMI)[8] to estimate the quantity of VOC emissions. SOCMI factors were developed from petroleum refinery and petrochemical plant data using Method 21.

Method 21 instrumentation technology has been used for over 30 years to detect leaks. The approach uses gas concentration measurement of air and combustible gas drawn into the tip of a probe manually circumscribed on or within one centimeter along the entire potential seal surface or center of a vent to detect equipment leaks. This original practice is required for certain regulated components that are reachable with the hand-held leak detection instrument used while standing on the ground or fixed platform accessible by stairs (i.e. does not require climbing ladders, standing on stools or use of bucket-lift trucks to access components). In a study conducted by API at seven California refineries[9] with over five years of measured data (11.5 million data points), it was found that 0.13 percent of the components contributed over 90 percent of the controllable emissions (i.e. equipment leaks or vented emissions that can be mitigated once detected). Given the fact that only a small number of sources contribute to the majority of emissions, it is important for this final rule to detect and quantify leaking sources beyond the scope of Method 21.

Performance standards for remote leak sensing devices, such as those based on infrared (IR) light imaging, or laser beams in a narrow wavelength absorbed by hydrocarbon gases, were promulgated in the general provisions of EPA 40 CFR Part 60. This alternate work practice (AWP) permits leak detection using an instrument which can image both the equipment and leaking gas for all 40 CFR 60 subparts that require monitoring under LDAR.

In a typical Method 21 program, the costs of conducting emissions detection remain the same during each recurring study period. This is because the determination of whether a potential source is emitting or not is made only after every regulated source is screened for emissions as described above. The OVA/TVA requires the operator to physically access the emissions source with the probe and thus is much more time intensive than using the optical gas imaging instrument. Optical gas imaging instruments were found to be more cost effective for leak detection for this reporting rule as these instruments are able to scan hundreds of source components quickly, including components out of reach for an OVA/TVA.

[8] EPA (1995). *Protocol for Equipment Leak Emission Estimates.* Research Triangle Park, NC. Publication No. EPA-453/R-95-017. Online at: http://www.epa.gov/ttnchie1/efdocs/equiplks.pdf

[9] Hal Taback Company *Analysis of Refinery Screening Data*, American Petroleum Institute, Publication Number 310, November 1997.

Although leak detection with Method 21 or the AWP in their current form in conjunction with leaking component emission factors may not be the best suited for all mandatory reporting, the principle could potentially be adopted for estimating emissions from minor sources such as equipment leaks from components. Emissions can be detected from sources (including those not required under Method 21, i.e. not within arm's reach) using AWP procedures for the optical gas imaging instrument, and applying leaker emissions factors available from studies conducted specifically with methane emissions in its scope. This will be easier for industry to adapt to and also avoid the use of Synthetic Organic Chemical Manufacturing Industry correlation equations or leak factors developed specifically for different industry segments (i.e. petroleum refineries and chemical plants). This method will also result in the estimation of real emissions, as opposed to potential emissions from population emissions factor calculations.

f. Portable VOC Detection Instruments for Leak Measurement

As discussed above under Method 21, portable VOC detection instruments do not quantify the volumetric or mass emissions. They quantify the concentration of combustible hydrocarbon in the air stream induced through the maximum one fourth inch outside diameter probe. Since these small size probes rarely ingest all of the emissions from a component leak, they are used primarily for equipment leak detection. EPA provides emissions quantification guidelines, derived from emissions detection data, for using portable VOC detection devices. One choice of instrument emissions detection data is referred to as "leak/no-leak," where equipment is determined to be leaking when the portable instrument indicates the provided leak definition. Different leak definitions are specified within the subparts of the Clean Air Act. Subpart KKK of 40 CFR Part 60 defines "leakers" for natural gas processing facilities as components with a concentration of 10,000 ppm or more when measured by a portable leak detection instrument. Components that are measured to be less than 10,000 ppm are considered "not leaking." Hence, these quantification tables have a "no-leak" emission factor for all components found to have emissions rates below the leak definition, and "pegged" emission factors for all components above the leak definition. Alternatively, the "stratified" method has emission factors based on ranges of actual leak concentrations below, at and above the leak definition. Portable leak detection instruments normally peg at 10,000 ppm, and so are unsuitable for use with the "stratified" quantification factors.

g. Mass Balance for Quantification

There are mass balance methods that could be considered to calculate emissions for a reporting program. This approach would take into account the volume of gas entering a facility and the amount exiting the facility, with the difference assumed to be emitted to the atmosphere. This is most often discussed for emissions estimation from the transportation segment of the industry. For transportation, the mass balance is often not recommended because of the uncertainties surrounding meter readings and the large volumes of throughput relative to equipment leaks. The mass balance approach may, however, be feasible in cases where the volume of emissions is significantly large and recognizable as meter readings. One such source is an acid gas recovery unit where the volume of CO_2 extracted from natural gas is significant enough to be registered in a compositional difference of the natural gas and can be determined using mass balance.

h. Gulf Offshore Activity Data System program (GOADS)

The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) conducts a comprehensive activity data collection effort under its Gulf Offshore Activity Data System program (GOADS) in compliance with 30 CFR 250.302 through 304. This requires all petroleum and natural gas production platforms located in the Federal Gulf of Mexico (GoM) to report their activities to BOEMRE once in every three to four years. The activity data reported includes counts of emissions sources, volumes of throughputs from several pieces of equipment, fuel consumption by combustion devices, and parametric data related to certain emissions sources such as glycol dehydrators. This activity data is then converted into emissions estimates by BOEMRE and reported subsequently by BOEMRE. The BOEMRE summary report provides estimates of GHG emissions in the GoM as well as a detailed database of emissions from each source on platform in the GoM. The EPA could potentially use this data reported by the GOADS program. However, since the data has historically been collected once every three to four years, EPA will not receive new emissions information for every reporting period. This means that between BOEMRE reporting periods if a new platform is commissioned, an old platform is de-commissioned, new equipment is installed on existing platforms, or operating levels of platforms change then this information will not get recorded and reported for periods when BOEMRE GOADS is not being conducted. This issue however, can be resolved by requiring new platforms to use the most recent GOADS methods to estimate emissions and other reporters to adjust their emissions annually based on the time each platform was operating in comparison to the GOADS reporting year. Finally, the BOEMRE GOADS program does not collect information from platforms in the GoM under State jurisdiction, as well as platforms in the Pacific and Alaskan coasts. These platforms not under GOADS purview will not have existing data to report if GOADS reporting were to be adopted by EPA. Nevertheless, a reporting rule can potentially require non-GOADS platforms to adopt the GOADS methodology to calculate emissions. If BOEMRE discontinues or delays their GOADS, then platform operators under a reporting rule using GOADS may refer to the most recently published version of the GOADS program instructions to continue reporting.

i. Additional Questions Regarding Potential Monitoring Methods

There are several additional issues regarding the potential monitoring methods relevant to estimating equipment leak and vented emissions from the petroleum and natural gas industry.

i. Source Level Equipment Leak Detection Threshold

This document does not indicate a particular equipment leak definition or detection threshold requiring emissions measurement. This is because different equipment leak detection instruments have different levels and types of detection capabilities, i.e. some instruments provide a visual image while others provide a digital value on a scale (not necessarily directly related to mass emissions). Hence the magnitude of actual emissions can only be determined after measurement. This, however, may not serve the purpose of a reporting rule, which is to limit the burden by focusing only on significant sources of emissions. A facility can have hundreds of small emissions (as low as 3 grams per hour) and it might not be practical to measure all of them for reporting.

There are, however, two possible approaches to overcome this issue, as follows; provide an instrument performance standard such that any source determined to be emitting per the instrument is considered an emissions source, or provide a threshold value for the emitter such that any source below the threshold magnitude is not considered an emitter.

Instrument Performance Standards

Performance standards can be provided for equipment leak detection instruments and usage such that all instruments follow a minimum common detection threshold. Alternatively, the AWP to Detect Leaks from Equipment standards for optical gas imaging instruments recently adopted by EPA can potentially be proposed. In such a case, all detected emissions from components subject to the final rule may require measurement and reporting. This avoids the necessity of specifying performance standards.

The EPA Alternative Work Practice (AWP) promulgated the use of optical gas imaging instruments that can detect in some cases emissions as small as 1 gram per hour. The AWP requires technology effectiveness of emissions statistically equivalent to 60 grams/hour on a bi-monthly screening frequency, i.e. the technology should be able to routinely detect all emissions equal to or greater than 60 grams/hour. EPA determined by Monte Carlo simulation that 60 grams/hour leak rate threshold and bi-monthly monitoring are equivalent to existing work practices (Method 21). To implement the technology effectiveness, the AWP requires that the detection instrument meet a minimum detection sensitivity mass flow rate. For the purposes of the proposed supplemental rule, such a performance standard could be adapted for the detection of natural gas emissions with methane as the predominant component (it should be noted that Method 21 is specifically meant for VOCs and HAPs and not for methane).

Equipment Leak Threshold

One alternative to determining an emission source is to provide a mass emissions threshold for the emitter. In such a case, any source that emits above the threshold value would be considered an emitter. For portable VOC monitoring instruments that measure emission concentrations a concentration threshold equivalent to a mass threshold can be provided. However, the concentration measurement is converted to an equivalent mass value using SOCMI correlation equations, which were developed from petroleum refinery and petrochemical plant data. In the case of an optical imaging instrument, which does not provide the magnitude of emissions, either concentration or mass emissions, quantification would be required using a separate measurement instrument to determine whether a source is an emitter or not. This could be very cost prohibitive for the purposes of this rule.

ii. Duration of Equipment Leaks

Equipment leaks by nature occur randomly within the facility. Therefore, there is no way of knowing when a particular source started emitting. If the potential monitoring method requires a one time equipment leak detection and measurement, then assumptions will have to be made regarding the duration of the emissions. There are several potential options for calculating the duration of emissions. If a component leak is detected, total emissions from each source could be quantified under one of the following three scenarios: 1) if a facility conducts one comprehensive leak survey each reporting period, applicable component leaker emissions factors could be applied to all specific component emissions sources and emissions quantified based on emissions occurring for an entire reporting period; 2) if a facility conducts two comprehensive leak surveys during a single reporting period, applicable component leaker emissions factors could be applied to all component emissions sources. If a specific emission source is found not leaking in the first survey but leaking in the second survey, emissions could be quantified from the date of the first leak survey conducted in the same reporting period forward through the remainder of the reporting period. If a specific emissions source is found leaking in the first survey but is repaired and found not leaking in the second survey, emissions could be quantified from the first day of the reporting period to the date of the second survey. If a component is found leaking in both surveys, emissions could be quantified based on an emission occurring for an entire reporting period; 3) if a facility conducts multiple comprehensive leak surveys during the same reporting period, applicable component leaker emissions factors could be applied to component emissions sources. Each specific source found leaking in one or more surveys is quantified for the period from a prior finding of no leak (or beginning of the reporting period) to a subsequent finding of no leak (or end of the reporting period). If a component is found leaking in all surveys, emissions could be quantified based on an emissions occurring for an entire reporting period.

iii. Equipment Leak and Vented Emissions at Different Operational Modes

If a reporting program relies on a one time or periodic measurement, the measured emissions may not account for the different modes in which a particular technology operates throughout the reporting period.   This may be particularly true for measurements taken at compressors. Compressor leaks are a function of the mode in which the compressor is operating: i.e. offline pressurized, or offline de-pressurized. Typically, a compressor station consists of several compressors with one (or more) of them on standby based on system redundancy requirements and peak delivery capacity. When a compressor is taken offline it may be kept pressurized with natural gas or de-pressurized. When the compressor is offline and kept pressurized, equipment leaks and vented emissions result from closed blowdown valves and reciprocating compressor rod packing leaks, respectively. When the compressor is offline and depressurized, emissions result from leaking isolation valves. When operating, compressor vented emissions result from compressor seals or rod packing and other components in the compressor system. In each of the compressor modes, the resultant equipment leak and vented emissions are significantly different. One potential approach to account for these varying levels of equipment leak and vented emissions is to have operators measure all compressors in each operating mode once a reporting period. Operators would also need to report the time for which the compressor is in the different modes. The disadvantages to this approach is that it will increase the reporting burden because measurements will have to be taken at each mode of compressor operation in each reporting period and the time that the equipment is in various operational modes would also have to be tracked. In addition, it is not feasible to require operators to take compressors off-line every year to conduct measurements in offline pressurized and depressurized modes. One alternative approach is to report compressor emissions in the mode the compressors are found, also known as reporting compressor emissions “as-is”. The reporters could then determine emission factors for each mode and apply them to the period of time each compressor was not in the mode it was measured in for the reporting period. Since most compressors would be found in the, pressurized, operating mode, reporters could be required to measure each compressor in an offline mode less frequently (e.g. every three reporting periods) to ensure sufficient data points are collected in the less common offline modes.

A similar issue exists with tanks where the operating conditions change more often than for compressors. The amount of throughput through tanks varies continuously as new hydrocarbon liquids are introduced and stored liquids are withdrawn for transportation. Unlike other equipment, the operational level of tanks cannot be categorized into a fixed and limited number of modes. This makes it all the more challenging to characterize emissions from storage tanks. One option is to require operators to use best judgment and characterize a few different modes for the storage tanks and make adjustments to the monitored emissions accordingly.

iv. Natural Gas Composition

When measuring equipment leaks and vented emissions using the various measurement instruments (high volume sampler, calibrated bags, and meters) or using engineering estimation for vented emissions, only flow rate is measured or calculated and the individual CH_4 and CO_2 emissions are estimated from the natural gas mass emissions using natural gas composition appropriate for each facility. For this purpose, the monitoring methodologies discussed above would require that facilities use existing gas composition estimates to determine CH_4 and CO_2 components of the natural gas emissions (acid gas recovery units, flare stacks, and storage tank vented emissions are an exception to this general rule). These gas composition estimates are assumed to be available at facilities. But this may or may not be a practical assumption for reporting. In the absence of gas composition, periodic measurement of the required gas composition for speciation of the natural gas mass emissions into CH_4 and CO_2 mass emissions could be a potential option.

In addition, GHG components of natural gas may change significantly in the facilities during the reporting period and different sources in the same facility may be emitting different compositions of natural gas. This is most prevalent in onshore production, offshore production and natural gas processing facilities. One potential option is to apply an average composition across all emissions sources for the reporting facility. Another option is to apply specific composition estimates across similar streams in the same facility. For example, in processing, the natural gas composition is similar for all streams upstream of the de-methanizer. The same is true of all equipment downstream of the de-methanizer overhead.

For onshore production and offshore production monthly or quarterly samples can be taken to account for the variation in natural gas being produced from different combinations of production wells throughout the reporting period.

v. **Physical Access for Leak Measurement**

All emissions measurement techniques require physical access to the leaking source. The introduction of remote leak detection technologies based on infrared (IR) light absorption by hydrocarbon gas clouds from atmospheric leaks makes leak detection quicker and possible for sources outside of arms reach from the ground or fixed platforms. Leaks from flanges, valve stems, equipment covers, etc. are generally smaller than emissions from vents. Component leaks are expensive to measure where they are not accessible within arms reach from the ground or a fixed platform. For these inaccessible sources, the use of emission factors for emissions quantification may be appropriate. Vent stacks are often located out of access by operators for safety purposes, but may represent large emission sources. Where emissions are detected by optical gas imaging instruments, emissions measurement may be cost-effective using the following source access techniques:

- Short length ladders positioned on the ground or a fixed platform where OSHA regulations do not require personnel enclosure and the measurement technique can be performed with one hand;
- Bucket trucks can safely position an operator within a full surround basket allowing both hands to be used above the range of ladders or for measurement techniques requiring both hands;
- Relatively flat, sturdy roofs of equipment buildings and some tanks allow safe access to roof vents that are not normally accessible from fixed platforms or bucket trucks;
- Scaffolding is sometimes installed for operational or maintenance purposes that allow access to emission sources not normally accessible from the ground, fixed platforms and out of reach of bucket trucks.

7. Procedures for Estimating Missing Data

It is possible that some companies would be missing data necessary to quantify annual emissions. In the event that data are missing, potential procedures to fill the data gap are outlined below and are organized by data type.

In general, although there is always the possibility of using a previous periods' data point to replace missing data in the current reporting period, this is not ideal since varying operating conditions can dramatically impact emissions estimates. Where using previous reporting periods' data are not desirable, then a reporting rule might require 100% data availability. In other words, there would be no missing data procedures provided. If any data were identified as missing, then there would be an opportunity to recollect the emissions data over the course of the current reporting period.

a. Emissions Measurement Data

Measured data can be collected by trained engineers using a high volume sampler, meter, or calibrated bag. Over the course of the data collection effort, some of the measured emissions rates could get lost temporarily or permanently due to human error, or storage errors such as lost hard-drives and records. If measured data is missing then the field measurement process may have to be repeated within the reporting period. If this proves to be impossible and the company clearly certifies that they lost the data and can justify not repeating the survey within the given reporting period, then the previous reporting period's data could be used to estimate equipment leaks from the current reporting period.

b. Engineering Estimation Data

Engineering estimations rely on the collection of input data to the simulation software or calculations. A potential procedure for missing input data is outlined below for each type of input parameter.

- Operations logs. If operating logs are lost or damaged for a current reporting period, previous reporting period's data could be used to estimate emissions. Again, using previous reporting periods' data are not as desirable as there could be significant differences from period to period based on operating conditions.
- Process conditions data. Estimating vented emissions from acid gas removal vent stacks, blowdown vent stacks, dehydrator vents, natural gas driven pneumatic valve bleed devices, natural gas driven pneumatic pumps, and storage tanks requires data on the process conditions (e.g., process temperature, pressure, throughputs, and vessel volumes). If, for any reason, these data are incomplete or not available for the current reporting period, field operators or engineers could recollect data wherever possible. If this data cannot be collected, then relevant parameters for estimation of emissions can be used from previous reporting period. However, where possible current reporting period parameters should be used for emissions estimation due to the reasons listed above.

c. Emissions Estimation Data for Storage Tanks and Flares

Emissions from storage tanks and flares might require a combination of both direct measurement and engineering estimation to quantify emissions. In such cases the storage tank emissions calculation requires the measurement of "emissions per throughput" data. If this data is missing then the previous reporting periods' estimate of "emissions per throughput" measured data could be used with current period throughput of the storage tank to calculate emissions.

Calculating emissions from flares requires the volume of flare gas measured using a meter. If these data are missing then the flare gas in the current reporting period could be estimated by scaling the flare gas volume from previous reporting period by adjusting it for current period throughput of the facility.

d. Emissions Estimation Data Using Emissions Factors

If population emissions factors are used then the only data required is activity data. In such a case missing data should be easily replaceable by undertaking a counting exercise for locations from which the data is missing. Alternatively, previous reporting period activity data can be used to fill in missing data. However, if facility and/ or equipment modifications have resulted in increase or decrease in activity data count then this may not be a feasible approach.

If leaker emissions factors are used then activity data will have to be collected using some form of equipment leak detection. In such case, missing data may not be easily replaceable. Previous period reported activity data may be used but it may not be representative of current period emissions. A detection survey to replace missing data may be warranted.

8. QA/QC Requirements

a. Equipment Maintenance

Equipment used for monitoring, both emissions detection and measurement, should be calibrated on a scheduled basis in accordance with equipment manufacturer specifications and standards. Generally, such calibration is required prior to each monitoring cycle for each facility. A written record of procedures needed to maintain the monitoring equipment in proper operating condition and a schedule for those procedures could be part of the QA/QC plan for the facility.

An equipment maintenance plan could be developed as part of the QA/QC plan. Elements of a maintenance plan for equipment could include the following:

- Conduct regular maintenance of monitoring equipment.
  - Keep a written record of procedures needed to maintain the monitoring system in proper operating condition and a schedule for those procedures;
  - Keep a record of all testing, maintenance, or repair activities performed on any monitoring instrument in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring instrument and records of any corrective actions associated with a monitor's outage period.

b. Data Management

Data management procedures could be included in the QA/QC Plan. Elements of the data management procedures plan are as follows:

- Check for temporal consistency in production data and emission estimate. If outliers exist, can they be explained by changes in the facility's operations, etc.?

- A monitoring error is probable if differences between annual data cannot be explained by:
    - Changes in activity levels,
    - Changes concerning monitoring methodology,
    - Changes concerning change in equipment,
    - Changes concerning the emitting process (e.g. energy efficiency improvements).[10]

- Determine the "reasonableness" of the emission estimate by comparing it to previous year's estimates and relative to national emission estimate for the industry:
  - Comparison of emissions by specific sources with correction for throughput, if required,
  - Comparison of emissions at facility level with correction for throughput, if required,
  - Comparison of emissions at source level or facility level to national or international reference emissions from comparable source or facility, adjusted for size and throughput,
  - Comparison of measured and calculated emissions.[10]

- Maintain data documentation, including comprehensive documentation of data received through personal communication:
  - Check that changes in data or methodology are documented

c. Calculation checks

Calculation checks could be performed for all reported calculations. Elements of calculation checks could include:

- Perform calculation checks by reproducing a representative sample of emissions calculations or building in automated checks such as computational checks for calculations:
  - Check whether emission units, parameters, and conversion factors are appropriately labeled,
  - Check if units are properly labeled and correctly carried through from beginning to end of calculations,
  - Check that conversion factors are correct,
  - Check the data processing steps (e.g., equations) in the spreadsheets,
  - Check that spreadsheet input data and calculated data are clearly differentiated
  - Check a representative sample of calculations, by hand or electronically,
  - Check some calculations with abbreviated calculations (i.e., back of the envelope checks),

[10] Official Journal of the European Union, August 31, 2007. Commission Decision of 18 July 2007, "Establishing guidelines for the monitoring and reporting of GHG emissions pursuant to Directive 2003/87/EC of the European Parliament and of the Council. Available at http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2007:229:0001:0085:EN:PDF.

- Check the aggregation of data across source categories, business units, etc.,
- When methods or data have changed, check consistency of time series inputs and calculations.[11]

9. Reporting Procedure

(a) The facilities that cross the potential threshold for reporting could report the following information to EPA:

(1) Emissions monitored at an aggregate source level for each facility, separately identifying those emissions that are from standby sources. In several onshore natural gas processing plants CO_2 is being capture for Enhanced Oil Recovery operations. Therefore, these CO_2 emissions may have to be separately accounted for in the reporting.

(2) Activity data, such as the number of sources monitored, for each aggregated source type level for which emissions will be reported.

(3) The parameters required for calculating emissions when using engineering estimation methods.

In addition, the following reporting requirements could be considered for a reporting rule;

(b) Equipment leaks by nature occur randomly within the facility, therefore, where emissions are reported on an annual basis, it may not be possible to determine *when* the equipment leaks began. As discussed in more detail in Section (I)(ii) of the TSD, under these circumstances, annual emissions could be determined assuming that the equipment leaks were continuous from the beginning of the reporting period or from the last recorded not leaking in the current reporting period and until the equipment leak is repaired or the end of the reporting period.

(c) Due to the point-in-time nature of direct measurements, reports of annual emissions levels should take into account equipment operating hours according to standard operating conditions and any significant operational interruptions and shutdowns, to convert direct measurement to an annual figure.

10. Verification of Reported Emissions

As part of the data verification requirements, the owner or operator could submit a detailed explanation of how company records of measurements are used to quantify equipment leaks and vented emissions measurement within 7 days of receipt of a written request from EPA or from the applicable State or local air pollution control agency (the use of electronic mail can be made acceptable).

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[11] U.S. EPA 2007. Climate Leaders, Inventory Guidance, Design Principles Guidance, Chapter 7 “Managing Inventory Quality”. Available at http://www.epa.gov/climateleaders/documents/resources/design_princ_ch7.pdf.

Appendix A: Segregation of Emissions Sources using the Decision Process

The tables provided in this appendix represent the outcome of the decision process used to identify a starting list of potential sources that were evaluated for inclusion in the final rule. The decision process was applied to each emission source in the natural gas segment of the U.S. GHG Inventory. The petroleum onshore production segment has emission sources that either are equivalent to their counter-parts in the natural gas onshore production segment or fall in the exclusion category. Petroleum transportation was not analyzed further due to the level of emissions and refineries are treated separately in Subpart Y.

Sources Contributing to 80% of Equipment Leaks and Vented Emissions from Each Industry Segment

Source	Offshore Production	Onshore Production	Processing	Transmission	Storage	LNG Storage	LNG Import and Export	Distribution
Separators		4%						
Meters/Piping		4%						
Small Gathering Reciprocating Comp.		2%						
Pipeline Leaks		7%						
CBM Powder River		2%						
Pneumatic Device Vents		43%	0.26%	12%	13%			
Gas Pneumatic Pumps		9%	0.49%					
Dehydrator Vents	2%	3%	3%					
Well Clean Ups (LP Gas Wells)/ Blowdowns		7%						
Plant/Station/ Platform Fugitives	4%		5%		16%	14%	3%	
Reciprocating Compressors			48%	40%	45%	54%	14%	
Centrifugal Compressors	22%		16%	8%	6%	19%	4%	
Acid Gas Removal Vents			2%					
Vessel Blowdowns/Venting			6%					
Routine Maintenance/Upsets - Pipeline venting				10%				
Station venting				8%			2%	
M&R (Trans. Co. Interconnect)				4%				
Pipeline Leaks Mains								36%
Services								16%
Meter/Regulator (City Gates)								37%
Residential Customer Meters								
Flare stacks	1%							
Non-pneumatic pumps	0.03%							
Open ended lines	0.005%							
Pump seals	0.41%							
Storage tanks	50%							
Wellhead fugitive emissions					4%			
Well completions		0.0004%						
Well workovers		0.04%						

NOTE: Pink cells represent sources that were included over riding the decision tree process. Blue cells represent sources that are not present in the respective segments. Green cells represent sources that are not explicitly identified in the U.S. GHG Inventory; however, these sources may potentially be found in the respective segments. Blank cells are sources in the U.S. GHG Inventory.

Inventory of Methane Emissions from Natural Gas Systems

PRODUCTION OFFSHORE	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
Amine gas sweetening unit	0.2	80	0.01%	0.0001%	NE	c	c	a	n
Boiler/heater/burner	0.8	332	0.05%	0.0002%		c	d	a	n
Diesel or gasoline engine	0.01	6	0.001%	0.000004%		c	d	a	n
Drilling rig	3	1,134	0.17%	0.001%		c	d	a	n
Flare	24	9,583	1.47%	0.01%		c	c	b	n
Centrifugal Seals	358	144,547	22%	0.10%		a	a	a	b
Connectors	0.8	309	0.05%	0.0002%		b	b	b	b
Flanges	2.38	960	0.15%	0.001%		b	b	b	b
OEL	0.1	32	0.005%	0.00002%		b	b	b	b
Other	44	17,576	2.70%	0.01%		b	b	b	b
Pump Fugitive	0.5	191	0.03%	0.0001%		b	b	a	b
Valves	19	7,758	1%	0.01%		b	b	b	b
Glycol dehydrator	25	9,914	2%	0.01%		c	c	b	n
Loading operation	0.1	51	0.01%	0.00004%		c	d	a	n
Separator	796	321,566	49%	0.23%		c	c	b	b
Mud degassing	8	3,071	0.47%	0.002%		c	d	a	n
Natural gas engines	191	77,000	12%	0.05%					
Natural gas turbines	3	1,399	0.22%	0.001%					
Pneumatic pumps	7	2,682	0.41%	0.002%		c	b	a	b
Pressure/level controllers	2	636	0.10%	0.0005%		c	b	a	b
Storage tanks	7	2,933	0.45%	0.002%		c	c	a	n
VEN exhaust gas	121	48,814	8%	0.03%		c	c	b	n

NOTES: Leak Detection: a – Yes and cost effective; b – Yes but cost burden c - No. Cost effectiveness based on expert judgment.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.

PRODUCTION ONSHORE	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
Normal Fugitives									
Gas Wells									
Non-associated Gas Wells (less Unconventional)	2,682	1,083,539	2%	0.77%	376784	b	b	b	b
Unconventional Gas Wells	69	27,690	0.06%	0.02%	35440	a	b	b	b
Field Separation Equipment					0				
Heaters	1,463	591,023	1%	0.42%	89720	a	b	b	b
Separators	4,718	1,906,206	4%	1%	247919	b	b	b	b
Dehydrators	1,297	524,154	1%	0.37%	37925	a	b	b	b
Meters/Piping	4,556	1,840,683	4%	1%	315487	b	b	b	b
Gathering Compressors					0				
Small Reciprocating Comp.	2,926	1,182,062	2%	1%	28490	a	a	b	b
Large Reciprocating Comp.	664	268,133	0.54%	0.19%	112	a	a	b	b
Large Reciprocating Stations	45	18,178	0.04%	0.01%	14	a	a	b	b
Pipeline Leaks	8,087	3,267,306	7%	2%	392624	b	b	b	n
Vented and Combusted									
Drilling and Well Completion									
Completion Flaring	0	188	0.00%	0.00%	597	c	c	c	n
Well Drilling	96	38,946	0.08%	0.03%	35600	c	c	a	y
Coal Bed Methane									
Powder River	2,924	1,181,246	2%	1%	396920	c	c	a	n
Black Warrior	543	219,249	0.44%	0.16%		c	c	a	n
Normal Operations									
Pneumatic Device Vents	52,421	21,178,268	43%	15%		c	b	a	b
Chemical Injection Pumps	2,814	1,136,867	2%	0.81%		c	b	a	b
Kimray Pumps	11,572	4,674,913	9%	3%		c	b	a	n
Dehydrator Vents	3,608	1,457,684	3%	1%		c	c	a	n
Condensate Tank Vents									
Condensate Tanks without Control Devices	1,225	494,787	1%	0.35%		c	c	a	b
Condensate Tanks with Control Devices	245	98,957	0.20%	0.07%		c	d	a	b
Compressor Exhaust Vented									
Gas Engines	11,680	4,718,728	9%	3%					
Well Workovers									
Gas Wells	47	18,930	0.04%	0.01%		c	d	b	y
Well Clean Ups (LP Gas Wells)	9,008	3,639,271	7%	3%		c	d	a	n
Blowdowns									
Vessel BD	31	12,563	0.03%	0.01%		c	d	a	n
Pipeline BD	129	52,040	0.10%	0.04%		c	d	a	b
Compressor BD	113	45,648	0.09%	0.03%		c	d	a	n
Compressor Starts	253	102,121	0.20%	0.07%		c	d	a	n
Upsets									
Pressure Relief Valves	29	11,566	0.02%	0.01%		c	d	b	n
Mishaps	70	28,168	0.06%	0.02%		c	d	b	n

Notes: Leak Detection: a – Yes and cost effective; b – Yes but cost burden; c - No. Cost effectiveness based on expert judgment.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.

GAS PROCESSING PLANTS	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
Normal Fugitives									
Plants	1,634	660,226	5%	0.47%		a	a	b	b
Recip. Compressors	17,351	7,009,755	48%	5%		a	a	b	b
Centrifugal Compressors	5,837	2,358,256	16%	2%		a	a	b	b
Vented and Combusted									
Normal Operations									
Compressor Exhaust									
Gas Engines	6,913	2,792,815	19%	2%					
Gas Turbines	195	78,635	1%	0.06%					
AGR Vents	643	259,592	2%	0.18%		c	c	a	n
Kimray Pumps	177	71,374	0.49%	0.05%		c	b	a	b
Dehydrator Vents	1,088	439,721	3%	0.31%		c	c	a	n
Pneumatic Devices	93	37,687	0.3%	0.03%		c	b	a	b
Routine Maintenance									
Blowdowns/Venting	2,299	928,900	6%	1%		c	d	a	n

Notes: Leak Detection: a – Yes and cost effective; b – Yes but cost burden; c - No. Cost effectiveness based on expert judgment.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.

TRANSMISSION	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
Fugitives									
Pipeline Leaks	166	67,238	0.17%	0.05%		a	c	a	n
Compressor Stations (Transmission)									
Station	5,619	2,270,177	6%	2%		a	a	b	b
Recip Compressor	38,918	15,722,907	40%	11%		a	a	b	b
Centrifugal Compressor	7,769	3,138,795	8%	2%		a	a	b	b
M&R (Trans. Co. Interconnect)	3,798	1,534,238	4%	1%		a	a	b	b
M&R (Farm Taps + Direct Sales)	853	344,646	1%	0.25%		b	b	b	b
Vented and Combusted									
Normal Operation									
Dehydrator vents (Transmission)	105	42,329	0.11%	0.03%		c	c	a	n
Compressor Exhaust									
Engines (Transmission)	10,820	4,371,314	11%	3%					
Turbines (Transmission)	61	24,772	0.06%	0.02%					
Generators (Engines)	529	213,911	0.55%	0.15%					
Generators (Turbines)	0	60	0.0002%	0.00004%					
Pneumatic Devices Trans + Stor									
Pneumatic Devices Trans	11,393	4,602,742	12%	3%		c	b	a	b
Routine Maintenance/Upsets									
Pipeline venting	9,287	3,752,013	10%	3%		c	d	a	b
Station venting Trans + Storage									
Station Venting Transmission	7,645	3,088,575	8%	2%		c	d	a	n

Notes: Leak Detection: a – Yes and cost effective; b – Yes but cost burden; c - No. Cost effectiveness based on expert judgment.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.

STORAGE	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
Fugitives									
Compressor Stations (Storage)									
Station	2,801	1,131,492	16%	1%		a	a	b	b
Recip Compressor	8,093	3,269,454	45%	2%		a	a	b	n
Centrifugal Compressor	1,149	464,354	6%	0.33%		a	a	b	n
Wells (Storage)	695	280,891	4%	0.20%		a	a	b	y
Vented and Combusted									
Normal Operation									
Dehydrator vents (Storage)	217	87,514	1%	0.06%		c	c	a	n
Compressor Exhaust									
Engines (Storage)	1,092	441,108	6%	0.31%					
Turbines (Storage)	9	3,680	0.05%	0.003%					
Pneumatic Devices Trans + Stor									
Pneumatic Devices Storage	2,318	936,324	13%	1%		c	b	a	b
Station venting Trans + Storage									
Station Venting Storage	1,555	628,298	9%	0.45%		c	d	a	n

Notes: Leak Detection: a – Yes and cost effective; b – Yes but cost burden; c - No. Cost effectiveness based on expert judgment.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.

LNG STORAGE	**Total Emissions Nationally (MMcf/year)**	**Tonnes CO2e/ Year**	**% of Sector Emissions**	**% of total Inventory Emissions**	**Activity Factors**	**Leak Detection**	**Direct Measurement**	**Engineering Estimate**	**Accesible Source**
LNG Storage									
LNG Stations	552	222,824	14%	0.16%		b	b	b	b
LNG Reciprocating Compressors	2,084	842,118	54%	1%		b	b	b	b
LNG Centrifugal Compressors	715	288,756	19%	0.21%		b	b	b	b
LNG Compressor Exhaust									
LNG Engines	172	69,632	5%	0.05%					
LNG Turbines	1	261	0.02%	0.0002%					
LNG Station venting	306	123,730	8%	0.09%		c	d	a	n

LNG IMPORT AND EXPORT TERMINALS	**Total Emissions Nationally (MMcf/year)**	**Tonnes CO2e/ Year**	**% of Sector Emissions**	**% of total Inventory Emissions**	**Activity Factors**	**Leak Detection**	**Direct Measurement**	**Engineering Estimate**	**Accesible Source**
LNG Import Terminals									
LNG Stations	22	8,880	3%	0.01%		b	b	b	b
LNG Reciprocating Compressors	105	42,347	14%	0.03%		b	b	a	b
LNG Centrifugal Compressors	27	10,820	4%	0.01%		b	b	a	b
LNG Compressor Exhaust									
LNG Engines	586	236,647	78%	0.17%					
LNG Turbines	3	1,370	0.45%	0.001%					
LNG Station venting	12	4,931	2%	0.004%		c	d	a	n

Notes: Leak Detection: a – Yes and cost effective; b – Yes but cost burden; c - No.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.
Export Terminals are not currently included in the U.S. GHG Inventory, therefore they were not included in this analysis. There is currently only one export terminal, located in Alaska.

DISTRIBUTION	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
Normal Fugitives									
Pipeline Leaks									
Mains - Cast Iron	9,222	3,725,675	14%	3%		a	b	b	n
Mains - Unprotected steel	6,515	2,632,209	10%	2%		a	b	b	n
Mains - Protected steel	1,422	574,529	2%	0.41%		a	b	b	n
Mains - Plastic	6,871	2,775,759	10%	2%		a	b	b	n
Total Pipeline Miles			36%	7%					
Services - Unprotected steel	7,322	2,957,970	11%	2%		a	b	b	n
Services Protected steel	2,863	1,156,473	4%	1%		a	b	b	n
Services - Plastic	315	127,210	0.47%	0.09%		a	b	b	n
Services - Copper	47	19,076	0.07%	0.01%		a	b	a	n
Total Services			16%	3%					
Meter/Regulator (City Gates)			37%	7%					
M&R >300	5,037	2,034,986	7%	1%	3,198	a	a	b	b
M&R 100-300	10,322	4,170,101	15%	3%	12,325	b	b	b	b
M&R <100	249	100,480	0.37%	0.07%	6,587	a	c	b	b
Reg >300	5,237	2,115,726	8%	2%	3,693	a	a	b	b
R-Vault >300	25	9,976	0.04%	0.01%	2,168	a	a	b	b
Reg 100-300	4,025	1,625,929	6%	1%	11,344	b	b	b	b
R-Vault 100-300	8	3,247	0.01%	0.002%	5,097	a	c	b	b
Reg 40-100	306	123,586	0.45%	0.09%	33,578	b	b	b	b
R-Vault 40-100	23	9,115	0.03%	0.01%	29,776	b	b	b	b
Reg <40	17	6,690	0.02%	0.005%	14,213	b	b	b	b
Customer Meters									
Residential	5,304	2,142,615	8%	2%	37017342	b	b	a	y
Commercial/Industry	203	81,880	0.30%	0.06%	4231191	b	b	a	y
Vented									
Rountine Maintenance									
Pressure Relief Valve Releases	63	25,346	0.09%	0.02%		c	d	b	n
Pipeline Blowdown	122	49,422	0.18%	0.04%		c	d	a	n
Upsets									
Mishaps (Dig-ins)	1,907	770,405	3%	1%		c	d	b	n

NOTES: Leak Detection: a – Yes and cost effective; b – Yes but cost burden; c - No. Cost effectiveness based on expert judgment.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.

Appendix B: Development of revised estimates for four U.G. GHG Inventory emissions sources

Well Completion and Workover Venting

This discussion describes the methods used to estimate total U.S. methane emissions from well completion and workover venting. For the purposes of this estimate, it is assumed that all unconventional wells are completed with hydraulic fracturing of tight sand, shale or coal bed methane formations (i.e. completions involving high rate, extended back-flow to expel fracture fluids and sand proppant, which also leads to greater gas venting or flaring emissions than conventional well completions). It is understood that not all unconventional wells involve hydraulic fracturing, but some conventional wells are hydraulically fractured, which is assumed to balance the over-estimate.

►*Estimate the Number of Gas Wells Completed*

The data in Exhibit B-1 was extracted from EPA (2008)[12]. The unconventional well column only includes CBM wells and shale gas wells, but does not include tight sands formations because that data is not readily available either publically or in the U.S. Inventory. Thus, this analysis underestimates the activity associated with unconventional well completions and workovers.

Exhibit B-1. 2007 Natural Gas Wells

Year	Approximate Number of Onshore Unconventional Gas Wells	Approximate Number of Onshore Conventional Gas Wells	Total Number of Gas Wells (both conventional and unconventional)
2006	35,440	375,601	411,041
2007	41,790	389,245	431,035

Exhibit B-1 was used to calculate that there was a net increase of 19,994 wells (both conventional and unconventional) between 2006 and 2007. Each of these wells is assumed to have been completed over the course of 2006. EPA (2008) also estimates that 35,600 gas wells were drilled in 2006. This includes exploratory wells, dry holes, and completed wells. EPA (2008) also indicates that 19,994 of those natural gas wells were drilled and completed. The difference between the 35,600 drilled and 19,994 new wells is 15,606 wells, which we assume are replaced for shut-in or dry holes. This analysis assumed that 50% of those remaining 15,606 wells were completed. Thus, the total number of gas well completions, both conventional and unconventional, was estimated to be 27,797 wells in 2006.

$$19{,}994\,wells + \left(50\% \times \left(35{,}600\,wells - 19{,}994\,wells\right)\right) = 27{,}797\,wells$$

That is 78% of the total gas wells drilled in 2006. We assumed this same percentage of completed wells applies to the year 2007. EPA (2008) estimates 37,196 gas wells were

[12] EPA.. (2008) *U.S. Inventory of Greenhouse Gas Emissions and Sinks: 1990 – 2007*. Available online at: <http://epa.gov/climatechange/emissions/usgginv_archive.html>.

drilled in 2007, so applying this completion factor, 78% of 37,196 wells equals 29,043 gas wells completed in 2007.

►*Estimate the Number of Conventional and Unconventional Well Completions*
Exhibit B-1 shows a net increase of 6,350 unconventional wells from 2006 to 2007. This is 32% of the 19,994 net increase in all wells over that period. It was assumed that 32% of the estimated 29,043 well completions in 2007 (see previous section) were unconventional wells. The remaining gas well completions were assumed to be conventional wells. These results are summarized in Exhibit B-2. This analysis also assumed that all unconventional wells require hydraulic fracture upon completion. Because these completions and workovers only account for CBM wells and shale gas wells, it is a significant underestimate since tight sands formations are omitted.

Exhibit B-2. 2007 Completions Activity Factors

2007 Conventional Well Completions	19,819
2007 Unconventional Well Completions	9,224

►*Estimate the Number of Conventional and Unconventional Well Workovers*
GRI (1996)[13] provides activity data for 1992 on conventional workovers. It reported that 9,324 workovers were performed with 276,014 producing gas wells. This activity data was projected to 2007 using the ratio of 2007 producing gas wells to 1992 producing gas wells; as shown in Exhibit 3:

Exhibit B-3. Calculation of 2007 Conventional Workover Activity Factor

$$2007\,ConventionalWorkovers = 1992\,ConventionalWorkovers \times \frac{2007\,GasWells}{1992\,GasWells}$$

$$2007\,ConventionalWorkovers = 9{,}324\,workovers \times \frac{431{,}035\,wells}{276{,}014\,wells}$$

Unconventional gas wells were assumed to be re-fractured once every 10 years. Thus, the number of unconventional gas well workovers was 10% of the existing unconventional well count in 2007.

The resulting activity factors for conventional and unconventional gas well workovers are summarized in Exhibit B-4.

Exhibit B-4. Summary of 2007 Workover Activity Factors

[13] GRI. *Methane Emissions from the Natural Gas Industry*. 1996. Available online at: <http://epa.gov/gasstar/tools/related.html>.

2007 Conventional Well Workovers	$9{,}324 workovers \times \frac{431{,}035 wells}{276{,}014 wells} =$	14,569
2007 Unconventional Well Workovers	$10\% \times 41{,}790 wells =$	4,179

►*Estimate the Emission Factor for Conventional Well Completions*
GRI (1996) estimated that conventional well completions emit 0.733 Mcf of methane each. GRI (1996) assumed that all completion flowback was flared at 98% combustion efficiency and the produced gas was 78.8% methane by volume. This analysis estimated the amount of gas sent to the flare by dividing the reported GRI factor by the 2% un-combusted gas. The resulting emission factor for conventional well completions was **36.65 Mcf of methane/completion**.

►*Estimate the Emission Factor for Conventional Well Workovers*
The GRI (1996) emission factor for well workovers was accepted for this analysis. That emission factor is **2.454 Mcf of methane/workover** for conventional wells.

►*Estimate the Emission Factor for Unconventional Well Completions*
The emission factor for unconventional well completions was derived using several experiences presented at Natural Gas STAR technology transfer workshops.

One presentation[14] reported that the emissions from all unconventional well completions were approximately 45 Bcf using 2002 data. The emission rate per completion can be back-calculated using 2002 activity data. API *Basic Petroleum Handbook*[15] lists that there were 25,520 wells completed in 2002. Assuming Illinois, Indiana, Kansas, Kentucky, Michigan, Missouri, Nebraska, New York, Ohio, Pennsylvania, Virginia, and West Virginia produced from low-pressure wells that year, 17,769 of those wells can be attributed to onshore, non-low-pressure formations. The Handbook also estimated that 73% (or 12,971 of the 17,769 drilled wells) were gas wells, but are still from regions that are not entirely low-pressure formations. The analysis assumed that 60% of those wells are high pressure, tight formations (and 40% were low-pressure wells). Therefore, by applying the inventory emission factor for low-pressure well cleanups (49,570 scf/well-year[1]) approximately 5,188 low-pressure wells emitted 0.3 Bcf .

$$40\% \times 12{,}971 wells \times \frac{49{,}570 scf}{well} \times \frac{1 Bcf}{10^9 scf} \approx 0.3 Bcf$$

The remaining high pressure, tight-formation wells emitted 45 Bcf less the low-pressure 0.3 Bcf, which equals 44.7 Bcf. Since there is great variability in the natural gas sector and the resulting emission rates have high uncertainty; the emission rate per unconventional (high-pressure tight formation) wells were rounded to the nearest thousand Mcf.

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[14] EPA. *Green Completions*. Natural Gas STAR Producer's Technology Transfer Workshop. September 21, 2004. Available online at: <http://epa.gov/gasstar/workshops/techtransfer/2004/houston-02.html>.
[15] API. *Basic Petroleum Data Handbook*. Volume XXIV, Number 1. February, 2004.

$$\frac{44.7\,Bcf}{60\% \times 12{,}971\,wells} \times \frac{10^6\,Mcf}{Bcf} \approx 6{,}000\,Mcf\ /\ completion$$

The same Natural Gas STAR presentation[14] provides a Partner experience which shares its recovered volume of methane per well. This analysis assumes that the Partner recovers 90% of the flowback. Again, because of the high variability and uncertainty associated with different completion flowbacks in the gas industry, this was estimated only to the nearest thousand Mcf – 10,000 Mcf/completion.

A vendor/service provider of "reduced emission completions" shared its experience later in that same presentation[14] for the total recovered volume of gas for 3 completions. Assuming that 90% of the gas was recovered, the total otherwise-emitted gas was back-calculated. Again, because of the high variability and uncertainty associated with different completion flowbacks in the gas industry, this was rounded to the nearest hundred Mcf – 700 Mcf/completion.

The final Natural Gas STAR presentation[16] with adequate data to determine an average emission rate also presented the total flowback and total completions and re-completions. Because of the high variability and uncertainty associated with different completion flowbacks in the gas industry, this was rounded to the nearest 10,000 Mcf – 20,000 Mcf/completion.

This analysis takes the simple average of these completion flowbacks for the unconventional well completion emission factor: **9,175 Mcf/completion**.

►*Estimate the Emission Factor for Unconventional Well Workovers ("re-completions")*
The emission factor for unconventional well workovers involving hydraulic re-fracture ("re-completions") was assumed to be the same as unconventional well completions; calculated in the previous section.

►*Estimate the Total National Emissions (disregarding reductions)*
The estimated activity factors were multiplied by the associated emission factors to estimate the total emissions from well completions and workovers in the U.S. for 2007. This does not reflect reductions due to control technologies such as flares or bringing portable treatment units onsite to perform a practice called "reduced emission completions." The results are displayed in Exhibit B-5 below.

Exhibit B-5. Summary of Flowback: U.S. Completion and Workover Venting 2007

Activity	Activity Factor	Emission Factor	Total U.S. Emissions
Conventional Gas Well Completions	19,819 completions	36.65 Mcf/completion	~0.7 Bcf
Conventional Gas Well Workovers	14,569 workovers	2.454 Mcf/workover	<< 1 Bcf

[16] EPA. *Reducing Methane Emissions During Completion Operations*. Natural Gas STAR Producer's Technology Transfer Workshop. September 11, 2007. Available online at: <http://epa.gov/gasstar/documents/workshops/glenwood-2007/04_recs.pdf>.

Unconventional Gas Well Completions	9,224 completions	9,175 Mcf/completion	~85 Bcf
Unconventional Gas Well Workovers	4,179 workovers	9,175 Mcf/workover	~38. Bcf
Note: The emission factors and calculated emissions as presented in this table were rounded independently.		**TOTAL:**	**~120 Bcf**

►*Estimate the Volume of Emissions That Are Not Flared*
Some states regulate that completion and re-completion (workover) flowbacks must be flared or recovered. Industry representatives have shared with EPA that flaring of completions and workovers is required in Wyoming; however, it is not required in Texas, New Mexico, and Oklahoma. EPA assumed that no completions were flared in the Texas, New Mexico, and Oklahoma, then took the ratio of unconventional wells in Wyoming to the unconventional wells in all four sample states to estimate the percentage of well completions and workovers that are flared. EPA assumed that this sample was indicative of the rest of the U.S. This ratio was estimated to be approximately 51%.

The portion of flared natural gas was deducted from the results of Exhibit B-5 so that only the vented portion of natural gas from well completions and workovers was estimated. It then converted these natural gas emissions to methane emissions using an average methane content in produced natural gas of 78.8% by volume. The results are in Exhibit B-6, below.

Exhibit B-6. Summary of Methane Emissions: U.S. Completion and Workover Venting 2007

Activity	Unmitigated Flowback	Natural Gas Vented	Methane Vented
Conventional Gas Well Completions	~0.7 Bcf	~0.37 Bcf	~0.29 Bcf
Conventional Gas Well Workovers	<< 1 Bcf	<< 1 Bcf	<< 1 Bcf
Unconventional Gas Well Completions	~85 Bcf	~43 Bcf	~34 Bcf
Unconventional Gas Well Workovers	~38. Bcf	~19 Bcf	~14 Bcf
Note: The emission factors and calculated emissions as presented in this table were rounded independently.		**TOTAL:**	**~48 Bcf**

The final resulting methane emissions from well completions and workovers is **48 Bcf**. This estimate does not include hydraulic fracturing due to completions and workovers of gas wells in tight sands formations. Tight sands wells are not tracked by the U.S. Inventory and may substantially increase this estimate of unconventional well completions and workovers. A 2008 INGAA study[17] estimated that, in fact, approximately twice as many unconventional wells were completed than this analysis and approximately twice as many unconventional wells exist, 10% of which may require workover. This increase in activity is due to the inclusion of tight sands formations. If this analysis were to account for that activity level, not only would the number of hydraulic fractures increase substantially, but also the distribution of wells that are required to flare by law would be shifted such that only 15% of hydraulic

[17] INGAA Foundation Inc.. Availability, *Economics, And Production Potential of North American Unconventional Natural Gas Supplies*. November 2008.

fracture flowbacks would be estimated to be flared. Using INGAA's estimates of activity, emissions would increase to 141 Bcf.

Well Blowdown Venting for Liquid Unloading

This discussion describes the methods used to estimate total U.S. methane emissions from low-pressure well blowdowns for liquid unloading.

►*Estimate the Fraction of Conventional Wells that Require Liquid Unloading*

This analysis assumed that the survey of 25 well sites conducted by GRI (1996) for the base year 1992 provides representative data for the fraction of conventional wells requiring unloading. That is, 41.3% of conventional wells required liquid unloading.

►*Calculate Emissions per Blowdown*

This analysis used a fluid equilibrium calculation to determine the volume of gas necessary to blow out a column of liquid for a given well pressure, depth, and casing diameter. The equation for this calculation is available in an EPA, Natural Gas STAR technical study[18]. The equation is displayed in Exhibit B-7.

Exhibit B-7. Well Blowdown Emissions for Liquid Unloading

$$V_v = \left(0.37 \times 10^{-6}\right) \times D^2 \times h \times P$$

where,

V_v	=	Vent volume (Mcf/blowdown)
D	=	casing diameter (inches)
h	=	well depth (feet)
P	=	shut-in pressure (psig)

A combination of GASIS[19] and LASSER[20] databases provided well depth and shut-in pressures for a sample of 35 natural gas basins. The analysis assumed an average casing diameter of 10-inches for all wells in all basins.

►*Estimate the Annual Number of Blowdowns per Well that Require Unloading*

For wells that require liquid unloading, multiple blowdowns per year are typically necessary. A calibration using the equation in the previous section was performed using public data for the shared experiences of two Natural Gas STAR Partners.

One Partner reported that it recovered 4 Bcf of emissions using plunger lifts with "smart" automation (to optimize plunger cycles) on 2,200 wells in the San Juan basin[21]. Using the

[18] EPA. *Installing Plunger Lift Systems in Gas Wells: Lessons Learned from Natural Gas STAR Partners*. October, 2003. Available online at: <http://epa.gov/gasstar/documents/ll_plungerlift.pdf>.
[19] DOE. *GASIS, Gas Information System*. Release 2 – June 1999.
[20] LASSER™ database.
[21] EPA. *Natural Gas STAR Partner Update: Spring 2004*. Available online at: <http://epa.gov/gasstar/documents/partner-updates/spring2004.pdf>.

data for San Juan basin in the equation in Exhibit B-6 required approximately 51 blowdowns per well to match the 4 Bcf of emissions.

Another Partner reported that it recovered 12 MMcf of emissions using plunger lifts on 19 wells in Big Piney[18]. Using information for the nearest basin in the equation in Exhibit B-6 required approximately 11 blowdowns per well to match the 12 MMcf of emission.

The simple average of 31 blowdowns per well requiring liquid unloading was used in the analysis to determine the number of well blowdowns per year by basin.

►*Estimate the Percentage of Wells in Each Basin that are Conventional*
GASIS and LASSER provided approximate well counts for each basin and GRI provided the percentage of conventional wells requiring liquid unloading for 35 sample basins. However, many of those basins contain unconventional wells which will not require liquid unloading. EIA posts maps that display the concentration of conventional gas wells in each basin[22], the concentration of gas wells in tight formations by basin[23], and the concentration of coal bed methane gas wells by basin[24]. These maps were used to estimate the approximate percentage of wells that are conventional in each basin. These percentages ranged from 50% to 100%.

►*Estimate Emissions from 35 Sample Basins*
The total well counts for each basin were multiplied by the percentage of wells estimated to be conventional for that basin to estimate the approximate number of conventional wells in each of the basins. The resulting conventional well counts were multiplied by the percentage of wells requiring liquid unloading, as estimated by the GRI survey (41.3%). The number of wells in each basin that require liquid unloading were multiplied by an average of 31 blowdowns/well to determine the number of well blowdowns for each basin. The emissions per blowdown, as calculated using the equation in Exhibit B-6, were then multiplied by the number of blowdowns for each basin to estimate the total well venting emissions from each of the 35 sample basins due to liquid unloading. Using the GRI estimate that the average methane content of production segment gas is 78.8% methane by volume, the total methane emissions from the sample of 35 basins were calculated to be 149 Bcf.

►*Extrapolate Sample Data to Entire U.S.*
The sample of 35 gas well basins represented only 260,694 conventional gas wells. EPA's national inventory[25] estimated that there were 389,245 conventional gas wells in 2007. The emission estimates were extrapolated to the entire nation by the ratio of the conventional gas wells. The final resulting emissions from gas well venting due to liquid unloading were estimated to be **223 Bcf**.

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[22] EIA. *Gas Production in Conventional Fields, Lower 48 States*. Available online at: <http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm>.
[23] EIA. *Major Tight Gas Plays, Lower 48 States*. Available online at: <http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm>.
[24] EIA. *Coal Bed Methane Fields, Lower 48 States*. Available online at: <http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm>.
[25] EPA. *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2006*. 2007. Available online at http://www.epa.gov/climatechange/emissions/usinventoryreport.html.

This estimate does not include emission reductions from control methods such as plunger lifts, plunger lifts with “smart” automation, or other artificial lift techniques.

Appendix C: Development of threshold analysis

As the main text has pointed out the petroleum and natural gas sector includes hundreds, and in some cases thousands, of operators, many of them with few emission sources as well as ones with over 100 emission sources. Requiring all operators to report would impose a large burden on the industry and also on EPA. A rule-of-thumb, substantiated by survey work, is that 80 percent of the emissions come from 10 percent of the analysis. Therefore, a threshold analysis was performed so that the large emitters would be identified and small insignificant emitters could be excluded from the reporting requirement.

Threshold Analysis for Onshore Production

The following points lay out the methodology for the threshold analysis for the onshore petroleum and natural gas production segment

- The threshold analysis for onshore (including EOR) production sector estimated the equipment leaks, vented emissions, and combustion emissions per unique operator per basin.
- The oil and gas production volumes per operator per basin were obtained from the HPDI™ database 2006. The total onshore oil and gas production process and combustion (CH_4 and CO_2) emissions estimated in the U.S. GHG Inventory 2006 were apportioned to each operator based on the oil or gas production volumes.
- The U.S. GHG Inventory emissions estimates for the following sources were revised: gas well hydraulic fracture completion venting, gas well liquids unloading venting, and gas well workover venting following hydraulic fracture. Natural Gas STAR emission reductions reported by partners from these sources are higher than the current inventory emission estimates. As a result emissions from these sources are currently under-estimated in the inventory. The methodology used to revise these emissions estimates can be found in Appendix B. In addition, emissions from storage tanks vented and flared emissions are believed to be under estimated in the U.S. GHG Inventory. EPA independently estimated the storage tank emissions using publicly available data described in docket memo “Analysis of Tank Emissions” (EPA-HQ-OAR-2009-0923-0002). EPA’s estimated emissions from onshore production storage tanks may be as high as 75 billion cubic feet (Bcf) as compared with the 12 Bcf estimate provided in the 2006 inventory. In addition, the threshold analysis does not account for several sources that are not represented in the U.S. GHG Inventory such as associated gas venting and flaring, well testing venting and flaring and gas well hydraulic fracture completion venting in tight sands, the latter because these wells are not included in state data (See Appendix B). For all of these sources which are believed to be under estimated in the U.S. GHG Inventory, there are Natural Gas STAR reductions reported by production partners for year 2006 of 67 Bcf. However, Natural Gas STAR reports generally do not state exactly where the reported reductions were made, and in the case of production, whether they were onshore or offshore or included oil and gas gathering equipment. Therefore, EPA has concluded that the increase in emissions not accounted for in the U.S. GHG Inventory approximately offset the reductions reported by Natural Gas STAR production

partners. Because it is not feasible to map the emissions reductions reported by Natural Gas STAR Partners to their respective facilities, apportioning reductions equally would distort the threshold analysis. Hence, the threshold analysis does not include both the revised estimates from storage tanks (and other missing sources) and reductions from Natural Gas STAR because they cancel out.[26]

- The combustion emissions from the following sources were estimated separately as they are not included in the U.S GHG Inventory: heater-treater, well drilling (oil and gas), dehydrator reboiler, and acid gas removal (AGR) units.
    - **Heater-Treaters Combustion:** The total national combustion emissions from heater-treaters were calculated by estimating the total fuel required to increase the temperature by 10^{o}C of total oil produced in 2006. CO_2 and N_2O combustion emission factor for natural gas from the API compendium 2004 was used to estimate the total national CO_2 and N_2O emissions. The total emissions were apportioned to the operators based on their oil production volumes.
    - **Dehydrator and AGR Combustion:** The total national combustion emissions from dehydrators and AGR units were estimated by applying the fuel consumption factor of 17 Mcf of natural gas/ MMcf of gas throughput, obtained from the EPA's Lesson Learned 2006, *Replacing Glycol Dehydrators with Desiccant Dehydrator*. The total national throughput was assumed to be equal to the total national gas produced obtained from the EIA. CO_2 and N_2O combustion emission factor for natural gas from the API compendium 2004 was used to estimate the total national CO_2 and N_2O emissions. The total emissions were apportioned to the operators based on their gas production volumes.
    - **Well Drilling Combustion:** The total national combustion emissions from well drilling was estimated by multiplying the emissions per well drilled with the national number of oil and gas wells drilled in the year 2006. The emissions per well was estimated by assuming the use of two 1500 hp diesel engines over a period of 90 days to drill each well. CO_2 and N_2O combustion emission factor for diesel from the API compendium 2004 was used to estimate the total national CO_2 and N_2O emissions. The total emissions were apportioned to different states based on the percentage of rigs present in the state. The number of rigs per state was obtained from Baker Hughes. The total oil and gas well drilling combustion emissions per state was apportioned to each operator in the state based on their oil and gas volumes respectively.
- The total barrels of oil produced per field and operator using EOR operations was obtained from the OGJ (2006) *EOR/Heavy Oil Survey*.

[26] A similar issue occurs with the other segments of the industry. For processing facilities, emissions from flares are not included in the threshold analysis. For transmission segment, emissions from scrubber dump valves and compressor unit isolation valves are not included in the threshold analysis. For the distribution segment, the emission from combustion sources are not included in the threshold analysis. The missing and under accounted emissions estimates roughly offset the Natural Gas STAR reductions reported. Hence, EPA has assumed that the missing and under-accounted cancel out the Natural Gas STAR Reductions and therefore did not include them in the threshold analyses.

- The total make-up CO_2 volume required for EOR operations was estimated using 0.29 metric tons CO_2/ bbl oil produced from EOR operations obtained from DOE, *Storing CO_2 with Enhanced Oil Recovery*. The total recycled CO_2 volumes per operator was estimated using a factor of 0.39 metric tons CO_2/bbl estimated from DOE, *Storing CO_2 with Enhanced Oil Recovery*.
- The equipment count for EOR operations was estimated by apportioning the U.S. GHG Inventory activity factors for onshore petroleum production to each field using the producing well count or throughput (bbl) based on judgment. E.g. the total number of compressors in the US used in EOR onshore production operations per field was estimated by using the ratio of the throughput per field to the national throughput and multiplying it by the total number of national compressors in onshore operations.
- The emission factors in the U.S. GHG Inventory and the re-estimated activity factors for EOR operations were used to estimate total methane emissions by volume for EOR operations. This volume was adjusted for methane composition (assumed to be 78.8% from GRI) to estimate the natural gas emissions from EOR operations. The composition of 97% CO_2 and 1.7% CH_4 was applied to the total natural gas emissions to estimate CO_2 and CH_4 emissions from leaking, vented, and combustion sources covered in the U.S. GHG Inventory 97% CO_2 and 1.7% CH_4 composition was obtained from *Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2 EOR) Injection Well Technology*.
- The following EOR emissions sources are not covered in the U.S. GHG Inventory and therefore were estimated separately:
    - Recycled injection CO_2 dehydrator vented emissions
    - Recycled injection CO_2 compressor - vented and combustion emissions
    - CO_2 injection pumps - combustion and vented emissions
    - Water injection pumps – combustion emissions
    - Orifice meter - vented emissions from calibration

Emissions from the above mentioned sources were calculated in the following manner:

- **Recycled CO_2 Dehydrator**: The number of dehydrators per EOR field was estimated by using the ratio of gas throughput to the number of dehydrators indicated in the GRI report and multiplying it by the recycled CO_2 volumes. The recycled dehydrator vented emissions were estimated using readjusted U.S. GHG Inventory emission factor. The GRI methane emission factor was divided by 78.8% methane composition to calculate the natural gas emission factor. The natural gas emission factor was adjusted to EOR operation using the critical density of CO2. 97% CO_2 and 1.7% CH_4 composition obtained from *Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2EOR) Injection Well Technology* was used to estimate emissions.
- **Recycled CO_2 Injection compressor**: The recycled CO_2 injection compressor fuel gas requirement was estimated using an assumed value of 65 kWhr/metric ton CO2 injected. The assumption was based on the DOE study, *Electricity use of EOR with Carbon dioxide*. It is assumed that only 50% of the injected CO2 requires natural gas powered compressors. CH_4 and CO_2 combustion emissions were estimated by applying API compendium relevant combustion emission factors to the fuel gas used by each operator. The fuel gas consumption was estimated using the horsepower

requirements of engines per operator. N_2O (CO_2e) combustion emissions were estimated by applying API compendium N_2O combustion emission factors to the fuel gas used by each plant. The number of compressor per field was estimated using an assumed number of 12 hp/ bbl of EOR produced oil. This number was obtained from *Enhanced Recovery Scoping Study* conducted by the state of California. It is assumed that a typical compressor used in EOR operations is 3000 hp. This number is obtained from DOE study, *Electricity use of EOR with Carbon dioxide*. The compressor blowdown emissions was estimated assuming one blowdown event per year, the estimated number of compressors per field, and compressor blowdown emission factor obtained from the U.S GHG inventory. The compressor blowdown emission factor was adjusted for critical CO_2 density, CO_2 and CH_4 gas composition. 97% CO_2 and 1.7% CH_4 composition obtained from *Summary of Carbon Dioxide Enhanced Oil Recovery (CO2EOR) Injection Well Technology* was used to estimate emissions. .

- **CO2 Injection pumps**: The supercritical CO_2 injection pumps are assumed to be electrically driven and therefore have no combustion emissions. 97% CO_2 and 1.7% CH_4 composition obtained from *Summary of Carbon Dioxide Enhanced Oil Recovery (*CO_2*EOR) Injection Well Technology* was used to estimate emissions. The pump blowdown emissions were estimated assuming an internal diameter of 12 inches and length of 30 feet with a 50% void volume. The pipe length between the blowdown valve and unit valve was assumed to be 10 feet with a diameter of 5.38 inches. It is assumed that the pump and pipeline vent gas equivalent to their volume once a year during blowdown operations. The number of supercritical pumps required per field was estimated by assuming that the EOR operations use pumps with 600 hp with a throughput of 40 Mcf/day. These pump specifications were obtained from an unnamed Natural Gas STAR Partner.
- **Water injection pumps**: The injection pump fuel gas requirement was estimated using an assumed value of 6 kWhr/bbl of oil produced. The assumption was based on the DOE study, *Electricity use of EOR with Carbon dioxide*. It is assumed that only 50% of the injection pumps are natural gas powered. CH_4 and CO_2 combustion emissions were estimated by applying API compendium (2004) relevant combustion emission factors to the fuel gas used by each operator. The fuel gas consumption was estimated using the horsepower requirements of engines per operator. N_2O (CO_2e) combustion emissions were estimated by applying API compendium N_2O combustion emission factors to the fuel gas used by each plant.
- **Orifice Meter Vented Emissions**: It is assumed that there are 5 orifice meters for each field based on data provided by an unnamed Natural Gas STAR Partner. The orifice meters are assumed to be calibrated once per year during which the volume of meter is vented to the atmosphere. The orifice meters are assumed to be 8 inches in diameter and 12 feet in length. 97% CO_2 and 1.7% CH_4 composition obtained from *Summary of Carbon Dioxide Enhanced Oil Recovery (CO2EOR) Injection Well Technology* was used to estimate emissions.
- The total emissions per operator were calculated by summing up all the process and combustion emissions for EOR operations and onshore production.
- Each operator was assigned a “1” if it crossed a threshold and a “0” otherwise, by running the following logic checks:
    - IF(operator total emissions > 1000) then reporting

- IF(operator total emissions > 10000) then reporting
- IF(operator total emissions > 25000) then reporting
- IF(operator total emissions >100000) then reporting

Threshold Analysis for Offshore Production

- Federal GOM offshore platforms, by their complex ID, and their corresponding CO_2 combustion and equipment leak emissions (CO_2e), CH_4 equipment leaks (CO_2e), CH_4 vented emissions (CO_2e), and N_2O combusted emissions (CO_2e) for the year 2000 was obtained from the BOEMRE Goads Summary Access File "Final GOADS Emissions Summaries"
- The ratio of 2006 to 2000 Gulf of Mexico offshore productions was calculated and applied to the emissions from each platform to estimate emissions for the year 2006.
- The total number of GOM offshore production platforms was obtained from the BOEMRE website.
- Each platform was assigned a "1" or "0" based on if it crossed an emissions threshold by running the following logic checks:
  - IF(operator total emissions > 1000) then reporting
  - IF(operator total emissions > 10000) then reporting
  - IF(operator total emissions > 25000) then reporting
  - IF(operator total emissions >100000) then reporting
- The total number of state platforms (Alaska and Pacific) was obtained from the Alaska Division of Oil and Gas and *Emery et al*[27] respectively. The number of state and federal offshore oil and gas wells for GOM, Pacific, and Alaska was obtained from the LASSER™ database. The ratio of federal GOM oil and gas wells to federal platforms and the number of state offshore oil and gas wells were used to estimate the state GOM platform count.
- The ratio of gas to oil platforms was obtained from the U.S GHG Inventory 2006. All the state offshore platforms were assumed to be shallow water platforms.
- The state offshore equipment leak, vented, and combustion emissions were estimated by applying the ratio of state to federal platforms and multiplying it by the federal offshore equipment leak, vented, and combustion emissions.
- The percentage of platforms that fall within each emissions threshold (1000, 10,000, 25,000 and 100,000 metric tons CO_2e) for the federal GOM offshore was calculated and applied to the estimated state equipment leak, vented, and combustion emissions to calculate the volume of state offshore emissions that fall within each threshold.
- The number of state platforms that fall within each category was estimated by taking the ratio of federal emissions to platform count within each threshold and multiplying it by the state emissions covered by each threshold.
- The emissions from state and federal offshore platforms were summed up to estimate the total emissions from offshore operations

[27] Emery, Brian M. et al. *Do oil and gas platforms off California reduce recruitment of bocaccio (Sebastes paucispinis) to natural habitat? An analysis based on trajectories derived from high frequency radar*. http://www.icess.ucsb.edu/iog/pubs/DrifterSimulationsFinal_v5.pdf

Threshold Analysis for Processing

- US gas processing plants, plant throughputs, and equipment count per plant were obtained from the OGJ (2006). 2005 and 2006 emissions are assumed to be the same on a plant basis as the total national throughput from 2005 to 2006 did not change significantly and were 45,685 MMcf/d and 45,537.4 MMcf/d respectively as indicated by the U.S. GHG Inventory
- CH_4 and CO_2 process emissions (CO_2e) per facility were estimated by multiplying the equipment count per plant (activity factor) obtained from the Gas Processing Survey with their corresponding emission factors obtained from GRI/ EPA 1996 reports. The national processing sector average composition (CH_4 and CO_2 content) of natural gas was obtained from GTI and applied to the GRI emission factors. Emission factor for centrifugal compressor wet seals was obtained from Bylin et al[5]. Due to the uncertainty in centrifugal compressor wet seal emissions, the point that it is not possible to ascribe Natural Gas STAR processing partner emission reductions to a particular processing plant or even to processing plants in general as opposed to gas gathering equipment, the Natural Gas STAR reported processing reductions of 6 Bcf/year were not incorporated into this analysis[26].
- CH_4, CO_2 and N_2O combustion emissions (CO_2e) were estimated by applying CH_4, CO_2 and N_2O API compendium relevant combustion emission factors to the fuel gas used by each plant. The fuel gas consumption was estimated using the horsepower requirements of engines and turbines per plant.
- N_2O combustion emissions (CO_2e) were estimated by applying API compendium N_2O combustion emission factors to the fuel gas used by each plant.
- The different emissions per plant was summed up to provide total emissions (CO_2e)
- Each facility was assigned a “1” or “0” based on if it crossed a threshold by running the following logic checks:
    - IF(operator total emissions > 1000) then reporting
    - IF(operator total emissions > 10000) then reporting
    - IF(operator total emissions > 25000) then reporting
    - IF(operator total emissions >100000) then reporting
- Summing the results of the above logic checks for each threshold provided the number of facilities exceeding that threshold.
- Multiplying the logic checks above by the total emissions for each facility, then summing the results yielded the total emissions covered at each threshold.
- The resulting O&M and capital costs from the cost burden analyses were entered for each facility in the spreadsheet. The sum of the product of O&M or capital costs and the logic checks described above provides the total cost burdens for each reporting threshold. Dividing the total cost burdens by the number of reporting facilities (calculated above) provides the average facility cost burdens at each reporting threshold.

Threshold Analysis for Transmission

- “Facility” in the natural gas transmission segment is defined as a compressor station. Data for individual compressor stations on interstate transmission pipelines are reported to FERC Form 2[28], and data for compressor stations on intrastate pipelines were obtained from EIA through personal contact. However, the data collected for intrastate pipelines were incomplete.

- For intrastate pipeline facilities that did not have the number of compressor stations listed, it was assumed that each facility has one compressor. The compressor horsepower per intrastate pipeline was estimated by multiplying design throughput per intrastate pipeline with the ratio of total interstate pipeline compressor horsepower (engine and turbine) to the total interstate design throughput.
- The FERC data, supplemented with intrastate data and assumptions, list pipeline states, names, designed throughput capacity, and in some cases the type of compressor (centrifugal, reciprocating, and/or electric), and the installed horsepower for each station.
- In cases where the installed reciprocating horsepower is provided, it was used for installed engine capacity (Hp). In cases where the installed capacity was provided, but the type of compressor was not specified, the analysis assumes that 81% of the installed capacity is reciprocating. In cases where the provided installed capacity is both centrifugal and reciprocating, it is assumed that 81% is for engines. The 81% assumption is the ratio of reciprocating compressor engine capacity in the transmission sector to centrifugal turbine drivers for 2006 taken from the U.S. GHG Inventory
- The ratio of reciprocating compressor engine driver energy use (MMHphr, EPA[1]) to interstate station design throughput capacity (MMcfd, FERC[28]) was calculated. Then, the reciprocating compressor energy use for each station was assigned by multiplying the installed station throughput capacity by the ratio calculated previously in this bullet.
- In cases where the installed centrifugal horsepower is provided, it was used directly for installed turbine capacity (Hp). In cases where the installed capacity was provided, but the type of compressor was not specified, the analysis assumes that 19% of the installed capacity is centrifugal. In cases where the provided installed capacity is both centrifugal and reciprocating, it is assumed that 19% is for turbines. The 19% assumption is the ratio of centrifugal compressor turbine capacity in the transmission sector to reciprocating engine drivers taken from the U.S. GHG Inventory.
- The ratio of centrifugal compressor engine driver energy use (MMHphr, EPA[1]) to interstate station design throughput capacity (MMcfd, FERC[28]) was calculated. Then, the reciprocating compressor energy use for each station was assigned by multiplying the installed station throughput capacity by the ratio calculated previously in this bullet.
- The total emissions for 2006, both vented and equipment leak methane and non-energy CO_2, were estimated in the U.S. GHG Inventory. Emission factor for centrifugal compressor wet seals was obtained from Bylin et al[5]. Due to the uncertainty in centrifugal compressor wet seal emissions, the point that it is not possible to ascribe Natural Gas STAR transmission partner emission reductions to a

[28] FERC. *Form 2 Major and Non-major Natural Gas Pipeline Annual Report.* Available online at: <http://www.ferc.gov/docs-filing/eforms/form-2/data.asp#skipnavsub>.

particular compressor station or even to transmission in general as opposed to gas storage equipment, the Natural Gas STAR reported transmission reductions of 25 Bcf/year were not incorporated into this analysis[26]. The total emissions were allocated to each facility based on its portion of the segment's total station throughput capacity, as shown in the following equation:

$$\text{Station "}i\text{" process emissions} = \frac{StationCapacity_i}{\sum_i StationCapacity} \times TotalInventoryEmissions$$

- Combustion CO_2 and N_2O emissions were estimated for each facility by applying the following emission factors:
  - EF_{CO2} = 719 metric tons CO_2e/MMHphr
  - EF_{N20} = 5.81 metric tons CO_2e/MMHphr
  - $Emissions_{CO2\ or\ N20} = EF_{CO2\ or\ N20} \times$ Compressor $energy_i$ (MMHphr)
- The total emissions for each facility were calculated by summing the calculated process and the combustion emissions.
- Each facility was assigned a "1" or "0" based on if it crossed a threshold by running the following logic checks:
  - IF(operator total emissions > 1000) then reporting
  - IF(operator total emissions > 10000) then reporting
  - IF(operator total emissions > 25000) then reporting
  - IF(operator total emissions >100000) then reporting
- Summing the results of the above logic checks for each threshold provided the number of facilities exceeding that threshold.
- Multiplying the logic checks above by the total emissions for each facility, then summing the results yielded the total emissions covered at each threshold.

Threshold Analysis for Underground Storage

- "Facility" in the underground natural gas storage segment is defined as storage stations and the connected storage wellheads. Underground storage data by operator are collected in form EIA-176[29].
- The data collected in EIA-176 contained each underground storage operator, field, and location as well as the storage capacity and maximum daily delivery.
- The total compressor energy use in 2006 for the underground storage segment was estimated in the U.S. GHG Inventory. This total energy use, in millions of horsepower hours (MMHphr), is allocated to each facility based on its portion of the segment's total maximum daily delivery capacity; as described in the following equation:

[29] EIA. *EIA-176 Query System.* Available online at: <http://www.eia.doe.gov/oil_gas/natural_gas/applications/eia176query_historical.html>.

$$\text{Compressor energy}_i \text{ (MMHphr)} = \frac{MaximumDailyDelivery_i}{\sum_i MaximumDailyDelivery} \times TotalSegmentMMHphr$$

Where, index "*i*" denotes an individual facility

- The total process emissions for 2006, both vented and equipment leak methane and non-energy CO_2, were estimated in the U.S. GHG Inventory. These total process emissions were allocated to each facility based on its portion of the segment's total maximum daily delivery capacity, using the same methods as compressor energy use.
- Combustion CO_2 and N_2O emissions were estimated for each facility by applying the following emission factors:

  EF_{CO2} = 719 metric tons CO_2e/MMHphr

  EF_{N20} = 5.81 metric tons CO_2e/MMHphr

  $Emissions_{CO2\text{ or }N20} = EF_{CO2\text{ or }N20} \times \text{Compressor energy}_i$ (MMHphr)
- The total emissions for each facility were calculated by summing the calculated process and the combustion emissions.
- Each facility was assigned a "1" or "0" based on if it crossed a threshold by running the following logic checks:
  - IF(operator total emissions > 1000) then reporting
  - IF(operator total emissions > 10000) then reporting
  - IF(operator total emissions > 25000) then reporting
  - IF(operator total emissions >100000) then reporting
- Summing the results of the above logic checks for each threshold provided the number of facilities exceeding that threshold.
- Multiplying the logic checks above by the total emissions for each facility, then summing the results yielded the total emissions covered at each threshold.

Threshold Analysis for LNG Storage

- "Facility" in LNG storage segment is defined as LNG storage plants (peak shaving or satellite). Data for each peak shaving facility is provided in *The World LNG Source Book – An Encyclopedia of the World LNG Industry*. Summary data for all satellite facilities is estimated in the *Additional Changes to Activity Factors for Portions of the Gas Industry* background memo for EPA's U.S. GHG Inventory.
- The data reported in *The World LNG Source Book – An Encyclopedia of the World LNG Industry* includes the operator, liquefaction capacity, storage capacity, vaporization design capacity for each individual peak shaving plant.
- U.S GHG Inventory reports that in addition to peak shaving plants there are approximately 100 satellite facilities with a total storage capacity of 8.7 Bcf. The ICF memo also provides several key assumptions that will be discussed at the appropriate locations below.
- The total liquefaction compressor energy use for the segment was estimated using the methods and assumptions detailed in the background memo for EPA's U.S. GHG Inventory. LNG company contacts provided the memo's assumption that 750 MMHphr are required for liquefaction for each million cubic feet per day of liquefaction capacity. It assumes the liquefaction takes place over a 200-day "fill"

season. It assumes that approximately 50% of compressors are driven by gas-fired engines or turbines. EIA provides the LNG storage additions for 2006 on its website, totaling 38,706 MMcf. Thus, the total liquefaction energy use for the segment was calculated using the following formula:

$$\text{LEU} = \frac{38{,}706 MMcf}{200 days} \times \frac{750 Hp}{1 MMcfd} \times \frac{24 hours}{day} \times 200 days \times 50\% \times \frac{1 MMHphr}{1{,}000{,}000 Hphr}$$

where,

LEU = total liquefaction energy use for the segment, gas fired (MMHphr)

- The total calculated liquefaction compressor energy use was apportioned to individual facilities based on their share of the total liquefaction capacity for the segment, as shown in the following equation:

$$\text{Facility "i" liquefaction MMHphr} = \frac{LC_i}{\sum_i LC} \times TotalSegmentMMHphr$$

Where "i" indexes facilities and LC = liquefaction capacity.

- Storage capacity, provided in gallons by *The World LNG Source Book – An Encyclopedia of the World LNG Industry*, was converted to million cubic feet with a conversion factor of 1 gallon of LNG = 81.5 standard cubic feet of natural gas.
- Boil-off liquefaction compressor energy use was calculated using assumptions outlined in the U.S GHG Inventory. The memo assumes that 0.05% of storage capacity boils off and is recovered by vapor recovery compressors and liquefied. These compressors must operate all year and require the same 750 Hp per 1 MMcfd liquefied. The boil-off liquefaction compressor energy use was thus estimated for each facility using the following equation:

$$\text{FBEU}_i = \frac{SC_i \times 0.05\%}{365 days} \times \frac{750 Hp}{MMcfd} \times \left(365 days \times \frac{24 hours}{day}\right) \times \frac{MMHphr}{1{,}000{,}000 Hphr}$$

where,

FBEU_i = Facility "i" boil-off liquefaction compressor energy use (MMHphr)

SC = Facility "i" storage capacity (MMcf)

- Vaporization and send-out compressor energy use was also calculated based on assumptions from the U.S GHG Inventory. It estimates that with an average send-out pressure of 300 psia and inlet pressure of 15 psia, using 2-stage compression, a satellite facility requires 1.86 MMHphr for each MMcfd of send-out. The send-out period lasts all year, unlike the "fill" season. The memo also estimates that 75 Bcf of gas were sent out from peak shaving facilities compared to 8.7 Bcf from satellite facilities in 2003. This equates to 89.6% of send-out coming from peak shaving plants in 2003; the analysis assumes the same is true for 2006. EIA[30] provides that in 2006, total LNG withdrawals were 33,743 MMcf. The send-out compressor energy

[30] EIA. *Liquefied Natural Gas Additions to and Withdrawals from Storage*. Available online at: <http://tonto.eia.doe.gov/dnav/ng/ng_stor_lng_dcu_nus_a.htm>.

use by all peak shaving plants in the segment was calculated using the following equation:

$$\text{Total send-out energy use} = \frac{33{,}743 MMcf}{365 days} \times \frac{1.86 MMHphr}{MMcfd} \times 89.6\%$$

- Send-out compressor energy use was apportioned to each peak shaving facility by its share of the total peak shaving segment's send-out capacity; using the same method as apportioning liquefaction energy use. (See liquefaction bullet).
- The 100 satellite facilities were assumed to be equal size and capacity. That is, 8.7 Bcf storage capacity, all of which is sent out each year. It was assumed that satellite facilities have no liquefaction, except for that which is necessary for boil-off. We performed the above analysis on the "average" satellite facility to estimate its energy use and emissions. The only difference was that 10.4% of EIA reported LNG withdrawals was attributed to the satellite facilities.
- The total process emissions for 2006, both vented and equipment leak methane and non-energy CO_2, were estimated in the U.S. GHG Inventory. These total emissions were allocated to each facility based on its portion of the segment's total storage capacity, using the same methods as apportioning liquefaction and send-out compressor energy use.
- Combustion CO_2 and N_2O emissions were estimated for each facility by applying the following emission factors:

  EF_{CO2} = 719 metric tons CO_2e/MMHphr
  EF_{N20} = 5.81 metric tons CO_2e/MMHphr
  $Emissions_{CO2\ or\ N20} = EF_{CO2\ or\ N20} \times$ Compressor $energy_i$ (MMHphr)
- The total emissions for each facility were calculated by summing the calculated equipment leak, vented, and combustion emissions.
- Each facility was assigned a "1" or "0" based on if it crossed a threshold by running the following logic checks:
  - IF(operator total emissions > 1000) then reporting
  - IF(operator total emissions > 10000) then reporting
  - IF(operator total emissions > 25000) then reporting
  - IF(operator total emissions >100000) then reporting
- Summing the results of the above logic checks for each threshold provided the number of facilities exceeding that threshold.
- Multiplying the logic checks above by the total emissions for each facility, then summing the results yielded the total emissions covered by each threshold.
- Satellite facilities crossed the 1,000 and 10,000-metric ton reporting threshold, but fell well short of the 25,000-metric ton threshold.

Threshold Analysis for LNG Import Terminals

- "Facility" in the LNG import segment is defined as the import terminals. Data is available for this on the FERC website[31]. It provides the owner, location, capacity, and 2006 import volumes for each LNG terminal.
- ICF *Additional Changes to Activity Factors for Portions of the Gas Industry* background memo for EPA's U.S. Inventory assumptions were used to estimate liquefaction, boil-off liquefaction, and send-out compressor energy use for each of the LNG import terminals.
- It was assumed that import terminals do not have liquefaction capacity.
- Boil-off liquefaction compressor energy use was calculated using assumptions outlined in ICF *Additional Changes to Activity Factors for Portions of the Gas Industry* background memo for EPA's U.S. Inventory. The memo assumes that 0.05% of capacity boils off and is recovered by vapor recovery compressors and liquefied. These compressors must operate all year and require the same 750 Hp per 1 MMcfd liquefied. The boil-off liquefaction compressor energy use was thus estimated for each facility using the following equation:

$$FBEU_i = \frac{IV_i \times 0.05\%}{365 days} \times \frac{750 Hp}{MMcfd} \times \left(365 days \times \frac{24 hours}{day}\right) \times \frac{MMHphr}{1{,}000{,}000 Hphr}$$

  where,

  $FBEU_i$ = Facility "i" boil-off liquefaction compressor energy use (MMHphr)

  IV_i = Facility "i" import volume (MMcf)

- Vaporization and send-out compressor energy use was also calculated based on assumptions from ICF *Additional Changes to Activity Factors for Portions of the Gas Industry* background memo for EPA's U.S. GHG Inventory. It estimates that with an average send-out pressure of 300 psia and inlet pressure of 15 psia, using 2-stage compression, satellite facilities require 1.86 MMHphr for each MMcfd of send-out. The following equation estimates the energy use at each facility:

$$\text{Facility "i" send-out energy use} = \frac{IV_i}{365 days} \times \frac{1.86 MMHphr}{MMcfd}$$

- The total process emissions for 2006, both vented and equipment leak methane and non-energy CO_2, were estimated in the U.S. GHG Inventory. These total process emissions were allocated to each facility based on its portion of the segment's total import volume, using the following equation:

$$\text{Facility "i" process emissions} = \frac{IV_i}{\sum_i IV} \times InventorySegmentEmissions$$

where,

IV_i = import volume and "i" represents individual facilities

- Combustion CO_2 and N_2O emissions were estimated for each facility by applying the following emission factors:

  EF_{CO2} = 719 metric tons CO_2e/MMHphr

[31] FERC. *Import Terminals*. Available online at: <http://www.ferc.gov/industries/lng.asp>.

EF_{N20} = 5.81 metric tons CO_2e/MMHphr

$Emissions_{CO2\ or\ N20} = EF_{CO2\ or\ N20} \times$ Compressor $energy_i$ (MMHphr)

- The total emissions for each facility were calculated by summing the calculated process and the combustion emissions.
- Since there were only 5 active import terminals, all were assumed to be "medium" in size.
- Each facility was assigned a "1" or "0" based on if it crossed a threshold by running the following logic checks:
  - IF(operator total emissions > 1000) then reporting
  - IF(operator total emissions > 10000) then reporting
  - IF(operator total emissions > 25000) then reporting
  - IF(operator total emissions >100000) then reporting
- Summing the results of the above logic checks for each threshold provided the number of facilities exceeding that threshold.
- Multiplying the logic checks above by the total emissions for each facility, then summing the results yielded the total emissions covered by each threshold.

Threshold Analysis for Distribution

- "Facility" in the natural gas distribution segment is defined as the local distribution company (LDC). The Department of Transportation (DOT)[32] provides a set of data that contains distribution main pipelines miles by pipeline materials and distribution service counts by pipeline material for each LDC.
- CO_2 and CH_4 equipment leaks from distribution mains were evaluated for each facility by multiplying its pipeline data by the appropriate emission factor, summarized in the table below, from the U.S GHG Inventory[1].

Exhibit C-8: LDC's Equipment Leak Emission Factors

Pipeline Type/Material	Equipment Leak Emission Factor
Mains – Unprotected Steel	110 Mcf/mile/year
Mains – Protected Steel	3.07 Mcf/mile/year
Mains – Plastic	9.91 Mcf/mile/year
Mains – Cast Iron	239 Mcf/mile/year
Services – Unprotected Steel	1.70 Mcf/service/year
Services – Protected Steel	0.18 Mcf/service/year
Services – Plastic	0.01 Mcf/service/year
Services – Copper	0.25 Mcf/service/year

- The total miles of mains pipelines of all materials were summed for each LDC.
- The total emissions from metering and regulating (M&R) stations for 2006, both vented and equipment leak methane and non-energy CO_2, were estimated by EPA

[32] DOT. *2006 Distribution Annuals Data*. Available online at: <http://www.phmsa.dot.gov/pipeline/library/data-stats>.

U.S GHG Inventory. These total emissions were allocated to each facility based on its portion of the segment's total import volume, using the following equation:

$$\text{Facility “i” M\&R emissions} = \frac{MM_i}{\sum_i MM} \times InventorySegmentEmissions$$

where,

MM = total miles of mains pipeline, and "i" represents individual facilities

- The total emissions for each facility were calculated by summing the calculated pipeline leaks and M&R station emissions[26].
- Each facility was assigned a "1" or "0" based on if it crossed a threshold by running the following logic checks:
  - IF(operator total emissions > 1000) then reporting
  - IF(operator total emissions > 10000) then reporting
  - IF(operator total emissions > 25000) then reporting
  - IF(operator total emissions >100000) then reporting
- Summing the results of the above logic checks for each threshold provided the number of facilities exceeding that threshold.
- Multiplying the logic checks above by the total emissions for each facility, then summing the results yielded the total emissions covered at each threshold.

Appendix D: Analysis of potential facility definitions for onshore petroleum and natural gas production

The purpose of this appendix is to determine the barriers in using a physical definition of a facility for the onshore petroleum and natural gas production segment. The paper also discusses a potential alternative to a physical definition by using a corporate level reporter definition.

A. Facility Definition: Any production sector reporting configuration will need specific definitions on what constitutes a facility.

i. Field level – A field may be defined by either physically aggregating certain surface equipment, referred to as physical field definition. Or the field may be defined by demarcation of geographical boundaries, referred to as Geographic field definition.

Physical field definition:
The challenge in defining a field as a facility is to recognize a common structure through the oil and gas production operations. Such a definition can be achieved by identifying a point in the system upstream of which all equipment can be collectively referred to as a field level facility. All oil and gas production operators are required by law to meter their oil and gas production for paying royalties to the owner of the gas and taxes to the state, referred to as the lease meter. All equipment upstream of this meter can be collectively referred to as a facility.

There is no precedence for such a definition in the CAA. It must be noted, however, that the facility definitions commonly used in the CAA pertain specifically to pollutants whose concentration in the ambient atmosphere is the deciding factor on its impact. This is not necessarily true of GHGs that have the same overall impact on climate forcing irrespective of how and where they occur.

Geographic field definition:
An alternative to the lease meter field level definition is to use the EIA Oil and Gas Field Code Master[33] to identify each geological field as a facility. This definition is structurally similar to the corporate basin level definition, i.e. it uses geological demarcations to identify a facility rather than the above ground operational demarcation.

ii. Basin level – The American Association of Petroleum Geologists (AAPG) provides a geologic definition of hydrocarbon production basins which are referenced to County boundaries. The United States Geological Survey (USGS)

[33] EIA Oil and Gas Field Master – 2007, http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/field_code_master_list/current/pdf/fcml_all.pdf

also provides such a definition, which is different than the AAPG definition. The AAPG definition identified by the "geologic province code" is most commonly used by the industry and can be used to report emissions from each basin. The individual counties in each state are allocated to different geologic province codes and therefore there is no ambiguity in associating an operation with the relevant basin (geologic province code). An operation physically located on a basin as defined by the AAPG can be identified with that particular basin, irrespective of which basins the wells are producing from. (Well pads may have multiple wells producing from different fields and zones in a reservoir, and possibly different basins as well).

B. **Level of Reporting:** It is important to clearly distinguish the level of reporting- i.e., the facility level or the corporate level. The level of reporting is where the threshold level is applied and thus determination on whether reporting is required. In some cases, the owner or operator of the facility itself is the reporter and in other cases it is the overall company that is the reporter. For example, in subpart NN of the MRR published on September 22, 2009, reporting for natural gas sent to the end use customers is at the local distribution company, and not the individual physical locations (or facilities) that send the natural gas into the economy. Alternatively, in subpart MM of the initial rule proposal, the owner or operator of the individual refinery is the reporter as opposed to the company owning multiple refineries.

For the purposes of onshore petroleum and natural gas production reporting can be at either the facility level or the corporate level. If the level of reporting is at the corporate level, it could still be required that data be reported for individual facilities.

C. Qualitative Analysis of Facility Options

The following qualitative evaluation provides a discussion on the advantages and disadvantages of using any of the three reporting level definitions, based on expert opinion.

i. Ease of practical application of reporter and facility definitions

1) Field level facility definition – In this case the physical demarcation of field level by aggregating field equipment is difficult to implement. On the other hand, field level definition based on boundaries identified by the EIA Oil and Gas Field Code Master should be easy to implement, since the classification if widely used in the industry.

   Physical Field Definition:
   There are no standard guidelines or operational practices on how many wells can be connected to one lease meter. The choice of whether multiple wells are connected to the same lease meter depends on; the well spacing, number of owners of leases, volume of hydrocarbons produced per well, geographical

boundaries, and ease of operation. Therefore, such a definition will lead to facilities of all kinds of sizes; at one extreme several well pads with multiple wells could be connected to one lease meter, while at the other extreme where situation demands only one well with no equipment could directly be connected to a lease meter. In addition there will be thousands of facilities that will be under purview.

Any lease meters located upstream of a compression system will exclude compressors from the facility definition. This means that the required threshold for emissions reporting may not be reached due to exclusion of the equipment leaks as well as the combustion emissions from compressors. Alternatively, the threshold will have to be set very low to capture any reasonable amount of emissions from field level definition.

Geographic field definition:
The EIA publishes its Field Code Master on a yearly basis. Also, the classification system is widely used in the industry. Hence such a definition should be easy to implement.

2) Basin level facility definition - Basin level definition is more practical to implement given that operational boundaries and basin demarcations are clearly defined. Furthermore, more emissions will be captured under this facility definition than the field level or well level definitions.

3) Corporate reporting -
It can be difficult to identify who the corporation is that would be responsible for reporting. If the corporation can be readily identified and defined then applying a field level facility definition using the EIA field classification or basin level facility definition using AAPG classification becomes practical.

ii. Coverage that can be expected from each definition type

1) Field level facility definition – This definition (both physical and geographical) provides the highest level of detail possible on emissions sources. However, any field level definition along with a 25,000 metric tons CO_2e/year threshold for reporting could potentially exclude a large portion of the U.S. oil and gas operations. Hence only a portion of the entire emissions from the U.S. oil and gas operations will get reported.

2) Basin level facility definition - Basin level information will throw light on the difference in patterns of emissions from sources both as a result of being located in different basins and as a result of different operational practices in different companies. This definition will result in the reporting of a significant portion of the emissions for the identified sources from the entire U.S. onshore oil and gas operations.

3) Corporate reporting - This definition will result in reporting of a significant portion of the emissions for the identified sources from the entire US onshore oil and gas operations. Since the reporting will be at a company level, variations in emissions from sources due to location on different basins may not be evident. However, if corporate national level reporter definition is used in addition to field and/or basin level reporting then all possible patterns in emissions will be evident.

D. Data Sources for Research and Analysis

i. Clean Air Act
ii. United States Geological Survey
iii. Natural Gas STAR Technical Documents
iv. EPA National GHG Inventory
v. DOE GASIS database
vi. Lasser® database
vii. Energy Information Administration
viii. Oil & Gas Journal
ix. HARC - VOC Emissions from Oil and Condensate Storage Tanks
x. State Oil and Gas Commissions
xi. American Association of Petroleum Geologists

Appendix E: Development of multipliers to scale emissions or miscellaneous sources connected to storage tanks

This method of quantifying tank emissions assumes that thermodynamically based models such as E&P Tank can accurately predict the effect of flashing emissions from hydrocarbons in fixed roof storage; but are unable to predict or account for emissions from vortexing or dump valves. Either direct measurement or a correction factor is required to represent the total emissions from hydrocarbon storage tanks.

This appendix compares two methods of correcting E&P Tank (GEO-RVP) data to account for non-flashing emission effects on tanks. Actual measurement data from a Texas Commission on Environmental Quality (TCEQ) report[34] were compared to E&P Tank (GEO-RVP) data runs on the same tanks to develop a correction factor which can be applied to E&P Tank (GEO-RVP) results in which additional non-flashing emissions or vortexing are detected.

Selected Data

All data considered were presented in a TCEQ-funded report that compared tank emission predicting equations, charts, and models to actual measured data. Data from the E&P Tank 2.0 GEO-RVP setting were compared against to direct measurement results. The TCEQ study focused on comparing the various methods of predicting VOC portion of emissions; however, for the purposes of this analysis, the total gas-oil ratios were compared.

Where direct measurement results were within ±100% of E&P Tank (GEO-RVP) results, those tanks were assumed to be exhibiting typical flashing emissions only. Direct measurement results greater or less than ±100% of E&P Tank (GEO-RVP) results were used to develop a correction factor for non-flashing effects on tank emissions.

The data were separated into two regimes:

- Hydrocarbon liquids with API gravities less than 45˚API were considered "oil"
- Hydrocarbon liquids with API gravities greater than 45˚API were considered "condensate"

Correction factors were developed for both ranges.

Method 1 – Least Squares Analysis of Emission Difference

The first method sorts qualifying tanks in ascending order of emission rates estimated by the E&P Tank (GEO-RVP) runs. The difference between the measured emission rate and E&P Tank (GEO-RVP) emission rates was plotted against the E&P Tank (GEO-RVP) emission rates and a trend line was fitted to the equation, as shown in Exhibits E-9 and E-10.

Exhibit E-9. Oil Tank Correction Factors

[34] Texas Commission on Environmental Quality (TCEQ). *Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation*. July 16, 2009.

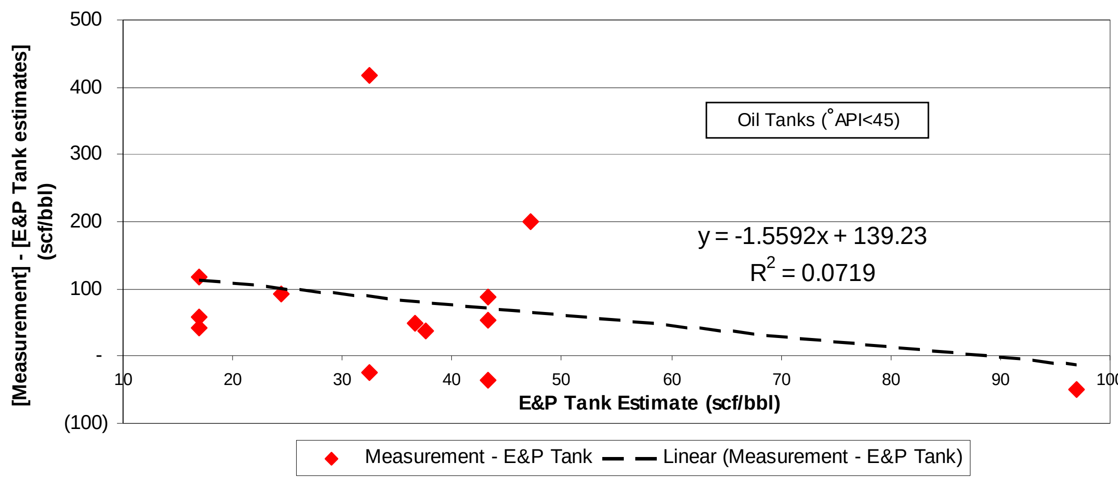
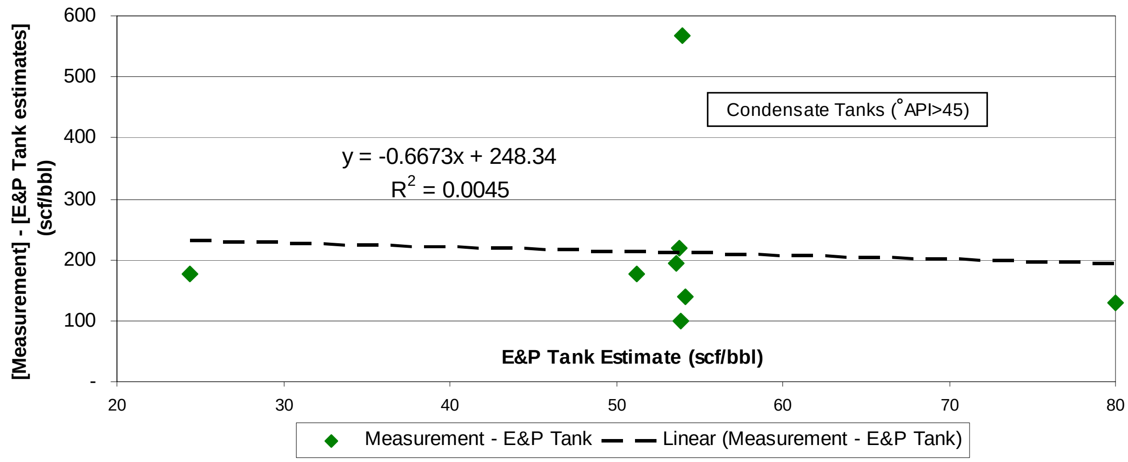


Exhibit E-10. Condensate Tank Correction Factors



The equation for the line of best fit can be used on E&P Tank (GEO-RVP) results where non-flashing emission affects are detected to estimate the true tank emissions. The data used to derive this relationship range from oil gravities from 29.1 to 44.8˚API and separator pressures from 15 to 70 psig; and for condensate gravities from 45.3 to 82.2˚API and separator pressures from 30 to 231 psig.

The E&P Tank (GEO-RVP) emission estimates can be corrected with the following equations:

- For oil: CE = (-0.5592 × EE) + 139.23
- For condensate: CE = (0.3327 × EE) + 248.34

Where "EE" is the E&P Tank (GEO-RVP) emission estimate and "CE" is the corrected emission estimate.

As demonstrated in Exhibits E-9 and E-10, the correlations for the correction factor are very weak, with R^2 values of 0.0719 for oil and 0.0045 for condensate.

Method 2 – Average Emissions Ratio Analysis
This method takes the simple average of the ratio of qualifying measured emission rates to simulated emission rates generated by E&P Tank (GEO-RVP) for the oil and condensate ranges.

Using this method, E&P Tank (GEO-RVP) emission estimates can be corrected with the following equations:

- For oil: $CE = 3.87 \times EE$
- For condensate: $CE = 5.37 \times EE$

Where "EE" is the E&P Tank (GEO-RVP) emission estimate and "CE" is the corrected emission estimate.

Summary
Predicting and evaluating non-flashing effects on emissions (such as dump valves or vortexing) has not yet been thoroughly studied or quantified. The methods above have significant weaknesses as:

1. The sample data set is limited
2. Only weak correlations were observed for the available data.

Method 1 naturally suggests that very low estimates are underestimating the tank emissions and very high estimates (over 89 scf/bbl for oil) are overestimating the emissions. This will tend to "even out" estimates so that none are extremely high or extremely low. It also suggests that if E&P Tank (GEO-RVP) estimates 0 scf/bbl flashing emissions, the emission rates are actually higher than if E&P Tank (GEO-RVP) estimates large (near 89 scf/bbl for oil) emission rates.

Method 2 does not "even out" emission rates, and assumes that in all cases where non-flashing effects are present, each case is uniformly underestimated.

Appendix F: Development of leaker emission Factors

Natural Gas Emission Factors for Onshore Production

Leaker Emission Factors – All Components, Light Crude Service

Methodology
Average emission factors by facility type are taken from API's *Emission Factors for Oil and Gas Production Operations*[35]. Hydrocarbon liquids greater than or equal to 20°API are considered "light crude." The methane content of associated natural gas with onshore light crude is 61.3% is taken from the same API publication, Table ES-4, page ES-3.

Component EF, scf/hour/component = ((Component EF, lb/day THC) * (**A**)) / ((**B**) * (**C**))

Component Name	Component EF, scf/hour/comp	Component EF, lb/day THC
Valve	2.03	3.381
Connector	0.90	1.497
Open-Ended Line	0.96	1.6
Pump	2.35	3.905
Other	2.31	3.846

EF: Emission Factor
THC: Total Hydrocarbons

Conversions:
A: 0.613 – CH_4 content of onshore light crude associated natural gas
B: 0.04246 CH_4 density lb/scf
C: 24 hours/day

Leaker Emission Factors – All Components, Heavy Crude Service

Methodology
Average emission factors by facility type are taken from API's *Emission Factors for Oil and Gas Production Operations*[35]. Hydrocarbon liquids less than 20°API are considered "heavy crude." The methane content of associated natural gas with onshore heavy crude is 94.2% taken from the same API publication, Table ES-4, page ES-3.

Component EF, scf/hour/component = ((Component EF, lb/day THC) * (**D**)) / ((**B**) * (**C**))

Component Name	Component EF, scf/hour/component	Component EF, lb/day THC
Valve	3.13	3.381
Flange	4.15	4.49
Connector (other)	1.38	1.497
Open-Ended Line	1.48	1.6
Other	3.56	3.846

[35] API. *Emission Factors for Oil and Gas Production Operations*. Table 10, page 16. API Publication Number 4615. January 1995.

EF: Emission Factor
THC: Total Hydrocarbons

Conversions:
B: 0.04246 CH_4 density lb/scf
C: 24 hours/day
D: 0.942 – CH_4 content of onshore heavy crude associated natural gas

Total Hydrocarbon Emission Factors for Processing

Leaker Emissions Factors – Reciprocating Compressor Components, Centrifugal Compressor Components, and Other Components, Gas Service

Methodology
The leaker emissions factors are from Clearstone Engineering's *Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants*[36] and Clearstone's *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*[37]. The components were categorized into three groups: reciprocating compressor related, centrifugal compressor related and all other components. Furthermore, the components related to reciprocating and centrifugal compressor were segregated into components before and after the de-methanizer. Once categorized, the sum of the leak rates from components known to be leaking was divided by the sum of number of leaking components.

Component EF, scf/hour/component = (Leak rate**,** Mscf/day/component) * (**E**) / (**C**)

Component Name	Reciprocating Compressor Component, (scf/hour/comp)		Centrifugal Compressor Component, (scf/hour/comp)		Other Components, (scf/hour/comp)
	Before De-Methanizer	After De-Methanizer	Before De-Methanizer	After De-Methanizer	
Valve	15.88	18.09	0.67	2.51	6.42
Connector	4.31	9.10	2.33	3.14	5.71
Open-Ended Line	17.90	10.29	17.90	16.17	11.27
Pressure Relief Valve	2.01	30.46	-	-	2.01
Meter	0.02	48.29	-	-	2.93

Conversions:
C: 24 hours / day
E: 1000 scf / Mscf

[36] EPA. *Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants*. Clearstone Engineering Ltd. June 20, 2002. <www.epa.gov/gasstar/documents/four_plants.pdf>
[37] National Gas Machinery Laboratory, Kansas State University; Clearstone Engineering, Ltd; Innovative Environmental Solutions, Inc. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. For EPA Natural Gas STAR Program. March 2006.

Total Hydrocarbon Emission Factors for Transmission

Leaker Emission Factors – All Components, Gas Service

Methodology

Gas transmission facility emissions are drawn from the *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*[38] and the *Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry*[39]. All compressor related components were separated from the raw data and categorized into the component types. Once categorized, the sum of the leak rates from components known to be leaking was divided by the sum of number of leaking components.

Component EF, scf/hour/component = (Gas Transmission Facility Emissions, kg/h/src) * (**F**) / (**B**)

Component Name	Component EF, (scf/hour/comp)
Connector	2.7
Block Valve	10.4
Control Valve	3.4
Compressor Blowdown Valve	543.5
Pressure Relief Valve	37.2
Orifice Meter	14.3
Other Meter	0.1
Regulator	9.8
Open-Ended Line	21.5

Conversions:
B: 0.04246 CH_4 density lb/scf
F: 2.20462262 lb/kg

Methane Emission Factors for LNG Storage

Leaker Emission Factors – LNG Storage Components, LNG Service

Methodology

[38] Clearstone. *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*. Clearstone Engineering Ltd., Enerco Engineering Ltd, and Radian International. May 25, 1998.
[39] Clearstone. *Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry*. Clearstone Engineering Ltd., Canadian Energy Partnership for Environmental Innovation (CEPEI). April 16, 2007.

The light liquid emission factors with leak concentrations greater than or equal to 10,000 ppmv were taken from *Protocol for Equipment Leak Emission Estimates*[40]. The emissions are assumed to be 100% methane.

Component EF, scf/hour/component = (Light Liquid >= 10,000 ppmv Emission Factor) * (**F**) / (**B**)

Component Name	Component EF, scf/hour/comp	†Light Liquid EF, kg/hr THC
Valve	1.19	2.30E-02
Pump Seal	4.00	7.70E-02
Connector	0.34	6.50E-03
Other	1.77	3.40E-02
†Greater or equal to 10,000 ppmv		

Conversions:
B: 0.04246 CH_4 density lb/scf
F: 2.20462262 lb/kg

Total Hydrocarbon Emission Factors for Processing, Transmission, and Underground Storage

Leaker Emissions Factors –Compressor Components, Non-Compressor Components, Gas Service

Methodology
Several leaker emission factors for the processing segment, such as open-ended lines before the de-methanizer for reciprocating compressors, did not have sufficient data points to justify a representative emission factor. To eliminate this issue, the segregation of components into reciprocating versus centrifugal and before the de-methanizer versus after the de-methanizer was eliminated.

In addition, the leaker emission factors from transmission were combined with those from processing. Equipment leak emissions from transmission compressors and processing compressors are similar because they are comparable in size and discharge pressure. Compressors in processing either inject residue gas into high pressure transmission pipelines or pressurize large volumes of production gas for processing facility processes.

The same LEFs can also be used for compressor related components in underground natural gas storage because compressors in this sector have a large throughput and inject gas at high pressure into the ground or into transmission pipelines. The final emission factors were corrected to 68˚F and 14.7 psia per the definition of “standard conditions” set forth in subpart A of Title 40 CFR 98.

[40] EPA. *Protocol for Equipment Leak Emission Estimates*. Emission Standards Division. U.S. EPA. SOCMI Table 2-7. November 1995.

Component EF, scf/hour/component = (Leak rate**,** Mscf/day/component) * (**E**) / (**C**)

Component Name	Emission Factor (scf/hour/component)
Leaker Emission Factors – Compressor Components, Gas Service	
Valve	15.07
Connector	5.68
Open-ended Line	17.54
Pressure Relief Valve	40.27
Meter	19.63
Leaker Emission Factors – Non -Compressor Components, Gas Service	
Valve	6.52
Connector	5.80
Open-ended Line	11.44
Pressure Relief Valve	2.04
Meter	2.98

Conversions:
C: 24 hours / day
E: 1000 scf / Mscf

Methane Emission Factors for LNG Terminals

Leaker Emission Factors – LNG Terminals Components, LNG Service

Methodology
See methodology for Leaker Emission Factors – LNG Storage Components, LNG Service for LNG Storage[40].

Methane Emission Factors for Distribution

Leaker Emission Factors – Above Grade M&R Stations Components, Gas Service

Methodology
Gas distribution meter/regulator station emissions are drawn from: *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*[38] and *Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry*[39].

Component EF, scf/hour/component = (Gas Distribution Meter/Regulator Station Emissions, kg/h/src) * (**F**) / (**B**)

Component Name	Component EF, scf/hour/comp	Gas Distribution Meter/Regulator Station Emissions, kg/h/src
Connector	0.67	0.01292

Block Valve	1.49	0.02872
Control Valve	3.94	0.07581
Pressure Relief Valve	5.24	0.1009
Orifice Meter	0.46	0.0088
Other Meter	0.01	0.0002064
Regulator	2.14	0.04129
Open-Ended Line	6.01	0.1158

Conversions:
B: 0.04246 CH_4 density lb/scf
F: 2.20462262 lb/kg

<u>Leaker Emission Factors – Distribution Mains and Services, Gas Service</u>

Methodology
Emission factors for pipeline leaks (mains and services) are drawn from GRI's *Methane Emissions from the Natural Gas Industry*[41].

Component EF, scf/hour/leak = (Pipeline Leak, scf/leak-year) / (**G**)

Component Name	Component EF (Mains), scf/hour/leak	Pipeline Leak EF (Mains), scf/leak-yr	Component EF, (Services) scf/hour/leak	Pipeline Leak EF (Services), scf/leak-yr
Unprotected Steel	6.02	52748	2.33	20433
Protected Steel	2.38	20891	1.08	9438
Plastic	11.63	101897	0.35	3026
Copper			0.88	7684

Conversions:
G: 8,760 hours/year

NATURAL GAS EMISSION FACTORS FOR ONSHORE PRODUCTION

Onshore production	Emission Factor (scf/hour/component)
Leaker Emission Factors - All Components, Gas Service	
Valve	NA
Connector	NA
Open-ended Line	NA
Pressure Relief Valve	NA
Low-Bleed Pneumatic Device Vents	NA
Gathering Pipelines	NA
CBM Well Water Production	NA
Compressor Starter Gas Vent	NA
Conventional Gas Well Completion	NA

[41] GRI. *Methane Emissions from the Natural Gas Industry*. Volume 9. Tables 8-9 and 9-4. June 1996. <www.epa.gov/gasstar/documents/emissions_report/9_underground.pdf>

Conventional Gas Well Workover	NA
Leaker Emission Factors - All Components, Light Crude Service[1]	
Valve	2.03
Connector	0.90
Open-ended Line	0.96
Pump	2.35
Other	2.31
Leaker Emission Factors - All Components, Heavy Crude Service[2]	
Valve	3.13
Flange	4.15
Connector (other)	1.38
Open-ended Line	1.48
Other	3.56

[1] Hydrocarbon liquids greater than or equal to 20˚API are considered "light crude"
[2] Hydrocarbon liquids less than 20˚API are considered "heavy crude"

TOTAL HYDROCARBON EMISSION FACTORS FOR PROCESSING

Processing[1]	Before De-Methanizer Emission Factor (scf/hour/component)	After De-Methanizer Emission Factor (scf/hour/component)
Leaker Emission Factors - Reciprocating Compressor Components, Gas Service		
Valve	15.88	18.09
Connector	4.31	9.10
Open-ended Line	17.90	10.29
Pressure Relief Valve	2.01	30.46
Meter	0.02	48.29
Leaker Emission Factors - Centrifugal Compressor Components, Gas Service		
Valve	0.67	2.51
Connector	2.33	3.14
Open-ended Line	17.90	16.17
Leaker Emission Factors - Other Components, Gas Service[2]		
Valve	6.42	
Connector	5.71	
Open-ended Line	11.27	
Pressure Relief Valve	2.01	
Meter	2.93	

METHANE EMISSION FACTORS FOR TRANSMISSION

Transmission	Emission Factor (scf/hour/component)
Leaker Emission Factors - All Components, Gas Service	
Connector	2.7
Block Valve	10.4

Control Valve	3.4
Compressor Blowdown Valve	543.5
Pressure Relief Valve	37.2
Orifice Meter	14.3
Other Meter	0.1
Regulator	9.8
Open-ended Line	21.5
Leaker Emission Factors - Other Components, Gas Service	
Low-Bleed Pneumatic Device Vents	NA

[1] Emission Factor is in units of "scf/hour/mile"

METHANE EMISSION FACTORS FOR UNDERGROUND STORAGE

Underground Storage	Emission Factor (scf/hour/component)
Leaker Emission Factors - Storage Station, Gas Service	
Connector	0.96
Block Valve	2.02
Control Valve	3.94
Compressor Blowdown Valve	66.15
Pressure Relief Valve	19.80
Orifice Meter	0.46
Other Meter	0.01
Regulator	1.03
Open-ended Line	6.01
Leaker Emission Factors - Storage Wellheads, Gas Service	
Connector	NA
Valve	NA
Pressure Relief Valve	NA
Open-ended Line	NA
Leaker Emission Factors - Other Components, Gas Service	
Low-Bleed Pneumatic Device Vents	NA

TOTAL HYDROCARBON EMISSION FACTORS FOR PROCESSING, TRANSMISSION, AND, UNDERGROUND STORAGE

Processing, Transmission, and Underground Storage	Emission Factor (scf/hour/component)
Leaker Emission Factors – Compressor Components, Gas Service	
Valve	15.07
Connector	5.68
Open-Ended Line	17.54
Pressure Relief Valve	40.27
Meter	19.63
Leaker Emission Factors – Non-compressor Components , Gas Service	
Valve	6.52
Connector	5.80
Open-Ended Line	11.44

Pressure Relief Valve	2.04
Meter	2.98

[1]Valves include control valves, block valves, and regulator valves.

METHANE EMISSION FACTORS FOR LNG STORAGE

LNG Storage	Emission Factor (scf/hour/component)
Leaker Emission Factors - LNG Storage Components, LNG Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other	1.77
Leaker Emission Factors - LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor	NA

METHANE EMISSION FACTORS FOR LNG TERMINALS

LNG Terminals	Emission Factor (scf/hour/component)
Leaker Emission Factors - LNG Terminals Components, LNG Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other	1.77
Leaker Emission Factors - LNG Terminals Compressor, Gas Service	
Vapor Recovery Compressor	NA

METHANE EMISSION FACTORS FOR DISTRIBUTION

Distribution	Emission Factor (scf/hour/component)
Leaker Emission Factors - Above Grade M&R Stations Components, Gas Service	
Connector	1.69
Block Valve	0.557
Control Valve	9.34
Pressure Relief Valve	0.270
Orifice Meter	0.212
Regulator	26.131
Open-ended Line	1.69
Leaker Emission Factors - Below Grade M&R Stations Components, Gas Service	
Below Grade M&R Station, Inlet Pressure > 300 psig	NA
Below Grade M&R Station, Inlet Pressure 100 to 300 psig	NA
Below Grade M&R Station, Inlet Pressure < 100 psig	NA
Leaker Emission Factors - Distribution Mains, Gas Service[1]	
Unprotected Steel	6.02

Protected Steel	2.38
Plastic	11.63
Cast Iron	NA
Leaker Emission Factors - Distribution Services, Gas Service[1]	
Unprotected Steel	2.33
Protected Steel	1.08
Plastic	0.35
Copper	0.88

[1] Emission Factor is in units of "scf/hour/leak"

Summary

This Appendix provides leaker emissions factors that can be applied to any individual emissions source which meets the leak detection definition in a leak detection survey. These emissions factors provide an estimate of real emissions as opposed to potential emissions since they are applied only to leaking emissions sources. However, it must be noted that these leaker emissions factors assume that any emissions source found leaking has been leaking for the duration of an entire year.

Appendix G: Development of population emission factors

Natural Gas Emission Factors for Onshore Production

<u>Whole Gas Population Emission Factors – All Components, Gas Service</u>

Methodology

The well counts and emission factors were taken from GRI's *Methane Emissions from the Natural Gas Industry*[42]. The emission factors for each source are calculated using gas production for the Eastern and Western United States. The average methane content of produced natural gas is assumed to be 78.8%.

Eastern/Western U.S. Component EF, scf/hour/component = (EF Eastern/Western U.S., mscf/yr) * (**A**) * (**B**) / (**C**) / (**D**)

Component	Eastern U.S. EPA/GRI EF (mscf CH_4/year)	Eastern U.S. Subpart W EF (scf natural gas/hour)
Valve	0.184	0.027
Connector	0.024	0.004
Open-Ended Line	0.420	0.062
Pressure Relief Valve	0.279	0.041

Component	Western U.S. EPA/GRI EF (mscf CH_4/year)	Western U.S. Subpart W EF (scf natural gas/hour)
Valve	0.835	0.123
Connector	0.114	0.017
Open-Ended Line	0.215	0.032
Pressure Relief Valve	1.332	0.196

Conversions:
A: 1,000 scf/mscf
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
C: 8,760 hours/year
D: 78.8% methane by volume in produced natural gas

"High Continuous Bleed Pneumatic Device Vents" Methodology

Methane emissions per pneumatic device are from API's *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry* [43]. The average methane content of natural gas is assumed to be 78.8%.

48.1 scf/hour/component EF = (**896** [scfd CH_4/pneumatic devises, high bleed]) * (**B**) / (**D**) / (**E**)

[42] GRI. *Methane Emissions from the Natural Gas Industry*. Volume 8. June 1996. <www.epa.gov/gasstar/documents/emissions_report/8_equipmentleaks.pdf>

[43] API. *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*. American Petroleum Institute. Table 5-15, page 5-68. August 2009.

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
D: 78.8% – production quality of natural gas (% methane) [44]
E: 24 hours/day

"Low Continuous Bleed Pneumatic Device Vents" Methodology

Methane emissions per pneumatic device are from API's *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*[43]. The average methane content of natural gas is assumed to be 78.8%.

1.80 scf/hour/component EF = (**33.4** [scfd CH_4/pneumatic devises, low bleed]) * (**B**) / (**D**) / (**E**)

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
D: 78.8% – production quality of natural gas (% methane)
E: 24 hours/day

"Intermittent Bleed Pneumatic Device Vents" Methodology

Methane emissions per pneumatic device are from API's *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*[43]. The average methane content of natural gas is assumed to be 78.8%.

17.4 scf/hour/component EF = (**323** [scfd CH_4/pneumatic devises, low bleed]) * (**B**) / (**D**) / (**E**)

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
D: 78.8% – production quality of natural gas (% methane)[44]
E: 24 hours/day

"Pneumatic Pumps" Methodology

Methane emissions per pneumatic pump are from GRI's *Methane Emissions from the Natural Gas Industry*[45]. The average methane content of natural gas is assumed to be 78.8%.

13.3 scf CH_4/hour/component EF = (**248** [scfd CH_4/pneumatic devises, low bleed]) * (**B**) / (**D**) / (**E**)

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[44] GRI. "Vented and Combustion Source Summary," *Methane Emissions from the Natural Gas Industry,* U.S. EPA, Volume 6, Appendix A, page A-2.
[45] GRI. *Methane Emissions from the Natural Gas Industry*. Volume 13. Tables 4-4. June 1996. <http://epa.gov/gasstar/documents/emissions_report/13_chemical.pdf>.

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
D: 78.8% – production quality of natural gas (% methane)[46]
E: 24 hours/day

<u>Population Emission Factors – All Components, Light Crude Service</u>

Methodology
Average emissions factors by facility type were taken from API's *Emission Factors for Oil and Gas Production* Operations.[47] Hydrocarbon liquids greater than or equal to 20°API are considered "light crude."

Component EF, scf/hour/component = (Average Emissions Factors by Facility Type, lb/component-day) * (**B**) / (**E**) / (**F**)

Component Name	Component EF, scf/hr/comp	Average EF by Facility Type, lb/component-day
Valve	0.04	7.00E-02
Flange	0.002	4.07E-03
Connector	0.005	8.66E-03
Open-Ended Line	0.04	6.38E-02
Pump	0.01	1.68E-02
Other	0.23	3.97E-01

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
D: 24 hours/day
F: 0.072 gas density lb/scf – assumes a gas composition of 61.2% methane, 20% ethane, 10% propane, 5% butane, and 3.8% pentanes+

<u>Population Emission Factors – All Components, Heavy Crude Service</u>

Methodology
Average emissions factors by facility type were taken from API's *Emission Factors for Oil and Gas Production Operations*[48]. Hydrocarbon liquids less than 20°API are considered "heavy crude." The methane content of associated natural gas with onshore light crude is 94.2% from the same study.

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[46] GRI. "Vented and Combustion Source Summary," *Methane Emissions from the Natural Gas Industry*, U.S. EPA, Volume 6, Appendix A, page A-2.
[47] API. *Emission Factors for Oil and Gas Production Operations*. Table 9, page 10. API Publication Number 4615. January 1995.
[48] API. *Emission Factors for Oil and Gas Production Operations*. API Publication Number 4615. page ES-3, Table ES-4, January 1995.

Component EF, scf/hour/component = (Average Emissions Factors by Facility Type, lb/component-day) * (**B**) / (**D**) / (**F**)

Component Name	Component EF, scf/hr/comp	Average EF by Facility Type, lb/component-day
Valve	0.0004	6.86E-04
Flange	0.0002	1.16E-03
Connector (Other)	0.0004	4.22E-04
Open-Ended Line	0.004	8.18E-03
Other	0.002	3.70E-03

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
D: 24 hours/day
F: 0.072 gas density lb/scf – assumes a gas composition of 61.2% methane, 20% ethane, 10% propane, 5% butane, and 3.8% pentanes+

Methane Emission Factors For Processing

<u>Population Emission Factors – All Components, Gas Service</u>

There are no population emission factors in subpart W for the onshore natural gas processing segment.

Methane Emission Factors for Transmission

<u>Population Emission Factors – All Components, Gas Service</u>

Gas transmission facility emission factors were taken from the *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*[49]. "Connector" includes flanges, threaded connections, and mechanical couplings. "Block Valve" accounts for emissions from the stem packing and the valve body, and it applies to all types of block valves (e.g., butterfly, ball, globe, gate, needle, orbit, and plug valves). Leakage past the valve seat is accounted for the Open-Ended Line emission category. Leakage from the end connections is accounted for by the connector category (i.e., one connector for each end). "Control Valve" accounts for leakage from the stem packing and the valve body. Emissions from the controller and actuator are accounted for by the Instrument Controller and Open-Ended Line categories respectively. This factor applies to all valves with automatic actuators (including fuel gas injection valves on the drivers of reciprocating compressors). "Orifice Meter" accounts for emissions from the orifice changer. Emissions from sources on pressure tap lines etc. are not included in the factor (i.e., these emissions must be calculated separately).

[49] CEPEI. *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*. May 25, 1998.

"Other Meter" accounts for emissions from other types of gas flow meters (e.g., diaphragm, ultrasonic, roots, turbine, and vortex meters).

Component EF, scf/hour/component = (Gas Transmission Facility Emissions, kg/h/src) * (**B**) * (**I**) / (**F**)

Component Name	Component EF, scf/hour/comp	Gas Transmission Facility Avg. Emissions, kg/hr/src
Connector	0.01	2.732E-04
Block Valve	0.11	2.140E-03
Control Valve	1.04	1.969E-02
Pressure Relief Valve	14.74	2.795E-01
Orifice Meter	0.18	3.333E-03
Other Meter	0.0005	9.060E-06
Regulator	0.17	3.304E-03
Open-Ended Line	4.40	8.355E-02

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
F: 0.04246 CH_4 density lb/scf
I: 2.20462262 lb/kg

<u>Population Emission Factors – Other Components, Gas Service</u>

"Low Continuous Bleed Pneumatic Device Vents" Methodology
Methane emissions per pneumatic device are from API's *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*[43]. The average methane content of natural gas is assumed to be 78.8%.

1.41 scf/hour/component EF = (**33.4** [scfd CH_4/pneumatic devises, low bleed]) * (**B**) * (**J**) / (**D**) / (**E**)

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
D: 78.8% – production quality of natural gas (% methane) from: "Vented and Combustion Source Summary," *Methane Emissions from the Natural Gas Industry*, U.S. EPA, Volume 6, Appendix A, page A-2.
E: 24 hours/day
J: 93.4% – pipeline quality natural gas (% methane) from: "Vented and Combustion Source Summary," *Methane Emissions from the Natural Gas Industry*, U.S. EPA, Volume 6, Appendix A, page A-2.

"High Continuous Bleed Pneumatic Device Vents" Methodology

Methane emissions per pneumatic device are from GRI's *Methane Emissions from the Natural Gas Industry*[50]. The average methane content of natural gas is assumed to be 78.8%.

18.8 scf/hour/component EF = (**162,197** [scfy CH_4/pneumatic devises, low bleed]) * (**B**) / (**C**)

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
C: 8,760 hours/year

"Intermittent Bleed Pneumatic Device Vents" Methodology
Methane emissions per pneumatic device are from GRI's *Methane Emissions from the Natural Gas Industry*[50]. The average methane content of natural gas is assumed to be 78.8%.

18.8 scf/hour/component EF = (**162,197** [scfy CH_4/pneumatic devises, low bleed]) * (**B**) / (**C**)

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
C: 8,760 hours/year

Methane Emission Factors for Underground Storage

<u>Population Emission Factors – Storage Station, Gas Service</u>

Methodology
See methodology for "Population Emission Factors – All Components, Gas Service" for Transmission.

<u>Population Emission Factors – Storage Wellheads, Gas Service</u>

Methodology
Emission factors for injection/withdrawal wellheads are from GRI's *Methane Emissions from the Natural Gas Industry*[42].

Component EF, scf/hour/component = (Injection/Withdrawal Wellhead) (**A**) * (**B**) / (**C**)

Component Name	Component EF, scf/hr/comp	Injections/Withdrawal Wellhead, Mcf/yr
Connector	0.01	0.125

[50] GRI. *Methane Emissions from the Natural Gas Industry*. Volume 12. Page 52. June 1996. <http://epa.gov/gasstar/documents/emissions_report/12_pneumatic.pdf>.

Valve	0.10	0.918
Pressure Relief Valve	0.17	1.464
Open-Ended Line	0.03	0.237

Conversions:
A: 1,000 scf/mscf
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
C: 8,760 hours/year

Population Emission Factors – Other Components, Gas Service

Methodology
"Low Continuous Bleed Pneumatic Device Vents" Methodology
See "Low Continuous Bleed Pneumatic Device Vents" Methodology for Population Emission Factors – Other Components, Gas Service for Transmission.

"High Continuous Bleed Pneumatic Device Vents" Methodology
See "High Continuous Bleed Pneumatic Device Vents" Methodology for Population Emission Factors – Other Components, Gas Service for Transmission.

"Intermittent Bleed Pneumatic Device Vents" Methodology
See "Intermittent Bleed Pneumatic Device Vents" Methodology for Population Emission Factors – Other Components, Gas Service for Transmission.

Methane Emission Factors for LNG Storage

Population Emission Factors – LNG Storage Components, LNG Service

Methodology
Component emission factors are from EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks*[51]. The emission factors were adjusted by an assumed average methane content of 93.4% by volume.

Component EF, scf/hour/component = (Component EF, Mscf/comp-yr) (**B**) * (**I**) / (**F**)

Component Name	Component EF, scf/hour/comp	Component EF, Mscf/comp-yr
Valve	0.10	0.867
Open-ended Line	1.30	11.2
Connector	0.02	0.147
PRV	0.72	6.2

Conversions:

[51] EPA. *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2006*. Available online at <http://www.epa.gov/climatechange/emissions/usinventoryreport.html>.

B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
F: 0.04246 CH_4 density lb/scf
I: 2.20462262 lb/kg

<u>Population Emission Factors – LNG Storage Compressor, Gas Service</u>

"Vapor Recovery Compressor" Methodology
The methane emissions per compressor are from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*[51].

4.23 scf/hour/component EF = (**100** scfd CH_4/compressor) * (**B**) / (**D**)
Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
D: 24 hours/day

Methane Emission Factors for LNG Terminals

<u>Population Emission Factors – LNG Terminals Components, LNG Service</u>

Methodology
See methodology for Population Emission Factors – LNG Storage Components, LNG Service for LNG Storage.

<u>Population Emission Factors – LNG Terminals Compressor, Gas Service</u>

Methodology
See "Vapor Recovery Compressor" Methodology for Population Emission Factors – LNG Storage Compressor, Gas Service for LNG Storage.

Methane Emission Factors for Distribution

<u>Population Emission Factors – Above Grade M&R Stations Components, Gas Service</u>

Methodology
Gas distribution meter/regulator station average emissions from: Gas transmission facility emissions are from the *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*[49]. "Connector" includes flanges, threaded connections, and mechanical couplings. "Block Valve" accounts for emissions from the stem packing and the valve body, and it applies to all types of block valves (e.g., butterfly, ball, globe, gate, needle, orbit, and plug valves). Leakage past the valve seat is accounted for the Open-Ended Line emission category. Leakage from the end connections is accounted for by the connector category

(i.e., one connector for each end). “Control Valve” accounts for leakage from the stem packing and the valve body. Emissions from the controller and actuator are accounted for by the Instrument Controller and Open-Ended Line categories respectively. This factor applies to all valves with automatic actuators (including fuel gas injection valves on the drivers of reciprocating compressors). “Orifice Meter” accounts for emissions from the orifice changer. Emissions from sources on pressure tap lines etc. are not included in the factor (i.e., these emissions must be calculated separately). “Other Meter” accounts for emissions from other types of gas flow meters (e.g., diaphragm, ultrasonic, roots, turbine, and vortex meters).

Component EF, scf/hour/component = (Gas Distribution Meter/Regulator Station Emissions, kg/h/src) * (**B**) * (**I**) / (**F**)

Component Name	**Component EF, scf/hour/comp**	**Gas Distribution Meter/Regulator Station Avg. Emissions, kg/h/src**
Connector	5.79E-03	1.098E-04
Block Valve	5.85E-02	1.109E-03
Control Valve	1.04E+00	1.969E-02
Pressure Relief Valve	8.78E-01	1.665E-02
Orifice Meter	1.76E-01	3.333E-03
Other Meter	4.78E-04	9.060E-06
Regulator	1.01E-01	1.915E-03
Open-Ended Line	4.39E+00	8.355E-02

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
F: 0.04246 CH_4 density lb/scf
I: 2.20462262 lb/kg

Population Emission Factors – Below Grade M&R Stations Components, Gas Service

Methodology
Average emission factors are from GRI’s *Metering and Pressure Regulating Stations in Natural Gas Transmission and Distribution*[52]. (Converted to 68˚F)

Below Grade M&R Station, Inlet Pressure > 300 psig: 1.32 scf/hour/station EF

Below Grade M&R Station, Inlet Pressure 100 to 300 psig: 0.20 scf/hour/station EF

Below Grade M&R Station, Inlet Pressure < 100 psig: 0.10 scf/hour/station EF

Population Emission Factors – Distribution Mains and Services, Gas Service

Methodology

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[52] GRI. *Methane Emissions from the Natural Gas Industry*. Volume 10. Table 7-1. June 1996. <www.epa.gov/gasstar/documents/emissions_report/10_metering.pdf>.

Emission factors for pipeline leaks (mains and service) are from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*[53]

Component EF, scf/hour/service = (Pipeline Leak mscf/mile/year) (**A**) * (**B**) / (**C**)

Component Name	**Component EF (Mains), scf/hr/service**	**Pipeline Leak EF (Mains), Mscf/mile-yr**	**Component EF (Services), scf/hr/service**	**Pipeline Leak EF (Services), Mscf/mile-yr**
Unprotected Steel	12.77	110.19	0.19	1.70
Protected Steel	0.36	3.07	0.02	0.18
Plastic	1.15	9.91	0.001	0.01
Cast Iron	27.67	238.7		
Copper			0.03	0.25

Conversions:
A: 1,000 scf/mscf
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
C: 8,760 hours/year

Nitrous Oxide Emission Factors for Gas Flaring

Population Emission Factors – Gas Flaring

Methodology
Emission factors are from API's *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*.

Gas Production: 5.90E-07 metric tons/MMcf gas production or receipts EF

Sweet Gas Processing: 7.10E-07 metric tons/MMcf gas production or receipts EF

Sour Gas Processing: 1.50E-06 metric tons/MMcf gas production or receipts EF

Conventional Oil Production: 1.00E-04 metric tons/barrel conventional oil production EF

Heavy Oil Production: 7.30E-05 metric tons/barrel heavy oil production EF

Summary

This Appendix provides population emissions factors for potential emissions sources. These population emissions factors could be used in conjunction with population counts that make it more cost effective in estimating emissions. However, these population emissions factors estimate potential emissions as the percentage of emissions sources leaking may or may not

[53] EPA. *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2007*. Available online at <http://www.epa.gov/climatechange/emissions/usinventoryreport.html>.

be the same as the assumption made when developing the emissions factors. Also, the population emissions factors assume that a subset of leaking emission sources is leaking continuously throughout the year.

Appendix H: Glossary

The following definitions are based on common industry terminology for the respective equipment, technologies, and practices.

Absorbent circulation pump means a pump commonly powered by natural gas pressure that circulates the absorbent liquid between the absorbent regenerator and natural gas contactor.

Acid gas means hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) contaminants that are separated from sour natural gas by an acid gas removal unit.

Acid gas removal unit (AGR) means a process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators.

Acid gas removal vent emissions mean the acid gas separated from the acid gas absorbing medium (e.g., an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

Air injected flare means a flare in which air is blown into the base of a flare stack to induce complete combustion of gas.

Basin means geologic provinces as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG-CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991) (incorporated by reference, see §98.7) and the Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in Cooperation with the USGS, 1978 (incorporated by reference, see §98.7).

Blowdown vent stack emissions mean natural gas and/or CO_2 released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing.

Calibrated bag means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to an emitting source such that the emissions inflate the bag to its calibrated volume.

Centrifugal compressor means any equipment that increases the pressure of a process natural gas or CO_2 by centrifugal action, employing rotating movement of the driven shaft.

Centrifugal compressor dry seals mean a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas or CO_2 from escaping to the atmosphere.

Centrifugal compressor dry seal emissions mean natural gas or CO_2 released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

Centrifugal compressor wet seal degassing vent emissions means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas or CO_2. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

Component means each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

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

Compressor means any machine for raising the pressure of a natural gas or CO_2 by drawing in low pressure natural gas or CO_2 and discharging significantly higher pressure natural gas or CO_2.

Condensate means hydrocarbon and other liquid, including both water and hydrocarbon liquids, separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions.

Dehydrator means a device in which a liquid absorbent (including desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

Dehydrator vent emissions means natural gas and CO_2 released from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator to the atmosphere or a flare, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

De-methanizer means the natural gas processing unit that separates methane rich residue gas from the heavier hydrocarbons (e.g., ethane, propane, butane, pentane-plus) in feed natural gas stream.

Desiccant means a material used in solid-bed dehydrators to remove water from raw natural gas by adsorption or absorption. Desiccants include activated alumina, pelletized calcium chloride, lithium chloride and granular silica gel material. Wet natural gas is passed through a bed of the granular or pelletized solid adsorbent or absorbent in these dehydrators. As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed on the surface or absorbed and dissolves the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto or absorbed into the desiccant material, leaving the dry gas to exit the contactor.

Engineering estimation means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

Enhanced oil recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this subpart, EOR applies to injection of critical phase or immiscible carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

Equipment leak means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Equipment leak detection means the process of identifying emissions from equipment, components, and other point sources.

External combustion means fired combustion in which the flame and products of combustion are separated from contact with the process fluid to which the energy is delivered. Process fluids may be air, hot water, or hydrocarbons. External combustion equipment may include fired heaters, industrial boilers, and commercial and domestic combustion units.

Natural gas distribution facility means the collection of all distribution pipelines, metering stations, and regulating stations that are operated by a Local Distribution Company (LDC) that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

Onshore petroleum and natural gas production facility means all petroleum or natural gas equipment on a well pad or associated with a well pad and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in §98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

Farm Taps are pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers. The gas may or may not be metered, but always does not pass through a city gate station. In some cases a nearby LDC may handle the billing of the gas to the customer(s).

Field means oil and gas fields identified in the United States as defined by the Energy Information Administration Oil and Gas Field Code Master List 2008, DOE/EIA 0370(08) (incorporated by reference, see §98.7).

Flare stack emissions means CO_2 and N_2O from partial combustion of hydrocarbon gas sent to a flare plus CH_4 emissions resulting from the incomplete combustion of hydrocarbon gas in flares.

Flare combustion efficiency means the fraction of hydrocarbon gas, on a volume or mole basis, that is combusted at the flare burner tip.

Gas conditions mean the actual temperature, volume, and pressure of a gas sample.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Gas well means a well completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil.

High-bleed pneumatic devices are automated, continuous bleed flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate in excess of 6 standard cubic feet per hour.

Intermittent bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. These are snap-acting or throttling devices that discharge the full volume of the actuator intermittently when control action is necessary, but does not bleed continuously.

Internal combustion means the combustion of a fuel that occurs with an oxidizer (usually air) in a combustion chamber. In an internal combustion engine the expansion of the high-temperature and –pressure gases produced by combustion applies direct force to a component of the engine, such as pistons, turbine blades, or a nozzle. This force moves the component over a distance, generating useful mechanical energy. Internal combustion equipment may include gasoline and diesel industrial engines, natural gas-fired reciprocating engines, and gas turbines.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

LNG boil-off gas means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

Low-bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate equal to or less than six standard cubic feet per hour.

Natural gas driven pneumatic pump means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

Offshore means seaward of the terrestrial borders of the United States, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of the United States under the Outer Continental Shelf Lands Act.

Oil well means a well completed for the production of crude oil from at least one oil zone or reservoir.

Onshore petroleum and natural gas production owner or operator means the person or entity who holds the permit to operate petroleum and natural gas wells on the drilling permit or an operating permit where no drilling permit is issued**,** which operates an onshore petroleum and/or natural gas production facility (as described in §98.230(a)(2). Where petroleum and natural gas wells operate without a drilling or operating permit, the person or entity that pays the State or Federal business income taxes is considered the owner or operator.

Operating pressure means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

Pump means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

Pump seals means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

Pump seal emissions means hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

Reciprocating compressor means a piece of equipment that increases the pressure of a process natural gas or CO_2 by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas or CO_2 that escapes to the atmosphere.

Re-condenser means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases.

Residue Gas and Residue Gas Compression mean, respectively, production lease natural gas from which gas liquid products and, in some cases, non-hydrocarbon components have been extracted such that it meets the specifications set by a pipeline transmission company, and/or a distribution company; and the compressors operated by the processing facility, whether inside the processing facility boundary fence or outside the fence-line, that deliver the residue gas from the processing facility to a transmission pipeline.

Sales oil means produced crude oil or condensate measured at the production lease automatic custody transfer (LACT) meter or custody transfer tank gauge.

Separator means a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.

Sour natural gas means natural gas that contains significant concentrations of hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

Sweet Gas is natural gas with low concentrations of hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) that does not require (or has already had) acid gas treatment to meet pipeline corrosion-prevention specifications for transmission and distribution.

Transmission pipeline means high pressure cross country pipeline transporting saleable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

Turbine meter means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

United States means the 50 States, the District of Columbia, the Commonwealth of Puerto Rico, American Samoa, the Virgin Islands, Guam, and any other Commonwealth, territory or possession of the United States, as well as the territorial sea as defined by Presidential Proclamation No. 5928.

Vapor recovery system means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel.

Vaporization unit means a process unit that performs controlled heat input to vaporize LNG to supply transmission and distribution pipelines or consumers with natural gas.

Vented emissions means intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

Well completions means the process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment, steps that do not significantly vent natural gas to the atmosphere. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to fracture or re-fracture and prop open new fractures in existing lower permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

Well workover means the process(es) of performing one or more of a variety of remedial operations on producing petroleum and natural gas wells to try to increase production. This process also includes high-rate flowback of injected gas, water, oil, and proppant used to re-fracture and prop-open new fractures in existing low permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. Wellhead equipment includes all equipment, permanent and portable, located on the improved land area (i.e. well pad) surrounding one or multiple wellheads.

Wet natural gas means natural gas in which water vapor exceeds the concentration specified for commercially saleable natural gas delivered from transmission and distribution pipelines. This input stream to a natural gas dehydrator is referred to as "wet gas."

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