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GRI-94 / 0257.26
EPA - 600/R-96-080i
June 1996

Research and Development

METHANE EMISSIONS FROM THE
NATURAL GAS INDUSTRY
Volume 9: Underground Pipelines

Prepared for

Energy Information Administration (U. S. DOE)

Prepared by

National Risk Management
Research Laboratory
Research Triangle Park, NC 27711

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before comp

1. REPORT NO. EPA-600/R-96-080i
2.

4. TITLE AND SUBTITLE
Methane Emissions from the Natural Gas Industry, Volumes 1-15 (Volume 9: Underground Pipelines)

5. REPORT DATE
June 1996

6. PERFORMING ORGANIZATION CODE

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8. PERFORMING ORGANIZATION REPORT NO.
DCN 96-263-081-17

9. PERFORMING ORGANIZATION NAME AND ADDRESS
Radian International LLC
P.O. Box 201088
Austin, Texas 78720-1088

10. PROGRAM ELEMENT NO.

11. CONTRACT/GRANT NO.
5091-251-2171 (GRI)
68-D1-0031 (EPA)

12. SPONSORING AGENCY NAME AND ADDRESS
EPA, Office of Research and Development
Air Pollution Prevention and Control Division
Research Triangle Park, NC 27711

13. TYPE OF REPORT AND PERIOD COVERED
Final; 3/91-4/96

14. SPONSORING AGENCY CODE
EPA/600/13

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

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

17. KEY WORDS AND DOCUMENT ANALYSIS

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

18. DISTRIBUTION STATEMENT	19. SECURITY CLASS (This Report)	21. NO. OF PAGES
Release to Public	Unclassified	95
	20. SECURITY CLASS (This page) Unclassified	22. PRICE

FOREWORD

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This publication has been produced as part of the Laboratory's strategic long-term research plan. It is published and made available by EPA's Office of Research and Development to assist the user community and to link researchers with their clients.

E. Timothy Oppelt, Director
National Risk Management Research Laboratory

EPA REVIEW NOTICE

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

METHANE EMISSIONS FROM THE NATURAL GAS INDUSTRY, VOLUME 9: UNDERGROUND PIPELINES

FINAL REPORT

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RESEARCH SUMMARY

Title	Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines Final Report
Contractor	Radian International LLC GRI Contract Number 5091-251-2171 EPA Contract Number 68-D1-0031
Principal Investigators	Lisa M. Campbell Michael V. Campbell David L. Epperson
Report Period	March 1991 - June 1996 Final Report
Objective	This report describes a study to quantify the annual methane emissions from underground pipelines in natural gas production, transmission, and distribution.
Technical Perspective	The increased use of natural gas has been suggested as a strategy for reducing the potential for global warming. During combustion, natural gas generates less carbon dioxide (CO_2) per unit of energy produced than either coal or oil. On the basis of the amount of CO_2 emitted, the potential for global warming could be reduced by substituting natural gas for coal or oil. However, since natural gas is primarily methane, a potent greenhouse gas, losses of natural gas during production, processing, transmission, and distribution could reduce the inherent advantage of its lower CO_2 emissions. To investigate this, Gas Research Institute (GRI) and the U.S. Environmental Protection Agency's Office of Research and Development (EPA/ORD) cofunded a major study to quantify methane emissions from U.S. natural gas operations for the 1992 base year. The results of this study can be used to construct global methane budgets and to determine the relative impact on global warming of natural gas versus coal and oil.
Results	The national annual emissions from underground pipelines, taking into account soil oxidation, are: 41.6 ± 65% Bscf for distribution; 0.2 ± 89% Bscf for transmission; and 6.6 ± 108% Bscf for production. Following is a comparison of the methane emissions from underground pipelines to the total methane emissions from all sources in each industry segment. As shown, the total methane emissions from underground pipelines

represents about 15% of the total national methane emissions from the gas industry.

COMPARISON OF METHANE EMISSIONS FROM UNDERGROUND PIPELINES TO INDUSTRY-WIDE EMISSIONS

Segment	Total Industry Emissions, Bscfy	Underground Pipeline Emissions, Bscfy
Production	84.4	6.6
Processing	36.4	-
Transmission/Storage	116.5	0.2
Distribution	77.0	41.6
TOTAL	314	48

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

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

A leak measurement technique was developed and implemented as a method to quantify methane emissions from underground pipelines in the natural gas industry. A cooperative program was developed between distribution companies volunteering to provide leakage measurements and GRI/EPA. A total of 146 leak measurements have been collected by the participating companies. These data were used to derive the emission factors for estimating methane leakage from distribution, transmission, and production underground pipelines. The leakage rate data were adjusted for soil oxidation of methane based on the results of a separate study conducted at Washington State University and the University of New Hampshire. 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.

In the distribution segment, activity factors were based on the national database of leak repairs, allocated into pipe material categories based on data provided by ten companies. These data were combined with historical leak records provided by six companies. The activity factors represent the number of equivalent leaks that are leaking year round, with repaired leaks being accounted for as fractional equivalent leaks.

In the transmission and production segments, the emission factors were based on the leak measurement data collected from distribution mains as part of the cooperative leak measurement program. The activity factors were derived from a nationally tracked database of pipe mileage/leak repair records.

Project Implications

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

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

Robert A. Lott
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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF TABLES (Cont'd.)

Page

1.0 SUMMARY

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

This report documents the estimation of methane emissions from underground pipelines in natural gas production, transmission, and distribution. A leak measurement technique was developed and implemented as a method to quantify methane emissions from underground pipelines in the natural gas industry. A cooperative program was developed between distribution companies volunteering to provide leakage measurements and GRI/EPA. A total of 146 leak measurements have been collected by ten participating companies. These data were used to derive the emission factors for estimating methane leakage from distribution, transmission, and production underground pipelines. The leakage rate data were adjusted for soil oxidation of methane based on the results of a separate study conducted at Washington State University and the University of New Hampshire. 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.

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In the transmission and production segments, the methane emissions estimate 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 annual methane emissions were 0.2 Bscf accounting for soil oxidation, with a 90% confidence interval of ± 89%. For gathering pipeline in gas production, the estimated annual methane emissions were 6.6 Bscf, with a 90% confidence interval of ± 108%.

2.0 INTRODUCTION

Early in the Gas Research Institute (GRI) and U.S. Environmental Protection Agency (EPA) methane emissions project, preliminary estimates were developed for each source of methane emissions in the natural gas industry. These preliminary estimates were used to prioritize sources of methane emissions in the natural gas industry for further research. One source of methane emissions that was identified was leakage from underground distribution mains and services. Leakage from underground piping systems is 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 significant source of methane emissions from the gas industry.

A comprehensive program was developed and implemented by GRI and EPA to expand the database of leakage measurements from underground pipelines in the gas industry. This program was designed as a cooperative effort between participating distribution companies and the program sponsors. The data collected from this cooperative effort was not only used to develop an estimate of emissions in the distribution segment of the gas industry, but was also used to extrapolate emissions to the underground pipelines used in the production and transmission segments of the industry.

This report documents the overall approach used to estimate leakage from underground pipelines in the U.S. natural gas industry. An overview of how the program was developed and implemented is provided in Section 3. Test design and sample selection are described in Sections 4 and 5, respectively. Section 6 documents the leak measurement protocol used during the testing efforts. The data analyses and the extrapolation methodology used to derive a national estimate of methane emissions from underground pipelines are discussed in Sections 7 and 8, respectively. The results and conclusions are presented in Section 9. This report is one of several volumes under the GRI/EPA methane emissions project.

3.0 PROGRAM OVERVIEW

A cooperative program was developed by GRI and EPA to improve the precision of the leakage estimate from underground distribution mains and services in the natural gas industry. Two companies had published the results from limited studies of the magnitude of natural gas leakage from underground mains and services in their distribution networks.[1,2] These data were evaluated to project the overall magnitude of methane emissions from the entire U.S. distribution segment of the industry. Based on the limited data available, the overall estimates of leakage from the distribution segment were significant and, therefore, targeted as a high priority for further research.

To devise a measurement program for leakage from underground pipelines, the number of measurements, or samples, required needed to be determined. The determination of the appropriate sample size was based on a number of considerations, including:

- Size of the population of mains and services in the distribution segment of the gas industry;
- Nature and distribution of the leak rate (dependent variable) and any influences on leak rate, such as pipe age and pipe material (independent variables);
- Expected mean and variance of the dependent and independent variables;
- Target accuracy for the final estimates;
- Anticipated actual accuracy of the final estimates; and
- Costs associated with collecting the required information for each individual leak measurement.

The target accuracy was defined as an overall leakage estimate for an individual company that would be within $\pm$ 25% of the true value based on a 90% level of confidence. The mean and associated variance from the available preliminary leak test data were used to calculate an estimated accuracy. Initial calculations suggested a required sample size of nearly 500 leak tests for a simple random sampling scheme. To reduce the sample size, the effect of various experimental designs and sampling schemes on total sample size was also examined. Based on the assumptions surrounding a stratified, random sampling scheme, the required number of leak tests could be significantly reduced by dividing or stratifying the sample population into categories or strata that reduce the variability within strata. The final calculation determined that a total sample size of at least 200 tests could potentially achieve the defined target accuracy if a stratified sampling approach were adopted.

To quantify the methane emissions from distribution mains and services by performing 200 tests, a cooperative program was developed between GRI/EPA and distribution companies volunteering to participate in the study. The cooperative program was developed to share the cost of performing extensive testing. The concept that sufficient parameters could be identified to distinguish differences between leakage characteristics from location-to-location and company-to-company was the underlying basis of the cooperative program. By pooling data from each contributing company, a higher overall accuracy could be achieved compared to the single contribution from an individual company.

To identify and select potential participants in the program, GRI invited a representative cross-section of gas companies in the U.S. to participate. Over 30 companies were contacted and invited to participate, which represented different geographical areas in the U.S. The companies volunteering to participate were asked to perform a total of 20 tests. Of the original invitees, only nine U.S. companies elected to participate by providing either data previously collected or the sites and resources required to complete the testing. In addition to the nine U.S. companies, two Canadian companies and two European companies volunteered to participate in the study. (Note: To date, only six U.S. companies have provided data for this study.)

The cooperative program includes program planning, design, coordination, and data analysis provided by GRI/EPA. GRI/EPA developed a standardized testing protocol to guide companies in making measurements and help ensure consistent testing and quality assurance/quality control (QA/QC) procedures. A test plan for the cooperative program was developed and issued to each company participating in the study.[3] Training sessions were held at several host sites to provide classroom and hands-on training to participants. To date, about 146 leak tests have been performed by the participating companies out of the targeted 200 tests.

4.0 TEST DESIGN

As part of the test plan for the cooperative leak measurement program, a test matrix was developed to meet the objectives of the program. The test matrix is based upon the concept of a stratified sampling scheme.

4.1 Population Stratification

Stratification refers to division of the population in categories, or strata, which are expected to have significantly different leak characteristics. The goal of stratifying the population was to decrease the variability in the leak rate data within a given strata. Controlling variability by stratification has the following advantages:

- Reduction in the total sample size required for the test program as compared to a non-stratified sampling approach;
- Increase in the overall precision by segregating the population into homogenous subsets;
- Reduction in the estimated error terms within the homogenous strata as compared to the total error associated with the heterogenous, pooled population;
- Improved ability to identify specific factors that influence gas leak rates; and
- Provide a more detailed assessment of overall estimate accuracy through the assessment of accuracy within each stratum.

Stratification was necessary to meet the target accuracy defined for the leakage estimates of each participating company while minimizing the number of tests required. However, employing an experimental design with too many stratifying variables, while potentially identifying and partitioning the error terms with even greater detail, would likely result in a prohibitively large sample size.

Many factors that may influence below-ground natural gas leak rates were identified by industry experts and engineering judgement. Several meetings were held with an industry review group to develop the testing protocol and sample matrix. With all potential influences identified that may impact leak rate, the test matrix required would have been excessively large, defeating the purpose of defining parameters to reduce the overall number of tests required. Therefore, industry expertise was used to rule out parameters that were likely not important factors in influencing the leak rate. In this manner, the test matrix was reduced to a manageable size. The prioritization of the influencing factors is a function of both the suspected level of impact on leak rates and the availability of each factor in terms of characterizing both the sample and target populations. The ability to extrapolate the final sample leak rate estimates to the entire population was a vital component in the overall program.

Stratification for this study was limited to three primary variables:

- Pipe use (i.e., mains versus services);
- Pipe material; and
- Pipe age.

The proposed classes or levels assigned to each of the primary stratifying variables were selected using the available industry characterization data and engineering judgement from distribution industry experts.

Using 4 material types and 3 age intervals, 12 possible strata were identified both for mains and services, for a total of 24 possible strata. However, several age/material combinations are not common in the population and were consequently omitted from the test matrix, as shown in Figure 4-1. Therefore, a total of 16 strata, 8 for mains and 8 for services, were identified for the test design.

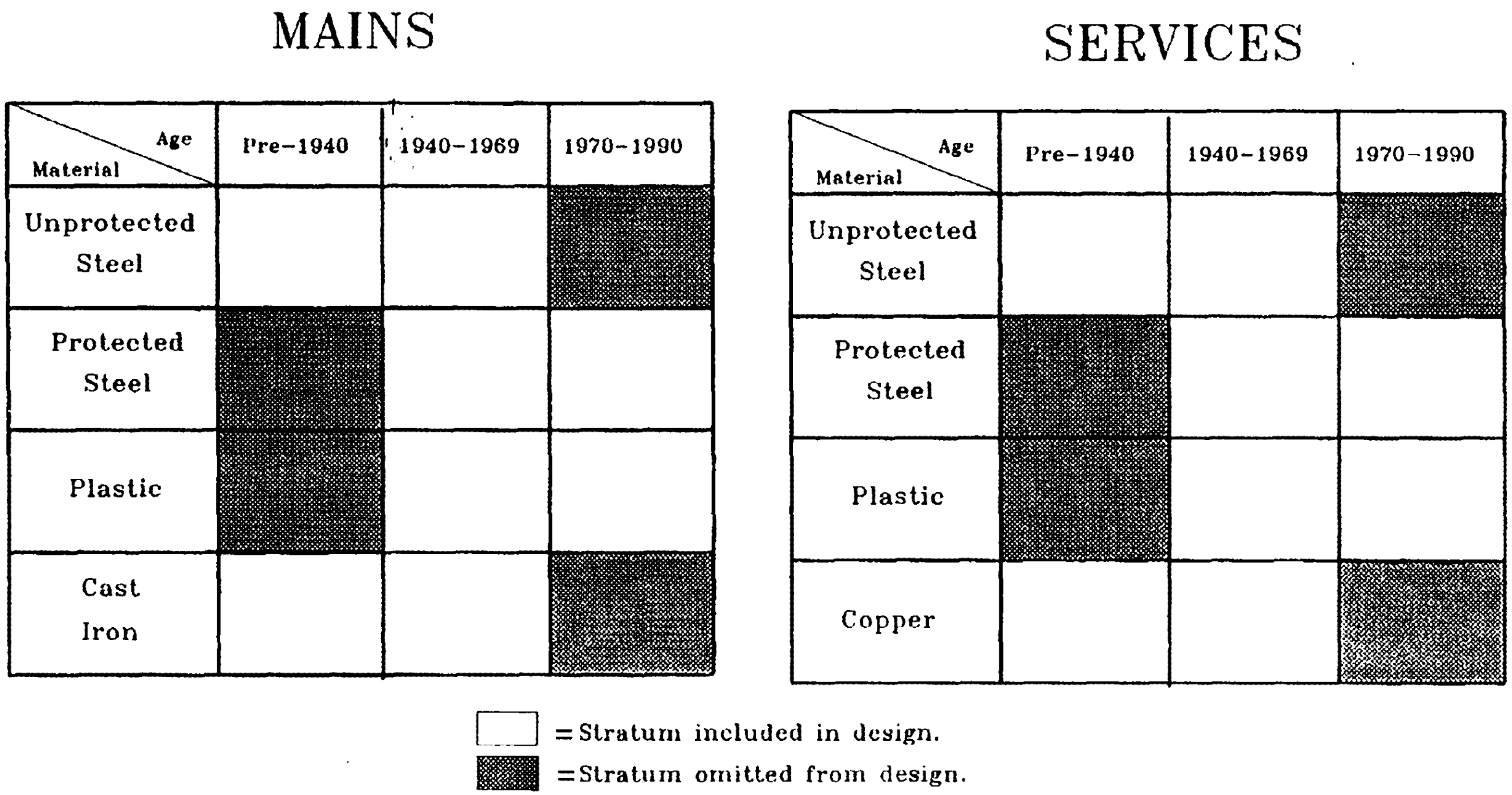

Figure 4-1. Primary Variable Stratification

4.2 Factorial Design and Implementation

The remaining factors that may potentially influence below-ground leak rates were also evaluated in the test design, and included:

- System leak detection and repair programs;
- Pipe operating pressure;
- Distribution system soil characteristics; and
- Pipe diameter.

To detect the impact of these secondary factors, leak tests were allocated within each stratum through an embedded factorial test matrix. The factorial design assigns individual observations to all combinations of the secondary parameters. The analysis of variance (ANOVA) used in a factorial experiment determines which independent variables, both singularly and in combination, significantly influence the dependent variable. The efficiency afforded by factorials lies in the development of the factor/level combinations.

The factorial design defined two levels for the four secondary factors. The two levels presented for each of the four factors were defined based on industry expertise. Soil type defines coarse, sandy soils as porous and heavy, clay soils as nonporous. Ideally, soil type would be a criteria for selecting suitable measurement sites. However, because of practical constraints of the program, soil type selection was not a variable that could be controlled.

The leak detection and repair classes were defined in an attempt to account for company-specific differences in the standard leak survey and repair practices. The leak survey, detection, monitoring, and repair practices for each participating company were rated relative to one another based upon the stated company practices, with an appropriate level assigned. A more definitive measure of the relative status of a company's leak detection and repair practices was also included as part of the overall protocol for the leak measurement program. This included a side-by-side comparison of the company's standard leak survey procedures with a standardized, rigorous procedure outlined in the program test plan. By comparing the number of leaks identified using both survey procedures on the same sections of pipe, along with the average number of leak indications per mile, a relative ranking of leak detection and repair practices could be assigned to each company. (Note: To date, the survey comparison evaluation has not been completed by all companies participating in the program.)

Gas operating pressure was classified as high and low and is dependent on the pipe use (i.e., main versus service) and pipe material type. Pipe diameter was also a factor used in the factorial design because diameter was believed to possibly influence the leak rate from cast iron pipe. (The leak rate of a single joint in a cast iron main may be a function of the circumference of the joint.) Again, the large and small categories of pipe diameter depend upon the pipe use and pipe material type.

To maximize the amount of information gained from the factorial design, individual leak tests were assigned to the participating companies in two stages. Relationships defined by the analysis of the initial or stage one leak tests were used to determine the assignment of the stage two leak tests. With 16 strata (8 for mains and 8 for services), the full factorial design would require 256 tests (16 tests in each strata) to observe each of the 4 secondary factor/level combinations. The efficiency gained by employing a two-stage sampling scheme permitted the test matrix used for the program to be reduced to a half-factorial design. Table 4-1 shows the eight factor level combinations for each of the primary strata (i.e., pipe service, material, and age).

TABLE 4-1. TEST MATRIX FOR LEAK MEASUREMENT PROGRAM

Test Number	LDAR[a] Practices	Gas Operating Pressure	Soil Type	Pipe Diameter
1	Good	High	Porous	Large
2	Good	High	Nonporous	Small
3	Good	Low	Porous	Small
4	Good	Low	Nonporous	Large
5	Fair	High	Porous	Large
6	Fair	High	Nonporous	Small
7	Fair	Low	Porous	Small
8	Fair	Low	Nonporous	Large

[a]LDAR = Leak detection and repair.

The stage one allocation included assigning roughly two-thirds of the total number of tests each company committed to utilize this half-factorial design. A target of 128 tests were to be conducted within stage one of the testing program. The remaining 72 stage two tests would then be assigned to specific factor/level combinations, within specific strata where additional data are needed to detect significant influences. The stage two leak test allocations were consequently made in the strata with the greatest total emissions and strata with highly variable leak rates. (Note: To date, most participating companies have not completed all their tests. A total of 146 samples have been collected with a resulting accuracy of the national emissions estimate from underground mains and services of ± 65% based on a 90% level of confidence. This level of accuracy is well within the target accuracy for the national emissions estimate from underground mains and services and meets the 80% completeness criteria for the program.)

5.0 SAMPLE SELECTION

To prevent bias in the final extrapolated emissions estimate from underground distribution mains and services, the sample population should be representative of the national population and the actual measurement sites chosen should be selected as randomly as possible. The assumption that the underground sample population (i.e., program participants) is representative of the target population (i.e., national distribution industry) was an important consideration in developing the experimental design, defining the appropriate sampling scheme, and assessing the accuracy of the leakage estimates. A comprehensive industry characterization analysis suggests that the nine U.S. program participants are very representative of the national industry with respect to pipe material and pipe age. Figures 5-1 and 5-2 compare the nine participants to the top 100 U. S. gas distribution systems. The ranking of the top 100 distribution systems is based on total miles of underground mains. These 100 distribution systems account for roughly 80% of the total national gas throughput. Figure 5-1 shows that the relative proportions of distribution main pipeline materials for the nine companies are nearly equal to the proportions for the top 100 companies. Figure 5-2 shows that the program participants are representative of the national population in terms of number of services broken down by pipe material.

Theoretically, the actual measurement sites chosen should be completely random to eliminate bias in the selection. The factorial approach requires that leaks be selected for testing that meet specific constraints; however, it was important that random test sites be selected within the specifications of the test matrix. Therefore, criteria were established to guide selection of leak measurement sites.

For test site selection associated with the segment testing method (entire segment potentially containing multiple leaks is tested), the candidate selections for testing were generally pipe sections that were being taken out of service. To prevent bias in the segment selection for testing, the acceptable criteria for these segments included: 1) intact pipe relocated due to proposed construction activities, and 2) pipe scheduled for an across the

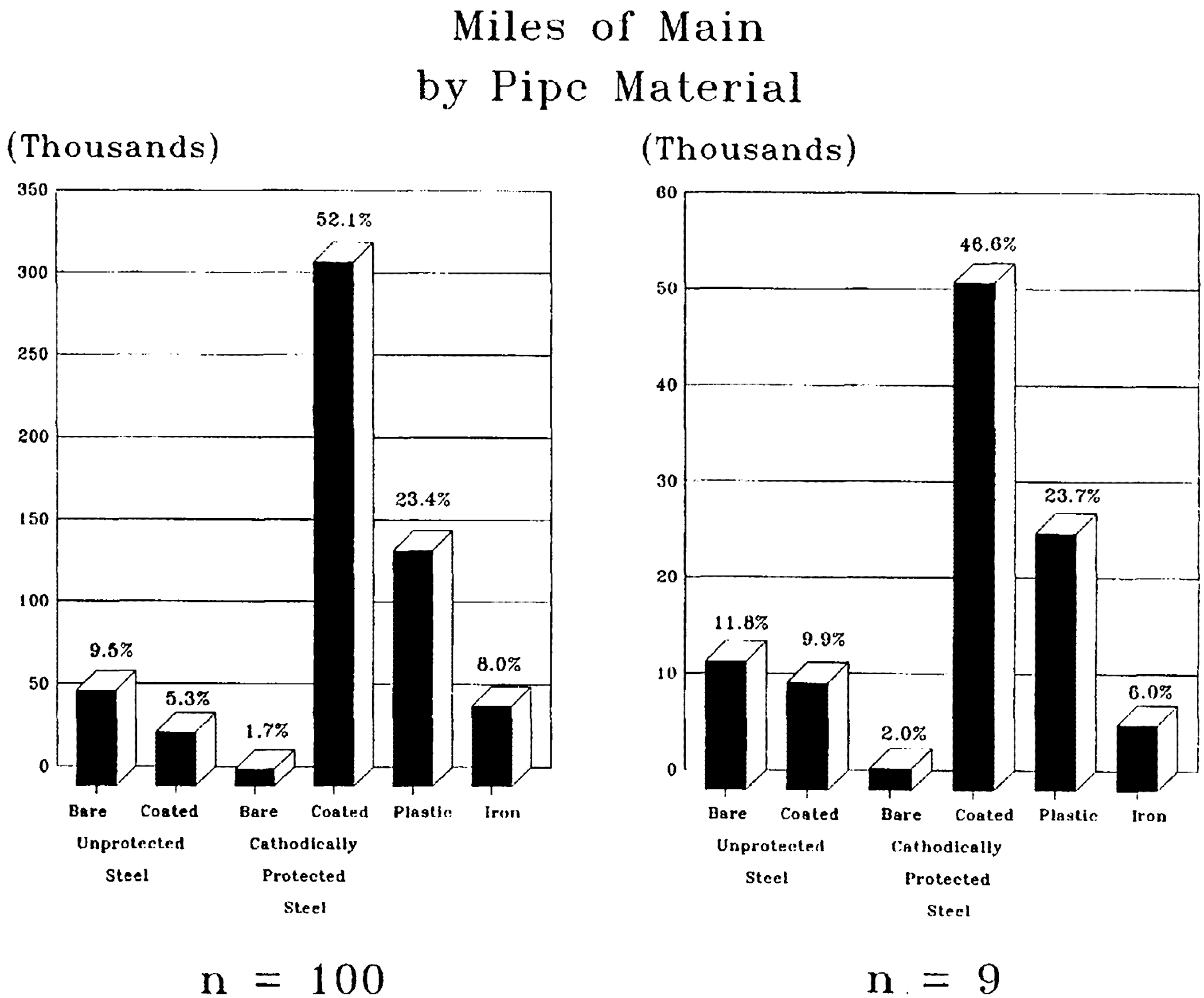

Figure 5-1. Comparison of Miles of Main by Pipe Material--Top 100 Distribution Systems Versus 9 Program Participants

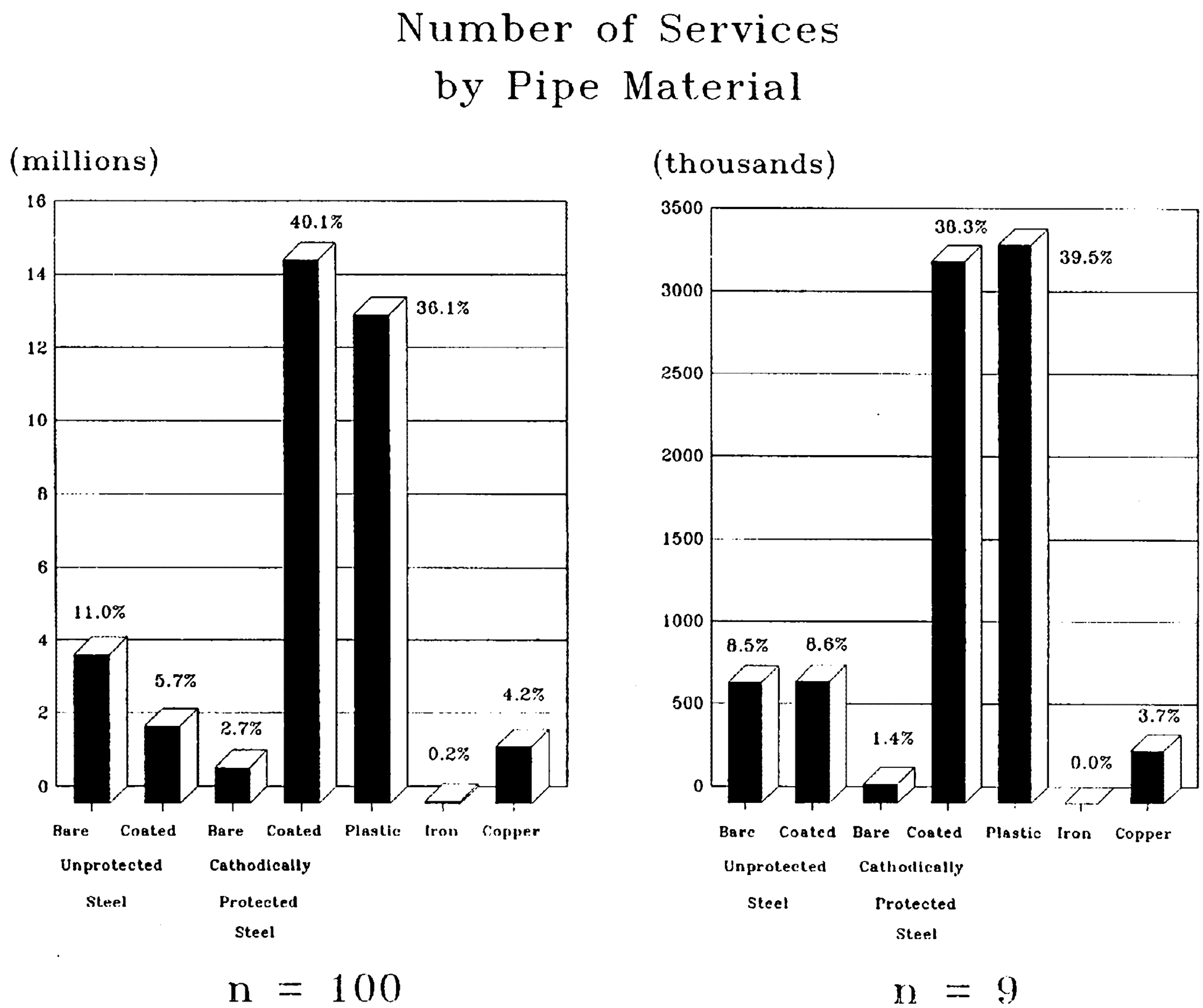

Figure 5-2. Comparison of Number of Services by Pipe Material--Top 100 Distribution Systems Versus 9 Program Participants

board replacement program. To prevent biasing the test results, pipe was not chosen if it was being replaced due to excessive leakage (for the pipe category tested).

Leaks due to corrosion in mains and services are believed to increase in size (and leakage rate) with time. Therefore, for a distribution system with a multi-year survey cycle, the leaks detected in the current year's survey should represent the largest leaks in the system, and the leaks which have occurred in the segment of the system surveyed and repaired in the previous year should represent the smallest leaks in the system. Therefore, to accurately represent an average leakage rate for the entire network, leaks from both sections (the section currently scheduled for survey and the section surveyed in the previous year) should be selected for testing. Randomly selected areas within both of these sections of the network should be surveyed (or resurveyed for the areas surveyed in the previous year) using the standardized leak survey protocol (outlined in the test plan) to identify all detectable leaks. The final selection of leaks for testing should be randomly drawn from the resulting pool of detectable leaks in both sections surveyed.

6.0 LEAK RATE MEASUREMENT METHOD

The basic technique used to measure the leakage rate from underground pipe is based on a metered gas measurement procedure which has been used by several gas companies to quantify their leakage contribution to unaccounted-for (UAF) gas. The general procedure entails selecting a suitable test site; centering the leak(s); isolating the segment of pipe containing the leak(s) (without disturbing the soil surrounding them); and measuring the gas flow rate required to maintain the segment at normal operating pressure. Figure 6-1 is a general schematic representation of the piping and associated gas routing system needed to allow emission rate testing of an individual leak in a main pipeline. The steps of the measurement procedure are described below.

6.1 Steps of Measurement Procedure

Identifying/Centering the Leak

Gas distribution operators use leak detection procedures to locate and classify leaks for repair. To identify a leak in a section of pipe, a portable hydrocarbon analyzer or flame ionization detector (FID) was used to screen immediately above the ground while walking the pipeline. Any excursions above the background level (typically 2-3 ppm) may indicate a nearby leak. The leak was centered by boring holes on each side of the pipe for a short distance and determining the point of maximum leak concentration. To avoid disturbing the soil immediately surrounding the leak, the depth of the barholes were specified not to exceed approximately 12 inches above the level of the pipe. The gas concentration in each barhole was measured, with the point of highest concentration typically being the most probable location for the leak. Once the leak was centered, the site was prepared for testing.

Isolating the Pipe Segment

Once the most probable leak location was determined, a careful excavation was made to expose the pipe at least 10 feet on each side of the leak without disturbing the

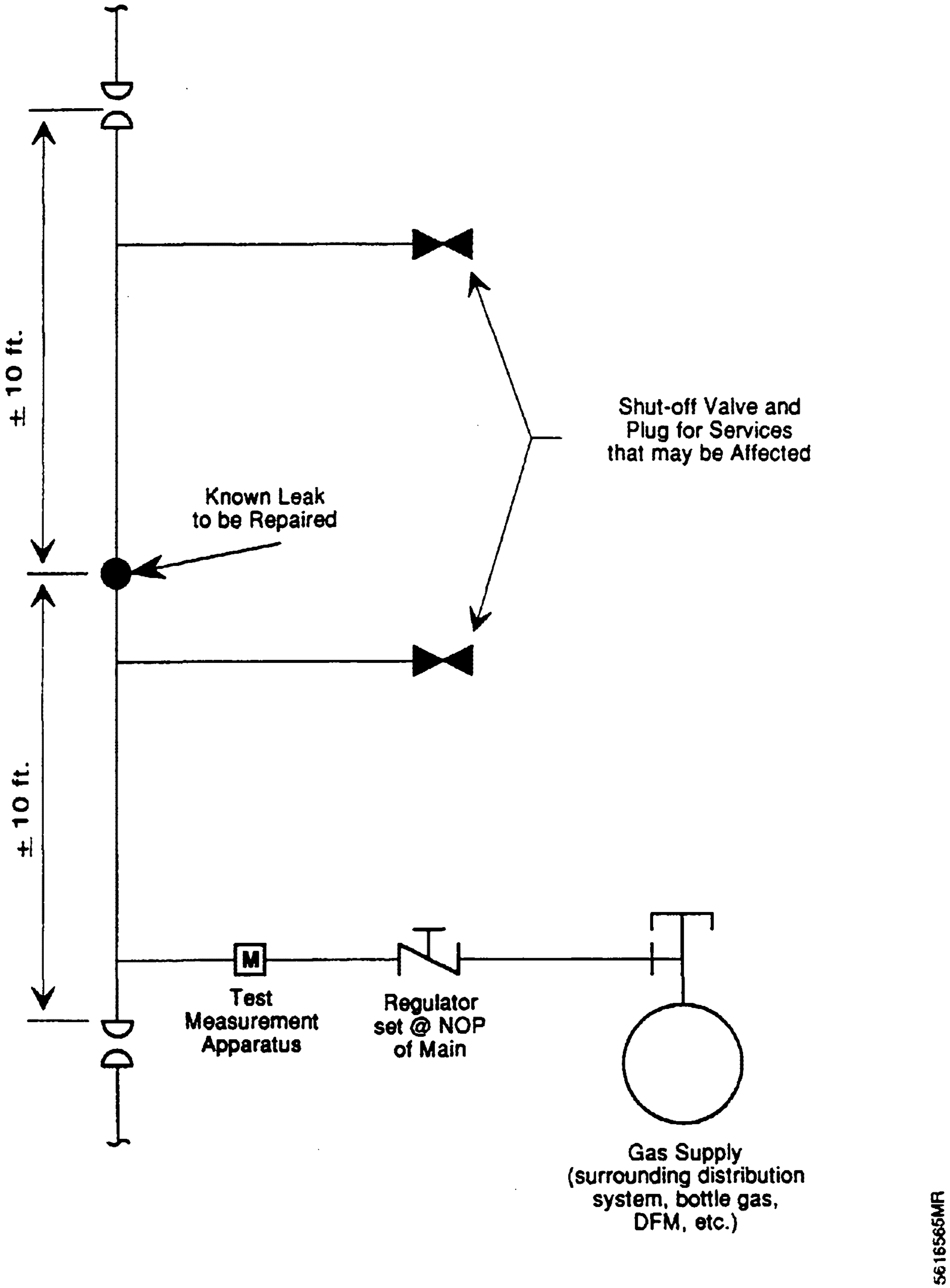

Figure 6-1. Schematic of the Test Procedure

soil surrounding the leak. Using appropriate methods, the section of pipe containing the leak was isolated by first routing the gas flow through a bypass line around the segment containing the leak. The segment of pipe containing the leak was then physically severed and capped off at each end of the live main and each end of the segment to be isolated. The excavation and isolation procedures were performed without disturbing the soil or surface covering immediately surrounding the leak.

Measuring the Leak Rate

After the segment of pipe containing the leak was isolated, it was equipped to receive gas from the live main or pressurized gas cylinder through the leak measurement apparatus. The isolated segment was first returned to its normal operating pressure and, then after the pressure had stabilized, the gas flow rate required to maintain operating pressure was measured. (For low pressure lines, less than 30 inches water column, the pressure in the isolated segment would not reach the pressure of the live main due to the pressure drop across the flow measurement equipment. This was overcome by using a pressurized gas cylinder as the gas supply, or installing a U-tube manometer on the gas supply and isolated segment to monitor the differential pressure. Although not deemed necessary, the gas flow rate measurements could be adjusted by the differential pressure to more accurately represent the leakage rate associated with the supply line pressure.)

Leak Measurement Apparatus -- The leak measurement apparatus used in the program consists of a series of progressively larger laminar flow elements (LFEs), which can rapidly and very accurately measure a pressure differential across the LFE. The LFE causes the flow to be laminar by passing through a series of capillaries within the device. The flow rate is a linear function of the differential pressure within the range of the LFE, as specified on a vendor supplied calibration curve specific to each instrument. Four LFEs were specified for the test apparatus, to accurately cover a flow rate range between 0 and 450 scfh, with individual capacity ranges as follows:

- 0 - 0.8 scfh;
- 0.8 - 10 scfh;
- 10 - 170 scfh; and
- 170 - 450 scfh.

For leakage measurements exceeding 450 scfh, a dry gas meter was used to quantify the leakage rate. The leak measurement apparatus contains a temperature and pressure gauge in order to convert the actual flow rates to standard conditions, along with an inclined manometer to measure differential pressure.

Test Approach -- The segment to be tested was either: 1) a service which was isolated (capped-off) at the service-to-main connection and the customer's meter, 2) a short segment of main (at least 20 feet long) containing the detectable leak which was isolated by capping off both ends of the isolated segment and both ends of the live main, or 3) a long segment of main containing multiple leaks which was isolated by capping off each end of the segment to be tested and each end of the live main.

For all pipe materials except cast iron, an individual leak test approach was used. As previously described, the general procedure for testing individual leaks entailed selecting and centering the leak, isolating the short segment of pipe containing the leak, and measuring the gas rate required to maintain the isolated segment at normal operating pressure. For services, the procedure was identical except that the isolated segment included the entire service line from the main-to-service connection to the customer's meter. This technique was based on testing leaks which are detected using leak survey procedures (i.e., detected leaks), and may exclude smaller or more diffuse leaks that are not detected at the soil surface.

For cast iron mains, a segment test approach was used since many undetected leaks are known to exist in cast iron. Cast iron pipe fittings are prone to leak because of their bell and spigot design, and the frequency of the fittings (every 10-14 feet). The general procedure for testing entire segments of main included selecting the segment to be tested, isolating the segment, and measuring the gas rate required to maintain the segment at normal operating pressure. The resulting test data represent a leakage rate per unit length of main which includes all sources of leakage in the segment, even leaks that may not be detected at the soil surface. Based on a separate study of the oxidation of methane in the soil,[4] many small leaks from cast iron are oxidized before they reach the soil surface. The segment of pipe tested was also surveyed to determine the number of detected leaks and the corresponding concentration of methane detected for each leak in the segment.

6.2 Soil Sampling/Analysis

The key soil characteristics which were expected to affect leakage of gas from distribution systems were divided into two groups.

Soil Characteristics Influencing Vapor Transport

The first group of parameters which likely influence vapor transport through the soil and, therefore, leakage rate include:

- Porosity/bulk density;
- Moisture content; and
- Particle size distribution.

Porosity is the percentage of the total soil volume occupied by open pore space. Soil gas diffusion rates are controlled to some extent by porosity. Bulk density is the mass of dry soil per unit bulk volume, including the air space. The higher the bulk density, the lower the porosity of the soil and, therefore, the lower the expected diffusion rate of gas through the soil.

The soil moisture content affects the gas diffusion rate since water can occupy the pore space. Therefore, the higher the moisture content of the soil, the lower the expected diffusion rate of gas through the soil. Particle size distribution also affects the soil gas diffusion rates. Very fine soil particles, such as clays, tend to increase the compaction capacity, thereby decreasing the diffusion rate of gas through the soil.

Soil Characteristics Influencing Corrosivity

The second group of key soil characteristics influence the corrosivity of the soil. Although the corrosive nature of the soil does not impact the gas diffusion rate, it may affect the frequency of leak occurrence and possibly the mean leak size. The soil parameters which determine the corrosivity of the soil include:

- pH;
- Resistivity or conductivity; and
- Moisture content.

The lower the soil pH, the higher the hydrogen ion content of the soil which promotes greater corrosion potential. The lower the resistivity, the greater the potential for current flow causing corrosion. The moisture content of the soil tends to lower resistance to current flow and increases the corrosive conditions.

Soil samples were collected at each test site using a core sampling device and sent to a laboratory for measurements of bulk density, particle size distribution, moisture content, pH, and resistivity. Soil samples were collected at three different soil depths relative to the pipe location for each test site: at the soil horizon, halfway between the soil horizon and pipe location, and at the pipe location. Because of the possibility of damage to a soil sample while in transit, bulk density (using a push penetrometer) and relative moisture content (using a soil moisture meter) were also measured at each test site when the soil samples were collected.

6.3 Quality Assurance/Quality Control

Quality assurance specifications were developed as part of the testing protocol to ensure that the data collected from various companies would be acceptable. In the design of the test equipment, an in-line filter was specified to assure that any particulates or moisture in the gas stream were removed before flowing through the laminar flow elements. As long as the laminar flow elements are not contaminated by particulates or moisture, the calibration should remain unchanged over the life of the equipment. Additionally, each company was instructed to leak check the test apparatus before each measurement was made.

According to the manufacturer's specifications, the laminar flow elements have an accuracy in the range of 1/2% of the reading. They are calibrated by the manufacturer and include calibration curves specific to each instrument to convert from differential pressure to standard flow rate. In addition to the manufacturer's calibration, the prototype test assembly used for training purposes was calibrated using a bubbleometer standard to confirm the manufacturer's calibration curves.

A scheduled audit of each company's test procedures was performed to identify and correct any deviations from the specified testing protocol. During the audit, calibrated orifices were used to check the calibration of each company's test apparatus. The calibration checks were conducted using critical orifices as calibration standards as described in 40 CFR Part 60, Appendix A, Method 5, Section 7.2.[5]

The leak measurement data obtained from the participating companies were reviewed for consistency and proper interpretation and conversion. All measurement data were checked for accuracy and reasonableness. The data were entered into a database, which was thoroughly checked to ensure accurate entry and interpretation. Data validation was performed on the measurement data including calculations for precision and accuracy and comparison with the program objectives. Data potentially identified as outliers or otherwise suspect were investigated.

7.0 DATA ANALYSES

The leak measurement data collected to date include 108 data points from the North American companies and 38 data points from the European companies participating in the cooperative program. (Although the original program design specified that a total of 200 tests should be collected, the program still achieved an overall accuracy of $\pm$ 65% based on a 90% level of confidence, which is within the target accuracy guidelines for the national estimate.) These data were statistically analyzed to determine primary and secondary influences on leakage. The data were first analyzed to establish whether they represent a normal distribution and were concluded to be lognormally distributed.

Preliminary statistical test results indicate that the influence of pipe use and pipe material is statistically significant. Therefore, the data were disaggregated by mains versus services and by material types. Table 7-1 shows an overview of the North American leak test data with a summary of the data disaggregated by mains versus services and by pipe material. Table 7-1 presents the sample size or number of tests performed, the mean emission rate, and the 90% confidence limits around the estimated mean emission rate. As shown, there is a large variance in the mean leak rates for the data disaggregated by pipe material, ranging from 2.6 to 12.5 scf/leak-hour for mains (excluding cast iron, with an average leak rate of 0.009 scf/foot-hr) and from 0.4 to 2.5 scf/leak-hour for services.

The relatively high leak rate for plastic mains is due to a very small sample size (six data points) with one large data point that skews the average emission rate. Companies participating in the measurement program were encouraged to collect additional test data on plastic mains to reduce the overall uncertainty. However, according to the participants, leaks in plastic mains are relatively infrequent and suitable plastic main test sites were not identified. Therefore, the large data point is likely not representative of the average leakage rate from plastic mains, but no technical reasons to omit the data were identified.

Statistical outlier tests were performed to determine whether the large plastic main data point could justifiably be omitted from the data set. The results of the statistical outlier tests conclude that the large data point cannot be excluded based on a statistical evaluation. (The statistical outlier test results are discussed in Appendix A.) However, as indicated in Sections 8.1.1 and 9.1, even though the data suggest that plastic mains may be subject to relatively high leak rates on a per leak basis, plastic mains experience significantly fewer leaks than the other pipe materials; therefore, the overall contribution to methane emissions from plastic mains is small. (Note: If the large data point were excluded from the dataset for plastic mains, the average leak rate would be 2.7 scf/leak-hour, a factor of nearly 5 lower.)

TABLE 7-1. SUMMARY OF THE NORTH AMERICAN LEAK MEASUREMENT DATA

Pipe Use	Pipe Material	Sample Size	Average Leak Rate, (scf/leak-hour)[a]	90% Confidence Interval, (scf/leak-hour)[a,b]
Mains	Cast Iron	21	0.0093[c]	0.0053[c]
	Unprotected Steel	20	6.45	5.61
	Protected Steel	17	2.55	2.01
	Plastic	6	12.45	19.81
Services	Unprotected Steel	13	2.50	2.46
	Protected Steel	24	1.15	0.62
	Plastic	4	0.37	0.51
	Copper	5	0.94	0.62

[a] Leak rate of natural gas (not adjusted for methane content or soil oxidation).
[b] 90% confidence interval around the mean value (upper bound minus the mean).
[c] scf/foot-hour.

A statistical analysis was performed on the leak measurement database to determine if any of the secondary data parameters are influencing the leak rates and could potentially be used to help predict the leak rates. First, the SAS CORR[6] procedure was used to produce correlation matrices for the parameters of interest. A strong correlation would indicate that the parameter might be correlated with the leakage rate (dependent variable) and, therefore, useful in a predictive model. Next, scatter plots that corresponded to the correlations were constructed to provide visual confirmation of the correlations. Finally, the SAS stepwise regression option in the REG[7] procedure was applied to the data parameters to help uncover possible regression models.

Because the leak measurement data were collected for different pipe use (i.e., mains versus services) and pipe materials, the data were divided into subsets of homogeneous categories to remove confounding effects in the statistical analysis. Table 7-2 shows the correlations of key parameters with the leak rate for mains versus services. The cast iron mains were analyzed separately because the leak rate is expressed in terms of scf/leak-hour. As shown by the low correlation coefficients, none of the correlations were statistically significant at any of the common significance levels (i.e., 99%, 95%, or 90%). This is not surprising for the combined main or service groups, because these groups contain different pipe materials that may confound the statistical results.

Table 7-3 shows the correlations of the key parameters with the leak rate broken down by pipe material for mains, and Table 7-4 shows the correlations for services. For mains broken down by pipe material, none of the correlations were statistically significant and only a few correlations were statistically significant for plastic or protected steel services. Even for cast iron mains which have a sufficient sample size, no statistically significant correlations were found with soil type, age, diameter, or operating pressure.

As footnoted in the tables, caution should be used for sample sizes of 10 or less. This is because such small sample sizes do not contain enough information to determine if the data really are correlated or not. Thus, the statistically significant correlation coefficients for plastic and copper services should be discounted based on an insufficient sample size. The correlation coefficients for protected steel services associated with soil content should also be discounted because of insufficient sample size. And though statistically significant with an adequate sample size, the leak rates from protected steel

TABLE 7-2. CORRELATION COEFFICIENTS FOR COMBINED MAIN AND SERVICE LEAK DATA
(sample size is indicated in parentheses)[a]

Leak Parameter[b]	Mains[c] (scf/leak-hr)	Services (scf/service-hr)
Sand % (top)	-0.10 (16)	0.41 (15)
Sand % (middle)	0.06 (16)	0.34 (15)
Sand % (bottom)	-0.00 (16)	0.38 (15)
Silt % (top)	0.22 (16)	-0.31 (15)
Silt % (middle)	0.11 (16)	-0.24 (15)
Silt % (bottom)	0.09 (16)	-0.27 (15)
Clay % (top)	-0.14 (16)	-0.39 (15)
Clay % (middle)	-0.21 (16)	-0.45 (15)
Clay % (bottom)	-0.12 (16)	-0.40 (15)
Operating Pressure (psig)	-0.03 (43)	-0.13 (46)
Pipe Age (year)	-0.00 (39)	-0.17 (40)
Pipe Diameter (inches)	-0.08 (43)	0.16 (46)

[a] None of the correlation coefficients are statistically significant at either the 99%, 95%, or 90% significance levels.

[b] Top refers to near the soil surface; middle refers to halfway between the soil surface and the pipe location; bottom refers to the pipe location.

[c] Excludes cast iron mains.

TABLE 7-3. CORRELATION COEFFICIENTS FOR THE MAIN LEAK DATA (sample size is indicated in parentheses)[a]

Leak Parameter[c]	Cast Iron	Unprotected Steel	Plastic	Protected Steel
Sand % (top)	0.11 (41)	-0.14 (11)	-	-0.17[b] (4)
Sand % (middle)	0.09 (41)	0.05 (11)	-	-0.04[b] (4)
Sand % (bottom)	0.06 (41)	-0.04 (11)	-	0.40[b] (4)
Silt % (top)	-0.03 (41)	0.33 (11)	-	0.05[b] (4)
Silt % (middle)	-0.10 (41)	0.21 (11)	-	-0.21[b] (4)
Silt % (bottom)	-0.02 (41)	0.17 (11)	-	-0.60[b] (4)
Clay % (top)	-0.04 (41)	-0.21 (11)	-	0.27[b] (4)
Clay % (middle)	-0.03 (41)	-0.28 (11)	-	0.46[b] (4)
Clay % (bottom)	-0.08 (41)	-0.15 (11)	-	-0.00[b] (4)
Operating Pressure (psig)	0.06 (46)	-0.19 (20)	0.36[b] (6)	0.19 (17)
Pipe Age (year)	0.22 (56)	0.14 (20)	0.82[b] (4)	0.17 (15)
Pipe Diameter (inches)	-0.06 (57)	-0.21 (20)	-0.04[b] (6)	-0.17 (17)

[a] None of the correlation coefficients are statistically significant at either the 99%, 95%, or 90% significance levels.

[b] Caution should be used for sample sizes of 10 or less.

[c] Top refers to the near soil surface; middle refers to halfway between the soil surface and the pipe location; bottom refers to the pipe location.

TABLE 7-4. CORRELATION COEFFICIENTS FOR THE SERVICE LEAK DATA
(sample size is indicated in parentheses)

Leak Parameter[c]	Unprotected Steel	Copper	Plastic	Protected Steel
Sand % (top)	0.45[a] (6)	-0.28[a] (4)	-	-0.68[a] (4)
Sand % (middle)	0.49[a] (6)	0.08[a] (4)	-	-0.53[a] (4)
Sand % (bottom)	0.33[a] (6)	-0.49[a] (4)	-	0.42[a] (4)
Silt % (top)	-0.38[a] (6)	0.19[a] (4)	-	0.79[a] (4)
Silt % (middle)	-0.36[a] (6)	-0.25[a] (4)	-	0.81[a] (4)
Silt % (bottom)	-0.31[a] (6)	0.93[a] (4)	-	0.40[a] (4)
Clay % (top)	-0.56[a] (6)	0.21[a] (4)	-	-0.14[a] (4)
Clay % (middle)	-0.61[a] (6)	0.52[a] (4)	-	-0.06[a] (4)
Clay % (bottom)	-0.34[a] (6)	-0.13[a] (4)	-	-0.90[a] (4)
Operating Pressure (psig)	-0.18 (13)	0.25[a] (5)	0.91[a,b] (4)	0.46[b] (24)
Pipe Age (year)	0.05[a] (10)	-0.27[a] (5)	0.20[a] (3)	0.14 (22)
Pipe Diameter (inches)	0.12 (13)	-0.31[a] (5)	-0.06[a] (4)	-0.37[b] (24)

[a] Caution should be used for sample sizes of 10 or less.
[b] Indicates that the correlation coefficient is statistically significant at the 90% significance level.
[c] Top refers to near the soil surface; middle refers to halfway between the soil surface and the pipe location; bottom refers to the pipe location.

services were only marginally correlated with the operating pressure or pipe diameter. However, since no other pipe use/material combinations showed a similar trend in correlation between leak rate and operating pressure or pipe diameter, the correlation for protected steel services is suspect. Thus, the correlation analysis indicated either inconclusive results for the data from small samples or no correlations when sample sizes were sufficient, with the exception of marginal correlations for operating pressure and diameter for protected steel services.

Scatter plots were constructed to visually confirm the results of the correlation analysis. First, a separate scatter plot was constructed for the main and service categories shown in Table 7-2. Figure 7-1 shows the scatter plot for the mains leak data (including protected steel, unprotected steel, and plastic mains) versus the soil silt content (%), which gave the largest, but still insignificant, correlation coefficient for this group shown in Table 7-2. For each of the pipe materials separately, the sample size was not large enough to provide dependable information for the results of the correlation analysis; namely, the leak data were not correlated with the soil silt content. The scatter plot confirms this by showing the large overall variability in the data and the variability within the few data points for each pipe material.

Figure 7-2 shows the scatter plot for the service (including copper, plastic, protected steel, and unprotected steel services) leak data versus the soil clay content (%), which gave the largest, but still insignificant, correlation coefficient for this group shown in Table 7-2. Again, in this case the sample size was not large enough to provide dependable information for the results of the correlation analysis for any of the pipe materials; namely, the leak data were not correlated with the soil clay content. The scatter plot confirms this by showing the large spread among the few data points for each pipe material.

Figure 7-3 shows the scatter plot for the cast iron mains leak data versus the pipe age. As shown in Table 7-3, although the sample size was large enough to draw a conclusion, the leak data were not correlated with the pipe age.

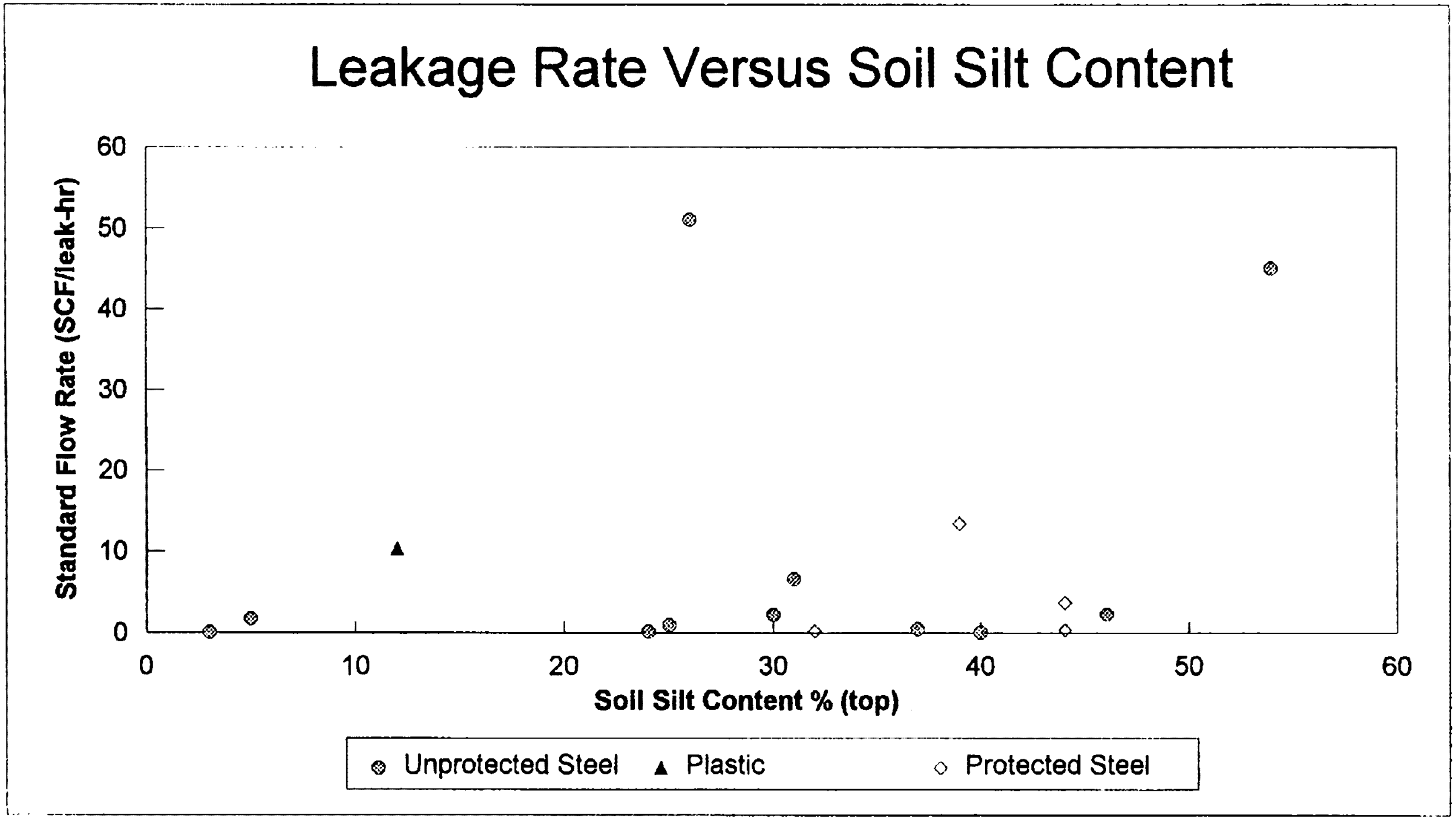

Figure 7-1. Scatter Plot of Leakage Rate Versus Soil Silt Content for Distribution Mains

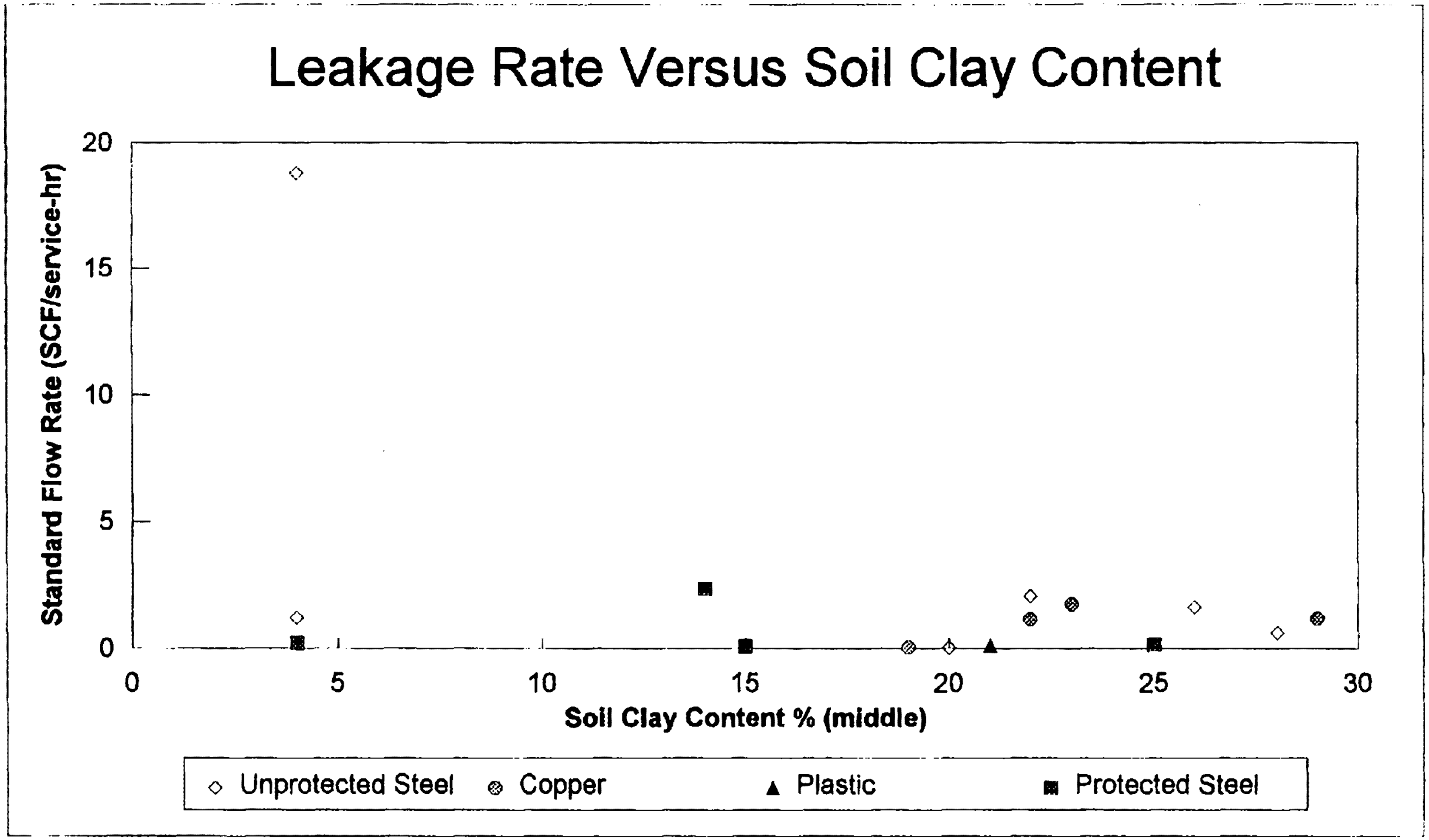

Figure 7-2. Scatter Plot of Leakage Rate Versus Soil Clay Content for Distribution Services

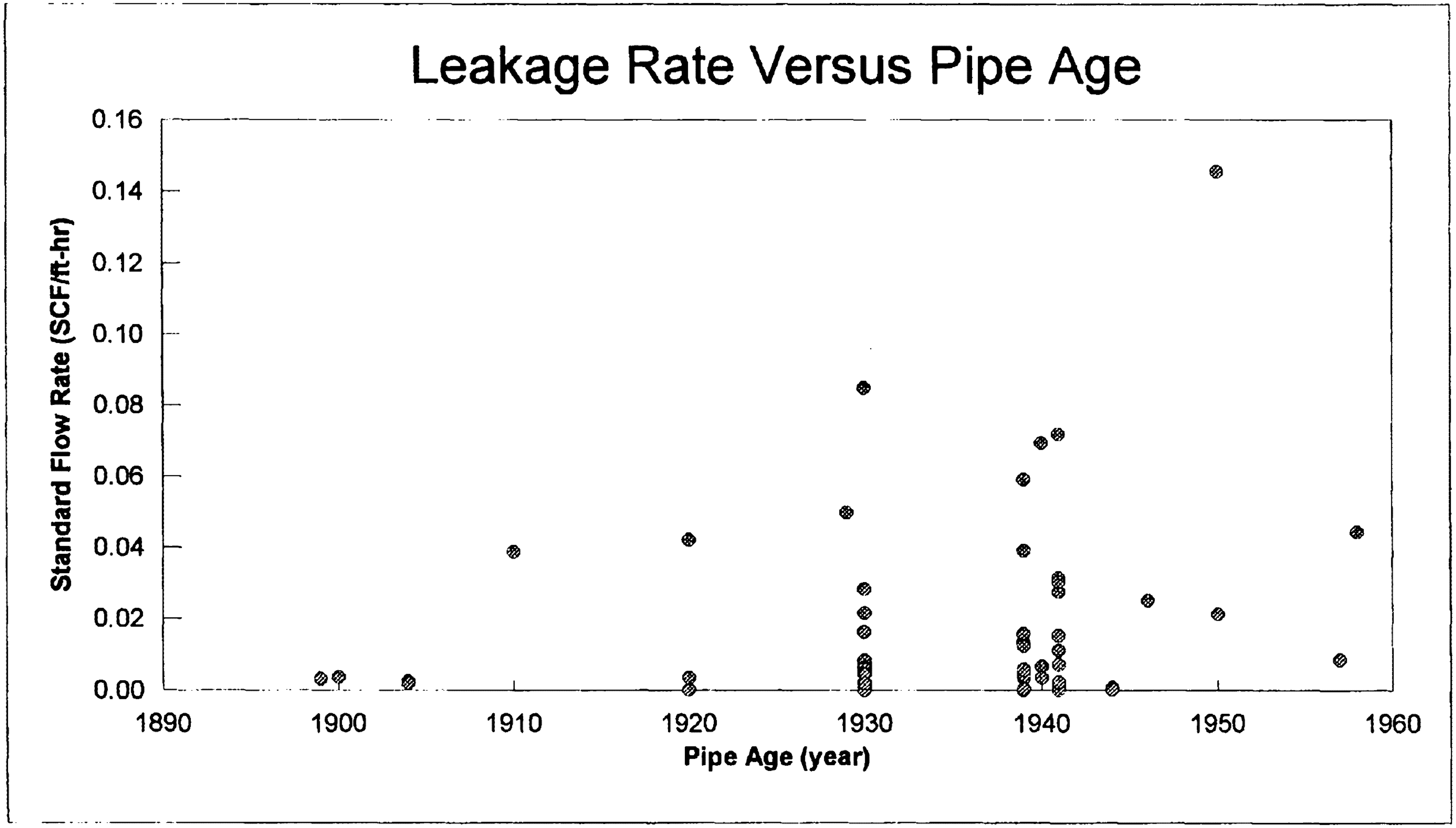

Figure 7-3. Scatter Plot of Leakage Rate Versus Pipe Age for Cast Iron Mains

Figure 7-4 shows the pipe material-specific scatter plot for the protected steel service leak data versus the operating pressure of the pipe, which gave a statistically significant correlation coefficient of 0.46. This coefficient was considered marginal, and Figure 7-4 shows that the data are very scattered, which supports classifying this relationship as weak or inconclusive. Since the relationship between leak rate and operating pressure for protected steel services was the strongest, but still considered inconclusive, the overall data suggest that there is not a correlation between leak rate and normal operating pressure. [Note: For a given pipeline system, when the pressure is increased above the normal operating pressure, the leak rate does increase. (For a given hole size in the pipe, the leak rate is a function of pressure.) However, when comparing one system operating at a lower pressure to another system at a higher pressure, the data suggest that the leak rates are not dependent on the normal operating pressure of the systems.]

Even though the correlation analyses and scatter plots gave no promise of developing a predictive model from the leak database, a preliminary stepwise regression analysis was performed to confirm the correlation analyses results. The stepwise regression analysis selects the single parameter that gives the best model R^2 (i.e., the most variation is explained by this single parameter.) Then, the parameter that increases the R^2 the most is added to the model, and so on. This procedure was applied using all of the data parameters for which correlations were examined (see the listings in Table 7-2 through Table 7-4) for each of the service/pipe material groups. In many cases, no parameter met the input criteria for entry into the model. That is, a specified small amount of variance must be explained. Models could only be generated from this procedure for two groups: copper services and protected steel services. However, only four data points were available for the soil composition data for both groups, which makes the results inconclusive. Thus, even when forcing a model, no useful results were obtained.

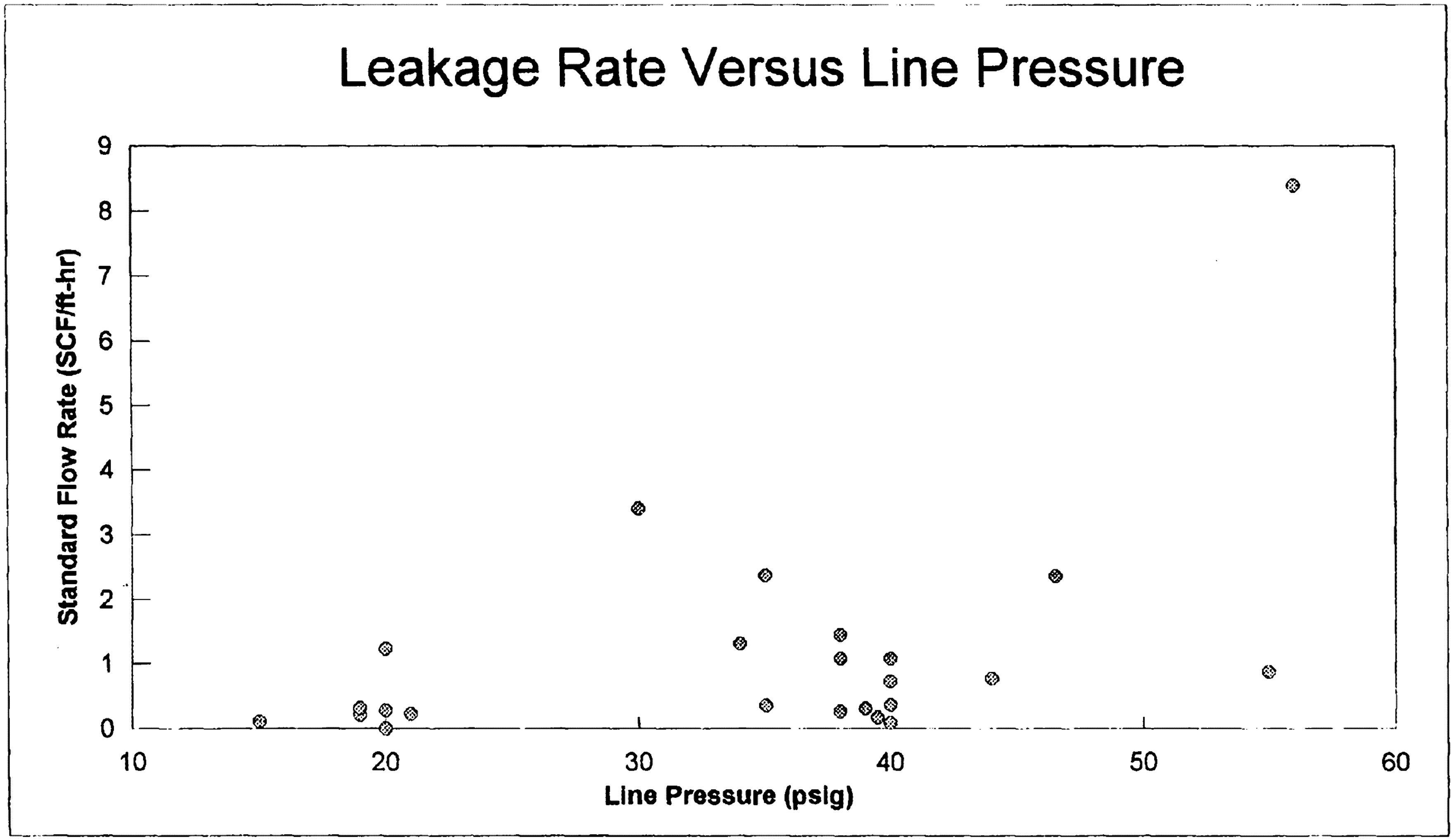

Figure 7-4. Scatter Plot of Leakage Rate Versus Operating Pressure for Protected Steel Services

8.0 EXTRAPOLATION METHOD

The calculated emissions estimate from underground pipeline leaks is the product of an emission factor and an activity factor. The emission factor is derived from the leak measurements provided by participating companies. As previously discussed, the participating companies measure gas leakage from underground mains by testing either individual leaks or leaking services (units = standard cubic feet/leak-hour) or pipe segments (units = standard cubic feet/mile-hour).

The activity factor is derived by combining national leak repair records for underground pipelines with leak history data provided by the participating companies, to determine the total number of leaks. (For cast iron mains that are tested using a segment method, the activity factor is the total mileage of cast iron pipe in the United States.) Leak estimates were derived from historical leak records provided by the participating companies in combination with nationally tracked statistics of leak repairs. A detailed discussion of the approach used to estimate the total number of leaks for each pipe material category is included in Section 8.2.

8.1 Emission Factor Development

The emission factors were derived from the leak measurement database, segregated into the pipe use (mains versus services) and pipe material categories. The emission factors for distribution pipelines were also applied to underground transmission and production pipelines as discussed in Sections 8.1.2 and 8.1.3, respectively.

8.1.1 Distribution Emission Factors

The emission factors for underground distribution pipelines represent the average leak rates for each pipe use/material category. The leakage rates previously presented in Table 7-1 were adjusted for the average methane content of pipeline quality gas, 93.4 volume percent. The methane emission rates on an hourly basis were then converted to an annual basis, assuming that each leak or leaking segment is continuously leaking year round. The fact that many leaks are repaired throughout the year and, therefore, are not leaking year round is accounted for in the activity factor. (Leaks that are repaired during the year are counted as partial leaks.)

Table 8-1 presents the average methane leakage rates from underground distribution mains and services, stratified by pipe material. As shown, the leakage rate for unprotected steel is significantly higher than for protected steel for both mains and services. As previously mentioned, the leakage rate for plastic mains is even higher than for unprotected steel mains, because of a small sample size with one very large leak measurement. As discussed in Appendix A, the single large leak measurement cannot be justifiably excluded from the data set based upon the results of statistical outlier tests. However, since plastic mains have significantly fewer leaks than other pipe material categories, their overall contribution to emissions is small.

TABLE 8-1. METHANE LEAKAGE RATES FOR UNDERGROUND DISTRIBUTION PIPELINES

Pipe Use	Pipe Material	Average Methane Leakage Rate,[a] (scf/leak-yr)	90% Confidence Interval,[a,b] (scf/leak-yr)
Mains	Cast Iron	399,867[c]	227,256[c]
	Unprotected Steel	52,748	45,876
	Protected Steel	20,891	16,479
	Plastic	101,897	162,102
Services	Unprotected Steel	20,433	20,130
	Protected Steel	9,438	5,064
	Plastic	3,026	4,134
	Copper	7,684	5,061

[a] Methane leakage rate, not adjusted for soil oxidation.
[b] 90% confidence interval around the mean value (upper bound minus the mean).
[c] scf/mile-year.

The leakage rate for cast iron mains was derived from the data collected in North America, which represents a sample size of 21. Since the leakage characteristics of cast iron mains from the European participants are different than the North American companies, only data from the North American companies were used to derive the cast iron emission factor for the United States.

The methane leakage rates were adjusted for soil oxidation based on data presented in *Soil Consumption of Methane from Natural Gas Pipeline Leaks*.[4] The soil oxidation rates of methane were experimentally determined to be a function of the methane leakage rate, depth of pipe, soil moisture content, and soil temperature. In general, the larger the leakage rate per leak, the lower the soil oxidation rate. Because of the variation in leakage rates among the pipe material categories, the average soil oxidation rates are different for the various pipe materials. Table 8-2 shows the methane emission factors for distribution pipelines adjusted for soil oxidation. The precision of the soil oxidation adjustment was assumed to be ± 25% based on engineering judgement. Therefore, the overall 90% confidence interval was calculated by propagating the errors for the leakage rate estimate and the soil oxidation rates.

8.1.2 Transmission Emission Factors

Leak survey practices for transmission lines are generally more stringent than for distribution mains. Transmission lines are required to be surveyed annually, and more frequently in populated areas. In addition, many transmission companies perform additional routine aerial surveys to monitor the transmission lines for leakage. Based on conversations with several transmission companies, any leaks found in the pipe wall are extremely small and are repaired immediately for safety reasons. Based on the rigorous leak survey and repair practices of transmission companies (i.e., leaks are discovered and repaired earlier in transmission lines), the average leak rate from a transmission line is believed to be of the same order of magnitude as a leak found in a distribution main, even though there may be a substantial difference in the operating pressure of the pipelines. (Note: As discussed in

TABLE 8-2. METHANE EMISSION FACTORS FOR UNDERGROUND DISTRIBUTION PIPELINES[a]

Pipe Use	Pipe Material	Average Methane Leakage Rate (scf/leak-yr)	Soil Oxidation (%)	Average Emission Factor[a] (scf/leak-yr)	90% Confidence Interval[a,b] (scf/leak-yr)
Mains	Cast Iron	399,867[c]	40.3	238,736[c]	152,059[c]
	Unprotected Steel	52,748	1.8	51,802	48,212
	Protected Steel	20,891	3.0	20,270	17,243
	Plastic	101,897	2.0	99,845	165,617
Services	Unprotected Steel	20,433	1.1	20,204	21,129
	Protected Steel	9,438	2.6	9,196	5,581
	Plastic	3,026	21.2	2,386	3,412
	Copper	7,684	0	7,684	5,559

[a] Adjusted for soil oxidation of methane.
[b] 90% confidence interval around the mean value (upper bound minus the mean).
[c] scf/mile-year.

Section 7, data from the underground distribution program suggest that the leakage rate is not a function of the pipeline operating pressure. When comparing one pipeline system at a lower operating pressure to another system at a higher operating pressure, no discernible difference in leakage rate is observed, based on the current data available. One possible explanation for this observation is that most leaks are detected and subsequently repaired at around the same surface threshold concentration, regardless of system operating pressure.)

Therefore, the emission factors for leakage from transmission pipelines are based on the average leakage rates for main pipelines from the cooperative distribution leakage measurement program. A mean value of the estimated leak rate per leak was calculated using the test data, for all pipe materials except cast iron. For cast iron mains, a segment test approach was used which quantifies the leakage rate for a long isolated segment of pipe; therefore, the mean leakage rate for cast iron is in terms of leakage per unit length of pipe. The natural gas leak rate was adjusted for methane content by multiplying by the volume percent of methane for transmission (93.4 volume percent). The methane emission factor was also adjusted for soil oxidation of methane. The value of the emission factor and 90% confidence interval for each pipe material category is identical to that shown in Table 8-2 for distribution mains.

8.1.3 Production Emission Factors

The emission factors for leakage from gathering pipelines are based on the average leakage rates for main pipelines from the cooperative distribution leakage measurement program. The natural gas leakage rates were adjusted for methane content by multiplying by the average volume percent of methane in the production segment (78.8 volume percent), and adjusted for soil oxidation of methane. The resulting emission factors for gathering pipelines in the production segment of the industry are shown in Table 8-3.

TABLE 8-3. METHANE EMISSION FACTORS FOR UNDERGROUND GATHERING PIPELINES IN THE PRODUCTION SEGMENT

Pipe Material	Average Methane Emission Factor,[a] (scf/leak-yr)	90% Confidence Interval,[a,b] (scf/leak-yr)
Protected Steel	17,102	14,548
Unprotected Steel	43,705	40,675
Plastic	84,237	139,729
Cast Iron	201,418[c]	128,290[c]

[a] Adjusted for soil oxidation of methane.
[b] 90% confidence interval around the mean value (upper bound minus the mean).
[c] scf/mile-year.

8.2 Activity Factor Development

The methodology used to derive the total leaks in underground distribution mains and services is presented in Section 8.2.1. Sections 8.2.2 and 8.2.3 present the activity factors for the transmission and production sectors of the gas industry, respectively.

8.2.1 Distribution Activity Factor

Since the emission factor for quantifying emissions from underground distribution mains and services was stratified by pipe use (mains versus services) and by pipe material (i.e., cast iron, cathodically protected steel, unprotected steel, plastic, and copper), the activity factor was also stratified to extrapolate emissions.

With the exception of cast iron main pipeline, the activity factor used to extrapolate the leakage estimate for underground distribution mains and services was the number of annual equivalent leaks. (For cast iron pipeline, the activity factor was the total mileage of cast iron mains in the United States, which is a nationally tracked statistic.[8]) Annual equivalent leaks are defined as the number of leaks that leak continuously year round. For example, if leaks that are repaired during the year are leaking for half the year, on average, then each repaired leak would be counted as half an annual equivalent leak.

The number of annual equivalent leaks was derived from the national database of leak repair records broken down by mains and services [U.S. Department of Transportation (DOT), Research and Special Programs Administration (RSPA)].[8] To allocate leak repairs into pipe material categories, data were collected from ten local distribution companies representing different regions within North America. The average leak repairs per mile or per service based on the company data was multiplied by the national miles/services,[8] to provide the percentage of leak repairs in each material category. The total number of nationally tracked leak repairs for mains and services, respectively, was used to estimate the national leak repairs in each category. An estimate of the national leak repairs allocated by pipe material type is shown in Table 8-4.

To derive annual equivalent leaks from the national leak repair records, additional information was needed including the number of leaks found during the year (leak indications) and the unrepaired leaks at the beginning of the year (outstanding leaks).

TABLE 8-4. NATIONAL LEAK REPAIRS ALLOCATED BY PIPE MATERIAL CATEGORY

Pipe Use	Pipe Material	Average Leak Repairs/Mile or Service[a]	National Miles/Services[b]	Extrapolated Leak Repairs	Percent Leak Repairs	Estimated Total Leak Repairs	90% Confidence Interval[c] (Leak Repairs)
Mains	Cast Iron	1.38	55,288	76,400	33.8	69,776	42,382
	Protected Steel	0.08	451,466	34,954	15.5	31,924	14,982
	Unprotected Steel	1.09	82,109	89,377	39.6	81,627	34,359
	Plastic	0.08	299,421	25,189	11.2	23,006	24,134
	Subtotal			225,920	100	206,333[b]	
Services	Protected Steel	0.006	20,352,983	126,799	42.2	182,562	221,755
	Unprotected Steel	0.027	5,446,393	148,823	49.5	214,271	205,990
	Plastic	0.001	17,681,238	22,367	7.5	32,202	27,067
	Copper	0.011	233,246	2,507	0.8	3,608	3,517
	Subtotal			300,496	100	432,643[b]	

[a] Based on data provided by ten companies.
[b] Based on nationally tracked database, U.S. Department of Transportation, Research and Special Programs Administration.[6]
[c] 90% confidence interval around the mean value (upper bound minus the mean).

Since leak indications and outstanding leaks are not tracked nationally, this information was requested from individual companies.

Data were collected from the companies participating in the cooperative leak measurement program on the annual number of leak repairs, number of leak indications, and outstanding leaks at the beginning of the year (reference year in most cases was 1991). The data were requested to be disaggregated by mains versus services and by pipe material. Complete data were provided by only four companies, coupled with a breakdown of the total mileage of mains and number of services by pipe material. Two additional companies provided the data requested, although with no breakdown by pipe material or use. Table 8-5 shows the data from the North American companies that provided a complete set of data required to estimate the total number of leaks in their distribution system. (Note: The leak data disaggregated by pipe use and material type have been difficult to obtain from many companies, since leak records are often not maintained in this manner.)

An estimate of the total annual equivalent leaks for each of the six companies was developed for each pipe material category except cast iron, based on the following methodology:

$$TEL = OL + LI + UDL + URL - (0.5 \times RL)$$

where

TEL	=	Total annual equivalent leaks
OL	=	Outstanding leaks at the beginning of the year
LI	=	Leak indications recorded during the year, including call-ins
UDL	=	Undetected leaks which cannot be found using an industry standard survey procedure
URL	=	Unreported leaks that have developed in parts of the network not surveyed during the current year
RL	=	Repaired leaks -- estimated to be leaking half the year, on average

Undetected leaks which cannot be found using an industry standard survey procedure were quantified based on information provided by Southern Cross.[9] According to their experience

TABLE 8-5. SUMMARY OF LEAK RECORD DATA FROM PARTICIPATING COMPANIES

Company	Annual Leak Indications	Annual Leak Repairs	Annual Outstanding Leaks	Estimated Total Equivalent Leaks	Ratio of Equivalent Leaks to Leak Repairs
A	3,747[a]	2,061[a]	0	3,378	1.64
B	9,249	17,003	11,701	18,796	1.11
C	2,115	2,443	0	2,832	1.16
D	--[b]	14,681	--[b]	41,286	2.81
E	1,999	2,287	2,396	6,250	2.73
F	5,992	3,421	1,558	11,597	3.39
Average					2.14
90% Confidence Interval					0.79

[a] Mains only.
[b] Data not available.

in performing leak surveys and survey audits, Southern Cross predicts that a standard industry survey procedure using a flame ionization detector (FID) instrument finds 85% of the leaks. (Note: The standard industry survey procedure involves using either a walking or mobile survey, as appropriate for the area being surveyed, using an FID instrument. Any potential leak that is found with the FID instrument, registering a concentration above background, is investigated using bar holing procedures.) Therefore, the number of undetected leaks is estimated by:

$$UDL = [(1/0.85) - 1] \times LI$$

The total annual equivalent leaks are derived using the estimated leak duration for each type of leak, based on the following:

- Repaired leaks are assumed to be leaking half the year, on average.
- Outstanding leaks, leak indications, and undetected leaks are estimated to be leaking the entire year (i.e., 8,760 hours per year).

The leak duration of unreported leaks is factored into the estimation methodology for these leaks. Unreported leaks are those leaks which occur in parts of the network not surveyed during the year (i.e., multi-year survey cycle). The number of unreported leaks is based on the annual leak indications and the undetected leaks as well as the frequency of the leak survey. The number of unreported leaks in the system that is surveyed every "n" number of years is calculated based on the following:

- For the first year in the cycle -- $1/n \times (LI + UDL)$ leaks are leaking half the year; $(n-1)/n \times (LI + UDL)$ leaks are not yet leaking.
- For the second year in the cycle -- $1/n \times (LI + UDL)$ leaks are leaking the entire year; $1/n \times (LI + UDL)$ leaks are leaking half the year. $(n-2)/n \times (LI + UDL)$ leaks are not yet leaking.

- For the third year in the cycle -- 2/n × (LI + UDL) leaks are leaking the entire year; 1/n × (LI + UDL) leaks are leaking half the year; (n-3)/n × (LI + UDL) leaks are not yet leaking.
- For the fourth year in the cycle -- 3/n × (LI + UDL) leaks are leaking the entire year; 1/n × (LI + UDL) leaks are leaking half the year; (n-4)/n × (LI + UDL) leaks are not yet leaking.

Based on the methodology described above, the number of equivalent leaks was estimated for each of the six companies providing detailed data. The ratio of equivalent leaks to leak repairs was then calculated for each of the companies. The average ratio of equivalent leaks to leak repairs was used to extrapolate the national database of leak repairs. Table 8-5 presents a summary of the leak record data provided by the six companies, the estimated equivalent leaks, and the corresponding ratio of equivalent leaks to leak repairs. As shown, the average ratio of equivalent leaks to leak repairs is 2.14.

The national estimate of annual equivalent leaks, broken down by pipe use and material type, is shown in Table 8-6. As shown, the activity factor for cast iron mains is miles of pipeline, to correspond to the emission factor in units of scf/mile-year. The estimate of annual equivalent leaks is highest for unprotected steel services, followed by protected steel services. For mains, unprotected steel is the category with the highest estimated annual equivalent leaks. The precision of the estimate is based on the variability in leak repair data allocated by material type from ten companies and the variability in the ratio of equivalent leaks per leak repair from six companies.

8.2.2 Transmission Activity Factors

The activity factors for the transmission segment were derived from the total number of transmission pipeline leaks (excluding pipeline incidents) reported to the U.S. DOT, RSPA.[8] The leaks reported to RSPA include both repaired leaks (6,120 leaks) and

TABLE 8-6. SUMMARY OF ACTIVITY FACTORS FOR DISTRIBUTION UNDERGROUND PIPELINES

Pipe Use	Material Category	Estimated Total Leak Repairs[a]	Average Activity Factor (equivalent leaks)[b]	90% Confidence Interval Activity Factor,[c] (equivalent leaks)
Mains	Cast Iron	69,776	55,288[d]	2,764[d]
	Unprotected Steel	81,627	174,657	101,685
	Protected Steel	31,924	68,308	42,545
	Plastic	23,006	49,226	58,018
	Subtotal	206,333		
Services	Unprotected Steel	214,271	458,476	499,850
	Protected Steel	182,562	390,628	526,354
	Plastic	32,202	68,903	66,840
	Copper	3,608	7,720	8,521
		432,643		

[a] Based on national leak repair database[7] and data provided by six companies (see Table 8-4).
[b] Based on estimated ratio of annual equivalent leaks to leak repairs of 2.14 (see Table 8-5).
[c] 90% confidence interval around the mean value (upper bound minus the mean).
[d] Miles.

outstanding leaks at the end of the year (1,369 leaks). Therefore, the total number of leak indications is the summation of the repaired leaks and outstanding leaks at the end of the year, or 7,489 leak indications:

$$\text{Leak Indications} = \text{Leak Repairs} + \text{Outstanding Leaks}$$

Because transmission lines are surveyed at least once per year using a walking survey method, the number of undetected leaks is estimated based on the effectiveness of the walking survey. According to one company specializing in distribution surveys,[9] roughly 85% of the leaks are found using a walking survey. This estimated survey effectiveness was applied to transmission surveys, resulting in roughly 1,320 undetected leaks:

$$\text{Undetected Leaks} = [(\text{Leak Indications} / 0.85) - \text{Leak Indications}]$$

The leak duration for outstanding leaks and undetected leaks is estimated to be 8,760 hours per year, and the leak duration for repaired leaks is half a year (4,380 hours/year), on average. Because transmission lines are surveyed at least once per year, there are no unreported leaks from multiple year survey cycles. The resulting estimate of equivalent leaks represents the number of leaks with a year round leak duration. (Each leak repair is counted as half an equivalent leak to compensate for leak duration.) Therefore, the equation used to estimate equivalent leaks is:

Equivalent Leaks = Leak Indications + Undetected Leaks
= (0.5 × Repaired Leaks) + (Outstanding Leaks + Undetected Leaks
= (0.5 × Repaired Leaks) +
[((Repaired Leaks + Outstanding Leaks)/0.85)-Repaired Leaks]

The total number of equivalent transmission pipeline leaks, 5,750, was allocated on a pipeline material category basis in the same proportion (adjusted for the fraction of mileage as well as the different leak frequency in each material category) as in the distribution sector. (The ratio of percent leaks to percent miles in the transmission segment is the same as the ratio in the distribution segment.)

The precision of the estimated total leaks was calculated based on the estimated 90% confidence interval associated with each parameter in the activity factor equation:

- Repaired leaks: ±100%;
- Outstanding leaks: ±100%;
- Leak duration: ±25%; and
- Leak survey effectiveness: ±15%.

A statistical software program (@ RISK)[10] was used to determine the overall 90% confidence interval of the activity factor, ± 76%.

For cast iron transmission lines, the activity factor is the total mileage based on the RSPA database for transmission and gathering lines. The precision of the estimate is assumed to be ± 10%. Table 8-7 presents the transmission pipeline activity factors.

TABLE 8-7. SUMMARY OF ACTIVITY FACTORS FOR TRANSMISSION UNDERGROUND PIPELINES

Pipe Material	Total Miles	Average Activity Factor, (equivalent leaks)	90% Confidence Interval of Activity Factor,[a] (equivalent leaks)
Protected Steel	287,155	5,077[b]	3,859[b]
Unprotected Steel	5,233	659	501
Plastic	2,621	14	11
Cast Iron	96	96[a]	10[a]

[a] 90% confidence interval around the mean value (upper bound minus the mean).
[b] Miles.

8.2.3 Production Activity Factors

The estimated number of leaks in field gathering pipelines is based on a leak repair frequency for gathering lines owned and operated by transmission companies reported in the RSPA database.[8] This database reports an estimated 8,153 repaired leaks and 270 outstanding leaks in 31,918 miles of gathering pipeline. The leak frequency is derived by compensating for leaks that are repaired during the year and, therefore, not contributing to leakage year round. On average, the repaired leaks are assumed to be leaking for half the year, and each leak repair is counted as half an equivalent leak. Outstanding and undetected leaks are assumed to be leaking the entire year.

Most production lines owned and operated by production companies are not regulated by the U.S. DOT and many are not monitored for leaks in the rigorous fashion employed by distribution and transmission companies. Therefore, undetected leaks are accounted for based on the effectiveness of the survey method performed, which is estimated to find 35 and 85% of the total leaks for a vegetation and walking survey, respectively. This is based on the experience of Southern Cross, a company specializing in leak surveys.[9] Based on limited data provided by production companies, production company owned gathering lines are only surveyed using a vegetation method. However, transmission company owned gathering lines are surveyed annually using a FID instrument while walking the lines.

Based on an analysis of equivalent leaks (similar to the analysis presented for transmission activity factor development in Section 8.2.2), the leak frequency is 0.18 leaks per mile for a walking survey and 0.63 leaks per mile for a vegetation survey. This leak frequency was used to ratio the number of leaks to the total estimated population of gathering pipeline.

Gathering Pipeline Mileage

Total gathering pipeline mileage is not reported or tracked nationally and, therefore, was determined from the value of the number of miles of gathering line per well supplied by various production companies. The "gathering pipeline" designation includes three categories of pipeline: 1) production company-owned gathering pipeline for gas wells not associated with oil production (i.e., non-associated gas wells); 2) production company-owned gathering pipeline for oil wells that produce marketed gas (i.e., associated gas wells); and 3) transmission company-owned gathering pipeline. The third category of transmission-owned pipelines are assumed to be in addition to the production pipeline miles associated with wells. This is consistent with the site visit data since gathering lines owned by transmission companies were intentionally excluded from the site mileage totals. (The production companies did not report pipeline miles beyond their custody transfer meters.)

Total miles of gathering pipeline for non-associated gas wells were estimated using site visit data from the thirteen production companies shown in Table 8-8. Seven of the thirteen sites provided estimates of their total miles of pipeline. The fifth site's mileage was estimated from a map of its pipelines.

TABLE 8-8. SITE SPECIFIC DATA ON GATHERING LINE MILEAGE PER GAS WELL

Site	Gathering Miles	Number of Wells	Miles per Total Wells
Site 1	46.3	80	
Site 2	8	26	
Site 3	40	130	
Site 4	15.4	12	
Site 5	11	6	
Site 6	5.2	193[a]	
Site 7	600	1000	
Site 8	441.3	425	
Site 9	0.7	1	
Site 10	27.7	24	
Site 11	2.1	3	
Site 12	7.1	7	
Site 13	154.2	126	
TOTAL	1359.0	2033	0.67 ± 28%[b]

[a] Includes 55 oil wells.
[b] 90% confidence interval.

The estimate of total gathering miles per non-associated gas well was derived as the weighted average total miles divided by total wells (0.67 ± 28%). The average mile per well ratio was extrapolated by the nationally tracked number of non-associated gas wells (276,000).[11] The resulting estimate of national gathering pipeline miles associated with gas wells is 184,000.

For the gathering pipeline mileage associated with oil wells that market gas, the same ratio of gathering miles per well was applied. However, it was assumed that only half of the gathering pipeline mileage was attributed to the gas industry; the other half was attributed to the oil industry. Therefore, the average ratio of pipeline miles to oil wells marketing gas was estimated to be 0.33. This average ratio was extrapolated by the estimated number of oil wells marketing gas in the United States (209,000).[12] The resulting estimate of gathering pipeline mileage associated with oil wells that market gas is 70,000.

The third category of gathering pipeline owned by transmission companies is reported by the American Gas Association to be 86,200 miles.[11] Utility-owned pipelines were assumed to be included in the total production owned gathering pipeline miles and are not included in the transmission company owned gathering line mileage.

The resulting total national gathering pipeline mileage from gas wells, oil wells marketing gas, and transmission companies was estimated to be 340,200 miles. A rigorous determination of the 90% confidence interval gave an error less than ±4%, which was considered low based on the quality of the data used to generate the activity factor. Thus, a 90% confidence interval of ± 10% was assumed based on engineering judgement.

Equivalent Leaks

Based on the analysis resulting in a leak frequency of 0.18 leaks per mile for transmission-owned gathering lines employing a walking survey and 0.63 leaks per mile for production-owned gathering lines employing a vegetation survey, the activity factor can be calculated as follows:

$$[(86{,}200 \times 0.18)] \div [(340{,}200 - 86{,}200) \times 0.63] = 174{,}779 \text{ equivalent leaks/year}$$

The breakdown of total equivalent leaks by pipe material category is based on the breakdown of pipe mileage reported in the 1991 DOT RSPA[8] database for transmission-owned gathering lines. It was estimated that the breakdown of production-owned gathering line mileage into material categories is equivalent to the transmission-owned pipelines, with the exception of cast iron. It was assumed that no additional cast iron gathering lines are in service. (The cast iron gathering line mileage reported in the RSPA database for transmission-owned gathering lines accounts for the total in the United States.)

The total number of estimated gathering line leaks was allocated on a pipeline material category basis in the same proportion (adjusted for the fraction of mileage in each material category) as in the distribution sector. The 90% confidence interval of the estimated total leaks was calculated using a statistical program (@ RISK)[10] to be ± 76%. For cast iron gathering lines, the mileage is based on the RSPA database for transmission and gathering lines.[8] The 90% confidence interval of the cast iron mileage estimate is assumed to be ± 10%. Table 8-9 summarizes the estimated average activity factor and the 90% confidence interval for gathering pipeline.

TABLE 8-9. SUMMARY OF ACTIVITY FACTORS FOR GATHERING PIPELINES IN THE PRODUCTION SEGMENT

Pipe Material	Total Miles	Average Activity Factor, (equivalent leaks)	90% Confidence Interval of Activity Factor,[a] (equivalent leaks)
Protected Steel	268,082	53,657	40,779
Unprotected Steel	41,400	114,655	87,138
Plastic	29,862	6,467	4,915
Cast Iron	856	856[b]	86[b]

[a] 90% confidence interval around the mean value (upper bound minus the mean).
[b] Miles.

9.0 RESULTS AND CONCLUSIONS

9.1 Distribution Underground Pipeline Emissions

The overall methane emission estimate for underground mains and services in the distribution sector extrapolated to a national average is presented in Table 9-1, which has been adjusted for soil oxidation of methane. As shown, the mean methane emission factors for each pipe use/material type category are combined with an estimate of the number of equivalent leaks (or miles of main for cast iron) in the nation to predict the total emissions. As shown in Table 9-1, the annual estimated methane emissions to the atmosphere from underground distribution mains and services in the U.S. natural gas industry is 41.6 Bscf, with an estimated 90% confidence interval of ± 27.1 Bscf (± 65%).

TABLE 9-1. SUMMARY OF METHANE EMISSIONS ESTIMATE FROM UNDERGROUND DISTRIBUTION PIPELINES[a]

Pipe Use	Pipe Material	Average Methane Emission Factor, (scf/leak-yr)	Average Activity Factor, (equivalent leaks)	Methane Emissions Estimate, (Bscf)	90% Confidence Interval of Emissions Estimate[b](Bscf)
Mains	Cast Iron	238,736[c]	55,288[d]	13.2	8.4
	Unprotected Steel	51,802	174,657	9.1	11.1
	Protected Steel	20,270	68,308	1.4	1.6
	Plastic	99,845	49,226	4.9	13.9
Services	Unprotected Steel	20,204	458,476	9.3	17.5
	Protected Steel	9,196	390,628	3.6	6.1
	Plastic	2,386	68,903	0.2	0.4
	Copper	7,684	7,720	0.1	0.1
Total				41.6	27.1

[a] Adjusted for soil oxidation of methane.
[b] 90% confidence interval around the mean value (upper bound minus the mean).
[c] Scf/mile-year.
[d] Miles.

As shown, the contribution to the total emissions from cast iron mains (over 30%) is higher than any other single category, even though the total mileage of cast iron mains represents the smallest material category. Unprotected steel services and mains represent the second and third largest contributor to emissions, respectively, at around 22% of the total emissions for each. All other categories combined represent only 25% of the total emissions. Therefore, even though the emission factor for plastic mains is relatively high, the overall contribution to total emissions is relatively small (around 12% of the total).

Table 9-2 presents the total estimate of methane leakage from distribution mains and services, which has not been adjusted for the soil oxidation of methane. (Note: The methane leakage rate has been adjusted for an average 93.4 volume percent methane in natural gas.) The total estimated methane leakage, 51.1 Bscf, is about 9.5 Bscf higher than the total annual methane emissions to the atmosphere. The major difference between the estimated methane leakage rate shown in Table 9-2 and the methane emissions rate shown in Table 9-1 is the soil oxidation of methane from leaks in cast iron mains. The methane leakage rate from cast iron mains is 22.1 Bscf, while the methane emissions rate is 13.2 Bscf. The reason that the emissions rate is significantly lower than the leakage rate is that cast iron mains have a lower leakage rate per individual leak than other pipe materials, which results in a higher soil oxidation rate.

9.2 Transmission Underground Pipeline Emissions

Table 9-3 summarizes the estimated methane emissions from transmission pipeline leaks in the U.S. natural gas industry. As shown, the annual methane emissions to the atmosphere are 0.16 Bscf with a 90% confidence interval of ± 0.14 Bscf (± 89%).

As shown in Table 9-3, the largest contributor to the overall emissions estimate from transmission underground pipelines is protected steel, representing about 67% of the total leakage. This is expected since the total mileage of transmission pipeline is made up of around 97% protected steel pipe, according to nationally tracked statistics.

TABLE 9-2. SUMMARY OF METHANE LEAKAGE ESTIMATE FROM UNDERGROUND DISTRIBUTION PIPELINES[a]

Pipe Use	Pipe Material	Average Methane Leakage Rate, (scf/leak-yr)	Average Activity Factor, (equivalent leaks)	Methane Leakage Estimate, (Bscf)	90% Confidence Interval of Leakage Estimate,[b] (Bscf)
Mains	Cast Iron	399,867[c]	55,288[d]	22.1	12.6
	Unprotected Steel	52,748	174,657	9.2	10.7
	Protected Steel	20,891	68,308	1.4	1.6
	Plastic	101,897	49,226	5.0	13.7
Services	Unprotected Steel	20,433	458,476	9.4	17.1
	Protected Steel	9,438	390,628	3.7	6.0
	Plastic	3,026	68,903	0.2	0.5
	Copper	7,684	7,720	0.1	0.1
Total				51.1	28.1

[a] Methane leakage rate not adjusted for soil oxidation. The leakage rate for methane has been adjusted for an average 93.4 volume percent methane in natural gas.
[b] 90% confidence interval around the mean value (upper bound minus the mean).
[c] Scf/mile-year.
[d] Miles.

TABLE 9-3. SUMMARY OF METHANE EMISSIONS ESTIMATE FROM UNDERGROUND TRANSMISSION PIPELINES[a]

Pipe Material	Average Emission Factor (scf/leak-yr)	Average Activity Factor (equivalent leaks)	Methane Emissions Estimate (Bscf)	90% Confidence Interval of Emissions Estimate[b] (Bscf)
Protected Steel	20,270	5,077	0.10	0.14
Unprotected Steel	51,802	659	0.03	0.05
Plastic	99,845	14	0.001	0.003
Cast Iron	238,736[c]	96[d]	0.02	0.02
Total			0.16	0.14

[a] Adjusted for soil oxidation of methane.
[b] 90% confidence interval and the mean value (upper bound minus the mean).
[c] Scf/mile-year.
[d] Miles.

9.3 Production Underground Pipeline Emissions

Table 9-4 summarizes the estimated methane emissions from gathering pipeline leaks in the production segment of the gas industry. As shown, the annual methane emissions to the atmosphere are 6.6 Bscf with a 90% confidence interval of ± 7.2 Bscf (± 108%).

TABLE 9-4. SUMMARY OF METHANE EMISSIONS ESTIMATE FROM UNDERGROUND PRODUCTION PIPELINES[a]

Pipe Material	Average Emission Factor, (scf/leak-yr)	Average Activity Factor, (equivalent leaks)	Methane Emissions Estimate, (Bscf)	90% Confidence Interval of Emissions Estimate,[b] (Bscf)
Protected Steel	17,102	53,657	0.9	1.2
Unprotected Steel	43,705	114,655	5.0	7.0
Plastic	84,237	6,467	0.6	1.2
Cast Iron	201,418[c]	856[d]	0.2	0.1
Total			6.6	7.2

[a] Adjusted for soil oxidation of methane.
[b] 90% confidence interval around the mean value (upper bound minus the mean).
[c] Scf/mile-year.
[d] Miles.

Although the majority of gathering pipeline was estimated to be protected steel (around 79% of the total mileage), the largest contributor to total emissions from gathering lines is unprotected steel pipelines. Not only is the total number of equivalent leaks from unprotected steel gathering lines greater than from protected steel lines, but the emission factor for unprotected steel gathering lines was estimated to be significantly higher than for protected steel lines.

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APPENDIX A

Results of Outlier Tests for Plastic Pipe Leakage Data

APPENDIX A

RESULTS OF OUTLIER TESTS FOR PLASTIC PIPE LEAKAGE DATA

Overview

The GRI gas data for plastic pipes were screened for potential outliers. The Grubbs test (Grubbs, 1969), the Dixon test (Grubbs, 1969), the Fourth-Spread test (Hoaglin et al., 1983), and a conservative approach (NSI, 1989) were used to identify potential outliers in the plastic pipe data. The Grubbs and Dixon tests require that the data being screened are normally distributed. The Fourth-Spread test does not strictly require normality, but it could produce spurious results if the data distribution were markedly asymmetric. The conservative approach addresses cases of normality and non-normality.

The largest value and the smallest value in the plastic pipe dataset were tested separately. Table A-1 lists the results of the four outlier tests for both the largest and smallest plastic pipe data values. The smallest value is identified as a potential outlier only in the Fourth-Spread test; all other tests indicate no outliers. However, the test criteria from both the Grubbs and Dixon tests suggest that the smallest value is closer to being a potential outlier than the largest value.

Data

The plastic pipe flow rate data and the natural logarithms of these data, as well as the means and standard deviations, are shown in Table A-2. The data in Table A-2 are arranged so that the smallest value appears in the first row and the largest value appears in the last row of the table. Only six data points comprise the plastic pipe data and these six points span five orders of magnitude, ranging from 0.008 SCF/leak-hour to 61.000 SCF/leak-hour.

The Shapiro-Wilk W statistic, generated by the SAS UNIVARIATE (SAS, 1990) procedure, was used to determine whether the nontransformed and natural

TABLE A-1. RESULTS OF THE OUTLIER TESTS

Outlier Test	Data Value Tested (natural logarithm)	Criteria[a]	Result
Grubbs	Minimum: −4.8283 (ID 2014)	1.71<1.82	not an outlier
	Maximum: 4.1109 (ID 2002)	1.26<1.82	not an outlier
Dixon	Minimum: −4.8283 (ID 2014)	0.50<0.56	not an outlier
	Maximum: 4.1109 (ID 2002)	0.20<0.56	not an outlier
F-Spread	Minimum: −4.8283 (ID 2014)	outside bounds: −4.3850 to 6.3571	OUTLIER
	Maximum: 4.1109 (ID 2002)	inside bounds: −4.3850 to 6.3571	not an outlier
Conservative Approach	Minimum: −4.8283 (ID 2014)	inside bounds: −8.7334 to 9.3532	not an outlier
	Maximum: 4.1109 (ID 2002)	inside bounds: −8.7334 to 9.3532	not an outlier

[a] The criteria are based on the 5% significance level for the Grubbs and Dixon tests

TABLE A-2. PLASTIC PIPE FLOW RATE DATA AND NATURAL LOGARITHMS OF THE FLOW RATES

Test ID Number	Standard Flow Rate (SCF/leak-hour)	Natural Log of Standard Flow Rate
2014	0.008	−4.8283
3020	0.700	−0.3567
3019	1.130	0.1222
3039	1.620	0.4824
11002	10.266	2.3288
2002	61.000	4.1109
Mean	**12.454**	**0.309894**
Standard Deviation	**24.084**	**3.014434**

log-transformed plastic pipe data were normally distributed. For the nontransformed data, the W-statistic was 0.6068 and the associated p-value was 0.0001, indicating that the nontransformed data were not normally distributed. However, for the natural log-transformed data, the W-statistic was 0.9396 and the associated p-value was 0.6747, indicating that the natural log-transformed data were normally distributed, within random variability. Because of the small sample size (6), however, this test is not highly sensitive. Small or moderate deviations from normality might not be detected based on a hypothesis test with this sample size. Figure A-1 Shows the frequency histogram for the nontransformed data and Figure A-2 shows the frequency histogram for the natural log-transformed data to illustrate the results suggested by the W-statistics. The nontransformed data are obviously skewed and not normally distributed, while the natural log-transformed data are much more symmetric and appear to be closer to the normal distribution.

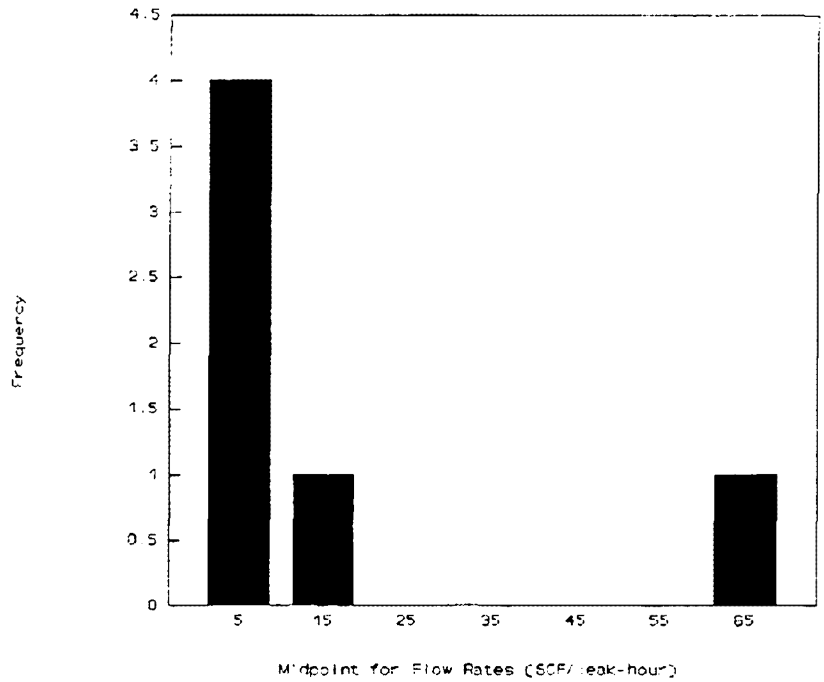

Figure A-1. Frequency Histogram for Plastic Pipe Flow Rate Data

Based on the results of the normal distribution tests, the natural logarithms of the plastic pipe flow rates were tested for outliers using the Grubbs, Dixon, and Fourth-Spread tests. Following is a discussion of outlier screening in general, followed by specific details pertaining to each of the outlier tests used in this analysis.

Outlier Screening

Outliers have been defined as observations that do "not conform to the pattern established by other observations" (Hunt et al., 1981) or as observations that appear "to deviate markedly from other members of the sample in which" they occur (Grubbs, 1969). Outliers may be caused by transcription, keypunch, or data-coding errors, instrument breakdowns, calibration problems, and power failures, or they may be manifestations of a greater amount of inherent spatial or temporal variability than expected (Gilbert, 1987).

Many different tests exist to screen for outliers, some of which have certain limitations that prevent them from being applied to all datasets. Some tests require that the data be distributed normally because statistical parameters are used in the outlier test, while other tests rely on other types of information from the data to perform the outlier test. Because of the variety and number of different outlier tests, it is therefore important that no datum be discarded solely on the basis of a single statistical test. There should always be some plausible explanation other than the test result that warrants the exclusion or the replacement of an outlier (Gilbert, 1987). If possible, several different types of tests should be applied to validate the results of the outlier screening process.

The four different tests applied to the GRI plastic pipe data represent some of the different types of outlier tests. The Grubbs test (Grubbs, 1969) relies on statistical parameters (mean and standard deviation), the Dixon test relies on ratios of values in the

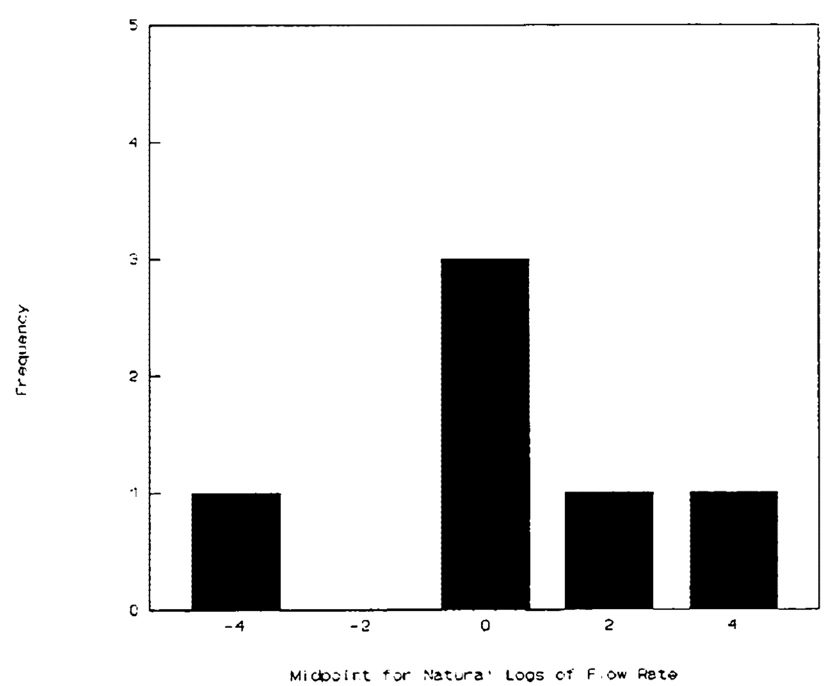

Figure A-2. Frequency Histogram for the Natural Logarithms of the Plastic Pipe Flow Rate Data

tails, the Fourth-Spread test relies on the spread of the central half of the data, and the conservative approach is capable of handling any data distribution. Following are specific details regarding how each of these tests were applied to the plastic pipe data.

Grubbs Test (Grubbs, 1969)

The hypothesis tested in the Grubbs test is that all observations in the sample come from the same normal population. Thus, transformation of skewed data, such as taking the natural logarithms, may be necessary. The data are ordered from smallest to largest for the Grubbs test, such that:

$$\{X_1 \leq X_2 \leq X_3 \leq \ldots \leq X_n\} \tag{1}$$

The Grubbs test is then applied to a single suspect value–either the largest value (X_n) or the smallest value (X_1). For the largest value (X_n), the test statistic (T_n) is calculated as follows:

$$T_n = \frac{X_n - \bar{X}}{s} \tag{2}$$

where:

X_n = the largest data value,

$\bar{X}$ = the arithmetic average of all n values, and

s = the sample standard deviation, with $n-1$ degrees of freedom.

For the smallest value (X_1), the test statistic (T_1) is calculated as follows:

$$T_1 = \frac{\bar{X} - X_1}{s} \tag{3}$$

where:

X_1 = the smallest data value, and

$\bar{X}$ and s = the same as for Equation (2).

The test statistic (T_1 or T_n) is compared to the appropriate critical value for the statistic. When the test statistic is larger than the critical value, then the suspect data point is deemed a potential outlier.

Using the mean and standard deviation shown in Table A-2 for the plastic pipe data, T_1=1.71 and T_n=1.26 for the natural logarithms of the flow rates. The critical value for a one-sided test using the 5% significance level for a sample size of six is 1.82, and the critical value using the recommended 1% significance level (Grubbs, 1969) is 1.94. Therefore, neither the largest nor the smallest of the natural logarithms of the plastic pipe flow rates were considered outliers by the Grubbs test.

Dixon Test (Grubbs, 1969)

The Dixon test is an alternative system that does not rely on the calculation of statistical parameters (e.g., the mean or standard deviation), and is based entirely on ratios of differences between some of the observations. As with the Grubbs test, the Dixon test requires a normal data distribution because the ratios of differences are calculated from both tails. One drawback to the Dixon test is that not all of the data are utilized–only data from the tails are used. Similarly to the Grubbs test, the data are ordered from smallest to largest for the Dixon test, as shown in Equation (1). The Dixon test is then applied to a single suspect value, either the largest or smallest of all of the data values. A test statistic (r_{xx}) that depends on sample size is calculated. The formula for the largest value (X_n) from a sample size of 6 (the plastic pipe data sample size) is:

$$r_{10} = \frac{X_n - X_{n-1}}{X_n - X_1} \tag{4}$$

where:

X_n = the largest data value,

X_{n-1} = the second largest data value, and

X_1 = the smallest data value.

The corresponding formula for the smallest value (X_1) from a sample size of 6 (the plastic pipe data sample size) is:

$$r_{10} = \frac{X_2 - X_1}{X_n - X_1} \tag{5}$$

where:

X_2 = the second smallest data value,

X_1 = the smallest data value, and

X_n = the largest data value.

The test statistic (r_{10}) is compared to the appropriate critical value for the statistic. When the test statistic is larger than the critical value, then the suspect data point is deemed a potential outlier.

Using the data shown in Table A-2 for the plastic pipe data, r_{10}=0.20 for the largest value and r_{10}=0.50 for the smallest value of the natural logarithms of the flow rates. The critical value for a one-sided test using the 5% significance level for a sample size of six is 0.560, and the critical value using the recommended 1% significance level (Grubbs, 1969) is 0.698. Therefore, neither the largest nor the smallest of the natural logarithms of the plastic pipe flow rates were considered outliers by the Dixon test.

Fourth-Spread Test (Hoaglin et al., 1983)

The Fourth-Spread (F-Spread) test does not rely on the calculation of the mean or standard deviation, rather it relies on information from the center half of the data mass to define the distance, beyond which, data points should be considered potential outliers. The center half of the distribution is relatively insensitive to outliers and, therefore, provides a reasonable basis for characterizing the distribution under the hypothesis that no outliers are present. As with the Grubbs and Dixon tests, the data must be arranged from smallest to largest, as shown in Equation (1). The data need not be normally distributed, but the distribution should be symmetric. First, the lower and upper fourths (also called the 25th and 75th percentiles, respectively) for the data distribution are calculated. The F-Spread (d_F) is then calculated by subtracting the lower-fourth (F_L) from the upper-fourth (F_U). Any data points larger than $F_U+(1.5\times d_F)$ and any data points smaller than $F_L-(1.5\times d_F)$ are then considered potential outliers. Figure A-3 shows the relationship between the fourths and cutoffs used to define outliers with the F-Spread method.

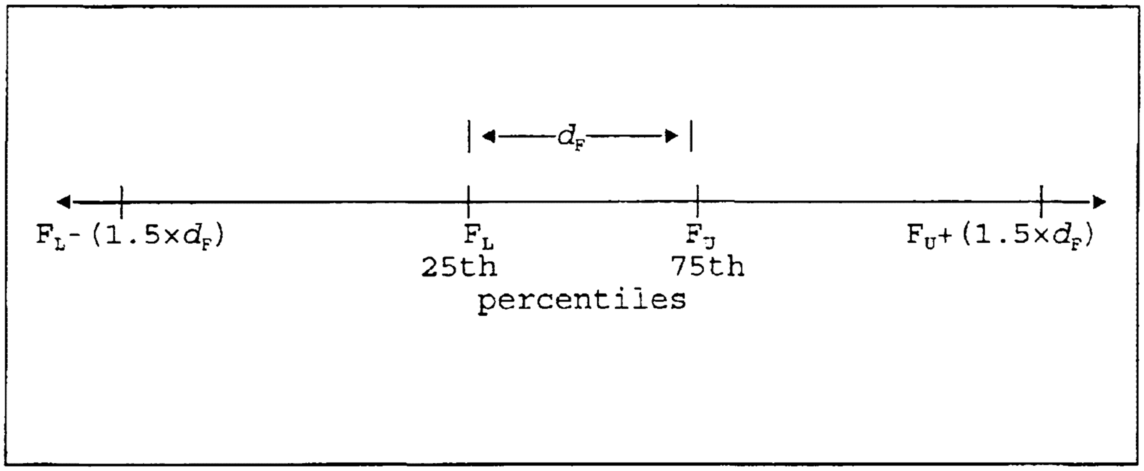

Figure A-3. Depiction of the Fourths (F_L and F_U), Fourth-Spread (d_F), and Boundaries (F_L-1.5$\times d_F$; F_U+1.5$\times d_F$) for the F-Spread Outlier Detection Method

The F-Spread for the plastic pipe flow rate data was 2.6855 (F_U=2.3288 and F_L=−0.3567). Thus, data values smaller than −4.3850 or larger than 6.3571 should be considered potential outliers. One of the six plastic pipe data points, the smallest (ID=2014, value=0.008 SCF/leak-hour, ln value=−4.8283), was therefore considered a potential outlier.

Conservative Approach (NSI, 1989)

This approach is conservative because it screens for only the most blatant outliers. Thus, data points that may be considered outliers in other methods, may not be considered outliers by this approach, unless they are separated by a rather large distance from the main data mass. The histogram for the nontransformed data and the histogram from the natural log-transform of the data are used as visual aids in this method. Some measure of the normality (e.g., the Shapiro-Wilk W-statistic) for the data distributions shown in the two histograms is also used in this method. The following four steps are applied in sequence until the conditions are met and the criteria are defined for identifying outliers:

(1) The untransformed data distribution is normal. Values more than 3 standard deviations from the mean (mean±3×standard deviation) are considered potential outliers.

(2) The natural log-transformed data distribution is normal. Values more than 3 standard deviations from the mean of the natural logarithms (mean±3×standard deviation) are considered potential outliers.

(3) The untransformed data distribution is visually symmetric, but not normal. Values more than 3 standard deviations from the mean (mean±3×standard deviation) are considered potential outliers.

(4) The untransformed data distribution is not normal and not visually symmetric. Values more than 6 standard deviations from the mean (mean±6×standard deviation) are considered potential outliers.

For the plastic pipe data, this method produced the following results for the first two steps (at which point the conditions were met and outlier criteria were established):

(1) The untransformed data distribution is not normal. Go to step 2.

(2) The natural log-transformed data distribution is normal. Therefore, values more than 3 standard deviations from the mean are considered potential outliers. Thus, using the mean and standard deviation shown in Table 2 for the natural logarithms of the flow rates, values more than 9.3532 or less than −8.7334 should be considered potential outliers. None of the data points met these criteria and therefore there were no outliers.

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APPENDIX B

Source Sheets for Underground Pipeline Leakage

D-2
DISTRIBUTION SEGMENT SOURCE SHEET

SOURCES: Main and Service Pipeline
OPERATING MODE: Normal Operations
EMISSION TYPE: Steady, Fugitives (Leakage)
ANNUAL EMISSIONS: 41.6 Bscf +/- 65%

BACKGROUND:
Distribution mains are the pipelines that serve as a common source of natural gas supply for more than one customer. Services are the branch connection lines from the mains to the customer meters. Leakage from the underground distribution network occurs from corrosion pits, joint and fitting failures, and pipe wall fractures. Gas distribution operators use leak detection procedures to locate and classify leaks. The leak is classified and prioritized for repair based on the concentration of gas detected and the proximity of the leak to existing structures.

EMISSION FACTOR: (scf/leak-year)

The value of the emission factor and standard deviation for each pipe material category is given below:

Material Category	Pipe Use	Number of Samples	Average Emission Factor[a]	Units of Emission Factor	90% Confidence Interval of Emission Factor
Cast Iron	Main	21	238,736	scf/mi-yr	152,059
Unprotected Steel	Main	20	51,802	scf/lk-yr	48,212
Protected Steel	Main	17	20,270	scf/lk-yr	17,243
Plastic	Main	6	99,845	scf/lk-yr	165,617
Unprotected Steel	Service	13	20,204	scf/lk-yr	21,129
Protected Steel	Service	24	9,196	scf/lk-yr	5,581
Plastic	Service	4	2,386	scf/lk-yr	3,412
Cooper	Service	5	7,684	scf/lk-yr	5,559

[a] Adjusted for the soil oxidation of methane.

A cooperative leak measurement program has been developed to measure a representative sample of underground leaks to estimate the average leak intensity, which is combined with company leak records to estimate leak frequency. Leak measurements were performed at five U.S. companies and two Canadian distribution companies in accordance with the testing protocol developed as part of the program. The test data were disaggregated by material type and mains versus services, based on a combination of statistical analyses and engineering judgement. A mean value of the estimated leak rate per leak was calculated using the test data, for all pipe materials except cast iron. In these tests, an individual leak was randomly selected for testing based on criteria outlined in the program plan. For cast iron, long segments of pipe were tested to measure the leak rate per mile rather than the leak rate per leak. Cast iron was tested in long segments since it tends to have a very high frequency of leaks (due to the joint spacing of 10 to 16 feet) and the relatively high occurrence of undetectable leaks in cast iron. The measured natural gas leak rates were adjusted for the average volume percent of methane in pipeline-quality gas (93.4 vol. %), and the soil oxidation rates of methane.

ACTIVITY FACTOR:

The mean activity factor and standard deviation for each pipe material category is given below:

Material Category	Pipe Use	Estimated Total Leak Repairs	Average Activity Factor (Equivalent Leaks)	Units of Activity Factor	90% Confidence Interval of Activity Factor
Cast Iron	Main	69,776	55,288	miles	2,764
Unprotected Steel	Main	81,627	174,657	equivalent leaks	101,685
Protected Steel	Main	31,924	68,308	equivalent leaks	42,545
Plastic	Main	23,006	49,226	equivalent leaks	58,018
Unprotected Steel	Service	214,271	458,476	equivalent leaks	499,850
Protected Steel	Service	182,562	390,628	equivalent leaks	526,354
Plastic	Service	32,202	68,903	equivalent leaks	66,840
Copper	Service	3,608	7,720	equivalent leaks	8,521

The national database of leak repairs was used to extrapolate data provided by individual companies. Data were requested from each company participating in the underground leak test program, based on their historical leak records. To allocate leak repairs into pipe material categories, data were collected from ten local distribution companies representing different regions within North America.

Data on the total number of annual leak repairs, leak indications, and outstanding leaks within the distribution system were provided by six companies. An estimate of the number of annual equivalent leaks for each of the six companies was developed based on the following methodology:

$$\text{Total Equivalent Leaks} = \text{Outstanding Leaks} + \text{New Leaks} - \text{Leak Repairs}$$

The total number of annual equivalent leaks represents the equivalent leaks which are leaking all year. (That is, for leaks with a leak duration of half year, these leaks are counted as half an equivalent annual leak.)

The total number of leaks in the system are quantified by incorporating the leak duration into the estimated equivalent leaks. For example, if a leak is only leaking half the year, it is counted as 0.5 equivalent leaks. The assumptions made in deriving the estimated number of equivalent leaks for each company include:

- Approximately 85 percent of leaks are found during a leak survey when an organic vapor analyzer (OVA) instrument is used along with bar holing.
- Leaks that are repaired during the year are leaking half of the year, on average.
- Outstanding leaks are leaking at the beginning of the year.
- The number of new leaks in the system is estimated based on the annual leak indications and the frequency of the leak survey.

The number of new leaks in a system that is surveyed every n years is calculated based on the following:

- For the first year in the cycle -- 1/n leaks are leaking half the year; (n-1)/n leaks are not yet leaking.
- For the second year in the cycle -- 1/n leaks are leaking the entire year; 1/n leaks are leaking half the year; and (n-2)/n leaks are not yet leaking.
- For the third year in the cycle -- 2/n leaks are leaking the entire year; 1/n leaks are leaking half the year; and (n-3)/n leaks are not yet leaking.
- For the fourth year in the cycle -- 3/n leaks are leaking the entire year; 1/n leaks are leaking half the year; and (n-4)/n leaks are not yet leaking.

Based on the data provided by each of the six companies, a ratio of the annual equivalent leaks to leak repairs was calculated. The average ratio (2.14) was multiplied by the estimated number of leak repairs in each pipe material category to extrapolate the national database of leak repairs to represent annual equivalent leaks. The precision of the estimate is based on the variability in the leak repair disaggregation provided by ten companies and the variability in the calculated ratio of annual equivalent leaks to leak repairs provided by six companies.

The activity factor for cast iron mains is the total estimated mileage of cast iron mains in the U.S., as reported by the U.S.DOT RSPA.[1] The standard deviation was assumed to be 5% of the estimated mileage, based on engineering judgement.

EMISSIONS ESTIMATE: (41.6 +/- 65 %)

The emissions estimate for each category of pipe material/use was dervied multiplying the respective emission factor (scf/leak-yr or scf/mile-yr) by the activity factor (total number of leaks or miles).

Material Category	Pipe Use	Average Emission Factor (scf/lk-yr)	Average Activity Factor (equivalent leaks)	Annual Emissions Estimate (Bscf)	90% Confidence Interval of Emission Estimate (Bscf)
Cast Iron	Main	238,736[a]	55,288[b]	13.2	8.4
Unprotected Steel	Main	51,802	174,657	9.1	11.1
Protected Steel	Main	20,270	68,308	1.4	1.6
Plastic	Main	99,845	49,226	4.9	13.9
Unprotected Steel	Service	20,204	458,476	9.3	17.5
Protected Steel	Service	9,196	390,628	3.6	6.1
Plastic	Service	2,386	68,903	0.2	0.4
Copper	Service	7,684	7,720	0.1	0.1
Total				41.6	27.1

[a]scf/mile-yr
[b]miles

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1. U.S. Department of Transportation. Research and Special Programs Administration. 1991.

T-3
TRANSMISSION SOURCE SHEET

SOURCES: Transmission Pipelines
OPERATING MODE: Normal Operations
EMISSION TYPE: Unsteady, Fugitives (Pipeline Leaks)
ANNUAL EMISSIONS: 0.16 Bscf +/- 89%

BACKGROUND:
Transmission pipelines are the inter- and intrastate high pressure underground pipelines that transport natural gas from the production/processing operations to the end user or distribution network. Leakage from underground transmission lines occurs from corrosion pits, joint and fitting failures, pipe wall fractures, and external damage.

EMISSION FACTOR: (scf/leak-year)

Leak survey practices for transmission lines are generally more stringent than for distribution mains. Transmission lines are required to be surveyed annually, and more frequently in populated areas. In addition, many transmission companies perform additional routine aerial surveys to monitor the transmission lines for leakage. Based on conversations with several transmission companies, any leaks found in the pipewall are extremely small and are repaired immediately for safety reasons. Based on the rigorous leak survey and repair practices of transmission companies (i.e., leaks are discovered and repaired earlier in transmission lines), the average leak rate from a transmission leak is believed to be of the same order of magnitude as a leak found in a distribution main, even though there may be a substantial difference in the operating pressure of the pipelines.

Therefore, the emission factors for leakage from transmission pipelines are based on the arithmetic average leakage rates for main pipelines from the cooperative underground distribution leakage measurement program. A mean value of the estimated leak rate per leak was calculated using the test data, for all pipe materials except cast iron. For cast iron mains, a segment test approach was used which quantifies the leakage rate for a long isolated segment of pipe; therefore, the mean leakage rate for cast iron is in terms of leakage per unit length of pipe. The natural gas leak rate is adjusted for methane by multiplying by the volume percent of methane for transmission (93.4 vol. %), and is adjusted for the soil oxidation of methane. The value of the emission factor and standard deviation for each pipe material category is given below:

Pipe Material	Number of Samples	Average Emission Factor	Units of Emission Factor	90% Confidence Interval of Emission Factor
Protected Steel	17	20,270	scf/leak-yr	17,243
Unprotected Steel	19	51,802	scf/leak-yr	48,212
Plastic	6	99,845	scf/leak-yr	165,617
Cast Iron	21	238,736	scf/mile-yr	152,059

Preliminary data from the underground distribution program indicate that the leakage rate is not a function of the pipeline pressure. Therefore, the leakage rates for transmission pipelines have not been adjusted based on the difference in average operating pressure of the transmission lines versus distribution lines.

EMISSION FACTOR DATA SOURCES:

1. Leakage rate data on a rate per leak basis for cathodically protected steel mains, unprotected steel mains, and plastic mains from the cooperative leak measurement program.
2. Leakage rate data on a rate per unit length basis for cast iron mains from the cooperative leak measurement program for distribution mains.
3. Assumes that the leak rates from transmission pipelines are identical to leak rates from distribution mains, based on the more rigorous leak survey and repair practices of transmission companies.
4. Assumes that the leak rates from underground pipelines are independent of pressure and pipe diameter, based on preliminary results from the underground distribution leak measurement program.

ACTIVITY FACTOR: (equivalent leaks)

The mean activity factor and precision for each pipe material category is given below:

Pipe Material	Total Miles	Average Activity Factor	Units of Activity Factor	90% Confidence Interval of Activity Factor
Protected Steel	287,155	5,077	equivalent leaks	3,859
Unprotected Steel	5,233	659	equivalent leaks	501
Plastic	2,621	14	equivalent leaks	11
Cast Iron	96	96	miles	10

The number of total leaks (excluding pipeline incidents) in transmission pipelines is based on the 1991 DOT RSPA database[1] for transmission pipelines, including both repaired leaks (6,120 leaks) and outstanding leaks (1,369 leaks). Because transmission lines are surveyed at least once per year using a walking survey method, the number of unreported leaks is estimated based on the effectiveness of the walking survey. According to one contract company specializing in distribution surveys, roughly 85 percent of the leaks are found using a walking survey. This estimated survey efficiency was applied to transmission surveys, resulting in roughly 1,320 unreported leaks.

The leak duration for outstanding leaks and unreported leaks is estimated to be 8,760 hours per year, and the leak duration for repaired leaks is half a year (4,380 hours/year), on average. The resulting estimate of equivalent leaks represents the number of leaks with a year round leak duration. (That is, each leak repair is counted as half an equivalent leak to compensate for the leak duration.) Therefore, the equation used to estimate equivalent leaks is:

$$0.5 \times (\text{repaired leaks}) + \{[(\text{repaired leaks} + \text{outstanding leaks})/0.85] - \text{repaired leaks}\}$$

The total number of estimated transmission pipeline leaks, 5,750, was allocated on a pipeline material category basis in the same proportion (adjusted for the fraction of mileage in each material category) as in the distribution sector. (That is, the ratio of percent leaks to percent miles in the transmission segment is the same as the ratio in the distribution segment.) The precision of the estimated total leaks was calculated based on the estimated 90% confidence interval associated with each parameter in the activity factor equation:

- repaired leaks; outstanding leaks: ± 100%

- leak duration: ± 25%
- leak survey effectiveness: ± 15%

A statistical software program (@RISK[2]) was used to determine the overall 90% confidence interval of the activity factor: ± 76%.

For cast iron transmission lines, the mileage is based on the 1991 DOT RSPA database for transmission and gathering lines. The precision of the estimate is assumed to be ± 10%.

ACTIVITY FACTOR DATA SOURCES:

1. 1991 DOT RSPA database[1] for transmission and gathering pipelines.
2. Total number of leaks is assumed equal to the total number of leak repairs plus the outstanding (unrepaired leaks) and unreported leaks.
3. Leak survey effectiveness estimation provided by Southern Cross Company.[3]
4. The allocation of estimated leaks per pipe material category is based on the leak frequency for underground distribution main pipelines, adjusted for the fraction of total mileage per pipe material category.
5. @RISK statistical software program[2] used to estimate the 90% confidence interval.

ANNUAL EMISSIONS: (0.16 Bscf ± 89%)

Pipe Material	**Average Emission Factor (scf/leak-yr)**	**Average Activity Factor (equivalent leaks)**	**Annual Emissions Estimate, (Bscf)**	**90% Confidence Interval of Emissions Estimate, (Bscf)**
Protected Steel	20,270	5,077	0.10	0.14
Unprotected Steel	51,802	659	0.03	0.05
Plastic	99,845	14	0.001	0.003
Cast Iron	238,736[a]	96[b]	0.02	0.02
Total			0.16	0.14

[a]scf/mile-yr
[b]miles

The total leakage was determined by multiplying an emission factor for each type of pipeline material by the estimated number of leaks in each respective pipe material category.

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1. U.S. Department of Transportation. Research and Special Programs Administration. 1991.

2. Palisade Corporation. *@ Risk, Risk Analysis and Simulation Add-in for Lotus 1-2-3, Version 1.5*, March 1989.

3. Southern Cross Corporation. *Comments on Docket PS-123 Notice 1, Leakage Surveys*, 49 CFR Part 192, Department of Transportation, Research and Special Programs Administration, Materials Transportation Bureau, Office of Pipeline Safety Regulations, December 19, 1991.

P-3
PRODUCTION SEGMENT SOURCE SHEET

SOURCES:	Gathering Pipelines
OPERATING MODE:	Normal Operations
EMISSION TYPE:	Steady, Fugitives (Pipeline Leaks)
ANNUAL EMISSIONS:	6.6 Bscf ± 108%

BACKGROUND:
Gathering field pipelines transport the gas from the production well to gas conditioning or processing facilities. Leakage from gathering pipelines occurs from corrosion, joint and fitting failures, pipe wall fractures, and external damage.

EMISSION FACTOR: (scf/leak-year)

The emission factors for leakage from gathering pipelines are based on the arithmetic average leakage rates for main pipelines from the cooperative underground distribution leakage measurement program. A mean value of the estimated leak rate per leak was calculated using the test data for all pipe materials except cast iron. For cast iron mains, a segment test approach was used which quantifies the leakage rate for a long isolated segment of pipe; therefore, the mean leakage rate for cast iron is in terms of leakage per unit length of pipe. The natural gas leak rate is adjusted for methane by multiplying by the volume percent of methane for production (78.8 vol. %), and is adjusted for the soil oxidation of methane. The value of the emission factor and standard deviation for each pipe material category is given below:

Pipe Material	Number of Samples	Average Emission Factor	Units of Emission Factor	90% Confidence Interval of Emission Factor
Protected Steel	17	17,102	scf/leak-yr	14,548
Unprotected Steel	20	43,705	scf/leak-yr	40,675
Plastic	6	84,237	scf/leak-yr	139,729
Cast Iron	21	201,418	scf/mile-yr	128,290

EMISSION FACTOR DATA SOURCES:

1. Leakage rate data on a rate per leak basis for cathodically protected steel mains, unprotected steel mains, and plastic mains from the cooperative leak measurement program.
2. Leakage rate data on a rate per unit length basis for cast iron mains from the cooperative leak measurement program for distribution mains.
3. Assumes that the leak rates from gathering lines are identical to leak rates from distribution mains.

ACTIVITY FACTOR:

The estimated number of leaks in field gathering pipelines is based on a leak repair frequency for gathering lines owned and operated by transmission companies reported in the 1991 DOT RSPA database.[1] This database reports an estimated 8,153 repaired leaks and 270 outstanding leaks in 31,918 miles of gathering pipeline. The leak frequency is derived by compensating for leaks that are repaired during the year and, therefore, not contributing to leakage year round. On average, the repaired leaks are assumed to be leaking for half the year, and each leak repair is counted as half an equivalent leak. Outstanding and unreported leaks are assumed to be leaking the entire year.

Most production lines owned and operated by production companies are not regulated by DOT and many are not monitored for leaks in the rigorous fashion employed by distribution and transmission companies. Therefore, unreported leaks are accounted for based on the effectiveness of the survey method performed, which is estimated to find 35% and 85% of the total leaks for a vegetation and walking survey, respectively, based on one contract company specializing in distribution surveys. It is estimated that production company owned gathering lines are only surveyed using a vegetation method. However, transmission company owned gathering lines are estimated to be surveyed annually using a walking method, based on conversations with several transmission companies.

Based on this analysis of equivalent leaks, the leak frequency is 0.18 leaks per mile for a walking survey and 0.63 leaks per mile for a vegetation survey. This leak frequency was used to ratio the number of leaks to the total estimated population of gathering pipeline.

Total gathering pipeline mileage is not reported or tracked nationally and must be estimated. The "gathering pipeline" designation includes three categories of pipeline: 1) production company owned gathering pipeline for gas wells not associated with oil production (i.e., non-associated gas wells); 2) production company owned gathering pipeline for oil wells that produce marketed gas (i.e., associated gas wells); and 3) transmission company owned gathering pipeline. The third category of utility-owned pipelines are assumed to be in addition to the production pipeline miles associated with wells. This is consistent with the site visit data since gathering lines owned by transmission companies were intentionally excluded from the site mileage totals. (The production companies did not report pipeline miles beyond their custody transfer meters.)

Total miles of gathering pipeline for non-associated gas wells were estimated using site visit data from the thirteen production sites shown in the following table. Seven of the thirteen sites provided estimates of their total miles of pipeline. The fifth site's mileage was estimated from a map of its pipelines.

Site	Gathering Miles	Number of Wells	Miles per Total Wells
Site 1	46.3	80	
Site 2	8	26	
Site 3	40	130	
Site 4	15.4	12	
Site 5	11	6	
Site 6	5.2	193[a]	
Site 7	600	1000	
Site 8	441.3	425	
Site 9	0.7	1	
Site 10	27.7	24	
Site 11	2.1	3	
Site 12	7.1	7	
Site 13	154.2	126	
TOTAL	1359.0	2033	0.67 +/- 28%

[a]Includes 55 oil wells.

The estimate of total gathering miles per non-associated gas well was derived as the weighted average total miles divided by total wells (0.67 ± 28%). The average mile per well ratio was extrapolated by the nationally tracked number of non-associated gas wells (276,000). The resulting estimate of national gathering pipeline miles associated with gas wells is 184,000.

For the gathering pipeline mileage associated with oil wells that market gas, the same ratio of gathering miles per well was applied. However, it was assumed that only half of the gathering pipeline mileage was attributed to the gas industry; the other half was attributed to the oil industry. Therefore, the average ratio of pipeline miles to oil wells marketing gas was estimated to be 0.33. This average ratio was extrapolated by the estimated number of oil wells marketing gas in the U.S. (209,000). The resulting estimate of gathering pipeline mileage associated with oil wells that market gas is 70,000.

The third category of gathering pipeline owned by transmission companies is reported by the American Gas Association (A.G.A.)[2] to be 86,200 miles. Utility-owned pipelines were assumed to be included in the total production owned gathering pipeline miles and are not included in the transmission company owned gathering line mileage.

The resulting total national gathering pipeline mileage from gas wells, oil wells marketing gas, and transmission companies was estimated to be 340,200 miles. A rigorous determination of the 90% confidence interval gave an error less that 4%, which was considered low based on the quality of the data used to generate the activity factor. Thus, a 90% confidence interval of ± 10% was assumed based on engineering judgement.

Based on the analysis resulting in a leak frequency of 0.18 leaks per mile for transmission-owned gathering lines employing a walking survey, and 0.63 leaks per mile for production-owned gathering lines employing a vegetation survey, the activity factor can be calculated as follows:

$[(86{,}200 \times 0.18)] + [(340{,}200 - 86{,}200) \times 0.63] = 174{,}779$ equivalent leaks/year

The breakdown of total equivalent leaks by pipe material category is based on the breakdown of pipe mileage reported in the 1991 DOT RSPA database[1] for transmission-owned gathering lines. It was estimated that production-owned gathering line mileage is equivalent to the transmission-owned pipelines, with the exception of cast iron. It was assumed that no additional cast iron gathering lines are in service. (That is, the cast iron gathering line mileage reported in the RSPA database accounts for the total in the United States.)

The total number of estimated gathering line leaks was allocated on a pipeline material category basis in the same proportion (adjusted for the fraction of mileage in each material category) as in the distribution sector. The precision of the estimated total leaks was calculated based on the estimated 90% confidence interval associated with each parameter in the activity factor equation:

- repaired leaks; outstanding leaks: ± 100%
- leak duration: ± 25%
- leak survey effectiveness: ± 15%

A statistical software program (@ RISK[3]) was used to determine the overall 90% confidence interval of the activity factor: ± 76%.

For cast iron gathering lines, the mileage is based on the 1991 DOT RSPA database for transmission and gathering lines. The precision of the cast iron mileage estimate is assumed to be ± 10%. The following table summarizes the estimated average activity factor and the precision:

Pipe Material	Total Miles	Average Activity Factor	Units of Activity Factor	90% Confidence Interval of Activity Factor
Protected Steel	268,082	53,657	equivalent leaks	40,779
Unprotected Steel	41,400	114,655	equivalent leaks	87,138
Plastic	29,862	6,467	equivalent leaks	4,915
Cast Iron	856	856	miles	86

ACTIVITY FACTOR DATA SOURCES:

1. Leak repair frequency from (DOT RSPA[1]) gathering line data.
2. Leak survey effectiveness provided by Southern Cross Company.[4]
3. The gathering miles for gas and oil wells marketing gas was estimated using Phase 3 site visit data for seven production companies. The number of gas and oil wells for these companies was also used to extrapolate out to the national estimate.
4. The number of producing gas wells in the United States was taken from A.G.A. *Gas Facts*[2] for 1992.
5. The number of oil wells producing marketed gas in the United States was estimated by Radian.[5] See activity factor section and sheet P-2.

6. The field and gathering miles owned by transmission companies was taken from A.G.A. *Gas Facts*[2] for 1992.

ANNUAL EMISSIONS: (6.6 Bscf ± 108%)

The activity factor was multiplied by the emission factor to derive this total leakage rate. The 90% confidence intervals were propagated through this multiplication.

Pipe Material	Average Emission Factor (scf/leak-yr)	Average Activity Factor (equivalent leaks)	Annual Emissions Estimate, (Bscf)	90% Confidence Interval of Leakage Estimate (Bscf)
Protected Steel	17,102	53,657	0.9	1.2
Unprotected Steel	43,705	114,655	5.0	7.0
Plastic	84,237	6,467	0.6	1.2
Cast Iron	201,418[a]	856[b]	0.2	0.1
Total			6.6	7.2

[a]scf/mile-yr.
[b]miles.

REFERENCES

1. U.S. Department of Transportation, Research and Special Programs Administration. 1991.

2. American Gas Association, *Gas Facts*, 1992.

3. Palisade Corporation. *@ Risk, Risk Analysis and Simulation Add-In for Lotus 1-2-3, Version 1.5,* March 1989.

4. Southern Cross Corporation. *Comments on Docket PS-123, Notice 1, Leakage Surveys*, 49 CFR Part 192, Department of Transportation, Research and Special Programs Administration, Materials Transportation Bureau, Office of Pipeline Safety Regulations, December 19, 1991.

5. Stapper, B.E. *Methane Emissions from the Natural Gas Industry, Volume 5, Activity Factors*, Final Report, GRI-94/0257.22 and EPA-600/R-96-080e. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.