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METHODS FOR ESTIMATING METHANE EMISSIONS FROM NATURAL GAS AND OIL SYSTEMS

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INTRODUCTION

The EIIP guidelines are designed to describe emission estimation techniques for greenhouse gas sources in a clear and unambiguous manner and to facilitate preparation of inventories at the state level. This chapter presents the methodology for estimating methane emissions from natural gas and oil systems. The methodology presented in this chapter has been revised to reflect new activity data, emission factors, and methods pertaining to this source category. Where possible, the methodology has been updated to be consistent with the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2002*.

Section 2 of this chapter contains a general description of this source category. Section 3 provides a listing of the steps involved in estimating methane emissions from natural gas and oil systems. Section 4 presents the preferred estimation method. Section 5 provides an alternative estimation method for estimating emissions from natural gas systems. A summary of uncertainty for this source category is provided in Section 6. References used in developing this chapter are identified in Section 7.

In addition to these guidelines, there are a series of user friendly spreadsheet tools available to assist in the development of emission inventories at the state level. Please consult the Natural Gas and Oil Activities Systems of the State Inventory Tool[1] to calculate emissions from this source category using the preferred emission estimation method.

[1] Note: The spreadsheet tool may have a different order of calculations, and may not show all calculations to the user.

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SOURCE CATEGORY DESCRIPTION

2.1 EMISSION SOURCES

Together, oil and natural gas systems are the second largest source of methane (CH_4) in the United States, comprising 24.2 percent of CH_4 emissions and 2.1 percent of total greenhouse gas emissions in 2002 (U.S. EPA 2004). Natural gas systems alone are the second largest source of CH_4 in the United States, with emissions five times greater than CH_4 emissions from oil systems.

This source category contains many distinct subcategories. It is important to account for emissions from oil and natural gas systems separately because the methods are fuel specific. For purposes of this chapter, the terms "natural gas" or "gas" are used to refer to both natural gas extracted from the ground and to "synthetic" or "substitute" natural gas (comprised mostly of CH_4), which is produced from other petroleum-based products or sources. Depending on its origin and processing, commercially distributed natural gas also will include various amounts of non-methane hydrocarbons (e.g., ethane, butane, propane, and pentane), carbon monoxide, carbon dioxide, and nitrogen. In this chapter, "oil" is used to refer to oil extracted directly from the ground as well as oil produced by various synthetic processes, such as recovery of oil from oil shale or tar sands.

CH_4 is emitted during oil and gas production, storage, transportation, and distribution. Fugitive sources of emissions within oil and gas systems include: releases during normal operations, such as emissions associated with venting and flaring during oil and gas production; chronic leaks or discharges from process vents; emissions during routine maintenance, such as pipeline repair; and emissions during system upsets and accidents.

Oil and Natural Gas System Overview

(1) **Oil and Gas Production**: Oil and gas are withdrawn from underground formations using onshore and offshore wells. While most gas production is from gas wells, gas is frequently found in association with oil. The associated gas is withdrawn simultaneously from the same geologic formation and then separated. Gathering lines are used to bring the crude oil and raw gas to a collection point or points within a production field. Because CH_4 is the major component of natural gas, leaks or venting from the gathering systems result in CH_4 emissions.

(2) **Crude Oil Transportation and Refining**: The oil sector's largest single source of CH_4 emissions is venting from crude oil storage facilities, which hold the oil before it is piped or trucked to refineries. The CH_4 in solution vaporizes, and it is vented from the storage tanks directly to the atmosphere, unless vapor recovery units capture the CH_4. Some emissions also occur as crude oil is transferred to tankers and pipelines for shipment to refineries. CH_4

emissions from crude oil streams are strongly dependent on the original CH_4 content of the crude oil and on the oil's preparation for transport.

Refineries process crude oil into a variety of hydrocarbon products such as gasoline and kerosene. Refineries account for only about two percent of the CH_4 emissions from the oil sector. Refinery outputs, referred to as "refined products," generally contain negligible amounts of CH_4. Consequently, CH_4 emissions are not estimated for transporting and distributing refined products.

(3) **Natural Gas Processing, Transportation, and Distribution**: Natural gas is processed to remove water, to recover heavier hydrocarbons (such as ethane, propane, and butane), and to prepare the dried gas for transportation to consumers. Most gas is transported through transmission and distribution pipelines. A small amount of gas is shipped by tanker as liquefied natural gas, or LNG.

The main processing, transportation, and distribution activities are the following:

- <u>Gas processing plants</u>: Natural gas is usually processed in gas plants to remove and process the natural gas liquids and to prepare the natural gas for pipeline transportation. During processing, natural gas is dried, and a variety of processes may be used to remove most of the heavier hydrocarbons, or condensate, from the gas. Processed gas is then injected into the natural gas transmission system, and the heavier hydrocarbons are marketed separately. Major CH_4 emission sources in the gas processing are compressor fugitives, compressor exhaust, vents, pneumatic devices, and blowdown.

- <u>Transmission pipelines</u>: Transmission pipelines are large diameter, high-pressure lines that transport gas from production fields, processing plants, storage facilities, and other sources of supply over long distances to local distribution companies or to large volume customers. A variety of facilities support the overall system, including metering stations, maintenance facilities, and compressor stations located along pipeline routes. Compressor stations, which maintain the pressure in the pipeline, generally include upstream scrubbers, where the incoming gas is cleaned of particles and liquids before entering the compressors. Reciprocating engines and turbines are used to drive the compressors. Compressor stations normally use pipeline gas to fuel the compressor. They also use the gas to fuel electric power generators to meet the compressor stations' electricity requirements. Major CH_4 emission sources are chronic leaks, compressor fugitives, compressor exhaust, vents, and pneumatic devices.

- <u>Local distribution companies</u>: Distribution pipelines are extensive networks of generally small diameter, low-pressure pipelines. Gas enters distribution networks from transmission systems at city gate stations, where the pressure is reduced for distribution within cities or towns. Major CH_4 emission sources are chronic leaks, meters, regulators, and mishaps.

3

OVERVIEW OF AVAILABLE METHODS FOR ESTIMATING EMISSIONS

Section 4 presents two preferred methods for estimating methane (CH_4) emissions, one for natural gas systems and the other for oil systems.

Section 5 presents an alternative method for estimating CH_4 emissions from natural gas systems. This method is less complex than the preferred method, and it uses data that are more readily available. It is also less accurate than the preferred method. Note that there is no alternative method for oil systems.

The data required for the preferred method for natural gas systems include: (1) the number of wells and offshore platforms, (2) the number of miles of gathering pipeline, (3) the number of gas processing plants, (4) the number of miles of transmission pipeline, and (5) the total number of services (e.g., gas meters). The data required for the alternative method for natural gas systems are state-level data on gas production and gas consumption.

The preferred method for natural gas systems is based on a set of activity levels for the activities from which CH_4 is emitted and on a set of emission factors presented in a study by the Gas Research Institute and the U.S. Environmental Protection Agency (GRI 1996). The study was based on a large survey of emissions from the natural gas industry.

The GRI study developed emission factors for activities in four segments of the natural gas industry: production, processing, transmission (including storage), and distribution. Within each segment, industry facilities and operations were analyzed to identify fugitive emissions, leaks, and vented emissions. The study identified approximately 100 components of natural gas systems that are CH_4 emission sources. For each component, the study developed an emission factor. To estimate emissions, the emission factors were multiplied by the activity level for each component (e.g., amount of gas produced, numbers of wells, miles of pipe of a given type and operating regime, or hours of operation of a given type of compressor).

The U.S. EPA uses the finely grained GRI data on emission factors and activity levels to develop the annual *U.S. Inventory of Greenhouse Gas Emissions and Sinks*. This approach is also the “Tier 3” approach developed by the Intergovernmental Panel on Climate Change (IPCC) (IPCC/UNEP/OECD/IEA 1997). However, for purposes of state-level estimation of methane emissions from natural gas systems, U.S. EPA has developed simplified emission factors. The simplified approach aggregates the emissions throughout the natural gas systems, and it associates the aggregated emissions with a natural gas system activity factor. In other words, for each activity, the methodology provides an emission factor that represents emissions both from the specified activity and from several associated activities. The emission factors were last updated in 2004, in order to incorporate new data. Section 4 details the simplified approach, which requires the collection of only a few, key activity data. The simplified approach estimates emissions using data on the natural gas system infrastructure, rather than natural gas production data.[2] However, the emission factors for the natural gas system infrastructure components also account for the emissions from production.

The simplified approach is relatively accurate. When used to estimate total United States emissions from the natural gas industry, it matches the estimate generated using the full GRI database. However, the simplified approach is less accurate when used to estimate emissions on a state level. For example, the simplified approach would overestimate the emissions of a state that transmits large amounts of gas but does not produce much gas, because the simplified method would allocate to the state some emissions from other states' gas production.

U.S. EPA and the American Petroleum Institute are developing similar CH_4 emission factors and activity levels for the oil industry, although they have not been finalized at this writing (U.S. EPA 1999). Thus, the preferred method for estimating CH_4 emissions from oil systems continues to be the "Tier 1" approach developed by the IPCC (IPCC/UNEP/OECD/IEA 1997). The approach is simpler than the preferred method for natural gas systems, and it is also less accurate. This method involves three relatively simple steps: (1) obtain the required state-level data on oil production, refining, and transportation; (2) multiply activity levels by the appropriate emission factors; and (3) sum across activity types to calculate total emissions. While it is relatively easy to obtain the necessary activity data, note that the basis for developing the emission factors used in this method is weak. Because oil systems are comprised of a complex set of facilities, simple relationships between emissions and components of the systems are not easily defined. In addition, no single set of emission factors can apply to all conditions. Consequently, more detailed assessments would be required to more accurately reflect the diverse nature of the industry throughout the United States.

The oil system emission factors presented here are implied emission factors derived from *Inventory of U.S. Greenhouse Gas Emission and Sinks: 1990-2002* (U.S. EPA 2004). Seventy activities that emit CH_4 from petroleum systems were examined for this report. Annual emissions from each of the 70 petroleum system activities analyzed were estimated by multiplying the activity data for each year by the corresponding emission factor. These annual emissions for each activity are then summed to estimate the total annual CH_4 emissions. Most of the activities analyzed involved crude oil production field operations, which accounted for 97 percent of the total oil industry emissions. Crude transportation and refining accounted for the remaining emissions, or about one and two percent respectively.

Using the available published oil system emissions estimates, the implied emission factors from each study were developed by dividing the emissions estimates from each of the major activity groups (production, refining and transportation) by appropriate measures of activity at the

[2] The purpose of this guidance is to present emission estimation techniques for greenhouse gas sources and sinks in a clear and unambiguous manner. To this end, the simplified method strikes a balance between rigor, data collection efforts, and applicability to specific states. However, we understand that data availability and emission factors may vary by state and we encourage states to tailor this method as needed.

national level. These implied emission factors are calculated for every year from 1990 through 2002. The emission factors can be considered to be no better than “order of magnitude” estimates. Actual emissions depend on site-specific characteristics including facility design, operation, and maintenance.

As noted above, the alternative method for natural gas systems is analogous to the preferred method for oil systems.

4

PREFERRED METHODS FOR ESTIMATING EMISSIONS

This section presents two preferred methods, one for natural gas systems and one for oil systems.

The Natural Gas and Oil Systems Module of the State Inventory Tool (hereafter referred to as the State Inventory Tool) provides all of the emission factors and formulas described in this section. In the tool, the activity data for each year needs to be provided by the state. The required activity data, and recommended sources from which to obtain them, are provided in this section.

4.1 PREFERRED METHOD FOR ESTIMATING EMISSIONS FROM NATURAL GAS SYSTEMS

To estimate methane (CH_4) emissions from natural gas systems, follow the following three steps: (1) obtain required data; (2) calculate CH_4 emissions; and (3) convert units to metric tons of carbon equivalent (MTCE).

Step (1): Obtain Required Data

- *Required Data*: The following data are required to estimate CH_4 emission from natural gas production, processing, transmission, and distribution.

  For estimating production emissions: The data required are (1) number of wells, including both non-associated wells and associated wells;[3] (2) the number of offshore platforms in the Gulf of Mexico (if applicable); and (3) the number of offshore platforms in water bodies other than the Gulf of Mexico (if applicable).

  The characteristics of wells differ throughout the United States, so the emission factors also vary by region.

  For estimating gas processing emissions: The data required are the number of gas processing plants.[4]

  For estimating gas transmission emissions: The data required are (1) the number of miles of transmission pipeline; (2) the number of transmission compressor stations and storage compressor stations (or use a default based on pipeline length as discussed below); (3) the

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[3] Non-associated wells produce only gas, while associated wells produce both gas and oil.

[4] In the State Inventory Tool, the emissions from gas processing plants are estimated under the Gas Transmission sector on the worksheet "Natural Gas – Transmission."

number of liquefied natural gas (LNG) storage stations; and (4) the number of miles of gathering pipeline.

For estimating gas distribution emissions: The data required are (1) the number of miles of cast iron main pipeline; (2) the number of miles of unprotected steel main pipeline; (3) the number of miles of protected steel main pipeline; (4) the number of miles of plastic main pipeline; (5) the total number of services (i.e., the number of customer connections); (6) the number of unprotected steel services; and (7) the number of protected steel services.[5]

- *Data Sources*: Most of the activity level data required to estimate emissions are available in the publications described below. Bibliographic information can be found in both the State Inventory Tool and in Section 6.

Data on the number of wells by state can be found in the *Natural Gas Annual* published by the Energy Information Administration (EIA) (e.g., *Natural Gas Annual 2000*), the *Basic Petroleum Data Book* published by American Petroleum Institute (API), *Gas Facts* published by the American Gas Association (AGA), or *The Oil & Gas Producing Industry in Your State* published by the Independent Petroleum Association of America (IPAA). Number of offshore platforms is reported by the Minerals Management Service (MMS). *Gas Facts* and the Department of Transportation's Office of Pipeline Safety (OPS) provide data on the number of miles of gathering pipeline.

Each June, the *Oil and Gas Journal* provides data on the number of gas processing plants by state.

Data on the number of miles of transmission pipeline by state are reported in *Gas Facts* and by OPS. Data on the number of gas transmission compressor stations and gas storage compressor stations may be available from state sources. If these data are not available, the number of gas transmission and storage compressor stations may be estimated by multiplying the state's mileage of transmission pipeline by 0.0060 (for transmission compressor stations) and 0.0015 (for storage compressor stations). The number of LNG storage stations may be available from state sources or from EIA.

Both *Gas Facts* and OPS report mileage of distribution pipeline by type. The OPS data are more exhaustive than *Gas Facts*, but it is collected on a utility, rather than a state level. If a state has detailed data on mileage of each of the four types of pipeline shown in Table 5.4-1, those data may be used with emission factors in the table for each type of pipeline. The mileage of each type of pipeline may also be estimated based on the ratios shown in the footnotes to Table 5.4-1. Alternatively, Table 5.4-1 provides a single emission factor applicable to all distribution pipelines.

Gas Facts provides data on number of gas-utility industry end-users by state. OPS also reports data on the number of services, or end-users, and on the breakdown between

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[5] As a default, the total number of services may be used to estimate protected and unprotected steel services, as discussed below.

protected steel services and unprotected steel services. Alternatively, the data may be available from local gas distribution companies. If state-level data are not available for the number of protected and unprotected steel services, a state may estimate these numbers by multiplying the total number of services by 0.2841 for protected steel services and by 0.0879 for unprotected steel services. (The remaining services are made of plastic or copper.)

- *Units for Activity Data*: The units for activity data are either the number of a given type of unit (e.g., the number of wells) or the number of miles of a given type of pipeline.

Step (2): Calculate Methane Emissions

The method for calculating CH_4 emissions is demonstrated in the example below, as well as in the State Inventory Tool. Each emission factor accounts for emissions from several activities. For example, in calculating the production emissions for an Appalachian state, N (the number of wells) has an emission factor of 2.78 metric tons of CH_4 per well. This factor represents emissions not just from wells but also from pneumatic devices, dehydrator vents,[6] Kimray pumps, gas engines, and well clean-ups. The product (N*2.78) is an approximation of the emissions from all of these sources. The sum of all calculations in a sector, such as “Production Emissions,” will give a subtotal of CH_4 emissions from the natural gas industry attributable to the sector.

Example: This example shows calculations for CH_4 emissions from natural gas systems in Virginia for 2000. These steps calculate emissions from the Gas Transmission sector; the same steps should be applied for the activity data and emission factors in the other sectors.

Virginia has 20 gas transmission compressor stations, 20 gas storage compressor stations, 2,084 miles of transmission pipeline, and 3 LNG storage stationstorage compressor stations. CH_4 emissions from gas transmission are calculated as follows, using the default emission factors from Table 5.4-1:

(20 gas transmission compressor stations x 984 metric tons CH_4/station) + (20 gas storage compressor stations x 964 metric tons CH_4 /station) + (2,084 miles of transmission pipeline x 0.62 metric tons CH_4/mile of pipeline) + (3 LNG storage stations x 1,185 metric tons CH_4/station) = 43,807 **metric tons CH_4**

These results should be summed across all natural gas industry sectors to provide total CH_4 emissions for Virginia.

Step (3): Convert Units to Metric Tons of Carbon Equivalent (MTCE)

In order to convert from metric tons of CH_4 to MTCE, multiply by 21, the global warming potential (GWP) of CH_4, and then by 12/44, the ratio of the atomic weight of carbon to the molecular weight of CO_2.

CH_4 Emitted (MTCE) = CH_4 Emitted (metric tons) x 21 x 12/44

[6] Although glycol dehydrators may represent the single most important venting-related release, in the interest of keeping the method simple, emissions from glycol dehydrators are “rolled up” in the regional emission factors.

Table 5.4-1: Methane Emission Factors for the Natural Gas Industry

A. Required Activity Data	B. Emission Factor (metric tons CH_4 per unit N from column A)
SECTOR: PRODUCTION EMISSIONS	
Appalachian States (West Virginia, Pennsylvania, Kentucky, New York, Maryland, & Virginia)	
N, total number of wells	2.78
East North Central States (Illinois, Indiana, Michigan, Ohio, and Wisconsin)	
N, total number of wells	2.78
Rest of the U.S.	
N, total number of wells	3.71
N_{pg}, number of off-shore platforms in the Gulf of Mexico	108.3
N_p, number of off-shore platforms not including those in the Gulf of Mexico	13.2
All States	
L_{gp}, miles of gathering pipeline	0.40
SECTOR: GAS PROCESSING EMISSIONS (ALL STATES)	
P, number of gas processing plants	1,250
SECTOR: GAS TRANSMISSION EMISSIONS (ALL STATES)	
S_T, number of gas transmission compressor stations[1]	984
S_S, number of gas storage compressor stations[2]	964
L, miles of transmission pipeline	0.62
S_{LNG}, number of LNG storage stations	1,185
SECTOR: GAS DISTRIBUTION EMISSIONS (ALL STATES)	
SUB-SECTOR: DISTRIBUTION PIPELINE EMISSIONS	
M_{CI}, miles of cast iron distribution pipeline[3]	5.80
M_{US}, miles of unprotected steel distribution pipeline[4]	2.12
M_{PS}, miles of protected steel distribution pipeline[5]	0.06
M_{Pl}, miles of plastic distribution pipeline[6]	0.37
Alternative approach—Default for M: miles of distribution pipeline	0.54
SUB-SECTOR: DISTRIBUTION SERVICES EMISSIONS	
H, total number of services	0.015
H_{US}, number of unprotected steel services[7]	0.033
H_{PS}, number of protected steel services[8]	0.003

[1] In the absence of more accurate data, S_T may be estimated by the following: L*0.0060, where L is the length of transmission pipeline in miles.

[2] In the absence of more accurate data, S_S may be estimated by the following: L*0.0015, where L is the length of transmission pipeline in miles.

[3] In the absence of more accurate data, M_{CI} may be estimated by the following: 0.0392*M, where M is the length of distribution pipeline in miles.

[4] In the absence of more accurate data, M_{US} may be estimated by the following: 0.0571*M, where M is the length of distribution pipeline in miles.

[5] In the absence of more accurate data, M_{PS} may be estimated by the following: 0.4627*M, where M is the length of distribution pipeline in miles.

[6] In the absence of more accurate data, M_{Pl} may be estimated by the following: 0.4406*M, where M is the length of distribution pipeline in miles.

[7] In the absence of more accurate data, H_{US} may be estimated by the following: H*0.0879, where H is the total number of services.

[8] In the absence of more accurate data, H_{PS} may be estimate by the following: H*0.2841, where H is the total number of services.

4.2 PREFERRED METHOD FOR ESTIMATING EMISSIONS FROM OIL SYSTEMS

This method estimates CH_4 emissions from oil systems, based on oil production, oil transport by tanker, and oil refining. The method and emission factors are included in the State Inventory Tool.

The sources of CH_4 emissions from oil systems can be categorized into emissions from: (1) normal operations, (2) routine maintenance, and (3) system upsets and accidents. In Table 5.4-2, the emission types are linked to the different stages in oil systems. The sources listed as “major” account for the majority of emissions from each segment; typically the majority of the emissions are from normal operations. Because data are limited and there is considerable diversity among oil systems throughout the United States, other potential sources are also listed, which may, in some cases, be important contributors to emissions.

Table 5.4-2: Emissions from Oil Systems

Segment	Major Emissions Sources	Other Potential Emission Sources
Oil Production Oil wells Gathering lines Treatment facilities	Venting Normal operations; fugitive emissions; deliberate releases from pneumatic devices and process vents.	Flaring, maintenance, system upsets and accidents.
Crude Oil Transportation and Refining Pipelines Tankers Storage tanks Refineries	Normal operations; fugitive emissions; deliberate releases from process vents at refineries, during loading and unloading of tankers and storage tanks.	Flaring, maintenance, system upsets and accidents.

Source: IPCC/UNEP/OECD/IEA 1997.

(1) **Normal Operations**: Normal operations are the day-to-day operations of a facility. Emissions from normal operations can be divided into two main source categories: (1) venting and flaring, and (2) discharges from process vents, chronic leaks, etc.

Venting and Flaring: Venting and flaring refer to the disposal of gas that cannot be contained or otherwise handled. Venting and flaring activities are associated with combined oil and gas production and take place in production areas where gas pipeline infrastructure is incomplete and the natural gas is not injected into reservoirs. Vented gas typically has a high CH_4 content. If the excess gas is burned in flares, the emissions of CH_4 will depend on efficiency of combustion. Generally, the combustion efficiency for flare sources is assumed to be between 95 and 100 percent.

Discharges from Process Vents, Chronic Leaks, etc.: Oil production and transportation facilities emit CH_4 due to a wide variety of operating practices and factors, including:

- Emissions from pneumatic devices, such as gas-operated controls such as valves and actuators. These emissions depend on the size, type, and age of the devices, the frequency of their operation, and the quality of their maintenance.

- Leaks from system components. These emissions are unintentional and typically consist of continuous releases associated with leaks from the failure of a seal or the development of a flaw, crack, or hole in a component designed to contain or convey oil. Connections, valves, flanges, instruments, and compressor shafts can develop leaks from cracks or from corrosion.

- Emissions from process vents, such as vents on glycol dehydrators and vents on crude oil tankers and storage tanks. Vapors, including CH_4, are emitted from the vents as part of the normal operation of the facilities.

- Emissions from starting and stopping reciprocating engines and turbines.

- Emissions during drilling activities, e.g., gas migration from reservoirs through wells.

(2) **Routine Maintenance**: Routine maintenance includes regular and periodic activities performed in the operation of the facility. These activities may be conducted frequently, such as launching and receiving scrapers (pigs) in a pipeline, or infrequently, such as evacuation of pipes ("blowdown") for periodic testing or repair. In each case, the required procedures release gas from the affected equipment. Releases also occur during maintenance of wells ("well workovers") and during replacement or maintenance of fittings.

(3) **System Upsets and Accidents**: System upsets are unplanned events in the system. The most common upset is a sudden pressure surge resulting from the failure of a pressure regulator. The potential for unplanned pressure surges is considered during facility design, and facilities are provided with pressure relief systems to protect the equipment from damage due to the increased pressure.

Relief systems vary in design. In some cases, gases released through relief valves may be collected and transported to a flare for combustion or re-compressed and reinjected into the system. In these cases, CH_4 emissions associated with pressure relief events will be small. In older facilities, relief systems may vent gases directly into the atmosphere or send gases to flare systems where complete combustion may not be achieved.

The frequency of system upsets varies with the facility design and the operating practices. In particular, facilities operating well below capacity are less likely to experience system upsets and related emissions. Emissions associated with accidents are also included in the category of upsets.

To estimate CH_4 emissions from oil systems, follow the following three steps: (1) obtain required data; (2) calculate CH_4 emissions; and (3) convert units to MTCE.

Step (1): Obtain Required Data

- *Required Data*. Required data include the amount of oil produced, refined, and transported in the state.

- *Data Sources*: The required data are available from the *Petroleum Supply Annual* published by the EIA.

  Oil Production: State-level oil production data can be obtained from Table 14, "Production of Crude Oil by PAD District and State."

  Oil Refined: State-level data on amount of crude refined is not available. The data are available at the Petroleum Administration for Defense District (PADD) level. Using this data along with available data on refining capacity by state, the amount of crude refined in a state can be estimated as follows:

$$\text{Crude Refined by State} = \text{Total Crude Refined by PADD} \times \frac{\text{State Operating Refining Capacity}}{\text{PADD Refining Capacity}}$$

  Total crude refined by PADD, listed as gross input (daily average) of Atmospheric Crude Oil Distillation, is available in Table 16, "Refinery Input of Crude Oil and Petroleum Products by PAD and Refining Districts." The daily average can be converted into an annual number by multiplying by 365 days/year.

  The State and PADD Operating Refining Capacities are available under the column labeled "Atmospheric Crude Oil Distillation Capacity" in Table 36, "Number and Capacity of Operable Petroleum Refineries by PAD District and State." The operating capacity, given in barrels (bbl) per calendar day, should be annualized.

  Oil Transported: In-state agencies should be consulted first. Oil transported by state is the sum of oil transported by all modes of transport, including pipelines, barges, tankers, and trucks. For oil transported on waterways, such as tankers and barges, the Army Corps of Engineers' Waterborne Commerce Statistics Center provides data.[7] Data on oil transported by pipeline is not readily available for all states. In the absence of pipeline transportation data, total oil transported by a state can be approximated by the total amount of crude oil refined in that state, based on the assumption that crude oil in transit is ultimately destined for refineries.

- *Units for Reporting Data*: Data should be provided in thousand barrels (1,000 bbl) of oil per year.

Step (2): Calculate Methane Emissions

To estimate CH_4 emissions from oil systems, multiply activity data by the appropriate emission factor, as presented in Table 5.4-3. Sum the three activity types in order to obtain total CH_4 emissions from oil systems. To obtain metric tons of CH_4, divide the calculated kg CH_4 by 1,000 kg/metric ton. An example is provided below.

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[7] Internet address: http://www.iwr.usace.army.mil/ndc/wcsc.htm

Example:	For each 1,000,000 bbl of oil produced in a state, estimated CH_4 emissions from oil production facilities would be the following:
	1,000,000 bbl x 511.14 kg CH_4/1,000 bbl = 511,140 kg CH_4
	511,140 kg CH_4 ÷ 1,000 kg/metric ton = 511.14 **metric tons CH_4**

Table 5.4-3: Methane Emission Factors for Oil Activities

A. Activity Data (1,000 bbl/yr)	B. Emission Factor* (kg CH_4/1000 bbl)
P, Oil Production	511.14
R, Oil Refined	4.95
T, Oil Transported	0.92

* These emission factors vary by year and are updated annually; shown here are the 2002 emission factors. Emission factors for other years are included in the State Inventory Tool (U.S. EPA 2004).

Step (3): Convert Units to Metric Tons of Carbon Equivalent

To convert from metric tons of CH_4 to MTCE, multiply by 21, the GWP of CH_4, and by 12/44, the ratio of the atomic weight of carbon to the molecular weight of CO_2.

CH_4 Emitted (MTCE) = CH_4 Emitted (metric tons) x 21 x 12/44

5

ALTERNATIVE METHOD FOR ESTIMATING EMISSIONS FROM NATURAL GAS SYSTEMS

This section provides an alternative methodology for estimating methane (CH_4) emissions from natural gas systems, based on gas production and consumption.

The sources of CH_4 emissions from natural gas systems can be categorized into emissions from (1) normal operations, (2) routine maintenance, and (3) system upsets and accidents as discussed for oil systems in Section 4.2.

To estimate CH_4 emissions from natural gas systems using the alternative method, follow these three steps: (1) obtain required data; (2) calculate CH_4 emissions; and (3) convert units to metric tons of carbon equivalent (MTCE).

Step (1): Obtain Activity Data

- *Required Data*. The alternative method is based on activity data (e.g., production), rather than gas infrastructure. Required data include the amount of natural gas produced and the amount consumed.

- *Data Sources*: In-state agencies should be consulted first. However, if it is difficult to obtain data from state sources, state-by-state data on natural gas systems may be found in *Natural Gas Annual* (*e.g.*, EIA 1997a) and *Gas Facts* (*e.g.*, AGA 2000).

- *Units for Reporting Data*: Data should be provided in units of million Btu (MMBtu). Since gas data are usually reported in thousand cubic feet (Mcf),[8] the conversion factors listed in Table 5.5-1 can be used to convert to MMBtu.

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[8] Occasionally the term Mscf, thousand *standard* cubic feet is reported. Also, the term decatherm (Dth or Dt) may be used. A therm is 100,000 Btus and is the unit most often used by distribution companies. One Dth is 10 therms, or one MMBtu (one million Btu).

Table 5.5-1: Conversion Factors to Million Btu (MMBtu)

Fuel Type	If Data are Reported in	Multiply by
Natural Gas	Mcf	1.000*

*The Btu content of gas varies between on average 950 and 1,050 Btus per cf. For convenience, 1,000 Btus can be used.

Step (2): Calculate Methane Emissions

To develop estimates of CH_4 emissions, multiply activity data by the appropriate emission factor, as presented in Table 5.5-2. Do this for each activity type presented in Table 5.5-2. Sum across the four sectors in order to obtain total CH_4 emissions from natural gas systems in lbs CH_4. Divide the number of lbs CH_4 obtained by 2,004.6 lbs/metric ton to obtain metric tons of CH_4 produced. Note that actual emissions depend on site-specific characteristics including facility design, operation, and maintenance, so the emission factors can be considered to be no better than "order of magnitude" estimates.

Table 5.5-2: Methane Emission Factors for Natural Gas Activities

Sector	Activity Data (MMBtu)	Emission Factor (lbs CH_4/MMBtu)
Gas Production	Total Gas Production	0.2101
Gas Processing	Total Gas Production	0.0807
Gas Transmission	Total Gas Consumed	0.1856
Gas Distribution	Total Gas Consumed	0.1373

Sources: U.S. EPA 2004; EIA 2003a, b; these values are derived as implied emission factors from U.S. Inventory data for year 2002.

The equations and examples are shown below:

lbs CH_4 = Activity Level (MMBtu) x Emission Factor (lbs CH_4/MMBtu)

Metric Tons CH_4 (for each activity) = lbs CH_4 (for each activity) ÷ 2,204.6 lbs/metric ton

Example: For each 1,000,000 million Btu (MMBtu) of natural gas consumed in a state, estimated CH_4 emissions from natural gas transmission would be the following:

1,000,000 MMBtu x 0.1856 lbs CH_4/MMBtu = 185,600 lbs CH_4

185,600 lbs CH_4 ÷ 2,204.6 lbs/metric ton = 842 **metric tons CH_4**

Step (3): Convert Units to Metric Tons of Carbon Equivalent

To convert from units of metric tons of CH_4 to MTCE, multiply CH_4 emitted in metric tons by 21, the GWP of CH_4, and by 12/44, the ratio of the atomic weight of carbon to the molecular weight of CO_2.

CH_4 Emitted (MTCE) = CH_4 Emitted (metric tons) x 21 x 12/44

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UNCERTAINTY SUMMARY

This section explains the sources of uncertainty in estimating methane (CH_4) emissions from natural gas and oil systems using the methods presented in the previous sections.

As noted in Section 3, uncertainty surrounds the preferred methods available for estimating emissions from the natural gas sector at the state level. The main sources of uncertainty in this approach relate to the emission factors, which are based on a combination of measurements, equipment design data, engineering calculations and studies, surveys of selected facilities, and statistical reporting. Statistical uncertainties arise from natural variation in measurements, equipment types, operational variability and survey and statistical methodologies. The main emission factor for this approach is determined by bundling together the factors of several individual components and sources. In the process of aggregation, the uncertainties of each individual component get pooled to generate a larger uncertainty for the simplified emission factor.

Additionally, this approach is relatively accurate at the national level but less accurate when used to estimate emissions on a state level. For example, this method would overestimate the emissions of a state that has a large number of wells but a lower than average production rate since the emission factor is based on number of wells with a national average production rate.

The preferred method of estimating emissions from petroleum systems and the alternate method of estimating emissions from natural gas systems use implied emissions factors derived from the national GHG Inventory. The two main sources of uncertainty in these methods are the uncertainties associated with estimates of national emissions and regional differences in industry infrastructure and activity levels. National emissions are estimated using a bottom-up approach that accounts for emissions from individual sources, each of which has uncertainty associated with its emissions and activity factor. These uncertainties are aggregated in the overall emissions estimate and passed on to the implied emission factors derived from it.

Additionally, the implied emission factor represents the average for the entire country. However, the natural gas and petroleum production and infrastructure in a state may be different from the national average thus giving rise to uncertainty due to regional differences. For example, the national inventory takes into account emissions from off-shore platforms, but an individual state may not have any offshore platforms, thus its emissions may be overestimated.

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