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GRI-94 / 0257.23
EPA - 600/R-96-080f
June 1996

Research and Development

METHANE EMISSIONS FROM THE
NATURAL GAS INDUSTRY
Volume 6: Vented and Combustion Source Summary

Prepared for

Energy Information Administration (U. S. DOE)

Prepared by

National Risk Management
Research Laboratory
Research Triangle Park, NC 27711

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GRI-94/0257.23

EPA-600/R-96-080f
June 1996

METHANE EMISSIONS FROM THE NATURAL GAS INDUSTRY, VOLUME 6: VENTED AND COMBUSTION SOURCE SUMMARY

FINAL REPORT

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RESEARCH SUMMARY

Title	Methane Emissions From Vented and Combusted Sources Final Report
Contractor	Radian International LLC GRI Contract Number 5091-251-2171 EPA Contract Number 68-D1-0031
Principal Investigators	Theresa M. Shires Matthew R. Harrison
Report Period	March 1991 - June 1996 Final Report
Objective	This report summarizes methane emissions from vented and combusted sources. Significant sources of vented and combusted emissions are discussed, as well as miscellaneous minor sources of emissions. In addition, documentation for the methane compositions used for each industry segment is provided. This report also discusses inconsistencies in reported vented and flared emissions reported by other sources.
Technical Perspective	The increased use of natural gas has been suggested as a strategy for reducing the potential for global warming. During combustion, natural gas generates less carbon dioxide (CO_2) per unit of energy produced than either coal or oil. On the basis of the amount of CO_2 emitted, the potential for global warming could be reduced by substituting natural gas for coal or oil. However, since natural gas is primarily methane, a potent greenhouse gas, losses of natural gas during production, processing, transmission, and distribution could reduce the inherent advantage of its lower CO_2 emissions. To investigate this, Gas Research Institute (GRI) and the U.S. Environmental Protection Agency's Office of Research and Development (EPA/ORD) cofunded a major study to quantify methane emissions from U.S. natural gas operations for the 1992 base year. The results of this study can be used to construct global methane budgets and to determine the relative impact on global warming of natural gas versus coal and oil.
Results	Vented emissions account for approximately 94 Bscf of methane emissions annually. Compressor exhaust is the primary source of

combustion emissions, contributing approximately 25 Bscf of methane emissions annually.

Based on data from the entire program, methane emissions from natural gas operations are estimated to be 314 ± 105 Bscf for the 1992 base year. This is about 1.4 ± 0.5% of gross natural gas production. The overall program also showed that the percentage of methane emitted for an incremental increase in natural gas sales would be significantly lower than the baseline case.

The project reached its accuracy goal and provides an accurate estimate of methane emissions that can be used to conduct methane inventories and analyze fuel switching strategies.

Technical Approach

Vented emissions primarily result from three categories: 1) pneumatic devices, 2) blow and purge emissions, and 3) dehydrator emissions. Combusted emissions result from the incomplete combustion of methane in burners, flares, and engines.

Vented and combusted emissions are typically considered unsteady emission sources, that is, sources with highly variable emissions. These emission sources vary from company to company and site to site, because of different maintenance practices and operating conditions. Therefore, it is impractical to measure every source continuously for a year. Each unsteady emission source requires a unique set of equations and gathered data based on the equipment type, various components, and operating modes to produce an emissions factor. Data on unsteady emissions were gathered at multiple sites in each segment of the industry: production, gas processing, transmission, storage, and distribution.

This report summarizes methane emissions from significant, as well as minor miscellaneous sources of vented and combusted emissions. In addition, this report serves to document the data sources used to determine methane compositions for the various industry segments. Finally, a discussion of inconsistencies in reported vented and flared emissions is provided to support the decision for using a bottom-up approach in this project to more accurately account for emissions from these sources.

Project Implications

For the 1992 base year the annual methane emissions estimate for the U.S. natural gas industry is 314 Bscf ± 105 Bscf (± 33%). This is equivalent to 1.4% ± 0.5% of gross natural gas production. Results from this program were used to compare greenhouse gas emissions from the fuel cycle for natural gas, oil, and coal using the global warming potentials (GWPs) recently published by the Intergovernmental Panel on Climate Change (IPCC). The analysis showed that natural gas contributes less to potential global warming than coal or oil, which supports the fuel switching strategy suggested by IPCC and others.

In addition, results from this study are being used by the natural gas industry to reduce operating costs while reducing emissions. Some companies are also participating in the Natural Gas-Star program, a voluntary program sponsored by EPA's Office of Air and Radiation in cooperation with the American Gas Association to implement cost-effective emission reductions and to report reductions to the EPA. Since this program was begun after the 1992 baseline year, any reductions in methane emissions from this program are not reflected in this study's total emissions.

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1.0 SUMMARY

This report is one of several volumes that provides background information supporting the Gas Research Institute and U.S. Environmental Protection Agency, Office of Research and Development (GRI-EPA/ORD) methane emissions project. The objective of this comprehensive program is to quantify the methane emissions from the gas industry for the 1992 base year to within ± 0.5% of natural gas production starting at the wellhead and ending immediately downstream of the customer's meter.

This report summarizes methane emissions from vented and combustion sources. Vented emissions primarily result from three categories: 1) pneumatic devices, 2) blow and purge emissions, and 3) dehydrator emissions, which combined account for approximately 94 Bscf of methane emissions annually. Combustion emissions result from the incomplete combustion of methane in burners, flares, and engines. Compressor engine exhaust is the only significant source of methane in this category, accounting for approximately 25 Bscf of methane emissions annually.

2.0 INTRODUCTION

For this project, sources of methane emissions from the natural gas industry were classified as follows:

- **Vented** - Vented emissions are intentional releases from equipment blowdown for maintenance, releases from emergency depressuring (from safety valves and station emergency blowdown), direct venting of gas used to power equipment (such as pneumatic devices), or accidental releases due to mishaps (such as pipeline dig-ins).
- **Combustion** - Combustion emissions refer to methane that enters the atmosphere due to the incomplete combustion of natural gas. Examples are methane in compressor engine exhaust and methane from flare stacks and burners.
- **Fugitive** - Fugitive emissions are unintentional leaks from sealed surfaces (such as valve stem packing, flange gaskets, compressor shaft seals, and pipelines).

This report summarizes emissions from vented and combustion sources. Vented and combustion emissions are typically considered "unsteady." Unsteady emitters are defined as sources with highly variable emissions, such as a pneumatic device on an isolation valve or a maintenance activity that requires blowdown. These emission sources vary from company to company and site to site, because of different maintenance practices and operating conditions.

In contrast, emission sources with continuous bleed rates, or with reasonably steady bleed rates over a typical measurement time, are considered "steady" sources. Fugitive emissions are generally considered steady. Extensive measurements of fugitive emissions have been made in this and other studies in all segments of the gas industry.[1,2,3]

Section 3 of this report discusses data collection techniques used to estimate unsteady emissions. Results from vented and combustion sources considered significant are presented in Section 4. Details on emission estimates for compressors, pneumatic devices, dehydrators, chemical injection pumps, mishaps, etc. are available in other volumes.[4,5,6,7,8,9] Section 5 discusses miscellaneous minor emission sources. Documentation supporting the methane compositions used for each industry segment is provided in Appendix A. This report also discussed inconsistency in vented and flared emissions in Appendix B.

3.0 DATA COLLECTION

This GRI/EPA study calculated emission factors for unsteady emission sources, rather than measuring them. Each unsteady source requires a unique set of equations and gathered data based on the equipment type, various components, and operating modes to produce the emission factor quantity. However, all sources require the following general information:

1) A detailed technical description of the source, identifying the important emission-affecting parameters (i.e., equipment components and operating modes). This was generally accomplished through a source characterization report.

2) Data to estimate the volume of natural gas released and the frequency of releases from multiple site visits or existing reports.

3) Data on gas composition (percent methane) in various industry segments (production, gas processing, transmission, and distribution). Details on the methane composition results are provided in Appendix A.

Step 1 was accomplished by researching each particular source and gathering manufacturer, operator, and site data so that a full technical description of the important emission characteristics of the source category could be written. Using this description, data on the emission-affecting characteristics of each source were gathered through site visits or existing resources.

For many emission sources, the frequency of release events was measured (such as strokes/minute for pneumatic actuators); but for extremely infrequent releases (such as equipment maintenance blowdowns), the frequency was estimated by gas industry field personnel. The emission volume per event was not measured for most sources (as in the case of compressor exhaust methane) but was often calculated using gathered site data, existing reports, and first principles.

During this study, data on unsteady emissions were gathered at multiple sites in each segment of the industry: production, gas processing, transmission, storage, and distribution. Details on the industry segments and boundaries are provided in Volume 5 on the activity factors.[10] The site visits and literature searches allowed construction of a matrix that shows all the emission sources within the gas industry grouped by process segment and operation mode. Table 3-1 shows this grouping. The industry characterization also allowed a grouping of sources by emission type, as shown in Table 3-2.

TABLE 3-1. EMISSION SOURCES

Industry Segment	Operating Mode	Emission Sources (Equipment or Activities)
Production	Start Up	Drilling (mud emissions) Well completion testing
	Normal Operations	Fugitives Pneumatic devices -control valves Chemical injection pumps Glycol dehydrators Compressor exhaust Compressor starts
	Maintenance	Well bore maintenance Blow and purge
	Upsets/Mishaps	Emergency blowdowns Dig-ins
Gas Processing Plants	Start Up	Not applicable or negligible activity
	Normal Operations	Fugitives Pneumatic devices - isolation valves Glycol dehydrators Acid Gas Recovery vents Engine exhaust Compressor starts
	Maintenance	Blow and purge
	Upsets/Mishaps	Emergency blowdowns NO MISHAPS
Transmission and Storage	Start Up	Not applicable or negligible activity
	Normal Operations	Fugitives Pneumatic devices - control valves - isolation valves Glycol dehydrators Engine exhaust Compressor starts
	Maintenance	Blow and purge
	Upsets/Mishaps	Emergency blowdown Dig-ins
Distribution	Start Up	
	Normal Operations	Fugitives Pneumatic devices - control valves - isolation valves Glycol dehydrators Engine exhaust Compressor starts
	Maintenance	Blow and purge
	Upsets/Mishaps	Emergency blowdown Dig-ins

TABLE 3-2. EMISSION SOURCE GROUPS BY TYPE

Source	Type	Emission Sources
Combustion Sources	Unsteady	Engine exhaust (compressors and other gas-driven engines) Flares Burners
Vented Sources	Unsteady	Pneumatic devices Chemical injection pumps Glycol circulation pumps Glycol dehydrator vent Acid Gas recovery (AGR) vent Blow and purge (for start up, maintenance, and upsets/emergency conditions) Mishaps
Fugitive Sources	Steady	Leaks from sealed surfaces (flange gaskets, valve stem packing, valve seats open to the atmosphere, pressure relief valve seats, compressor seals, etc.) Leaks from small holes in pipelines

4.0 RESULTS

This section reviews the characterization results on the major unsteady categories. (Major categories were defined as any source over 1 Bscf.) Minor categories are discussed in Section 5. Table 4-1 summarizes the results determined for each category of unsteady emissions in each industry segment. Details on the techniques used and the data gathered for each of the unsteady emission categories are provided in other documents of this multi-volume set on methane emissions.[4,6,8,9,11,12]

4.1 Compressor Exhaust

Methane emitted to the atmosphere in compressor engine exhaust is a significant source of unsteady emissions and accounts for approximately 25 Bscf of methane emissions.[4] Methane emissions result from the incomplete combustion of the natural gas fuel, which allows some of the methane in the fuel to exit in the exhaust stream. There are two primary types of compressor drivers: 1) reciprocating gas engines, and 2) gas turbines. A few compressors in the industry are driven by other means such as electrical motors, but the majority are natural gas-fueled drivers. In addition to compressors, there are some natural gas drivers that operate site electrical generators for gas plants and compressor stations.

Reciprocating engines emit more methane per horsepower or per unit of fuel consumed than turbine drivers: 0.24 scf/HP•hr for reciprocating versus 0.0057 scf/HP•hr for turbines. Reciprocating engines account for over two-thirds of all installed horsepower in the gas industry (100,500 MMhp•hr compared to 44,300 MMhp•hr for gas turbines). Therefore, reciprocating engines account for 98% of the methane emissions for this category.

Emissions were determined by analyzing and combining several databases. A GRI database, the GRI TRANSDAT compressor module,[13] contains data from American Gas Association (A.G.A.) on types and models of compressors in use, as well as data on

TABLE 4-1. SUMMARY OF UNSTEADY EMISSIONS

Source	Annual Methane Emissions, Bscf	90% Confidence Interval
Compressor Exhaust		
Production	6.6	± 200%
Gas Processing	6.9	± 130%
Transmission	11.4	± 15%
Pneumatic Devices		
Production	31.4	± 65%
Gas Processing	0.1	± 64%
Transmission	14.1	± 60%
Chemical Injection Pumps	1.5	± 203%
Dehydrator Vents		
Production	3.4	± 193%
Gas Processing	1.05	± 208%
Transmission	0.10	± 392%
Storage	0.23	± 166%
Dehydrator Glycol Pumps		
Production	11.0	± 110%
Gas Processing	0.17	± 228%
Transmission		
Storage		
Acid Gas Recovery Vents	0.82	± 109%
Blow and Purge		
Production	6.6	± 329%
Gas Processing	3.0	± 262%
Transmission	18.5	± 177%
Distribution	2.2	± 1,783%
TOTAL	119	± 54%

compressor driver exhaust from the Southwest Research Institute (SwRI). A.G.A. gathers its data from government agencies, such as DOE and FERC, and from surveys of its member companies in transmission and distribution. SwRI data were generated through actual field testing. The data were combined to generate emission factors for this project by correlating compressor driver type, methane emissions, fuel use rate, and annual operating hours for 775 reciprocating engines and 86 gas turbines.

Horsepower•hour activity factors were developed for each industry segment using TRANSDAT, FERC, A.G.A., company databases, and site-visit data. TRANSDAT includes horsepower data for 7,489 reciprocating engines and 793 gas turbines in transmission. Transmission operating hours were based on FERC data for 1992 and one company's data for 524 reciprocating engines and 89 gas turbines. Storage horsepower was based on A.G.A. data and operating hours are based on data from 11 storage stations. Since national totals for transmission and storage horsepower are available, no industry extrapolation was necessary for these activity factors. Production horsepower•hours were based on one company's data for 516 reciprocating engines. Horsepower and operating hours for the gas processing segment were based on 10 site visits and company data for 18 gas processing plants. Horsepower•hours for production and processing were extrapolated to a total for the industry by using published data for nationally marketed gas produced and gas processed, respectively.

4.2 Pneumatic Devices

Pneumatic devices in the natural gas industry are valve actuators and controllers that use natural gas pressure as the force for valve movement. Gas from the valve actuator is vented during every valve stroke, and gas may bleed continuously from the valve controller pilot as well. Pneumatic devices are a significant source of unsteady emissions and account for 45.6 Bscf of methane emissions annually.[6] Methane emissions from pneumatic devices were calculated based on field measurements, site data, and manufacturers' data.

There are two primary types of these devices: 1) control valves that regulate flow, and 2) isolation valves that block or isolate equipment and pipelines. Of the two main types, isolation valves typically have lower annual emissions, although the emission rate per actuation can be large. This is because isolation valves are moved infrequently, for emergency or maintenance activities that require isolating a piece of equipment or section of pipeline. Alternatively, control valves typically move frequently to make adjustments for changes in process conditions, and some types of control valves bleed gas continuously.

Each segment of the industry has very different practices regarding the pneumatic devices, as described below:

Production

The production segment accounts for the majority of pneumatic emissions: 31.4 Bscf, or 69% of all pneumatic emissions. Compressed air is rarely used as a pneumatic operating medium in the production segment, since compressed air requires electricity at the often remote well sites, and since gas is readily available and less expensive. A typical production pneumatic device releases 126 Mscf methane annually and there are an estimated 249,000 pneumatic devices associated with natural gas production.

Gas Processing

Pneumatic emissions from the gas processing segment are very small: 0.12 Bscf annually, or approximately 1% of all pneumatic emissions. Only one-half (56%) of the gas processing plants participating in this project use natural gas to operate pneumatic controllers and isolation valves; other sites use compressed air or electric motors. The natural gas-powered isolation valves in this industry segment are operated infrequently (once/month or once/year), so the annual emissions per site are relatively small (approximately 165 Mscf of methane per gas processing plant).

Transmission/Storage

Pneumatic emissions from the transmission compression stations and storage stations account for 14.1 Bscf annually, or 31% of pneumatic emissions. In this industry segment, most of the pneumatics are gas-actuated isolation valves. There are a few pneumatic control valves used to reduce pressure or to control liquid flow from a separator or scrubber. The annual methane emissions from a transmission pneumatic device are 162 Mscf, and there are approximately 87,000 of these devices nationally.

Distribution

Pneumatic emissions for the distribution segment are included in the meter and regulation station "fugitive" emission factor.[2]

4.3 Chemical Injection Pumps

Chemical injection pumps are a source of unsteady emissions and account for 1.5 Bscf of annual methane emissions.[8] Gas-driven chemical injection pumps use gas pressure to move a piston which pumps the chemical on the opposite end of the piston shaft; the power gas is then vented to the atmosphere at the end of the stroke. The power gas may be natural gas or compressed air. Two types of chemical injection pumps were observed: 1) piston pumps, and 2) diaphragm pumps. The larger diaphragm pumps emit more gas per stroke, and they are used to pump a higher flow rate of chemical or to pump the chemical into high pressure equipment.

Chemical injection pumps are used to add chemicals such as corrosion inhibitor, scale inhibitor, biocide, demulsifier, clarifier, and hydrate inhibitor to operating equipment. These additives protect the equipment or help maintain the flow of gas. The vast majority of these pumps exist in the production segment, located at the well sites, so that the chemical can protect all of the downstream and downhole equipment. As with pneumatic control valves, the chemical injection pumps in production are primarily powered by natural gas.

In the production segment, significant regional differences exist. Depending on the gas composition and conditions, some regions use very few pumps, while other regions use the pumps frequently. Many pumps also have seasonal operation since they protect against hydrate formation, which winter temperatures exacerbate. Approximately 17,000 chemical injection pumps are associated with natural gas production. A typical methane emission rate is 248 scfd per pump, based on site and manufacturer data.

Only a few pumps exist in the gas processing and transmission segments. The pumps that do exist are powered by compressed air at these stations, and as a result, have no methane emissions.

4.4 Dehydrator Vents

Glycol dehydrator vents are a significant source of methane emissions and account for 4.8 Bscf of methane emissions annually.[11] The majority of the glycol dehydrators are located in production, but dehydrators are also present in the gas processing, transmission, and storage segments of the natural gas industry. Methane emissions are higher in the production segment (71% of the total emissions are attributed to glycol dehydrator vents) due to the high activity factor for this segment and the lack of flash tanks in most production dehydrators.

Glycol dehydrators remove water from the natural gas through continuous glycol absorption. The water-rich glycol is then regenerated, or heated, which drives the water back out of the glycol. The glycol also absorbs some other compounds from the gas, including a small amount of methane. The methane is driven off with the water in the regenerator and vented to the atmosphere.

The important emission-affecting variables for dehydrators are: gas throughput, use of a flash tank, use of stripping gas, and use of vent controls routed to a burner. An emission factor was established for glycol dehydrator regenerator vents using three sources of data: 1) computer simulations of dehydrator operations using first principles; 2) data from actual on-line analyzer samples taken from regenerator vents; and 3) multiple site visits. The resulting annual methane emission factors are: 276 scf/MMscf throughput for production, 122 scf/MMscf for gas processing, 94 scf/MMscf for transmission, and 117 scf/MMscf for storage. For each industry segment, the emission factor was combined with an activity factor to generate the national emission rate, where the activity factors are based on the annual volume of gas dehydrated (12.4 Tscf for production, 8.6 Tscf for gas processing, 1.1 Tscf for transmission, and 2.0 Tscf for gas storage).

4.5 Dehydrator Glycol Pumps

Glycol dehydrator circulation pumps are a significant source of unsteady emissions and account for approximately 11 Bscf of annual methane emissions.[12] These pumps use the high pressure of the rich glycol from the absorber to power pistons that pump the low-pressure, lean glycol from the regenerator. The pump configuration pulls additional gas from the absorber along with the rich glycol (more gas than would flow with the rich glycol if conventional electrical pumps and level control were used). This gas is emitted along with other absorbed methane through the dehydrator vent stack.

Gas-powered glycol circulation pumps are common throughout the industry, even in sites where electrical pumps are the standard for other equipment. The dehydrator equipment is often specified as a separate bid package, and the vendors most often use the Kimray gas pump as their standard pumping unit. The pumps are an integral part of the glycol dehydrator unit and their emissions occur through the same point. However, the pumps are the cause for most of the methane emissions from dehydrators, so they are considered separately.

Unlike chemical injection pumps which vent the driving gas directly to the atmosphere, dehydrator pumps pass the driving gas along with the wet glycol to the reboiler. Therefore, methane emissions from the pump depend on the design of the dehydrator, since gas recovery on the dehydrator will also recover gas from the pump. The demographics generated for the glycol dehydrator control system (flash drum recovery and vent vapor recovery) were also used to determine the net emission rate for glycol pumps.

Based on a gas throughput basis, emission factors for glycol pumps were estimated to be 992 scf methane/MMscf for production and 178 scf/MMscf for gas processing. The corresponding annual activity factors are 1.1 Tscf and 0.96 Tscf, respectively.

4.6 Blow and Purge

Blow and purge is a large source of unsteady emissions and accounts for approximately 30 Bscf of methane emissions annually.[9] Blow (or blowdown) gas refers to gas that is vented due to maintenance, routine operations, or emergency conditions. A piece of process equipment or an entire site is isolated from other gas-containing equipment and depressured to the atmosphere. The gas is discharged to the atmosphere for one of the following reasons:

1) Maintenance Blowdown - the gas is vented from equipment to eliminate the flammable material inside the equipment, thus providing a safer working environment for workers that service the equipment or enter the equipment.

2) Emergency Blowdown - the gas is vented from a site to eliminate a potential fuel source. For example, if an equipment fire begins at a compressor station, the station emergency shutdown and emergency blowdown system blocks the station away from the pipelines and discharges the gas inside the station, thus reducing the fuel that could feed the fire.

The factors that affect the volume of methane blowdown released to the atmosphere are: frequency, volume of gas blowdown per event, and the disposition of the blowdown gas.

Blowdown from maintenance releases was determined for each equipment category: compressor blowdown, compressor starts, pipeline blowdown, vessel blowdown, gas wellbore blowdown, and miscellaneous equipment blowdown. Emergency blowdown refers to the unexpected release of gas by a safety device, such as a pressure-relief valve (PRV) on a vessel or the automatic shutdown/emergency blowdown of a transmission compressor station. Dig-ins, which are pipeline ruptures caused by unintentional damage, were also classified as an emergency release of gas. Table 4-2 summarized the emission factors and activity factors for the various blow and purge sources.

Emission estimates for each industry segment were based on data from one or more of the following sources: 1) site-visit data; 2) company-tracked data; 3) company studies; and 4) equipment characteristics. Data quality in the transmission segment was considered superior since it was based upon rigorous company-tracked data. Gas-processing data were extrapolated from transmission data based upon the similarities between gas plant compression and transmission compressor stations. Distribution segment data were considered good since they were based upon company studies. Production data were considered poor (and may be underestimated) since they are based upon operator recollections of blowdown frequency gathered during site visits.

TABLE 4-2. BLOW AND PURGE EMISSION RESULTS

Industry Segment	Annual Emission Factor	Activity Factor	National Annual Methane Emission Rate, Bscf
Production:			
Gas Wells Unloading	49,570 ± 344% scf/well	114,139 ± 45% wells	5.66 ± 380%
Compressor Blowdowns	3,774 ± 147% scf/comp.	17,112 ± 52% compressors	0.065 ± 173%
Compressor Starts	8,443 ± 157% scf/comp.	17,112 ± 52% compressors	0.144 ± 184%
Pipeline Miles	309 ± 32% scf/mile	340,000 ± 10% miles	0.105 ± 34%
Production Vessels	78 ± 266% scf/vessel	255,996 ± 26% vessels	0.020 ± 276%
Completion Flaring	733 ± 200% scf/completion	844 ± 10% completions	0.0006 ± 201%
Well Workovers	2,454 ± 459% scf/workover	9,329 ± 258% workovers	0.023 ± 1,296%
PRV Releases	34 ± 252% scfy/PRV	529,440 ± 53% PRVs	0.018 ± 289%
ESD Releases	256,888 ± 200% scf/platform	1,115 ± 10% platforms	0.286 ± 201%
Dig-ins	669 ± 1,925% scf/mile	340,000 ± 10% miles	0.23 ± 1,934%
Gas Processing	4,060 ± 322% Mscf/plant	726 ± 2% plants	2.95 ± 262%
Transmission and Storage:			
Stations	4,359 ± 322% Mscf/station	2,175 ± 8% stations	9.48 ± 263%
Pipeline Miles	31.6 ± 343% Mscf/mile	284,500 ± 5% miles	9.00 ± 236%
Distribution:			
PRV Releases	0.050 ± 3,914% Mscf/main mile	836,760 ± 5% miles main	0.04 ± 3,919%
Dig-ins	1.59 ± 1,922% Mscf/mile	1,297,569 ± 5% miles	2.06 ± 1,925%
Blowdowns	0.102 ± 2.521 Mscf/mile	1,297,569 ± 5% miles	0.13 ± 2,524%

5.0 MISCELLANEOUS MINOR CATEGORIES

There were many emission categories that contributed negligible amounts of methane (less than 1 Bscf). Although small, these categories are discussed in order to provide a complete picture of the industry, but these emission sources are not itemized in the summary of annual emissions reported by this study. Emissions from a few other minor categories are quantified in Volume 7 on blow and purge activities.[9]

5.1 Burners

Burner combustion refers to the controlled burning of natural gas in order to add heat to a process stream. Burners combine air and gas in a controlled manner to maximize combustion efficiency. In the natural gas industry, burners are used in all industry segments. In the production segment, a high-pressure gas well requires a choke and an in-line heater to avoid freezing water in the line from the pressure drop flash. Glycol dehydrators, which are present in all industry segments, require a reboiler burner to heat and regenerate the glycol. Above-ground liquefied natural gas (LNG) facilities may have boilers or hot oil furnaces for methane vaporization. Some gas plants may have additional burners in boilers and other sources.

Non-combusted methane may be emitted by burners in two ways: 1) since combustion is not 100% efficient, there is a small amount of methane that escapes from the burner uncombusted, and 2) if the burner has a flameout, all of the methane sent to the burner can be emitted uncombusted. This report has assumed that flameout emissions are negligible, based upon interviews with gas industry personnel. Therefore only incomplete combustion emissions are calculated in this section.

The combustion efficiency of natural gas in burners was determined from Section 1.4 of the U.S. EPA's AP-42 document.[14] The burners in the natural gas industry fall under the industrial furnace category (between 10 and 100 MMBtu/hr of fuel fired). AP-

42 shows that uncontrolled methane emissions from natural gas burners in industrial boilers are three pounds of methane per million cubic feet of fuel. The accuracy of these numbers is low, since AP-42 gives the data a rating of "C."

In general, annual averages of combustion emissions are generated by estimates of the total gas flow to the burners, combustion efficiency, and flameout frequency and duration. The activity factor for this category is the total amount of burner fuel used in the industry. Nationally published numbers are available that show the total annual "lease and plant fuel use" and "pipeline fuel use," as shown in Table 5-1.[15,16] However, compressor engine fuel must be subtracted from these totals to determine burner fuel use. Since there are no nationally available numbers for compressor engine fuel, compressor fuel use was estimated.

TABLE 5-1. BURNER FUEL GAS ACTIVITY FACTOR

National Fuel Use	10^6 scf
"Lease and Plant Fuel" (*Gas Facts*, Table 3-3)[14]	1,070,452
- Production Compressor Fuel[a]	-219,700
- Gas Plant Compressor Fuel[a]	-469,500
- Estimated Burner Fuel (Production)	381,252
"Pipeline Fuel Use" (*Gas Facts*, Table 3-4)[15]	630,083
- Transmission Compressor Fuel[a]	-400,100
- Storage Compressor Fuel[a]	-53,210
- Estimated Burner Fuel (T&S)	176,773

[a] Estimated based on HP·hr from Volume 11 on compressor driver exhaust, the AP-42 "CO_2 per HP·hr" emission factor, and the combustion equation.[4,14]

In addition, gas lift compressors also consume natural gas as fuel. Emissions from these compressors are considered to be attributed to the petroleum industry, based on the industry boundaries defined by this project.[10] Methane emissions from this source have not been quantified and subtracted from the natural gas industry emissions.

The burner combustion efficiency was determined by using the AP-42 emission factors. The AP-42 emission factor (3 lb/10^6 ft^3) can be converted to a combustion efficiency as follows:

$$\frac{3 \text{ lb } CH_4}{10^6 \text{ cf fuel}} \times \frac{\text{lbmol } CH_4}{16 \text{ lb } CH_4} \times \frac{379 \text{ scf}}{\text{lbmol}} = 0.000071 \ \frac{\text{scf } CH_4}{\text{scf fuel}} \quad (1)$$

Multiplying the emission factor by the activity factor yields the emission rate for burners:

$$(381{,}252 \text{ MMscf} + 176{,}773 \text{ MMscf}) \times 0.000071 \ \frac{\text{scf } CH_4}{\text{scf fuel}} = 0.039 \text{ Bscf} \quad (2)$$

This value is insignificant, and therefore is not listed as an emission source in the total emissions estimate for this project.

5.2 Flares

Flares are devices used to provide a safe and economical means of gas disposal from routine operations, upsets, or emergencies via combustion of the gas. Flares prevent a controlled release of methane from building up into a large cloud of gas that could explode. There is a wide variety of flares used in the natural gas industry ranging from small open-ended pipes at wellheads to large, horizontal, or vertical flares with pilots, such as those at gas plants.

Methane emissions from flares result from the incomplete combustion of gas in the flare's flame or from time periods where there is no flame at the flare tip (flame-out) due to flare operational problems. Either of these cases results in emissions of non-combusted methane to the atmosphere. To determine the total emissions from flares in the gas industry, two factors must be known: 1) the average methane combustion efficiency of flares (including flame-out periods) and 2) the total annual amount of natural gas flowing to flares in the United States.

5.2.1 Combustion Efficiency

The combustion efficiency of flares is primarily dependent upon the flame stability which, in turn, depends on the gas velocity, heat content, and wind conditions. There are many problems in testing industrial flares for combustion efficiency; some of these include flare (and therefore flame) size, radiant heat, wind conditions, and proper probe placement within the flare flame. Therefore, most of the studies have been conducted on pilot flares, with the results extrapolated to the larger industrial-size flares. Table 5-2 provides a summary of flare combustion efficiency studies compiled by Pohl and Soelberg.[17]

Only two of these studies used natural gas as the flare gas. The study by Straitz has a wide-efficiency range, but instrument problems are also noted. The only other study to use natural gas (Howes) shows an excellent combustion efficiency (>99%). However, the composition of the natural gas is unknown in Howes' combustion efficiency. Although methane is a clean-burning gas, the composition of the natural gas in the production segment can vary substantially. As shown in Table 5-2, gas streams with heavier hydrocarbons or with a substantial sulfur content, such as sour gas, result in lower combustion efficiencies.

Table 5-2 shows two studies for open-ended pipes with combustion efficiency ranges of 90 to 99.9% and 92 to 99.7%. The lower efficiencies for these studies are due in part to the lack of features and controls, which are used to ensure flame stability in the larger, more efficient commercial flares. Another reason for the lower efficiency was that these two studies were conducted on heavier gas mixtures that did not include methane or natural gas. In the article by Straitz, "Flare Technology Safety," the author claims that typical flare combustion efficiencies are 99+% for natural gas.[18] The author also points out that the combustion efficiency will be lower for gases with low-Btu heat content (due to nitrogen, water vapor, or H_2S). Other sources give typical flare efficiencies as 98 to 99% as long as the flare is operated within the stability limits of the flame.[19,20]

TABLE 5-2. SUMMARY OF PREVIOUS FLARE COMBUSTION EFFICIENCY STUDIES[16]

Study	Year	Flare Size (in)	Design	Gas Exit Velocity (f/s)	Gas Heating Value (Btu/ft^3)	Gas Flared	Measured Combustion Eff. (%)	Comments
Palmer	1972	0.5	Steam assisted experimental nozzle	50-250	1448	Ethylene	<97.8	Helium tracer for full-size flare evaluation
Merget	1977	47	Full size	NA	NA	Carbon black vinyl monomer	2500:1 reduction in CO	EPA ROSE remote sensing system
Straitz	1978	2-6	Steam and pilot	-	1000-2350	Natural gas, propane	75-99	Results of limited validity due to instrument range sensitivity
Siegel	1980	17	Commercial flare gas	0.7-16	1500	Refinery gas[a]	97-99	Multiposition plume extractive sampling
Lee & Whipple	1981	2	Holes in 2" cap (1.1 in^2 open area)	1.8	2190-2385	Propane	96-100	
Howes, et al.	1981	6[b]	Commercial air assist. Zink STF-LH	40-60	2385	Propane	92-100	Both extractive and EPA ROSE plume sampling
	1982	3 at 4[c]	Commercial H.P.	Near Sonic (estimate)	1000	Natural gas	>99	
McDaniel	1983	8	Commercial Zink STF-S-8	0.03-62	209-2183	Propylene/N_2	67-100	Extractive and EPA ROSE plume sampling
	1983	6[b]	Commercial air assist. Zink STF-LH-457-5	1.4-218	83-2183	Propylene/N_2	55-100	

Continued

TABLE 5-2. (Continued)

Study	Year	Flare Size (in)	Design	Gas Exit Velocity (f/s)	Gas Heating Value (Btu/ft^3)	Gas Flared	Measured Combustion Eff. (%)	Comments
Pohl, et al.	1984	3-12	Open pipe and commercial	0.2-420	291-2350	Propane/N_2	90-99.9	Multiprobe plume extractive sampling
Pohl and Soelberg	1985	0.042	Nozzle	31-854	923-3320	25 different gas mixtures	>98 (80-99.99 destruction efficiency)	Comparative screening tests
	1985	1.5-12	Commercial coanda steam injection, pressure assisted, air assisted, open pipe, pilot assisted	0.2-591	122-2350	Propane/N_2	36-99.9	Comparative commercial flare type evaluation
	1985	0.042-2.5	Nozzle	5.6-891	588-2350	Propane/N_2	NM	Flame aerodynamic tests
	1985	3	Open pipe	0.15-139	145-877	H_2S/propane/N_2 NH_3/propane/N_2 1,3 butadiene/N_2 Ethylene Oxide/N_2	92-99.7 (92-99.9 destruction efficiency)	Gas mixture testing

NA = Not Available
NM = Not Measured
[a] 50% hydrogen plus light hydrocarbons.
[b] Supplied through spiders; high Btu gas through area is 5.30 in^2 and low Btu gas through 11.24 in^2.
[c] Three spiders, each with an open area of 1.3 in^2.

Additional problems exist in the case of open-ended pipes used for flaring in the production segment of the gas industry. These flares typically do not have a pilot and must be lit manually. Therefore, the potential exists for the gas to be vented rather than flared when operating personnel are not available to light the flare (i.e., gas vented through a pressure relief valve to a flare). Much of the flaring done in the production segment occurs at well completion. Since operating personnel are always present during this activity, the volume of gas vented during well completion is small. In addition, most state agencies require that any ongoing (post-completion) vent of wellhead gas be burned; the agencies have field auditors to ensure that this requirement is followed.

On the basis that natural gas is predominantly methane (as presented in Appendix A), a combustion efficiency of 98% was used for the production segment of the natural gas industry and 99% for the other industry segments. A lower efficiency was used for the production segment to provide a more conservative estimate of emissions due to the variability of the composition of the natural gas as it is extracted from the well. Both efficiencies assume the flare to be operating under optimum flame stability.

Flame-out in the natural gas industry was assumed to be negligible. Most gas processing plants are manned, so that flame-out at the flare would be observed and corrected quickly. In addition, many of these sites have pilots and/or ignitors that ensure that the flame remains lit. For transmission, flare stacks at compressor stations are uncommon; where they do exist, they have pilots and/or ignitors that ensure that the flame remains lit. In the production segment, most flaring from natural gas industry wells is performed either with operator supervision or occasionally with piloted flares, so that flame-out is minimal.

5.2.2 Total Natural Gas Flow to Gas Industry Flares

There are no published sources for the total volume of gas flared in the natural gas industry. While the American Gas Association (A.G.A.) does publish natural gas production and distribution volumes that include a number called "Vented and Flared,"[15] this number does not split the amount vented from the amount flared. For 1992, A.G.A. reports 167.5 Bscf of natural gas "vented and flared" from production and gas processing. The A.G.A. number is derived by a pseudo material balance and includes all gas that is not marketed, reinjected, or used in the production field. Therefore, the A.G.A. estimate includes fugitive gas losses and vented losses, as well as flared volumes. If the A.G.A. estimate were reduced by the actual amount "vented" to the atmosphere (fugitive + vented volumes), the result would be the amount of natural gas that A.G.A. assumes is flared. This GRI/EPA study estimates 48.4 Bscf of methane from production and processing fugitive emissions and 58.9 Bscf of methane from production and processing vented emissions. Converting the GRI/EPA numbers to natural gas, based on the methane composition for each industry segment, results in 132.3 Bscf of natural gas as shown in Table 5-3.

TABLE 5-3. NON-COMBUSTED EMISSIONS FROM PRODUCTION AND GAS PROCESSING (GRI/EPA ESTIMATE BASIS)

	Bscfy Methane	Bscfy Natural Gas
Fugitive Emissions		
Production	24.0	30.4
Processing	24.4	28.1
Vented Emissions		
Production	53.8	67.9
Processing	5.1	5.9
TOTAL	107.3	132.3

If the difference between the A.G.A. "Vented and Flared" volume (167.5 Bscf natural gas) and the non-combusted emission volume from this study (132.3 Bscf natural gas) is assumed to result in the flared volume, then 35.2 Bscf of natural gas would be flared. Using a flaring efficiency of approximately 99% (as discussed in Section 5.2.1) and an average methane composition for production and processing of 82.9%, a flared emission rate can be estimated:

$$35.2e9 \text{ scf gas} \times \frac{0.829 \text{ scf } CH_4}{\text{scf gas}} \times \frac{0.01 \text{ scf } CH_4 \text{ non-combusted}}{\text{scf } CH_4 \text{ flared}} = 0.29 \text{ Bscf } CH_4 \quad (3)$$

There are concerns with the accuracy of this approach, in that the "Vented and Flared" volume report by A.G.A. is fraught with inconsistencies: it includes items not truly vented or flared, it does not include all vented and flared volumes (some sources from production and processing are overlooked, and transmission and distribution sources are not included), and each state may have different reporting requirements for the number. Appendix B discusses why this number is an inaccurate representation of the total vented and flared volume.

Selected Method

Without reasonable nationally-tracked numbers for flaring, site data were sought. Most sites, however, did not measure nor track flared volumes. This was especially true in the production segment. Therefore, an alternate approach was used based on an assumption that the total amount of gas flared would be equal to half of the total amount directly vented to the atmosphere by the industry. Table 5-4 shows the methane volumes vented in each industry segment, as presented in Volume 7 (*Methane Emissions from Blow and Purge Activities*).[9] Using the flaring efficiencies for each industry segment discussed earlier, a flare emission rate can be calculated by multiplying the assumed flow by the combustion inefficiency term.

As shown in Table 5-4, this alternate approach produces an estimate of 15.2 Bscf of natural gas flared, which is significantly smaller than the A.G.A. approach. Since the A.G.A. approach is believed to overstate the flared amount, this alternate approach was selected.

TABLE 5-4. MAXIMUM FLARING EMISSIONS

Industry Segment	Assumed Flow to Flare,[a] Bscf	Flaring Efficiency	Maximum Annual Methane Emissions from Flaring, Bscf
Production	0.5 (6.6 ± 329%)	98%	0.066 ± 329%
Gas Processing	0.5 (3.0 ± 262%)	99%	0.015 ± 262%
Transmission and Storage	0.5 (18.5 ± 177%)	99%	0.093 ± 177%
Distribution	0.5 (2.2 ± 1,783%	99%	0.011 ± 1,783%
TOTAL	15.2 ± 185%		0.185 ± 183%

[a]The methane volume is assumed to be equivalent to half the vented quantity, where the vented volumes are reported in the Blow and Purge Report.[9]

With either calculation approach, the estimated annual emissions from flares are negligible (less than 0.3 Bscf), and may be conservatively high, given the problems built into the A.G.A. number and that the flow to natural gas industry flares flare may be overestimated in the second approach. Therefore, this small category does not show up as an itemized contribution to total emissions in this report.

5.3 Acid Gas Recovery Vents

Acid Gas Recovery (AGR) vents are a very minor source of methane emissions and account for only 0.82 Bscf of methane emissions. AGR systems are used to remove acid gases (H_2S and CO_2) by contacting the stream with a solvent (usually amines) and then driving the absorbed components from the solvent. The amines can also absorb methane and, therefore, methane can be released to the atmosphere through the reboiler vent.

Methane emissions were calculated using an ASPEN PLUS™ process simulation. The disposition of AGR vent gas and the number of AGR units were taken from an API survey of U.S. Natural Gas Reserve Demographics.[21] The following assumptions were used in determining the emission rate: 1) AGR units do not use flash drums or stripping gas; 2) AGRs have an absorption of methane similar to water; 3) the total number of AGR units in the United States are in the gas processing segment; and 4) 82% of AGR emissions are controlled (18% of the emissions are vented).

5.4 Salt Water Tanks

Methane emissions from production salt water tanks were estimated using an ASPEN PLUS* process simulation. The flash calculations were based on the following assumptions:

1) The natural gas industry produces 497 million barrels of salt water annually, of which approximately 100 million barrels are from coal bed methane wells.[22]

2) 70% of the water from gas wells is reinjected, leaving 30% of the water stored in atmospheric tanks.[22]

3) The hydrocarbon composition is 100% methane.

The flash calculation results are summarized in Table 5-5 for cases with the salt content varied from 2 to 20%, and the pressure varied from 50 psi to 1000 psi. The simulation results indicate that methane emissions from salt water tanks are negligible.

*ASPEN PLUS™ is a registered trademark of Aspen Technology, Inc.

TABLE 5-5. SALT WATER TANK EMISSIONS

Salt Content, Wt %	Pressure, psi	Methane Emissions, 10^6 lb/yr	Methane Emissions, Bscf
20% Salt	50	1.6	0.0
	250	10.8	0.0
	1000	38.8	0.0
10% Salt	250	16.4	0.0
	1000	58.7	0.0
2% Salt	250	19.4	0.0
	1000	69.5	0.0

5.5 Drilling

Drilling operations typically use hydraulic pressure from the drilling mud to keep the oil and gas in the formation while drilling. The intent is to prevent the uncontrolled flow of oil and gas up the well bore (a potential blowout) until the surface equipment is ready to receive the material. Drilling mud does absorb some gas and releases it in the degasser at the surface. The quantity is typically small and has been excluded for this project.

Blowouts during drilling or completion can be a large individual source of emissions, since the formation flows uncontrolled to the surface. The drilling industry has developed procedures and devices throughout the evolution of oil and gas production to prevent such an event. As a result, blowouts today are very infrequent and have not been considered.

Once the desired formation or depth is hit, the well must be "completed" before it can be produced. Less expensive tubing replaces the strong drill string and an outer annular casing is cemented in place. The casing has many uses. It prevents the formation from caving in around the tubing, allows easier well maintenance, and allows onshore, dead (no surface pressure) oil wells to produce oil up the tubing string and gas up the outer casing. If the oil and gas were produced in the tubing, the pumps would become vapor locked.

Once the casing is in place, it is perforated and the formation begins to flow into the well. A clear completion fluid is used (heavy salt water) instead of mud, and the completion fluid will flow or be pumped to surface tanks or pits. Again, some small amount of gas may evolve from the completion fluid, but it is typically insignificant.

After the completion fluid is out of the well, oil and/or gas flow begins. Depending on the type of well, the gas may be vented, flared, or immediately produced. If the well was drilled in a known field with other existing wells, it is called a Developmental, or an Infill well. In that circumstance, the reservoir pressure and size are already defined, and the operator can have production meters and equipment sized and in place for completion. Very little venting and flaring would occur at completion, if any.

If the well was an exploratory "discovery" well (i.e., one drilled in a new area of unknown reservoir potential), facilities may not be ready for the well's production. The well is flared for the time that it takes to measure the flow rates so that equipment can be sized. This period is referred to as completion, completion flaring, or well testing. Emissions from completion flaring are minimal but are included in the blow and purge emissions.[9]

5.6 Drips

Some longer sections of gas-gathering and transmission pipelines may have small liquid collection pots located along the line. These pots are periodically blown down to clear collected hydrocarbon condensate, and the blowdown vents methane directly to the atmosphere. An unaccounted-for (UAF) gas study by Pacific Gas and Electric (PG&E)

defined drip blowdown emissions under unmetered company gas usage.[23] They found the category to be insignificant, at 0.00035% of their total throughput.

5.7 Sampling

Gas is consumed in sampling and analyzing gas for composition and heating value. Much of this gas is then emitted to the atmosphere from the on-line analyzers or from the sample containers. Most sampling efforts begin in the gas processing areas, and field sampling represents a small fraction of the total samples. The PG&E UAF gas project estimated this category as insignificant, at 0.00107% of their total throughput.[23]

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APPENDIX A

Methane Composition

APPENDIX A
METHANE COMPOSITION

The composition of methane in natural gas is needed to calculate methane emissions from natural gas that is emitted to the atmosphere. This section describes the characteristics of natural gas streams in production, processing, transmission, and distribution. The methane composition for each segment is presented in Table A-1.

TABLE A-1. METHANE COMPOSITION BY INDUSTRY SEGMENT

Segment	Methane (volume %)
Production	78.8 ± 5%
Gas Processing	87.0 ± 5%
Transmission/Storage	93.4 ± 1.5%
Distribution	93.4 ± 1.5%

Production Segment - The production segment of the gas industry includes natural gas produced from gas wells (non-associated) and oil wells (associated). Data from the United States Bureau of Mines, Division of Helium Field Operations, and A.G.A. *Gas Facts* were used to calculate the production methane composition.[1,2] The Bureau of Mines (BOM) has been collecting analytical data from oil and gas wells and natural gas pipelines since 1917 in an effort to locate sources of helium. Under another GRI project, all published BOM data through 1987 were obtained on magnetic tape and loaded it into an Empress® database.[3] The focus of this earlier project was to determine the major contaminants in sour natural gas, specifically, hydrogen sulfide and carbon dioxide. Over 14,000 records were used to determine county and state averages for natural gas composition, including methane content.

The BOM data were corrected since a few non-gas industry wells that have very high helium or carbon dioxide content with little or no methane were included in the data set. For the largest producing states, the Empress data files were reviewed and the entries with less than 40% methane were removed. Table A-2 shows the average methane content and marketed production by state. This information was regionalized to estimate the national average methane content of 78.8 mol % ± 5% as shown in Table A-3.

Gas Processing Segment - The only source of methane data identified for the processing segment is from the *Gas Engineer's Handbook.*[4] These data are from November 1951 and consist of eight data points with only two states, California and Texas, represented (see Table A-4). The data are reported as "after processing plant" and were assumed to represent typical speciation data for natural gas leaving this industry segment. Due to the limited data set, an average methane content was calculated instead of a weighted average based on the state's fraction of U.S. production. The average methane content for the processing segment is 87 mol percent. A 90% confidence interval of 5% was calculated based on the spread of the available data.

Transmission and Storage Segments - The methane composition for transmission and storage was based on the GRI TRANSDAT database,[5] which has analyses of fifty fuel gas samples from various transmission compressor stations. Since the fuel gas is from the pipeline, these should represent transmission gas quality. The resulting average methane composition for transmission is 93.4 mol% ± 1.5% (90% confidence interval is based on the spread of data).

Distribution Segment - The *Gas Engineer's Handbook* provided methane composition data for the distribution segment.[4] This data set includes distribution in 48 cities, representing 29 states and the District of Columbia, for the fall of 1962. A weighted average was not used for this industry segment since the distribution of natural gas does not necessarily reflect the origin of the gas. The resulting average methane content is approximately 89 mol %.

The composition of gas leaving the processing segment should agree with the methane composition in the transmission and distribution segments, since the gas is only transported or stored. However, the distribution value is less than the methane composition determined for the transmission segment. Because the transmission data are based on the more recent and more extensive data source, the same composition is used for distribution. Therefore, the distribution methane composition used in determining emission factors is 93.4 vol % ± 1.5%.

TABLE A-2. AVERAGE STATE METHANE CONTENT AND PRODUCTION RATE

Region	States[a]	Methane Composition, Volume %	1989 Marketed Gas Production, Bscf
Gulf Coast	AL	86.4	151
	FL	60.2	8
	LA	87.8	5,087
	MS	79.8	165
	TX	75.1	6,401
Central Plains	AR	87.7	174
	CO	65.4	227
	KS	69.4	601
	MO	69.4	4
	MT	69.4	51
	ND	62.5	56
	NE	53.4	1
	NM	64.4	856
	OK	79.8	2,237
	SD	--	4
	WY	69.9	756
Pacific and Mountain	AK	76.5	394
	AZ	--	1
	CA	75.3	364
	OR	--	3
	UT	--	120
Atlantic & Great Lakes	IL	86.2	2
	KY	76.2	72
	MI	74.4	156
	NY	90.0	20
	OH	82.0	160
	PA	91.0	192
	TN	85.2	2
	VA	88.0	18
	WV	86.9	177

[a] States not shown had insignificant 1989 marketed gas production rates.

TABLE A-3. METHANE COMPOSITION OF PRODUCTION GAS

Region	Volume Percent Methane (from state vol %'s weighted by state production)	Comments
Gulf Coast	80.76	All states but GA represented
Central Plains	73.68	Some states with insignificant production were excluded (IA, MN)
Pacific and Mountain	75.92	Alaska and California only
Atlantic and Great Lakes	83.59	Some states with insignificant production were excluded (CT, DE, IN, MA, MD, ME, NC, NH, NJ, RI, SC, VT, WI)
Total U.S.	78.8	Weighted average by regional production

TABLE A-4. METHANE COMPOSITION IN GAS PROCESSING

Location	Methane Composition, Vol %
CA, Kettleman North Dome	93.0
CA, Ventura	92.7
TX, Agua Dulce	93.0
TX, Carthage	91.7
TX, Hugoton	79.0
TX, Keystone	86.2
TX, Panhandle	81.5
TX, Wasson	76.9
Average	86.8

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APPENDIX B

Reported "Vented and Flared" Data

APPENDIX B

REPORTED "VENTED AND FLARED" DATA

National numbers for "vented and flared" volumes are reported by production and processing companies to state agencies, which then report to the Department of Energy (DOE) Energy Information Administration (EIA). *Gas Facts* publishes this EIA national number for "venting and flaring" (V&F) at approximately 0.71% of the total natural gas production.[1] Initially, it was assumed that the reported V&F number was valid, and the approach for this project focused on simply splitting this number into a vented volume and a flared volume, so that vented emissions could be accurately quantified. However, this study discovered that the reported V&F number has many problems, and it is not a useful measure of actual venting or flaring.

The reported numbers do not represent actual "vented and flared" quantities of gas, since companies do not use a standard practice or protocol for determining their V&F amount. In fact, many sites use a protocol that results in an erroneous value for V&F. Many gas plants simply report all material balance discrepancies as "vented and flared," even though most material balance losses are due to other factors, such as metering inaccuracies. Other companies have operators simply guess the amount of gas vented or flared in order to fill out a state form. Very few sites actually measure or accurately calculate V&F volumes. Even if the reported V&F volumes were accurate, there is not a reliable method of splitting the number into the amounts flared (burned) and the amounts vented. Furthermore, there is no method for separating the amount of vented, unmarketed natural gas attributable to oil production.

The GRI/EPA project abandoned use of the reported V&F number, and turned to a technique that identified each source of vented emissions, and estimated emissions from each source type. This technique is described in more detail in Volume 3 on general methodology.[2] This appendix discusses the problems with the V&F numbers reported by operators to various state and federal government agencies. This section is only intended to offer data supporting the decision not to use the reported V&F numbers in this GRI/EPA project. Sources of data for the United States and for individual states, as well as the quality of the data are covered in detail in the following subsections.

B.1 Specific States

Specific state data were analyzed for Texas, Oklahoma, and Louisiana. These three states comprise 68% of all the gas produced in the U.S. in 1989 and are representative of gas production facilities. States that are major producers of oil and gas generally have state governmental agencies that regulate and maintain data on the oil and gas industry. The regulating agencies for Texas, Louisiana, and Oklahoma are the Texas Railroad Commission (RRC), the Louisiana Department of Natural Resources (DNR), and the Oklahoma Corporation Commission, respectively.

The primary goal of these agencies is to control the industry (provide "fair play" for all operators), collect fees, and protect the community and the environment. Methane emissions have not been a concern for these agencies except where the emitted methane represents 1) an unnecessary waste of natural resources that should come out of a company's "allowable" production quota; 2) a toxic gas hazard (H_2S); or 3) a fire or explosive hazard. To the extent that methane emissions represent a measurable loss of natural resources, the agencies track data on "venting and flaring." For many agencies, the V&F numbers are grouped together. No differentiation is made between amounts actually burned versus amounts vented; however, there is one exception. Permits filed under Rule 32 in the Texas RRC code do differentiate between venting and flaring.

The accuracy and extent of the reported V&F numbers are a function of the V&F definition the state uses in the reporting regulations, the state's enforcement of reporting regulations, and the exclusions that the state allows. Given a broader definition, more emissions are included; however, given more exclusions, fewer events will be reported.

Finally, given weaker enforcement, more unreported quantities will exist. Some of the state-specific data are discussed below.

B.1.1 Texas

For Texas, most of the V&F numbers are reported as one number to the RRC on a monthly basis. Gas plant operators send in R-3 forms, and oil and gas producers send in P-1 and P-2 forms, respectively. Oil wells are tracked by the lease, and gas wells are tracked by the individual well. The data from these forms are summed into tables in the RRC's published *Oil and Gas Annual Report*.[3] The RRC also requires a permit for flares or vents lasting more than 24 hours in the R-32 form. The specific forms are discussed in more detail below.

Among the states, Texas probably has the strongest regulations, the strongest enforcement, and the most comprehensive published data. Nevertheless, the reported vented and flared numbers in Texas are difficult to assess; there are areas over-reported and under-reported due to definition. Amounts vented from compressor engine exhausts, pneumatic actuators, glycol vents, and acid gas recovery vents have never been considered as part of the V&F definition for reporting. In addition, the definition of V&F is different even among the various RRC forms.

R-3 Gas Plants - For gas plants, the V&F number on the R-3 is simply the result of a material balance closure around the gas plant. The rule is:

$$\text{GAS IN - PRODUCTS OUT - CONSUMPTION} = \text{V\&F}$$

Measured outlet dispositions (pipeline gas, fuel, extraction loss, etc.) are subtracted from the inlet plant meter, and the difference is reported as V&F. The difference is really just an "unaccounted-for" (UAF) number arrived at by an accounting procedure; it is usually positive and in the range of 0.3% of the total gas processed. The flare, which in the gas plant has orifice meter readings near zero, is not considered in the calculation of the reported V&F number.

If the gas plant material balances are absolutely accurate (all quantities included are on the same basis) and have a zero meter bias (doubtful, but possible), then the reported V&F number, even though a calculated value, is a true "emitted, vented, or flared" amount. From the V&F number, the flare meter reading could be subtracted, the fugitive emissions subtracted, and the remaining value would be material actually vented. This is the "top-down" yardstick that the "bottom-up" emissions rates for gas plants can be compared to.

R-3 Cycling Plants (Pressure Maintenance) - Cycling plants process gas to reduce the dew point of condensibles in the formation and thus extend the life of a field. In most cases, not all of the gas is returned to the formation in a cycling plant. Again, data from the Texas Railroad Commission indicate that for the 15 pressure maintenance facilities in Texas, 51.6% of the residue gas is used for repressurizing or cycling, while 26.6% is sent to transmission pipelines.[3] It should be noted also that the V&F estimate for cycling plants is 0.3% of the total gas processed, which is the same as for gas plants.

P-1, P-2 Production - A P-1 report is generated for each oil lease and a P-2 report for each gas well. For production facilities, V&F on the P-1 and P-2 reports is meant to represent a real vented and flared quantity at the wellhead. Nevertheless, many releases are exceptions to the reporting requirements, including: well completion flaring for up to 10 days, events less than 24 hours in duration, well cleanups, and venting and flaring from certain field equipment (glycol separators and pneumatic devices). This excludes many of the true release events from the numbers recorded by the RRC.

Even the accuracy of the categories that are included in reporting is questionable. Production flares have no pilot and no meter, so reported values are operator estimates. The operators generally base their estimates upon the most recent well test data or upon the field's gas-to-oil ratio. No actual measurements are used for P-1 or P-2 reported values, and the RRC admittedly has no way to verify the reported values.

There are so many exceptions and estimations in the reported production numbers that it is impossible to intuitively tell whether the number is over- or under-reported. As with gas plants, a method that does not use the reported V&F numbers must be used to estimate real production emissions. The reported numbers can then be adjusted to use only as a check value for the bottom-up calculations.

Rule R-32 - The Texas RRC Rule 32 does have some impact on the V&F amounts. The rule allows 10 days of venting following completion of a well, and then requires all gas to be flared. In addition, permits are required for flares or vents beyond initial completion (exceptions are well cleanups or repairing/modifying a gas-gathering system). The permit form has one very useful piece of data: a designation of venting that is different from flaring. The form is the only place in the reported V&F category where the operator must designate whether he intends to vent or to flare for the specific release permit.

The RRC tracks Rule 32 permits to make sure that sour gas is burned and that large vented releases are not near major roadways nor populated areas. Releases of unburned sour gas can be toxic, and large vented releases can be explosion or fire hazards. The R-32 data were used for this project to establish a percentage split between vented versus flared for all the production V&F totals that are reported. The data were reviewed for 1991 permits and showed that the amount vented was 7.7% and the amount flared was 92.3% of the total V&F. However, the assumption that the non-permitted quantities have the same split may be incorrect, since events less than 24 hours and well cleanups are exceptions. Therefore, many venting events may not be part of these data.

Oil and Gas Annual Report - With all of the above limitations in mind, the data from annual reported values were analyzed. Most of the reported venting and flaring volumes were for casinghead gas (oil well gas). There are many more oil wells than gas wells. For that reason, there is a significant quantity of casinghead gas produced. In Texas, 23% of all gas produced is casinghead gas.

Of the total reported V&F amounts, V&F from casinghead gas at the well accounts for 47.5%, while V&F from gas at the well accounts for only 5%. Gas well gas V&F is likely under-reported, since well cleanups are not reported. The data show that a disproportionate amount of the reported V&F is due to casinghead gas. The remainder of the reported V&F amounts is due to V&F reported at gas plants. This accounts for 47.5% of the reported total V&F amount.

These data show that gas wells typically vent or flare infrequently. This makes sense from an economic point of view, since vented gas represents a direct loss of the well's only revenue. Casinghead gas (oil well gas) is vented or flared more frequently. Gas lost through V&F at oil wells is also a loss of revenue but on a much less significant scale. The oil revenue is typically much larger than the gas revenue.

Casinghead gas that is V&F may be from wells that never produce gas to a pipeline and, therefore, should not be considered part of the gas industry emissions. Those wells would either consume all of the produced gas as lease fuel, reinject all of the gas, or vent/flare all of the gas. Summing those three disposition categories for the RRC's casinghead gas annual table shows that 4.3% of the total casinghead gas is used for those purposes. If all oil wells had identical gas production, this would mean that the maximum amount of oil wells that should be excluded is 4.3%. For a more exact answer, the number of oil wells that do not market gas must be known.

The reported V&F numbers for Texas imply that 0.53% of all gas produced is vented or flared. However, the following problems are associated with the Texas statistics [pluses (+) are shown for comments that would raise the reported numbers when corrected, and minus (-) symbols are shown for items that would reduce the reported numbers]:

(-) Approximately one-half of the V&F amount is due to gas plant V&F, which is an accounting closure number and not really venting and flaring. Even if a gas plant material balance is assumed to have a zero bias, fugitives should be subtracted from the V&F numbers reported.

(-) Nearly half of the reported venting and flaring gas is from casinghead gas. Some of this casinghead gas is associated with oil wells that do not produce to a gas pipeline, and that fraction is, therefore, not part of the natural gas industry as defined by this project. This amount could be excluded if a defensible basis were derived to separate those wells.

(-) Venting and flaring permit rates are usually overestimated (in the RRC's opinion) because many of the producers do not want to apply for permit exceptions if the rate increases.

(+) Many events are exempted from the reporting rules (such as well cleanup, well completion, and events less than 24 hours).

(+) Some oil wells that produce associated or dissolved gases do not report V&F.

(+) Emissions from tank batteries, glycol dehydrators, AGRs, and other miscellaneous sources are not reported.

Therefore, even though Texas' reported V&F numbers appear to give an overall emission estimate for V&F emissions, they cannot be used as a quantitative measurement.

B.1.2 Louisiana

The Louisiana Department of Natural Resources (DNR) tracks V&F in a manner similar to the Texas RRC. Operators report the monthly production (wellhead) disposition data on the R-5D form and the gas plant data on the R-6 form. The DNR, like the Texas RRC, compiles all of the monthly data on computer files. The DNR, however, only makes the data available through specific, standardized computer runs which must be pre-paid by the requestor.

Radian has not requested Louisiana runs; however, Louisiana provided the 1988 Parish Report during a visit to the DNR. The report showed a total onshore V&F number similar to Texas, at 0.47% of total gas production (Texas was 0.51%).

Louisiana's definitions of venting and flaring for reported numbers appear to be similar to Texas; and, therefore, Louisiana data will have the same problems that were described for the Texas data. Louisiana also has no method of separating the split between vented and flared quantities from the single V&F numbers reported on the R-5D and R-6 forms. In fact, the term "venting," such as the "vented" column on the R-6 form, refers to venting or flaring.

Although Louisiana does not have a Rule 32 flare permit requirement as Texas does, it has a Statewide Order 45-I that requires a semiannual status report, which lists casinghead and natural gas "vented" by lease and explains why the gas is not being recovered. Unfortunately, the DNR does not aggregate these data; the data are received in nonstandard letter format and stored as received. It would be very difficult and time-consuming to assemble all of these data into a meaningful form. For example, Radian's examination of three 45-I status reports indicated very different results as shown in Table B-1.

TABLE B-1. COMPARISON OF 45-I REPORTS

Company	Type of Gas	Reason for Venting
Mid-size company	Casinghead gas	Uneconomical to recover. Most vent points were low-pressure heater treaters. Some fields used intermittent gas lift, thus, consuming all of the produced gas intermittently.
Large company	Unknown	Majority of emissions were from compressor downtimes.
Small company	Unknown	Compressor downtimes.

B.1.3 Oklahoma

The Oklahoma Corporation Commission's Oil and Gas Conservation Division issues venting and flaring permits. However, only rates above 50 Mcfd require a permit, and few wells fall into that category. The permit file for 1991 had only nine permits issued as shown in Table B-2.

TABLE B-2. 1991 FLARING PERMITS FOR OKLAHOMA

Number of Permits	Percent of Total Permits	Reason for Request
6	67	Recover load water from gas well (well clean-up).
1	11	H_2S found, pulled from gathering system and flared.
2	22	Other (unknown)

Oklahoma appears to have significantly fewer reporting requirements than Texas or Louisiana and had no other data on V&F available. Interestingly, Oklahoma does not appear to exclude well cleanups from the permit requirements as Texas does. As shown above, well cleanups constitute a large percentage of the permits issued in Oklahoma.

B.2 United States

There are several sources of information gathered on the natural gas industry for the entire United States. These sources include federal agencies, such as the Federal Energy Regulatory Commission (FERC) and the Department of Energy (DOE), and gas industry representatives, such as the American Gas Association (A.G.A.). Numerous publications are compiled by these agencies and include information on gas industry financials, gas production and disposition, and gas storage and reserves. Data are also collected from regulatory agencies and other private agencies, such as the American Petroleum Institute (API).

There are five FERC forms that deal specifically with the natural gas industry. The main form completed by gas companies regulated by FERC is the FERC Form No. 2, "Annual Report for Major Natural Gas Companies." This form is an annual requirement for major gas companies, which are defined by the FERC as "having combined gas sold for resale and gas transported or stored for a fee exceeding 50 Bcf (at 14.73 psia 60°F) in each of the three previous calendar years." Most of the information collected on this form is financial and, therefore, does not contribute to the data gathering effort for V&F. The other FERC forms collect information on underground storage (FERC-8), gas pipelines (FERC-11,-15), and gas supply (FERC-16).

The Energy Information Administration (EIA) of the DOE, publishes many reports on the natural gas industry. One of the most useful publications is the *Natural Gas Annual*.[4] Two EIA forms provide most of the information used in this report; EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition," and EIA-627, "Annual Quantity and Value of Natural Gas Report." The EIA-176 is a mandatory form to be completed by all companies that deliver natural gas to consumers or transport interstate gas. The EIA-627 is a voluntary form completed by energy or conservation agencies in gas-producing states. Other sources of information used by EIA for the *Natural Gas Annual* include the FERC, the United States Geological Survey (USGS), and the Interstate Oil Compact Commission (IOCC). Information directly from the USGS and the IOCC has not been gathered for this venting and flaring task.

The *Natural Gas Annual* provides information on gas production, transmission, and consumption for the United States as a whole and for each gas-producing state individually. Included in this report are numbers for gas V&F. Both the EIA-176 and the EIA-627 collect gas V&F information. Since these data are taken directly from the responsible state agencies, any differences in reporting requirements and/or the definition of vented and flared are not accounted for in this publication. Some of these differences were identified in the previous sections on individual state reporting. The EIA is aware of this inherent problem, but it is not known if the agency adjusts the data to reflect these differences.

The A.G.A.'s *Gas Facts* is an annual publication containing data on the gas utility industry. The data concentrate on gas distribution and transmission but also include some information from the gas-producing segment of the industry. Most of the information is gathered by the A.G.A. in its survey entitled "Uniform Statistical Report. The only information on venting and flaring provided in the *Gas Facts* was taken from the EIA *Natural Gas Annual*. Again, this information is just a reiteration of the numbers reported by the responsible state agencies with the inherent problems already discussed. A summary of the national statistics in *Gas Facts* is shown in Table B-3.[1]

It appears that any data which are derived from an overall United States approach are just a summation of the data reported by the individual gas-producing states. Due to the variability in these data, the task of characterizing V&F in the natural gas industry should follow a bottom-up approach and begin with the identification of the individual sources. Then, respective methane emission estimates could be calculated and added to determine the overall emission number for the entire United States.

REFERENCES

1. American Gas Association: *Gas Facts: 1990 Data*, (Table 3-3), Arlington, VA, 1991.

2. Harrison, M.R., H.J. Williamson, and L.M. Campbell. *Methane Emissions from the Natural Gas Industry, Volume 3: General Methodology,* Final Report, GRI-94/0257.20 and EPA-600/R-96-080c, Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

3. Texas Railroad Commission. *Oil and Gas Annual Report,* Volume 1 "Cycling Plant Operations in Texas," Data Source: RRC Form R-3, 1991.

4. U.S. Department of Energy. "Quantity of Natural Gas Used as Lease Plant Fuel by State," *Natural Gas Annual 1992,* Volume 1. Energy Information Administration, Office of Oil and Gas, U.S. Dept. of Energy, Washington, DC, November 1993, p. 240.

TABLE B-3. SUPPLY AND DISPOSITION OF GAS IN THE UNITED STATES - 1989[a]

	MMcf	Percent of Total
Production		
Gas Wells	15,735,849	74.9
Oil Wells	5,262,981	25.1
Total	20,998,030	100.0
Disposition		
Extraction Loss	784,502	3.7
Fuel and Lease Use	1,070,452	5.1
Pipeline Fuel	630,083	3.0
Gas Lift	Unreported	-
Repressure and Pressure Maintenance	2,451,342	11.7
Cycled	Unreported	-
Underground Storage (Net Charge)	(310,802)	(1.5)
To Transmission Lines	15,688,047	73.3
To Carbon Black Plants	Unreported	-
Vented or Flared	140,532	0.7
Acid Gas (H_2S, CO_2, H_2O)	362,457	1.7
Plant Meter Difference (UAF)	182,217	0.9

[a] Data reported includes gas processing.

TECHNICAL REPORT DATA
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1. REPORT NO. EPA-600/R-96-080f	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE Methane Emissions from the Natural Gas Industry, Volumes 1-15 (Volume 6: Vented and Combustion Source Summary)		5. REPORT DATE June 1996 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) L. Campbell, M. Campbell, M. Cowgill, D. Epperson, M. Hall, M. Harrison, K. Hummel, D. Myers, T. Shires, B. Stapper, C. Stapper, J. Wessels, and *		8. PERFORMING ORGANIZATION REPORT NO DCN 96-263-081-17
9. PERFORMING ORGANIZATION NAME AND ADDRESS Radian International LLC P.O. Box 201088 Austin, Texas 78720-1088		10. PROGRAM ELEMENT NO. 11. CONTRACT/GRANT NO. 5091-251-2171 (GRI) 68-D1-0031 (EPA)
12. SPONSORING AGENCY NAME AND ADDRESS **EPA, Office of Research and Development** **Air Pollution Prevention and Control Division** **Research Triangle Park, NC 27711**		13. TYPE OF REPORT AND PERIOD COVERED Final; 3/91-4/96 14. SPONSORING AGENCY CODE **EPA/600/13**

15. SUPPLEMENTARY NOTES EPA project officer is D. A. Kirchgessner, MD-63, 919/541-4021. Cosponsor GRI project officer is R. A. Lott, Gas Research Institute, 8600 West Bryn Mawr Ave., Chicago, IL 60631. (*)H. Williamson (Block 7).

16. ABSTRACT The 15-volume report summarizes the results of a comprehensive program to quantify methane (CH4) emissions from the U.S. natural gas industry for the base year. The objective was to determine CH4 emissions from the wellhead and ending downstream at the customer's meter. The accuracy goal was to determine these emissions within +/-0.5% of natural gas production for a 90% confidence interval. For the 1992 base year, total CH4 emissions for the U.S. natural gas industry was 314 +/- 105 Bscf (6.04 +/- 2.01 Tg). This is equivalent to 1.4 +/- 0.5% of gross natural gas production, and reflects neither emissions reductions (per the voluntary American Gas Association/EPA Star Program) nor incremental increases (due to increased gas usage) since 1992. Results from this program were used to compare greenhouse gas emissions from the fuel cycle for natural gas, oil, and coal using the global warming potentials (GWPs) recently published by the Intergovernmental Panel on Climate Change (IPCC). The analysis showed that natural gas contributes less to potential global warming than coal or oil, which supports the fuel switching strategy suggested by the IPCC and others. In addition, study results are being used by the natural gas industry to reduce operating costs while reducing emissions.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Pollution	Pollution Prevention	13B
Emission	Stationary Sources	14G
Greenhouse Effect	Global Warming	04A
Natural Gas		21D
Gas Pipelines		15E
Methane		07C

18. DISTRIBUTION STATEMENT **Release to Public**	19. SECURITY CLASS *(This Report)* **Unclassified**	21. NO. OF PAGES 61
	20. SECURITY CLASS *(This page)* **Unclassified**	22. PRICE

EPA Form 2220-1 (9-73)

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