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METHANE EMISSIONS FROM THE NATURAL GAS INDUSTRY

Volume 2: Technical Report

Prepared for

Energy Information Administration (U.S. DOE)

Prepared by

National Risk Management
Research Laboratory
Research Triangle Park, NC 27711

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METHANE EMISSIONS FROM THE NATURAL GAS INDUSTRY VOLUME 2: TECHNICAL REPORT

FINAL REPORT

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NOTE: EPA's Office of Research and Development quality assurance/quality control (QA/QC) requirements are applicable to some of the count data generated by this project. Emission data and additional count data are from industry or literature sources, and are not subject to EPA/ORD's QA/QC policies. In all cases, data and results were reviewed by the panel of experts listed in Appendix D of Volume 2.

RESEARCH SUMMARY

Title	Methane Emissions from the Natural Gas Industry, Volume 2: Technical Report Final Report
Contractor	Radian International LLC GRI Contract Number 5091-251-2171 EPA Contract Number 68-D1-0031
Principal Investigators	Matthew R. Harrison Lisa M. Campbell Terri M. Shires R. Michael Cowgill
Report Period	March 1991 - June 1996 Final Report
Objective	This report describes the results of a study to quantify the annual methane emissions from the natural gas industry.
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 purpose of this study was to provide emissions data that could be used to construct global methane budgets and to determine the relative impact of natural gas on global warming versus the impact from coal and oil. This summary report is volume 2 of a multi-volume set of reports that fully describe the project.

Results

The national emissions for the base year are 314 ± 105 Bscf (± 33%), which is equivalent to 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.

On an industry segment basis, the production segment emits 84.4 Bscf, gas processing plants emit 36.4 Bscf, transmission and storage facilities emit 116.5 Bscf, and distribution systems emit 77.0 Bscf. The report also shows that the largest type of methane emissions is fugitives, which accounts for 195.2 Bscf from all segments combined.

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

Technical Approach

The techniques used to determine methane emissions were developed to be representative of annual emissions from the natural gas industry. However, it is impractical to measure every source continuously for a year. Therefore, emission rates for various sources were determined by developing annual emission factors for sources in each industry segment and extrapolating these data based on activity factors to develop a national estimate, where the national emission estimate is the product of the emission factor and activity factor.

The development of specific emission factors and activity factors for each industry segment are presented in a separate report.

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 the IPCC and others.

In addition, results from this study are being used by the natural gas industry to reduce both operating costs and 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 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.

Robert A. Lott
Senior Project Manager, Environment and Safety

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1.0 SUMMARY

This report summarizes the results of a project sponsored by Gas Research Institute (GRI) and U.S. Environmental Protection Agency's Office of Research and Development (EPA/ORD) to quantify methane emissions from the natural gas industry. The project was initiated to evaluate whether the suggested strategy of increasing the use of natural gas to reduce global warming was valid in light of methane emitted from the industry. It also had the purpose of determining the gas industry's contribution of methane to the global inventory of greenhouse gas emissions.

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, GRI and 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.

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 1992 gross natural gas production. The project reached it accuracy goal of determining emissions within ± 0.5% of production, and provides an accurate methane emissions estimate that can be used in fuel switching analyses. The program also showed that the percentage of methane emitted for an

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*Readers more comfortable with metric units will find a conversion table in Appendix C.

incremental increase in natural gas production would be significantly lower than the baseline case.

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).[1] 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. Even across a wide range of assumptions on factors affecting the global warming potentials, natural gas production and use in the United States contributes less to global warming than coal or oil.

The results are currently being used by the natural gas industry to reduce operating costs while reducing emissions. This has led to the development of a voluntary program, the Gas-Star program, sponsored by EPA in cooperation with the American Gas Association (A.G.A.).[2] As part of this voluntary program, participating companies implement cost-effective emission reductions and report the reductions to EPA.

2.0 INTRODUCTION

The increased use of natural gas has been suggested by IPCC and EPA as a strategy for reducing global warming.[1,3] 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, global warming could be reduced by substituting natural gas for coal. However, since natural gas is primarily methane, a potent greenhouse gas, losses of natural gas during production, transmission, and distribution could reduce the inherent advantage of its lower CO_2 emissions. For this reason, GRI and EPA jointly funded and managed a program to estimate methane emissions from the U.S. natural gas industry for the 1992 base year. The objective of this comprehensive program was to quantify methane emissions from the gas industry starting at the wellhead and ending immediately downstream of the customer's meter. The accuracy goal of the project was to determine these emissions to within 0.5% of natural gas production based on a 90% level of confidence. This is equivalent to an accuracy goal of ±111 billion standard cubic feet (Bscf) per year for the 1992 base year.

The methane emissions program was conducted in three phases: scoping, methods development, and implementation phase. During the scoping phase of the program, the methane emissions from each source in the gas industry were quantified on the basis of available data and engineering judgement. These initial estimates were used to set priorities for data collection according to the relative importance of their contribution to emissions or the uncertainty in emissions.

In the second phase of the program, methods were developed to measure and/or calculate methane emissions from the variety of sources that make up the gas industry. These methods were validated through tests designed to quantify the accuracy of the measurement approach (i.e., proof of concept tests), and through industry review of the analytical methods. However, emissions could not be measured or calculated from each piece of equipment (e.g., every glycol dehydrator, compressor engine, etc.) in the industry because of the vast amount of

equipment. Therefore, a major task in the second phase was to develop defensible techniques for extrapolating a limited amount of data collected for each source category to other sources in the category in order to develop a national emissions estimate.

The third phase of the program focused on collecting data needed to define emissions from all sources and extrapolating these data to estimate nationwide methane emissions. Data collection in the third phase of the program concentrated on high priority sources (i.e., sources with large emissions and/or large uncertainties). An Advisory Committee consisting of industry representatives, project sponsors, and other interested parties including scientists, government policy analysts, and environmentalists provided guidance and peer review for all phases of the program. In addition, Gas Industry Review Panels for each segment of the gas industry provided more detailed technical review of the project to ensure that the methodologies and assumptions used in the study were consistent with industry practices.

The final analysis of the data and the methodologies used in the program have been documented in a series of 31 reports. Table 2-1 shows the report name, report volume number, report reference number, and the author of each report. The first 15 reports present final data and analysis, and these reports have been assigned volume numbers. The first 15 reports are available through the National Technical Information Service (NTIS) or from GRI. The remaining reports represent field data, proof of concept tests, and efforts cofunded by others, and have not been assigned volume numbers. These reports are listed here only as references, and must be ordered from the listed author by the reference number.

The first five volumes present the executive summary, the technical report, the general methodology, the statistical methodology, and the activity factors. These first five volumes are the most important source of overall information on the project. Volumes 6 through 15 present the details of the test program and calculation procedures for determining specific emission and activity factors.

TABLE 2-1. U. S. GAS INDUSTRY METHANE EMISSIONS STUDY REPORT LIST

Report Name	Report Number or Reference	Authors/ Contractor
Methane Emissions from the Natural Gas Industry, Volume 1: Executive Summary [4]	GRI-94/0257 EPA-600/R-96-080a	M.R. Harrison et al.
Methane Emissions from the Natural Gas Industry, Volume 2: Technical Report	GRI-94/0257.1 EPA-600/R-96-080b	M.R. Harrison et al.
Methane Emissions from the Natural Gas Industry, Volume 3: General Methodology [5]	GRI-94/0257.20 EPA-600/R-96-080c	M.R. Harrison et al.
Methane Emissions from the Natural Gas Industry, Volume 4: Statistical Methodology [6]	GRI-94/0257.21 EPA-600/R-96-080d	H.J. Williamson et al.
Methane Emissions from the Natural Gas Industry, Volume 5: Activity Factors [7]	GRI-94/0257.22 EPA-600/R-96-080e	B.E. Stapper
Methane Emissions from the Natural Gas Industry, Volume 6: Vented and Combustion Source Summary [8]	GRI-94/0257.23 EPA-600/R-96-080f	T.M. Shires and M.R. Harrison
Methane Emissions from the Natural Gas Industry, Volume 7: Blow and Purge Activities [9]	GRI-94/0257.24 EPA-600/R-96-080g	T.M. Shires and M.R. Harrison
Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks [10]	GRI-94/0257.25 EPA-600/R-96-080h	K.E. Hummel et al.
Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines [11]	GRI-94/0257.26 EPA-600/R-96-080i	L.M. Campbell et al.
Methane Emissions from the Natural Gas Industry, Volume 10: Metering and Pressure Regulating Stations in Natural Gas Transmission and Distribution [12]	GRI-94/0257.27 EPA-600/R-96-080j	L.M. Campbell and B.E. Stapper
Methane Emissions from the Natural Gas Industry, Volume 11: Compressor Driver Exhaust [13]	GRI-94/0257.28 EPA-600/R-96-080k	C.J. Stapper

(Continued)

TABLE 2-1. U. S. GAS INDUSTRY METHANE EMISSIONS STUDY REPORT LIST (Continued)

Report Name	Report Number or Reference	Authors/ Contractor
Methane Emissions from the Natural Gas Industry, Volume 12: Pneumatic Devices [14]	GRI-94/0257.29 EPA-600/R-96-080l	T.M. Shires and M.R. Harrison
Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps [15]	GRI-94/0257.30 EPA-600/R-96-080m	T.M. Shires
Methane Emissions from the Natural Gas Industry, Volume 14: Glycol Dehydrators [16]	GRI-94/0257.31 EPA-600/R-96-080n	D. Myers
Methane Emissions from the Natural Gas Industry, Volume 15: Gas-Assisted Glycol Pumps [17]	GRI-94/0257.33 EPA-600/R-96-080o	D. Myers and M.R. Harrison
An Engineering Estimate of the Incremental Change in Methane Emissions with Increasing Throughput in a Model Natural Gas System [18]	GRI-94/0257.32	Columbia Gas
Results of Tracer Measurements of Methane Emissions from Natural Gas System Facilities, Final Report [19]	GRI-94/0257.43	Aerodyne, Washington State University, University of New Hampshire
Evaluation of Methane Emissions from Natural Gas Production Operations Using Tracer Methodologies [20]	GRI-92/0102	SRI International
Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations[21]	API 4589	STAR Environmental
Fugitive Hydrocarbon Emission: Eastern Gas Wells (Final Report)[22]	GRI-95/0117	STAR Environmental

(Continued)

TABLE 2-1. U. S. GAS INDUSTRY METHANE EMISSIONS STUDY REPORT LIST (Continued)

Report Name	Report Number or Reference	Authors/ Contractor
Leak Rate Measurements for Natural Gas Customer Meters (Draft)[23]	GRI-94/0257.36	Indaco Air Quality Services
Leak Rate Measurements at U.S. Natural Gas Transmission Compressor Stations (Draft)[24]	GRI-94/0257.37	Indaco Air Quality Services
Emission Factors for Oil and Gas Production Operations[25]	API 4615	STAR Environmental
Fugitive Methane Emissions: Customer Meter Sets (Final Report)[26]	GRI-95/0204	STAR Environmental
Phase 3 Program Plan - Implementation Plan [27]	Radian DCN 92-263-081-02	Radian Corporation
Mass Balance of a Natural Gas Transmission System for Improved Estimates of Methane Emissions [28]	SwRI 04-4447	Southwest Research Institute
Soil Consumption of Methane from Natural Gas Pipeline Leaks[29]	GRI-94/0257.35	Aerodyne, Washington State University, University of New Hampshire
Sampler Enables Measurement of Leaks on Site-Specific Basis [30]	American Oil and Gas Reporter, March 1995	Lott, Webb, Howard

This technical report is organized as follows: Section 2 presents background information; Section 3 provides an overview of the methodologies developed and followed in the study which includes methods for characterizing the industry, measuring and calculating emission factors, collecting activity factor data (equipment and component counts), and extrapolating the data to derive an annual methane emissions estimate for the U.S. natural gas industry. Section 4 provides summaries of the largest methane emission sources. Section 5 provides an overview of the major conclusions drawn from the study.

3.0 METHODS

This section characterizes the natural gas industry and describes in general terms the methods used to define and extrapolate emissions for all source types or categories that comprise the industry.

3.1 Emission Source Characterization

The first step for estimating methane emissions from the U.S. natural gas industry is to identify and characterize each emission source within the industry, so that all significant sources are included. To fully characterize the industry, sources were defined by equipment type, mode of operation, and type of emissions.

While this section draws a general picture of the industry, it is not intended to be a definitive picture of any company or of the industry regarding specific operational practices and procedures. Rather, it is intended to define the general industry equipment practices and procedures used in 1992, the base year of the program, that could lead to measurable emissions of methane. Details that were useful for determining methane emissions are contained in specific reports (see Table 2-1).

3.1.1 General Industry Description

The natural gas industry uses wells to produce natural gas existing in underground formations, then processes, compresses, and transports the gas to the customer. Transportation and distribution of natural gas involve interstate and intrastate pipeline transportation, storage, and finally distribution of the gas by local distribution pipeline networks.

The generally accepted segments of the natural gas industry are:

1) Production
2) Processing
3) Transmission/storage
4) Distribution

Each of these segments is shown in the flow chart for the industry in Figure 3-1. Some of the major equipment in each segment is shown in Table 3-1. Each segment is described in more detail in the following subsections.

This project set specific boundaries for each segment of the industry that specify what equipment is included in the study. The guideline used for setting the boundaries was to include only the equipment in each segment that is required for marketing natural gas. For example, oil production equipment is excluded if it is used to produce oil and not natural gas. Similarly, gas processing equipment associated with the fractionation of propane, butane, and natural gas liquids are excluded from consideration. In distribution, all equipment up to and including the customer's meter are included. End-user emissions are not included in this estimate.

Each industry segment is described in more detail in the following subsections:

Production Segment Description

The production segment is comprised of gas and oil wells and the surface equipment required to produce gas. The well includes the holes drilled through subsurface rock to reach the producing formation and the subsurface equipment such as casing and tubing pipe. Gas and oil surface equipment can include separators, heaters, heater-treaters, tanks, dehydrators, compressors, pumps, and pipelines.

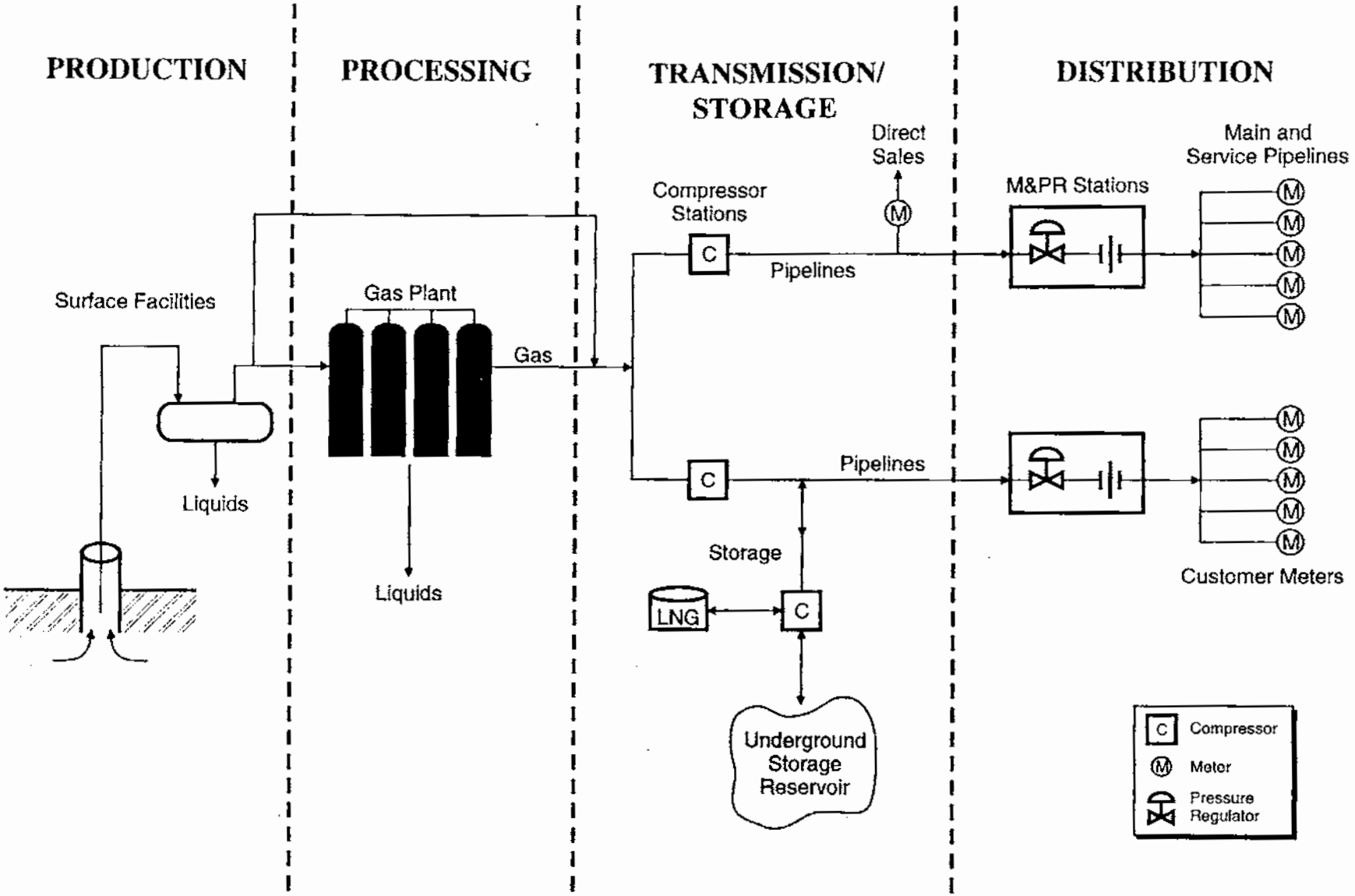

Figure 3-1. Gas Industry Flow Chart

TABLE 3-1. INDUSTRY CHARACTERIZATION

Segment	Facilities	Equipment at the Facility
Production	Well Sites, Central Gathering Facilities	Wellheads, Separators, Pneumatic Devices, Chemical Injection Pumps, Dehydrators, Compressors, Heaters, Meters, Pipelines
Processing	Gas Plants	Vessels, Dehydrators, Compressors, Acid Gas Removal (AGR) Units, Heaters, Pneumatic Devices
Transmission	Transmission Pipeline Networks, Compressor Stations, Meter and Pressure Regulating Stations	Vessels, Compressors, Pipelines, Meters/Pressure Regulators, Pneumatic Devices
Storage	Underground Injection/Withdrawal Facilities, and Liquefied Natural Gas (LNG) Facilities	Wellheads, Vessels, Compressors, Dehydrators, Heaters, Pneumatic Devices
Distribution	Main and Service Pipeline Networks, Meter and Pressure Regulating Stations	Pipelines, Meters and Pressure Regulators, Pneumatic Devices, Customer Meters

The definition for gas industry production equipment excludes equipment associated with oil production. Also, unmarketed natural gas, such as that produced by oil wells that vent gas or that reinject gas for gas lift circulation only, are not considered part of the natural gas industry. Figure 3-2 shows the general equipment found in the oil and gas production segment, as well as the boundaries between gas and oil production equipment used by this study.

The boundary between oil and gas equipment shown in Figure 3-2 affects the gas industry emissions estimate since it excludes some high emission rate production equipment associated with oil production. An accounting of total production segment emissions, or just oil industry emissions, will have to include the oil industry equipment excluded from this study (such as some pneumatics, some chemical injection pumps, and oil tanks).

Gas Processing Segment Description

Natural gas processing plants recover high value liquid products from the gas stream and maintain the quality (i.e., content and heating value) of the gas stream. The liquid products include natural gasoline, butane, propane, and in some cases, ethane. The products are removed by compression and cooling or by absorption.

A gas plant may have fractionation towers and stabilization towers to further purify the individual components of the product stream. The back end of the gas plant, such as the fractionation train, is excluded from the gas industry definition since its function is to purify and market liquid products. Also, the back end of the gas plant has negligible methane emissions since the liquids handled have little methane content.

The front end of the gas plant often contains dehydration facilities, wet gas compression, and the absorption or compression and refrigeration process. All natural gas processing plants are considered part of the natural gas industry, and methane emissions from these facilities are included in this study.

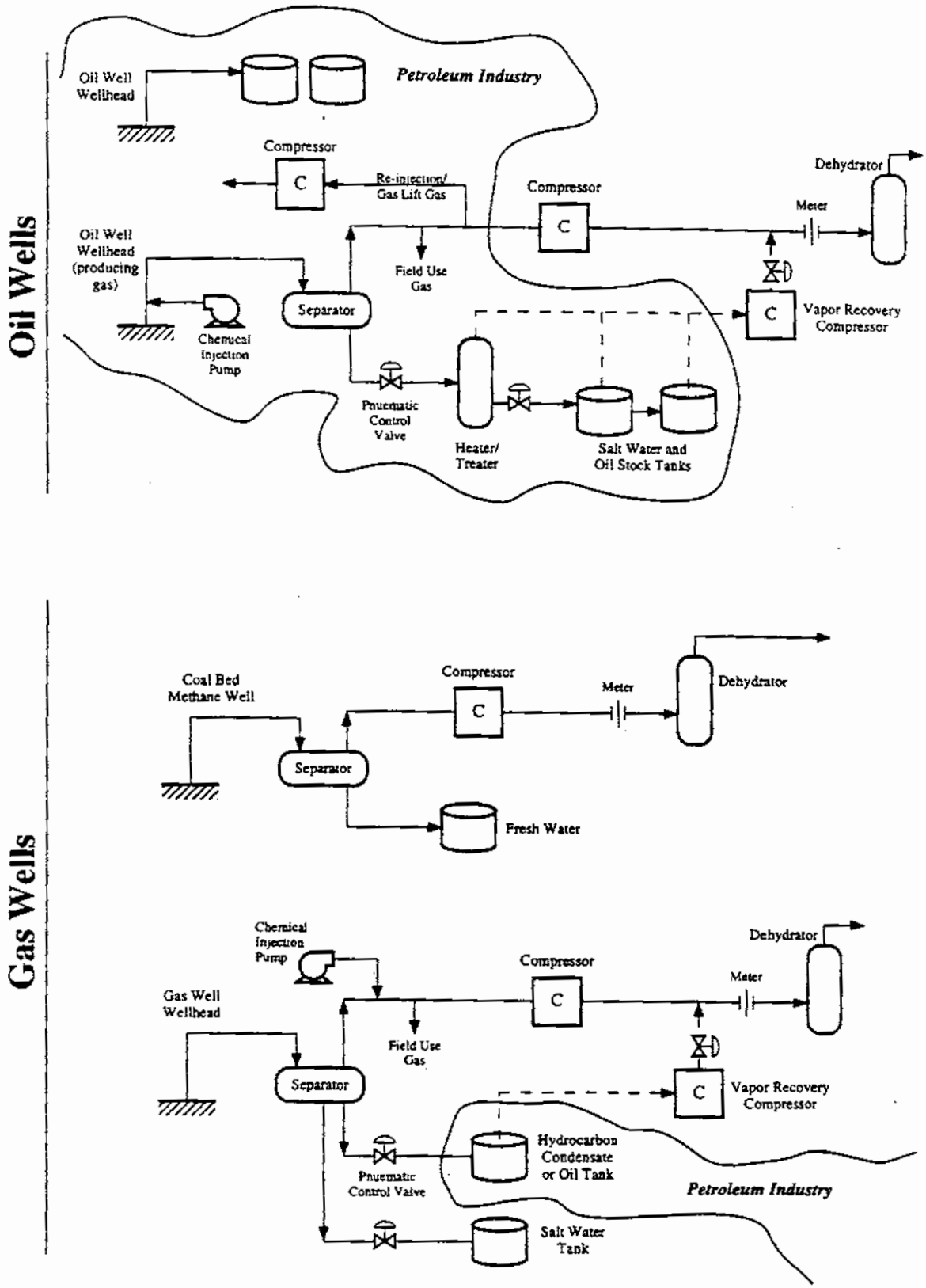

Figure 3-2. Gas Industry Boundaries

Transmission and Storage Segment Description

The transmission segment moves the natural gas from the gas plant or directly from field production to local distribution companies (LDCs). Gas is often transported across many states, such as from the Gulf Coast to the Eastern seaboard of the United States. The transmission segment consists of large diameter pipeline, compressor stations, and metering facilities. All of these facilities and all of the equipment they contain are considered part of the natural gas industry.

Transmission compressor stations usually consist of piping manifolds, reciprocating engines or gas turbines, reciprocating or centrifugal compressors, and generators, as shown in Figure 3-3. Dehydrators may be included but are not typically present because of upstream gas drying. Some transmission compressor stations may also include metering facilities.

Transmission companies also have metering and regulating stations (M&PR) where they exchange gas with other transmission companies, or where they deliver gas to LDCs or industrial customers. These stations may contain heaters, small dehydrators, and odorant addition equipment.

Most storage facilities exist to store natural gas produced during off-peak times (usually summer) so that gas can be produced and delivered during peak demand. Storage facilities are often located close to consumption centers so that cross-country transmission pipelines do not have to be sized for peak demand. Storage facilities can be below or above ground. Above-ground facilities are liquefied natural gas (LNG) facilities that liquefy the gas by supercooling and then storing the liquid phase methane in above ground, heavily insulated storage tanks. Below-ground facilities compress and store the gas (in vapor phase) in one of several formations: 1) spent gas production fields, 2) aquifers, or 3) salt caverns. Below-ground storage is the predominant means of gas storage.

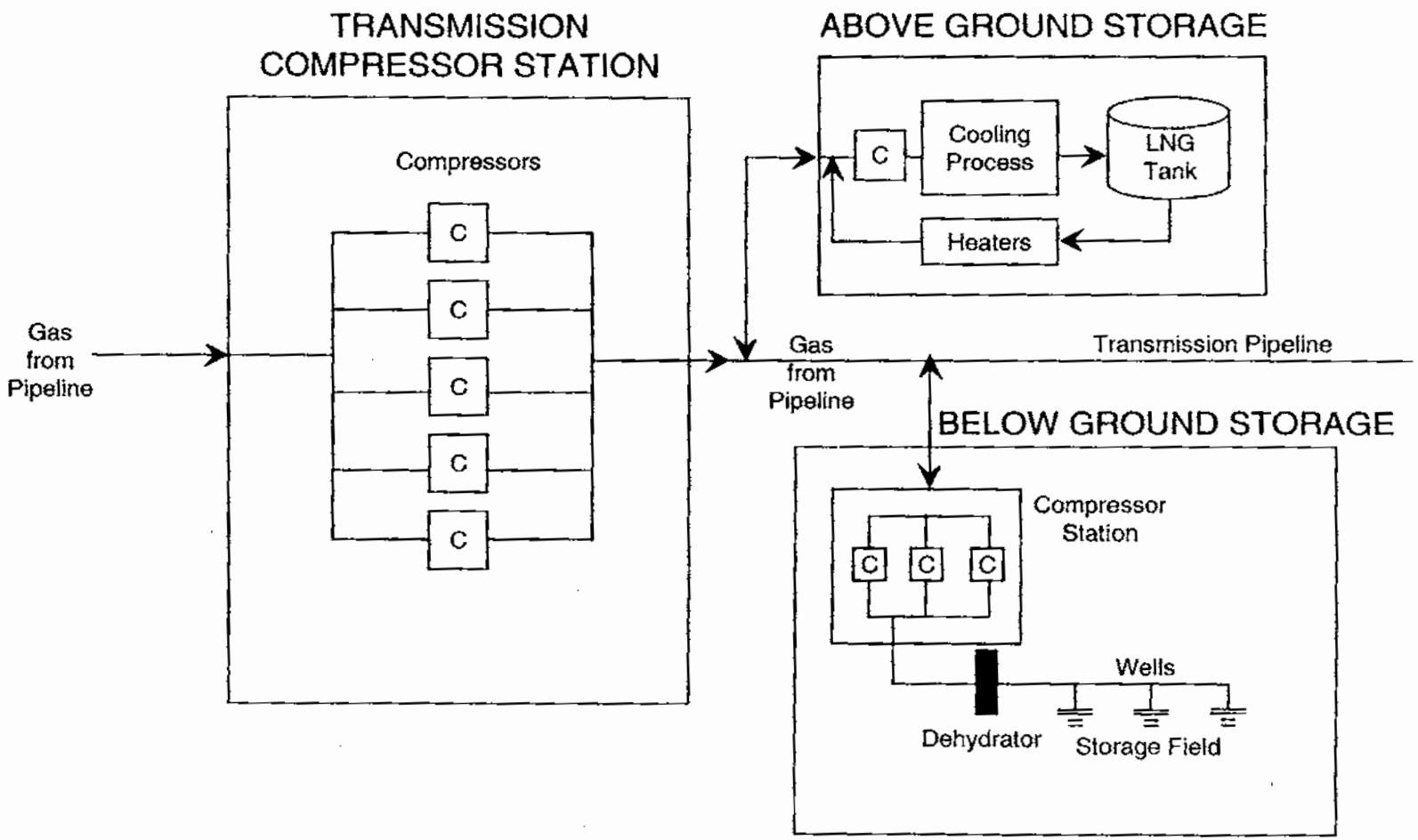

Figure 3-3. Transmission and Storage Stations

Most storage stations consist of a compressor station that is very similar to a transmission compression station (see Figure 3-3). Underground storage facilities also have storage field wells, and usually have dehydrators to remove water absorbed by the gas while underground. All storage equipment is included in boundaries of the natural gas industry defined by this project.

Distribution Segment Definition

The distribution segment receives high pressure gas from transmission pipelines, reduces the pressure, and delivers the gas to residential, commercial, and industrial consumers. This segment includes pipelines (mains and services), M&PR stations and customer meters. All of these facilities are considered to be an integral part of the gas industry. Figure 3-4 shows a schematic of the distribution segment and the equipment that it includes.

3.1.2 Operating Mode

After identifying the major equipment (source types) in each industry segment, emissions from each source were identified by examining the *operating modes* of the equipment that may lead to emissions, and by associating one of three possible *types* of emissions from the source: fugitive emissions, vented emissions, or combustion emissions.

The cause of emissions is directly related to the operating mode of the equipment. Since more than one cause of emissions can be associated with a particular piece of equipment, it is important to identify the various operating modes in order to identify all emissions. In general, the operating modes are:

- Start-up;
- Normal operations;
- Maintenance;
- Upsets; and
- Mishaps.

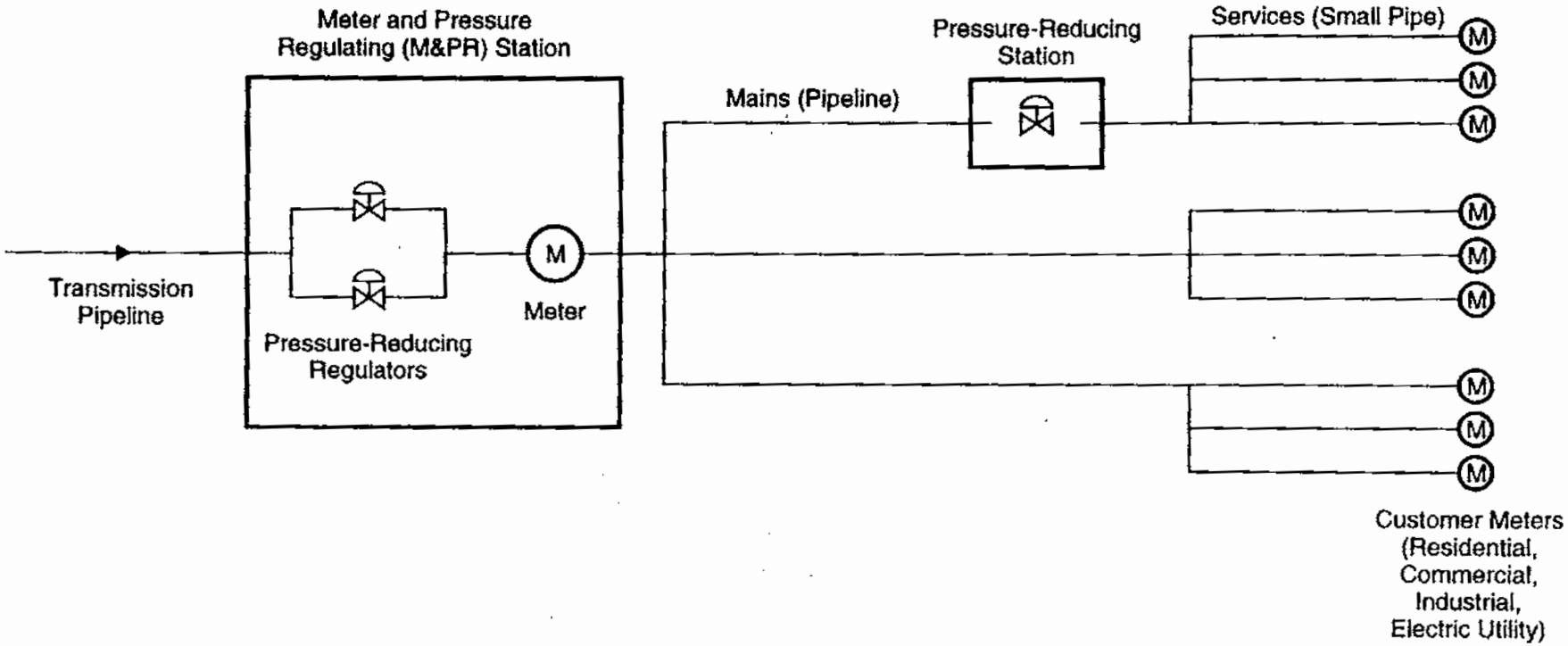

Figure 3-4. Distribution Segment Equipment

Start-up operations, such as purging a newly constructed plant or pipeline, can involve purging natural gas directly to the atmosphere. Emissions associated with normal operations include emissions from process vents, fugitive emissions from packed or sealed surfaces or underground pipeline leaks, and emissions from gas-operated pneumatic devices. Maintenance operations involve blowing down equipment, such as compressors, pipelines, or vessels, before equipment maintenance. Process upsets usually involve releasing natural gas to the atmosphere or to a combustion device, such as a flare, as the result of overpressure or emergency shutdown conditions. Mishaps are intended to include accidental occurrences that result in emissions, such as third-party damage to pipelines (dig-ins).

3.1.3 Emission Types

Emissions from each piece of equipment in the natural gas industry can be classified in one of three general emission types: 1) fugitive emissions; 2) vented emissions; and 3) combustion emissions. Fugitive emissions are unintentional leaks emitted from sealed surfaces, such as packings and gaskets, or leaks from underground pipelines (resulting from corrosion, faulty connections, etc.). Vented emissions are releases to the atmosphere by design or operational practice. Examples of vented emissions include emissions from continuous process vents, such as dehydrator reboiler vents; maintenance practices, such as blowdowns; and small individual sources, such as gas-operated pneumatic device vents. Combustion emissions are exhaust emissions from combustion sources such as compressor engines, burners, and flares.

In summary, the facilities and equipment comprising each segment of the industry were identified. Each source (i.e., piece of equipment) was then examined for different emissions during different operating modes. Emissions from each source were also categorized as either combustion, vented, or fugitive. Equipment, such as compressors, might emit gas under all three categories (fugitive emissions when pressurized, vented emissions when blown down for maintenance, and combustion emissions during normal operations).

3.2 Emission Estimation Technique

After all potential sources of methane emissions in the industry were identified and characterized, the annual emissions were estimated. Because it would be impractical to measure emissions all year for every source, it is important that a measurement be representative of the annual emissions. Some emissions from natural gas industry sources are continuous and nearly "steady" and a single measurement is representative of annual emissions. ("Steady" is a relative term and to some extent is dependent on the time period of data needed for the study. For this study, the annual value of methane emissions is needed.) The measurement techniques used in this study depended on the variability of the emission rate with time.

Emissions that are intermittent are considered "unsteady" and have variable emission rates during a year. Because it would not be practical to collect data continuously for a year for each source, emissions from these sources were calculated rather than measured. Table 3-2 shows examples of emission sources characterized by operating mode emission type and whether the emissions are steady or unsteady.

3.2.1 Measurement Techniques for Steady Emissions

Steady emissions result from unintentional leaks from sealed surfaces such as pipe connectors, valve packing, flange gaskets at surface facilities, and from components and small holes in below-ground equipment (i.e., pipelines). One method for measuring these steady fugitive emissions from above-ground facilities (surface production equipment, gas plants, compressor stations, etc.) is to measure emissions from individual components, and then sum all the component emissions for the facility. Other surface facility methods include the tracer gas method. Measuring emissions from buried pipelines is done through a leak statistics method. Each of these methods is described in the following subsections.

TABLE 3-2. EMISSION CHARACTERIZATIONS

Emission Type	Specific Source Examples	Operating Mode	Steady or Unsteady
Fugitive	Packed or Sealed Surfaces	Normal Operations	Steady
	Leaks (holes in gathering & distribution pipes)	Normal Operations	Steady
	Leaks (holes in transmission pipes)	Normal Operations	Steady
Vented	Dehydrator Vents	Normal Operations	Steady
	Pipeline Purge/Blowdown	Maintenance	Unsteady
	Pneumatic Devices	Normal Operations	Unsteady
	Compressor Starts	Normal Operations	Unsteady
	Equipment Blowdown	Maintenance	Unsteady
	Chemical Injection Pump Vents	Normal Operations	Unsteady
	Pressure Relief Valve Lift	Upsets	Unsteady
Combusted	Compressor Driver Exhaust	Normal Operations,	Unsteady
	Flaring	Upsets/Maintenance	Unsteady
	Burners	Normal Operations	Unsteady

Component Measurement Methods

One method for determining fugitive emissions from above-ground facilities is to determine emissions from basic components such as valves, flanges, seals, and other connectors and then sum these for a given facility to determine total emissions. As part of this program, GRI cofunded studies with API and others to update emission factors for pipe fittings and other components used in oil and gas production.[21,22,23,24,25,26] Nearly 200,000 components were screened at 33 facilities throughout the country. The approach was to measure emissions from a large number of randomly selected components and to determine the average emission rate (i.e.,

emission factor) for each type of component. After the components were screened to determine if they were leaking, the average emission rate was measured using one of several test methods:

- A high flow organic vapor analyzer that captures the entire leak and measures the methane concentration and flow rate. The emission rate is determined from the product of the concentration and flow rate. This method was developed as part of this natural gas industry program to provide a more accurate and cost-effective technique for measuring a methane emission rate directly.

- A total enclosure technique called bagging. Uncontaminated air is blown through an enclosure surrounding the component; the flow rate and outlet concentration are then measured. The leak rate is determined from the product of the concentration and flow rate.

- A screening technique in which the methane concentration is measured by passing a standard organic vapor analyzer around the sealed surface. The concentration is related to an emission rate by a correlation equation that relates bagged emissions to measured screening values.

Tracer Gas Method

The tracer gas method of measuring methane emissions consists of releasing tracer gas (at a known constant rate) near the emission source and measuring the downwind concentrations of tracer and methane. Assuming complete mixing of the methane and tracer gas, and assuming identical dispersion, the ratio of the downwind concentrations is equal to the ratio of the release rates. Based upon the downwind concentrations of methane and tracer gas and the known release rate of the tracer, the emission rate of methane can then be determined. This method was used primarily to measure emissions from M&PR stations.[12,19]

Leak Statistics Method

The leak statistics method is used to quantify methane emissions from underground main and service pipelines.[11] Emission rates are measured for a large number of leaks to accurately determine the average emission rate per leak as a function of pipe material, age, pressure, and soil characteristics. The measurement program was conducted as a cooperative effort between EPA/GRI and industry. The industry participants used specially designed equipment to measure leak rates from underground distribution mains and services. In the procedure, a pipe segment containing the leak is isolated, the isolated segment repressurized, and the volumetric flow required to maintain normal operating pressure in the isolated segment is equal to the leak rate. Historical leak records are analyzed to determine the number of leaks per mile for different pipe materials. Total emissions are determined by multiplying the average leak rate per leak by the estimated total number of leaks in the distribution segment.

3.2.2 Calculation Approach for Unsteady Emissions

For some methane emission sources, such as releases during maintenance, detailed company records are available for multiple years. However, many other sources of unsteady emissions are not tracked by companies and, therefore, must be calculated.

Each unsteady source of emissions requires data gathering and a unique set of equations to quantify the average annual emissions. In general, all unsteady sources of emissions require the following information to quantify annual emissions:

- Detailed technical characterization of the source and identification of the important parameters affecting emissions. (This information is documented for individual source types in the reports for each major source category.)
- Data from multiple sites that allow the methane emitted per emission event to be calculated from the governing equations.

- Data on the frequency of releases.

The estimate of emissions from a vessel blowdown for routine maintenance is an example of emissions calculated for an unsteady source . In this case, the volume, pressure, and temperature of gas contained in the vessel before blowdown is used to calculate losses from a blowdown event. Additionally, an average frequency of these vessel blowdown events is necessary to determine the annual loss.

In some cases, emissions per event from some unsteady sources were measured. These emissions data were combined with site data collected in this study to quantify the annual emissions from these sources. Examples of sources where emission measurements per event were used include emissions from compressor driver exhaust, gas-operated pneumatic devices, glycol dehydrator regenerator overhead vents, and gas-operated chemical injection pumps.

3.3 General Extrapolation Methodology

By necessity, data in this project were collected for a relatively small percentage of sources in each source category. Therefore, these data had to be extrapolated to develop national estimates for each source category. The extrapolation techniques for creating national emission estimates were developed so that the emissions from each source could be estimated with a relatively high level of precision (given the nature of this study) and negligible bias. (See Section 3.4 for definitions of precision and bias.)

The extrapolation approach is a method to scale-up the average emissions from a limited number of sources to represent the entire population of similar sources in the gas industry. The extrapolation approach uses the concept of emission and activity factors to estimate emissions based on a limited number of samples. These factors are defined in such a way that the product of emission and activity factors equals the annual national emissions from the source category.

Emission Factor × Activity Factor = National Emissions

Typically, the emission factor (EF) for a source represents the average emissions rate per source and the activity factor (AF) represents the total industry population of the source category.

3.3.1 Sampling Approach

Even if the overall precision of an estimate is acceptable because the variability in the data is relatively low, the overall accuracy may still be poor if the data are biased. Several approaches can be applied to avoid bias.

Because of various practical limitations, neither random sampling nor stratified random sampling was feasible in this study. For this reason, an alternate approach was used. While this approach is not a textbook sampling method, it is believed to be very effective for the specific needs of this project. This approach is similar to disproportionate stratified random sampling, with certain differences. These conventional sampling techniques and the reason why they were not applicable in this project are discussed in Volume 4 on statistical methodology.[6]

Initially, some data were collected to determine if a given source was a major contributor to methane emissions. For each source category, an initial estimate of the number of data points needed was calculated based on an estimate of the target precision and the estimated standard deviation for the source category. The accuracy targets for precision are based on the need to estimate the 1992 national emissions to within 0.5% of U.S. natural gas production with a 90% confidence limit. Sites were selected in a random fashion from known lists of facilities, such as GRI or A.G.A. member companies. However, the companies contacted were not required to participate, and a complete list of all sources in the United States was generally not available. Therefore, the final set of companies selected for sampling was not truly random. Each company that agreed to participate in the program was asked to select representative sites for sampling, rather than one-of-a-kind facilities.

After a limited set of data was collected, the data were screened for bias by evaluating the relationship between emission rate and parameters that may affect emissions. It is important to realize that just because a parameter or set of strata is identified that has a large effect on emissions from a given source category, it does not mean that there is bias in the data. A second condition is necessary, namely, that the sampling procedure would have to produce a disproportionate number of samples in the strata. To determine whether this has occurred, information is needed on the ratio of the total number of sources in a given stratum to the total number of sources throughout the country. If this ratio is different from the corresponding ratio for the sample data set, then there may be bias. But this bias can be eliminated by applying the correct emission factors and activity factors for the different strata.

Once the strata are identified, the precision of the emission rate extrapolated to a national basis was evaluated and compared to the accuracy target. Where necessary, additional data were collected in various strata to improve the precision of the national estimate of emissions from the source. The number of additional data points needed to meet the newly calculated accuracy target was computed based on the standard deviation and a 90% confidence interval.

In some cases, variability of the emissions data from source to source is very large. For source types of this nature, it is normally possible to reduce variability by redefining the emission factor or by stratification. This is important because reducing variability reduces the number of data points needed to achieve the accuracy target.

3.3.2 Redefining the Emission Factor

For a few types of sources, emissions can be more accurately estimated when the emission factor is defined not as a simple average of the data but is expressed in terms of a key parameter that influences the emissions from the source. Since this would significantly reduce the variability, fewer data points are required to achieve the desired level of accuracy. For example, the internal combustion engines that drive compressors in the gas industry vary in size

(i.e., horsepower rating). If data were collected on individual engines in the industry, and an average emission rate per engine was established, the variability from engine to engine would be very large because of size differences. However, if the emission factor for the engines is defined by horsepower of the engine (i.e., annual emissions per horsepower), then the variability from engine to engine and therefore the number of samples required to reach an acceptable accuracy are both significantly reduced.

As discussed previously, the number of data points required also may be reduced by stratifying on the basis of parameters that affect emissions. A source type can be stratified into categories with different emission characteristics; the objective is to produce strata with much less variability than the total data set. The sampling is performed within the strata and because the variability within the strata is smaller, fewer total data points are required to achieve target precision.

3.4 Accuracy

A key part of this project is the estimation of the accuracy of the annual national emissions. Accuracy is dependent on precision and bias, as discussed in Volume 4 on statistical methodology.[6] Precision, the random variability in the measurement, is calculated rigorously by propagating error from each individual group of measurements into the final numbers. However, bias, a systematic error in the measurements must be prevented or discovered and eliminated, rather than identified and calculated.

3.4.1 Precision

Most source activity factors and emission factors are made up of an average of multiple measurements or calculations. Therefore, assuming a normal distribution around a mean and error independence, standard deviations and 90% confidence limits can be calculated directly for each group of measurements in an activity or emission factor.

The confidence intervals or error bounds can be propagated through the addition of multiple emission source estimates to arrive at a confidence bound for the national emission estimate. These generally accepted statistical techniques are described in detail in the statistical methods report cited previously.

3.4.2 Bias

It is impossible to prove that there is no bias in any data set. While tests can be designed that are capable of revealing some bias, there are no tests nor group of tests that will reveal all possible biases. Assuming that a data set has no bias is only a hypothesis, even after extensive testing. Such hypotheses can be disproved, but not absolutely proven. However, the data collected during this project were extensively checked and rechecked to identify and then eliminate biases. Three basic methods were used to screen for bias: peer review by experts, subdivision of the data into strata, and extrapolation by different parameters. Some of these techniques were discussed previously in Section 3.3.

Data sets were tested repeatedly through extensive technical and industrial review. Numerous project advisor's meetings were held during the course of the study to examine the data with industry representatives and other experts so that systematic errors could be identified and eliminated. When biases in the sampling plan or extrapolation method were postulated, the project was altered to test for that bias and eliminate it if it existed. One example of the success of this review process is the identification of regional differences in production practices. These differences were identified during the advisor meeting review process. The regional bias was then eliminated by subdividing the production data into two offshore and four onshore regions, collecting random samples within each region, and extrapolating by region.

3.5 Quality Assurance and Quality Control Approach

As defined during the 1980s quality initiatives, quality is conformance to requirements.[31] The programmatic quality assurance requirement of this project was to develop a

national emission estimate of defined uncertainty and no known bias. Accordingly, the GRI/EPA-ORD program included quality assurance and quality control (QA/QC) activities designed to control and assess the quality of the data collected and the resultant conclusions.

Other QA/QC activities associated with the various data sources, data handling, project review, and statistical analysis are outlined in subsequent reports associated with this project. The report on general methodology explains the industry characterization used to identify each emission source, the measurement techniques, and calculation approaches.[5] The statistical approach for this project is presented in the statistical methodology report.[6] In addition, the individual reports for each emission source provide detailed statements regarding data quality efforts and uncertainties associated with the specific components that make up each emission estimate.

3.5.1 Overview

The first step in this project's QA/QC efforts was the establishment of project phases that had clear QC goals and that outlined QA review steps. This allowed the nature and breadth of data collection to be modified to ensure consistent data collection with minimal bias. The three phases of this study, and their inherent QA/QC goals were:

Scoping phase—The scoping phase included defining the boundaries of the natural gas industry and a comprehensive characterization of all equipment in the natural gas industry that could be a source of methane emissions. This process minimized the potential bias of missing sources or double counting sources in other industries, such as the oil production industry. Steps taken during this planning process ensured that all sources of emissions were examined and that the accuracy and bias goals of the project could be met.

Methods development phase—Based on the factors that contributed to each emission source, methods and protocols were developed to measure and/or

calculate each emission factor. Measurement methods were validated through controlled experiments (laboratory), tests in the field, and proof of concept tests designed to quantify the accuracy in the measurement approach. Methods were also developed to extrapolate limited emission estimates to a national emission rate, accounting for regional differences in equipment and operational practices. The methods were peer reviewed before they were implemented.

Implementation phase—The implementation phase focused on collecting the final field data required for emission factors and activity factors based on the developed methodologies. QC steps were used for data collection, and QA was performed on the data collected. Data were screened for bias and further stratified if a relationship between the emission rate and a parameter affecting emissions was identified. Uncertainty bounds were calculated to quantify precision and results were compared to the target precision. Where necessary, additional data were collected to improve the precision of the national emission estimate for a particular source.

The following sections outline the specific QA and QC goals and methods used throughout the project.

3.5.2 Definitions

In general, QC activities include those designed to control the data collection and data handling efforts to ensure consistency and reliability throughout the process. The QC activities incorporated throughout the project included:

- Proof of concept tests;
- Protocols for test methods and data collection;
- Methodology for data handling, and extrapolation; and

- Established documentation, reporting, and filing systems.

Quality assurance activities are generally considered those that are independent of the data gathering effort, per se. The QA activities incorporated throughout the project included:

- Quality audits;
- Industry peer review;
- Comparison to other studies; and
- Statistical analysis.

Both QC and QA steps were aimed to minimize any potential bias in the estimate. The following subsections describe the QC and QA efforts in more detail.

3.5.3 Quality Control

The GRI/EPA study was designed from the beginning to implement standard QC procedures, such as defined methods and protocols for data collection and handling. The most significant QC step was the development and use of general methodologies that ensured consistent results. During the methods development phase, a sampling plan and data gathering protocol were developed. Most of the plans and protocols are outlined in the Volume 3 Methodology Report,[5] or in the Phase 3 Program Plan.[27]

Emission factor measurement programs had a QC plan for measurement data gathering that included:

- Adherence to formal protocols for data collection; and
- Sampling and analysis QC checks, including
  - Sample collection during representative operations,
  - Instrument calibration,
  - Analysis of blank samples,

- Analysis of known standards, and
- Analysis of replicate samples.

In addition, where new measurement technologies were being applied, proof of concept tests were performed and documented. For example, for the new distribution tracer measurements of meter and regulation stations, QC efforts associated with emission factor measurements are outlined in the Phase 3 Program Plan[27] and in the tracer measurement field report.[19] Since the measurement technology is new to this distribution application, proof of concept tests were performed and are reported in a separate volume.[20] Similar QC efforts and proof of concept tests exist for underground pipeline leak measurements: QC plans were documented in the Phase 3 Program Plan and in the detailed field planning protocol[32], and QC results are documented in the Underground Pipeline Leaks report.[11] Other QC efforts for emission measurements, such as other fugitive emission efforts, are outlined in the specific field reports cited by this project (see Table 2-1).

For activity factors, a general data collection methodology was developed that is described in the Activity Factor Report.[7] The collection of activity factor data included the following QC efforts:

- Establishing a site visit protocol and data gathering form for each type of site;
- Establishing a data entry protocol (for spreadsheet data entry from the site visit forms and files);
- Validation of data entry;
- Comparison among site entries to identify unusual data; and
- Verification of unusual data.

In most cases, activity factor data were gathered directly through site visits or from published sources. In a few instances, data were collected from efforts outside of this program and for which no published field reports exist. For example, one production company provided their compressor database which was used in the production activity factor estimate of

horsepower·hours.[13] In these cases, QC efforts performed by this project were limited, and QA efforts were therefore intensified, as is described in the following section on QA.

Data on emission and activity measurements were collected and condensed electronically, so that auditable electronic files contain all of the major data points, calculations, and extrapolations. Many of these data are also printed in the field reports, and in the reports comprising the 15 volumes of this set.

In addition to methodologies and QC efforts directed at activity and emission data gathering, methodologies and QC efforts were developed for data handling and extrapolation techniques. These are outlined in the Activity Factor report[7] and the Statistical Methods report.[6]

3.5.4 Quality Assurance

The main goal of the QA program was to ensure the validity of the estimate through data audits, result reviews, and statistical analysis. As with the QC steps, one of the main goals of QA was to identify and eliminate bias. The main QA steps were audits, statistical analysis, technical review, and comparison to other studies. Each of these are described in the following paragraphs.

Quality audits of the databases and calculations were conducted to verify accuracy of the mathematical applications. Audits included the following:

- Checks of the calculations made by spreadsheets. These were provided by hand checking the results using the equations and data published in the various reports. Also, independent calculation was performed by the summary spreadsheet (in Appendix A). This validated the individual emission rate and confidence bound calculations made in each report.

- Checks of conformance to known technical relations and first principles. For example, in the QC checks of activity factor data provided on annual operating hours for compressors, data were rejected if operating hours exceeded 8760, the maximum number of hours in a year.

QA audits were also performed on industry databases provided by participant companies. In a few cases, specific company data were provided to a particular emission estimation process, such as compressor HP-hrs for an entire company's production division, or vented quantities from an entire transmission company's system. The data requirements were listed in a letter to the particular company. These data were checked for completeness by the project team, using follow-up questions to the supplier of the data, and some specific QA requirements for the data supplied. Some supplied data that did not meet the QA/QC validation criteria were rejected or not used. Data that were gathered in violation of typical QC controls such as consistently following a generally accepted measurement method. For example, pneumatic device emission rate data that did not follow the QC protocol of a single measurement for a single device were rejected from the dataset. (Some measurements were emissions from multiple devices; this rejected only 2 data points from a set of 43.)[14] In some cases, the project team visited the company to discuss the data. Specific data discussions are provided in the detailed emission source reports (Volumes 6 through 15[8-17] in Table 2-1).

Another QA step was the use of statistical analysis, using error propagation to define the precision and confidence in the final estimate. Uncertainty in the emission factors and activity factors was calculated for each emission source based on the variability in the data. The few exceptions relate to well documented data or emission sources with a very small contribution to the overall emission estimate. Narrow confidence bounds were assigned to well-known, often published values, where the confidence bounds were not published and the supporting data were not available to calculate a confidence bound (e.g., the natural gas production rate published in *Gas Facts*[33]). For source categories with a very small emission rate but unknown uncertainty, wide confidence bounds were assigned rather than expending resources to collect additional data for a source that had an insignificant contribution to the end result. The method for the confidence bound is carefully documented for each value in the applicable emission characterization reports.

In all cases, the resulting confidence limits on the emission rate (the product of the emission factor and the activity factor) were rigorously propagated from the confidence limits of the activity and emission factor values. The result is that statistical analysis was very robust. The analysis was made even more robust through analysis of potential correlation between the data, and potential bias effects. In addition, separate tests of the input data sets were performed. For example, outlier tests were performed on input datasets. (See the *Statistical Methods*[6] report for further details.) Any anomalies were verified and documented or corrected.

Another very important and unique QA step was the extensive technical review process. All stages of this project received detailed review by an advisory panel comprised of gas industry experts and representatives from other related industries, such as coal and oil. The panel approved the goals and scope of the project and verified that the general results of the project were acceptable. The advisory panel met six times during the 5-year duration of the project to review and approve the methods and protocols. In addition, the advisory panel reviewed the draft and final versions of the project reports.

Other industry reviewers were involved in the final stages of the project (spanning approximately two years). These individuals, who had industry experience relating to one or more specific project areas, reviewed emission estimates and the supporting data and methodology to verify that the results were not biased. In addition, the reviewers provided comments on individual reports in their areas of expertise. The involvement of these reviewers served as a QA measure by ensuring that all emission sources were accounted for and that all data handling methods were representative of the natural gas industry. A list of the advisors and reviewers is included in Appendix D of this report. The reviewers met four times to examine the detailed results and review the project team's own QA efforts that checked for:

- Representativeness—Data were analyzed to determined if the sample set was properly stratified with respect to pertinent emission affecting parameters and representative of the U.S. natural gas industry, including regional differences in equipment and operating practices.

- Technical and scientific validity—Data were reviewed for conflicting results, for data that was inconsistent with physical possibilities, and for results that contradicted common industry experience.

In addition to the review provided by industry experts, production activity factors developed by this project were compared to a separate source of national equipment counts.[34] EPA's Office of Air and Radiation (OAR) worked with an independent team of industry experts to estimate production activity factors using a consensus approach. Although the EPA-OAR results were not based on measured data, they provided an alternate method for estimating equipment counts and provided another check for potential bias. The EPA-OAR results compared well to the results of this GRI/EPA-ORD project.

4.0 DETAILED RESULTS

The natural gas industry's total methane emissions are 314 Bscf for the 1992 baseline year with a 90% confidence bound of ± 105 Bscf. (See Section 4.7 for further explanation of the confidence bound.) The total emissions can be expressed as a percent of production: 314 Bscf is 1.4% of gross 1992 production, which is 22,130 Bscf, or 1.7% of marketed gas production, which is 18,710 Bscf.

This section presents the detailed methane emission estimates produced by this project. The results are presented by emission type in Section 4.1, and the methods used for estimating emissions are briefly discussed in Sections 4.2 through 4.4. The largest sources within each segment are discussed in Section 4.5. The emissions are also presented for different types of equipment in Section 4.6.

4.1 Emission Type Summary

This section presents a summary of annual methane emissions by emission type. The emission types are fugitive, vented, and combusted, as described earlier in Section 3.1.3. Table 4-1 lists the largest sources of methane emissions in the U.S. gas industry by emission type. Fugitive emissions are the largest (195 Bscf), followed by vented emissions (94 Bscf), then combusted emissions (25 Bscf). Figure 4-1 shows the percentage of emissions by type for the gas industry. The major contributors to each emission type are discussed in more detail in the following subsections.

TABLE 4-1. UNITED STATES NATURAL GAS INDUSTRY LARGEST METHANE EMISSIONS SOURCES

Source	Annual Methane Emissions (Bscf)	% of Total
Fugitive Emissions (Sec 4.2) **SUBTOTAL**	**195.2**	**62.1**
Equipment Leaks		
Compressor Stations (transmission and storage)[a]	67.5	21.5
Production Facilities	17.4	5.5
Gas Plants	24.4	7.8
Metering and Pressure Regulating Stations[b]	31.8	10.1
Customer Meter Sets	5.8	1.8
Underground Pipeline Leaks (all segments)	48.4	15.4
Vented Emissions (Sec 4.3) **SUBTOTAL**	**94.2**	**30.0**
Pneumatics[a] (4.3.1)	45.7	14.6
Blow and Purge (4.3.2)	30.2	9.6
Dehydrator Glycol Pumps (4.3.3)	11.1	3.5
Dehydrator Vents (4.3.4)	4.8	1.5
Chemical Injection Pumps (4.3.5)	1.5	0.5
Other (AGR)	0.9	0.3
Combusted Emissions (Sec 4.4) **SUBTOTAL**	**24.9**	**7.9**
Compressor Exhaust (4.4)	24.9	7.9
TOTAL	**314**	**100**

[a]Includes wells at storage facilities.
[b]Emissions from meter and pressure regulating (M&PR) stations result from both pneumatic and fugitive emissions. Since these components cannot be separated, M&PR emissions are shown as fugitive by default.

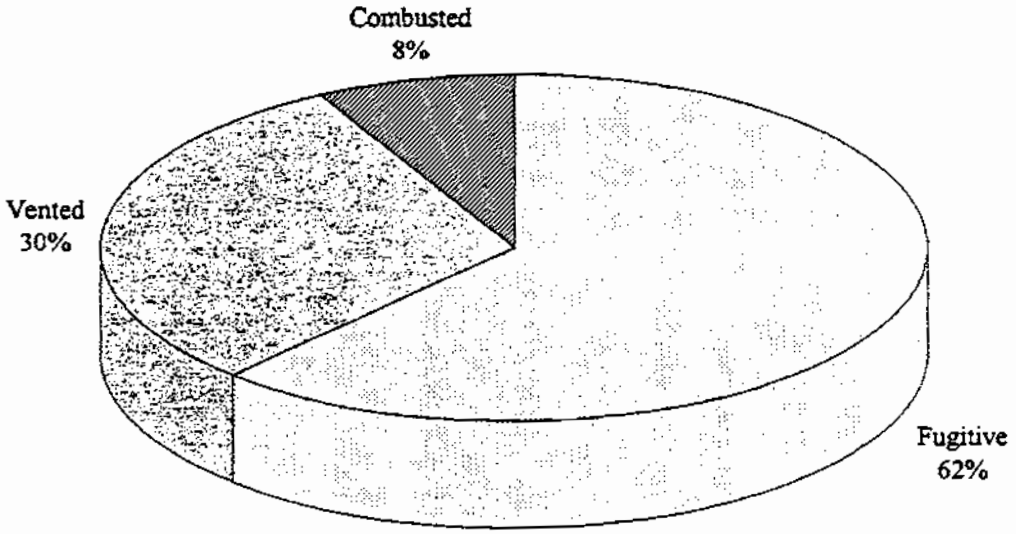

Figure 4-1. Emissions by Type

4.2 Fugitive Emissions

Fugitive emissions are defined as unintentional releases that include methane emissions from equipment leaks at sealed surfaces (component fugitive emissions), as well as from underground pipeline leaks. Figures 4-2 and 4-3 show the major contributors to fugitive emissions. Total fugitive emissions for the natural gas industry are 195.2 Bscf. Underground pipeline leaks account for 48.4 Bscf of emissions, and include leaks from production gathering lines, transmission pipelines, and distribution pipe systems. Equipment leaks account for 146.9 Bscf, and are typically low-level emissions of process fluid (gas or liquid) from the sealed surfaces on above-ground process equipment. Specific fugitive emission source types include various fittings such as valves, flanges, pump seals, compressor seals, or sampling connections. These components represent mechanical joints, seals, and rotating surfaces, which in time tend to wear and develop leaks.

Facilities and equipment that are significant contributors to equipment leak emissions include: production facilities, gas processing plants, compressor stations/facilities in transmission and storage, and meter and pressure regulating stations in transmission and distribution. The following subsections describe each of the major fugitive emission sources in more detail.

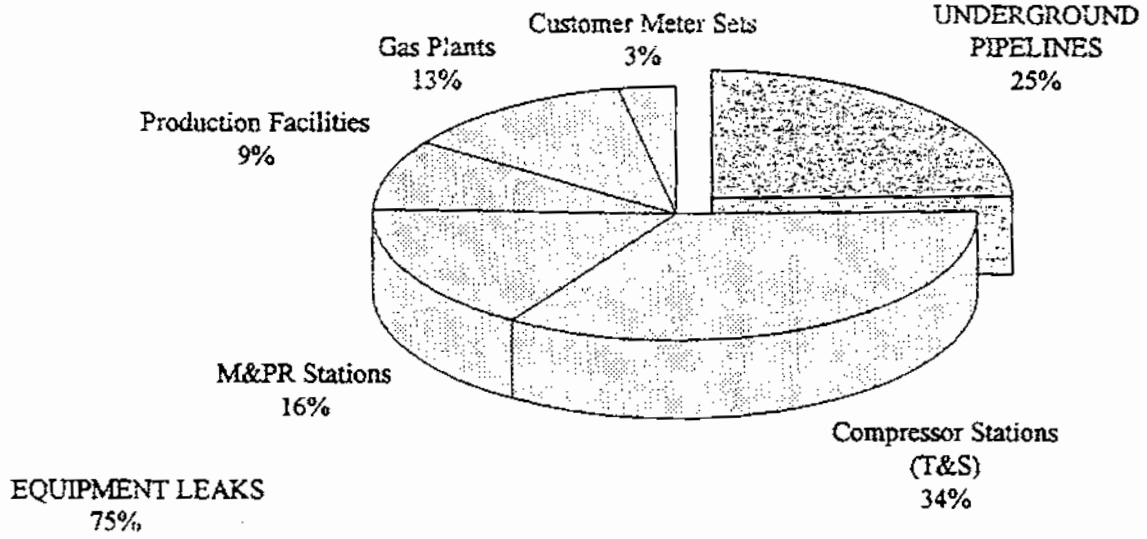

Figure 4-2. Major Contributors to Fugitive Emissions From the Natural Gas Industry

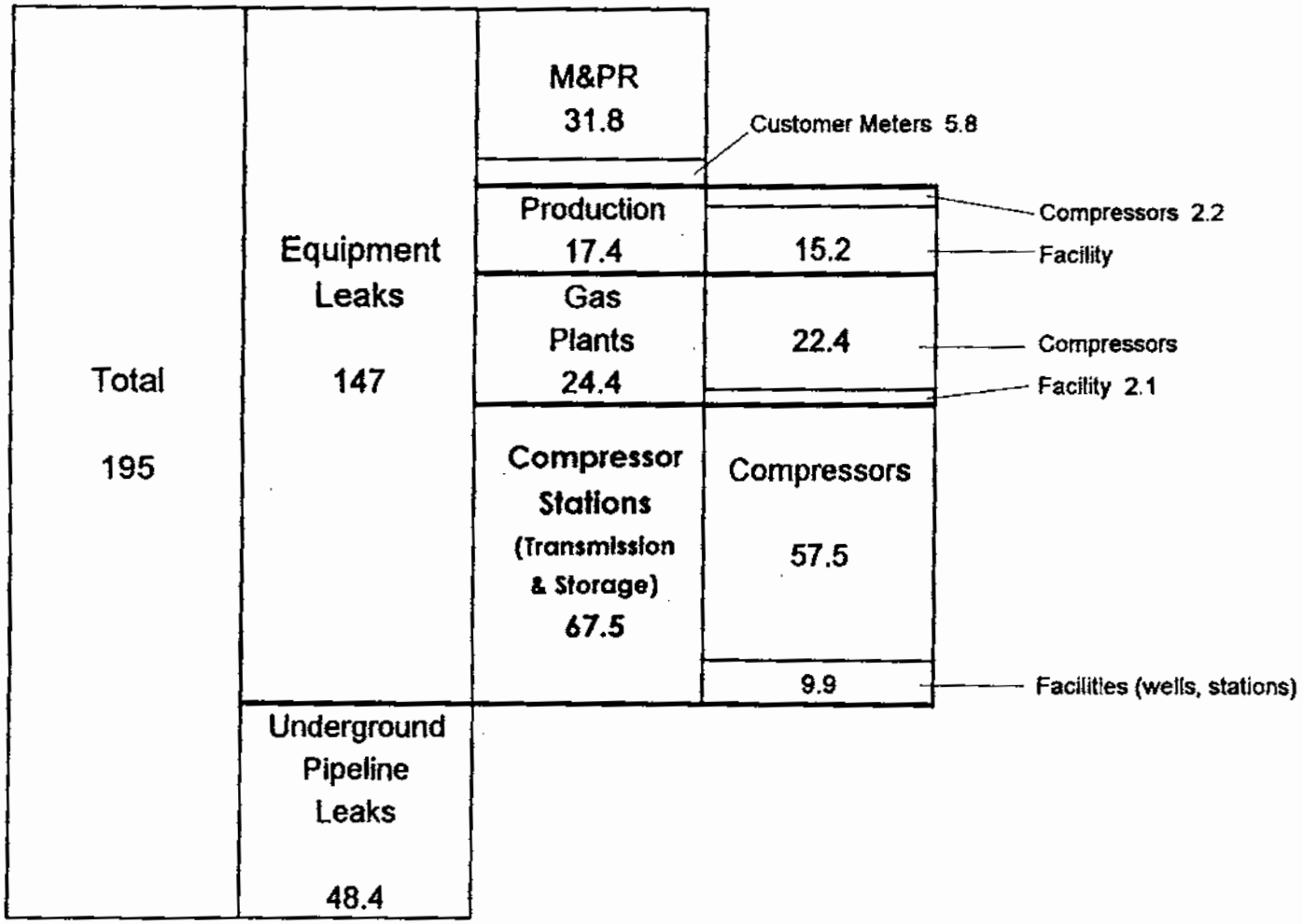

Figure 4-3. Major Contributors to Fugitive Emissions - By Segment Facilities

4.2.1 Equipment Leaks

Fugitive emissions from equipment leaks in the natural gas industry were estimated to be 146.9 Bscf. Of this total, 82.1 Bscf was attributed to compressors, 31.8 Bscf to meter and pressure regulating stations, 5.8 Bscf from customer meter sets, and 27.2 Bscf from other surface facilities. Other surface facilities are the non-compressor portion of production facilities, gas plants, and transmission and storage stations.

There are two general approaches for estimating fugitive methane emissions from equipment leaks: the tracer gas method and the component method. Tracer tests are conducted by releasing a tracer gas such as SF_6 at a known constant rate near the methane emissions source. The concentration of methane and tracer are then measured downwind. The methane emissions are calculated based on the relationship that the ratio of emissions is equal to the ratio of concentrations. The tracer method measures total emissions from the facility, and was used to measure emissions from metering and pressure regulating (M&PR) stations. The tracer method for M&PR stations is described in more detail in Volume 10.[12] The component method is described in more detail in Volume 8 on equipment leaks.[10] Both techniques are described in the following subsections.

In the component method for estimating emissions from equipment leaks, an average emission rate is determined for each of the basic components, such as valves, flanges, seals, and other connectors that comprise a facility. The average emission rate for each type of component is determined by measuring the emission rate from a large number of randomly selected components from similar types of facilities throughout the country. By knowing the average emission rate per component type (i.e., the component emission factor) and the average number of components associated with the major equipment or facility, an estimate of the average emissions per equipment/facility can be determined. Extrapolation to a national emission estimate can then be made by determining the total count of that specific equipment/facility in the United States.

The component approach was used to estimate fugitive emissions from gas production facilities, processing plants, transmission/storage facilities, and customer meters.[21,24,26,35] Separate component emission factors were developed for each industry segment because of differences in design and operating practices that could lead to differences in emissions characteristics. Some regional differences were also determined to have an impact on fugitive emissions; therefore, regional component emission factors were developed. (That is, regional component emission factors were developed for onshore and offshore production.)

For gas processing, transmission, and storage, separate emission factors were developed for components physically connected to, or directly adjacent to, compressors.[10,35] These compressor-related components were found to have significantly higher emission rates than components associated with other equipment. The higher emission rate from compressor-related components is due to the unique design, size, and operation, as well as from the vibrational wear associated with compressors. For gas processing, transmission, and storage facilities, emissions were calculated as a sum of compressor-related components and station (non-compressor related) components. Table 4-2 presents an example of the calculational approach used to calculate fugitive emissions using the component method.

Two approaches were used to quantify the component emission factors for valves, flanges, seals, and other connectors. The first approach is based on the EPA protocol document using EPA Reference Method 21.[36] The EPA protocol approach involves screening components using a portable instrument to detect total hydrocarbon (THC) leaks. The corresponding screening value for a component, which is a concentration measurement, is then converted to an emission rate by using a correlation equation developed from data collected using an enclosure measurement method. The enclosure method allows the actual leakage rate to be measured as the product of the flow rate of inert gas through the enclosure and the THC concentration. The correlation equation is developed by correlating the screening or concentration data with the emission rate data measured using the enclosure method. The correlation equation can then be applied to the same component type in similar service within the gas industry to estimate emissions using only screening data. The EPA protocol approach

TABLE 4-2. EXAMPLE OF NATIONAL EMISSIONS ESTIMATION FOR GAS STORAGE FACILITIES

Equipment Type	Component Type	Component Emission Factor, Mscf/component-yr	Average Component Count	Average Equipment Emissions, MMscf/yr	Activity Factor, Number of Plants/Compressors	National Methane Emissions, Bscf
Storage Facility (non-compressor related components)	Valve	0.867	1868	7.85	475	3.7
	Connection	0.147	5571			
	Open-Ended Line	11.2	353			
	Pressure Relief Valve	6.2	66			
	Site Blowdown Open-Ended Line	264	4			
Injection/Withdrawal Wellhead	Valve	0.918	30	0.042	17,999	0.75
	Connection	0.125	89			
	Open-Ended Line	0.237	7			
	Pressure Relief Valve	1.464	1			
Reciprocating Compressors	Compressor Blowdown Open-Ended Line	5024	1	7.71	1,396	10.8
	Pressure Relief Valve	317	1			
	Miscellaneous	153	1			
	Compressor Starter Open-Ended Line	1440	0.6			
	Compressor Seal	300	4.5			
Centrifugal Compressors	Compressor Blowdown Open-Ended Line	10233	1	11.16	136	1.5
	Miscellaneous	17	1			
	Compressor Starter Open-Ended Line	1440	0.5			
	Compressor Seal	126	1.5			

was used to quantify emissions from equipment leaks in onshore production (except for production facilities in the Atlantic and Great Lakes region), offshore production, and gas processing.

The second approach used to quantify component emission factors modifies the EPA protocol approach by using the GRI Hi-Flow™ sampler and direct measurements to replace the data collected using an enclosure approach. The GRI Hi-Flow™ sampler is a newly developed device which allows the leak rate of a component to be measured directly. The sampler creates a flow field around the component in order to capture the entire leak. As the stream passes through the instrument, the flow rate and concentration are measured. The GRI Hi-Flow™ sampling approach was used to quantify emissions from equipment leaks in onshore production in the Atlantic and Great Lakes region, gas transmission and storage, and customer meters. Direct measurements, such as rotameter readings, were also used on very high leak rates from open-ended lines at transmission and storage compressor stations.

The following subsections explain how fugitive emissions were calculated for each of the facility types that were significant contributors to total national emissions.

Compressor Stations (Transmission and Storage)

Compressor stations in transmission and storage are one of the largest sources of fugitive emissions. Equipment leaks from transmission compressor stations were separated into two distinct categories because of differences in leakage characteristics:

- Station components including all sources associated with the station inlet and outlet pipelines, meter runs, dehydrators, and other piping located outside of the compressor building; and
- Compressor-related components including all sources physically connected to or immediately adjacent to the compressors. The types of components associated with compressors include compressor blowdown

open-ended lines, starter open-ended lines, compressor seals, pressure relief valves, and other components such as cylinder valve covers and fuel valves.

Fugitive emissions from compressor stations are dominated by emissions from components related to compressors, which emit 57.5 Bscf, while emissions from all of the remaining components not associated with compressors contribute only 9.9 Bscf.

Fugitive emissions were estimated from measurement data collected at 15 compressor stations using the GRI Hi-Flow™ approach.[24] Leaking components were identified using soaping tests and all leaking components were directly measured using the GRI Hi-Flow™ sampler or a direct flow measurement, such as a rotameter. Based on the measurement data, fugitive emissions from the compressor blowdown open-ended line were found to be the largest source. Compressor blowdown open-ended lines allow a compressor to be depressurized when idle, and typically leak when the compressor is operating or idle. There are two primary modes of operation leading to different emission rates for compressor blowdown open-ended lines:

- Blowdown valve is closed and the compressor is pressurized, either during normal operation or when idle.
- Compressor blowdown valve is open. This occurs when the compressor is idle, isolated from the compressor suction and discharge manifolds, and the blowdown valve is opened to depressurize the compressor.

The fugitive emission rate is higher for the second operating mode when the blowdown valve is open, since leakage occurs from the valve seats of the much larger suction and discharge valves. Separate component emission factors were developed for the two operating modes of the compressor blowdown open-ended line. An overall average component emission factor was derived for compressor blowdown open-ended lines by

determining the fraction of time transmission compressors operate in each mode (i.e., pressurized and depressurized).

The majority of compressor fugitive emissions result from the transmission and storage segments, where a high number of very large compressors exist. Since compressors are also a part of production facilities and gas plants, the compressor component emission factors developed for the transmission and storage segments were also used for compressor components in those segments.

Production Facilities

Annual fugitive emissions from gas production facilities in the United States were estimated to be 17.4 Bscf. Component emission factors for fugitive equipment leaks in gas production were estimated separately for onshore and offshore production due to differences in operational characteristics. Regional differences were found to exist between onshore production in the Atlantic and Great Lakes region (i.e., Eastern U.S.) and the rest of the country (i.e., Western U.S.), and between offshore production in the Gulf of Mexico and the Pacific Outer Continental Shelf (OCS). In general, these regional differences were due to differences in the number, type, age, and leak detection and repair characteristics of equipment. Therefore, separate measurement programs were conducted to account for these regional differences.

For onshore production in the Eastern U.S., component emission factors and average component counts were based on a measurement program using the GRI Hi-Flow™ sampler to quantitate emission rates from leaking components.[22] A total of 192 individual well sites were screened at 12 eastern gas production facilities.

Fugitive emissions from onshore production in the rest of the U.S. (excluding the Eastern U.S.) were estimated using the EPA protocol approach. Component emission

factors were based on screening and enclosure data collected from 83 gas wells at 4 gas production sites in the Western U.S.[21] The average component counts were based on data from the onshore production measurement program and additional data collected during 13 site visits to gas production fields.[10]

Emissions from equipment leaks from offshore production sites in the U.S. were quantified based on two separate screening and enclosure studies using the EPA protocol approach:

- The oil and natural gas production operations measurement program,[21] which included 4 offshore production sites in the Gulf of Mexico; and
- The offshore production measurement program,[37] which included 7 offshore production sites in the Pacific OCS.

Gas Processing Plants

Fugitive emissions from gas processing plants contribute 24.4 Bscf to national annual methane emissions. The majority of fugitive emissions from gas processing plants are attributed to compressor-related components, which account for 22.4 Bscf. The component emission factors for compressor-related components in gas processing plants were based on the fugitives measurement program at 15 compressor stations.[10] Fugitive emissions from the remaining gas plant components, not associated with compressors, were estimated based on the oil and gas production measurement program.[21] In the oil and gas production measurement program, equipment leaks from a total of 8 gas processing plants were measured using EPA protocol approach.

Meter and Pressure Regulating Stations

Fugitive emissions from meter and pressure regulating stations (M&PR stations) contribute 31.8 Bscf to total annual methane emissions. Emissions from this category of surface equipment were measured using the tracer measurement approach, and therefore were reported separately from other categories of surface equipment fugitives. A total of 95 M&PR facilities were measured using the tracer technique.[12]

The primary losses from M&PR stations include both fugitive emissions and, in some cases, emissions from pneumatic devices. Since the tracer measurement technique used does not differentiate between fugitive and vented emissions, the vented pneumatic emissions are therefore included in the fugitive category by default. Some pressure regulating stations use gas-operated pneumatic devices to position the pressure regulators. These gas-operated pneumatic devices bleed to the atmosphere continuously and/or when the regulator is activated for some system designs. Other designs bleed the gas downstream into the lower pressure pipeline and, therefore, have no losses associated with the pneumatic devices.

Tracer measurements were used to derive the emission factors for estimating emissions from M&PR stations in both the transmission and distribution segments of the gas industry. The total emissions are a product of the emission factor and activity factor, which were stratified into inlet pressure and location (above ground versus in a vault) categories to improve the precision of the emissions estimate.

Metering/pressure regulating stations in the distribution segment include both transmission-to-distribution custody transfer points and the downstream pressure reduction stations. The emission factors for distribution are based on the average measured emissions for each station category, and the activity factors are based on the average data supplied by 12 distribution companies. The annual methane emissions for the M&PR stations in the distribution segment of the gas industry are 27.3 Bscf.

For the transmission segment, the stations include transmission to transmission custody transfer points and transmission-to-customer transfer. Emission factors for the transmission segment are derived from the tracer measurement database for M&PR stations, and the activity factors are based on survey data from six transmission companies. The annual estimated methane emissions for the transmission segment are 4.5 Bscf.

Customer Meter Sets

Fugitive emissions from commercial/industrial and residential customer meter sets contribute 5.8 Bscf to total national emissions. The average leak rate per residential meter set is only 0.01 scf/hr, but there are approximately 40 million customer meters located outdoors. The meter sets include the meter itself and the related pipe and fittings. Methane emissions from commercial and residential customer meter sets are caused by fugitive losses from the connections and other fittings surrounding the meter set. No losses have been found from the meter itself; only the pipe fittings surrounding the meter have been found to be leaking.

Methane emissions from customer meter sets were estimated based on fugitives screening data collected from 10 cities across the United States.[10,24,26] Although a total of around 1600 meter sets were screened as part of the GRI/EPA study, only about 20% of the meter sets screened were found to be leaking at low levels. For the majority of customer meter sets screened, the GRI Hi-Flow device was used to develop emission factors. For the other meter sets screened, the EPA protocol approach was used to convert the screening data into emission rates.

Emission factors for residential customer meter sets were defined as the average methane leakage rate per meter set for outdoor meters. Emissions from indoor meters are much lower than for outdoor meters because gas leaks within the confined space of a residence are readily identified and repaired. This is consistent with the findings that pressure regulating

stations located in vaults have substantially lower emissions than stations located above ground. Emission factors for commercial/industrial meter sets were estimated separately as the average emission rate per meter set.

The activity factors for residential customer meter sets were defined as the number of outdoor customer meters in the United States. The activity factor was based on published statistics including a breakdown of residential customer meters by region in order to estimate the number of meter sets located indoors. Data were obtained from 22 individual gas companies within different regions of the United States to estimate the number of indoor residential customer meters.

4.2.2 Underground Pipeline Leaks

Fugitive leakage from underground piping systems contributes 48.4 Bscf to total methane emissions. Pipeline leaks are caused by corrosion, material defects, and joint and fitting defects/failures. Based on limited leak measurement data from two distribution companies, leakage from underground distribution mains and services was targeted as a potentially large source of methane emissions from the gas industry.

A leak measurement technique was developed (Section 3.2.1) and was implemented as a method to quantify methane emissions from underground pipelines in the natural gas industry.[11] A total of 146 leak measurements were collected from the participating companies. These data were used to derive the emission factors for estimating methane leakage from distribution, transmission, and production underground pipelines.

The total emissions are a product of the emission factor and activity factor, and are stratified by pipe use (mains versus services) and pipe material categories to improve the precision of the estimate. The total annual methane emissions from underground pipeline leaks in all segments are 48.4 Bscf.

The soil oxidation rates of methane were experimentally determined to be a function of the methane emissions rate, pipe depth, and soil temperature. The methane leakage rate for underground pipelines was determined to be a function of the pipe service (main versus services) and the pipe material type. In general, the larger the leakage rate per leak, the lower the soil oxidation rate. Because of the type of pipelines in service in the distribution segment, the overall leakage rate per peak is lower. Therefore, the overall oxidation rates for distribution pipelines is higher than for transmission or gathering lines.

In the distribution segment, activity factors were based on the national database of leak repairs broken down by pipe material using information from ten companies, and then combined with historical leak records provided by six companies. The activity factors represent the number of equivalent leaks that are continuously leaking year round. (Repaired leaks are counted as fractional leaks.)

The activity factor combined with the emission factors derived from the leak measurement data produced an overall methane emissions estimate of 41.6 Bscf, which includes an adjustment for soil oxidation. The largest contributor to the overall annual emissions was cast iron mains, followed by unprotected steel services and mains. The average soil oxidation rate applicable to distribution piping was 18%, which primarily affects the emissions from cast iron mains, which have low leak rates per leak.

In the transmission and production segments, the estimated methane leakage was based on the emission factors derived from the leak rates measured on distribution mains and on activity factors derived from a nationally tracked database of pipe mileage/leak repairs. For transmission pipeline leakage, the estimated annual methane emissions were 0.2 Bscf, which includes an adjustment for soil oxidation.

For gathering pipeline in the production segment, the estimated annual methane emissions were 6.6 Bscf. The estimated methane emissions to the atmosphere from gathering lines includes an adjustment of 5% average methane oxidation in the soil.

4.3 Vented Emissions

Vented emissions primarily result from three categories: 1) pneumatic devices, 2) blow and purge emissions, and 3) dehydrator emissions. Emissions from chemical injection pumps is a minor category. Figure 4-4 shows each of the contributions to vented emissions. Each of these are described in more detail in the following sections.

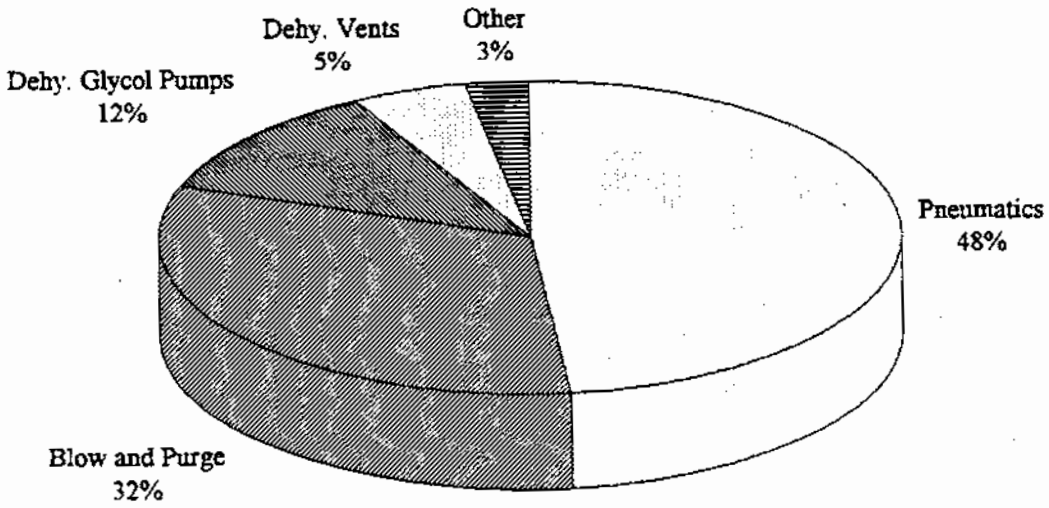

Figure 4-4. Contributions to Vented Emissions

4.3.1 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 major source of unsteady emissions and account for 45.7 Bscf of methane emissions.[14] 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 emission rates, 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.

Emission factor estimates for pneumatic devices were based on a combination of site information, manufacturers' data, and measured emissions from devices in the field. Each segment of the industry has very different practices regarding the use of pneumatic devices. These differences and a summary of the data collected to characterize the different pneumatic devices are described below.

Production

The production segment accounts for the majority of the pneumatic emissions: 31.4 Bscf, or 69% of all pneumatic emissions. High pressure natural gas is used to operate most of these devices, since production facilities are usually located at remote sites. Natural gas is readily available and less expensive than compressed air or electricity at the remote sites. The majority of devices are used to regulate flow and can emit methane either on a continuous basis or only when the device actuates. Data were collected from 22 sites to determine the fraction of continuous bleed devices versus intermittent bleed devices. A total of 44 measurements of various device types in field operation were used to estimate the emission factor. In addition, the four most common manufacturers of these devices were contacted for information regarding the

characteristics of the devices that affect emissions. The total number of pneumatic devices in the production segment were determined based on data from more than 35 sites.

Gas Processing

Pneumatic device emissions from the gas processing segment are very small: 0.1 Bscf, or less than 1% of all pneumatic emissions. Emissions were based on data collected from nine gas processing plants and from the four manufacturers of the devices observed. Of the gas processing plants surveyed, only one-half (56%) 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 per month or once per year), so the emissions per site are relatively small.

Transmission/Storage

Emissions from pneumatic devices at transmission compression stations and storage stations account for 14.1 Bscf, or 31% of pneumatic emissions. In this industry segment, most of the pneumatics are gas-actuated isolation valves. Data for these types of devices were provided by 16 sites and two manufacturers. There are a few pneumatic control valves used to reduce pressure or to control liquid flow from a separator or scrubber. Emissions for these devices were based on information collected from 54 sites and 23 measurements of operating devices. Site data from 54 stations were also used to determine the number of devices per station, which was extrapolated to a national number of pneumatic devices in the transmission segment.

Distribution

Pneumatic emissions for the distribution segment are included in the "fugitive" emission factor for M&PR stations. The M&PR pneumatics cannot be separated from fugitives, since M&PR total emissions were measured using the downwind tracer technique.

4.3.2 Blow and Purge

Blow and purge is a major source of unsteady emissions and accounts for approximately 30.2 Bscf of methane emissions.[9] Blow (or blowdown) gas refers to intentional and unintentional venting of gas for 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 personnel 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 were determined by equipment category: compressor blowdown, compressor starts, pipeline blowdown, vessel blowdown, gas wellbore

blowdown, and miscellaneous equipment blowdowns. Emergency blowdowns refer 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, pipeline ruptures caused by unintentional damage, were also classified under emergency release of gas and included in the blow and purge estimates.

Emission estimates for each industry segment were based on data from site visits or company tracked data. Blow and purge emissions from the production segment, accounting for approximately 6.5 Bscf of the total blow and purge emissions, were based on data from 25 sites. Emissions for transmission and gas processing plants, which have similar station blowdown practices, were based on data from eight companies. These industry segments account for 18.5 Bscf and 2.9 Bscf of the total blow and purge emissions, respectively. The distribution segment makes up about 2.2 Bscf of the total blow and purge emissions, and the emission estimate for this segment was based on detailed unaccounted-for gas studies from two distribution companies.

4.3.3 Dehydrator Glycol Pumps

Glycol dehydrator circulation pumps are a major source of unsteady emissions and account for 11.1 Bscf of methane emissions.[17] 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 through the dehydrator vent stack along with the methane absorbed in the rich glycol stream (see Section 4.3.4).

Gas-powered glycol circulation pumps are common throughout the industry, even at 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 nearly half 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 rich (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. Design data from Kimray were used to establish the amount of gas used by these pumps. Gas-assisted glycol pumps were found almost exclusively in production dehydrators, with a few in gas processing. No active gas-assisted pumps were found during the site visits to transmission or storage facilities, which is consistent with the fact that larger facilities tend to have electricity available.

4.3.4 Dehydrator Vents

Glycol dehydrator vents are a major source of methane emissions and account for 4.8 Bscf of methane emissions.[17] The majority of the glycol dehydrators are located in production, but dehydrators are also used in gas processing, transmission, and storage. Methane emissions are highest in the production segment; 71% of the total dehydrator vent emissions are attributed to dehydrators in the production segment. This is due to the high activity and emission factors for this segment. The absence of flash tanks in most production dehydrators leads to an emission rate per volume of gas dehydrated that is higher in production than in the other segments.

Glycol dehydrators remove water from the natural gas through continuous glycol absorption. The water-rich glycol is 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 where the gas is routed to a burner. An emission factor per unit of gas throughput 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 samples taken from regenerator vents; and 3) multiple site visits. The emission factor was combined with an activity factor to generate the emission rate. The activity factors are the volumes of gas dehydrated in each industry segment. The total glycol dehydrator throughput compares well with a separate study conducted by API.[38]

4.3.5 Chemical Injection Pumps

Chemical injection pumps are a source of unsteady emissions and account for 1.5 Bscf of methane emissions solely in the production segment.[15] Emission estimates for this source were based on data from 17 sites, 6 manufacturers, and emission measurements from a Canadian study.[39] The total number of chemical injection pumps nationally was extrapolated from data relating the number of chemical injection pumps to the number of gas wells at 38 sites.

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 inhibitors, scale inhibitors, biocides, demulsifiers, clarifiers, and hydrate inhibitors 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 where the gas is wet and has a high non-methane content. The pumps are most often located at the well sites, so that the chemical can protect all of the downstream and downhole equipment. Most of the chemical injection pumps in oil and gas production are associated with oil production and were not included in this study. As with pneumatic control valves, the chemical injection pumps in production are primarily powered by natural gas.[15]

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.

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 Combusted Emissions

Combusted emissions result from incomplete combustion of methane in burners, flares, and engines. Incomplete combustion of methane in compressor engine exhaust is the only significant source of methane in this category.

Methane emitted to the atmosphere in compressor driver exhaust is a major source of unsteady emissions and accounts for 24.9 Bscf of methane emissions.[13] 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 turbine drivers. A few compressors in the industry are driven by other means such as electrical motors, but the majority are natural gas fueled. In

addition to compressors, there are some natural gas drivers that run electrical generators at gas plants and compressor stations.

Reciprocating engines emit approximately 40 times more methane per horsepower or per unit of fuel consumed than gas turbine drivers. Reciprocating engines account for over two-thirds of all installed horsepower in the gas industry. Therefore, reciprocating engine compressor drivers account for over 98% of the methane emissions for this category.

Emissions were determined by analyzing and combining several databases to generate emission factors and activity factors. A GRI database, the TRANSDAT compressor module,[40] contains data from A.G.A. on types and models of compressors in use, as well as data on compressor driver exhaust from the Southwest Research Institute (SwRI). A.G.A. gathers its data from government agencies, such as the U.S. Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC), and from surveys of its member companies in transmission and distribution. SwRI data were generated through actual field testing. These 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 data from GRI TRANSDAT, FERC, A.G.A., company databases, and site visits. GRI TRANSDAT includes horsepower data for 7489 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 and operating hours were based on A.G.A. data and data from 11 storage stations, respectively. Since national totals for transmission and storage horsepower were available, no industry extrapolation was necessary for these activity factors. Production horsepower•hours were based on one company's data for 513 reciprocating engines and 6 gas turbines. Processing horsepower and operating hours were based on 10 site visits and company data for 11 gas processing plants.

Activity factors for production and processing were extrapolated to the industry using published data for national marketed gas production and gas processing, respectively.

4.5 Largest Sources by Industry Segment

This section summarizes the segment emissions and presents the data by largest emission categories within each segment. Table 4-3 presents a summary of emissions by gas industry sector. Figure 4-5 shows the same data in a chart format.

TABLE 4-3. SUMMARY OF METHANE EMISSIONS

Segment	Emissions (Bscf)	Percent of Total Emissions (%)	Emissions as a Percent of Gas Produced (Gross National Product)
Production	84.4	26.8	0.38
Processing	36.4	11.6	0.16
Transmission/Storage	116.5	37.1	0.53
Distribution	77.0	24.5	0.35
TOTAL	**314 ± 105**	**100.0**	**1.42**

*Gross national production of natural gas = 22,132 Bscf (22.13 Tscf)[41]
(Accuracy Goal is ± 110.7 Bscf or ± 0.5% of production)

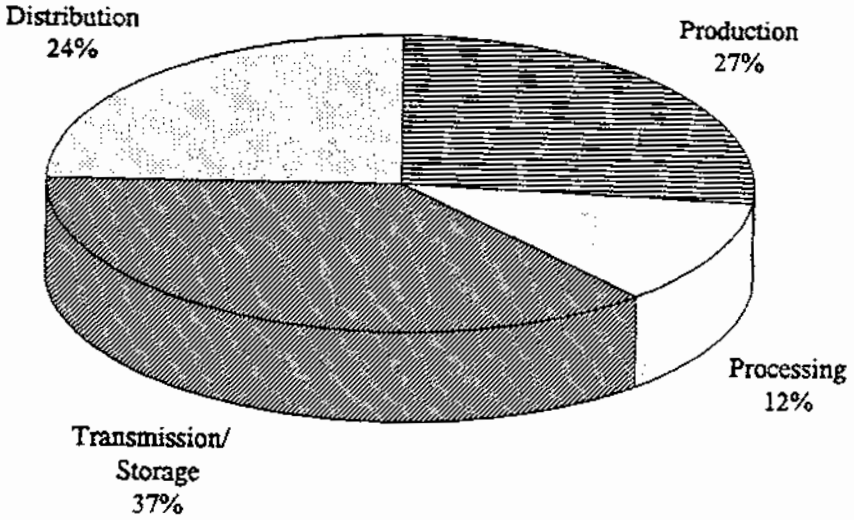

Figure 4-5. Summary of Methane Emissions

The total segment emissions presented in Table 4-3 and Figure 4-5 are split into emission type in Table 4-4. The largest emission type for the entire U.S. natural gas industry is fugitive emissions; however, the largest emission category in each segment varies. Vented emissions are the largest emission category in production because of the contribution from pneumatic devices. In the other segments of the industry, fugitive emissions are the largest source.

Segment emissions also can be broken down into the largest categories that were presented in Table 4-1, U.S. Natural Gas Industry Largest Methane Emission Sources. These categories are actually a mixture of emission types and equipment types, since some measurement programs were specific to a type of equipment (such as the buried pipeline leak statistics method), while others were not.

Since the characteristics of each segment of the natural gas industry are quite unique, and since companies within each segment will want to know their segment's emissions, the data have been recast by segment. Tables 4-5 through 4-8 show the largest sources within each segment. Figures 4-6 through 4-9 show the same data in chart format.

Table 4-5 shows that the largest sources in production were pneumatic devices and fugitive emissions. Table 4-6 shows that the largest sources in gas plants are fugitive emissions and compressor driver exhaust. Table 4-7 shows that the largest sources in transmission and storage are fugitives, pneumatic devices, blow and purge, and compressor driver exhaust. Table 4-8 shows that the largest sources in distribution are M&PR stations and underground pipeline leaks. There are nine categories (rows) on Tables 4-7 through 4-8 that exceed 10 Bscf, and four of these are in the transmission segment.

TABLE 4-4. EMISSIONS BY TYPE

Emission Type	Production Segment (Bscf)	Gas Processing Segment (Bscf)	Transmission and Storage Segment (Bscf)	Distribution Segment (Bscf)	Natural Gas Industry Emissions (Bscf)	Emission Type as Percent of Total (%)
Fugitive	24.0	24.4	72.1	74.7	195.2	62.1
Vented	53.8	5.1	33.0	2.2	94.2	30.0
Combusted	6.6	6.9	11.4	N/A	24.9	7.9
TOTAL*	**84.4**	**36.4**	**116.5**	**77.0**	**314**	**100%**

* Individual categories may not sum exactly to totals shown due to roundoff errors.

TABLE 4-5. PRODUCTION SEGMENT LARGEST SOURCES

Source	Annual Methane Emissions (Bscf)	% of Segment Total
Pneumatic Devices	31.4	37.2
Fugitive Emissions[a]	17.4	20.6
Underground Pipeline Leaks	6.6	7.8
Blow and Purge	6.5	7.8
Compressor Driver Exhaust	6.6	7.8
Glycol Dehydrator Pumps	11.0	13.0
Glycol Dehydrator Vent	3.4	4.0
Chemical Injection Pumps	1.5	1.8
Other	<0.1	<0.1
TOTAL	**84.4**	**100**

[a]Excludes underground pipeline leaks.

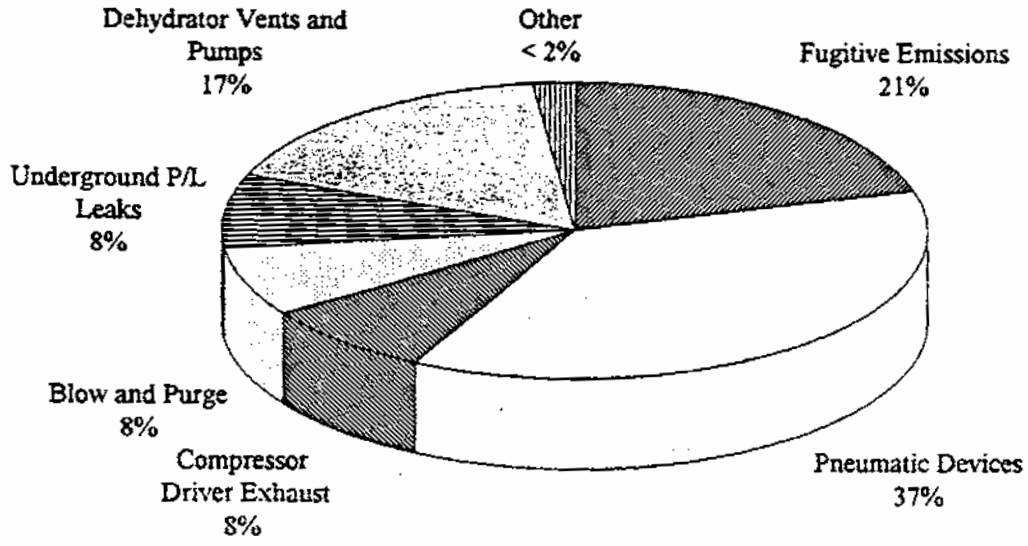

Figure 4-6. Production Segment Largest Sources

TABLE 4-6. GAS PROCESSING SEGMENT LARGEST SOURCES

Source	Annual Methane Emissions (Bscf)	% of Segment Total
Fugitive Emissions	24.4	67.1
Compressor Driver Exhaust	6.9	18.8
Blow and Purge	2.9	8.1
Other	0.9	2.6
Glycol Dehydrator Vent	1.0	2.9
Glycol Dehydrator Pumps	0.2	0.5
TOTAL*	**36.4**	**100**

*Individual categories may not sum exactly to total shown due to roundoff errors.

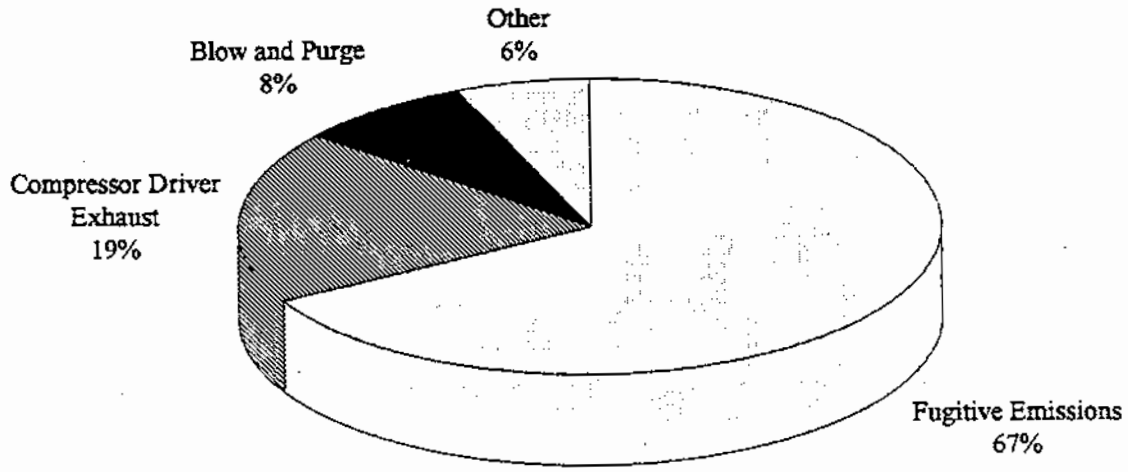

Figure 4-7. Gas Processing Segment Largest Sources

TABLE 4-7. TRANSMISSION AND STORAGE SEGMENT LARGEST SOURCES

Source	Annual Methane Emissions (Bscf)	% of Segment Total
Fugitive Emissions[a]	67.5	57.9
Blow and Purge	18.5	15.9
Pneumatic Devices	14.1	12.1
Compressor Driver Exhaust	11.4	9.8
M&PR Stations	4.5	3.9
Glycol Dehydrator Vent	0.3	0.3
Underground Pipeline Leaks	0.2	0.1
Glycol Dehydrator Pumps	0.0	0.0
Other	0.0	0.0
TOTAL	**116.5**	**100**

[a]Excludes underground pipeline leaks and M&PR leaks.

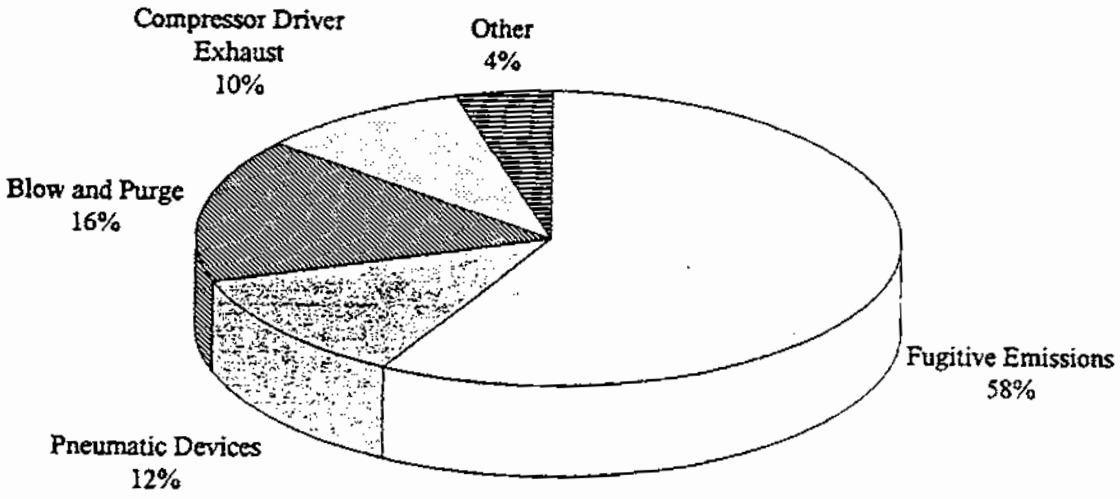

Figure 4-8. Transmission and Storage Largest Sources

TABLE 4-8. DISTRIBUTION SEGMENT LARGEST SOURCES

Source	Annual Methane Emissions (Bscf)	% of Segment Total
Underground Pipeline Leaks	41.6	54.1
Meter and Pressure Regulating Stations (includes fugitive and pneumatic device emissions)	27.3	35.5
Customer Meters	5.8	7.5
Other	2.2	2.9
TOTAL*	**77.0**	**100**

*Individual sources may not sum exactly to total shown due to roundoff errors.

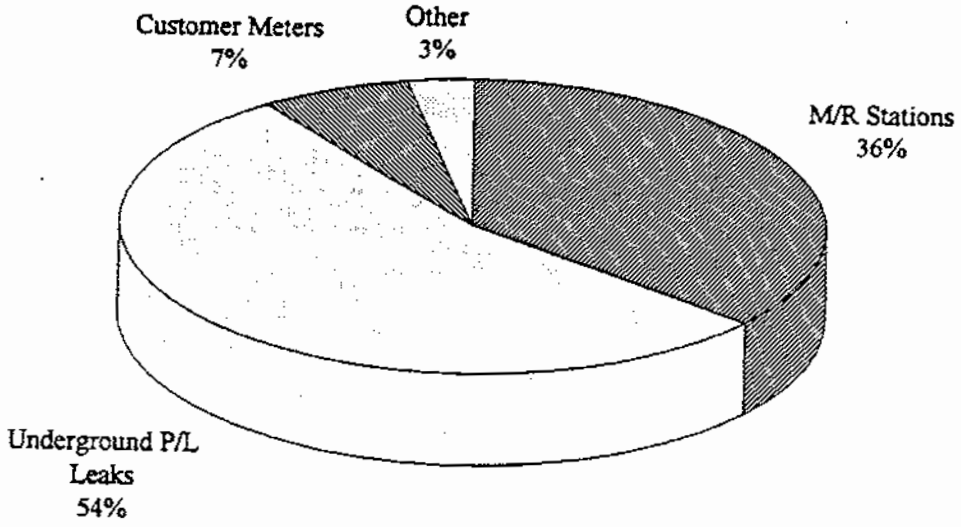

Figure 4-9. Distribution Largest Sources

4.6 Equipment Emissions

The data presented in Sections 4.1 through 4.4 and in the Summary Table in Appendix A are grouped by emission source or emission category. An alternate method for grouping the emissions is by equipment type. Since some companies may wish to use the methane emissions data to make decisions on equipment choices, it is important to know all of the methane emissions associated with each equipment type.

For example, this grouping would allow a company to make a better choice between turbine and reciprocating compressors, if methane emissions from the compressors were important to the company. Instead of using only the difference in compressor exhaust emissions between the two types, all of the compressor emissions should be used in the comparison. For example, all turbine compressor emissions would include: turbine compressor exhaust, turbine compressor blow and purge, turbine compressor fugitives, and turbine compressor pneumatics.

Unfortunately, recasting the data in this form cannot be done with precision since many emission categories cannot be accurately split into equipment types. The methods used to estimate the emissions simply do not provide this breakdown. Blow and purge emissions from compressors, for example, were calculated from total volumes for all events provided by a company. Since the companies did not provide the data by engine type, the data cannot be accurately split into compressor start gas for turbines, compressor start gas for reciprocating engines, blowdown gas for turbines, and blowdown gas for engines.

The assumptions used to split emissions into equipment types are listed in Table 4-9. Table 4-9 shows that reciprocating compressors contribute the most emissions among the categories (100 Bscf). This is due to the large number of reciprocating compressors, combined with large emission rates from the following: fugitive emissions associated with compressor components, the large compressor exhaust emissions from reciprocating compressors, and relatively large blowdown emissions associated with reciprocating compressors. The next highest equipment category is pipelines (60 Bscf), which have high emissions due to the

TABLE 4-9. EMISSIONS BY EQUIPMENT

Equipment Type	Emissions Included	Estimated Annual Emissions (Bscf)			
		Fugitives	Vented	Combusted	Total
Reciprocating Compressors	Exhausts, blow and purge (starts and blowdowns), fugitives, pneumatics, production stations	67.4	6.4	24.6	98.4
Pipelines (Gathering Transmission, Dist.)	Fugitives, dig-ins, blow and purge	48.4	11.5		59.9
Separators	Fugitives, pneumatics, chemical injection pumps, production vessel blowdowns, production PRV's	3.4	29.8		33.2
M&R Stations	Fugitives, distribution PRV's	31.8	<0.1		31.9
Transmission Station Vessels/Piping	Fugitives, pneumatics, station venting	9.2	22.2		31.4
Centrifugal Compressors	Exhausts, blow and purge (starts and blowdowns), fugitives	14.7	0.4	0.3	15.3
Glycol Dehydrators	Fugitives, pneumatics, dehydrator vents, AGR vents, dehydrator pumps	1.2	17.4		18.6
Wellheads	Fugitives, well workovers, well clean ups, completion flaring	3.0	5.7	<0.1	8.7
Production Meters/Piping	Fugitives	6.1			6.1
Customer Meters	Residential, commercial/industry	5.8			5.8
Gas Plant Vessels/Piping	Fugitives, pneumatics, blow and purge	2.1	0.4		2.5
Offshore Platforms	Fugitive, ESD	1.2	0.3		1.5
Heaters	Fugitives	1.1		Negl.	1.1
	TOTAL	**195**	**94.2**	**24.9**	**314**

Assumptions:
- Production pneumatics are broken down as: 90% separators, 2% dehydrators, 8% reciprocating compressors.
- Gas processing pneumatics are broken down as: 90% vessel/pipes, 10% reciprocating compressors.
- Transmission and storage pneumatics are broken down as: 90% vessel/pipes, 10% reciprocating compressors.
- Gas processing blowdowns are broken down as: 76% reciprocating compressors, 14% turbine, and 10% vessel/pipes.

tremendous mileage of pipe in the United States combined with relatively large dig-in and blow and purge emissions rates. The third highest equipment category is production separators (3 Bscf). Separators have a high emission rate due to the large population, combined with high emission rates from associated pneumatics, fugitives, and chemical injection pumps. There are four other equipment categories that each exceed 10 Bscf: M&R stations, transmission station vessels and piping (i.e. everything but the compressors), turbine compressors, and glycol dehydrators.

Many of the categories in Table 4-9 have high emissions due to a high population of equipment, rather than due to a high emission rate per equipment. Table 4-10 recasts the total data in Table 4-9 into equipment emission factors by using aggregate activity factors. Many of these aggregate factors are groupings of multiple categories, such as all types of pipeline miles. They are therefore not as specific as the individual activity factors presented in Appendix A, and should be used only for the purposes of comparison in this table.

Table 4-10 shows that the highest single sources on the list are gas plants and transmission and storage stations. These are large facilities with large equipment counts that result in relatively high fugitive and blow and purge emissions. The highest emission factors for individual equipment types are : 1) compressors, 2) glycol dehydrators, 3) separators, and 4) M&PR stations. Each of these are explained in more detail below.

While turbine compressors have the highest emission rates per compressor unit (due to fugitives and blowdowns), reciprocating engine-driven compressors have higher methane emissions per million horsepower hour. This makes sense because turbine driven compressors have specific maintenance practices that result in higher blowdown and fugitive emissions on a per compressor basis, yet have far lower driver exhaust emissions on a per HP-hr basis.

TABLE 4-10. ESTIMATED EQUIPMENT EMISSION FACTORS

Equipment Types	Estimated Activity Factor		Estimated Emission Factor (Mscf/equipment)			
			Fugitives	Vented	Combusted	Total
Reciprocating Compressors	29,000	compressors	2,327	222	832	3,381
	102,500	MMHp-hr	658*	62.3*	240*	960*
Total Pipelines (Gathering Transmission, Distribution)	1,620,000	miles	29.9	7.1		37.0
Separators	166,000	separators	20.2	180		200
M&R Stations	207,000	stations	154	0.202		154
Transmission & Storage Station Vessels/Piping	2,175	stations	4,219	10,212		14,430
Turbine/Centrifugal Compressors	1,540	compressors	9,530	268	164	9,962
	44,000	MMHp-hr	334*	9.4*	5.7*	349*
Glycol Dehydrators	38,000	dehydrators	32.4	458		490
Wellheads	272,000	wellheads	11.0	20.9	0.0	31.9
Production Meters/Piping	377,000	meters	16.1			16.1
Customer Meters	45,000,000	meters	0.128			0.128
Gas Plant Vessels/Piping	726	plants	2,886	554		3,440
Offshore Platforms	1,110	platforms	1,055	258		1,313
Heaters	51,000	heaters	21.0		Negl.	21.0

Assumptions: See Table 4-8
Note: * Mscf/MMHp-hr, not per equipment

Glycol dehydrators have high emission factors due to contributions from multiple sources on the dehydrator: the glycol vent, the glycol pump, fugitives, and pneumatics. The separator also has high emissions, mostly due to the high number of pneumatic devices associated with separators. Similarly, M&PR stations also have high emissions mostly due to the pneumatic devices associated with the stations.

4.7 Accuracy Results

The accuracy goal was to determine emissions from the natural gas industry to within ± 0.5% of natural gas production. This goal was established based on the accuracy needed for constructing emission inventories for use in global climate change models and for assessing the validity of the fuel switching strategy. Accuracy, which is made up of precision and bias, has been rigorously propagated through the calculations using techniques described in Volume 4 on statistical methodology.[6] The propagation of error resulted in a calculated uncertainty of ± 89.6 Bscf (0.4% of gross production). However, this assumes that the errors are normally distributed and that there is no correlation between source categories.

Since there are some correlated errors among categories, and since some categories might have lognormal distributions, the uncertainty estimate for the total emissions was modified. The effect of inter-category correlations was calculated, and the additional uncertainty was added to the uncertainty total. In addition, the effect of lognormal distribution assumptions was also calculated. A point midway between the result for normal and lognormal errors was used as a more reasonable conservative case than is the result based on the normal assumption. The midway point represents the possibility that there is asymmetry in the distribution of the error in the industry emission rate. While the selection of the midway point is arbitrary, it is considered a reasonable postulated conservative case, given the various issues discussed in the Volume 4 on statistical methodology.[6]

Therefore, with assumptions of inter-category correlations and some lognormality, the uncertainty is calculated to be ± 104.6 Bscf, which is slightly under 0.5% of national production. The conclusion is that, under assumptions that are not unrealistically conservative, the target precision was achieved.

The project has reached its accuracy goal for the annual emissions. The objective of the project was to determine the overall national methane emissions, not to accurately determine methane emissions for individual equipment or processes. The emission estimates for source categories represent industry average values and are not meant to be representative of any company's individual emissions or operations. Also, although the project has reached its accuracy goal for the total emissions, the percent accuracy of an emissions estimate for a specific category will likely have a much wider confidence bound than the national estimate.

5.0 ANALYSIS AND CONCLUSIONS

As presented in Section 4, the methane emissions estimate from the U.S. natural gas industry for the 1992 base year is 314 Bscf , which is 1.4% of gross natural gas production (i.e., 1992 gross production was 22,130 Bscf).

As part of this program, a rigorous calculation of the uncertainty in emissions from the significant sources was made to help plan the program. An overall accuracy target of 0.5% of natural gas production (± 111 Bscf) was set as a benchmark to address the fuel switching issue. The overall accuracy of the total methane emissions estimate generated from this program is ± 106 Bscf, or 0.5% of natural gas production. Therefore, the accuracy goal originally set forth for the program has been met (see Section 4.7).

Methane emissions from all U.S. anthropogenic sources are reported in the U.S. EPA Report To Congress (RTC).[3] Excluding the gas industry, the report states that total U.S. anthropogenic methane emissions are estimated to be between 1190 to 1336 Bscf. Therefore, the gas industry (based upon the new GRI/EPA estimate) accounts for 19% to 21% of total U.S. methane emissions. According to the RTC, landfills (421 to 614 Bscf) and livestock (328 to 546 Bscf), each has higher emissions of methane (Figure 5-1).

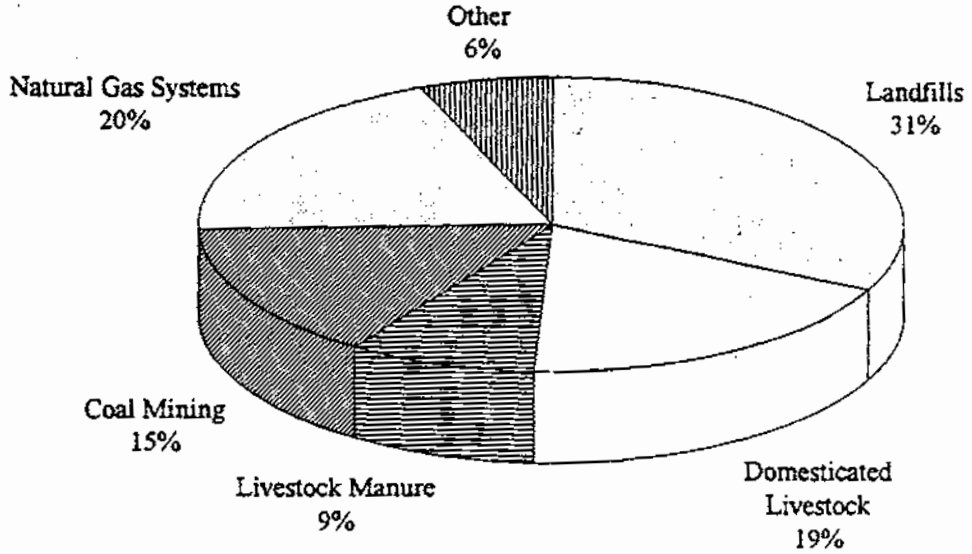

Figure 5-1. Contribution of Major Methane Sources to Total U.S. Anthropogenic Emissions

The following sections analyze the results of the GRI/EPA study in various contexts. Section 5.1 uses the results to examine the validity of the fuel switching strategy. Section 5.2 compares the results to previous estimates. Section 5.3 discusses trends in the natural gas industry that have changed total emissions since the base year of 1992. Finally, Section 5.4 summarizes some of the key lessons learned during this study.

5.1 Impact of Natural Gas Use on Global Warming

The primary purpose of the GRI/EPA methane emissions study was to help answer the question of whether the strategy of switching from other fossil fuels to natural gas would be successful in reducing global warming. To address this question, the amount of greenhouse gas released during the fuel cycle for each fossil fuel and the impact of these gases on the atmosphere are needed. For fossil fuels, only emissions of carbon dioxide (CO_2) and methane play a significant role. For methane emissions, it is important to account for emissions from the production of gas, oil, and coal and also from the transmission and distribution of natural gas. Methane emissions from the transportation and distribution of coal and oil are negligible, as are methane emissions from end-use combustion. Nearly all the CO_2 emitted results from end-use combustion of the fossil fuels.[38] Only 7 to 9% of the CO_2 emitted from natural gas is associated with upstream production, processing, and transportation, while 11% of the CO_2 emissions associated with oil are from production through product transport. Approximately 1% of the CO_2 emitted from coal is associated with production, processing and transportation.[42]

After determining the emissions of CO_2 and methane over the fuel cycle for each fossil fuel, the second step is to determine the impact of those emissions on global warming. This is a difficult problem because CO_2 and methane behave very differently when released into the atmosphere; they have different lifetimes and absorb substantially different amounts of infrared energy. As discussed in Appendix B, an index referred to as the Global Warming Potential (GWP) can be calculated that describes the impact of a given greenhouse gas on global warming compared to CO_2. The GWP can then be used to convert emissions of one greenhouse

gas, such as methane, into equivalent quantities of CO_2. For example, if the GWP of methane was seven, then one pound of methane would have the same impact on global warming as seven pounds of CO_2.

The impact of greenhouse gases such as CO_2 and methane is dependent on the amount of infrared energy they absorb (referred to as their radiative forcing) and their concentration. Since the concentration is a function of time, the GWP is calculated by integrating the ratio of the impact of methane to the impact of CO_2 as the concentration of the gases decreases with time.

The value of the GWP is highly dependent on the time period over which the integral is evaluated because the lifetime of methane is significantly shorter than the lifetime of CO_2. Some studies select a period long enough for concentrations of both gases to decrease to the original value (approximately 500 years), while others have chosen a shorter time period of 50 to 100 years. The GWP for methane is approximately 6.5 for an integration interval of 500 years, while the value of the GWP using a 50-year period is 34. Faced with such a large difference, two approaches were taken to examine the validity of the fuel switching strategy.

The first approach is to determine the breakeven percentage. The breakeven percentage is the amount of methane that would have to be emitted to the atmosphere from natural gas operations in order for natural gas to have the same impact on global warming as coal or oil (i.e., the amount of methane that would have to be leaked to eliminate the inherent advantages that gas has because of its lower CO_2 emissions). Comparing the breakeven percentage to the 1992 emission estimate provides an indication of the advantage that natural gas has over coal or oil. Likewise, the breakeven percentage can be compared to the percentage of natural gas emissions resulting from an incremental increase in gas use to determine the validity of the fuel switching strategy.

The analysis presented in Appendix B indicates that between 8 and 34% of the natural gas produced would have to be lost to the atmosphere for natural gas to have the same

impact on global warming that coal has, depending on whether the GWP was evaluated over a 50- or 500-year time period. A similar comparison for oil indicates that methane emissions from natural gas operations would have to be between 5 and 23% of production to have the same impact that oil has on global warming.

As discussed in Section 5.3.2, the GRI/EPA study not only evaluated emissions for the 1992 baseline system, but also estimated emissions from incremental increases in natural gas use ranging from 5 to 30%. The study found that incremental emission increases were proportionally less than the increases in gas usage for the scenarios examined.

Since the breakeven percentages for coal (8 to 34%) and oil (5 to 23%) are much larger than even the upper limit of the percent of gas lost per gas produced from an incremental increase in gas use (i.e., 1.38% compared to 1.42 for the 1992 baseline) the breakeven analysis shows that switching from other fossil fuels to natural gas is a valid strategy for reducing global warming.

In the second approach, the amount of "equivalent" CO_2 emissions was evaluated for each fossil fuel over the fuel cycle by converting methane emissions to "equivalent" CO_2 emissions. Since the GWP is a factor that relates the impact of releasing a pound of methane on global warming to that of releasing a pound of CO_2, the GWP can be used to convert methane emissions into equivalent amounts of CO_2. For the fuel switching analysis, emissions are expressed as the mass of equivalent CO_2 emissions per unit of energy (based on the higher heating value of the fuel). Thus for an energy requirement of one million Btu, the equivalent CO_2 emission contribution of each fuel can be compared. Table 5-1 presents the results of this comparison for GWPs of 6.5 and 34. (A more detailed discussion is presented in Appendix B.) Table 5-1 also shows the ratio of equivalent CO_2 emissions per MMBtu for coal and oil divided by the value for natural gas. This "equivalent CO_2 ratio" shows that oil has 1.2 to 1.4 times the impact on global warming compared to natural gas, and coal contributes 50 to 60% more equivalent CO_2 emissions than natural gas.

TABLE 5-1. EQUIVALENT CO_2 EMISSIONS

Fuel Source	lbs CO_2/MMBtu		Equivalent CO_2 Ratio	
	GWP = 6.5	GWP = 34	GWP = 6.5	GWP = 34
Gas	132	152	1.0	1.0
Oil	184	186	1.4	1.2
Coal	212	228	1.6	1.5

An analysis of the fuel switching strategy based on examining the equivalent CO_2 emissions from each fuel supports the conclusion reached by evaluating the fuel switching strategy using the breakeven percentage. Based on the results of both approaches, fuel switching is a valid strategy for reducing global warming. This conclusion is consistent with the Intergovernmental Panel on Climate Change (IPCC) report[43] on climate change.

5.2 Comparison to Previous Estimates

This project began in 1989 by posing the following questions: 1) "What are the methane emissions from the U.S. natural gas industry from the wellhead to the customer meter?" and 2) "Based on this emission estimate, is it reasonable to recommend switching from oil or coal to natural gas as a strategy for reducing the U.S. contribution to global climate change?" The project sponsors agreed that it would not be prudent to attempt to answer the second question unless an accuracy goal for the emission estimate of ± 0.5% of gas production could be achieved with 90% confidence. An emission estimate with this degree of accuracy, therefore, became the project objective.

A literature survey conducted at the outset of this project verified that previous studies contained insufficient data, individually or collectively, to meet the accuracy goals of this project. The majority of studies that were found during the literature survey employed a method common at that time in which "unaccounted-for gas" was assumed to be equivalent to losses to

the atmosphere.[44,45,46,47] "Unaccounted-for gas" is simply an accounting term which includes numerous categories in addition to losses to the atmosphere and therefore could greatly overstate gas industry losses.

These studies were followed by a report written by Pipeline System Incorporated (PSI) and funded by EPA-OAR and GRI in 1990.[48] The purpose of the early GRI/EPA study was to initially guide the more comprehensive GRI/EPA efforts that are presented in this report. The early PSI study produced an estimate showing that methane emissions were 1% of gross gas production. However, this study was only an attempt to identify major sources, and no emission measurements were made.

A Report to Congress (RTC) by EPA estimated that methane emissions from the natural gas industry were between 0.55 and 1.07% of gross production for 1990.[3] This study provided a reasonable synthesis of existing data at that time but did not expand the database. The need remained for an extended field sampling program and a statistical framework within which the data could be analyzed and accuracy targets could be calculated.

The 140 Bscf difference between the emission estimates from the RTC (110 to 220 Bscf) and the GRI/EPA study (307 Bscf) result from recent data that were not available at the time the RTC was written. The GRI/EPA study used new data to refine many source categories. The single category with the most significant difference was fugitive emissions, which accounts for almost 90% of the difference between the RTC and the GRI/EPA reports. The fugitive differences result from two major sources of new data: 1) compressor components (82 Bscf difference), and 2) distribution sources (60 Bscf difference), such as pipelines, meter and regulation (M&R) stations, and customer meters.

Compressor components, which are very large sources of fugitive emissions, were measured as part of the GRI/EPA study, but no measurements were available at the time of the RTC. Compressor components in processing, transmission, and storage facilities resulted in GRI/EPA estimates of 82 Bscf; these components had not been accounted for by the RTC.

The GRI/EPA report also refined the estimates for leakage from distribution pipelines and M&R stations through additional data gathering efforts. When the RTC was prepared, the only data available on pipeline leakage were for two very tight distribution systems that had very little cast iron pipe. In addition, no data were available on the number and type of M&R stations used in the gas industry. These data were gathered during the GRI/EPA study. Also, emissions from customer meters, which were not included in the RTC, were included in the GRI/EPA study and measured to be 6 Bscf. The new GRI/EPA data show that the total distribution segment emissions are approximately 60 Bscf higher than estimated by the RTC.

5.3 Current and Future Industry Emissions

Since the 1992 base year, emissions from the natural gas industry have changed because the amount of gas produced has increased and because gas industry practices have changed. In 1993 a joint industry-government program was started to reduce emissions. The impact of increased production and changes in practices is discussed in more detail in the following subsections.

5.3.1 Industry Practices to Reduce Methane Emissions

The natural gas industry has always been concerned with reducing natural gas losses. Every year the industry's practices continue to evolve and many companies have policies to recover gas or reduce losses. Examples are company programs to reduce losses through fugitive leak detection and repair programs (LDAR) for underground piping and above-ground facilities. Also as a result of this study, a number of companies became aware of ways to reduce operating costs while reducing emissions, and many of these companies are implementing cost/emission reduction programs.

In 1993, a joint industry-government effort began. The Environmental Protection Agency (EPA), in conjunction with the natural gas industry, created the Natural Gas STAR Program to help reduce methane emissions from its major sources.[2] The Natural Gas STAR Program was established as a flexible, voluntary partnership to reduce methane emissions using

cost-effective practices. The EPA[49] and industry identified several best management practices (BMPs) in each sector of the natural gas industry, including:

Distribution Sector

- Implement directed inspection and maintenance programs at surface facilities
- Identify and rehabilitate leaky distribution pipe

Transmission Sector

- Implement directed inspection and maintenance programs at compressor stations
- Consider use of turbines at compressor stations in lieu of reciprocating engines
- Identify and replace high-bleed pneumatic devices

Production Sector

- Identify and replace high-bleed pneumatic devices
- Install flash tank separators on dehydrators

The program also facilitates technology transfer among partners on other practices that cost-effectively reduce methane emissions. As of April 1996 the program included 54 partners, representing over 60% of all transmission pipeline, 30% of all distribution pipeline and 25% of all U.S. natural gas production. As the new Producers Program (launched in March, 1995) gets under way and as new distribution and transmission companies join, the program is expected to continue to reduce emissions of methane by 35 Bcf through the year 2000.

The gas industry may also decrease methane emissions in the future as it complies with maximum achievable control technology (MACT) standards for hazardous air pollutants (HAPs). The MACT rule will result in a reduction of certain hydrocarbon emissions and may also reduce methane emissions. However, the actual impact of the MACT is unclear at this point in time, due to questions on the language of the final rule, the compliance schedule, source applicability, and the required control technologies.

Since the Oil and Gas MACT Rule is scheduled for promulgation in 1997, the only information publicly available is from the preliminary Background Information Document (BID).[50] The effect of the Oil and Gas MACT on methane emissions cannot be easily determined because the language of the MACT does not specifically address these emissions. The BID suggests that glycol dehydrators and some sources of fugitive emissions will require controls for HAP emissions. Depending on the kind of controls implemented by the industry for these sources, methane emissions may be reduced as well.

The preliminary draft MACT proposes that equipment leaks at major sources, including gas processing plants and offshore platforms, must be controlled by a LDAR program. If this requirement becomes part of the final MACT rule, methane emissions from fugitive sources in the gas production and processing segments will decrease.

5.3.2 Incremental Increases in System Throughput

As part of this program, a study was conducted to determine the percent increase in emissions caused by an incremental increase in natural gas production and sales.[18] The study found that increases in throughput did, in many cases, produce increases in emissions. However, the average increase in emissions was proportionally smaller than the increase in system throughput.

This study examined the consequences of increasing gas sales by 5, 15, and 30 percent under three scenarios: uniform, winter peak, and summer peak load profiles. All segments of the gas industry were examined to determine the percent increase in equipment that would be needed in order to meet the increased demand. The percent increase in emissions was then estimated based on changes in the current system that would be required to accommodate the increase in gas sales. The GRI/EPA's emission estimates were used to calculate the percent increase in emissions that would result from an incremental increase in natural gas sales for several scenarios examined in the study. The most realistic scenario assumes that the system will be expanded using current technology, whereas the most conservative scenario assumes that the expanded system mirrors the existing system. Generally, emissions would only increase 2% to 21% for corresponding load increases of 5% to 30%. The incremental methane emission increases, when divided by the incremental production rate increases, result in emissions per production percentages of 0.3 to 1%, which are only one-third to two-thirds of the base emission rate (1.42% for 1992). Thus, the incremental emission increases are proportionally less than the load increase for all scenarios examined. (Results are explained further in Appendix B.)

5.4 Lessons Learned for Future Studies

The project team learned some key lessons during this multi-year project that may benefit other similar studies. The key lessons learned are grouped below in two categories: sampling/statistical methods and measurement methods.

5.4.1 Sampling/Statistical Methods

Because of the complexity and diversity of the natural gas industry, a detailed plan was implemented to meet the goals of the program.[27] Some of the procedures used in sample selection and statistical methodology were developed/implemented specifically for this program but would have potential utility in other similar studies. These sampling/statistical methods include:

- Sampling technique that is dependent upon the source population;
- Sampling techniques and statistical methods to minimize bias in a dataset;
- Use of accuracy targets to plan the program and allocate resources; and
- Statistical tests to handle small datasets that are highly variable.

Sampling Technique/Bias Minimization

Because of the complexity and often unknown equipment populations for a given source within the gas industry, the selection of a proper sampling approach was not straightforward. For some sources, such as production separators, even the population size was not known at the onset of the program. These factors made the selection of representative samples for measurement or observation difficult, and traditional sampling methods, such as random or stratified random sampling were not directly applicable in most cases. Therefore, an alternative approach, which is similar to disproportionate stratified random sampling, was used.

The sampling approach included selecting sites from known lists of facilities in as random a fashion as possible. However, the companies contacted were not required to participate and a complete list of all sources in the United States was generally not available; therefore, site selection was not truly random. Companies that elected to participate were asked to identify potential sites that were considered representative of company-wide operations.

The limited data set collected was screened for bias by evaluating the relationship between the emission rate and parameters that may affect emissions. The data set was then stratified by the parameter(s) found to significantly influence emissions. Because the sample set collected was not necessarily representative of the nationwide proportions of sites in each strata, an emission factor per strata was produced along with an activity factor per strata to eliminate bias in the disproportionate sample set.

Other techniques employed to minimize bias included evaluating regional differences in operating practices or gas composition. In many cases, regional differences were found and had to be accounted for in the emissions estimation approach. A group of industry experts was used to review the data and approach for estimating emissions, so that any additional biases could be identified and eliminated. Industry experts from each segment and other reviewers were called upon to regularly review the project sampling approach, extrapolation techniques, and preliminary estimates. These reviewers identified potential biases that were eliminated through changes to techniques or through additional data collection.

Use of Accuracy Targets

To effectively allocate resources within the budget constraints of the program, accuracy targets were established for each emissions source such that resource could be assigned to emission sources based on the impact of each source on accuracy. An overall target accuracy was set for the industry-wide methane emissions estimate, and individual source target accuracies were calculated based upon overall accuracy goal. Target accuracies were set so that if individual source accuracies were met, the overall accuracy for the project would be met. The individual source accuracy targets were calculated based on precision estimates of the activity and emission factors. After the individual source target accuracies were calculated, the required number of additional samples needed to meet the target was calculated. By setting accuracy targets for individual sources, small, highly uncertain sources of emissions could then be appropriately handled. This process was used continuously throughout the data collection phase of the program to help direct the most efficient use of resources required to meet the overall program goal.

5.4.2 Measurement Methods

A number of unique measurement methods were developed and tested as a result of this program. Many of these methods are applicable to sources outside of the natural gas industry. The most noteworthy of these are listed and described below:

- High flow device for fugitive emissions measurements;
- Tracer gas measurement method for estimating emissions from meter and pressure regulating stations;
- A cooperative effort between industry and GRI/EPA in measuring emissions from underground pipeline leaks; and
- A detailed mass balance approach for system-wide emissions from a sample transmission network.

High Flow Fugitives Measurement Device

At the beginning of the GRI/EPA methane emissions study, it was clear that new component emission factors would be needed to evaluate fugitive emissions from gas industry equipment. The factors developed by EPA in the 1970s for natural gas production facilities were no longer applicable because of the changes that took place in the industry over the past 15 to 20 years. In addition, emission factors for gas processing, transmission and distribution equipment were needed since these had not been developed previously.

The standard EPA approach for determining emission factors uses a combination of screening and enclosure methods. First, all components are screened using an organic vapor analyzer (OVA) to determine which pipefittings are leaking and to measure the maximum concentration at the point of the leak. This is done for thousands of components at sites throughout the country. The leak rate is measured using the enclosure method for hundreds of leaking fittings of each type. A correlation equation is developed that correlates the

concentration value measured with the OVA with the emission rate measured using the enclosure method. The correlation equation is then used to calculate the emission rate for all components based on OVA readings, and an average emission rate (i.e., emission factor) is calculated for each type of component.

The problem is that the scatter in the concentration versus emission rate data is 3 to 4 orders of magnitude. Because the correlation is poor, thousands of measurements are needed, and this is time consuming and expensive. Therefore, GRI funded a study to develop a new instrument that could accurately measure the emission rate directly in about the time required to measure the concentration. This method was used not only for developing emission factors for production equipment, but also for processing, transmission, and distribution.

The new instrument, called the GRI Hi-Flow sampler, can also be used to reduce operating cost. Since it provides a quick accurate measurement of the leak rate, the operator can determine if it is cost effective to fix the leak. It also can be used to accurately measure the fugitive emissions from a facility and determine whether the facility is subject to regulations and costly control and reporting requirements.

Tracer Gas Measurement Method

Tracer techniques were developed to measure methane emissions from sources of widely varying sizes and types. These sources included single regulator installations (above ground and below ground), city distribution M&PR stations, transmission tie-in points, transmission and production facilities, industrial gas users, municipal wastewater treatment facilities, landfills, and total city emissions.

The principle for each of these emission measurements was the same, but the application varied depending on the scale of the measurement. In each case, the tracer was used to measure the dilution of the methane from the source as it was transported to the receptor where

concentration was measured. For underground vaults and enclosures of single above-ground regulators, air was flushed through the enclosed volume. The methane emissions were measured by measuring the resulting dilution with a tracer released at a known rate while measuring both the tracer and methane concentrations. For larger sources such as M&PR stations, gas plants, and landfills, tracer was released at a known rate from an area inside the source boundaries, and the tracer and methane were measured at a downwind distance where the tracer and methane were well mixed. This again provided a measurement of the dilution of methane as it was transported from the source to receptors and allowed the calculation of the source strength from the ambient methane concentration.

Several lessons were learned concerning the application of tracers during this work. Real time instruments were used to track both the methane and tracer plumes and helped to identify interfering sources, to determine appropriate sampling points, and to integrate the plumes from very large scale sources such as landfills and cities. Measurements were validated using techniques developed in past studies which included comparing results from samplers at different crosswind locations in the methane plume, comparing plume traverses at different downwind distances, and conducting replicate measurements with different tracer source configurations or under different meteorological conditions.

Tracer emission measurement techniques have both advantages and disadvantages compared to techniques that measure emissions from individual components or flux chamber measurements made at landfills or treatment plants. The accuracy of the tracer technique is susceptible to some meteorological conditions and interferences from other sources. However, the tracer technique can provide the total site emission rate in a fraction of the time (a few hours under the appropriate conditions) that is required using individual component techniques or flux chambers. At a natural gas facility, this total emission rate will include non-fugitive sources such as compressor engine exhaust. Measuring total emissions proved to be an advantage in this study because it was used to determine if any sources were missed by comparing the sum of all known fugitive vented and combusted emissions to the total value measured using the tracer

technique. It was found that leakage from the blowdown valve was overlooked by the component measurement method because it was directed to a roof vent system.

Due to the inherent uncertainty of the component screening techniques originally used for the individual component measurements, the tracer method was the most accurate method available for determining total emissions from a facility. The development of the high flow sampler during this project now provides a component measurement method of the same or better accuracy than the tracer method. Consequently, the best measurement method will often depend on the goals of the measurement work. Tracer techniques do not provide any data on the location or magnitude of sources within a site. For a natural gas facility, effective emissions reductions cannot be accomplished without knowing which components are leaking and how much each is leaking. However, these individual component methods are more time consuming, have the potential to miss significant sources, and are not applicable to many sources. When trying to obtain as much data on total facility emissions as possible in the shortest amount of time, tracer techniques may provide the best method of emissions measurement.

Cooperative Industry Measurement Effort

Early in the program, leakage from underground pipelines in the distribution segment was targeted as a potentially large source. A measurement technique identified as being very accurate was proposed for the GRI/EPA program. However, this technique was extremely costly to implement on a per test basis, and due to the population size and uncertainty in emissions, the estimated sample size to reach the target accuracy was very large. Therefore, GRI/EPA solicited participation in a cooperative program between industry and the program sponsors to share the cost of collecting data. The GRI/EPA program provided a detailed test protocol, specifications for the measurement device, and training/auditing/support to the industry participants. The actual measurements were performed and funded by the companies agreeing to participate in the program. This cooperative effort proved to be a successful means to meet the objectives within the budget constraints of the GRI/EPA program.

Mass Balance Measurement Approach

An extremely detailed mass balance was performed on a sample transmission system to determine if emissions to the atmosphere could be determined by examining the differences in upstream/downstream meter readings. This effort did not prove successful due to the many uncertainties in mass balance measurements that could not be completely resolved and emissions could not be determined to meet the accuracy target.

5.4.3 Significant Sources

Several significant sources of methane emissions were identified or found to be much larger than anticipated. Compressor blowdown valve fugitives, M&PR stations, pneumatic devices, dehydrators, and maintenance emissions all were determined to be larger than estimated by previous studies.

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APPENDIX A

Summary Table of Emission Sources

METHANE EMISSION AND ACCURACY ESTIMATES

PROCESS SEGMENT Emission Type Source	1992 Emissions (Tg)	1992 Emissions (Bscf)	Percent of Total Emissions (%)	Percent of Total Production % (a)	Activity			Emission			Precision of Annual Emissions	Conservative Precision of Annual Emissions (d)	Target Precision (%) (c)
					Value	Units	Upper Bound (b)	Value	Units	Upper Bound (b)			
PRODUCTION													
Normal Fugitives													
Gas Wells (Eastern on shore)	0.0064	0.3352	0.11	0.002	129,157	wells	5%	7.11	Scfd/well	27%	27.49%	31.39%	1077.82
Field Separation Equipment (Eastern on shore)													
Heaters	0.0000	0.0013	0.00	0.000	260	heaters	196%	14.21	scfd/heater	43%	217.84%	423.13%	1500.00
Separators	0.0006	0.0301	0.01	0.000	91,870	separators	23%	0.90	scfd/sep	27%	38.01%	42.74%	1500.00
Gathering Compressors													
Small Recip. Compr.	0.0000	0.0006	0.00	0.000	129	compressors	33%	12.1	scfd/comp	27%	43.56%	53.45%	1500.00
Meters/Piping	0.0048	0.2508	0.08	0.001	78,262	meters	100%	9.01	scfd/meter	30%	108.63%	169.02%	1248.02
Dehydrators	0.0002	0.0083	0.00	0.000	1,047	dehydrators	20%	21.75	scfd/dehy	35%	40.91%	49.63%	1500.00
Gas Wells (Rest of US on shore)	0.0385	1.8969	0.60	0.009	142,771	wells	5%	36.40	Scfd/well	24%	24.54%	27.65%	453.08
Gulf of Mexico (offshore pltfrms)	0.0223	1.1815	0.37	0.005	1,092	platforms	10%	2914	Scfd/plat	27%	28.92%	33.24%	578.01
Rest of US (offshore platforms)	0.0002	0.0095	0.00	0.000	22	platforms	10%	1178	Scfd/plat	36%	37.54%	44.86%	1500.00
Field Separation Equipment (Rest of US on shore)													
Heaters	0.0208	1.0688	0.34	0.005	50,740	heaters	95%	57.7	scfd/heater	40%	109.86%	171.58%	603.64
Separators	0.0639	3.3252	1.06	0.015	74,674	separators	57%	122.0	scfd/sep	33%	88.50%	93.05%	342.20
Gathering Compressors													
Small Recip. Compr.	0.0318	1.6534	0.53	0.007	16,915	compressors	52%	267.8	scfd/comp	68%	92.62%	137.08%	485.29
Large Recip. Compr.	0.0102	0.5328	0.17	0.002	98	compressors	100%	15205.0	scfd/comp	65%	135.83%	227.42%	854.90
Large Recip. Stations	0.0007	0.0361	0.01	0.000	12	stations	100%	8247.0	scfd/station	102%	175.52%	319.62%	1500.00
Meters/Piping	0.1118	5.8153	1.85	0.026	301,160	meters	100%	52.9	scfd/meters	30%	108.63%	169.02%	258.78
Dehydrators	0.0235	1.2229	0.39	0.006	36,777	dehydrators	20%	91.1	scfd/dehy	25%	32.40%	37.84%	584.28
Pipeline Leaks	0.1269	6.6000	2.10	0.030	340,200	miles	10%	53.2	scfd/mile	107%	108.00%	187.72%	242.89
Vented and Combusted													
Drilling and Well Completion													
Completion Flaring	0.0000	0.0006	0.00	0.000	844	compl/yr	10%	733	scf/compl	200%	201.25%	382.35%	1500.00
Normal Operations													
Pneumatic Device Vents	0.6037	31.3948	9.99	0.142	248,111	controllers	48%	345	Scfd/device	40%	84.99%	87.10%	111.37
Chemical Inj Pumps	0.0295	1.5385	0.49	0.007	16,971	active pumps	143%	248.05	Scfd/pump	83%	203.53%	388.00%	503.41
Kimray Pumps	0.2108	10.9616	3.49	0.050	1.105E+07	MMscf/yr	82%	992.00	scf/MMscf	77%	110.03%	171.90%	188.47
Dehydrator Vents	0.0657	3.4171	1.09	0.015	1.240E+07	MMscf/yr	62%	275.57	scf/MMscf	154%	191.90%	359.38%	337.57
Compressor Exhaust Vented													
Gas Engines	0.1287	6.5904	2.10	0.030	27,460	MMHPhr	200%	0.240	scf/HPhr	5%	200.31%	380.04%	243.07
Routine Maintenance													
Well Workovers													
Gas Wells	0.0004	0.0230	0.01	0.000	9,392	w.o./yr	258%	2,454	scfy/w.o.	456%	1298.00%	2746.84%	1500.00
Well Clean Ups (LP Gas Wells)	0.1088	5.6579	1.80	0.026	114,139	LP gas wells	45%	49570	scfy/LP well	344%	379.90%	834.58%	262.34
Blowdowns													
Vessel BD	0.0004	0.0200	0.01	0.000	255,996	vessels	26%	78	Scfy/vsl	266%	276.07%	571.10%	1500.00
Pipeline BD	0.0020	0.1051	0.03	0.000	340,000	miles(gath)	10%	309	Scfy/mile	32%	33.68%	39.56%	1500.00
Compressor BD	0.0012	0.0646	0.02	0.000	17,112	compressors	52%	3774	Scfy/comp	147%	173.66%	315.14%	1500.00
Compressor Starts	0.0028	0.1445	0.05	0.001	17,112	compressors	52%	8443	Scfy/comp	157%	184.44%	341.18%	1500.00
Upsets													
Pressure Relief Valves	0.0003	0.0180	0.01	0.000	529,440	PRV	53%	34	Scfy/PRV	252%	290.09%	606.86%	1500.00
ESD	0.0055	0.2884	0.09	0.001	1,115	platforms	10%	256868	Scfy/plat	200%	201.25%	382.35%	1165.95
Mishaps (Dig-ins)	0.0044	0.2275	0.07	0.001	340,000	miles	10%	669	scf/mile/yr	1925%	1934.63%	3766.68%	1308.38

(a) Based on a total gross national production of 22132 Bscf for 1992.

(b) Precision based on a 90% confidence interval.

(c) Target Precision = 100*(6.24/SQRT(ER)), where ER = emissions in Bscf. Overall TP is +/- 110.66 Bscf.
Maximum Relative Category TP is +/- 1500%, Minimum Relative Category TP is +/- 75%, where TP = target precision.

(d) Conservative precision based on upper limit of a 90% confidence interval. This confidence interval is based on a lognormal assumption.

METHANE EMISSION AND ACCURACY ESTIMATES

PROCESS SEGMENT Emission Type Source	1992 Emissions (Tg)	1992 Emissions (Bscf)	Percent of Total Emissions (%)	Percent of Total Production % (a)	Activity			Emission			Precision of Annual Emissions	Conservative Precision of Annual Emissions (d)	Target Precision (%) (c)
					Value	Units	Upper Bound (b)	Value	Units	Upper Bound (b)			
Gas Processing Plants													
Normal Fugitives													
Plants	0.0403	2.0950	0.67	0.009	726	plants	2%	7906	scfd/plant	48%	48.05%	60.11%	431.12
Recip. Compressors	0.3216	16.7251	5.32	0.076	4,092	compressors	48%	11198	scfd/comp	74%	95.09%	141.87%	152.58
Centrifugal Compressors	0.1082	5.6257	1.79	0.025	726	compressors	77%	21230	scfd/comp	39%	91.39%	134.71%	283.09
Vented and Combusted													
Normal Operations													
Compressor Exhaust													
Gas Engines	0.1281	6.6624	2.12	0.030	27,760	MMHPhr	133%	0.240	scf/HPhr	5%	133.26%	221.71%	241.75
Gas Turbines	0.0038	0.1976	0.06	0.001	32,910	MMHPhr	121%	0.0057	scf/HPhr	30%	126.84%	214.17%	1440.74
AGR Vents	0.0158	0.8237	0.26	0.004	371	AGR units	20%	6083	scfd/AGR	105%	108.85%	189.48%	687.54
Kimray Pumps	0.0033	0.1703	0.05	0.001	957900	MMscf/yr	182%	177.75	scf/MMscf	57%	228.00%	449.12%	1500.00
Dehydrator Vents	0.0202	1.0490	0.33	0.005	8,630,000	MMscf/yr	22%	121.55	scf/MMscf	202%	208.20%	399.58%	609.26
Pneumatic Devices	0.0023	0.1196	0.04	0.001	726	gas plants	2%	164721	scfy/plant	133%	133.04%	221.23%	1500.00
Routine Maintenance													
Blowdowns/Venting	0.0567	2.9475	0.94	0.013	726	gas plants	2%	4060	Mscfy/plant	282%	282.16%	535.66%	383.46

(a) Based on a total gross national production of 22132 Bscf for 1992.
(b) Precision based on a 90% confidence interval.
(c) Target Precision = 100*(8.24/SQRT(ER)), where ER = emissions in Bscf. Overall TP is +/- 110.66 Bscf.
Maximum Relative Category TP is +/- 1500%, Minimum Relative Category TP is +/- 75%, where TP = target precision.
(d) Conservative precision based on upper limit of a 90% confidence interval. This confidence interval is based on a lognormal assumption.

METHANE EMISSION AND ACCURACY ESTIMATES

PROCESS SEGMENT Emission Type Source	1992 Emissions (Tg)	1992 Emissions (Bscf)	Percent of Total Emissions (%)	Percent of Total Production % (a)	Activity			Emission			Precision of Annual Emissions	Conservative Precision of Annual Emissions (d)	Target Precision (%) (c)
					Value	Units	Upper Bound (b)	Value	Units	Upper Bound (b)			
TRANSMISSION/STORAGE													
Fugitives													
Pipeline Leaks	0.0031	0.1600	0.05	0.001	284,500	miles	5%	1.541	scfd/mile	89%	89.00%	130.14%	1500.00
Compressor Stations (TRANS)													
Station	0.1047	5.4487	1.73	0.025	1,700	stations	10%	8778	scfd/station	102%	103.00%	157.55%	287.37
Recip. Compressor	0.7256	37.7333	12.01	0.170	6,799	comp.	17%	15205	scfd/comp.	65%	68.09%	92.35%	101.58
Centrifugal Compressor	0.1449	7.5328	2.40	0.034	681	comp.	26%	30305	scfd/comp	34%	43.71%	53.67%	227.36
Compressor Stations (STOR)													
Station	0.0717	3.7288	1.19	0.017	475	stations	5%	21507	scfd/station	100%	100.25%	152.05%	323.15
Recip. Compressor	0.2069	10.7594	3.42	0.049	1,396	comp.	58%	21116	scfd/comp	48%	80.27%	113.88%	190.24
Centrifugal Compressor	0.0292	1.5178	0.48	0.007	136	comp.	119%	30573	scfd/comp.	34%	130.21%	214.97%	508.53
Wells (STOR)	0.0145	0.7522	0.24	0.003	17,998	wells	5%	114.5	scfd/well	78%	78.26%	108.64%	719.47
M&R (Trans. Co. Interconnect)	0.0708	3.6834	1.17	0.017	2,533	stations	778%	3984	scfd/station	80%	996.98%	2197.40%	325.14
M&R (Farm Taps + Direct Sales)	0.0159	0.8271	0.26	0.004	72,630	stations	780%	31.2	scfd/station	80%	1002.09%	2207.28%	886.13
Vented and Combusted													
Normal Operations													
Dehydrator Vents (TRANS)	0.0020	0.1018	0.03	0.000	1,086,000	MMscf/yr	144%	93.72	scf/MMscf	208%	391.75%	864.25%	1500.00
Dehydrator Vents (STOR)	0.0045	0.2344	0.07	0.001	2,000,000	MMscf/yr	25%	117.18	scf/MMscf	160%	166.56%	298.24%	1288.98
Compressor Exhaust													
Engines (TRANS)	0.1864	9.6912	3.08	0.044	40,380	MMHPhr	17%	0.240	scf/HPhr	5%	17.74%	19.35%	200.45
Turbines (TRANS)	0.0011	0.0549	0.02	0.000	9,635	MMHPhr	33%	0.0057	scf/HPhr	30%	45.68%	58.58%	1500.00
Engines (STOR)	0.0227	1.1813	0.38	0.005	4,922	MMHPhr	27%	0.240	scf/HPhr	5%	27.49%	31.39%	574.13
Turbines (STOR)	0.0002	0.0099	0.00	0.000	1729	MMHPhr	626%	0.0057	scf/HPhr	30%	654.25%	1485.73%	1500.00
Generators (Engines)	0.0091	0.4748	0.15	0.002	1,978	MMHPhr	45%	0.240	scf/HPhr	5%	45.25%	55.94%	905.60
Generators (Turbines)	0.0000	0.0001	0.00	0.000	23.3	MMHPhr	1114%	0.0057	scf/HPhr	30%	1183.33%	2510.01%	1500.00
Pneumatic Devices	0.2720	14.1448	4.50	0.064	87,206	devices	38%	162197	scfy/device	44%	80.49%	79.65%	185.92
Routine Maintenance/Upsets													
Pipeline Venting	0.1732	9.0044	2.87	0.041	284,500	miles	5%	31.65	Mscfy/mile	238%	238.25%	489.92%	207.95
Station Venting	0.1823	9.4800	3.02	0.043	2,175	cmp stations	8%	4359	Mscfy/station	262%	262.66%	539.83%	202.67

(a) Based on a total gross national production of 22132 Bscf for 1992.

(b) Precision based on a 90% confidence interval.

(c) Target Precision = 100*(6.24/SQRT(ER)), where ER = emissions in Bscf. Overall TP is +/- 110.86 Bscf.
Maximum Relative Category TP is +/- 1500%, Minimum Relative Category TP is +/- 75%, where TP = target precision.

(d) Conservative precision based on upper limit of a 90% confidence interval. This confidence interval is based on a lognormal assumption.

METHANE EMISSION AND ACCURACY ESTIMATES

PROCESS SEGMENT Emission Type Source	1992 Emissions (Tg)	1992 Emissions (Bscf)	Percent of Total Emissions (%)	Percent of Total Production % (a)	Activity			Emission			Precision of Annual Emissions	Conservative Precision of Annual Emissions (d)	Target Precision (%) (c)
					Value	Units	Upper Bound (b)	Value	Units	Upper Bound (b)			
DISTRIBUTION													
Normal Fugitives													
Pipeline Leaks													
Mains - Cast Iron	0.2538	13.1992	4.20	0.080	55,288	miles	5%	238.7	Mscf/mile-yr	84%	83.97%	85.39%	171.76
Mains - Unprotected Steel	0.1740	9.0476	2.88	0.041	174,857	equiv. leaks	58%	51.8	Mscf/leak-yr	93%	122.42%	188.05%	207.45
Mains - Protected Steel	0.0266	1.3846	0.44	0.006	68,308	equiv. leaks	62%	20.3	Mscf/leak-yr	85%	118.00%	188.59%	530.30
Mains - Plastic	0.0945	4.9150	1.56	0.022	49,226	equiv. leaks	118%	99.8	Mscf/leak-yr	186%	282.18%	588.88%	281.47
Services - Unprotected Steel	0.1781	9.2630	2.95	0.042	458,478	equiv. leaks	109%	20.2	Mscf/leak-yr	105%	189.27%	352.92%	205.03
Services - Protected Steel	0.0691	3.5922	1.14	0.016	390,628	equiv. leaks	135%	9.20	Mscf/leak-yr	81%	188.90%	303.79%	329.24
Services - Plastic	0.0032	0.1644	0.05	0.001	68,903	equiv. leaks	97%	2.39	Mscf/leak-yr	143%	221.58%	433.02%	1500.00
Services - Copper	0.0011	0.0593	0.02	0.000	7,720	equiv. leaks	110%	7.68	Mscf/leak-yr	72%	154.25%	269.35%	1500.00
Meter/Regulator (City Gates)													
M & R > 300	0.1048	5.4510	1.73	0.025	3,460	stations	71%	179.8	scfh/station	39%	85.46%	123.47%	267.27
M & R 100-300	0.2148	11.1731	3.56	0.050	13,335	stations	106%	95.8	scfh/station	112%	194.97%	388.89%	188.88
M & R < 100	0.0052	0.2693	0.09	0.001	7,127	stations	118%	4.31	scfh/station	227%	370.94%	812.08%	1202.35
Reg > 300	0.1090	5.6655	1.80	0.026	3,995	stations	68%	181.9	scfh/station	58%	87.37%	146.35%	282.18
R-Vault > 300	0.0005	0.0268	0.01	0.000	2,348	stations	86%	1.30	scfh/station	182%	230.44%	455.26%	1500.00
Reg 100-300	0.0837	4.3520	1.38	0.020	12,273	stations	61%	40.5	scfh/station	66%	88.47%	148.52%	299.12
R-Vault 100-300	0.0002	0.0087	0.00	0.000	5,514	stations	61%	0.180	scfh/station	94%	126.14%	206.09%	1500.00
Reg 40-100	0.0064	0.3317	0.11	0.001	36,328	stations	84%	1.04	scfh/station	74%	109.09%	169.96%	1083.42
R-Vault 40-100	0.0005	0.0244	0.01	0.000	32,215	stations	84%	0.0885	scfh/station	64%	98.97%	149.51%	1500.00
Reg < 40	0.0003	0.0179	0.01	0.000	15,377	stations	85%	0.133	scfh/station	135%	173.87%	315.87%	1500.00
Customer Meters													
Residential	0.1067	5.5468	1.76	0.025	40,049,306	outdr meters	10%	138.5	scfy/meter	17%	19.80%	21.80%	264.95
Commercial/Industry	0.0042	0.2207	0.07	0.001	4,608,000	meters	5%	47.9	scfy/meter	35%	35.40%	41.91%	1328.20
Vented													
Routine Maintenance													
Pressure Relief Valve Releases	0.0008	0.0418	0.01	0.000	836,780	mile main	5%	0.050	Mscf/mile	3914%	3918.69%	6199.19%	1500.00
Pipeline Blowdown	0.0025	0.1324	0.04	0.001	1,297,589	miles	5%	0.102	Mscfy/mile	2521%	2524.15%	4579.76%	1500.00
Upsets													
Mishaps (Dig-ins)	0.0397	2.0631	0.66	0.009	1,297,589	miles	5%	1.59	Mscfy/mile	1922%	1924.41%	3751.65%	434.43
INDUSTRY TOTAL EMISSIONS	6.0437	314.2714	100.0000	1.4200							28.51%	32.71%	35.21
UNCERTAINTY (+/-)	0.0172	89.6029											

(a) Based on a total gross national production of 22132 Bscf for 1992.

(b) Precision based on a 90% confidence interval.

(c) Target Precision = 100*(6.24/SQRT(ER)), where ER = emissions in Bscf. Overall TP is +/- 110.68 Bscf.
Maximum Relative Category TP is +/- 1500%, Minimum Relative Category TP is +/- 75%, where TP = target precision.

(d) Conservative precision based on upper limit of a 90% confidence interval. This confidence interval is based on a lognormal assumption.

APPENDIX B

Effect of Methane Emissions on Global Warming

B.0 EFFECT OF METHANE EMISSIONS ON GLOBAL WARMING

Based on the recent climate change reports by the Intergovernmental Panel on Climate Change (IPCC), "switching from coal to oil or natural gas, and from oil to natural gas, can reduce (greenhouse gas) emissions."[1] The GRI/EPA study to estimate methane emissions from natural gas operations was undertaken primarily because this information was needed to determine if it makes sense to promote the increased use of natural gas as a strategy for reducing greenhouse gas emissions. This appendix attempts to put the results into perspective by examining whether the current estimate of methane emissions from natural gas operations is likely to affect this fuel switching strategy.

Carbon dioxide contributes as much to global warming as all other greenhouse gases combined. Natural gas emits substantially less CO_2 per unit of energy generated than either coal or oil.[1] However, methane, a more potent greenhouse gas than CO_2, is also emitted in the production, transmission and distribution of natural gas. The question raised was whether the fuel switching strategy is valid when emissions of all greenhouse gases are considered over the complete fuel cycle (production through end use combustion). To address this question, it is necessary to account for emissions of all greenhouse gases throughout the fuel cycle and to determine the impact of these gases on global warming.

Fortunately, in evaluating fossil fuel emissions, emissions of greenhouse gases other than methane and CO_2 are negligible and do not need to be considered. In addition, most of the CO_2 emissions result from fuel combustion and are accurately known. The uncertainty in estimating CO_2 emissions from production and transportation of the fuel is higher, but this is a relatively small value and does not have a large effect on the overall accuracy of the analysis. Estimates of methane emissions from natural gas operations prior to the GRI/EPA study generally ranged from 2 to 5 % of production.[2,3,4,5] The uncertainties in methane emissions from coal and oil production were equally as large. Although the uncertainty in emissions is still relatively large, the largest uncertainty in addressing the validity of the fuel switching strategy is

in determining the relative impacts of CO_2 and methane emissions on global warming. In order to simplify a comparison of the impact of one greenhouse gas with another, a global warming potential (GWP) has been defined.[6] The GWP is an index that relates the impact of a given greenhouse gas to an equal amount (by mass) of CO_2. The projected effect on global warming of a greenhouse gas over a chosen time horizon can be estimated by multiplying the appropriate GWP by the amount of gas emitted. Considerable work has been done in this area by the Intergovernmental Panel on Climate Change (IPCC). However, as discussed below, the uncertainty in the GWP is still very large.

B.1 Global Warming Potential

Although a trace gas can have a strong radiative forcing per molecule, its greenhouse heating potential depends on its lifetime and the rate at which it is injected into the atmosphere. The GWP for a trace gas addresses the net effect of the radiative forcing and the lifetime of the gas by calculating the time integrated radiative forcing of a unit mass impulse to the atmosphere.[6] The GWP is defined as the impact on global warming caused by an incremental amount of a given greenhouse gas divided by the impact of releasing an equivalent amount of CO_2. The GWP for methane can be approximated by the following equation:

$$GWP_M = \frac{\int_{t_o}^{t_1} A_{CH_4} C_{CH_4}\, dt}{\int_{t_o}^{t_1} A_{CO_2} C_{CO_2}\, dt} \qquad \textbf{(B1)}$$

where

A	=	radiative forcing per unit mass
C	=	concentration
CH_4	=	subscript designating methane
CO_2	=	subscript designating CO_2
t_o	=	time of release
(t_1-t_o)	=	time period over which the GWP is evaluated

The concentration is often approximated by the expression:

$$C = e^{-\lambda t} \qquad \textbf{(B2)}$$

where t = time; and
λ = 1/lifetime

In addition to the direct effect of methane on global warming (the radiative forcing due to methane itself, as given above), methane can also contribute to the formation of other greenhouse gases such as tropospheric ozone and water vapor in the stratosphere. These indirect effects of methane must be added to the direct effect to determine the total contribution of methane.

IPCC has published the results of studies to evaluate the GWP for the various greenhouse gases. Their findings in 1990, 1992, and 1994 are shown in Table B-1 for the direct effects of methane for different integration time periods (t_i-t_o).[7,8,9] The GWPs for methane, including both the direct and indirect effects, are also presented in Table B-1 for 1990, 1994, and 1995. Because the IPCC believed that the uncertainties in the indirect effects were very large, they decided not to publish a total GWP for methane in 1992. The change in values from 1994 to 1995 reflects a change in the lifetimes of gases that react primarily with tropospheric hydroxyl radical (OH) concentration, based on a revised estimate in the mean global OH concentration.[6]

TABLE B-1. GLOBAL WARMING POTENTIAL OF METHANE

	Integration Interval (years)					
	Direct Effects			Direct and Indirect Effects		
Year	20	100	500	20	100	500
1990	35*	11	4	63	21	9
1992	35	11	4	--	--	--
1994	43-52	12-21	5-6	62 ± 20	24.5 ± 7.5	7.5 ± 2.5
1995	--	--	--	56 ± 20	21 ± 7.4	6.5 ± 2.3

* A value of 35 indicates that one pound of methane has the same effect as 35 pounds of CO_2
--Data not available

As implied by the variations in the values shown in Table B-1, there are significant uncertainties in the GWP for methane. Some of these uncertainties result from differences in the models and model limitations. In 1990 and 1992 the lifetime of methane was determined by calculating the decay rate while the composition of the atmosphere was held constant. In the 1994 and 1995 calculations, the atmosphere was allowed to respond to the change in methane by coupling the methane chemistry to the calculation of the radiative forcing. This resulted in a reduction in the OH concentration. Since OH is primarily responsible for the oxidation of methane, the lifetime of methane in the atmosphere increased. The effect of including the chemistry was initially thought to be small, but as shown in Table B-1, the 1994 GWPs increased by approximately 35 to 50%. The change in GWP from 1994 to 1995 includes a decrease of about 10% based on an improved estimate in the concentration of methyl chloroform which is used as a reference compound in determining the mean global OH concentrations.

Other issues could also have significant effects on the calculated GWP when they are eventually addressed. Some examples are:

- The size of the incremental increase in methane. A relatively large pulse of methane is used in the models to evaluate the GWP. Because the chemistry is highly nonlinear, a large pulse can generate a nonlinear change in the lifetime of methane that would produce a much larger GWP than using a small pulse.

- Grid size. Emissions of NO_x and other gases are smeared over large grid cells and are artificially diluted. Because NO_x/methane/ozone chemistry is highly nonlinear, this could have a significant effect on the tropospheric ozone calculation and the evaluation of indirect effects of methane on GWP.

- Nonmethane hydrocarbons (NMHCs). NMHCs are not included in the current models. Since most NMHCs are more reactive than methane, the impact of increased methane emissions on tropospheric ozone could be overstated. This would cause an erroneously high value for the indirect contribution to GWP for methane.

Of all the parameters discussed, however, the parameter that has the largest effect on GWP is the time interval (t_1-t_o) used in evaluating GWP. There is not a consensus on the proper value, particularly between policy analysts and scientists. Some policy analysts use a time interval as short as 50 years. For methane, the time interval is an important question because there is a large difference in the lifetime of methane (approximately 12.2 years ± 25%) and the effective lifetime of CO_2 (200 to 250 years). If a time period of 50 years is selected, the GWP calculated by the IPCC would be approximately 34. The implication is that one pound of methane released into the atmosphere would have the same impact on global warming as 34 pounds of CO_2. The problem is that this is only true for the first 50 years. The amount and percentage of methane and CO_2 in the atmosphere based on releasing 34 pounds of CO_2 for each pound of methane (i.e., a GWP of 34) is presented in Table B-2 as a function of time after release. At the end of 50 years, the methane concentration would have decreased to a negligible level, but approximately 80% of the CO_2 would remain in the atmosphere and still contribute to global warming.

TABLE B-2. AMOUNT OF CO_2 AND METHANE REMAINING IN ATMOSPHERE WITH TIME

Greenhouse Gas	Time (Yrs.)[a]			
	20	50	100	500
% CO_2	90	78	61	8
% CH_4	19	1.6	0.03	--
lbs. CO_2[b]	31	26	21	3
lbs. CH_4	0.19	0.02	--	--

[a] Lifetime of methane and CO_2 used were 12.2 and 200 years, respectively.
[b] Assumed $GWP_M = 34$.

If a 50-year time interval is used to develop emission trading policies, then 1 pound of methane emissions could be traded for 34 pounds of CO_2. The problem is that after 50 years the 1 pound of methane would have decayed to less than 0.02 pounds, but there would still be 26 pounds of CO_2 remaining in the atmosphere. A century later, 21 pounds of the original 34 pounds of CO_2 released would still be contributing to global warming. These contributions of CO_2 are neglected by choosing a time period of 50 years.

In considering the impact of using different types of fuels, the time interval should be chosen so that both gases (in this case methane and CO_2) would have time to decay to negligible values. This suggests that the time interval for evaluating the GWP for methane should be in the range of 500 to 1000 years.

There currently is not a consensus on the integration interval. Because the GWP could be as low as 6.5 for a 500-year integration interval and as high as 34 for a 50-year interval (over five times larger), two approaches were taken in this analysis to examine the validity of the fuel switching strategy. In the first approach, a breakeven percentage is calculated. The breakeven percentage is the amount of methane that would have to be released during the natural gas fuel cycle to eliminate the advantage that natural gas has over coal and oil because of its lower CO_2 emissions. The breakeven percentage can be compared to the 1992 emission inventory for the natural gas industry to evaluate the relative advantage that natural gas has over

coal and oil. This approach is presented in Section B.2. In addition, to determine the validity of the fuel switching strategy, the breakeven percentage can be compared to the percentage of gas leaked due to the incremental increase in gas use that results from fuel switching from coal or oil to natural gas. This is presented in Section B.3. The second approach, presented in Section B.4, is to evaluate the amount of equivalent CO_2 emissions for each fossil fuel over the fuel cycle by converting total greenhouse gas emissions to "equivalent CO_2."

B.2 Breakeven Percentage

The first approach for evaluating the fuel switching analysis requires comparing the breakeven percentages of the various fuels. The breakeven percentage (BP) is the amount of methane that would have to be released in the production, distribution, and end use of natural gas for it to have the same impact on global warming that the fuel cycle of coal or oil would have. The breakeven percentage can be calculated knowing the GWP for the different greenhouse gases and the amount of each greenhouse gas released per unit of energy from the fuel cycle of natural gas, coal, and oil. The equation used is given below, along with the parameters used in the calculation.

$$BP = \frac{100}{G}\left(\frac{E_i - E_{NG}}{GWP_M} + EM_i\right) \qquad \textbf{(B11)}$$

where

E	=	pounds of CO_2 emitted from the fuel cycle for 10^6 Btu of fuel
G	=	pounds of methane in 10^6 Btu of natural gas
EM_i	=	pounds of methane emitted from the fuel cycle for 10^6 Btu's of fuel "i"
GWP	=	global warming potential calculated on a mass basis
i	=	subscript denoting type of fossil fuel (c for coal, o for oil)
NG	=	subscript denoting natural gas

M = subscript denoting methane

The results for coal are presented in Figure B-1 as a function of the GWP. Table B-3 presents the breakeven percentage for oil and coal based on IPCC's GWPs calculated for various time intervals, using the following values.

G = 38 pounds per MMBtu, based on an HHV of 1,031 for natural gas and a methane composition of 93.4%

E_c = 208 pounds per MMBtu

E_{NG} = 127 pounds per MMBtu

E_O = 184 pounds per MMBtu

EM_c = 0.6 pounds per MMBtu

EM_O = 0.06 pounds per MMBtu

TABLE B-3. BREAKEVEN PERCENTAGE (BP) FOR COAL AND OIL FOR VARIOUS GWP INTEGRATION INTERVALS

Integration Interval	GWP	BP (for coal)	BP (for oil)
50	34	8	5
100	21	12	7
500	6.5	34	23

As shown for a GWP of 6.5, approximately 34% of the natural gas produced would have to be leaked for natural gas to have the same impact on global warming as coal, or for oil, 23% of natural gas would have to be leaked to have the same impact. For a GWP of 34, the percentage is approximately 8% for coal and 5% for oil.

All the breakeven percentages are substantially larger than the percent of methane emitted from natural gas operations (1.42% of production for 1992). This indicates that natural gas has an inherent advantage over the other fuels for the 1992 base case.

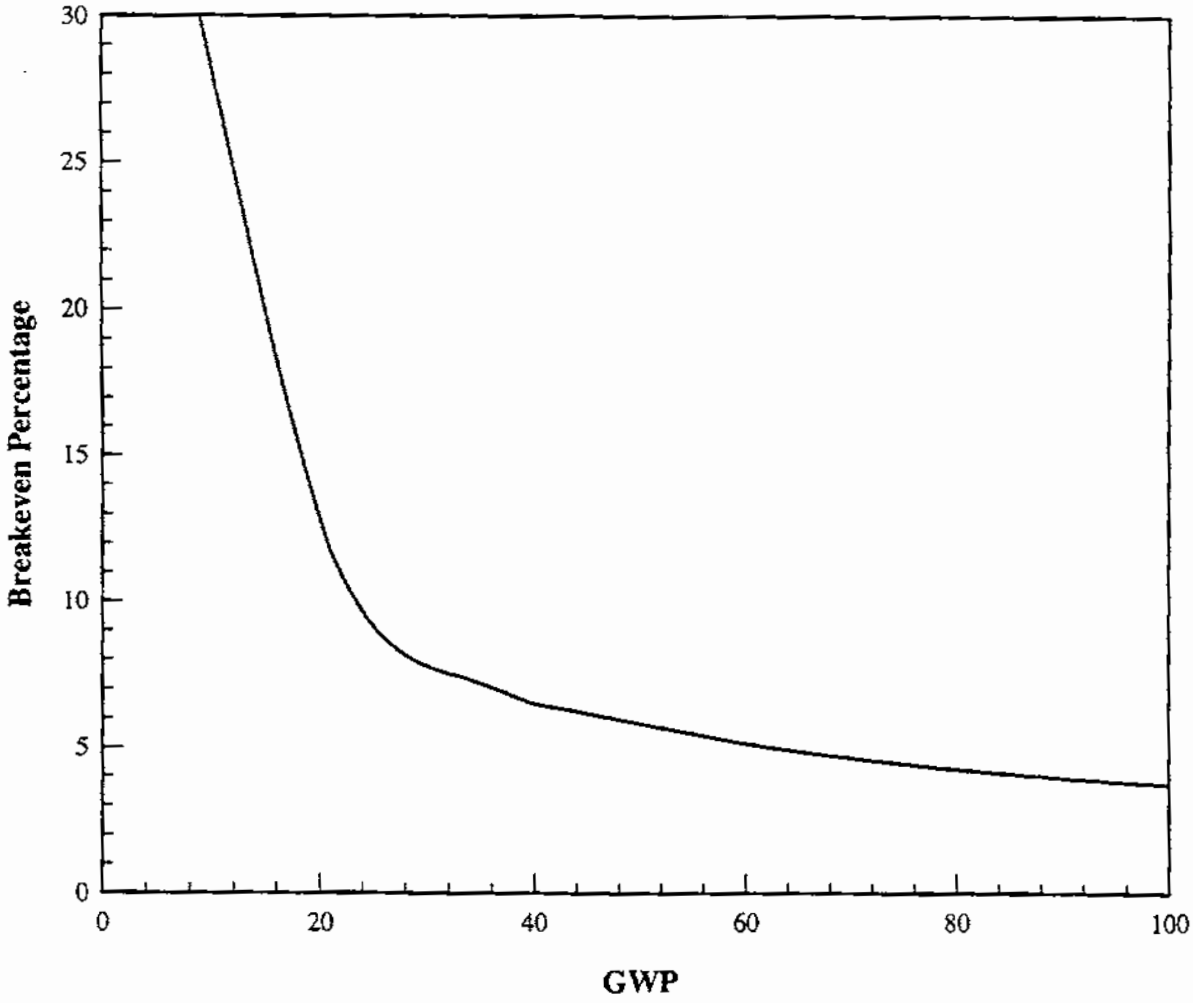

Figure B-1. Breakeven Percentage - Natural Gas Compared with Coal

For the fuel switching strategy, where natural gas consumption could replace some of the energy supplied by coal or oil, the breakeven percentage needs to be compared with the emissions that would result from an incremental increase in gas use. As will be shown in the next section, the incremental increase in emissions (above the 1992 baseline) are between 0.3% and 1.0% of the incremental increase in gas production, which is approximately one-third to two-thirds of the base year methane emissions (1.42% of the total gas production rate).

B.3 Emissions from Increased Gas Sales

As part of the GRI/EPA project, a separate study was conducted to determine the percent increase in emissions caused by an incremental increase in natural gas production and sales.[10] This study examined the consequences of increasing gas sales by 5, 15 and 30% under three scenarios: uniform, winter peak, and summer peak load profiles.

All segments of the gas industry were examined to determine the percent increase in equipment that would be needed to meet the increased demand. The percent increase in emissions was then estimated based on changes in the current system that would be required to accommodate the increase in gas sales. GRI/EPA's emission estimates were used to calculate the percent increase in emissions that would result from an incremental increase in natural gas sales for seven scenarios. The results are presented in Tables B-4 and B-5 for two cases: expected and upper limit, respectively. The assumption for the values listed under "expected" was that the system will be expanded using the latest technologies. The assumption for the values listed under "upper limit" was that the expanded system mirrors the existing system (i.e., new equipment or technologies for reducing emissions are not utilized).

For most components, facility and operating changes are not linearly related to increased gas throughput due to excess capacity or practices such as pipeline looping. Therefore, the study showed that an increase in gas use for either a system mirroring current technology or a system utilizing the latest technology would increase emissions by an amount less than the

TABLE B-4. INCREMENTAL CHANGES IN EMISSIONS RESULTING FROM INCREASED GAS SALES - EXPECTED CASE

		Increased System Throughput (%)						
		Uniform Load			Winter Peak			Summer Peak
	Base Case	5	15	30	5	15	30	15
Total Emissions, Bscf	314	319	328	343	320	333	352	324
% Increase over Base Case	--	1.37	4.43	9.20	1.90	5.84	12.0	2.98
Total Emissions/ Total Gas Production Rate	1.42%	1.37%	1.29%	1.19%	1.38%	1.31%	1.22%	1.27%
Δ Emissions/Δ Production Rate	--	0.39%	0.42%	0.44%	0.54%	0.55%	0.57%	0.28%

TABLE B-5. INCREMENTAL CHANGES IN EMISSIONS RESULTING FROM INCREASED GAS SALES - UPPER LIMIT CASE

		Increased System Throughput (%)						
		Uniform Load			Winter Peak			Summer Peak
	Base Case	5	15	30	5	15	30	15
Total Emissions, Bscf	314	319	336	361	321	346	380	331
% Increase over Base Case	--	1.37	6.98	15.0	2.12	9.98	21.0	5.42
Total Emissions/ Total Gas Production Rate	1.42%	1.37%	1.32%	1.26%	1.38%	1.36%	1.32%	1.30%
Δ Emissions/Δ Production Rate	--	0.39%	0.66%	0.71%	0.60%	0.95%	0.99%	0.51%

percent load increase. For the expected system, total emissions (Bscfy of methane) increase by 1.4% to 12% over the load scenarios examined for corresponding increases in gas sales of 5% to 30%. The incremental methane emission increase (5 to 38 Bscfy), when divided by the incremental production rate increase (1,110 to 6,640 Bscf natural gas), results in emissions per production percentages of 0.3 to 0.6%. For the upper limit case, total emissions increase by 1.4% to 21% for the same scenarios. The incremental methane emission increase for these scenarios (5 to 66 Bscfy), when divided by the incremental production rate increase, results in emissions per production percentages of 0.4 to 1.0%. Compared to the base year emissions per production percentage of 1.42 %, the incremental emission rates (Δ methane emissions per Δ production volume) are only one-third to two-thirds of the base emission rate. The incremental emission percentages are much lower than the breakeven percentages of either coal (8 to 34%) or oil (5 to 23%) based on a GWP time interval of 50 or 500 years, respectively. Therefore, this analysis supports the validity of the fuel switching strategy.

B.4 Equivalent CO_2 Emissions

The second approach used to examine the validity of the fuel switching strategy is based on quantifying the emissions of methane and CO_2 for each fuel over the fuel cycle and then converting the methane emissions to equivalent CO_2 by multiplying by the GWP. The GWP relates the radiative forcing of other greenhouse gases, such as methane, to the radiative forcing of CO_2 over a period of time, accounting for the changing concentration of the greenhouse gases over time. For a given fuel, the equivalent CO_2 emissions are calculated using the following equation:

$$\text{Equivalent } CO_2 = \sum_{i=1}^{n}\left[E_{CO_2} + \sum_{j=1}^{GHG}\left(GWP_j \times E_j\right)\right] \qquad \textbf{(B4)}$$

where:

i	=	subscript that denotes the various fuel cycle operations (production, transportation, processing, and combustion)
j	=	subscript to denote the various greenhouse gases (GHGs)
E_{CO2}	=	mass of CO_2 emissions (lb) per energy input
GWP_j	=	global warming potential used to convert emissions of GHG, "j," to equivalent CO_2 emissions
E_j	=	mass of other greenhouse gas emissions (lb) per energy input

This equation results in the total fuel cycle emissions by accounting for:

1) End use CO_2 emissions from fuel combustion;

2) CO_2 emissions by the industry resulting from the production, processing, and transportation of the fuel; and

3) CO_2 equivalent emissions that result from industry methane emissions.

For the purpose of the fuel switching analysis, equivalent CO_2 emission factors of the various energy sources are reported as the mass of equivalent CO_2 emissions per unit of energy. Therefore, for an energy requirement of one million Btu, the relative contribution of equivalent CO_2 emissions of the various fuels can be compared.

The energy content of the fuel can be expressed in terms of either the lower heating value (LHV) or the higher heating value (HHV). The difference between lower (or net) and higher (or gross) heating value is the heat of vaporization ($\Delta\hat{H}_v$) from the moisture produced during combustion, where the higher heating value includes this amount:

$$HHV = LHV + n\Delta\hat{H}_v(H_2O) \qquad \textbf{(B5)}$$

where:

n	=	moles of water produced

$\Delta\hat{H}_v(H_2O)$ = heat of vaporization of water at 25 °C

The difference between the higher and lower heating values can be significant when comparing the combustion efficiency from various end use equipment, since the latent heat is recovered by some end-use equipment, but not by all end-use equipment. For this study, the efficiencies of end use equipment are not considered. The fuels are compared on a higher heating value basis, which is the convention commonly used in the U.S. and is also the convention used by IPCC.[1,11] The general methodology is shown in the following equation:

$$\frac{\text{Emissions (mass/yr)}}{\text{Marketed Fuel Production (mass/yr)}} \times \text{HHV}_{\text{fuel}} \frac{\text{(mass)}}{\text{(MMBtu)}} = \frac{\text{Emissions (mass)}}{\text{MMBtu}} \quad \textbf{(B6)}$$

CO_2 and methane are the only greenhouse gases, related to fuel use, that make a substantial contribution to global warming.[12] (Fuel combustion also contributes to N_2O emissions, but these emissions result primarily from mobile source combustion which is not considered in this analysis.[12]) Methane emissions resulting from the production of gas, oil, and coal must be considered, as well as emissions from the transportation and distribution of natural gas. Methane emissions from the transportation of crude/refined product and coal are small, and methane emissions from the end use combustion of natural gas, oil, and coal are negligible.

The results of the equivalent CO_2 emissions analysis are presented in Table B-6, which summarizes the data sources used to develop each equivalent CO_2 emission estimate and the values that resulted for a GWP of 34. As stated earlier, the equivalent CO_2 emissions for each type of fuel were developed from three basic parts: 1) combustion end use emissions of CO_2, 2) CO_2 emissions from production through transport, and 3) methane emissions converted to equivalent CO_2.

As the table shows, combustion end use emissions are the largest contributor for all fuel types. Approximately 76% (for GWP of 34) of the CO_2 equivalent emissions per MMBtu from natural gas are from end use combustion. For fuel oil and coal, nearly 90% of total

TABLE B-6. SOURCES OF CO_2 EQUIVALENTS FOR EACH FUEL TYPE

Emission Type/Source	Natural Gas		Fuel Oil		Coal	
	lb Eq. CO_2 per MMBtu	Data Source	lb Eq. CO_2 per MMBtu	Data Source	lb Eq. CO_2 per MMBtu	Data Source
Combustion of fuel in end use (direct CO_2)	115.6	Based on fuel content and HHV (this study)	164.4	ABB/Combustion Engineering[13]	205.8	EPA Greenhouse Gas Report[10]
Methane emissions from production, processing, refining, transportation (methane converted to CO_2 based on a GWP of 34)	24.5	GRI/EPA Methane Emissions (this study)	2.0	API Study[14]	20.4	EPA Reports[12,15]
CO_2 emissions during production, processing, refining, transportation (direct CO_2)	11.7	AP-42 Emission Factors, Activity Factors from this study	19.6	API Study[14]	2.1	Energy International[13]
TOTAL lb Equivalent CO_2/MMBtu	152		186		228	

CO_2 emissions per MMBtu are attributable to end-use combustion. The CO_2 emissions from end use combustion are well defined, since they depend primarily upon the carbon content of the fuels. Therefore, the uncertainty associated with the largest portion of the equivalent CO_2 estimate is relatively small.

The CO_2 emissions from production through transport and the methane emissions from coal and oil operations play a much smaller role in the overall comparison.

Methane emissions comprise only 16% of the equivalent CO_2 emission estimate for natural gas, 1.1% for oil, and 9% for coal. Therefore the impact of the methane emission estimate is far less than that of the end use component. Methane emissions for natural gas are well known (± 33 %), while the estimates for oil and coal may have much wider confidence bounds (possibly with an upper bound larger than 100%). Therefore the equivalent CO_2 emission comparison for natural gas is conservative, since the emissions from coal and oil may be much higher.

The following sections on natural gas, coal, and oil describe the methods and assumptions used to determine the equivalent CO_2 emissions for each fuel type that were presented in Table B-6.

Natural Gas

Approximately 116 lbs of CO_2/MMBtu is emitted from the combustion of natural gas. This emission rate was calculated assuming the complete combustion of marketed natural gas (17.84×10^6 scf for 1990)[16] with a gross energy content of 1031 Btu/scf[12] and the corresponding composition of 93.4% methane, 4.0% ethane, 0.5% propane, and 2.1% inerts. (Note: the mole percents of ethane, propane, and inerts were determined by weighting the respective higher heating values to achieve the desired methane composition and energy content of the gas mixture.)[12,17]

Carbon dioxide is also emitted through combustion in compressors, burners, and flares. Emissions from gas-fired compressor engines used to transport natural gas from production to market were determined using a CO_2 emission factor of 0.89 lb CO_2/hp·hr[18] and the total hp·hr for production, transmission, and processing of 145×10^9 hp·hr.[19] This results in 7.0 lbs CO_2/MMBtu emissions. Similarly, carbon dioxide emissions result from burning natural gas for other plant, lease, or pipeline fuel requirements. The amount of natural gas used for fuel purposes other than compressors was estimated in the *Vented and Combustion Source Summary* to be approximately 558 Bscfy.[17] This results in an additional 3.6 lb CO_2/MMBtu, based on the CO_2 emission factor from natural gas combustion of 120 lb CO_2/Mscf.[20] It should be noted that this estimate is conservatively high since a portion of the fuel gas is used by the petroleum industry to operate equipment such as gas-lift compressors and heater-treaters. Finally, a small amount of CO_2 is generated from flaring natural gas. The *Vented and Combustion Source Summary* estimates 15.1 Bscfy of methane is flared from production through distribution.[17] Based on a 98% to 99% combustion efficiency, where all of the methane combusted is assumed to form CO_2, 0.1 lb CO_2/MMBtu result from flaring.

Methane emissions from the production, transmission, gas processing, and distribution of natural gas are approximately 314 Bscf or 6.04 Tg/yr (methane emissions from end uses are negligible). Based on the marketed gas volume of 17.84×10^6 scf and the natural gas HHV of 1,031 Btu/scf,[12,14] the methane emissions equate to 0.72 lbs CH_4/MMBtu. Converting the methane emissions to equivalent CO_2 emissions requires a GWP, which for methane is 34 for an integration interval of 50 years and is 6.5 for an integration interval of 500 years.[6,7,8,9] Applying these conversion factors, the equivalent CO_2 emissions for methane are then 24.5 lbs CO_2/MMBtu for a GWP of 34, and 4.7 lbs CO_2/MMBtu for a GWP of 6.5.

Natural gas results in a total of 132 lbs CO_2/MMBtu for a GWP of 6.5, and 152 lbs CO_2/MMBtu for a GWP of 34. Table B-7 summarizes the various components that contribute equivalent CO_2 emissions from the natural gas fuel cycle.

TABLE B-7. CO_2 EQUIVALENT EMISSIONS FROM NATURAL GAS

		lb CO_2 Equivalent/MMBtu	
	Emission Source	**GWP = 6.5**	**GWP = 34**
End-use	Combustion CO_2 Emissions	115.6	115.6
Industry	Compressor CO_2 Emissions	7.0	7.0
	Burner CO_2 Emissions	4.6	4.6
	Flare CO_2 Emissions	0.1	0.1
	Methane Emissions	4.7	24.5
	TOTAL	132.0	151.8

Coal

Methane emissions result primarily from coal mining; emissions of methane from the transport or end uses of coal are negligible. EPA's *Inventory of Greenhouse Gas Emissions and Sinks* reports methane emissions from coal mining activities ranging between 3.2 and 5.0 million metric tonnes of methane for the year 1992.[12] Based on the 1992 coal production of 997.5 million short tons,[21] and the coal higher heating value of 10,395 Btu/lb,[15] methane emissions from this source equate to 0.44 lbs methane/MMBtu. In comparison, another EPA report shows 30 to 50 million metric tonnes of methane emitted globally corresponding to coal production of 5 billion tonnes.[13] For the same heating value, these values result in 0.77 lbs methane/MMBtu. An average of the two sources (0.60 lbs methane/MMBtu) was used to estimate equivalent CO_2 emissions of 3.9 lbs CO_2/MMBtu for a GWP of 6.5 and approximately 20.4 lbs CO_2/MMBtu for a GWP of 34.

The primary source of CO_2 emissions from coal results from combustion. EPA reported that CO_2 emissions from energy production were 430.4 million metric tonnes of carbon equivalent (MMTCE) for 1992.[12] The energy generated from coal consumption for that year was 16,910 trillion Btu.[12] Based on these values, CO_2 emissions are approximately 206 lbs CO_2/MMBtu. In addition, CO_2 emissions from production and transportation equipment and the

loss of coal during transport are estimated to result in an additional increase in CO_2 emissions of approximately 1%, or 2.1 lbs CO_2/MMBtu.[14]

Table B-8 summarizes greenhouse emissions from the coal fuel cycle. The result is an equivalent CO_2 emission rate of 212 to 228 lbs CO_2/MMBtu, depending on the GWP for methane.

TABLE B-8. CO_2 EQUIVALENT EMISSIONS FROM COAL

		lb CO_2 Equivalent/MMBtu	
	Emission Source	**GWP = 6.5**	**GWP = 34**
End Use	CO_2 Combustion Emissions (Electric Utilities)	205.8	205.8
Industry	Other CO_2 Emissions	2.06	2.06
	Methane Emissions	3.9	20.4
	TOTAL	212.3	228.3

Oil

A study was conducted by the American Petroleum Institute (API) for the petroleum industry to quantify methane and CO_2 emissions resulting from petroleum operations (production through transportation of refinery products) for the base year 1990.[22] End use emissions were not included in the API study. Emission estimates for production, crude transportation, refining and product transportation are presented in Table B-9.

TABLE B-9. 1990 METHANE AND CO_2 EMISSIONS FROM CRUDE PRODUCTION THROUGH REFINED PRODUCT TRANSPORTATION

Industry Segment	Methane Emissions tons Methane	CO_2 Emissions, Million tons CO_2/yr
Production	823,609	95.16
Crude Transport	11,192	8.87
Refining	13,845	171.24
Product Transport	0	8.77
TOTAL	848,646	284.04

For the fuel switching analysis, estimating equivalent CO_2 emissions from the oil industry on a basis comparable to emissions from natural gas and coal is complicated by the many different products generated from crude oil. Starting in refining, emissions from individual fuel products are directly related to the emission sources associated with those products; before the refining segment, a direct relation is not possible. Some portion of emissions generated from crude production and transport must be assumed to be associated with individual fuel products. For the purpose of this study, the fuels of interest (i.e., those comparable with the primary uses of natural gas and coal—residential heating and generating electricity) are distillate and residual fuel oils. Emissions associated with these fuel oils are assumed to be proportional to the ratio of the mass of distillate and residual fuel produced in refining to the mass of the total refinery crude charge:

$$\frac{\text{Fuel oil produced (mass)}}{\text{Refinery crude charge (mass)}} \approx \frac{\text{Total fuel oil emissions (mass)}}{\text{Total crude emissions (mass)}} \qquad \textbf{(B7)}$$

Therefore, the total emissions reported in Table B-7 will be scaled according to the following equation to estimate emissions associated with distillate and residual fuel oil only:

$$E_{p-p/t}\ \text{(mass/yr)} \times \frac{\text{Fuel oil produced (mass)}}{\text{Refinery crude charge (mass)}} \qquad \textbf{(B8)}$$

where:

$E_{p \to p/t}$ = Emissions of CO_2 or methane from production through product transportation

The mass of fuel oil produced for market in 1992 is 2.215×10^8 tons. This is based on 1.09×10^9 bbls of distillate[23] with a specific gravity of 0.8654,[24] resulting in 1.65×10^8 tons distillate produced in 1992. In addition, residual production of 5.64×10^7 tons is based on 3.26×10^8 bbls of residual[23] with a specific gravity of 0.982 (which is estimated from the specific gravities of fuel oils Nos. 2, 4, 5, and 6 weighted by the relative volumes of each produced).[24] The mass of refinery crude charge for 1992 is 7.53×10^8 tons (based on 4.91×10^9 bbls of crude and an average crude specific gravity of 0.876).[23,25] The resulting ratio of fuel oil to crude charge is approximately 0.294.

The general methodology for estimating emissions from the fuel cycle of distillate and residual oils is then:

$$\frac{E_{p-p/t}\ (\text{mass/yr}) \times 0.29}{\text{Marketed Fuel Oil Production (mass/yr)}} \times HHV_{\text{Fuel oil}}\ \frac{(\text{mass})}{(\text{MMBtu})} + \frac{E_{\text{end use}}\ (\text{mass})}{MMBTU_{\text{end use}}} = \frac{E\ (\text{mass})}{\text{MMBtu}} \qquad \textbf{(B9)}$$

which includes the addition of end use emissions from distillate and residual fuels (not included in the API study). The combined higher heating value for distillate and residual fuel oil is 19,194 Btu/lb based on the individual HHVs (19,524 Btu/lb for distillate and 18,228 Btu/lb for residual)[25] weighted by the relative production rate of each fuel (presented above).

The resulting CO_2 emissions from production through product transport are 19.6 lb CO_2/MMBtu. Methane emissions equate to 0.059 lb methane/MMBtu. When converted to equivalent CO_2 emissions, this results in 0.38 lb equivalent CO_2/MMBtu for a GWP of 6.5 and 2.0 lb equivalent CO_2/MMBtu for a GWP of 34.

End use emissions of methane, from the combustion of petroleum products in turbines or boilers, are negligible. However, CO_2 end use emissions from these sources are significant. A Combustion Engineering report provided fuel oil properties,[24] which were used to calculate combustion emissions based on the following equation:

$$\frac{\text{lb fuel}}{\text{gal fuel}} \times \frac{\text{lb C}}{\text{lb fuel}} \times \frac{44 \text{ lb } CO_2}{12 \text{ lb C}} \times \frac{\text{gal fuel}}{\text{MMBtu}} = \frac{\text{lb } CO_2}{\text{MMBtu}} \qquad \textbf{(B10)}$$

This assumes all of the carbon present in the fuel oil is combusted to form CO_2. The properties of distillate and residual fuel oils and the corresponding CO_2 combustion emissions are shown in Table B-10.

TABLE B-10. PROPERTIES OF FUEL OILS

Property	Distillate Fuel Oil	Residual Fuel Oil
Density, lb/gal	7.206	8.212
% Carbon	86.4	85.7
HHV, MMBtu/gal	0.141	0.150
lb CO_2/MMBtu	161.9	172.0

These values were combined to generate one end use emission estimate for fuel oils based on a weighted average with respect to the production rate of each fuel oil type (1.65×10^8 tons distillate and 5.64×10^7 tons residual, as discussed previously). The resulting CO_2 end use emissions from fuel oils used in residential heating and electricity generation are 164.4 lb CO_2/MMBtu.

Table B-11 summarizes the emission estimates for the fuel cycle of residual and distillate fuel oils.

TABLE B-11. CO_2 EQUIVALENT EMISSIONS FROM FUEL OIL

Emission Source		lb CO_2 Equivalent/MMBtu	
		GWP = 6.5	GWP = 34
End Use	Fuel Combustion CO_2 Emissions	164.4	164.4
Industry	Prod. through Product Transport CO_2 Emissions	19.6	19.6
	Prod. through Product Transport CH_4 Emissions	0.38	2.0
TOTAL		184.4	186.0

B.5 Global Warming Conclusions

Table B-12 lists the greenhouse gas emissions, expressed as pounds of equivalent CO_2 per MMBtu for natural gas, coal, and oil. To quantify the relative impacts on global warming of coal and oil compared to natural gas, the equivalent CO_2 emissions per unit of energy for coal and oil are divided by the value for natural gas. This "equivalent CO_2 ratio" is listed in Table B-12 for GWPs of 6.5 and 34.

TABLE B-12. EQUIVALENT CO_2 EMISSIONS FOR NATURAL GAS, OIL, AND COAL

Fuel Source	lbs CO_2/MMBtu		Equivalent CO_2 Ratio	
	GWP = 6.5	GWP = 34	GWP = 6.5	GWP = 34
Gas	132	152	1.0	1.0
Oil	184	186	1.4	1.2
Coal	212	228	1.6	1.5

Using oil has between 1.2 and 1.4 times the impact on global warming emissions than the use of natural gas. Similarly, coal contributes 50 to 60% more equivalent CO_2 emissions than natural gas, resulting in 1.5 to 1.6 times the impact on global warming. These results are in basic agreement with IPCC's conclusions on fuel switching to reduce greenhouse gas emissions:

> Switching from coal to oil or natural gas would reduce carbon emissions in proportion to the carbon intensity of the fuel. For example, switching from coal to natural gas would reduce emissions by 40%. In addition, the higher energy efficiency available with natural gas would reduce emissions further—for example, a shift from coal to natural gas in power generation by 20%.[1]

The net result is that switching from other fuels to natural gas can help the United States reach its goals on limiting greenhouse gas emissions and their potential impact on global warming.

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APPENDIX C

Conversion Table

Unit Conversion Table

English to Metric Conversions

1 scf methane	=	19.23 g methane
1 Bscf methane	=	0.01923 Tg methane
1 Bscf methane	=	19,230 metric tonnes methane
1 Bscf	=	28.32 million standard cubic meters
1 short ton (ton)	=	907.2 kg
1 lb	=	0.4536 kg
1 ft^3	=	0.02832 m^3
1 ft^3	=	28.32 liters
1 gallon	=	3.785 liters
1 barrel (bbl)	=	158.97 liters
1 inch	=	2.540 cm
1 ft	=	0.3048 m
1 mile	=	1.609 km
1 hp	=	0.7457 kW
1 hp-hr	=	0.7457 kW-hr
1 Btu	=	1055 joules
1 MMBtu	=	293 kW-hr
1 lb/MMBtu	=	430 g/GJ
T (°F)	=	1.8 T (°C) + 32
1 psi	=	51.71 mm Hg

Global Warming Conversions

Calculating carbon equivalents of any gas:

$$\text{MMTCE} = (\text{MMT of gas}) \times \left(\frac{\text{MW, carbon}}{\text{MW, gas}} \right) \times (\text{GWP})$$

Calculating CO_2 equivalents for methane:

$$\text{MMT of } CO_2 \text{ equiv.} = (\text{MMT } CH_4) \times \left(\frac{\text{MW, } CO_2}{\text{MW, } CH_4} \right) \times (\text{GWP})$$

where MW (molecular weight) of CO_2 = 44, MW carbon = 12, and MW CH_4 = 16.

Notes

scf	=	Standard cubic feet. Standard conditions are at 14.73 psia and 60°F.
Bscf	=	Billion standard cubic feet (10^9 scf).
MMscf	=	Million standard cubic feet.
Mscf	=	Thousand standard cubic feet.
Tg	=	Teragram (10^{12} g).
Giga (G)	=	Same as billion (10^9).
Metric tonnes	=	1000 kg.
psig	=	Gauge pressure.
psia	=	Absolute pressure (note psia = psig + atmospheric pressure).
GWP	=	Global Warming Potential of a particular greenhouse gas for a given time period.
MMT	=	Million metric tonnes of a gas.
MMTCE	=	Million metric tonnes, carbon equivalent.
MMT of CO_2 eq.	=	Million metric tonnes, carbon dioxide equivalent.

APPENDIX D

Project Reviewers

PROJECT REVIEWERS*

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Carter, Doug	DOE
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Childress, P.D.	Colorado Interstate Gas
Ching, Jason	EPA
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Cook, Tracy	SoCal
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Derkowski, Carrie	Coastal
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Fritz, Eric	Natural Gas Pipeline
Fung, Inez	NASA Goddard Institute for Space Studies
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Matthews, Neil	Southern Natural Gas
Magid, Hillel	Allied Signal Corp.
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Mercado, Donna	American Gas Association
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Reilly, Mike	CNG
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Roose, Tom	GRI
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Yundt, Paul	Gas Technology Canada
Zinkham, Jeffrey	Amoco

*Project reviewers have participated in one or more review meetings for this project over the time period 1990-1996.

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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 AmeriGas 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

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Emission	Stationary Sources	14G
Greenhouse Effect	Global Warming	04A
Natural Gas		21D
Gas Pipelines		15E
Methane		07C

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