Interstate Natural Gas Association of America

June 09, 2009

U.S. Environmental Protection Agency
EPA Docket Center (EPA/DC)
Mailcode 6102T
Attention: Docket ID No. EPA-HQ-OAR-2008-0508
1200 Pennsylvania Avenue, NW
Washington, D.C. 20460

Re: **Comments Regarding the Proposed Rule, Mandatory Reporting of Greenhouse Gases (Proposed Rule) dated April 10, 2009 (74 FR 16448)**

Dear Docket Clerk:

The Interstate Natural Gas Association of America (INGAA), a trade association of the interstate natural gas pipeline industry, respectfully submits these comments regarding the Proposed Rule, Mandatory Reporting of Greenhouse Gases (Proposed Rule) dated April 10, 2009 (74 FR 16448). The Proposed Rule addresses greenhouse gas (GHG) stationary source requirements in Title 40, Part 98 of the Code of Federal Regulations (40 CFR 98).

INGAA member companies transport more than 90 percent of the nation's natural gas, through some 200,000 miles of interstate natural gas pipelines. INGAA member companies operate over 6,000 stationary natural gas-fired spark ignition internal combustion (IC) engines and 1,000 stationary natural gas-fired combustion turbines, which are installed at compressor stations along the pipelines to transport natural gas to residential, commercial, industrial and electric utility customers. Many of the compressor stations would be affected by the Proposed Rule, including requirements in 40 CFR 98, Subpart C and Subpart W. INGAA member companies have taken a proactive role on GHG emissions, including supporting the development of the INGAA document, *Greenhouse Gas Emission Estimation Guidelines for Natural Gas Transmission and Storage.*. The INGAA GHG Guidelines present emission estimation approaches for natural gas transmission and storage systems. INGAA has also completed a cooperative effort with other natural gas trade associations to review currently available GHG emission factors, and continues to pursue projects to improve GHG emission factors and estimation methods for natural gas systems.

As discussed in detail below, INGAA has many concerns with the proposed Subpart W, including that the proposed Subpart W direct measurement program will be impossible to implement as written, and will result in neither accurate nor reliable fugitive emissions data. For these reasons, INGAA is proposing an alternative procedure and method under which entities subject to Subpart W, including natural gas transmission companies, would measure or estimate fugitive emissions.

INGAA appreciates your consideration of these comments, prompt attention to this submission and looks forward to your response. Please contact me at 202-216-5935 or lbeal@ingaa.org if you have any questions. Thank you.

Sincerely,

Lisa S Beal

Lisa Beal
Director, Environment and Construction Policy
Interstate Natural Gas Association of America

Attachment: INGAA Comments RE: Docket No. EPA-HQ-OAR-2008-0508, Mandatory Reporting of Greenhouse Gases (Proposed Rule) dated April 10, 2009 (74 FR 16448)

Cc by email: Bill Irving, US EPA
Dina Kruger, US EPA
Roger Fernandez, US EPA
Lisa Hanle, US EPA
Suzie Waltzer, US EPA
Suzie Kocchi, US EPA
Barbora Jemelkova, US EPA

COMMENTS ON THE PROPOSED RULE
FOR MANDATORY REPORTING OF GREEENHOUSE GASES

Proposed Addition to Code of Federal Regulations Title 40, Part 98

74 Federal Register 16447, April 10, 2009

Submitted by:
Interstate Natural Gas Association of America (INGAA)
10 G Street, N.E., Suite 700
Washington, D.C. 20002

Submitted to:
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1200 Pennsylvania Avenue, NW
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EXECUTIVE SUMMARY

INGAA's members share EPA's desire to collect accurate, reliable and reasonably complete data on greenhouse gas (GHG) emissions. In fact, INGAA's members have worked with EPA to develop improved tools for collecting emissions data. INGAA's members also understand EPA's desire to improve the quality of data on fugitive emissions of methane at compressor stations along natural gas pipelines. Nevertheless, and with all due respect, the direct measurement program detailed in proposed Subpart W will provide inferior data, and will do so at the inordinate cost of directly measuring emissions from thousands of individual components at every compressor station.

INGAA has developed an alternative approach that combines state-of-the-art operations information with recognized statistical sampling techniques to produce superior data at a fraction of the cost. Within each source category covered by Subpart W, the alternative approach focuses on the components known to generate the bulk of fugitive emissions. These components are examined at a statistically derived sample of sources to develop company-specific emission factors that, in turn, are used to calculate reported fugitive emissions.

INGAA's alternative is technically sound, generates superior data and requires a fraction of the time and expense that would be required under the direct measurement proposal. **Adoption of INGAA's alternative is imperative.**

INGAA supports a number of key provisions of the proposed rule, particularly: (1) setting the reporting threshold at 25,000 metric tons of CO_2e per year; (2) excluding natural gas pipeline segments from Subpart W; (3) using facility-based reporting; (4) assigning to local distribution companies the burden for reporting emissions from natural gas consumption; (5) permitting self-certification; (6) allocating reporting requirements on both downstream and upstream sources; (7) determining that sources do not have to report their electricity purchases; (8) basing reports on actual emissions, even if estimated, as opposed to potential emissions; and, (9) refraining from delegating data collection and enforcement authority to individual states.

INGAA urges EPA to defer implementation of this rule for one year, with data collection beginning January 1, 2011, and the first set of reports due in 2012. An extension is particularly appropriate for the natural gas transmission industry, which is being asked to adopt a wide array of procedures that have never been in place before. On a related note, reporting should be deferred until EPA and the affected public can develop and deploy a standard electronic reporting protocol. The deadline for filing annual emissions reports should be June 30th, not March 31st, in recognition of the significant number of environmental reports that are already due each March 31st.

INGAA opposes the "once in always in" reporting requirement. Facilities that fall below the reporting threshold for three straight years should be relieved from further reporting.

At present, the only way to be certain that a Subpart W facility is not subject to emissions measurement and reporting is conduct emissions measurement. EPA needs to adopt a *de minimis* rule to address this problem.

While adopting INGAA's alternative approach to calculating fugitive emissions will address many issues with Subpart W, a few items remain:

- ✦ The monitoring and measurement requirements in Proposed Section §98.234 cannot be implemented as proposed due to limitations or unnecessary restrictions in the procedures and the inability of the commercial market to meet demand.
- ✦ In several respects Proposed Section §98.234 is subjective or ambiguous, which is not consistent with regulatory measurement standards.
- ✦ Proposed Section §98.234 is overly restrictive and will likely stifle innovation.
- ✦ Proposed Section §98.234 relies on implied standards or qualifications that do not currently exist.
- ✦ Differences between vented sources and fugitive leaks need to be clarified.
- ✦ Reasonable missing data procedures should be allowed for Subpart W measurement and monitoring.
- ✦ Measurement should be based on a minimum leak threshold and not required for all leaks detected.
- ✦ Mass balance calculations are appropriate for vented emission sources.
- ✦ The list of 24 source types includes replication and overlap of sources. INGAA's alternative addresses this issue, but if the INGAA approach is not implemented EPA should clearly indicate that source classification within these categories is not a basis for defining a reporting error or compliance issue.
- ✦ Proposed Section §98.233(b) should be amended to include tanks as a source type where engineering estimation methods are allowed and references to direct measurement from tanks should be deleted. The use of engineering models for determining tank emissions is consistent with current practice and should be included in the rule.

INGAA also offers the following comments on Subpart C, concerning GHG emissions from combustion sources:

- ✦ INGAA supports the tiered approach for reporting combustion CO_2 emissions. A minor clarification on Tier 4 requirements is requested.
- ✦ INGAA supports aggregation for reporting combustion emissions.
- ✦ For clarity, §98.336 should identify the horsepower (hp) equivalent to 250 MMBtu/hr and INGAA recommends 30,000 hp.
- ✦ Proposed Section §98.234 relies on implied standards or qualifications that do not currently exist.
- ✦ For Tiers 1 and 2, EPA should clarify that fuel use estimates consistent with other Clean Air Act reporting approaches are acceptable.
- ✦ The natural gas transmission industry is expert in fuel measurement, and operator defined QA/QC procedures should be accepted.

- INGAA recommends including additional fuel rate measurement methods and adding a streamlined approach for accepting additional methods.
- In addition to the generic default emission factors for CH_4 and N_2O, operator-defined emission factors for CH_4 and N_2O should be allowed as long as the factors are technically defensible.
- Proposed Section §98.30(b) should be amended to remove the reference to "permitted" because some emergency engines are not permitted depending upon state program requirements.
- Subpart C should include a *de minimis* threshold for combustion sources so that reporting of small units with insignificant emissions is not required. INGAA recommends a *de minimis* threshold of 10 MMBtu/hr.
- When monthly HHV measurement is required, annual reporting should be based on the 12 month average HHV for homogeneous fuels such as natural gas with limited month-to-month variability.
- In §98.36(d)(2), the schedule for operator response to a request for additional information should be revised from 7 days to at least 2 weeks.

Consistent with its past work with EPA on GHG issues, INGAA prefers to address the proposed rule through constructive engagement on the merits of specific proposals. Nevertheless, INGAA would be remiss if it did not point out that the proposed rule may well exceed EPA's authority under the Clean Air Act and the Consolidated Appropriations Act. By commenting on the substance of the Proposed Rule, INGAA neither expressly nor implicitly waives its right to pursue this legal issue on judicial review.

I. INTRODUCTION

A. The Role Of Natural Gas In Meeting The Nation's Environmental And Energy Security Future.

As the U.S. economy moves to reduce GHG emissions, natural gas will continue to have an important role to play. The role of natural gas in balancing energy demand, increasing energy security, and meeting environmental goals, may be a long one — lasting several decades — because natural gas is the cleanest burning fossil fuel. Natural gas is already recognized as a clean source of fuel for generating electricity and has in fact been the fuel of choice for the vast majority of new electrical generating capacity built in the U.S. over the last ten years. Also, natural gas is a vital, value-added feedstock in chemical manufacturing and many other industries, and it is an extremely efficient and cost effective fuel for home heating, water heating, stovetops and other direct uses.

The carbon content of natural gas (measured in CO_2 emissions per unit of energy) is 44 percent less than the carbon content of coal. Moreover, because of the relative efficiency of currently deployed gas combustion technologies, the carbon advantages of natural gas are even greater when considering CO_2 emissions per unit of electricity output. Simply put, electricity produced from natural gas generates less than half the GHG emissions compared to coal.

A well-balanced energy portfolio is needed to meet the nation's energy requirements, employing all fossil fuels, renewable sources, nuclear and hydro facilities. The deployment of new nuclear generating stations and clean coal technologies (*e.g.*, Integrated Gasification Combined Cycle units and carbon sequestration) will take years to achieve significant market penetration and, during this transition period, natural gas-fired power plants will be one of the few low-emissions alternatives for generating the electricity needed to keep pace with increasing demand (as well as the capacity needs that may result from the retirement of less efficient and higher emitting older generators) And, while solar- and wind-fueled electricity technology must play an increasing role in meeting our nation's energy needs, these technologies still continue to depend on natural gas-fired generation to compensate for their intermittent availability.

Any federal climate policy is inextricably linked to national energy policy and energy security. Therefore, policies must be optimized to ensure real energy demand and energy security concerns are addressed, while mitigating potential risks from climate change. Hence, GHG regulation must be crafted with an eye toward the effect on the nation's energy and economic security. Indeed, the Department of Energy expressed particular concern that regulation of GHGs under the CAA could have significant adverse effects on U.S. energy supplies, reliability, and security.[1]

[1] See ANPR, 73 Fed. Reg. 44368 ("While the Department has general concerns about the portrayal of likely effects of proposals to regulate GHGs under the CAA on all sectors of the U.S. economy, DOE is particularly concerned about the effects of such regulation on the energy sector. The effects of broad based, economy-wide regulation of GHGs under the CAA would have significant adverse effects on U.S. energy supplies, energy reliability, and energy security.") (Department of Energy preliminary comments)

B. INGAA Members Have Demonstrated A Strong Commitment To GHG Issues Through Voluntary Participation In The EPA Natural Gas Star Program. INGAA Members Have Consistently Worked To Improve Estimates Of GHG Emissions Estimations And Reduce Fugitive Emissions.

INGAA and its members have worked closely with EPA and other natural gas sector trade associations to prioritize and develop GHG emissions estimation methodologies and improve current emission factors. INGAA has developed the document, *Greenhouse Gas Emission Estimation Guidelines for Natural Gas Transmission and Storage* and other resources are available to provide estimates from other natural gas industry sectors, including the American Petroleum Institute (API) *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry* (API Compendium), GRI-GHGCalc™ software, and commercial consulting services or software. In addition, INGAA members have demonstrated a strong commitment to GHG emission reductions through voluntary participation in the EPA Natural Gas STAR program and other industry efforts[2]. In fact, fugitive emissions of CH_4 and CO_2 from natural gas systems have decreased 20 percent from 1995 to 2007[3] even as interstate deliveries of natural gas have increased 10 percent during the same time period[4].

Concerns with fugitive methane emission estimate uncertainty in the STAR program apparently resulted in proposed Subpart W requirements that would significantly burden the natural gas transmission sector. These concerns have been acknowledged by EPA as INGAA worked with the agency on solutions.

As proposed, the Subpart W direct measurement program will not result in the most accurate or reliable fugitive emission data from natural gas transmission facilities. Mandating a direct measurement program only makes sense if it will result in high quality data. International studies of fugitive emissions in the transmission and distribution sector[5], and internal company data have shown that the leak rate distribution for most component categories is highly skewed and the uncertainty associated with fugitive emission factors is not necessarily reduced by collecting more direct measurement data. These large datasets have demonstrated that greater sample sizes actually increase uncertainty limits as the full emission rate profiles are better delineated. Furthermore, as explained in more detail in section III of these comments, the EPA proposal of a one-time "spot" check, will not provide an accurate characterization of fugitive emissions from compressor stations and thus, would result in significantly lower quality information than engineering estimations. It is well understood that fugitive GHG emissions in natural

[2] Best management Practices: Management of Fugitive Emissions at Natural Gas Transmission and Distribution Facilities. Prepared by Clearstone Engineering Ltd. for Canadian Energy Partnership for Environmental Innovation (CEPEI), May 18, 2009 (Attachment A).

[3] Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2007, EPA 430-R-09-004, (April 2009)

[4] Energy Information Administration, Annual U.S. Natural Gas Interstate Deliveries, http://tonto.eia.doe.gov/dnav/ng/hist/na1250_nus_2a.htm (May 2009)

[5] Technical Report: Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry. Prepared by Clearstone Engineering Ltd. for Canadian Energy Partnership for Environmental Innovation (CEPEI), April 16, 2007 (Attachment B).

gas transmission systems predominately result from system components such as compressor seals, and valve packings. As proposed, the emission sources and activity data basis for fugitive emissions are based upon primary equipment that includes subcomponents, such as:

- Piping and associated components,
- Compressors,
- Storage well components, and
- Organic liquids storage tanks.

A typical compressor station may consist of thousands of individual components. Direct measurement of each and every one of these components is impractical and again, does not provide reasonable assurance of an accurate estimate of the actual emissions. We do not believe that EPA has proposed an accurate or practical program. In the comments that follow, we suggest an alternative program that we believe will provide a significantly more accurate level of information.

II. GENERAL COMMENTS

A. INGAA Supports Key General Features Of The Reporting Rule.

Although INGAA has significant concerns about many aspects of Subparts W and C of the Proposed Rule, INGAA supports many general features of the Proposed Rule. Particular aspects which should be preserved if and when the Rule is finalized include:

1. Threshold For Reporting.

The general emission threshold of 25,000 metric tons CO_2e per year that triggers reporting obligations achieves an appropriate balance between the scope of the Proposed Rule and its administrative cost. As EPA recognizes in the Preamble,[6] a lower threshold would dramatically increase the burdens of the proposed requirements, while adding little to the understanding of national GHG emission patterns. However, as discussed in section III-A of our comments, INGAA does not support the proposed method for determining whether natural gas facilities exceed the reporting threshold.

2. Definition Of Natural Gas Facilities.

INGAA strongly supports EPA's decision to exclude pipeline segments from the definition of the source category in the proposed Subpart W.[7] EPA's Technical Support Document for the Petroleum and Natural Gas Industry correctly notes that pipeline segments cannot be characterized as coherent "facilities" and would present severe monitoring problems, since they extend over thousands of miles.[8]

6 *Id*. 16448.

7 Proposed 40 C.F.R. § 98.230.

8 Background TSD, Fugitive Emissions Reporting from the Petroleum and Natural Gas Industry at 20 (2009).

3. Facility-Based Reporting.

For the reasons EPA identifies in the Preamble, INGAA agrees that facility-based reporting is more straightforward, useful and feasible than corporate-level reporting of GHG emissions. INGAA notes that facilities that have mixed uses or contain multiple types of source categories may be difficult to disaggregate for purposes of facility-level reporting. For example, there may be no obvious boundary between a transmission compressor and an underground natural gas storage facility located on the same site. In order to facilitate reporting, EPA should permit aggregation of emissions data for diverse source types located at the same facility.

However, Subpart W of the proposed rules should be revised to clarify that a compressor station that compresses gas into one or more underground natural gas storage fields does not include within the same "facility" either (i) the attached pipelines located beyond the fenceline of the storage compressor station, or (ii) any storage well connected to those pipelines unless the storage well happens to be located within the fenceline of the storage compressor station.

4. Reporting For Natural Gas Suppliers.

INGAA agrees that natural gas "upstream emissions," that is, emissions resulting from natural gas consumption, should be reported by local distribution companies.[9] EPA correctly concluded, it would not be appropriate to place this reporting burden on interstate pipelines networks because their systems are too interconnected and complex.[10]

5. Self-Certification Of Emissions.

EPA correctly decided to propose self-certification of emissions reports with EPA verification, rather than third-party verification. This system has served EPA well in the context of the Acid Rain Program and other emissions reporting programs. Self-certification would also minimize the risk of inconsistency and conflicts of interest in the verification process.

6. Proposed Reporting Structure.

INGAA supports the reporting obligations in the Proposed Rule over the alternative structure suggested by EPA,[11] in which "double reporting" would be eliminated in favor of a combination of upstream fossil fuel reporting and limited downstream emissions reporting. For the reasons discussed in the preamble of the proposed rule, INGAA believes that the proposed reporting structure, which imposes reporting requirements on both downstream and upstream sources, more fairly distributes the regulatory

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9 See generally, Proposed Rule, 74 Fed. Reg. at 16720-21 (Proposed Subpart NN).

10 Id., 74 Fed. Reg. at 16576. INGAA intentionally limited its remarks to support this portion of the Proposed Rule as written, and refrained from addressing broader issues concerning the value and utility of reporting upstream emissions in general. Accordingly, INGAA respectfully reserves the right to comment further should reporting responsibility for these emissions be reassigned.

11 74 Fed. Reg. 16466.

burden than the alternative approach. In addition, as EPA states in the preamble, the proposed approach may provide information about the GHG emissions sources and data accuracy that may be valuable to EPA in formulating GHG policy in the future.

7. Indirect Emissions.

INGAA agrees that parties should not have to report their electricity purchases. With very few exceptions, facility owners and operators do not know where their electricity is sourced, let alone what indirect emissions are associated with their electricity supply.[12] The emissions associated with power production are captured at the generating stations, as they should be, and no constructive purpose is served by double counting these emissions with data of, at best, questionable value.

8. Reporting Of Actual, Not Potential Emissions.

EPA correctly determined that parties should report actual emissions, even if estimated, as opposed to potential emissions. A reporting system based on potential-to-emit would dramatically overstate GHG emissions, and provide misleading information to EPA, Congress and others who may rely on this data concerning the most significant sources of emissions and important trends in emission patterns.

9. Non-Delegation Of Authority To Collect Data And Otherwise Enforce The Reporting Regulations.

Section 114 of the CAA grants EPA discretion to delegate the implementation and enforcement of the proposed regulations, including data collection, to the states.[13] EPA elected not to exercise that discretion, and INGAA supports EPA's decision.

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As noted in the preamble, "The intent of this proposed rule is to collect accurate and consistent GHG data that can be used to inform future decisions."[14] Delegation risks creating an implementation and enforcement patchwork, with the states' varying interpretations undermining the internal consistency and quality of the data. Delegation also poses particular concern for interstate natural gas pipelines, since individual states might impose inconsistent, even conflicting, operating requirements on our integrated multi-state transportation systems.

B. Responses to Questions Posed within the NOPR.

1. EPA Should Defer Implementation Of The Rule For One Year.

EPA's proposal to begin monitoring GHG emissions on January 1, 2010 and require the first annual report to be submitted by March 31, 2011 would pose severe and likely impossible logistical

[12] The lone exceptions are facilities that are directly connected to power plants. Even in cases where an owner or operator purchases from a "green power" provider, if service is delivered via an integrated network the electrons entering the facility are delivered by displacement and their source cannot be determined.

[13] 42 U.S.C. § 7414(b)(1); *see generally*, NOPR, 74 Fed. Reg. at 16594-95.

[14] NOPR, 74 Fed. Reg. at 16461.

problems for the natural gas transmission industry. Unlike other industry sectors, such as electricity-generating facilities, the natural gas transmission industry is being required to monitor and measure GHG emissions by implementing new procedures that have not been previously required by other applicable Subparts of the Clean Air Act. Moreover, the Proposed Rule does not provide simplified methods through which fugitive GHG emissions can be calculated from readily available data. As a result, almost every aspect of the human and physical infrastructure needed for the natural gas transmission industry to implement the Proposed Rule remains undeveloped as of mid-2009. Most of our members lack the necessary equipment to carry out leak detection and measurement on the scale required; trained personnel to operate that equipment; data management systems to collect, archive, interpret and transmit emissions information; or quality control procedures to ensure the integrity and completeness of emissions information. Contractors competent to perform the necessary detection and measurements are also in short supply, and likely to remain so for at least one to two years.[15] The time required to properly train contractors and personnel cannot be overlooked, especially since some of EPA's proposed measurement methods – such as the use of high-volume samplers – can only be mastered through experience.

In light of these logistical challenges, INGAA supports the full postponement of the rule for a year, as suggested by EPA.[16] Alternatively, INGAA requests EPA postpone the Subpart W effective date by one full year as those requirements have disproportionately high compliance challenges. A one-year deferral of the Proposed Rule would provide the natural gas transmission industry with additional time to develop the required systems to monitor GHG emissions. Finally, EPA's alternative "best available data" approach[17] would also be preferable to the proposed timetable for commencing monitoring.

15 EPA has estimated there are approximately 1,944 gas transmission facilities in the U.S, all of which would have to undergo fugitive emissions measurement in order to determine the applicability of the proposed Subpart W. NOPR, 74 Fed. Reg. at 16532 (Table W-2). The number of individual components within each facility that would require monitoring under Subpart W can be conservatively estimated at approximately 2,000. Because a well-seasoned crew can monitor two facilities of that size per week, at least 972 crew-weeks would be required in order to monitor all of these facilities once (this figure would be higher if re-measurement is required to remedy missing data). INGAA estimates that for the 2010 monitoring year, approximately thirty to fifty crews would be required to carry out the methods prescribed in subpart W assuming that data reduction, reporting and other administrative duties will reduce field time to half of the available year. However, there are limited experienced corporate or contractors with sufficient knowledge in North America to carry out provisions related to monitoring and reporting.

16 NOPR, 74 Fed. Reg. at 16471.

17 Compared with the proposed implementation schedule, even the "best available data" alternative, id., would be preferable. However, this approach would yield uncertain and inconsistent data for gas transmission facilities, because there is considerable disagreement over what constitutes "best available data" in this sector. In addition, GHG emission estimates based on "best available data" will not be comparable to figures for 2011 and subsequent years, making that data of limited use to EPA. Lastly, efforts to gather "best available data" for the 2010 monitoring year would divert time and resources that could better be applied to preparing personnel, equipment, and data management systems for emissions monitoring in 2011. Ultimately, EPA's regulatory efforts would be best served by allowing the gas transmission sector an additional year to ensure a smooth transition to GHG monitoring.

2. Reports Should Be Due June 30th, Not March 31st.

The annual emissions reports should be due June 30th, which marks the end of the second financial quarter. A second-quarter deadline would be more consistent with existing state GHG reporting programs, and avoid adding to the already heavy first-quarter environmental reporting obligations that many industries face. The June 30th deadline is consistent with The Climate Registry's (TCR) deadline for submittal of reports that underwent considerable review and input from stakeholders. [18] The Board members of TCR, who are essentially the Administrators of GHG programs in 42 states, determined that TCR reports would be due June 30th after giving due consideration of the time it takes time to download, organize, correct, and analyze emission data, as well as prepare inventories in a format suitable for submission.

Moving the reporting deadline is particularly important for INGAA's members. Natural gas transmission companies are already obligated to submit several data-intensive reports to various agencies, including EPA, in the first quarter of the year. These include Title V semiannual monitoring reports and annual certifications under the Clean Air Act; quarterly deviation reports under the Clean Air Act; Discharge Monitoring Reports under the Clean Water Act; and Tier II reports under the Emergency Preparedness and Community Right-to-Know Act. A June 30th submission deadline would help prevent GHG reporting obligations from interfering with these existing reporting requirements.

3. An Electronic Reporting Tool Should Be Developed Before Reporting Begins.

EPA proposes to develop an electronic tool for reporting GHG emissions. While INGAA supports developing a tool that will make GHG reporting more streamlined and efficient, we urge EPA to provide an opportunity for stakeholders to comment and provide input to the process. The development of reporting tools in other GHG reporting programs, such as the California Registry and the Regional Greenhouse Gas Initiative, benefited greatly from the input of stakeholders. Most INGAA members operate in multiple jurisdictions and since the reporting rule does not pre-empt existing state reporting programs already underway, we strongly urge the EPA to consider TCR's common reporting framework.[19] As mentioned earlier, TCR is a non-profit collaboration of over 40 states and sovereign nations. We understand potential concerns from the EPA related to using a third-party tool, but we ask EPA to consider the common reporting framework to help alleviate the reporting burden on INGAA and other multi-jurisdictional reporters. Since considerable expertise was expended to developing TCR's framework, using it will avoid redundancy, spare EPA staff the burden of developing a separate system, and eliminate the costs that would otherwise need to be expended for EPA to develop an entirely new system.

4. INGAA Opposes "Once In Always In" Mandatory Reporting.

INGAA does not support a "once-in always in" standard for reporting GHG emissions under the proposed rule. Rather, INGAA urges EPA to adopt a similar program to that of the California Air

[18] For example, June 30th is the submission deadline for the General Reporting Protocol of the Climate Registry, which has been accepted in 42 states and the District of Columbia. The Climate Registry, General Reporting Protocol v.1.1 at 8 (2008), *available at* http://www.theclimateregistry.org/downloads/GRP.pdf.

[19] Available at http://www.theclimateregistry.org/government-services/common-framework.php.

Resources Board where facilities that show three years worth of data below the reporting threshold are allowed to opt-out of the reporting program. This is an important concept as it will provide an important incentive for operators to reduce emissions from reporting facilities. Absent such a provision, operators would be required to include facilities with little or no emissions of GHGs.

C. The Scope Of The Reporting Rule Should Reflect A Clear Understanding Of How The Data Will Be Used.

As a general preface to our comments on Subparts W and C of the Proposed Rule, INGAA notes that EPA's draft reporting requirements far exceed what would be required to furnish the agency with a reasonably complete and accurate understanding of national GHG emissions patterns. The level of detailed information that would be required by the Proposed Rule is not consistent with a reporting rule that seeks to obtain information to develop GHG policy. Rather, the requirements of the Proposed Rule, in particular Subpart W, appear designed to achieve the rigorous oversight that would be part of a GHG cap-and-trade program. INGAA respectfully submits that this approach could cause EPA to collect data that will ultimately not prove useful, at great cost to regulated entities. Subpart W, which is the single most costly subpart of the Proposed Rule, would require the oil and natural gas sector to undertake extensive and unproven monitoring programs.

A better approach would be for EPA to focus its present efforts on developing a reasonably accurate GHG inventory, based on estimates derived from reasonably available data. It is in this spirit that INGAA offers an alternative fugitive emissions measurement methodology, described in further detail below, which combines limited direct measurement of emissions with cost-effective emission factor models. This approach should provide EPA with more than adequate information to form accurate judgments as to the scale and direction of fugitive emissions from the oil and natural gas sector. If and when EPA decides to pursue GHG mitigation under specific Clean Air Act authorities or pursuant to GHG-specific legislation, EPA will then be in a position to identify further data needs and request data that is well tailored to its purposes.

III. COMMENTS SPECIFIC TO PROPOSED SUBPART W

A. EPA's Proposed Method For Determining The GHG Emissions Under Subpart W Negates The Benefits Of The Emission Threshold For Reporting.

As noted above, INGAA supports the 25,000 metric tons CO_2e per year emission threshold that would generally trigger reporting obligations under the Proposed Rule. However, the proposed method for determining the *applicability* of the Proposed Rule to a given facility undermines the benefits of that threshold, especially with regards to natural gas facilities covered by Subpart W. In order to initially determine whether a given natural gas facility exceeds the threshold for emissions reporting, the Proposed Rule requires an estimation of that facility's fugitive emissions using the methods prescribed in Subpart W.[20] In subsequent years, the Proposed Rule requires repeated estimation of the facility's emissions

[20] Proposed 40 C.F.R. § 98.2(b)(1).

under Subpart W if the facility undergoes any physical or operational changes that could cause its emissions to exceed the reporting threshold.[21]

At many natural gas compressor stations, combustion GHG emissions alone are not sufficient to place the facility above the reporting threshold of 25,000 metric tons CO_2e per year. [22] In these cases, the applicability of the reporting rule turns on the facility's fugitive emissions.

In its discussion of the implementation schedule for the Proposed Rule, EPA assumes that many reporting entities already have GHG monitoring capability due to the requirements of other air quality programs.[23] This assumption is **not** valid for oil and natural gas systems, which have never been subject to extensive direct measurement of fugitive emissions as called for in the proposed Subpart W. Unlike other industrial sectors, oil and natural gas facilities do not have already-installed mechanisms for monitoring and measuring fugitive emissions as called for in the Proposed Rule. ¨ For INGAA members, Subpart W — and the task of determining the applicability of the rule to existing facilities — would represent a significant departure from current practice requiring considerable time and resources.

Moreover, fugitive emissions at a given facility vary over time. Because a facility owner or operator could rarely be certain as to whether a facility has exceeded the 25,000 metric ton threshold for a given reporting year, the Proposed Rule would require Subpart W emission estimation methods (monitoring and direct measurement) to be applied to **every** natural gas transmission compression facility, year in and year out in order to determine applicability. As currently written, these requirements would vastly increase the cost of Subpart W relative to EPA's estimates, and would negate the administrative and cost advantages that EPA sought to achieve by selecting a 25,000-metric ton CO_2e threshold.

As a result, oil and natural gas systems represent particularly appropriate candidates for a capacity-based threshold or "simplified emission calculation tools" that would allow natural gas transmission compression facility operators to easily determine whether Subpart W's reporting requirements apply.[24] Recognizing that EPA has requested comment on the need for such tools, INGAA offers our preferred approach and a brief description of other possible methods to determine fugitive emissions for sources specified in Subpart W below:

[21] Proposed 40 C.F.R. § 98.2(f).

[22] Proposed Rule, 73 Fed. Reg. at 16471.

[23] INGAA estimates that approximately 50 percent of pipeline compressor stations produce less than 25,000 tons CO_2e per year in combustion emissions.

[24] NOPR, 74 Fed. Reg. at 16470 ("EPA requests comment on the need for developing simplified emission calculation tools for certain source categories to assist potential reporters in determining applicability. These simplified calculation tools would provide conservatively high emission estimates as an aid in identifying facilities that could be subject to the rule."

INGAA prefers using a self determination method

1. ***Self-Determination / Consultative Approach***

The Proposed Rule could simply not provide an explicit mandatory method for estimating emissions (i.e., engineering estimates or direct measurement), allowing each owner/operator to use its sound engineering judgment and judge for itself how much risk of erroneous non-reporting to shoulder. One of the additional rule of thumb proposals below would likely be used by each company, but this approach would allow companies to use internal knowledge and industry best practices to determine applicability under the Rule. This approach gives companies the most flexibility but would not diminish the level of due diligence and accuracy in determining whether or not a given facility was subject to the Rule. Accordingly, this approach could promote a consultative approach between EPA and industry regarding development of industry best practices.

However, in adopting this approach, if EPA imposes fugitive requirements on pipeline operations without specifying a calculation or measurement methodology for determining applicability, INGAA believes that the agency should expressly acknowledge that regulated facilities that follow industry-developed best management practices for such applicability determination should not be subject to EPA second guessing that methodology in an individual facility's case. Unless the agency first undertakes, with proper notice, to propose specific requirements for calculation and/or measurement of fugitive emissions for the purposes of applicability determination, it should accept a facility's use of appropriate industry best management practices subject only to the facility's adherence to those BMPs.

In the absence of self determination, INGAA suggests a rule-of-thumb approach

2. *Threshold based on capacity, size, or component counts (or combination thereof)?*

EPA should allow natural gas transmission and distribution facility owners to use readily available data, such as a certain level of gas throughput, a certain physical size, or certain component count (or any combination of these factors), to determine if a compressor stations is below the 25,000 metric tons CO_2e, reporting threshold. INGAA suggests that one or a combination of these characteristics serve as a "rule of thumb". Two such approaches are as follows:

a. Use a fuel consumption based rule of thumb that assumes CO_2 from combustion typically represents 50 percent of total emissions[25]. Facilities that do not meet a 12,500 metric ton CO_2 screening threshold according to Subpart C would not be subject to the reporting requirements.
b. Base applicability on a minimum 30 mmbtu/hr installed capacity.

Other alternatives include:

[25] U.S. EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006," USEPA #430-R-08-005**,** April 2008.

3. Use existing emission factors to determine applicability.

Under this approach, the most current emission factors available (from the 1992 GRI study or later) would be applied to the facility to estimate fugitive emissions. Alternatively company-specific emissions factors should be permitted, possibly with a reasonable margin of safety added until the company-specific work is verified by EPA.

4. Use Subpart W engineering estimates for vented emissions and existing emission factors to estimate other fugitive emissions.

Subpart W engineering estimation methods would be applied to vented sources and the remaining fugitive sources would be estimated using existing emission factors as described in Alternative 3. Engineering estimates and emission factors are consistent with current industry practices and the data is readily available, thus providing a less onerous alternative to direct measurement.

5. Mass balance approach.

Under this approach, those facilities with the necessary measurement equipment would have the option of determining the amount of gas leaving the facility or combusted for energy and subtracting that from the amount of gas entering the facility. The difference would be considered to have been lost to the atmosphere, and would serve as an estimate of fugitive emissions. This method has significant technological limitations and is estimated to very expensive to install and maintain to achieve the level of accuracy for compliance with the proposed rule. However, there may be a small population of facilities where the mass balance method may be feasible to implement or is currently in place. In such cases, INGAA would support affording the flexibility to use mass balance in lieu of monitoring/engineering methods provisions outlined in sections 98.233 and 98.234.

B. An Alternative Method Is Warranted For Sources Required To Identify Fugitive Emissions Under Subpart W.

EPA has expressed concern about emission factors for fugitive emission estimates, but a point-in-time direct measurement raises the same concerns about the ability to accurately quantify emissions due to questions about leak changes over time, the influence of operating modes, representativeness of generic factors, and other issues. As proposed, Subpart W direct measurement requirements are onerous and costly. Additionally, they will be difficult or impossible to implement, especially for reporting of 2010 emissions.

The Subpart W direct measurement approach includes inherent uncertainties in the resulting data. INGAA, therefore, provides an alternative monitoring and measurement recommendation below for GHG fugitive emissions from natural gas systems, which incorporates important features that promote accurate fugitive reporting at a reasonable cost and support development of an emissions data knowledge base that will continue to grow over time.

The methods for monitoring and measurement are included within proposed §98.234. As discussed in comments below, INGAA recommends that monitoring and measurement methods be defined *separate* from the Proposed Rule and cited in Subpart W. This is more consistent with common regulatory practice and provides the opportunity for technology and methodology to grow and mature over time, with new approaches addressed in the cited test methods. Currently, standardized methods are not available and EPA has attempted to identify measurement procedures within §98.234. As discussed further in comments below, the proposed methodologies are impractical and will stifle innovation, and the additional costs associated with annual measurement of all fugitive emission sources do not have compensating benefits. In some cases, the proposed methods are far too ambiguous to ensure quality data will be collected; in other cases, the methods and hierarchy for measurement are too restrictive. The methodologies need to be standardized and consensus procedures developed. In conjunction with implementation of the Alternative Monitoring Method, INGAA proposes a cooperative effort to develop consensus guidelines and methods for implementing leak monitoring and measurement for natural gas systems. This is an important and necessary endeavor. It is important to understand that leak *measurement* requirements are not standardized and have not been historically required for regulated fugitives (e.g., VOC regulations). Thus, Subpart W is establishing new regulatory requirements based on non-standard methodologies. To ensure consistent implementation and good quality data, these methodologies should be addressed through guidance so that they can evolve more readily into standard method.

Consistent with precedent for air quality related regulations, INGAA strongly believes that a regulatory mandate for emissions monitoring or measurement must be accompanied by standard methods to accomplish that objective. The procedures in §98.234 do not accomplish that objective. While INGAA's proposed approach will be initiated prior to finalization of measurement guidelines and standards, INGAA is committed to working with EPA and/or consensus bodies to develop appropriate procedures as the fugitive program is implemented.

C. Comment And Discussion Of The INGAA Alternative Subpart W Measurement Program.

The preamble of Subpart W of the proposed rule, covering fugitive emissions from oil and natural gas systems, makes clear EPA's intention is to focus on the most significant GHG sources and to do so in an effective manner. Further, the attention to detail in Subpart W, outlining the proposed survey and measurement techniques, indicates that EPA wants to develop detailed emissions monitoring and accurate emissions estimation from fugitive sources to support future climate policy and programs. It is also clear that current emissions estimation techniques fall short of EPA's future policy goals.

In support of EPA's goal for quality data to inform future climate change policy decisions, INGAA members have proposed an alternate method for measuring, estimating and reporting fugitive emissions for covered facilities within the oil and natural gas systems sector (Subpart W) This alternate method will not only ensure that the data reported provides a reasonable representation of emissions, but provides a more practical approach to monitoring fugitive emissions. This approach is consistent with the goals laid out by the EPA in the preamble and also more importantly, will aid EPA and/or others in developing future climate policies for this sector. The alternative method is comprised of 3 key elements:

1. Focus on sector-specific key equipment components and sources that have been shown in numerous industry studies to account for over 80 percent of GHG emissions within each sector.

2. Conduct a direct measurement survey of these key leaking equipment components at a randomly selected, statistically representative, sample of the full population of covered facilities. Estimate, using engineering calculations and best available data, emissions from key sources of vented emissions. Based on the preliminary results of an ongoing statistical review of industry data, it is estimated that a random sampling of 20 percent of the full population of transmission and storage facilities will yield a representative data set in the first year on which to calculate emission factors. INGAA believes that in due course, the results from the data may warrant a change in the sample size and thus should be reviewed periodically.
3. Include mode of operation for certain of the key target equipment components, allowing a better understanding and accounting of the annual emissions associated with various modes of operation.

Recommended Alternative Monitoring Method

1. Focus monitoring and reporting effort on sector-specific key equipment components and sources

Numerous studies,[26] including EPA-sponsored studies, internal industry studies, industry workshops and international studies of fugitive emissions at upstream oil and natural gas facilities and oil and natural gas transmission and storage facilities report that key equipment components and sources are typically responsible for in excess of 80-90 percent of GHG emissions from fugitives at a given facility. Due to the dispersed nature of fugitive emissions and the vast number of equipment components and potential sources at oil and natural gas facilities, it is appropriate and efficient to focus monitoring and reporting efforts on the fraction of total equipment components and sources that contribute most to emissions, such that there would be an administratively manageable number of sources. This would significantly reduce the monitoring burden while capturing no less than 80% of emissions.

EPA should seek comment from representative industry groups to determine key components by sector. INGAA proposes to work in concert with EPA to review data from industry studies and emission monitoring programs undertaken by individual companies to identify and compile the list of key equipment components and sources for the natural gas transmission and storage sector. INGAA's recommended list of key equipment components and sources at natural gas transmission and storage facilities to be targeted and proposed monitoring method is included in Table 1 below. Analogous lists for all sectors shall be compiled. INGAA recommends direct measurement for these key components by focusing directly on measurement under § 98.234 (f)-(h). This will further an organizations ability to focus resources and time on direct measurement and data improvement.

[26] "Leak Rate Measurements at U.S. Natural Gas Transmission Compressor Stations" GRI Report No. GRI-94/0257.37. Prepared by: Indaco Air Quality Systems June 1995. "Cost Effective Leak Mitigation at Natural Gas Transmission Compressor Stations" PRCI Report No. PR-246-9526. Prepared by: T. Howard, R. Kantamaneni, and G. Jones December 1998.

Table 1: Proposed Transmission and Storage Key Equipment Components and Sources

KEY COMPONENT / SOURCE	EMISSION MONITORING METHOD
LEAKING EQUIPMENT COMPONENTS	
Compressor Unit Block Valve Vent	Direct Measurement
Compressor Unit Blowdown Valve Vent	Direct Measurement
Compressor Unit Pressure Relief Valve Vent	Direct Measurement
Reciprocating Compressor Seals	Direct Measurement
Centrifugal Compressor Seals	Direct Measurement
VENTED SOURCES	
Compressor Unit Blowdown Events	Engineering Estimation
Station Blowdown Events	Engineering Estimation
Engine Starter Events	Engineering Estimation

Note: A typical engineering estimation process is to calculate the isolated volume of the piping at atmospheric pressure and correcting the volume calculation by utilizing the pressure in the piping at the initiation of venting.

2. <u>Conduct direct measurement of key leaking equipment components at a randomly selected, statistically representative sample of the full population of covered facilities.</u>

To further reduce the monitoring burden and make data acquisition more cost effective under the Alternate Method, INGAA proposes to use the results of ongoing statistical reviews of internal company data to show that a representative comparable result can be obtained by conducting direct measurement of key leaking equipment components at a representative, randomly selected sub-set of facilities. INGAA is providing an example of a statistical analysis that reviews leakage emissions by key source component within typical compressor types and accounted for different operating mode/conditions as Attachment C[27]. Based on the preliminary results of these reviews, it is estimated that annual monitoring at a random sampling of 20 percent of the full population of covered facilities will yield a representative data set in the first year. In each subsequent year, a successive random sampling of the remaining covered population of facilities will be monitored and added to the data set. At a rate of 20 percent of facilities sampled each year, all facilities could be monitored within a 5-year period.

Alternate sampling programs may be suggested, as appropriate (i.e., companies with a small data pool may need to survey a larger fraction of facilities to develop a statistically valid sample size); however, as evidenced by the El Paso example, preliminary results clearly indicate that monitoring a subset of facilities will yield a statistically valid result.

This alternative method for monitoring of emissions from key leaking equipment components (i.e., compressor seals and compressor unit block, blowdown, and pressure relief valves) includes the following features:

a. Emissions from key leaking equipment components at the determined sub-set for covered facilities will be monitored and measured following the guidance outlined in the reporting rule.

[27] Statistical Analysis of Leak Rates and Sample Size Requirements, El Paso Corporation, 2009 (Attachment C)

b. Operators will measure key leaking equipment components.

Operators will measure key leaking equipment components under this proposal. Under the current proposed rule, elevated sources are excluded from consideration due to accessibility issues. However, major contributors to fugitive emissions within all sectors of the petroleum and natural gas industry, including the equipment components listed as target sources in this document are typically vented at building rooflines or from dedicated vents, which are normally elevated. These key sources would therefore be left out of the emissions reported using the proposed rule, and as a result, systematic under-reporting of fugitive emissions will occur. Under the proposed alternative sampling method, these key leaking equipment components would be measured. This is a highly focused monitoring proposal, that will provide a significantly more complete dataset for the key contributors to fugitive emissions than could be collected using the proposed sampling method, and the data would be suitable for use in the development of emission factors that can be used to provide reasonable estimation of emissions at the facility for compliance with the current goals of the reporting program and will aid immensely in focusing on future climate policy. Only target components for which emission measurement procedures are deemed to pose a personal or public safety risk could be excluded from the emission measurement program.

c. Operators will provide on-site equipment counts of key components at all covered facilities in the first year.

d. Operators-specific emission factors will be developed.

As stated above, operator-specific emission factors for the key leaking equipment components will be developed using monitoring data from the emission surveys. Operator-specific emission factors would provide more accurate estimates of emissions than the use of industry default emission factors because they are tailored to the specific characteristics of an individual system. These company-specific emission factors that would be applied operator-wide to the population of covered facilities using developed site-specific component counts in order to estimate emissions from leaking equipment components at all facilities.

The developed company-specific emission factors will be updated annually with new measurement data from monitored facilities. The factors will be dynamic and trending over time by analyzing year-over-year datasets is possible.

3. <u>Estimate, using engineering calculations and best available data, emissions from key sources of vented emissions</u>.

As is outlined in the Proposed Rule, it is appropriate to determine emissions from vented sources using engineering calculations, best available data and a log of number of events.

- Blowdown events: Each blowdown event will be recorded and an engineering estimate will be used to determine amount of gas blown down.

- Engine starters (powered by natural gas pressure) events: Each starting event on engines equipped with natural gas pressures starters will be recorded and an engineering estimate or actual measurement will be used to determine amount of natural gas emitted during each start.

4. Include mode of operation for certain of the key target equipment components.

Reporting the mode of operation will further improve data quality as compared to the current reporting rule, which will merely provide a 'snapshot' of emissions. In several studies**,** the state of the operating mode of compressor units has been shown to impact emissions from key equipment components**.** By developing emission factors for leaking equipment components that account for operating mode, a more robust estimate of annual fugitive emissions, particularly for compressor units, can be made. As identified in Appendix C, the statistical basis to arrive at the sample size of the compressors (and therefore facilities) accounted for the modes of operation.

All key leaking equipment components will be measured including the state of operating mode found at the time of the measurement (see Table 1 of Attachment C) and direct measurement data will be used to develop representative emission factors for each mode. Compressor unit annual emissions will be calculated by applying the appropriate emission factor to the time each compressor unit is in the given operating mode. The hours in each mode may be determined using engineering estimates and best available data.

Proposed modes of operation:

- Pressurized and running – compressor is being utilized by compressing gas at system operating conditions.
- Idle and pressurized – compressor is offline but line pressure in the unit is maintained.
- Depressurized – source is not in operation and compressor unit is blown down, but the station side of the suction and discharge valves is at line pressure.

To complete the emission calculations, hours in pressurized-operation, pressurized-idle and unpressurized modes must be known. Hours in each mode shall be tracked on a unit level or reasonable assumptions shall be made based on the operator's blowdown policies for each operating area or facility and equipment type (centrifugal or reciprocating compressors).

The above factors are expressed in thousands of cubic feet of natural gas. Component level emissions of CH_4 and CO_2 shall be calculated based on mass balance approach using the following equations:

$$Emissions_i\ CH_4\ (tons) = [Emission\ Factor_i\ (mscf\ ng)_{pressurized\ op} \times Hours_{pressurized\ op} + Emission\ Factor_i\ (mscf\ ng)_{pressurized\ idle} \times Hours_{pressurized\ idle} + Emission\ Factor_i\ (mscfng)_{unpressurized} \times Hours_{unpressurized}] / 8760 \times 1{,}000\ (scf/mscf) \times \frac{CH_4\ mole\%}{100} \times \frac{1}{379.3\ (scf/lbmole)} \times MW_{CH_4}\ (lb\ CH_4/lbmole\ CH_4) \times \frac{1\ ton}{2{,}000\ lb} \times Component\ Count$$

Equation 1

$$Emissions_i\ CO_2\ (tons) = [Emission\ Factor_i\ (mscf\ ng)_{pressurized\ op} \times Hours_{pressurized\ op} + + Emission\ Factor_i\ (mscf\ ng)_{pressurized\ idle} \times Hours_{pressurized\ idle} + Emission_i\ \ Factor\ (mscfng)_{unpressurized} \times \times Hours_{unpressurized}] / 8760 \times 1{,}000\ (scf/mscf) \times \frac{CO_2\ mole\%}{100} \times \frac{1}{379.3\ (scf/lbmole)} \times MW_{CO_2}\ (lb\ CO_2/lbmole\ CO_2) \times \frac{1\ ton}{2{,}000\ lb} \times Component\ Count$$

Equation 2

Individual compressor level emissions shall be calculated as a sum of emissions from the associated compressor components.

<u>Strengths of the Alternative Monitoring Method</u>

- Alternate monitoring method will allow companies to make a <u>more accurate and representative</u> report of fugitive emissions than existing or proposed practices:
    - Including all major sources of fugitive emissions in the sample
    - Focusing emission quantification and monitoring efforts on those components and sources responsible for most of the emissions
    - Conducting smaller annual sampling programs that are manageable but remain representative.
- Data quality will be higher:
    - All key components will be measured, resulting in a significantly more complete dataset for the key contributors to fugitive emissions.

  - The compressor unit operating mode will be incorporated into annual emission estimates, which is not possible with just an annual 'snapshot' of emissions. This is the only feasible way addressing the important issue of operating mode.
- Operator-specific emission factors will be developed and site-specific equipment component counts of key contributors to fugitive emissions will be developed. Emissions from the oil and natural gas industry will be well described through the development of a dynamic set of emission factors which reflect on current and evolving practices within the industry.
- The required survey techniques are very specialized and there is a very limited pool of experienced individuals and contractors available to conduct measurements both safely and accurately. The scope of the current Proposed Rule would require data to be collected by inexperienced individuals. This inexperience will certainly compromise the data quality. The industry must be allowed time to build capable resources in the field of fugitive emission measurement.

D. The Monitoring And Measurement Requirements In Proposed Section §98.234 Cannot Be Implemented As Proposed Due To Limitations Or Unnecessary Restrictions In The Procedures And The Inability Of The Commercial Market To Meet Demand.

Proposed Section §98.234 identifies methods for annual leak detection and fugitive emissions measurement. Typically, when emissions measurement is mandated by a regulation, an approved and validated reference method or consensus standard is cited in the regulation. Unfortunately, leak detection and measurement standards *do not exist* for methane leak detection and measurement from natural gas systems. §98.234 attempts to address this significant deficiency by discussing instrumentation, practices, and procedures in §98.234(c) through (k). However, these sections include significant implementation problems that will dramatically and adversely affect the objectives of quality data, accurate measurements, and GHG reporting accuracy.

It is inappropriate to attempt to implement methods and procedures through the descriptions in §98.234(c) – (k), and INGAA recommends a concerted effort to develop guidelines and methods separate from the rule. Several INGAA member companies have extensive experience in fugitive natural gas measurements and stand ready to develop with EPA the guidelines and methods needed. Then, consistent with the standard format for emissions measurement, the rule should cite reference / consensus methods for measurement. Specific examples are discussed below; however, in summary, implementation of the proposed requirements is problematic for numerous reasons including the specific examples discussed below:

- In some cases the proposed approach is arbitrary, subjective and/or ambiguous. In other instances a method is based on unestablished or fictitious criteria, and for other cases the approach is unnecessarily restrictive.
- There are a limited number of service providers familiar with leak detection and measurement for natural gas pipeline systems and it is not feasible for the commercial market to meet the demand that would be triggered by the proposed 2010 monitoring and measurement requirement at all facilities. If the proposed rule approach is pursued, data quality and subsequent decisions will surely be compromised.
- The proposed procedures exceed current requirements for leak detection and repair for regulated fugitive sources (e.g., VOC LDAR). It should not be presumed that those service providers and

practices can be readily adapted to meet market demand for Subpart W sources.

INGAA is hopeful that the Alternative Method discussed above will be implemented along with consensus methods being developed in parallel with that monitoring effort. Rather than provide a line-by-line review of each requirement in §98.234(c) – (k),), INGAA provides several examples of problems caused by including methodologies within the rule and the described procedures If needed, INGAA can provide additional input on our specific concerns with the long list of procedures. As noted above, INGAA offers our assistance in working with EPA and consensus bodies to develop appropriate standards.

1. In Several Respects Proposed Section §98.234 Is Subjective Or Ambiguous, Which Is Not Consistent With Regulatory Measurement Standards.

- For use of the infrared Remote Fugitive Emissions Detection, §98.234(d) indicates that detection is to be completed "under favorable conditions" and that you must "inspect the emissions source from multiple angles."
- Per §98.234(f), the high volume sampler is only for measuring "steady" emissions and should not be used if it "is not able to capture all of the emissions."
- When using calibrated bags per §98.234(g), you are required to "obtain consistent results."

These are a few of many examples where a method is ambiguous, subjective, or has no specific meaning. This is counter to current industry practice where standardized methods are used for regulatory mandated measurements. In addition, method development is typically a public process that includes review and input by leading professionals in the particular field. The basis for the methods, consideration of alternatives, and process for authoring the procedures in §98.234 is unclear.

2. Proposed Section §98.234 Is Overly Restrictive And Will Likely Stifle Innovation.

- The instruments specified address some, but not all of the techniques and approaches used for leak detection. For example, ultrasonic devices and soap bubble solution / "Snoop" are additional techniques that are commonly used to detect leaks. Specifying *instruments* clearly stifles innovation and technical advancement. This approach is also counter to standard performance-based measurement standards rather than instrument or vendor-specific criteria.
- Proposed Section §98.234(c) is prescriptive in defining which approach should be used for measurement and where and when the high volume sampler should be the method of choice. The Proposed Rule should not prescriptively define which measurement method to use or a method selection hierarchy.

In many cases, multiple approaches may be viable and accurate for completing a leak measurement, and the rule should not prescriptively define which should be implemented. In addition, regulations commonly identify *multiple* methods for completing a measurement. The method for a particular test can be selected at the discretion of the testing entity — as long as the method is in the list of accepted candidate methods.

Leak detection and measurement is an evolving field and identifying specific instruments and techniques in a rule is an unusual approach that will stifle the development of new, innovative, and cost effective approaches for leak detection and measurement. For example, infrared camera technology could advance to identify a minimum leak measurement threshold or even leak rate quantification. New instruments or techniques will surely be developed as measurement becomes more prevalent under this mandate. A rule that provides a means for alternative methods, with consensus methods validated separate from the rule, provides the most expedient path to support rather than preclude innovation and technology advancement.

Moreover, EPA should solicit the handful of operators that have performed this work for the natural gas industry in recent years, to provide to EPA the "toolbox" of techniques and methods used in practice and considered these tools for inclusion in methods or guidelines that are developed. Limiting the instrumentation or prescribing hierarchy for monitoring and measurement will introduce unnecessary restrictions which preclude knowledgeable professionals from implementing the "right" technical approach for the measurement. Given an appropriate amount of time, guidelines and methods can be developed to ensure that the measurement decisions are constrained within accepted practices and methods and not at the complete discretion of the fugitive emissions test team.

3. Proposed Section §98.234 Relies On Implied Standards Or Qualifications That Do Not Currently Exist.

- Proposed Section §98.234(f) indicates that a "trained technician" shall perform high volume sampler measurement. This implies some sort of accredited training, but no such program exists. To address this, Proposed Section §98.7 defines a trained technician as "a person who has completed a vendor provided or equivalent training program and demonstrated proficiency to use specific equipment for its intended purpose, such as high volume sampler for the purposes of this rule." This is an ambiguous definition and vendors with a business interest in rule requirements are an inappropriate training body unless operating under an accepted standard for accreditation.
- Technology vendors and service providers have an interest in the shape and form of rule requirements, and their business interest may bias their preferred approach. To depend on these vendors to develop qualifications and training independent of review by the public and/or consensus bodies is wholly inappropriate. The "trained technician" approach per the §98.7 definition should not be based on vendor defined procedures and INGAA objects to this philosophical approach to qualification.

The Proposed Rule rests on the premise that robust and viable companies exist to fulfill the implied obligations for training, instrument manufacturing, etc…. INGAA does not believe this to be the case and in fact, there are fewer than 5 vendors with any significant experience in the natural gas transmission industry. For example, INGAA recommends that EPA research the commercial availability of high volume flow samplers and the current corporate structures and resources available to develop not only commercial products but training and other requirements inherent to the approaches in the proposed rule. Because this market has been limited to date, the current commercial infrastructure is very limited and insufficient to support the requirements of the proposed rule.

Collectively, INGAA believes that the problems in §98.234 present insurmountable obstacles to implementation of the rule as proposed by EPA. INGAA recommends that the form and substance of this section be revised to reflect:

(1) if measurement programs are required prior to development of consensus guidelines and methods (e.g., for reporting of 2010 or 2011 emissions); EPA should investigate the current status of natural gas leak detection and measurement technology and availability of service providers, and the need for interim protocols that can be implemented; and

(2) a more standard rule structure that cites consensus methods / measurement guidelines that are separate from the rule. The desire to implement leak detection and measurement on an aggressive schedule and the lack of standard methods present challenges for restructuring this section, but the current approach should not be included in the Final Rule. INGAA offers our assistance to EPA in reconciling these important measurement method issues.

E. Differences Between Vented Sources And Fugitive Leaks Need To Be Clarified.

The "fugitive" definition in the Proposed Rule includes both fugitive leaks and vented emission sources. This is consistent with the common international definition (e.g., the IPCC definition), but introduces some confusion in Subpart W. In U.S. reporting and documentation, fugitive leaks and vented emissions have typically been reported separately. For example, reporting of VOC emissions under the Clean Air Act or state permits identifies fugitive and vented emissions separately. While INGAA understands the desire for consistency with international convention, the Proposed Rule should be clarified to highlight that "fugitives" per the Proposed Rule definition include both fugitive leaks and vented sources, and the Proposed Rule should be revised to more clearly segregate requirements for these different source types.

For example, engineering estimates including mass balance calculations are typically the preferred and most accurate choice for reporting vented sources, but not for fugitive leaks. In addition, §98.233(d) indicates that *leak detection methods* must be applied to all 24 source types listed in §98.232(a), and that list includes vented sources where leak detection is not required or necessary. In general, *leak detection* should be applied to fugitive leaks and not to vented emission sources, where engineering estimates are appropriate and preferred for defining emissions. The confusion between a vented source and a leak source under the proposed "fugitive" definition appears to contribute to this discrepancy in the Proposed Rule.

In addition, Subpart W should more clearly segregate fugitive leaks from vented sources, clarify that engineering estimates are appropriate for vented sources, and revise §98.233 to clearly indicate that monitoring (i.e., leak detection) is not required for vented sources.

F. Standardized Guidelines Or Consensus Methods Are Required And INGAA Can Assist With This Process While Implementing The Alternative Method.

INGAA realizes that EPA wants to implement reporting as soon as possible. Development of measurement guidelines or consensus methods could take several years. The INGAA proposed timeline for implementing an Alternative Method is discussed in other comments. A key component of the

INGAA Proposed Alternative Method is the annual testing of a random sampling of approximately 20 percent of the fugitive emission sources, rather than annual testing of all sources. With yearly testing of 20 percent of the fugitive emission sources rather than all sources, natural gas operators will be better able to control the measurement program quality by utilizing experienced service providers and focused measurement program management. Under the INGAA proposed approach, currently applied approaches for monitoring and measurement will be used by experienced service providers or company staff while a parallel effort develops guidelines and procedures. INGAA commits to working with EPA and consensus bodies to develop these methods, and INGAA is willing to discuss this initiative with EPA and devise an approach that addresses stakeholder needs and ensures a timely schedule for development and approval of guidelines and methods.

G. Reasonable Missing Data Procedures Should Be Allowed For Subpart W Measurement And Monitoring.

Proposed Section §98.235 indicates that there are no missing data procedures for Subpart W and if data is lost or an error occurs the measurements must be repeated. INGAA expects that EPA is attempting to ensure that all required leak monitoring and measurement is completed, and INGAA understands that objective. However, the "no missing data" criterion is difficult to understand and implementation questions will arise. INGAA recommends that reasonable engineering approaches should be allowed to address minor missing data. For example: a "missing" temperature measurement could be reasonably determined after the fact from weather records; and, as a more in-depth knowledge base is developed as data are compiled, in subsequent years it may be reasonable for limited application of previous year's data if a particular test anomaly results in minimal missing data.

In addition, it is difficult to define or comprehend the meaning of "no missing data" and how that will be interpreted and implemented. Minor discrepancies could occur during a measurement program that could be addressed using reasonable engineering judgment. Minor year-to-year discrepancies could be considered "missing data" that needs to be addressed and causes unnecessary confusion. For example, component counts will surely differ by minor margins from year to year. Even a count by two "experts" completed at a facility at the same time will surely result in marginally different counts. This should not be considered "missing data" that needs to be addressed under §98.235.

INGAA recommends that the specifics associated with missing data procedures be defined separately in conjunction with the methods and guidelines developed for Subpart W monitoring and measurement, *i.e.*, data handling is a measurement issue and should not be addressed in the rule. Alternative processes can be included in the rule to ensure that primary leak sources that would skew results are not avoided or missed. Reasonable judgment should be allowed to address missing data while ensuring that monitoring and measurement objectives are addressed.

H. Measurement Should Be Based On A Minimum Leak Threshold And Not Required For All Leaks Detected.

In the preamble at 74 FR 16535, EPA requests comment regarding minimum leak thresholds. INGAA does not believe that it is appropriate to require measurement from all detected leaks and recommends that a minimum threshold be identified. Since high volume sampling is a key primary methodology proposed for leak measurement, the minimum threshold to be measured should be correlated to the minimum level achievable with the high volume sampler. If the alternative of measuring all detected leaks is implemented, a vast number of "measurements" that are not detectable with a high volume sampler would result, thus introducing considerable cost burden without benefit.

At this time, defining the leak threshold is complicated by the lack of standardized methods for implementing the detection and measurement program proposed for Subpart W fugitive leaks. Thus, defining the appropriate threshold should be a key objective of method standardization that is discussed in other comments. As possible examples, if an organic vapor analyzer (OVA) is used for leak screening, INGAA recommends that 10,000 ppmv serve as the minimum screening level that triggers a measurement because this threshold is probably most consistent with the high volume sampler detection limit. For other screening techniques, it may be necessary to introduce an intermediate step of OVA screening pending development of more advanced methods for categorizing detected leaks as quantifiable. As technologies and methods mature, more concise methods can be developed for identifying the leak measurement threshold. Developing methods separate from the rule will provide a more expedient path to advancing the technical approach for reconciling this issue.

I. Mass Balance Calculations Are Appropriate For Vented Emission Sources.

At 74 FR 16535, EPA requests feedback on mass balance for quantifying emissions. "Mass balance" can be described as a type of engineering calculation for determining vented source emissions, and engineering calculations are the preferred approach for determining vented emissions. The rule should clearly indicate that this is an accepted approach for vented emissions. It appears that EPA is concerned with estimates of fugitive *leaks* in the preamble discussion of "mass balance" quantification. However, possible confusion regarding the definition of fugitive emissions that includes both vented and fugitive leak sources (as discussed in the comment above) could lead some to believe that mass balance quantification is inappropriate for vented sources. To avoid any confusion, INGAA recommends that EPA clarify that mass balance engineering calculations are often appropriate and preferred for vented sources, and this application of mass balance calculations should not be confused with the issue discussed at 74 FR 16535.

J. EPA Requested Comment On The Dependence Of Emissions On Operating Mode. That Issue Is Addressed In INGAA's Proposed Alternative Measurement Program, Which Is One Of Several Positive Aspects Of The Proposed Alternative.

At 74 FR 16536, EPA discusses emission differences between standby and operating mode for fugitive emissions from compressors, and EPA requests comments on how to address emissions during different operating modes. The Proposed Rule does not specifically address this issue. The INGAA alternative measurement program discussed in Section III above includes measurement and data gathering under both operating and standby mode, with emission differences recorded and applied as appropriate in the emission calculation for Subpart W sources. Thus, the proposed Alternative Method would include development of company-specific emission factors based on measurement data for different modes and provide an improved methodology for emission estimates. This consideration of standby versus operating mode is one of the positive aspects of the proposed Alternative Method.

K. The List Of 24 Source Types Includes Replication And Overlap Of Sources. The INGAA Proposed Alternative Method Addresses This Issue. If The INGAA Approach Is Not Implemented, EPA Should Clearly Indicate That Source Classification Within These Categories Is Not A Basis For Defining A Reporting Error Or Compliance Issue.

If INGAA recommendations regarding an alternative measurement program are incorporated into the rule, the 24 source types in §98.232(a) will be revised for consistency with the new method. If that revision is not completed, the Proposed Rule should clarify reporting obligations for the 24 listed source types. There is duplication within the list that could cause confusion or an agency finding that emissions are improperly characterized. For example, "transmission station fugitive emissions" is an all encompassing descriptor and broadly defined in §98.6. Many of the other listed sources (e.g., multiple types of seals, rod packing, compressor fugitives, pneumatics, etc.) are also listed sources and there is redundancy and overlap within these categories – and all fit within the category of "transmission station fugitives" as well as other broad source categories. If these 24 source types (or a revised list) are retained in the rule, EPA should clarify that operators are not subject to reporting scrutiny or compliance questions regarding how data is classified in the report as long as the information is complete and relevant sources are included in the report – i.e., "misclassification" should not be considered a reporting error or deviation.

L. Proposed Section §98.233(B) Should Be Amended To Include Tanks As A Source Type Where Engineering Estimation Methods Are Allowed And References To Direct Measurement From Tanks Should Be Deleted. The Use Of Engineering Models For Determining Tank Emissions Is Consistent With Current Practice And Should Be Included In The Rule.

Proposed Section §98.233(c) identifies storage tanks as an emission source type that requires a combination of measurement and engineering estimation. The established practice for estimating VOC tank emissions in oil and gas operations are engineering estimates using models (i.e., simulation models). This approach is sanctioned and supported by EPA for tank emission estimates in other programs. An engineering estimate should also be used for estimating storage tank GHG emissions – i.e., methane losses. Within defined ranges for operating parameters (e.g., pressure and temperature) and liquid characteristics (e.g., gas-to-oil ratio, API gravity), models and other estimation methods perform well when inputs are accurate. Inaccuracies are more likely if a model or empirical correlation is applied outside of its intended use. In identifying an acceptable approach for methane estimates from tanks, limitations should be considered so that a model or correlation is not applied outside of its intended use. However, the Proposed Rule should not limit access to viable engineering estimation methods.

In addition, the required accuracy and acceptable emission estimation approaches should consider the relevance of the emissions. Significant expense can be incurred from measurement and sophisticated modeling to estimate storage tank emissions. For gas transmission and storage facilities, these emissions will likely comprise a very small percentage of facility emissions. Thus, the cost associated with sophisticated methods is not warranted for these types of facilities. If EPA is concerned that tank emissions are significant for some sectors subject to Subpart W, INGAA suggests that a tiered approach be considered, where facilities with relatively minimal emissions can estimate emissions using lower fidelity approaches.

combined emissions for those units. This aggregate reporting provides reasonable approaches to reporting detail while providing operators the opportunity to consider logical groupings within a facility. INGAA strongly supports these aggregate approaches for reporting combustion emissions.

C. For Clarity, §98.336 Should Identify The Horsepower (Hp) Equivalent To 250 Mmbtu/Hr And INGAA Recommends 30,000 Hp.

To avoid confusion during implementation and provide reporting consistency, INGAA recommends that EPA specify the horsepower (hp) equivalent to 250 MMBtu/hr. Combustion capacity at many facilities is permitted based on horsepower rating rather than firing rate, and presenting the horsepower equivalent will ensure that the aggregation threshold is consistently implemented for subject facilities. INGAA recommends that the rule indicate that aggregation for combustion reporting can be based on 250 MMBtu/hr or 30,000 hp. Similarly, the 30,000 hp equivalency to 250 MMBtu/hr should be used for defining whether a Tier 1 or Tier 2 approach can be used for an individual source (*i.e*., larger sources must use Tier 3 or Tier 4).

D. For Tiers 1 And 2, EPA Should Clarify That Fuel Use Estimates Consistent With Other Clean Air Act Reporting Approaches Are Acceptable.

Tiers 1 and 2 indicate that fuel combusted must be based on company records and the operator must provide an explanation and data used to determine fuel consumption. Natural gas sector operators are required to report combustion emissions for pollutants (e.g., NOx, VOCs, etc.) under Clean Air Act and state programs. For consistency, those technical approaches for fuel use determination should be allowed under Subpart C. As an example, fuel consumption is determined based on operating hours, source rated capacity, and brake specific fuel consumption (i.e., Btu/hp-hr fuel use, which is a measure of unit operating efficiency). INGAA's understanding is that the operator has discretion to use such approaches to determine fuel consumption for Tier 1 and Tier 2 and that current practice acceptable for other emissions reporting obligations are acceptable for GHG reporting under Subpart C.

E. The Natural Gas Transmission Industry Is Expert In Fuel Measurement, And Operator Defined QA/QC Procedures Should Be Accepted.

Accurate fuel measurement is inherent to natural gas transmission and storage operations, and expertise within this industry for natural gas fuel rate measurement is unsurpassed. For fuel metering, §98.34(d)(1) requires operators to follow methods in §98.7 or vendor defined calibration procedures. Within the natural gas industry, flow measurement quality control and quality assurance procedures have been developed and refined over years, and common practices are in place to ensure metering QA/QC. §98.34(d)(1) should be revised to provide the flexibility to use accepted operator-defined practices for fuel flow meter calibration and other QA/QC measures. This ensures that natural gas operators can continue to use accepted methodologies to ensure accurate fuel measurement.

F. INGAA Recommends Including Additional Fuel Rate Measurement Methods And Adding A Streamlined Approach For Accepting Additional Methods.

Proposed Section §98.7 includes a long list of accepted consensus method for measurement of fuel rate, gas quality (carbon content), fuel heating value, etc. INGAA has identified additional methods that should be included. In addition, as evident by the long list of methods already identified, there are many accepted methods for measuring fuel rate, heating value, etc. and method refinements and advances continue. Because of the breadth of coverage of the Proposed Rule, there needs to be a streamlined approach for accepting additional methods to address Subpart C measurement requirements for fuel flow, fuel carbon analysis, and heating value.

Many of the ASTM standards referenced in §98.7 are not generally recognized as measurement standards for natural gas sector operations. To date, INGAA has identified the following additional methods that should be added to §98.7:

AGA Report No. 3	Orifice Metering of Natural Gas Part 1: General Equations & Uncertainty Guidelines (1990)
AGA Report No. 3	Orifice Metering of Natural Gas Part 2: Specification and Installation Requirements (2000)
AGA Report No. 3	Orifice Metering of Natural Gas Part 3: Natural Gas Applications (1992)
AGA Report No. 3	Orifice Metering of Natural Gas Part 4: Background, Development Implementation Procedure (1992)
AGA Report No. 5	Natural Gas Energy Measurement
AGA Report No. 7	Measurement of Natural Gas by Turbine Meter (2006)
AGA Report No. 8	Compressibility Factor of Natural Gas and Related Hydrocarbon Gases (1994)
AGA Report No. 9	Measurement of Gas by Multipath Ultrasonic Meters (2007)
AGA Report No. 10	Speed of Sound in Natural Gas and Other Related Hydrocarbon Gases
AGA Report No. 11	Measurement of Natural Gas by Coriolis Meter (2003)
ANSI B109.3	Rotary-Type Gas Displacement Meters (2000)
GPA 2145-09	Table of Physical Properties for Hydrocarbons and Other Compounds of Interest to the Natural Gas Industry
GPA 2172-09	Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer
GPA 2261-00	Analysis of Natural Gas and Similar Gaseous Mixtures by Gas Chromatography
API 21.1	Manual of Petroleum Measurement Standards Chapter 21 - Flow Measurement Using Electronic Metering Systems Section 1 - Electronic Gas Measurement

In addition to this supplemental list, gas measurement and analysis methods continue to be revised and refined, and it is likely that additional consensus methods are available but have not been specifically identified to date. The process for accepting alternative methods into a final rule can be burdensome, time consuming, and cumbersome for operators and EPA. Thus, a streamlined approach is warranted to accept other consensus standards.

To address ongoing improvements and evolution in gas measurement methods, INGAA recommends that §98.34 add a provision that indicates that consensus methods not listed in §98.7 but authored by organizations with methods already listed in §98.7 be allowed for fuel flow, fuel carbon, and heating value analysis. In addition, EPA should indicate that other methods accepted by the Administrator are also acceptable. To facilitate approval under this authority, EPA should devise an approach (i.e., expert review group) for expedited review and approval of additional methods that become available or are identified.

G. In Addition To The Generic Default Emission Factors For CH_4 And N_2O, Operator-Defined Emission Factors For CH_4 And N_2O Should Be Allowed As Long As The Factors Are Technically Defensible.

Table C-3 of the Proposed Rule includes default CH_4 and N_2O emission factors for natural gas and §98.33(c) indicates that default values in Table C-3 should be used to calculate emissions. As an alternative, operator-defined emission factors should be accepted if the basis for the factors is documented and technically defensible (e.g., reference methods or reasonable standards for measurement; engine vendor provided test data). Typically, estimates based on source-specific emission factors would be more appropriate than an estimate based on a generic emission factor and the operator should have the opportunity to justify use of operator defined emission factors for methane or N_2O. In some cases, operators may already be estimating GHG emissions using more appropriate source-specific emission factor methods and should not have to default to generic emission factors that may not be accurate for a particular source type.

H. Proposed Section §98.30(B) Should Be Amended To Remove The Reference To "Permitted" Because Some Emergency Engines Are Not Permitted Depending Upon State Program Requirements.

Section **§**98.30(b) excludes emergency generators from the Subpart C source category. However, §98.30(b) indicates that the generators need to be "designated as emergency generators in a permit issued by a state or local air pollution control agency." The permitting requirement should be removed from this provision. Requirements differ for different jurisdictions. For example, units with a rating below a certain size may not be included in a permit. Thus, the small emergency units that EPA is attempting to exempt are exactly the type that is most likely to not be in a permit, because states are more likely to not require permits for small units. Section **§**98.30(b) should simply exempt portable and emergency units and delete the qualifying phrase related to permitting. Additional clarification on engine classification may be warranted, but the permit requirement must be deleted from the rule to avoid applicability for many small, emergency engines.

I. Subpart C Should Include A *De Minimis* Threshold For Combustion Sources So That Reporting Of Small Units With Insignificant Emissions Is Not Required. INGAA Recommends A *De Minimis* Threshold Of 10 Mmbtu/Hr.

The Proposed Rule does not include *de minimis* emission levels or exemption for small combustion sources that are not required to have a permit issued by a state or local air pollution control agency, and the rule notes that the burden associated with reporting small sources is addressed. Despite this claim, INGAA believes that unwarranted burden will be imposed and recommends that a *de minimis* or size-based exemption threshold be identified for combustion sources. INGAA recommends a 10 MMBtu/hr exemption threshold.

Many subject facilities include small combustors with minimal emissions. For example, water heaters at a small co-located office building and other small heaters will typically be present at subject facilities with much larger combustion sources. Typically, emissions will be inconsequential but activity data associated with these source types will not be readily available. Thus, an unnecessary amount of time will be spent devising fuel use or operating time estimates that will be highly uncertain and have an

INGAA suggests that utilizing process simulation models such as HYSIM, HYSIS, WINSIM, PROSIM, E&P Tank, or techniques such as "Flash Liberation Testing" will yield representative emissions rates of flash gas and constituents without undertaking a direct measurement program (as described in the proposed rule) that is subject to meter error, extended time frames and safety issues related to gaining access to storage tank vents. Using sophisticated process simulation models requires analysis of liquid streams to ensure accurate input data, and this may not be warranted for some facilities, where a less rigorous tier may suffice.

The engineering models require inputs that are "measured" values, but classifying tank emission estimates as a combination of direct measurement and engineering estimates will likely cause confusion. INGAA recommends adding storage tanks to §98.233(b) as a source type where emissions are determined using an engineering estimate. With engineering models a standard and accepted approach for storage tank emission estimates, storage tanks should be deleted from §98.233(c) and reference to storage tank metering in §98.234(b)(1)(vii) and measurement in §98.234(j)(2) should be deleted from the Proposed Rule.

IV. COMMENTS SPECIFIC TO PROPOSED SUBPART C

A. INGAA Supports The Tiered Approach For Reporting Combustion CO_2 Emissions, And Recommends Annual Averages Rather Than Monthly Calculations For Natural Gas-Fired Sources. A Minor Clarification On Tier 4 Requirements Is Requested.

As Section §98.33(a) identifies a tiered approach for determining combustion CO_2 emissions. INGAA supports this approach, which provides flexibility based on the information that is available while providing accurate combustion CO_2 estimates.

For natural gas-fired sources, fuel quality will typically be stable over extended time periods, thus an annual average value for gas quality parameters and annual fuel use should be allowed for calculating combustion CO_2 emissions for Tiers 2 and 3. This will minimize unnecessary reporting burden. Data quality can be assured via records that document consistent fuel quality. This issue is discussed in more detail in Comment IV-J below.

In addition, to avoid any potential for future confusion, INGAA requests clarification regarding application of the Tier 4 approach, which relies on continuous emissions monitoring systems (CEMS). CEMS are required for some large electric generating units and other select sources, and optional for other sources. §98.33(b)(5)(ii) identifies criteria that mandate CEMS, and it is apparent based on the preamble discussion that all of the criteria in (ii) must apply. However, when not clearly specified, regulatory criteria can be interpreted as "or" rather than "and" criteria. To avoid any potential for confusion, §98.33(b)(5)(ii) should be revised to indicate that Tier 4, "Shall be used for a unit if ***all of the following apply*:**"

B. INGAA Supports Aggregation For Reporting Combustion Emissions.

INGAA supports the aggregation approaches for unit-level reporting identified in § 98.36(c). §98.36(c)(1) allows aggregate reporting for up to 250 MMBtu/hr of combustion sources at a facility and §98.36(c)(3) allows multiple gas-fired or oil-fired units fed through a common fuel line to report insignificant affect on facility emissions. Affected sources are faced with significant implementation challenges due to the breadth and timing of the Proposed Rule, and the additional burden associated with reporting trivial emissions is not warranted. INGAA recommends that a 10 MMBtu/hr exemption threshold be included in the rule for combustion sources.

J. When Monthly Or More Frequent HHV Or Fuel Carbon Content Measurement Is Required, Annual Reporting Should Be Based On The Annual Average HHV OR carbon Content For Homogeneous Fuels Such As Natural Gas With Limited Variability.

In many cases, natural gas sector sources will have monthly high heating value (HHV) data and will thus fall under the Tier 2 calculation approach based on measured rather than default HHV. Similarly, Tier 3 requires monthly or more frequent fuel carbon content data. For natural gas transmission, there is typically little month-to-month or day-to-day variability in measured HHV or carbon content, but data tracking and report calculations will be more burdensome if emissions need to be calculated for each source for time scales shorter than annually. For sources with monthly (or more frequent) HHV or fuel carbon content measurement and little variation in the gas quality for those measurements, operators should have the option to complete the calculation *annually* based on the average of the twelve monthly (or more frequent) HHV or fuel carbon content measurements. This will reduce reporting burden without impacting report quality.

For fuels such as pipeline quality natural gas that are relatively homogeneous over extended time periods, average annual HHV or carbon content should be allowed for calculating combustion emissions under Subpart C. If needed, a maximum relative variability could be specified for this approach. INGAA recommends a target of 10% or less variation in the measured HHV or carbon content relative to the annual average. In this case, operators should be allowed to calculate combustion emissions based on the annual average HHV or carbon content and annual fuel use. EPA should address this in §98.33 by clarifying that the annual average can be used for fuel volume and HHV in Equation C-2a for Tier 2 and for fuel volume and carbon content in Equation C-5 for Tier 3 gaseous fuels. A similar clarification should be added for Equation C-10a regarding the use of annual average HHV and annual fuel use for calculating annual combustion emissions of methane and nitrous oxide.

K. In §98.36(D)(2), The Schedule For Operator Response To A Request For Additional Information Should Be Revised From 7 Days To At Least 2 Weeks.

Section 98.36(d)(2) identifies the requirements for operator response to agency requests regarding methods for quantifying fuel consumption and requires a response within 7 days of receipt of a written request. INGAA recommends that this requirement be revised to allow at least two weeks for such a response. A seven day response time is not adequate when considering the timing involved to review and process the request. For example, if key personnel are on business travel or otherwise out of the office for only a few days, that could severely hinder the ability to respond within 7 days. Two weeks or more should be allowed and this schedule is still indicative of an expeditious response to an agency request.

V. Legal Authority Under The Clean Air Act And The Consolidated Appropriations Act

Finally, INGAA believes EPA has crafted the Proposed Rule in a broad manner not contemplated or required in the FY2008 Consolidated Appropriations Act (Appropriations Act). In particular, EPA has wrongly interpreted the Appropriations Act as calling for *both* upstream and downstream reporting of GHG emission sources. INGAA believes that the explanatory statement to the Appropriations Act is most reasonably interpreted as an instruction to EPA to *consider* upstream and downstream reporting, but choose between these approaches as appropriate in any given sector. In many cases, it is needlessly costly and burdensome for EPA to count the same unit of GHG at the point of emission *and* further upstream. If there are compelling policy reasons in specific situations that would justify the collection of both upstream production and downstream sources, those situations and policies need to be clearly identified.

Moreover, although EPA mentions several *potential* uses of the data proposed to be gathered, it concedes that it does not yet know what programs the Proposed Rule will ultimately support. EPA's statutory authority for the Proposed Rule, Section 114 of the Clean Air Act, does provide the agency with broad data collection powers. However, those powers are not unlimited; in particular, Section 114 provides specific purposes for which data collection is authorized. INGAA submits that the Proposed Rule would be more precisely tailored to the agency's needs (neither gathering unnecessary data nor neglecting essential data), and more consistent with the limits of Section 114, if EPA were to provide more clarity as to which Clean Air Act programs it intends to pursue using the data collected. Section 114 does not provide EPA with license to collect any and all data that the agency might find useful for unspecified programs that may or may not be implemented at a later date.

VI. CONCLUSION

INGAA's members share EPA's desire to collect accurate, reliable and reasonably complete data on greenhouse gas (GHG) emissions. In fact, INGAA's members have worked with EPA to develop improved tools for collecting emissions data. INGAA's members also understand EPA's desire to improve the quality of data on fugitive emissions of methane at compressor stations along natural gas pipelines. While INGAA we have concerns with several aspects of the proposed rule, the cornerstone of our comments focus on the provisions of Subpart W. INGAA strongly believes that the direct measurement program detailed in proposed Subpart W will provide inferior data, and will do so at the inordinate cost of directly measuring emissions from thousands of individual components at every compressor station.

We urge EPA to consider INGAA's alternative approach that combines state-of-the-art operations information with recognized statistical sampling techniques to produce superior data at a fraction of the cost. Within each source category covered by Subpart W, the alternative approach focuses on the components known to generate the bulk of fugitive emissions. These components are examined at a statistically derived sample of sources to develop company-specific emission factors that, in turn, are used to calculate reported fugitive emissions.

INGAA's alternative is technically sound, generates superior data and requires a fraction of the time and expense that would be required under the direct measurement proposal. INGAA is committed to working with EPA and the other stakeholders subject to Subpart W as we further refine INGAA's proposed alternative.

Attachments

Attachment A

Best management Practices, Management of Fugitive Emissions at Natural Gas Transmission and Distribution Facilities. Prepared by Clearstone Engineering Ltd. for Canadian Energy Partnership for Environmental Innovation (CEPEI), May 18, 2009.

Attachment B

Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry. Prepared by Clearstone Engineering Ltd. for Canadian Energy Partnership for Environmental Innovation (CEPEI), April 16, 2007

Attachment C

Statistical Analysis of Leak Rates and Sample Size Requirements, El Paso Corporation, 2009

Attachment A

Best management Practices, Management of Fugitive Emissions at Natural Gas Transmission and Distribution Facilities. Prepared by Clearstone Engineering Ltd. for Canadian Energy Partnership for Environmental Innovation (CEPEI), May 18, 2009.

BEST MANAGEMENT PRACTICE

Management of Fugitive Emissions at Natural Gas Transmission, Storage and Distribution Facilities

PREPARED FOR

Canadian Energy Partnership for Environmental Innovation (CEPEI)

Attention: Jasmine Urisk
Program Director

PREPARED BY

Clearstone Engineering Ltd.
700, 900-6 Avenue S.W.
Calgary, Alberta, T2P 3K2
Canada

May 18, 2009

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LIST OF ACRYNOMS

BMP	-	Best Management Practice
CAC	-	Criteria Air Contaminant
CAPP	-	Canadian Association of Petroleum Producers
CCME	-	Canadian Council of Ministers of the Environment
DI&M	-	Direct Inspection and Maintenance (DI&M)
EPA	-	Environmental Protection Agency
GHG	-	Greenhouse Gases
LDAR	-	Leak Detection and Repair
MTBF	-	Mean Time Between Failure
NACE	-	National Association of Corrosion Engineers
NFPA	-	National Fire Protection Association
NMHC	-	Non-Methane Hydrocarbon
NPT	-	National Pipe Thread
PTFE	-	Polytetrafluoroethylene
THC	-	Total Hydrocarbons
TOC	-	Total Organic Compounds
TNMOC	-	Total Non-methane Organic Compounds
U.S. EPA	-	U.S. Environmental Protection Agency
VOC	-	Volatile Organic Compound

ACKNOWLEDGMENTS

The development of this best management practice (BMP) has been an iterative process and reflects the views and suggestions of the project steering committee, Canadian Energy Partnership for Environmental Innovation (CEPEI) and Natural Resources Canada (NRCan). The support and direction provided by each of the companies and organizations involved are gratefully acknowledged.

Special thanks are given to the following individuals and companies who participated on the project steering committee and/or provided review comments:

• Alliance Pipeline Inc.:	Troy Meinke
• ALTA Gas:	Darren Ribar
• ATCO Gas:	Wayne Alexander
	Weronica Isaksson
• CEPEI	Jasmine Urisk
• Enbridge Inc:	Tim Adamson
	Lynn Ross
• Manitoba Hydro:	Bob Gill
• Natural Resources Canada	Michael Layer
• Gaz Metro:	Abdelhaq El Ouardi
• SaskEnergy:	Bernie Ryma
	Michael McMurray
• Specra Energy:	Tony Irwin
• Terasen Gas:	Ian Neville
• TransCanada:	Mark Blundell
	Jim Cormack
• Union Gas Limited:	Peter Mussio

FORWARD

This best management practice (BMP) provides guidance for the management of fugitive equipment leaks at natural gas transmission, storage and distribution facilities. The management of leaks in pipelines is not addressed and is beyond the scope of this document.

Emissions from fugitive equipment leaks, in addition to being the loss of a marketable non-renewable resource, pose a potential safety hazard and is a noteworthy contributor of methane (CH_4) emissions, a powerful greenhouse gas (GHG).

The natural gas industry is characterized by many smaller facilities distributed over a large area rather than a few large, centrally located facilities; consequently, a practical approach is warranted which focuses on those facilities, components and service applications most likely to offer significant cost-effective control opportunities. This type of approach is referred to as directed inspection and maintenance (DI&M).

It is recognized that the potential for fugitive emissions from leaking equipment components is greater at natural gas transmission and storage facilities than at natural gas distribution facilities, thus warranting a different management approach in each of these sectors. This difference is attributed largely to the fact natural gas is typically odourized in distribution applications, allowing early and easy detection of leaks, and the facilities tend to lack some of the key high-leak-potential components (e.g., compressor seals and blowdown systems) more commonly encountered in transmission and storage applications. Furthermore, leak studies have shown that when components do leak, they leak, on average, less in distribution service applications. Also, distribution facilities are typically much smaller in size, less likely to be manned or frequently visited and, therefore, lack the same economies of scale for implementing leak management programs.

It is further recognized that fugitive emissions management is an ongoing requirement. Leaking components, even after successful repair, will eventually reoccur without proper inspection and maintenance. It is also recognized that different types of components and service applications have different leak potentials, and therefore, will require different levels of attention. The typical key sources of fugitive equipment leaks at natural gas facilities are identified, important considerations and constraints are noted, improved operating practices are suggested, and relevant technologies for the detection, measurement and control of fugitive emissions are identified.

The overall aim of this best management practice is to provide practical guidance to operators for developing customized approaches to manage fugitive emissions at individual natural gas facilities, while giving consideration to each facility's specific circumstances. This guidance is based on a review of fugitive emissions measurement data available for Canadian natural gas facilities, current industry practices and an examination of available and emerging fugitive emission detection, quantification and control technologies. This document will be periodically reviewed and updated, as warranted, to reflect new technologies and advancements in the science of managing fugitive equipment leaks.

CORPORATE COMMITMENT

Corporate commitment should entail full management support including adequate funding and resource allocation. Key goals should include: continuous improvement, optimizing the effectiveness of the overall fugitive emissions management program and eliminating barriers and disincentives.

1 APPLICABILITY

This BMP provides guidance for the management of fugitive equipment leaks at natural gas transmission, storage and distribution facilities. Fugitive equipment leaks are the unintentional loss of process fluid from equipment components (e.g., valves, flanges, compressor seals, opened lines, etc.) due to normal wear and tear, improper or incomplete assembly, inadequate material specification, manufacturing defects, damage during installation or use, corrosion, fouling and environmental effects (e.g., vibrations and thermal cycling). The potential for such emissions depends on a variety of factors including the type, style and quality of equipment component, type of service (gas/vapour, light liquid or heavy liquid), age of component, frequency of use, maintenance history, process demands, whether the process fluid is odorized and operating practices.

Components in odourized service tend to have much lower average fugitive emissions than those in non-odourized service. Components tend to have greater average emissions when subjected to frequent thermal cycling, vibrations or cryogenic service. Different types of components have different leak potentials and repair lives.

Only a small percentage of the equipment components have any measurable leakage, and of those, typically, only a small percentage contribute most of the emissions (e.g., 5 to 10 percent of leakers may account for 80 to 90 percent of the emissions). Thus, the control of fugitive emissions is a matter of minimizing the potential for big leakers and providing early detection and repair of these when they occur. While a big leaker may occur in any application at any time it is in use or under pressure, efficient management of fugitive emissions is best achieved through the application of directed inspection and maintenance (DI&M) techniques. DI&M focuses inspection and correction efforts on the areas most likely to offer significant cost-effective control opportunities, with coarse or less frequent screening of other areas for additional opportunities. Big leakers often go unnoticed because they occur in elevated, crowded or noisy areas where they are not readily detected or the magnitude of the leak is not fully appreciated due to a lack of quantitative measurement results making it difficult to justify corrective action.

2 IMPLEMENTATION

The extent to which measures for controlling fugitive equipment leaks are applied at individual facilities should be based on safety, environmental and health risks, the proximity of the facility to nearby residences, the effectiveness of existing measures for managing fugitive emissions, the cost-effectiveness of finding and controlling leaks and regulatory requirements. Some facilities may already have requirements for a fugitive emissions management plan as a condition of their operating approval.

Companies should fully consider how they will ensure good emissions control throughout the life of each facility.

3 BASIC CONTROL STRATEGY

The key elements for effective long-term control of fugitive emissions are the application of technology and standards, implementation of management systems and corporate commitment. The application of control technologies and design standards, alone, do not preclude the potential for fugitive emissions. Reliable fugitive emissions control requires:

- the development of leak survey programs, operating procedures and performance objectives for controlling fugitive emissions, and
- the enforcement of these requirements and maintenance of all control systems

3.1 Technology and Standards

The first step in controlling fugitive equipment leaks should always be to minimize their potential by applying proper design and material-selection standards (for example, CSA Z662 – Oil and Gas Pipeline Systems). It is also important to select practicable control technologies (e.g., reduction, recovery and treatment systems) and following the manufacture's specifications for the installation, use and maintenance of components.

3.2 Management Systems

A management system is needed to establish objective performance targets and to implement ongoing leak surveys and predictive maintenance programs to ensure that leaks are minimized.

3.3 Directed Inspection and Maintenance (DI&M)

The objective of DI&M is to minimize the potential for big leakers in the most practicable manner possible, while providing reasonable assurance that no major leaks have been missed. A typical program may comprise four key elements:

- **Periodic Comprehensive Leak Surveys**: A comprehensive leak screening program should be performed once every 3 to 5 years using either an infrared leak imaging camera or US EPA Method 21. The latter leak screening option is currently a mandatory requirement at petroleum refineries and chemical plants in Canada and is identified in CAPP's fugitive emissions management best practice as an acceptable option at upstream oil and gas facilities; although, use of infrared cameras is considered to be a more practicable option at medium to large sized facilities. Periodic comprehensive leak surveys will verify the effectiveness of a facility's overall fugitive emissions management program and provide a check of any components not specifically targeted by the other leak screening tiers.
- **Targeted Monthly and Quarterly Leak Surveys**: Targeted screening of equipment components having a medium to high leak potential should be conducted on a monthly to quarterly basis, according to the types of components, their specific leak potentials and their ongoing leak performance. A formal schedule for this work and a listing of the target components should be developed for this purpose and updated as needed to reflect any changes in the site infrastructure.

- **Permanent Instrumented Leak Detection:** Consideration should be given to installing permanent instrumented leak detection systems on all difficult-to-access components having a high leak potential.
- **Leak Checks Following Maintenance or Adjustments**: Whenever a component has been taken apart or disconnected (e.g., for inspection, maintenance or repair), it should be checked for leaks, as a standard practice, before being put back into service.

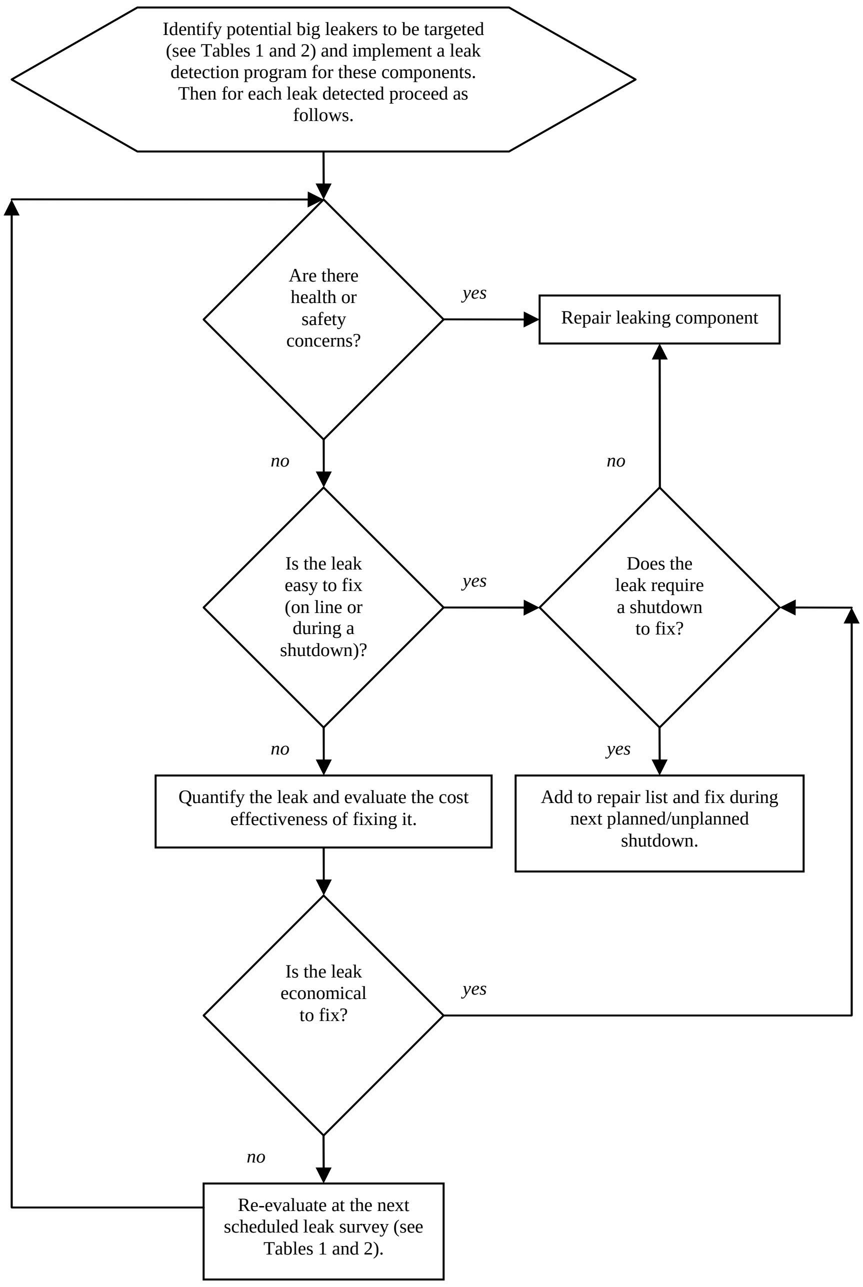
Typically, a facility may phase the DI&M program in over several years and progressively add to the list of target components until all key potential contributors are being targeted. Once a leak is detected, regardless of whether it is a target or non-target component, the decision tree presented in Figure 1 should be followed to determine if it should be fixed. A leak need only be fixed if it poses a health, safety, environmental or operability concern or is economical to repair.

3.3.1 Leak Definition

A leak is the loss of process fluid past a seal, mechanical connection or minor flaw at a rate that is in excess of normal tolerances allowed by the manufacturer or applicable health, safety and environmental standards. Those in the first category should be fixed wherever this is economical to do (i.e., based on direct repair or replacement costs and the value of the process fluid being lost), while those in the latter category must be fixed regardless of the cost.

In the absence of quantitative leak data that may be compared directly to the applicable tolerances or limits, an equipment component in natural gas service shall be deemed to be leaking and in need of repair or replacement when the emitted gas can be visualized using an infrared leak imaging camera, detected by an organic vapour analyzer in accordance with US EPA Method 21, or detected by any other techniques with similar or better detection capabilities. Leak detection methods that do not necessarily meet these performance requirements (e.g., by olfactory, visual or audible means) can be used as a supplementary approach, but are not, in themselves, sufficient for conducting a leak survey.

The IR camera is not always as sensitive as screening using organic vapour analyzers, but has been demonstrated to be sufficiently sensitive to detect the big leaks that are contributing most of the emissions. Typically, only the top 5 to 10 percentile of the leaks (i.e., when ranked from largest to smallest) contribute most of the fugitive emissions at a site, and therefore are most critical to repair.



1

Figure 1. Decision tree for conducting a DI&M program at a natural gas facility.

Where components are screened for leaks using organic vapour analyzers, in accordance with US EPA's Method 21, the leak definition shall be a screening value of 10,000 ppm or more[1]. This is a regulatory leak definition often applied in other industries. Below this threshold a component may still be experiencing some loss of fluid but the amount is deemed too small to be practical to repair. Despite the easy and objective application of this definition, it should be recognized that screening values are a poor indicator of the amount of emissions. In some situations it may be appropriate to measure the leak rate to provide a more accurate basis for deciding whether it is practicable to repair a particular component.

Leakage of a liquid from an equipment component shall be deemed to be controlled if a managed containment system, such as a drip pan, is provided to capture the liquid, and vapour emissions from the component and liquid containment system do not meet the definition of a gas or vapour leak.

3.3.2 Leak Screening Frequencies

The frequency at which equipment components are screened for leaks at target facilities should be commensurate with their leak potential (i.e., the product of their leak frequency and their average leak rate when they do leak). The overall objective should be one of continuous improvement and maximizing the level of control achieved by the available resources (i.e., on both a site-specific and company wide basis).

Recommended initial screening frequencies for different types of components are presented in Appendix I. These screening frequencies should be increased if necessary to ensure that no more than 2 percent of the components in each target category, excluding pump and compressor seals, are leaking at a time. For pump and compressor seals, the objective is less than 10 percent of the total number of these components or three may be leaking, which ever is greater. On reciprocating pumps and compressors, each cylinder has one seal. Small centrifugal pumps and compressors will typically only have one seal (i.e., where the impeller shaft penetrates the pump or compressor body). Larger units will have 2 seals since the shaft is supported at both ends and has bearings and seals on both ends (inboard and outboard). Tandem units will have even more.

Where the leak frequency performance targets have been consistently achieved in three or more consecutive surveys, consideration may be given to decreasing the screening frequencies to lower values for each applicable component category. Where a survey shows leak frequencies greater than the maximum target value, the survey frequency should be immediately increased to at least the next greatest screening frequency.

3.3.3 Target Facilities

All facilities and installations should be periodically screened for leaks, but in an optimal manner that maximizes the cost-effectiveness and impact of the overall leak management

[1] This is the current leak definition applied by the CCME (1993) guidelines for the measurement and control of fugitive volatile organic compound (VOC) emissions from equipment leaks at petroleum refineries and organic chemical plants.

program. During the roll-out of a leak management program this may mean targeting older and larger facilities first (i.e., a risk based approach). Ultimately, a performance based approach should be applied which is consistent with the leak frequency targets presented in Section 3.3.2.

3.3.4 Target Components

All equipment components in natural gas service should be surveyed for fugitive equipment leaks. The types of components may include flanged and threaded connections (i.e., connectors), valves, pressure-relief devices, open-ended lines, blowdown vents (i.e., during passive periods), instrument fittings, regulators and actuator diaphragms, compressor seals, engine and compressor crankcase vents, sump and drain tank vents and covers. The amount of emissions from a leaking component is generally independent of the size of the component.

Leakage into vent systems, compressor seals, pressure relief valves and open ended lines tend to be the most common sources of big leaks. Still, components such as connectors and valves can, on occasion, also be major leak sources. Examples of situations where this or other unexpected significant leak contributions may occur include the following:

- Connections left untightened after a plant turnaround or maintenance which go unnoticed due to high background noise levels or because the component is in a difficult to access or infrequently visited location (e.g., at high elevation location or on a pipe rack).
- Holes have developed in equipment or piping due to corrosion, abrasion or damage.
- Components have been improperly installed or were forgotten to be installed (e.g., a pressure gauge removed during maintenance work was not put back into its port and the valve on the port is in open or partially open position).
- A major failure of a valve stem packing system (e.g., blowout of the packing material) has occurred.

Accordingly, there is still value in surveying low leak potential components and process areas but not at the same frequency as high leak potential components.

If the leak potential (i.e., average emission rate per component) for a connector is set to 1 (see the final right-hand column in Table 1), then the leak potential for block valves is 9 time greater, the value for control valves is 37, open-ended lines is 205, a reciprocating compressor seal is 2400 and so on. Based on these statistics, their percentage contribution to total fugitive emissions and their leak frequencies, leak control efforts should be focused on the top 5 categories shown in Table 1, namely: blowdown systems, centrifugal compressor seals, reciprocating compressor seals, pressure relief valves and open-ended lines. Collectively, these five categories account for only 1.2 percent of the total component population but contribute more than 88 percent of the total emissions from fugitive equipment leaks. Furthermore, given the small population of these high-leak-potential components and their high leak frequencies, finding these leaks is not difficult, and if appropriate access facilities are in place, does not need to be a time-consuming exercise.

Table 1: Sample leak statistics for gas transmission facilities.						
Source	**Number of Sources[1]**	**Leak Frequency**	**Average Emissions (kg/h/source)**	**Percent of Component Population**	**Contribution to Total Emissions (%)**	**Relative Leak Potential**
Station or Unit Blowdown System	219	59.8	3.41E+00	0.131	53.116	7616
Compressor Seal – Centrifugal	103	64.1	1.27E+00	0.062	9.310	2838
Compressor Seal – Reciprocating	167	40.1	1.07E+00	0.100	12.764	2400
Pressure Relief Valve	612	31.2	1.62E-01	0.366	7.062	362
Open-Ended Line	928	58.1	9.18E-02	0.555	6.070	205
Orifice Meter	185	22.7	4.86E-02	0.111	0.641	109
Control Valve	782	9	1.65E-02	0.468	0.919	37
Pressure Regulator	816	7	7.95E-03	0.488	0.462	18
Block Valve	17029	2.8	4.13E-03	10.190	5.011	9
Connector	145829	0.9	4.47E-04	87.264	4.644	1
Other Flow Meter	443	1.8	9.94E-06	0.265	0.000	0.02

1 Population of equipment components in natural gas service.

3.3.5 <u>Inaccessible Components</u>

A component is deemed to be accessible for the purposes of screening if it can be safely accessed from ground level, a walkway or platform without the need for a ladder, manlift or any other special means. Equipment components that cannot be accessed by these means need not be screened if they do not have a high leak potential (i.e., do not require monthly or quarterly leak surveys) and do not have any visual, audible olfactory indications of leakage.

3.3.6 <u>Tagging Components</u>

All identified leaking components should be tagged and appropriate information regarding the location of these tags recorded for repair follow-up and the generation of an inventory list for reference for operations. Where a leaking component may be uniquely identified and easily located by another means, a leaker tag need not be hung on the component.

The leaker tags, when used, should be hung either directly on the leaking component, or, if this is not practical, then in a position, and with appropriate information marked on it, for others to be able to easily determine the location of the leak. The tags should be uniquely numbered, weather resistant, designed for high visibility and securely hung using either plastic zip ties or corrosion resistant wire. A sample leaker tag is provided in Appendix III.

Care should be taken to avoid placing the tag where it might melt, wear away, affect the operation of any equipment or instrumentation or pose a danger to the person hanging the tag. Useful information to include on the tags includes, but is not limited to: the date, type of component, and part of the component that is leaking and rate of leak if applicable. Information marked on the tag in the field should be done using indelible markers to resist fading of the ink over time from exposure to the elements.

When screening equipment components and installing tags, it is useful to follow a logical route through the process and place tags in sequential order to make them easier to find. The number of tags installed at the site should be carefully tracked. Additionally, the following information should be tracked on a separate form for each tag that is hung to assist in re-locating the tag, especially where a leak is to be surveyed for future repair and report generation: leaker tag identification number, process area or unit, process stream, type of component, size of component and process tag number.

All leaker tags should be left in place after the leak rate is measured to allow for follow-up action by maintenance personnel. The tags should only be removed once the component has been repaired and the leak is determined to be fixed.

3.3.7 Pipeline Leaks

The pipeline sections between facilities must be surveyed for leaks in accordance with the specific requirements of CSA Standard Z662 (Oil and Gas Pipeline Systems). The requirements of natural gas transmissions systems are presented in Section 10.2.7 of the Standard and for natural gas distribution pipelines in Section 12.10.2.2.

Pipelines that cross provincial or federal borders are regulated by the National Energy Board and, in addition to the CSA requirements, are subject to the Onshore Pipeline Regulations (1999). Part 6 (Operations and Maintenance), Subsection 39 (Surveillance and Monitoring) of the regulations requires companies to develop a surveillance and monitoring program for the protection of the pipeline, the public and the environment.

3.3.8 Leak Quantification

Leak rates need only be quantified where this is deemed necessary by operations and maintenance personnel for the purposes of evaluating the feasibility of the applicable repair, replacement or control option, or where it is decided to provide quantitative tracking of fugitive emissions (e.g., for use in greenhouse gas reporting). Where it is decided to quantify a leak rate, the accuracy should be sufficient for the required evaluation (e.g., within ±25 percent or enough to clearly establish a positive net financial benefit for repair decisions). The application of emission factors or leak rate correlations, while appropriate for the development of company-wide and regional emissions inventories, do not offer adequate accuracy when evaluating individual components. Depending on the type of component and information available, potentially valid quantification methods may include, but are not limited to, process modelling, material balances, flow capture and metering systems (such as the HiFlow™ Sampler), duct sampling techniques, tracer tests and some types of remote sensing methods.

Often there is a perception that if reductions in fugitive emissions do not stand out above random metering noise, or the error limits of accounting meters, the benefits of reducing leaks will not be realized. Random metering errors (or noise) may, on an individual day, obscure any reductions achieved in the amount of leakage; however, these reductions will still produce an upward shift in the baseline about which the metering noise fluctuates. Over time the random noise effects will cancel out, but the leak rate reduction will have a quantifiable cumulative impact until the leaks re-occur or new leaks form. The greater the leak rate reduction, the less time is required for the cumulative benefit of the reduction to be noticed.

Proportional metering errors introduce uncertainty in the total measured flow rate but do not prevent the instrument from reacting to an incremental change in the amount of flow. For example, if fugitive emissions are reduced by 0.5 percent of throughput at a site that initially reported gas sales of 200.0 x 10^3 m^3/d then the sales meter would read 201.0 x 10^3 m^3/d after the change, regardless of the meter accuracy.

3.3.9 Fixed Leak Detection Systems

The use of permanent leak detection systems to facilitate regular leak detection of key chronic leakers, and the installation of ports and sample lines to facilitate easy leak detection of key difficult-to-access components should be considered.

Screening ports should be provided on all emergency vent and flare lines and blowdown systems to allow convenient periodic detection and quantification of residual flows in these systems where continuous flow meters are not provided or where such meters are only sized to quantify large flow rates (e.g., during relief or blowdown episodes). These ports should be 1" National Pipe Thread (NPT) in size or larger. Where weld-o-lets or thread-o-lets are used on the pipe, care should be taken to ensure that the full inside diameter of the fitting is cut through the pipe wall to provide clear passage of any probes that may be inserted through the opening.

For pressure relief valves that discharge directly to the atmosphere through their own dedicated vent stack, it is good practice to either install end-of-pipe caps that pop off when appreciable leaks start to occur, or easy-to-access leak detection ports on the discharge piping.

Predictive maintenance techniques are preferable to reactive measures and should be considered for applications involving significant chronic or frequent leakers (e.g., compressor seal vents and leakage into vent and flare systems). This requires the implementation of continuous or frequent leak detection systems to provide advance notice of developing leaks and to facilitate pre-planning of repair or replacement activities. Devices such as flow switches, flow meters, vapour sensors or transducers for other parameters that provide a good indication of leakage may be installed to allow continuous or frequent detection of leaks from component vent ports (e.g., seal vents) and open-ended lines. Building or area hydrocarbon gas detection systems, although an accepted means of detecting workplace health and safety hazards, are not deemed to be an effective leak detection technology due to the dilution that may occur between the individual leakage points and the fixed sensors and the typically large building ventilation rates.

3.3.10 Leak Repairs

All leaks should be tagged, and repaired as soon as is practicable. Repairs that require a major shutdown to do may be delayed until the next schedule shutdown provided this delay does not result in exceedances of any applicable safety, health or environmental standards. Once a component has been fixed it should be re-screened to confirm that the repair has been successful.

A listing of all tagged leakers from each survey should be maintained and used to track when the leaks were detected and when they were repaired.

A reasonable supply of spare parts and components should be kept in inventory to minimize the potential for delays in fixing leaks, especially where long deliveries may otherwise apply.

Initial repair attempts should be made by the facility operators where the fix is easy to apply and this is allowed by corporate policies and leak tracking practices. Otherwise, or if the initial fix is unsuccessful, formal maintenance work orders should be issued for repair or replacement of the leaking component.

A leaking component need not be repaired if the component is shown to be uneconomic to repair and does not pose a significant safety, health or environmental concern. In such cases, the components should remain tagged and be re-screened at the next scheduled leak survey (see Table 2) to determine if and when conditions have worsened to the point of requiring repairs.

The economics of repairing or controlling a leak should be based on the market value of the process fluid being lost, the repair, replacement or control cost, and the life expectancy of the repair or applied control technology. All leak repairs that have a simple payback period of less than 1 year based on the following equation should be deemed economical to repair:

$$PBP = \frac{Cost\ of\ Control}{Annual\ Leak\ Rate \times Gas\ \mathrm{Pr}ice}$$

Where,

PBP	=	payback period (years).
Cost of Control	=	direct repair or replacement costs.
Annual Leak Rate	=	amount of gas/vapour emitted directly to the atmosphere or that leaked into a vent or flare system which does not have vent or flare gas recovery.
Gas Price	=	current market price of the gas.

More refined analyses that consider, for example, discount rates, inflation rates, capital cost allowances, changes in operating costs, etc., may be applied where warranted.

Components that have a payback period of greater than 1 year may be scheduled for repair at the next major shutdown to allow for budgeting of these repairs. Where the payback period is greater than the anticipated life expectancy of the repair or control measure, the component may be deemed uneconomic to repair and supporting details of this cost evaluation shall be kept on file. Default life expectancies of component repairs are presented in Table 2.

Table 2: Default man life of repair for economic analysis of repair costs.

Source	Category	Mean Repair Life[1] (years)
Compressors - Reciprocating	Seals	1
	Valve Covers	1
	Variable Volume Pocket	1
	Governor	1
	Cylinder Head	1
Compressors – Centrifugal	Seals	1
Connectors	All	5
Open-Ended Lines	All	2
Pressure Relief Valves	All	2
Pumps	Seals	1
Regulators	All	5
Tank Fittings	Hatches	1
	Pressure Vacuum Valves	2
Valves	Quarter-Turn	4
	Rising Stem	2
Vents	All	1

1 Based on continuous usage and typical quality of components, wear and tear.

3.3.11 Record Keeping

Operators should have a record system to support their DI&M system. Proper record keeping should assist in ensuring that leaking components are identified and repaired, and that appropriate follow-up actions are taken. This information will also assist in identifying the proper screening frequencies to achieve maximum cost-effective fugitive emissions reductions, while accounting for the size, type and characteristics of the facility.

Records of all completed leak surveys, quality assurance/quality control (QA/QC) measures and leak repairs should be kept on file for a period of at least five years. These records should include the leak survey results, training and calibration records, repairs made on leaking components and the economic analysis performed on all leaking equipment components that have not been fixed on the basis that this is uneconomic to do and does not pose a health, safety or environmental concern. Specific classifications or work categories should be created to allow easy look-up of leak-related work orders within the maintenance system.

3.3.12 Quality Assurance and Quality Control (QA/QC)

Fugitive emission programs that do not apply proper care, attention and resources will tend to miss leaks, result in incomplete emission capture during measurements and, generally, understate the amount and extent of fugitive emissions. Proper QA/QC measures are, therefore, an important part of establishing an effective fugitive emissions management program.

3.3.12.1 Personnel Training

The personnel responsible for leak detection and measurement work should be trained on leak detection and measurement techniques, component identification and all quality control and quality assurance requirements (e.g., calibration, daily functional checks and maintenance of the employed instruments). Basic training should also include standard safe work procedures and fall protection. Where third parties are used to do this work, documentation of their qualifications, training and QA/QC records (i.e., for the periods of engagement) should be provided in their reports.

Junior personnel should be accompanied by experienced personnel until such time as they have achieved an adequate level of competency. Thereafter, periodic audits of their work should be performed to ensure completeness and accuracy.

Generally, the larger and more complicated the facility, the more experience and process knowledge is needed to properly screen the facility. This is particularly true when detailed component counts are to be prepared for use in determining leak frequencies since unit-specific knowledge is usually needed to correctly recognize and establish the service of individual components. Even with detailed process knowledge, input from site operators may still be needed. Accordingly, field teams should include at least one senior level person when surveying natural gas processing facilities, compressor stations and sites with glycol dehydrators.

3.3.12.2 Primary Calibrations

All leak detection and quantification instruments should be factory serviced or serviced by a factory authorized technician and calibrated regularly in accordance with the procedures specified by the manufacturer, or whenever problems may arise.

3.3.12.3 Field Checks

All equipment should be subjected to a functional and zero check each time it is used, and more often where required. Where applicable, span checks should be performed at

4 REFERENCES CITED

The Canadian Council of Ministers of the Environment. 1993. Environmental Code of Practice for the Measurement and Control of Fugitive VOC Emissions from Equipment Leaks. Prepared by the National Task Force on The Measurement and Control of Fugitive VOC Emissions from Equipment Leaks. Ottawa, ON. pp. 35.

U.S. Environmental Protection Agency. 1988. Protocols for Generating Unit-specific Emission Estimates for Equipment Leaks of VOC and VHAP. Research Triangle Park, NC. Report No. EPA-450/3-88-010.

U.S. Environmental Protection Agency. 1980. VOC Fugitive Emissions in Synthetic Organic Chemicals Manufacturing Industry - Background Information for Proposed Standards. Report No. EPA-450/3-80-033a. Table 4-7. Page 4-24.

least as frequently as specified by the manufacturer. Zero checks should give values consistent with expected background levels. Span checks should give a result within the accuracy specified by the manufacturer. In the absence of any specific accuracy claims, span checks on gas detectors should be in error by no more than 5 percent of value, and the flow measurement devices should be in error by no more than 15 percent.

These errors may be calculated using the following relation:

$$Error = \left[1 - \frac{reading}{reference\ value}\right] \times 100\% \qquad (2)$$

Electronic gas sensors generally should not be used outside during wet or freezing conditions.

3.4 General Considerations

Efforts should be made to identify any potential disincentives to controlling fugitive equipment leaks at sites and develop adequate documented approaches to address these issues. For instance, unless a real value is assigned to leak reduction achievements, there will be an inherent disincentive to allocate time and resources to such initiatives. Where the pipeline company owns the gas, the value of lost gas should be included in operating budgets. Where the gas is owned by the shippers, consideration should be given to charging an incentive toll to encourage fugitive emissions management.

Regular employee awareness programs should be considered to sensitize both operations and maintenance personnel to the importance of leak control. Personnel responsible for conducting leak detection and quantification surveys should be given regular documented training in these methods and the surveys should be conducted under the direct supervision of personnel familiar with the target process systems.

Companies should regularly determine and closely track their performance in controlling fugitive equipment leaks and in enforcing their performance standards. Key performance indicators should include leak frequencies, repair success rates, percent of leakers repaired within 45 days, percent of components scheduled for repair at the next major facility turnaround.

5 APPENDIX I – RECOMMENDED INITIAL SCREENING FREQUENCIES

Tables 3 and 4 below present recommended initial leak screening frequencies. Ultimately, these should be adjusted to achieve the leak frequency objectives presented in Section 3.3.2. A distinction is made between natural gas transmission and storage facilities and natural gas distribution facilities to allow for differences in their leak potential, general characteristics and manageability.

For the purpose of applying Tables 3 and 4, facilities in odourized service should be deemed to be distribution facilities, and compressor stations should be treated as transmission and storage facilities, regardless of whether the natural gas is odourized.

Table 3: Suggested leak screening frequencies for equipment components, presented by component category and type.

Source Category	Type of Component	Service	Application	Screening Frequency	
				Transmission & Storage	Distribution[3]
Process Equipment	Connectors and Covers	All	Normal	Immediately after any adjustments and once every 3 years thereafter.	Immediately after any adjustments and once every 5 years thereafter.
		All	Thermal Cycling.	Bi-annually.	Bi-annually.
		All	Vibration	Annually.	Annually.
	Control Valves	Gas/Vapour/LPG	Normal	Annually.	Once every 5 years.
		Gas/Vapour/LPG	Thermal Cycling	Bi-annually.	Once every 5 years.
	Block Valves – Rising Stem	Gas/Vapour/LPG	All	Annually.	Once every 5 years.
	Block Valves – Quarter Turn	Gas/Vapour/LPG	All	Once every 3 years.	Once every 5 years.
	Compressor Seals[1]	All	All	Monthly.	Monthly.
	Pump Seals	All	All	Quarterly.	Quarterly.
	Pressure Relief Valves	All	All	Annually.	Annually.
	Open-ended Lines	All	All	Annually.	Annually.
	Emergency Vent and Blowdown	All	All	Quarterly.	Quarterly.

Table 3: Suggested leak screening frequencies for equipment components, presented by component category and type.					
Source Category	**Type of Component**	**Service**	**Application**	**Screening Frequency**	
				Transmission & Storage	**Distribution[3]**
	Systems[2]				
Vapour Collection Systems	Tank Hatches	All	All	Monthly.	N/A
	Pressure-Vacuum Safety Valves	All	All	Monthly.	N/A

N/A - Denotes "Not Applicable".
1 Alternatively, institute a predictive maintenance program monitor seal performance.
2 Emergency vents and blowdown systems should be screened during periods when relief or blowdown events are not occurring to determine the extent of any leakage into these systems. Such measurements must be done in a safe manner that either precludes the potential for an emergency relief or blowdown event during the measurement or precludes exposing workers to unsafe conditions in the event of such an event.
3 Source categories that do not normally apply to gas distribution and are more indicative of a transmission and storage service application are assigned the same screening frequency as transmission and storage; otherwise, the screening frequency is set to once every 5 years which is consistent with current industry practice.

Table 4: Suggested leak screening frequencies for equipment components, presented in the order of decreasing screening frequency.					
Screening Frequency		**Source Category**	**Type of Component**	**Service**	**Application**
Transmission & Storage	**Distribution[3]**				
Immediately after any adjustments and once every 5 years thereafter.	Immediately after any adjustments and once every 5 years thereafter.	Process Equipment	Connectors and Covers	All	Normal
Monthly.	N/A	Vapour Collection Systems	Tank Hatches	All	All
Monthly.	N/A	Vapour Collection Systems	Pressure-Vacuum Safety Valves	All	All
Monthly.	Monthly.	Process Equipment	Compressor Seals[1]	All	All
Quarterly.	Quarterly.	Process Equipment	Pump Seals	All	All
Quarterly.	Quarterly.	Process Equipment	Emergency Vent and Blowdown Systems[2]	All	All

Table 4: Suggested leak screening frequencies for equipment components, presented in the order of decreasing screening frequency.

Screening Frequency		Source Category	Type of Component	Service	Application
Transmission & Storage	**Distribution[3]**				
Bi-annually.	Bi-annually.	Process Equipment	Connectors and Covers	All	Thermal Cycling.
Bi-annually.	Bi-annually.	Process Equipment		Gas/Vapour/LPG	Thermal Cycling
Annually.	Annually.	Process Equipment	Connectors and Covers	All	Vibration
Annually.	Once every 5 years.	Process Equipment	Control Valves	Gas/Vapour/LPG	Normal
Annually.	Once every 5 years.	Process Equipment	Block Valves – Rising Stem	Gas/Vapour/LPG	All
Annually.	Once every 5 years.	Process Equipment	Pressure Relief Valves	All	All
Annually.	Annually.	Process Equipment	Open-ended Lines	All	All
Once every 5 years.	Once every 5 years.	Process Equipment	Block Valves – Quarter Turn	Gas/Vapour/LPG	All

N/A - Denotes "Not Applicable".

1 Alternatively, institute a predictive maintenance program monitor seal performance.

2 Emergency vents and blowdown systems should be screened during periods when relief or blowdown events are not occurring to determine the extent of any leakage into these systems. Such measurements must be done in a safe manner that either precludes the potential for an emergency relief or blowdown event during the measurement or precludes exposing workers to unsafe conditions in the event of such an event.

3 Source categories that do not normally apply to gas distribution and are more indicative of a transmission and storage service application are assigned the same screening frequency as transmission and storage; otherwise, the screening frequency is set to once every 5 years which is consistent with current industry practice.

6 APPENDIX II - COMPONENT-SPECIFIC CONTROL OPTIONS

Sections 5.1 to 5.9 present potential options for eliminating or controlling chronic leaks for each of the following common types of equipment components, respectively:

- Reciprocating compressors.
- Centrifugal compressors.
- Valve stem packing systems.
- Sewers and drains.
- Pump seals.
- Flanged and threaded connections.
- Pressure relief devices.
- Open-ended valves and lines.
- Sampling points.

6.1 Reciprocating Compressors

Packings are used on reciprocating compressors to control leakage around the piston rod on each cylinder. A schematic diagram of a conventional packing system is presented in Figure 2. Typically, the distance piece is either left open with the vent piping connected directly to the packing case, or the distance piece is closed and the vents may be connected to both the packing case and the distance piece. The packing and distance piece vents are commonly routed outside the building to the atmosphere, but, ideally, should be connected to an emission controlling vent system. The latter approach provides continuous treatment of any emissions and allows for more convenient scheduling of any required maintenance to the packing system.

6.1.1 Vent Screening Systems

It is good practice to install instrumentation on the vent lines to indicate excessive vent rates and the need for maintenance. A sensitive rotameter, an orifice and pressure differential indicator providing flow indication, or a temperature element may be used depending on the application.

6.1.2 Emission-Controlling Vent Systems

Where emission-controlling vent systems are employed they should be designed to minimize the potential for either the flow of process gas through the distance piece into the compressor crank case, or air ingress to the vent system through the nose of the packing case or through the air breather on the crank case and past the wiper packing leading to the distance piece (depending on the location of the vent connections). Both conditions pose a potential explosion hazard. Additionally, the leakage of process gas into the crank case could possibly result in contamination of the lubricating oil or corrosion problems (especially if the process gas contains hydrogen sulphide).

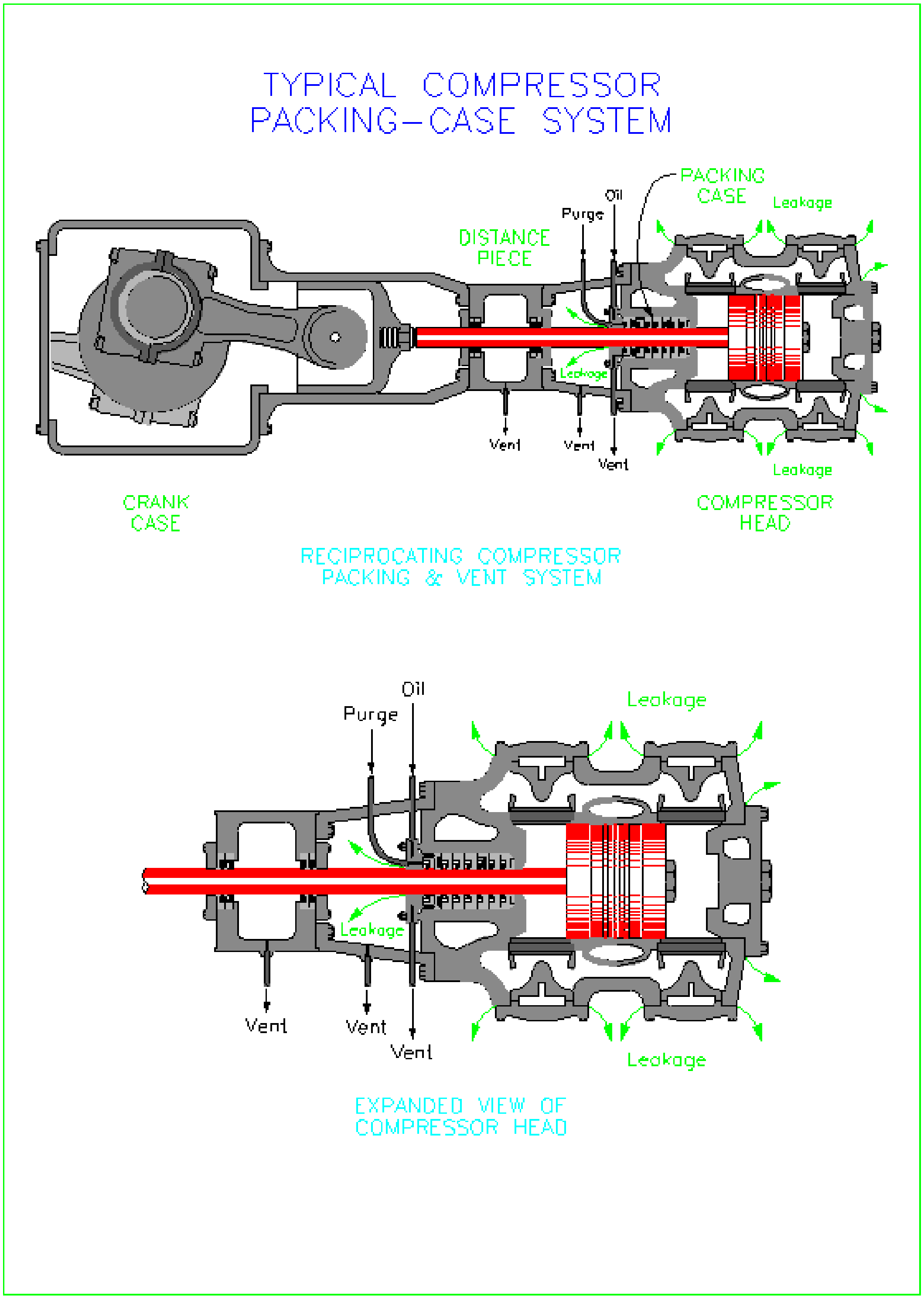


Figure 2. Schematic diagram of a piston-rod packing-case system on a reciprocating compressor.

There are three basic types of emission controlling vent systems that may be considered: low pressure vapour recovery units (e.g., for compressor fuel), incinerators, or flares. Vent gas capture may be achieved by using a small rotary vane or liquid ring vacuum pump or an ejector installed to maintain a vacuum on the vents and compress the vent gas for appropriate disposition. The gas can sometimes be used in the fuel gas system if it is compressed dry or it can be routed to a low pressure flare. The pump is usually run on a continuous basis and at a constant speed. If there is no vent gas flow, the pump produces maximum vacuum on the vent lines. To reduce the risk of pulling air into the vent gas capture system and creating an explosive atmosphere in these situations, a sweet natural gas purge controlled using a vacuum regulator may be used to limit the maximum vacuum produced

If there is not a continuous low pressure flare system on site and recovery of the vent gas is not practical, a small natural draft incinerator unit or shrouded ground-level flare may be most suitable. A vacuum pump is not usually needed with these devices if piping distances are not too great since the natural draft of the selected combustion unit will provide a slight vacuum. The incinerator or flare may be equipped with an electronic ignition system to maintain the pilot. The pilot consumes a small amount of fuel gas. A solar panel and battery may be used to power the ignition system if there is no electricity available on site.

With compressors using lubricated packings it is important to consider that the vented and drained fluids from the packing and distance piece will contain some oil. Small pressure vessels (drain pots) should be fitted on the vent and drain lines to capture these liquids. Appropriate design and operational practices must be followed to prevent gas release when these liquids are drained. If a closed process drain system is available which has a receiver vented to flare, this can be used. If a closed drain system is not available and it is a sweet application, the liquids may be injected into the flare header if the flare system is designed to accept non-volatile liquids. Fuel gas or an inert supply gas can be used to blow liquids up to the flare header and the oil eventually accumulates in the knock-out drum. Injecting high-viscosity "tallow" based lubricating oil into the flare system is not recommended (e.g., oils used for cylinder/packing lubrication), as this oil will eventually plug up the system.

6.1.3 High Performance Packing Systems

The effective life of packing systems can be increased by using more refined designs with tighter tolerances, smoother finishes, o-rings between packing cups and lapped cup surfaces. These changes must, however, be coupled with improved rod surfaces and alignment and increased packing case maintenance to be effective.

6.1.4 Unit Shutdown Practices

Leakage into unit blowdown systems can be a significant source of fugitive emissions from compressors. The amount of leakage is greatest when the compressor has been depressurized promoting leakage past the seats of the upstream and downstream unit isolation valves into the unit blowdown system. When the unit is left pressurized, leakage is only promoted past the seat of the unit blowdown valve. Thus, it is generally good practice to leave compressors pressurized when they are not running if this can be tolerated. The compressor can remain pressurized, but this should be reviewed on a case-by-case basis to ensure that the correct packing arrangement is installed.

6.1.5 <u>Static Packing Systems</u>

If compressors are left pressurized when shut down, emissions from the compressor seals may be eliminated during those periods by installing a static packing system to effect a seal around the piston rod after the compressor is stopped. This helps contain the gas in the compressor cylinders and eliminates the need to maintain barrier gas flow when the compressor is stopped. Leakage from cylinder gaskets and unloader glands can still occur. The emissions during operation are unaffected except that space taken up by the static packing may dictate that a less sophisticated running packing be used.

A static packing system replaces some cups in the packing case (it is usually necessary to lap the case). It comprises a conformable seal made of relatively soft rubber or teflon. The seal is brought into contact with the compressor rod by pressurized gas when the compressor is stopped. The amount of pressure required to actuate the seal is normally about half of the pressure in the cylinder; although, this may be higher. When the actuating pressure is lowered, the seal is released and the compressor may be restarted.

Static packing systems are not applicable to all compressors, (usually because of space and design limitations).

6.1.6 <u>Valve Cap Leakage</u>

Leakage past the valve caps, as depicted in Figure 2, is really only a problem with improperly specified O-Rings (i.e., due to explosive de-compression), or where lead or aluminum seals are used in lieu of O-Rings (such as EI, or IR compressors).

6.2 <u>Centrifugal Compressors</u>

Centrifugal compressors generally require shaft end seals between the compressor and bearing housings. Face contact oil lubricated mechanical seals or oil ring shaft seals are commonly used in hydrocarbon services. Dry gas shaft seals are frequently applied in many process and natural gas services and are the preferred choice for centrifugal compressors due to their lower leakage potential.

There are several options for reducing atmospheric emissions from the seals on centrifugal compressors: emission controlling vent systems (degassing drum vent control) for mechanical contact and oil film seals, dry gas seals and pressurized motor drive compressors.

6.2.1 <u>Emission-Controlling Vent Systems Used with Conventional Seals</u>

Face contact seals use two sealing rings held in close contact by a spring mechanism balanced with fluid pressures from the process gas and seal oil. An oil ring seal uses a journal type ring which is sealed with pressurized and circulating oil. Both oil lubricated face contact and oil film seals, often arranged in the double configuration, use oil at a pressure higher than the process gas pressure. They provide a positive seal from gas leakage along the shaft to the atmosphere; however, other emissions are associated with the system.

Some oil leaks inward through the seal and is collected in drain traps before being returned to the reservoir. Gas from the traps should be routed to an emission controlling vent system or back to the compressor suction. Any installations which vent the traps directly to atmosphere will have very high emissions and losses of process gas. The vent on lube oil degassing drums should therefore be tied in to an emission-controlling vent gas system provided this does not impose excessive backpressure on the degassing drum and lube oil reservoir.

6.2.2 Dry Gas Seals

Dry gas seals generally offer substantially reduced emissions compared to wet seal systems, depending on the vent gas controls provided, are commonly specified for new centrifugal compressors and can be retrofit to existing units. Additionally, when properly applied, gas seals often yield both capital and operating cost savings over conventional oil lubricated seals. The capital savings are due to the simplification of the oil system by deletion of the seal oil part of the system. Operational savings can be realized in services where clean seal gas is available due to the longer running life of the essentially non-contacting seals.

Dry gas seals operate without oil. The seal has two precision machined sealing plates, usually one of silicon carbide or tungsten carbide and one of carbon. The seals are separated by clean, filtered seal gas which is used to create a pressure dam effect involving radial or spiral groves in one seal face. Due to very close running clearances, leakage rates are very low. Per seal face set leakage rates of about 0.5 kg/h can be expected, depending on the seal size and pressure differential.

The pressure differential across the seal must be maintained or the hydrodynamic forces will not separate the faces. High vent back-pressure can therefore cause seal failure. To prevent loss of this pressure differential in applications involving single seals and low operating pressures, the outer seal vent is commonly routed to atmosphere at a safe location. The outer seal chamber is typically purged with nitrogen to prevent local discharge to atmosphere.

A tandem gas seal arrangement is available. The tandem arrangement provides protection in the event the inboard seal fails, and it is becoming the minimum standard for high pressure applications with flammable gases. The inter-seal vent can be routed to an appropriate emissions controlling vent system. Emissions are still typical at the outer seal vent.

6.3 Valves

There are two main locations on a typical valve where leakage may occur: (1) from the valve body and around the valve stem, and (2) past the valve seat. The latter potential source of emissions is only an environmental concern if the line downstream of the valve is open to the atmosphere, and if so, it is classified as an open-ended line.

A conventional process valve uses a packing gland to prevent the leakage of process fluid around the stem. The valve is equipped with a hand wheel or handle for manual operation, or an actuator for automatic control. The stem, itself, may be operated through either a sliding/rising or rotary motion depending on the type of valve.

The effectiveness of the packing gland is determined by the tightness of the packing material around the stem and the pressure of the process fluid. Over time the gland gradually looses some of the packing material due to extrusion and wear and must be tightened to maintain a proper seal. At some point, complete repacking of the gland is required.

Over-tightening a packing gland can prevent or make manual operation of a valve difficult. For control valves, it can cause slow stem movement, poor process control, bad seating and possibly stalled conditions. It can also damage the packing and reduce its life.

Rotary or quarter-turn valves where stems turn 90^o (e.g., plug, ball or butterfly valves) tend to be easier to seal than sliding-stem valves (e.g., gate or globe valves). This is because quarter-turn valves have less packing-to-shaft travel distance for each stroke of the valve, and therefore, less packing wear (Brestel et al., 1992). Additionally, quarter-turn valves have less of a tendency to draw dust and other abrasives into the packing gland during their operation. Wear on the stem packing is approximately 10 percent of sliding-stem valves. Leak frequencies and average leak rates for quarter turn valves are less than half of that for rising stem valves and only a quarter of that for gate valves in particular. Accordingly, where practicable to use, quarter-turn valves should be the preferred choice for manual and automated on/off applications in gas, LNG or LPG service.

For demanding service applications (e.g., vibration or thermal cycling) where leak frequencies of less than 2 percent are not being achieved and the use of rotary or quarter-turn valves is not practicable, consideration should be given to using high performance packing materials and stem seal designs such as live-loaded packings, bellows seals and dual packing with bleed or environmental screening ports.

Overall, graphite packing systems are reported to provide the best leak control. One graphite packing set at the outboard end is normally sufficient, with the intervening packing box volume filled with spacer rings (Lipton, 1992). Where preformed graphite rings are installed, braided end rings are necessary.

Polymeric packing may be quite acceptable in many undemanding service applications with temperatures below 200^oC. Braided non-asbestos materials are reported to be less effective than the previous braided asbestos packing and are limited to applications with process temperatures below 150^oC (Aikin, 1992). The problems are with the blocking agents and fibre size. The fibre sizes of the new materials are larger than that of asbestos, so voids between the fibres are larger. These voids are filled with various blocking agents, such as polytetrafluoroethylene (PTFE), which tend to extrude or burn off at high temperatures. In addition, the large fibres fracture at relatively low packing stresses (i.e., 27.6 MPa), and with relatively low numbers of stem stroking cycles. Consequently, they are subject to inherently high consolidation and therefore should be live-loaded and used with anti-extrusion rings.

An important consideration in changing to alternate packing materials is the potential for an increase in the force needed to stroke the valve. It may be necessary to install larger handles or handwheels on manual valves, and more powerful actuators on the control valves. Additionally, the packing follower (or gland) bolts may not be capable of generating enough stress to compress the packing (Wright, 1993). The coefficient of friction of many asbestos replacement materials prevents normal packing in multiple ring packing boxes from stressing the lower rings to the level required for sealing (Wright, 1993).

The valve must be in good mechanical condition to ensure optimum packing performance and low emissions. The stem should be straight and unmarked (especially for control valves). The packing box should also be unmarked and any unused bleed-off holes should be plugged.

Extended packing housings may be required to accommodate some alternate packing materials.

Packing removal (for inspection and repacking) with a metal pick is laborious and frequently results in marring of the stem and packing box wall. Specially designed water picks are commercially available which are much faster and easier to use, and which do not mar the stem or wall services (Lipton, 1992).

Maintenance of static packing by adjusting gland bolts is required to assure emission control.

6.4 Pumps

Excessive seal leakage is a direct symptom of the misapplication of a seal and improper operation of the seal or its associated rotating or reciprocating equipment. Few seals leak abnormally, and these can be readily identified and corrected. A strong correlation exists between the level of seal leakage and the mean time between failure (MTBF) of its associated equipment.

Mechanical seals should be the minimum standard for use on centrifugal pumps used in light hydrocarbon liquid service except where leakage from the pumps may pose an occupational health hazard (i.e., where the liquid contains large concentrations of benzene) or the pumped fluid has a specific gravity less than 0.4 (because single and tandem seals may be inadequately lubricated by such fluids). The available options for reducing emissions from the base case of single mechanical seals are, in the general order of increasing cost and performance capabilities:

- Bellows Seals,
- Throttle Bushing with Vent Diversion,
- Tandem Mechanical Seals,
- Double Mechanical Seals,
- Sealless Pumps,
- Gas Seals for Volatile Services, and

- Blow-cases Instead of Pumps.

Double seals are the best choice for maximum containment of the process fluid unless a vapour control system or sealless pumps are used. A double mechanical seal can be expected to reduce leakage to almost zero when operating properly. There are no direct or indirect increases in emissions associated with the use of this technology except leakage of the barrier fluid which is usually not a VOC or harmful substance. Some leakage of the barrier fluid into the product must be tolerated. Double seals may generate slightly more heat than tandem and single seals and additional cooling medium flow or auxiliary coolers may be required.

Sealless pumps are generally limited to single stage applications. Canned motor and magnetic drive pumps are available in sizes up to approximately 500 kW, and 50 kW, respectively.

Gas seals are not applicable to most pump services. Only very clean, volatile services such as propane are suitable.

A principal reason for using blow-cases is that they do not require electrical power; however they may offer potential for reduction of emissions in liquid moving applications as the only seals required are valve packings. Where blow cases are used the motive gas should be discharged to an emissions controlling vent system.

If change out of a mechanical seal is called for, upgrading of the existing seal chamber with an enlarged-bore retrofit seal chamber, as specified in the ANSI B-73 standard and API Standard 610, should be considered. Introduced in the mid-1980's, enlarged bore seal chambers with increased radial clearance between the mechanical seal and seal chamber wall, provide better circulation of liquid to and from seal faces. Improved lubrication and heat removal (cooling) of seal faces extend seal life and lower maintenance costs. Extensive field and laboratory evaluations have shown that, on average, seal life is doubled when a properly designed and applied seal is operated in an enlarged-bore seal chamber (Battilana, 1989).

Reciprocating pumps have similar sealing problems to reciprocating compressors. The performance of the packing systems may be greatly enhanced by installing a barrier fluid system similar to that described for reciprocating compressors (Section 6.1).

6.5 Threaded and Flanged Connections

A properly installed and maintained mechanical coupling or threaded or flanged connection can provide essentially leak free service for extended periods of time; however, there are many factors that can cause leakage problems to arise. Some of the common causes are summarized in Table 5. For instance, it is not uncommon for some connections to be inadvertently left un-tightened following a facility turnaround or specific inspection and maintenance activity (especially on fuel gas piping). Most of the listed issues can be addressed by conducting leak checks immediately following any changes or adjustments to a connection.

Table 5: Common causes of leakage from flanged and threaded connections.	
Flanged Connections	**Threaded Connections**
Thermal stress and cycles.	Thermal stress and cycles.
Incorrect or re-used gasket material.	Dirty, roughly cut or damaged threads.
Missing gaskets.	Crossed threads.
Misalignment of piping or flange faces.	Poor quality or no thread sealant used.
Dirty or damaged flange faces.	Misaligned piping.
Inadequate or non-uniform bolt stresses.	Inadequate tightening of the connection.
Improper tightening sequence.	External abuse.
External abuse.	

The application of proper mechanical design standards and material specifications are necessary to ensure adequate performance of connectors under load conditions (see ANSI Standards B16.5 and B31.3 for flanges).

Consideration should be given to reducing the number of threaded and flanged connections in designs and welding unnecessary connections at existing facilities (e.g., during convenient turnaround or shutdown periods).

6.6 Pressure Relief Devices

When relief or safety valves reseat after having been activated they often leak because the original tight seat is not regained either due to damage of the seating surface or a build-up of foreign material on the seat plug. As a result, they are often responsible for fugitive emissions. Another problem develops if the operating pressure is too close to the set pressure, causing the valve to "simmer" or "pop" at the set pressure.

It is good practice, where a relief or safety valve may require servicing between scheduled facility turnarounds, to install a block valve upstream of a relief system to facilitate early replacement or repair of the components. This use of an upstream block valve is allowed under most Boiler and Pressure Vessel Acts, provided the valve is normally car-sealed open.

In demanding service applications consideration may also be given to specifying the use of resilient valve seats (elastomeric o-rings), as they have superior re-sealing characteristics, or installing a rupture disk immediately upstream of the relief valve. A pressure gauge or suitable telltale indicator is needed between the disk and the relief valve to indicate when the disk has failed (ASME, 2004). The rupture disk will shield the relief valve from corrosive process fluids during normal operation. If an overpressure condition occurs, replacement of the disk may be delayed until the next scheduled shutdown period. In the interim, protection against over-pressuring is provided by the relief valve. The rupture disk should have a set pressure that is slightly higher than that of the relief valve to help avoid simmering problems.

Where relief valves are connected to a common vent system leakage is difficult to detect and, as a result, may lead to a significant level of waste and cause unnecessary emissions. Leakage into flare systems is considered to have a flaring efficiency of only 60 percent because the flare systems are sized normally for emergency relief, and performs less efficiently at low flows (U.S. EPA, 1980).

6.7 Open-ended Valves and Lines

An open-ended valve is any valve that may release process fluids directly to the atmosphere in the event of leakage past the valve seat. The leakage may result from improper seating due to an obstruction or sludge accumulation, or because of a damaged or worn seat. An open-ended line is any segment of pipe that may be attached to such a valve and that opens to the atmosphere at the other end.

Few open-ended valves and lines are designed into process systems; however, actual numbers can be quite significant at some sites due to poor operating practices and various process modifications that may occur over time.

Some common examples of instances where this type of source may occur are as follows: scrubber blowdowns, truck loading and unloading connections on storage tanks, instrument block valves where the instrument has been removed for repair or other reasons, manual methanol injection points on pipelines, drains, and purge or sampling points.

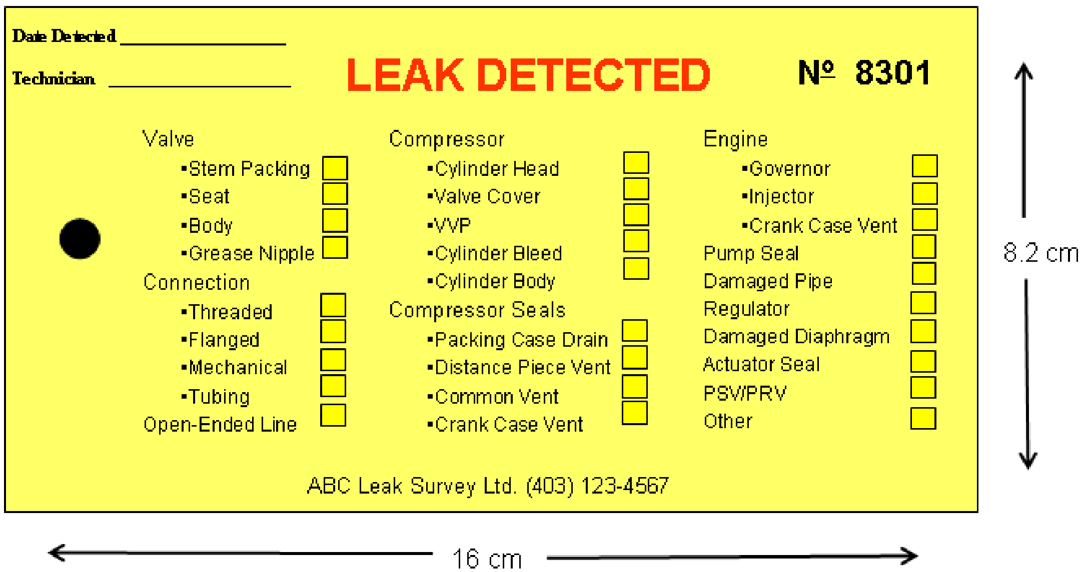
Fugitive emissions from these sources should be controlled by installing a stopper (for example, a cap, plug or blind flange) on open-ended valves, and a stopper or a second block valve on open-ended lines. If the open end of a line is easily accessible and in close proximity to the block valve, a stopper is usually the best solution. Otherwise, a second block valve should be installed. Where a stopper is used it should be chained so it is not lost or misplaced when temporarily removed for use of the valve or line. A swivel connection may be needed to allow easy removal and replacement of the stopper.

6.8 Sampling Points

Natural gas sampling systems are generally only relevant at gas transmission and selected upstream facilities.

Closed loop sampling is the primary method for controlling emissions from pressurized sampling points. This method returns purge fluid back to the process stream. Where this is not practicable, the purge material can be directed to the flare system.

7 APPENDIX III – SAMPLE LEAKER TAG



8 APPENDIX IV – SAMPLE DATA SHEETS

LEAK SURVEY FORM									Page __ of ___	
Site Name:									**Date**	
Operating Company:									**Technicians:**	
Location:										
Survey Contractor:										
Name or Identification Code	**Type**	**Leaker Tag No.**	**Process Tag No.**	**Type**	**Process Stream**		**Size**	**Measurement Method**	**THC Leak Rate (m^3/h at STP)**	**Repaired (Y/N)**
					Type	**Odourized (Y/N)**				
						Y/N				Y/N
						Y/N				Y/N
						Y/N				Y/N
						Y/N				Y/N
						Y/N				Y/N
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						Y/N				Y/N
						Y/N				Y/N

Direct Leak Rate Measurement Datasheet

Location:										
Date:										
Tag No.	**Source Data**			**Measurement Data**						**Comments**
	Type of Component	**Size**	**Process Unit**	**Meter Type**	**Leak Rate (m^3/h at STP)**	**Time (hour:minute)**	**THC Concentration (mol %)**	**Temp (C)**	**Pressure (kPa)**	

CV – Control Valve
NV – Needle Valve
BV – Ball Valve
GBV – Globe Valve
GTV – Gate Valve
PV – Plug Valve

BFV – Butterfly Valve
MW – Manway
PRV – Pressure Relief Valve
O – Open-Ended Line
PR – Pressure Regulator
R – Regulator

GOV – Govenor
PIG – Pig Trap Cover
FC – Filter Cover
VC – Valve Cap

C - Coupling
F – Flange
T – Threaded Fitting
TB – Tube Fitting
PS – Pump Seal
CS – Compressor Seal

PG – Sweet Process Gas
FG – Fuel Gas
S – Sales Gas
P – Propane
C2 – Ethane

C – Condensate
MP – Multipahse
O – Oil
CO – Crude Oil
AG – Acid Gas

9 APPENDIX V - US EPA METHOD 21

EMISSION MEASUREMENT TECHNICAL INFORMATION CENTRE
NSPS TEST METHOD

(EMTIC M-21, 2/9/93)

Method 21 - Determination of Volatile Organic Compound Leaks

1. APPLICABILITY AND PRINCIPLE

1.1 Applicability. This method applies to the determination of volatile organic compound (VOC) leaks from process equipment. These sources include, but are not limited to, valves, flanges and other connections, pumps and compressors, pressure relief devices, process drains, open-ended valves, pump and compressor seal system degassing vents, accumulator vessel vents, agitator seals, and access door seals.

1.2 Principle. A portable instrument is used to detect VOC leaks from individual sources. The instrument detector type is not specified, but it must meet the specifications and performance criteria contained in Section 3. A leak definition concentration based on a reference compound is specified in each applicable regulation. This procedure is intended to locate and classify leaks only, and is not to be used as a direct measure of mass emission rate from individual sources.

2. DEFINITIONS

2.1 Leak Definition Concentration. The local VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is present. The leak definition is an instrument meter reading based on a reference compound.

2.2 Reference Compound. The VOC species selected as an instrument calibration basis for specification of the leak definition concentration. (For example, if a leak definition concentration is 10,000 ppm as methane, then any source emission that results in a local concentration that yields a meter reading of 10,000 on an instrument meter calibrated with methane would be classified as a leak. In this example, the leak definition is 10,000 ppm, and the reference compound is methane.)

2.3 Calibration Gas. The VOC compound used to adjust the instrument meter reading to a known value. The calibration gas is usually the reference compound at a known concentration approximately equal to the leak definition concentration.

2.4 No Detectable Emission. The total VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is not present. Since background VOC concentrations may exist, and to account for instrument drift and imperfect

GAS SENSOR CALIBRATION RECORD		Page ___ of ___	
Site Name:		Date	
Operating Company:		Technicians:	
Location:			
Industry Sector:			
Facility Type:			

Device	Manufacturer	Serial No.	Date of Last Calibration		Field Calibration Checks						
			Factory	Office	Day	Time	Zero Check	Span Check			Units of Measure
							Reading	Actual	Reading	%Error	

FLOW METER CALIBRATION RECORD		Page ___ of ___	
Site Name:		**Date**	
Operating Company:		**Technicians:**	
Location:			
Industry Sector:			
Facility Type:			

Device	Manufacturer	Serial No.	Date of Last Calibration		Field Calibration Checks						
					Day	Time	Zero Check	Span Check			Units of Measure
			Factory	Laboratory			Reading	Reference	Reading	%Error	

reproducibility, a difference between the source surface concentration and the local ambient concentration is determined. A difference based on the meter readings of less than a concentration corresponding to the minimum readability specification indicates that a VOC emission (leak) is not present. (For example, if the leak definition in a regulation is 10,000 ppm, then the allowable increase is surface concentration versus local ambient concentration would be 500 ppm based on the instrument meter readings.)

2.5 Response Factor. The ratio of the known concentration of a VOC compound to the observed meter reading when measured using an instrument calibrated with the reference compound specified in the applicable regulation.

2.6 Calibration Precision. The degree of agreement between measurements of the same known value, expressed as the relative percentage of the average difference between the meter readings and the known concentration to the known concentration.

2.7 Response Time. The time interval from a step change in VOC concentration at the input of the sampling system to the time at which 90 percent of the corresponding final value is reached as displayed on the instrument readout meter.

3. APPARATUS

3.1 Monitoring Instrument.

3.1.1 Specifications

a. The VOC instrument detector shall respond to the compounds being processed. Detector types which may meet this requirement include, but are not limited to, catalytic oxidation, flame ionization, infrared absorption, and photoionization.

b. The instrument shall be capable of measuring the leak definition concentration specified in the regulation.

c. The scale of the instrument meter shall be readable to + or - 5 percent of the specified leak definition concentration.

d. The instrument shall be equipped with a pump so that a continuous sample is provided to the detector. The nominal sample flow rate shall be 0.1 to 3.0 liters per minute.

e. The instrument shall be intrinsically safe for operation in explosive atmospheres as defined by the applicable U.S.A. standards (e.g., National Electrical Code by the National Fire Prevention Association).

f. The instrument shall be equipped with a probe or probe extension for sampling not to exceed 1/4 in. in outside diameter, with a single end opening for admission of sample.

3.1.2 Performance Criteria.

a. The instrument response factors for the individual compounds to be measured must be less than 10.

b. The instrument response time must be equal to or less than 30 seconds. The response time must be determined for the instrument configuration to be used during testing.

c. The calibration precision must be equal to or less than 10 percent of the calibration gas value.

d. The evaluation procedure for each parameter is given in Section 4.4.

3.1.3 Performance Evaluation Requirements.

a. A response factor must be determined for each compound that is to be measured, either by testing or from reference sources. The response factor tests are required before placing the analyzer into service, but do not have to be repeated at subsequent intervals.

b. The calibration precision test must be completed prior to placing the analyzer into service, and at subsequent 3-month intervals or at the next use whichever is later.

c. The response time test is required before placing the instrument into service. If a modification to the sample pumping system or flow configuration is made that would change the response time, a new test is required before further use.

3.2 Calibration Gases.

The monitoring instrument is calibrated in terms of parts per million by volume (ppm) of the reference compound specified in the applicable regulation. The calibration gases required for monitoring and instrument performance evaluation are a zero gas (air, less than 10 ppm VOC) and a calibration gas in air mixture approximately equal to the leak definition specified in the regulation. If cylinder calibration gas mixtures are used, they must be analyzed and certified by the manufacturer to be within + or - 2 percent accuracy, and a shelf life must be specified. Cylinder standards must be either reanalyzed or replaced at the end of the specified shelf life. Alternatively, calibration gases may be prepared by the user according to any accepted gaseous preparation procedure that will yield a mixture accurate to within + or - 2 percent. Prepared standards must be replaced each day of use unless it can be demonstrated that degradation does not occur during storage.

Calibrations may be performed using a compound other than the reference compound if a conversion factor is determined for that alternative compound so that the resulting meter readings during source surveys can be converted to reference compound results.

4. PROCEDURES

4.1 Pretest Preparations. Perform the instrument evaluation procedure given in Section 4.4 if the evaluation requirement of Section 3.1.3 have not been met.

4.2 Calibration Procedures. Assemble and start up the VOC analyzer according to the manufacturer's instructions. After the appropriate warmup period and zero internal calibration procedure, introduce the calibration gas into the instrument sample probe. Adjust the instrument meter readout to correspond to the calibration gas value. (Note: If the meter readout cannot be adjusted to the proper value, a malfunction of the analyzer is indicated and corrective actions are necessary before use.)

4.3 Individual Source Surveys.

4.3.1 Type I - Leak Definition Based on Concentration. Place the probe inlet at the surface of the component interface where leakage could occur. Move the probe along the interface periphery while observing the instrument readout. If an increased meter reading is observed, slowly sample the interface where leakage is indicated until the maximum meter reading is obtained. Leave the probe inlet at this maximum reading location for approximately two times the instrument response time. If the maximum observed meter reading is greater than the leak definition in the applicable regulation, record and report the results as specified in the regulation reporting requirements. Examples of the application of this general technique to specific equipment types are:

a. Valves - Leaks usually occur at the seal between the stem and the housing. Place the probe at the interface where the stem exits the packing and sample the stem circumference and the flange periphery. Survey valves of multipart assemblies where a leak could occur.

b. Flanges and Other Connections - Place the probe at the outer edge of the flange-gasket interface and sample the circumference of the flange.

c. Pump or Compressor Seals - If applicable, determine the type of shaft seal. Perform a survey of the local area ambient VOC concentration and determine if detectable emissions exist as described above.

d. Pressure Relief Devices - For those devices equipped with an enclosed extension, or horn, place the probe inlet at approximately the centre of the exhaust area to the atmosphere.

e. Process Drains - For open drains, place the probe inlet as near as possible to the centre of the area open to the atmosphere. For covered drains, locate probe at the surface of the cover and traverse the periphery.

f. Open-ended Lines or Valves - Place the probe inlet at approximately the centre of the opening of the atmosphere.

g. Seal System Degassing Vents, Accumulator Vessel Vents, Pressure Relief Devices - If applicable, observe whether the applicable ducting or piping exists. Also, determine if any sources exist in the ducting or piping where emissions could occur before the control device. If the required ducting or piping exists and there are no sources where the emissions could be vented to the atmosphere before the control device, then it is presumed that no detectable emissions are present. If there are sources in the ducting or piping where emissions could be vented or sources where leaks could occur, the sampling surveys described in this section shall be used to determine if detectable emissions exist.

h. Access door seals - Place the probe inlet at the surface of the door seal interface and traverse the periphery.

4.3.2 Type II - "No Detectable Emission". Determine the ambient concentration around the source by moving the probe randomly upwind and downwind around one to two meters from the source. In case of interferences, this determination may be made closer to the source down to no closer than 25 centimetres. Then move the probe to the surface of the source and measure as in 4.3.1. The difference in these concentrations determines whether there are no detectable emissions. When the regulation also requires that no detectable emissions exist, visual observations and sampling surveys are required. Examples of this technique are: (a) Pump or Compressor Seals - Survey the local area ambient VOC concentration and determine if detectable emissions exist. (b) Seal System Degassing Vents, Accumulator Vessel Vents, Pressure Relief Devices - Determine if any VOC sources exist upstream of the device. If such ducting exists and emissions cannot be vented to the atmosphere upstream of the control device, then it is presumed that no detectable emissions are present. If venting is possible sample to determine if detectable emissions are present.

4.3.3 Alternative Screening Procedure.

4.3.3.1 A screening procedure based on the formation of bubbles in a soap solution that is sprayed on a potential leak source may be used for those sources that do not have continuously moving parts, that do not have surface temperatures greater than the boiling point or less than the freezing point of the soap solution, that do not have open areas to the atmosphere that the soap solution cannot bridge, or that do not exhibit evidence of liquid leakage. Sources that have these conditions present must be surveyed using the instrument technique of Section 4.3.1 or 4.3.2.

4.3.3.2 Spray a soap solution over all potential leak sources. The soap Solution may be a commercially available leak detection solution or may be prepared using concentrated detergent and water.

A pressure sprayer or squeeze bottle may be used to dispense the solution. Observe the potential leak sites to determine if any bubbles are formed. If no bubbles are observed, the source is presumed to have no detectable emissions or leaks as applicable. If any bubbles are observed, the instrument techniques of Section 4.3.1 or 4.3.2 shall be used to determine if a leak exists, or if the source has detectable emissions, as applicable.

4.4 Instrument Evaluation Procedures. At the beginning of the instrument performance evaluation test, assemble and start up the instrument according to the manufacturer's instructions for recommended warmup period and preliminary adjustments.

4.4.1 Response Factor.

4.4.1.1 Calibrate the instrument with the reference compound as specified in the applicable regulation. For each organic species that is to be measured during individual source surveys, obtain or prepare a known standard in air at a concentration of approximately 80 percent of the applicable leak definition unless limited by volatility or explosivity. In these cases, prepare a standard at 90 percent of the standard saturation concentration, or 70 percent of the lower explosive limit, respectively. Introduce this mixture to the analyzer and record the observed meter reading. Introduce zero air until a stable reading is obtained. Make a total of three measurements by alternating between the known mixture and zero air. Calculate the response factor for each repetition and the average response factor.

4.4.1.2 Alternatively, if response factors have been published for the compounds of interest for the instrument or detector type, the response factor determination is not required, and existing results may be referenced. Examples of published response factors for flame ionization and catalytic oxidation detectors are included in the Bibliography.

4.4.2 Calibration Precision. Make a total of three measurements by alternately using zero gas and the specified calibration gas. Record the meter readings. Calculate the average algebraic difference between the meter readings and the known value. Divide this average difference by the known calibration value and multiply by 100 to express the resulting calibration precision as a percentage.

4.4.3 Response Time. Introduce zero gas into the instrument sample probe. When the meter reading has stabilized, switch quickly to the specified calibration gas. Measure the time from switching to when 90 percent of the final stable reading is attained. Perform this test sequence three times and record the results. Calculate the average response time.

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Attachment B

Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry. Prepared by Clearstone Engineering Ltd. for Canadian Energy Partnership for Environmental Innovation (CEPEI), April 16, 2007

TECHNICAL REPORT

Fugitive Emissions Pilot Project:

Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry

PREPARED FOR:

Canadian Energy Partnership for Environmental Innovation (CEPEI)
75 Winbledon Road
Guelph, Ontario
N1H 7V7

PREPARED BY:

Clearstone Engineering Limited
700, 900-6 Avenue S.W.
Calgary, Alberta T2P 3K2

April 16, 2007

Executive Summary

A fugitive emission measurement program was conducted from 2004 to 2006 at a representative selection of natural gas transmission, storage and distribution facilities from across Canada. This was done as part of a fugitive emissions pilot project sponsored by CRESTech and included the development of a formal leak detection and measurement protocol aimed at providing reliable and consistent results. The objectives of this work were to improve the quality, coverage and compatibility of emission factors and average unit-specific component counts used to estimate fugitive methane emissions from the Canadian natural gas transmission, storage and distribution industry, and to calculate the uncertainty bounds associated with these industry-specific emission factors.

The selected natural gas facilities were chosen, in consultation with the project sponsors, to provide increased data for the source categories estimated to contribute most to total uncertainty in the gas industry's national GHG emissions inventory, while covering the range of operators, geographic locations, age, and type of facility or installation. Leak detection and measurement surveys were conducted at 149 facilities across the country including 121 distribution facilities (i.e., 50 regulator/gate stations, 20 commercial meter sets, 18 farm taps, 30 residential meter sets and 3 industrial meter sets), 27 gas transmission facilities (i.e., 2 mainline block valves, 13 receipt/sales meter stations and 12 compressor stations) and 1 liquefied natural gas (LNG) storage facility. The results were combined with the data from a similar measurement program conducted in 1995/96 [1], as well as the results of several leak measurement programs sponsored by individual gas companies (i.e., Alliance Pipeline and Terasen). The combined data set represents emission survey results from 438 facilities located throughout British Columbia, Alberta, Saskatchewan, Manitoba, Ontario and Quebec and operated by the following study participants: Alta Gas, Atco Gas, Atco Pipelines, Duke Energy, Enbridge, Gaz Metro, Manitoba Hydro, TransCanada Pipelines and Union Gas. The leak measurement work was performed by Clearstone Engineering in all of these cases, with the exception of the 1995/96 study, which was performed jointly with Environment Canada.

Before combing the results, some checks were performed to confirm that the data were all from the same population (i.e., that no statistically significant changes have occurred since the 1995/96 study). The combined results show that the leak-rate distribution for most component categories is highly skewed rather than normally distributed. As a result, much greater sample sizes are needed to accurately characterize the leak rate distribution than would be the case if the distributions were normal.

While in most cases the new average emission factors have changed little from the current factors being used by the Canadian natural gas industry, in a few cases quite significant changes have occurred and the uncertainty limits on these factors have actually increased. In these cases, the developed emissions factors have been affected by a few particularly large leakers detected during the current study at different facilities. It could be argued that these data are outliers and should be excluded from the emission factor calculations. However, it has viewed that these extreme leaker results actually help to better delineate the full profile of the skewed distributions for the respective component categories. Accordingly, these extreme values were retained as valid points in the emissions distribution.

The uncertainties in the developed emission factors were determined based on a 95-percent confidence interval in accordance with the IPCC (2000) Good Practice Guidance. This differs from the current practice in the United States where the US Environmental Protection Agency has been using a 90-percent confidence interval in GHG-related uncertainty analyses.

Overall, the data collected during the 2005/06 field measurement campaign at a large selection of transmission, storage and distribution facilities has re-affirmed and highlighted a number of key findings from previous studies of fugitive emissions in the industry. No new trends or anomalies were detected in the compiled data.

There were two LNG storage facilities included in the combined data set. Both facilities were relatively new but were operated by different companies and located in different provinces. Very little equipment at either facility was actually in LNG service, beyond a few fittings on the LNG spheres and vaporizers. Most of the equipment was in natural gas service and associated with the compressor units. There was insufficient data available to draw any meaningful conclusions regarding possible difference in fugitive emissions at LNG facilities; however, there was not indication of any differences.

The component counts used to develop the emission factors were all prepared by Clearstone Engineering based on actual counts performed while at the facilities. In some cases operators also provided their own counts which were understood to have largely been derived from drawings rather than field counts. The results for smaller facilities such as distribution meter stations tended to agree well with the field counts; however, the company supplied counts for larger facilities often greatly understated the population of components determined from the field counts (i.e., by as much as an order of magnitude). This reflects the lack of detail shown on most types of drawings, particularly for third party packages such as compressors. As well, it highlights the need to improve the quality of component counts being compiled by some operators..

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1.0 Introduction

The pilot measurement program comprised two parts. The first part was to develop a standard leak measurement protocol for detecting, measuring and classifying leaks at natural gas facilities. The second part, which is the focus of this document, was to apply the protocol at a representative sampling of natural gas transmission and distribution facilities to increase the current database of leak data for the industry and then use this information to develop improved emission factors and default unit-specific component counts.

Leak detection and measurement data collected during the 2005/2006 field campaign at 149 study participant facilities were combined with data collected during recent testing programs undertaken by independent companies[1] and with the data gathered for the1995/1996 GTC/EC study of Western Canadian natural gas facilities [1]. The combined data set was used to develop emission factors for estimating fugitive natural gas losses at Canadian gas transmission, storage and distribution facilities.

A summary of the leak detection and quantification program is given in Section 2. Section 3 provides a summary of the results including the updated average emission, comparison of the developed factors to published data and average unit-specific component counts. The conclusions of the study are presented in Section 4. A graphical comparison of the emission factors, by component type, developed by the current study to those and developed by the 1995/1996 GTC/EC Study of Western Canadian natural gas facilities is given in Appendix A, along with the associated uncertainty bounds for each of the factors. Appendix B provides a graphical comparison of the average emissions to published factors. An examination of leaker data distribution profiles and cumulative leak contributions are available in Appendix C and Appendix D, respectively. Appendix E presents the confidence limits for the developed average unit-specific component counts. The changes in leak frequency and emission factors between the 1995/1996 and 2005/2006 data sets are examined in Appendix F. Finally, Appendix G provides a summary of the total losses measured during the 2005/2006 field campaign and a listing of the top leaks encountered.

[1] Data used with permission.

2.0 Field Measurement Program

The field measurement program was conducted from 2005 to 2006 at a selection of facilities which provided a uniform representation of the Canadian natural gas transmission, storage and distribution industry. This work comprised identifying all natural gas equipment leaks at each host facility, measuring the amount of emissions from each detected leak, developing equipment counts and estimating the amount of emissions from non-leaking sources. The work was completed in accordance with the Fugitive Emissions Measurement Protocol [2]. A component was considered to be leaking if it produced a screening value of 10,000 ppm or greater using a portable organic vapour analyzer when screened in accordance with US Environmental Protection Agency's Method 21.

2.1 Surveyed Facilities

Facilities included in the study were selected by the industry participants and the project steering committee with the intent of providing a uniform representation of the Canadian natural gas transmission, storage and distribution system. Consideration was given to age, type, location and operator when selecting facilities.

Measurement data collected during the study were combined with other similar leak data that were available and satisfied the basic requirements of the developed Leak Measurement Protocol. These additional data included the results of an industry sponsored leak measurement program conducted in Canada in 1995/96 [1] and several recent leak measurement campaigns sponsored by individual gas companies in Canada (namely, Alliance Pipeline and Terasen). Table 2-1 provides a summary of the compiled data sources along with the number and types of facilities that were surveyed in each of these cases. The combined data set represents survey results from 44 compressor stations, 33 sales and receipt meter stations, 47 block/control valve stations, which includes 6 border meter stations, 2 LNG storage facilities, 26 industrial meter sites, 56 commercial meter sites, 111 residential meter sites, 28 farm taps and 94 regulation/gate stations. These facilities are located throughout British Columbia, Alberta, Saskatchewan, Manitoba, Ontario and Quebec and are operated by the following study participants: Alta Gas, Atco Gas, Atco Pipelines, Duke Energy, Enbridge, Gaz Metro, Manitoba Hydro, TransCanada Pipelines and Union Gas.

Table 2-1	**Scope of Survey**													
		GAS DISTRIBUTION									GAS TRANSMISSION			
	TOTAL	Regulator / Gate Station	Commercial Meter Set	Farm Tap	Residential Meter Set	Industrial Meter Set	Block / Control Valve Station[1]	Receipt / Sales Meter Station[1]	Compressor Station[1]	Storage Facility[1]	Block / Control Valve Station	Receipt / Sales Meter Station	Compressor Station	Storage Facility
2005/2006 Facilities Surveyed	149	50	20	18	30	3	0	0	0	0	2	13	12	1
Other Surveyed Facilities[2]	106	12	15	0	14	5	22	8	8	1	12	0	9	0
TOTAL CURRENT STUDY	255	62	35	18	44	8	22	8	8	1	14	13	21	1
1995/1996 GTC/EC Study	183	32	21	10	67	18	0	0	0	0	11	12	12	0
COMBINED DATA SET	**438**	**94**	**56**	**28**	**111**	**26**	**22**	**8**	**8**	**1**	**25**	**25**	**33**	**1**

[1] Odourized transmission facilities are deemed to be in distribution service and are categorized as such for the purpose of developing average emission factors
[2] Not all equipment surveyed at some facilities

2.2 Component Screening

Equipment components in pressurized natural gas service were screened for leaks in accordance with the methodology presented by the U.S. EPA [3] and following the methodology outlined in the Fugitive Emissions Measurement Protocol [2]. The types of components surveyed included connectors, valves, pressure relief devices, open-ended lines, blowdown vents (during passive periods), regulator and actuator diaphragms, flow meters, and compressor seal vents.

Screening was conducted using ultrasonic leak detectors, bubble tests with soap solution and portable hydrocarbon vapour analyzers calibrated to methane (Bascom-Turner Gas Sentry CGI-201 and CGI-211). A screening value of 10,000 ppmv in the vicinity of the component was used at the leak definition. Component determined to be emitting based on qualitative screening techniques were also screened using quantitative screening techniques to verify the leak definition was exceeded. Identified leaking equipment components were marked with sequentially numbered tags indicating the source of the leakage.

2.3 Leak Rate Measurement

Emission rates were measured for all components determined to be leaking. The HiFlow™ Sampler was the primary instrument used to quantify emissions from leaking sources. However, flow through meters (i.e. rotary meter, diaphragm meter and rotameter) and velocity probes (i.e. hot wire anemometer, thermal dispersion anemometer, vane anemometer, and micro-tip vane anemometer) were also utilized when the source type and emission rate was appropriate. Section 4 of the Fugitive Emissions Measurement Protocol [2] outlines the leak measurement techniques applied. Data collection and reporting was done in accordance with the source classification scheme provided in Section 2 of the Protocol.

2.4 Component Counts

Detailed counts of the components in natural gas service for each facility surveyed were developed by Clearstone Engineering in accordance with the Fugitive Emissions Measurement Protocol. Independent component counts were provided by approximately half the operators. Count verification results showed significant differences between the two data sets for some facility types and highlighted some of the challenges related to obtaining an accurate component population:

- Relying on piping and instrumentation drawings to develop equipment component counts can lead to a significant underestimation of the component population. P&IDs typically lack sufficient detail to develop an accurate count, details on packaged units are generally missing (particularly, for fuel gas system piping), and open-ended lines are not shown on drawings.
- A systematic approach, such as that laid out in the Protocol, must be employed to avoid either missing equipment components or double counting.

- Process knowledge and training is needed to recognize and exclude non-target service applications such as electrical conduit, coolant, heat medium and lubricating oil.
- Facilities of the same type and size may have very different numbers of components due to differences in design practices and the number of trains present.

Ultimately, only the Clearstone component counts were used to develop the average emission factors presented in the following section. Refer to Section 2.3 of the Fugitive Emission Measurement Protocol for a discussion of the component counting guidelines and basic component categories.

3.0 Results

Natural gas companies typically use average emission factors and estimated component populations to determine the amount of methane emitted at their facilities due to fugitive equipment leaks. This is done using the following relation:

$$ER = \sum_i \sum_j EF_{i,j} \cdot N_i \cdot X_j \qquad (1)$$

Where:

ER is the total emission rate for the target source population
EF is the average emission factor
N is the number of sources (src)
X is the mass fraction of the target pollutant in the process fluid

Updated average emission factors developed from the expanded leak measurement data set are presented in Section 3.1 below. Updated default unit-specific component counts are presented in Section 3.2; however, these values are derived from the 2005/2006 and independent study measurement data only since the 1995/96 GTC/EC data set does not contain the detail required to evaluate the confidence limits on the component counts.

Prior to combining the data sets, various statistical tests and quality assurance checks were performed on the data to ensure that they are representative of the same populations, to identify and deal with outliers and to harmonize component codes and database structures. Several comparisons were made between data from the current study (i.e., the 2005/2006 field campaign and recent independent company studies) and that from the 1995/1996 study. This included comparing the 95 percent confidence limits on the data sets, the data distributions and component populations.

3.1 Average Emission Factors

The average emission factors developed based on a statistical analysis of the total combined data set of leak measurement and component counts are presented in Table 3-1 along with their 95 percent confidence limits. The previous study [1] of the Canadian natural gas transmission, storage and distribution industry concluded that fugitive equipment leaks are dependent on the industry sub-sector and component type. Consequently, emission factors developed in this study are classified accordingly. Following the Fugitive Emissions Measurement Protocol, odourized transmission facilities are deemed to be in distribution service as fugitive emissions from odourized transmission facilities are lower than their unodourized counterparts. Previous study has shown that components in gas transmission service tend to leak more, on average, than components in gas distribution service and that odourization of the distribution gas is likely an important factor [2].

The average emission factors represent the total amount of organic emission observed in each source category divided by the corresponding number of potential sources. Consequently, the factors account for emissions from both leaking and non-leaking sources. Emission rates for all leaking components were quantified using the methods described in the Fugitive Emission Measurement Protocol. Emissions from non-leaking equipment component were assigned the average non-leaking emission rates presented in the US EPA Protocol for Equipment Leak Emission Estimates [7].

The 95 percent confidence limits provide an indication of the variability of the compiled average emission factors. In general, the confidence interval is narrow when there were a large number of data points or the data were clustered around the mean. If the data showed a wide variability around the mean or there were few data points, the 95 percent confidence interval is wide. Comparing the confidence limits of two data sets provides a simple means of establishing if the data sets are from the same population.

A comparison of the updated average emission factors to those developed from the 1995/1996 study and to factors published for U.S. gas production [4], upstream oil and gas [5] and U.S. gas transmission systems [6] is presented in Table 3-2.

An examination of the updated average emission factors for the Canadian natural gas transmission, storage and distribution industry shows that both the average emission factors and the 95 percent confidence limits have increased for a number of source categories. These changes to the average emission factors are attributed to the highly skewed emission rate distributions for leaking components and the inclusion of a few particularly big leakers detected during the current measurement program. Although most equipment components are considered non-leaking, those that do satisfy the leak definition contribute almost all the emissions. Furthermore, within the subset of leaking equipment components, the majority of emissions result from only a few big leakers. The top few leakers in each category, therefore, have a significant impact on the average emission rate. As a result of the highly skewed emission rate distributions encountered, sample sizes must be quite large to see the full range of emission rates.

Additionally, the confidence limits for the 1995/96 data are believed to be artificially tight due to the use of published leak-rate correlations to estimate emissions for some of the leaks detected during that study (i.e., actual leak rate measurements were only performed on what appeared to be the greatest leakers at each site).

Please refer to Appendix A for a graphical comparison of the average emission factors developed from 1995/1996 data to those from the 2005/2006 data sets and the combined data set, and to Appendix F for tabular summaries. Appendix B provides a graphical comparison of average emission factors to published sources. An examination of the leaker data distribution and cumulative leak contribution, both by component type, are provided in Appendix C and Appendix D, respectively.

Table 3-1 Average Emission Factors for Gas Transmission and Distribution Facilities from the Combined Data Set.

Source	Number of Sources	Leak Frequency	Average Emissions (kg TOC/h/source)	95% Confidence Limits	
Gas Transmission Facilities [1]					
Source	Number of Sources	Leak Frequency	Average Emissions (kg TOC/h/source)	Lower	Upper
Compressor Seal – Centrifugal [2]	103	64.1	1.269E+00	8.197E-01	1.718E+00
Compressor Seal – Reciprocating [2]	167	40.1	1.073E+00	6.130E-01	1.533E+00
Connector [3]	145829	0.9	4.471E-04	1.957E-04	6.985E-04
Control Valve [4]	782	9.0	1.650E-02	1.082E-02	2.219E-02
Controller [5]	50	90.0	2.371E-01	9.941E-02	3.747E-01
Station or Pressurized Blowdown System[6]	219	59.8	3.405E+00	0.000E-00	7.885E+00
Open-Ended Line	928	58.1	9.183E-02	5.395E-02	1.297E-01
Orifice Meter [7]	185	22.7	4.863E-02	0.000E-00	1.066E-01
Other Flow Meter [8]	443	1.8	9.942E-06	2.223E-07	1.966E-05
Pressure Regulator	816	7.0	7.945E-03	0.000E-00	1.882E-02
Pressure Relief Valve	612	31.2	1.620E-01	2.906E-02	2.950E-01
Valve [9]	17029	2.8	4.131E-03	2.748E-03	5.514E-03
Gas Distribution Facilities and Meter/Regulation Stations [1]					
Source	Number of Sources	Leak Frequency	Average Emissions (kg TOC/h/source)	Lower	Upper
Compressor Seal – Centrifugal [2]	Use Transmission Factor				
Compressor Seal – Reciprocating [2]	Use Transmission Factor				
Connector [3]	52051	0.9	8.227E-05	3.792E-05	1.266E-04
Control Valve [4]	605	13.7	1.949E-02	1.127E-02	2.771E-02
Controller [5]	25	84.0	3.997E-01	1.158E-01	6.836E-01
Station or Pressurized Blowdown System[6]	42	9.5	5.878E-03	0.000E-00	1.591E-02
Open-Ended Line	969	49.9	6.077E-02	3.086E-02	9.068E-02
Orifice Meter [7]	142	17.6	3.011E-03	1.890E-03	4.131E-03
Other Flow Meter [8]	348	2.0	7.777E-06	0.000E-00	1.752E-05
Pressure Regulator	1323	2.1	6.549E-04	0.000E-00	1.375E-03
Pressure Relief Valve	472	9.5	3.944E-03	0.000E-00	8.865E-03
Valve [9]	9817	2.0	5.607E-04	1.892E-04	9.322E-04

TOC – Total organic compounds.

Gas Distribution Commercial and Residential Sites					
Source	Number of Sources	Leak Frequency	Average Emissions (kg TOC/h/source)	95% Confidence Limits	
				Lower	Upper
Connector [3]	8616	0.2	4.467E-06	8.226E-07	8.112E-06
Control Valve [4]	8	0.0	1.006E-02	0.000E-00	2.466E-02
Open-Ended Line	642	72.1	8.355E-02	3.924E-02	1.279E-01
Orifice Meter [7]	107	19.6	3.274E-03	1.919E-03	4.630E-03
Other Flow Meter [8]	405	1.7	7.203E-06	0.000E-00	1.560E-05
Pressure Regulator	348	2.3	2.329E-05	2.410E-07	4.633E-05
Pressure Relief Valve	78	3.8	1.749E-03	0.000E-00	3.747E-03
Valve [9]	1340	0.1	2.173E-06	1.753E-06	2.593E-06

TOC – Total organic compounds.

[1] Includes two LNG storage facilities. Odourized transmission facilities are deemed to be in distribution service and have been categorized as such for the purpose of developing average emission factors.

[2] The Compressor Seal categories account for emissions from individual compressor seals (i.e., for a four cylinder reciprocating compressor unit there are four seals so the compressor seal emissions for the unit would be four times the factor in the table).

[3] Includes flanges, threaded connections and mechanical couplings.

[4] Accounts for leakage from the stem packing and the valve body. Emissions from the controller and actuator are accounted for by the Instrument Controller and Open-Ended Line categories respectively. This factor applies to all valves with automatic actuators (including fuel gas injection valves on the drivers of reciprocating compressors).

[5] The Instrument Controller category accounts for emissions from pneumatic control devices that use natural gas as the supply medium.

[6] Accounts for leakage past a valve seat through an open vent line to the atmosphere. These vents are typically six inches or greater in diameter and are used to blowdown major process units or sections of pipeline. Small diameter open-ended lines such as those used to blowdown chart recorders, meter runs etc. are accounted for by the Open-Ended Line category.

[7] Accounts for emissions from the orifice changer. Emissions from sources on pressure tap lines etc. are not included in the factor (i.e., these emissions must be calculated separately).

[8] Accounts for emissions from other types of gas flow meters (e.g., diaphragm, ultrasonic, roots, turbine and vortex meters).

[9] Accounts for emissions from the stem packing and the valve body, and it applies to all types of block valves (e.g., butterfly, ball, globe, gate, needle, orbit and plug valves). Leakage past the valve seat is accounted for by the Open-Ended Line emission category. Leakage from the end connections is accounted for by the connector category (i.e., one connector for each end).

Table 3-2 Comparison of Average Emission Factors (kg/h/source) from Published Sources to the 1995/1996 GTC/EC Study and the Combined Data Set.

Source	Service	US Gas Production [2]		Upstream Oil & Gas Operations (TOC) [3]	GRI Gas Transmission (TOC) [4]	95/96 GTC/EC Study Gas Transmission (TOC)	95/96 GTC/EC Study Gas Distribution (TOC)	95/96 GTC/EC Study Gas Distribution - CR (TOC)	Combined Data Gas Transmission (TOC) [1]	Combined Data Gas Distribution (TOC) [1]	Combined Data Gas Distribution - CR (TOC) [1]
		(VOC)	(TOC)								
Compressor Seal – Centrifugal	G/V	0.042	0.20	0.80488	0.418	0.8139	-	-	1.269	-	-
Compressor Seal – Reciprocating	G/V	0.042	0.20	0.8	1.00	0.6616	-	-	1.073	-	-
Connector	G/V	0.00046	0.0011	0.00253	0.000372	0.0002732	0.0001098	0.00000678	0.0004471	0.00008227	0.000004467
Control Valve	G/V	0.0075	0.200	0.04351	0.0203	0.01969	0.01969	-	0.01650	0.01949	0.01006
Controller	G/V	-	-	0.1996	0.411	0.4618	0.4618	-	0.2371	0.3997	-
Blowdown	G/V	-	-	-	0.669	0.9369	0.9369	-	3.405	0.005878	-
Open-Ended Line	G/V	0.014	0.022	0.001373	0.0284	0.08355	0.08355	0.08355	0.09183	0.06077	0.08355
Orifice Meter	G/V	-	-	-	-	0.003333	0.003333	-	0.04863	0.003011	0.003274
Other Flow Meter	G/V	-	-	-	-	0.00000906	0.00000906	0.00000906	0.000009942	0.000007777	0.000007203
Pressure Regulator	G/V	-	-	-	-	0.003304	0.001915	0.00002198	0.007945	0.0006549	0.00002329
Pressure Relief Valve	G/V	0.014	0.19	0.12096	0.0157	0.2795	0.01665	0.0002717	0.1620	0.003944	0.001749
Valve	G/V	0.0075	0.200	0.04351	0.00220	0.00214	0.001109	0.00000333	0.004131	0.0005607	0.000002173

G/V - Gas/Vapour
- No data available or the source category does not apply to this industry sector.
[1] Not all equipment was surveyed at some facilities.
[2] U.S. EPA. 1985. [3] Table 9.1.2
[3] Picard, D.J., B.D. Ross, and D.W.H. Koon. 1992. [5] Table 5, Page 49.
[4] Adapted from; Hummel et al. 1996. [6] Table 4-15, page 51.

3.2 Default Component Counts

To use the average emission factors presented in Table 3-1, the numbers of each of the different types of equipment components in each service category must be determined (see Section 2.4). In the absence of site-specific equipment component counts, however, the average equipment counts provided in Tables 3-2 and 3-3 may be used. These average counts were compiled by adding up the total number of each type of component at a particular type of facility and dividing by the number of such facilities surveyed. The industry-specific average component counts presented here are based on equipment component counts from 255 surveyed facilities, but data from the 1995/1996 GTC/EC study is not included.

Equipment schedules for residential meter sites, commercial meter sites, industrial meter sites, farm taps, district regulator stations and gate stations are presented on a per facility or per site basis. The amount of equipment at gas transmission facilities was found to vary widely from site to site. Refer to Appendix E where the upper and lower confidence limits on the component counts are provided. In an effort to manage the impact of this equipment variability, the schedules for meter stations are on a per meter run basis and compressor stations are on a per compressor unit basis. The amount of compressor yard station piping, excluding suction and discharge headers and valving for each unit, was found to be essentially independent of the number of compressor units [1]. Therefore, the total number of equipment components at a compressor station is determined by adding the components from yard piping to the components from each of the compressor units. If discharge coolers are used on site, the components from these must also be added.

Table 3-3	Equipment Schedules for Gas Transmission Facilities.					
Component	Mainline Block Valve	Receipt / Sales Meter Station [2]	Reciprocating Compressor Unit [3]	Centrifugal Compressor Unit [3]	Compressor Station Yard Piping [4]	Compressor Discharge Cooler [5]
Facilities Surveyed [1]	13	168	25	29	21	9
Compressor Seal – Centrifugal	-	-	-	2	-	-
Compressor Seal – Reciprocating	-	-	4	-	-	-
Connector	200	33	256	502	950	3527
Control Valve	0 [6]	0	1	5	13	0
Instrument Controller	0	0	0	0	1	-
Blowdown	0	-	1	1	4	-
Open-Ended Line	1	0	1	4	6	2
Orifice Meter	-	0	1	0	2	-
Other Flow Meter	0	1	-	0	1	-
Pressure Regulator	2	1	2	5	15	0
Pressure Relief Valve	0	0	2	3	8	0
Valve	36	7	22	120	217	33

1 Not all equipment at some facilities surveyed
2 Number of components per meter run
3 Number of components per compressor unit
4 Number of components per compressor station. For a station with 2 reciprocating compressor units, the total number of connectors would be: 2*256+985=1497
5 Number of components associated with discharge coolers at compressor stations. If the station has discharge coolers, add these additional components.
6 A zero value indicates a fractional value less than 0.5. Please refer to Appendix E for further discussion.

Table 3-4	**Equipment Schedules for Gas Distribution Facilities.**											
Component	Distribution – Commercial and Residential			Distribution Facilities								
	Residential Meter Set [2]	Commercial Meter Set [2]	Farm Tap [2]	Industrial Meter Set [2]	District Regulator Station [2]	Gate Station [2]	Border Meter Station	Mainline Block Valve	Reciprocating Compressor Unit [3]	Centrifugal Compressor Unit [3]	Compressor Station Yard Piping [4]	Compressor Discharge Cooler [5]
Facilities Surveyed [1]	44	35	18	15	32	30	6	22	2	12	9	
Compressor Seal – Centrifugal	-	-	-	-	-	-	-	-	-	2	-	-
Compressor Seal – Reciprocating	-	-	-	-	-	-	-	-	5	-	-	-
Connector	48	82	48	111	181	353	381	142	163	430	1172	527
Control Valve	0 [6]	0	0	0	1	2	1	1	1	5	19	0
Instrument Controller	-	-	-	-	-	0	-	0	-	-	-	-
Blowdown	-	-	-	-	-	-	-	-	1	1	3	-
Open-Ended Line	-	-	-	-	0	0	4	1	4	5	22	-
Orifice Meter	-	0	-	0	0	1	-	0	1	0	1	-
Other Flow Meter	1	2	0	1	0	1	1	0	-	1	1	-
Pressure Regulator	2	3	2	4	8	12	8	2	1	3	18	-
Pressure Relief Valve	0	1	2	0	2	3	3	1	2	2	18	1
Valve	8	14	13	26	40	64	62	33	20	83	222	14

1 Not all equipment at some facilities surveyed
2 Number of components per meter set (for residential, commercial and industrial meter sets) or site (for district and gate stations)
3 Number of components per compressor unit
4 Number of components per compressor station. For a station with 2 reciprocating compressor units, the total number of connectors would be: 2*256+985=1497
5 Number of components associated with discharge coolers at compressor stations. If the station has discharge coolers, add these additional components.
6 A zero value indicates a fractional value less than 0.5. Please refer to Appendix E for further discussion.

4.0 Conclusions

Updated average emission factors and average unit-specific component counts for the Canadian natural gas transmission, storage and distribution industry have been developed using data collected during leak detection and measurement programs conducted since 1995 at natural gas facilities throughout Canada. The confidence limits associated with these results are also provided and may be used, in accordance with IPCC Good Practice Guidance (2000), to help develop quantitative uncertainty estimates for emissions inventories.

An analysis of the data collected during the 2005/2006 field measurement campaign has re-affirmed and highlighted a number of key findings from previous study of fugitive emissions in the industry:

- Components satisfying the leak definition (i.e., those with screening values greater than 10,000 ppm) account for the vast majority of fugitive emissions at all facility types. Although non-leaking equipment components typically represent more than 98 percent of the component population, the contribution these components make to overall emissions is dwarfed by identified leakers.

- The distribution of emission rates for equipment components is highly skewed for most component categories, indicating that component population is predominantly composed of non-leakers. The major exceptions are the compressor seal categories, which have relatively flat emission rate distributions.

- Within the leaker subset of the component population, the distribution of emission rates is also highly skewed for all component categories. As a result, the top few leakers in each category have a significant impact on the average emission rate. Furthermore, a large sample population is required in order to define the shape of the emission rate distribution and see the full range of leakers.

- Detailed, accurate component counts, ideally based on actual site surveys, are essential in developing emission inventories. The complexity of many facilities requires technicians both to be knowledgeable about the process and to follow a systematic approach such as that laid out in the Fugitive Emission Measurement Protocol.

References

[1] Ross, B.D. and D.J. Picard. 1996. Measurement of Methane Emissions from Western Canadian Natural Gas Facilities – GTC Program #3 Environmental Technology Program.

[2] Clearstone Engineering Ltd. 2006. Canadian Energy Partnership for Environmental Innovation (CEPEI) – Fugitive Emissions Measurement Protocol.

[3] U.S. EPA (Environmental Protection Agency). 1997. Method 21 – Determination of Volatile Organic Compound Leaks. Available at: www.epa.gov/ttn/emc/promgate/m-21.pdf.

[4] U.S. EPA. 1985. Compilation of Air Pollutant Emission Factors – Volume I: Stationary Point and Area Sources. AP-42. Fourth Edition.

[5] Picard, D.J., B.D. Ross, and D.W.H. Koon. 1992. A Detailed Inventory of CH_4 and VOC Emissions from Upstream Oil and Gas Operations in Alberta. Volume III: Results of Field Validation Program. Prepared by Clearstone Engineering Ltd. for Canadian Petroleum Association.

[6] Hummel et al. 1996. Final Draft. Methane Emissions from the Natural Gas Industry. Volume 8: Equipment Leaks. Prepared by Radian International LLC for Gas Research Institute and U.S. Environmental Protection Agency.

[7] U.S. EPA. 1995. Protocol for Equipment Leak Emission Estimates. Publication No. EPA-453/R-95-017. Section 2.

[8] Intergovernmental Panel on Climate Change. 2000. Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories.

Glossary

Centrifugal Compressor Seal System	A mechanical seal used to prevent the loss of process fluid past a rotating compressor shaft where the shaft penetrates the compressor housing.
Connectors -	A connector is any flanged or threaded connection, or mechanical coupling, but excludes all welded or back-welded connections. If properly installed and maintained, a connector can provide essentially leak-free service for extended periods of time. However, there are many factors that can cause leakage problems to arise. Some of the common causes include vibration, thermal stress and cycles, dirty or damaged contact surfaces, incorrect sealing material, improper tightening, misalignment, and external abuse.
Control Valve	A valve equipped with an actuator for automated operation to control flow, pressure, liquid level or other relevant process parameter.
Leak Frequency	The portion of a population of components that are determined to be leaking at the time of a leak detection survey.
Open-ended Valves and Lines -	An open-ended valve is any valve that may release process fluids directly to the atmosphere in the event of leakage past the valve seat. The leakage may result from improper seating due to an obstruction or sludge accumulation, or because of a damaged or worn seat. An open-ended line is any segment of pipe that may be attached to such a valve that opens to the atmosphere at the other end. Few open-ended valves and lines are designed into process systems. However, actual numbers can be quite significant at some sites due to poor operating practices and various process modifications that may occur over time. Some common examples of instances where this type of source may occur are listed below: • scrubber, compressor-unit, station and mainline blowdown valves, • supply-gas valve for a gas-operated engine starter (i.e., where natural gas is the supply medium), • instrument block valves where the instrument has been

removed for repair or other reasons, and
- purge or sampling points.

Pneumatic Controller	A mechanism activated by an analog or digital signal that regulates the escape of a supply medium (e.g., compressed air or natural gas) to move mechanical controls such as valves and levers.
Pressure Regulator	A device used for maintaining a constant outlet pressure at a predetermined set point.
Pressure-Relief Valves -	Pressure relief or safety valves are used to protect process piping and vessels from being accidentally over-pressured. They are spring loaded so that they are fully closed when the upstream pressure is below the set point, and only open when the set point is exceeded. Relief valves open in proportion to the amount of overpressure to provide modulated venting. Safety valves pop to a full-open positions on activation. When relief or safety valves reseat after having been activated, they often leak because the original tight seat is not regained either due to damage of the seating surface or a build-up of foreign material on the seat plug. As a result, they are often responsible for fugitive emissions. Another problem develops if the operating pressure is too close to the set pressure, causing the valve to "simmer" or "pop" at the set pressure. Gas that leaks from a pressure-relief valve may be detected at the end of the vent pipe (or horn). Additionally, there normally is a monitoring port located on the bottom of the horn near the valve.
Reciprocating Compressor Packing Systems -	Packings are used on reciprocating compressors to control leakage around the piston rod on each cylinder. Conventional packing systems have always been prone to leaking a certain amount, even under the best of conditions. According to one manufacturer, leakage from within the cylinder or through any of the various vents will be on the order of 1.7 to 3.4 m^3/h under normal conditions and for most gases. However, these rates may increase rapidly as normal wear and degradation of the system occurs.
Standard Reference Conditions -	Most equipment manufacturers reference flow, concentration and equipment performance data at ISO standard conditions of 15°C, 101.325 kPa, sea level and 0.0 percent relative humidity.

The following equation shows how to correct air contaminant concentrations measured in the exhaust to 3 percent oxygen (15% excess air) for comparison and regulatory compliance purposes. To correct emission levels to 3 percent oxygen that are referenced to excess air levels other than 3 percent , use the following equation:

$$ppm\,(3\,\%) = \frac{21 - 3}{21 - O_2(actual)}\ x\ ppm\,(actual)$$

Total Hydrocarbons - All compounds containing at least one hydrogen atom and one carbon atom, with the exception of carbonates and bicarbonates.

Total Organic Compounds (TOC) - TOC comprises all VOCs plus all non-reactive organic compounds (i.e., methane, ethane, methylene chloride, methyl chloroform, many fluorocarbons, and certain classes of per fluorocarbons).

Valves - There are three main locations on a typical valve where leakage may occur: (1) from the valve body and around the valve stem, (2) around the end connections, or (3) past the valve seat. Leaks of the first type are referred to as valve leaks. Emissions from the end connections are classified as connector leaks. Leakage past the valve seat is only a potential source of emissions if the valve, or any downstream piping, is open to the atmosphere. This is referred to as an open-ended valve or line.

The potential leak points on each of the different types of valves are, as applicable, around the valve stem, body seals (e.g., where the bonnet bolts to the valve body, retainer connections), body fittings (e.g., grease nipples, bleed ports), packing guide, and any monitoring ports on the stem packing system. Typically, the valve-stem packing is the most likely of these parts to leak.

Vented Emissions - Vented emissions are releases to the atmosphere by design or by operational practice, and may occur on either a continuous or intermittent basis. The most common causes or sources of these emissions are gas operated devices that use natural gas as the supply medium (e.g., compressor start motors, chemical injection and odourization pumps, instrument control loops, valve actuators, and some types of glycol circulation pumps), equipment blowdowns and purging activities, and venting of still-column off-gas by glycol dehydrators.

Volatile Organic - Any compound of carbon, excluding carbon monoxide, and

Appendix C: Leaker Data Distribution

The figures in this appendix show the data distribution for leak measurements, sorted by source type, for the transmission and distribution industries. The percent of the leaker population is on the X-axis and the span of the leak rate measurements is on the Y-axis. Absolute emission rates can be inferred from the mean, standard deviation and confidence limits provided on each graph. These graphs only represent the emissions from identified leakers, and the statistical values provided on the graphs are for the leaking equipment component population rather than the entire population of leaking and non-leaking equipment components. The population of leaking equipment components at commercial and residential meter sets was not large enough to construct the corresponding figures for this industry sub-sector.

The leak frequencies provided in Table 3-1 show that the component population, for most component categories, is composed predominantly of non-leaking equipment components. The overall leak frequency at the facilities surveyed is approximately 1.9 percent. The distribution for most component types is very flat; therefore one is most likely to encounter non-leakers. The four exceptions to this are compressor seals, controllers, blowdowns and open-ended lines, all of which have leak frequencies exceeding 50 percent.

The distributions of leaker emission rates, shown in the following figures, illustrate a highly skewed population for most component categories. The emission rates from the vast majority of components in the leaker population are small and there are only a few large leakers in the component category, typically representing only 1 to 2 percent of the population. These top few leakers in each category have a significant impact on the average emission rate. Again, the major exceptions are compressor seals and controllers, which have a flat distribution. For these component types, the likelihood of encountering a small leaker and large leaker is similar.

Compounds (VOC) -	carbon dioxide, which participates in atmospheric chemical reactions. This excludes methane, ethane, methylene chloride, methyl chloroform, many fluorocarbons, and certain classes of per fluorocarbons.

Appendix A: Average Emission Factors by Component Type

The figures in this appendix provide a graphical comparison of the average emission factors, by component type, developed based on the 1995/1996 GTC/EC data set, the 2005/2006 data, which includes the independent company studies and factors developed from the combined data set. Each figure provides both whisker plots showing the average emission factor and the 95 percent confidence limits, and bar graphs indicating the number of surveyed sources. The bar graph scale is on the left axis and the average emission rate in kg/hr/source is on the right axis.

The average emission factors for transmission facilities have increased for some categories and dropped for others. The most notable increases are in the factors for compressor seals, connectors, blowdowns and valves. In contrast, the distribution average emission factors, are virtually all lower than those from previous study. A tabular summary of change in the number of surveyed sources, leak frequency and average emission factors between the 1995/1996 and 2005/2006 data sets is provided in Appendix F.

The whisker plots show the 95 percent confidence limits for each of the developed emission factors. In a number of instances, the confidence limits have become wider rather that tighter despite the larger sample population. In these cases, the relative increase in the sample variance was greater than the relative increase in the sample population. Examination of the leaker data shows that the top few largest leakers in each component category create a highly skewed emission rate distribution. Not only do these leakers introduce a great deal of variance into the data set, which accounts for the wider confidence limits, but they also have a significant impact on the average emission factor. Please refer to Appendix C for a discussion of the leaker data distribution.

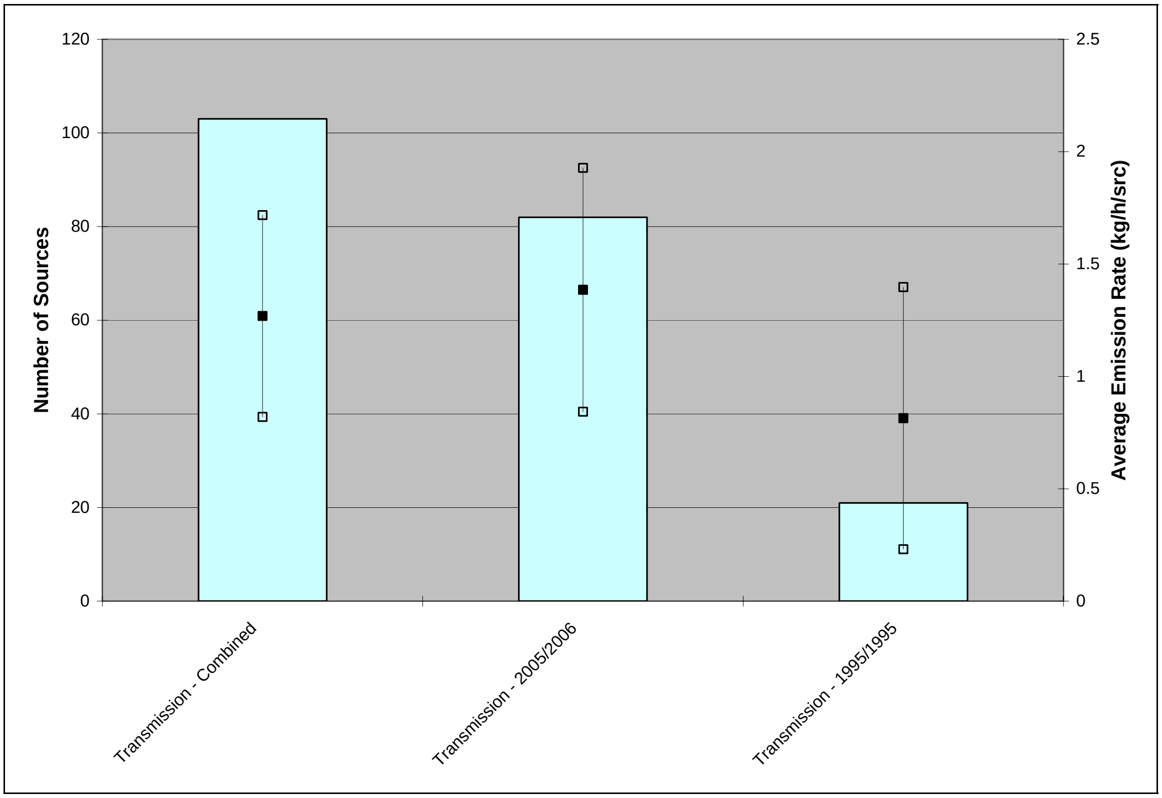


Figure A-1 Average Emission Factors – Centrifugal Compressor Seals

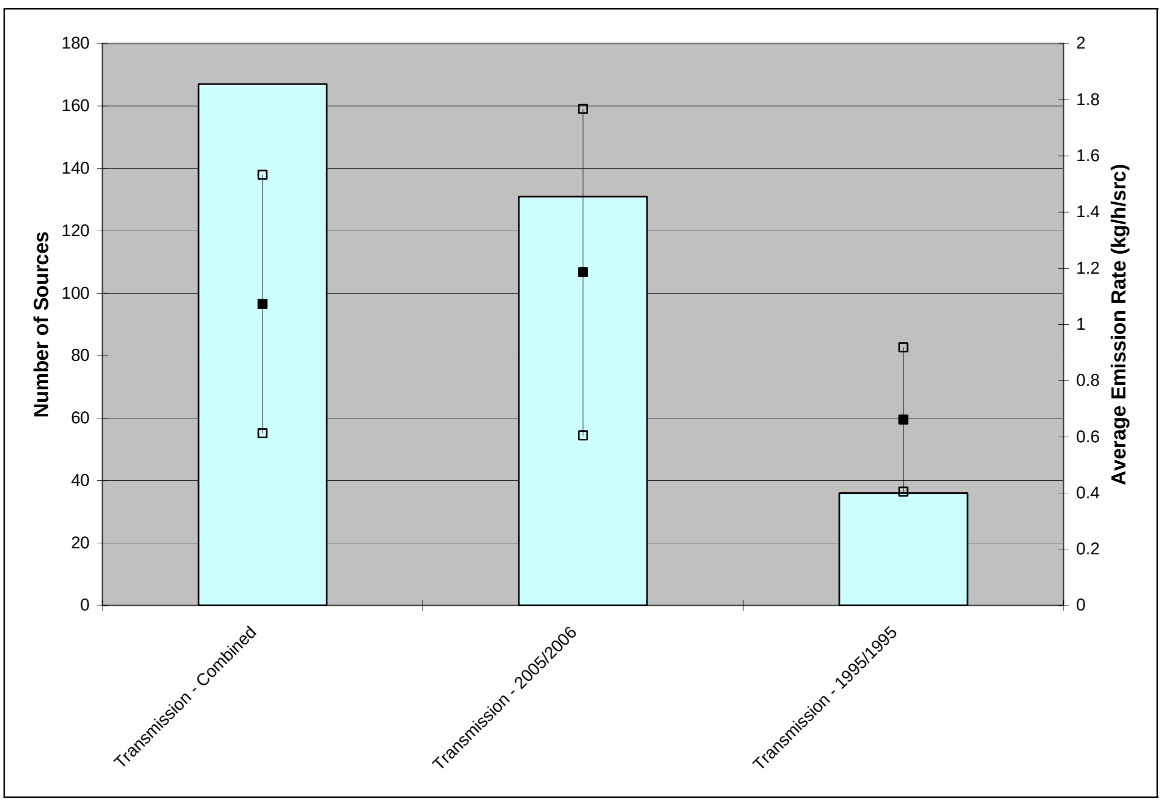


Figure A-2 Average Emission Factors – Reciprocating Compressor Seals

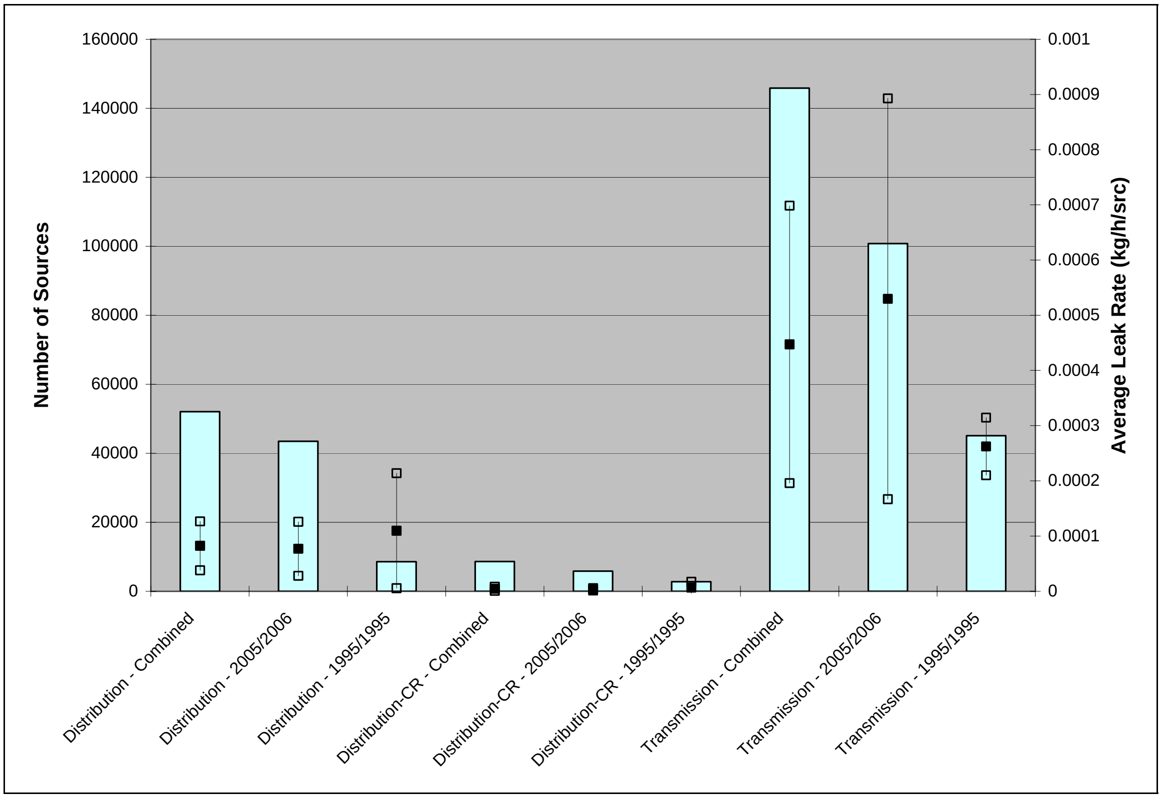


Figure A-3 Average Emission Factors – Connector

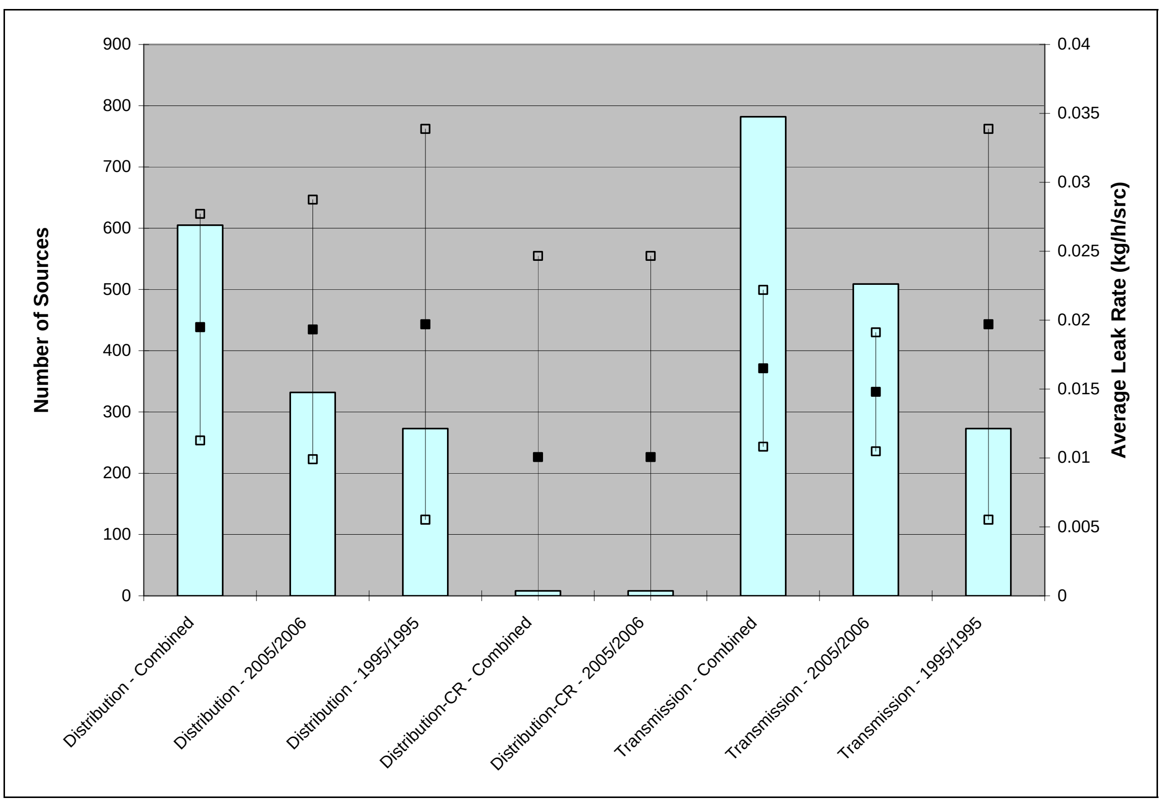


Figure A-4 Average Emission Factors – Control Valve

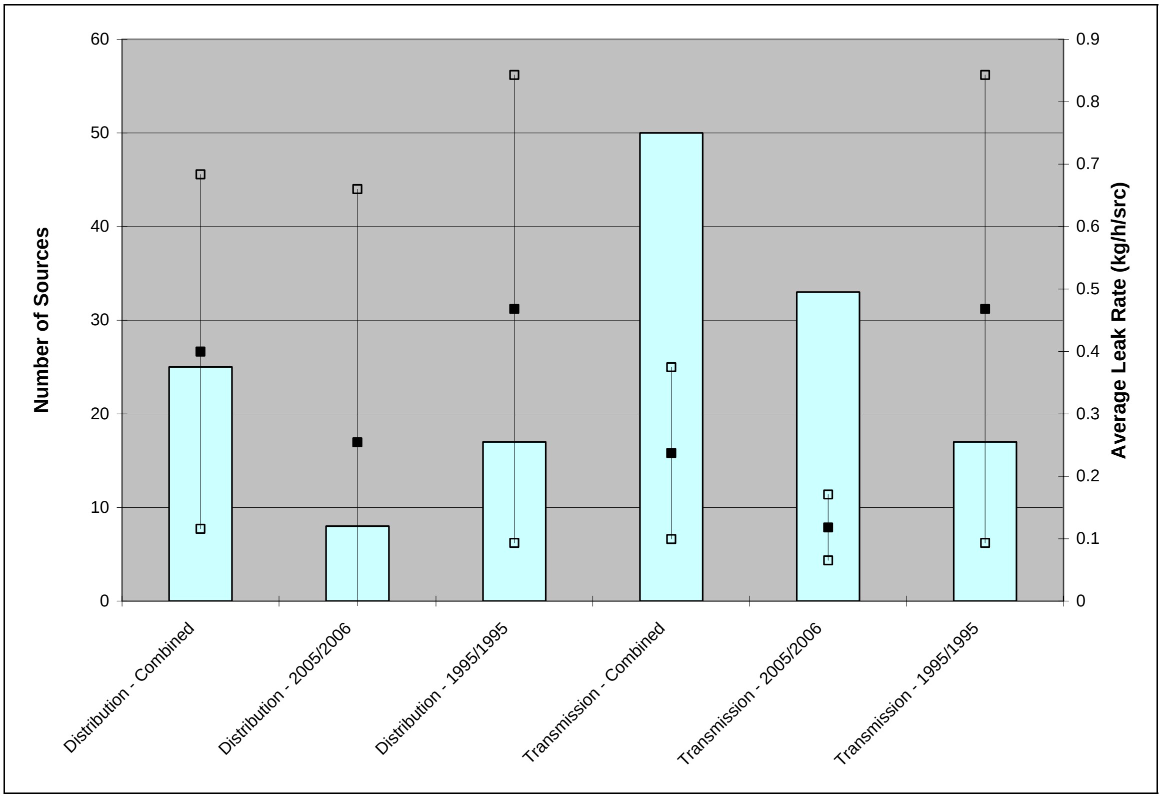


Figure A-5 Average Emission Factors – Controller

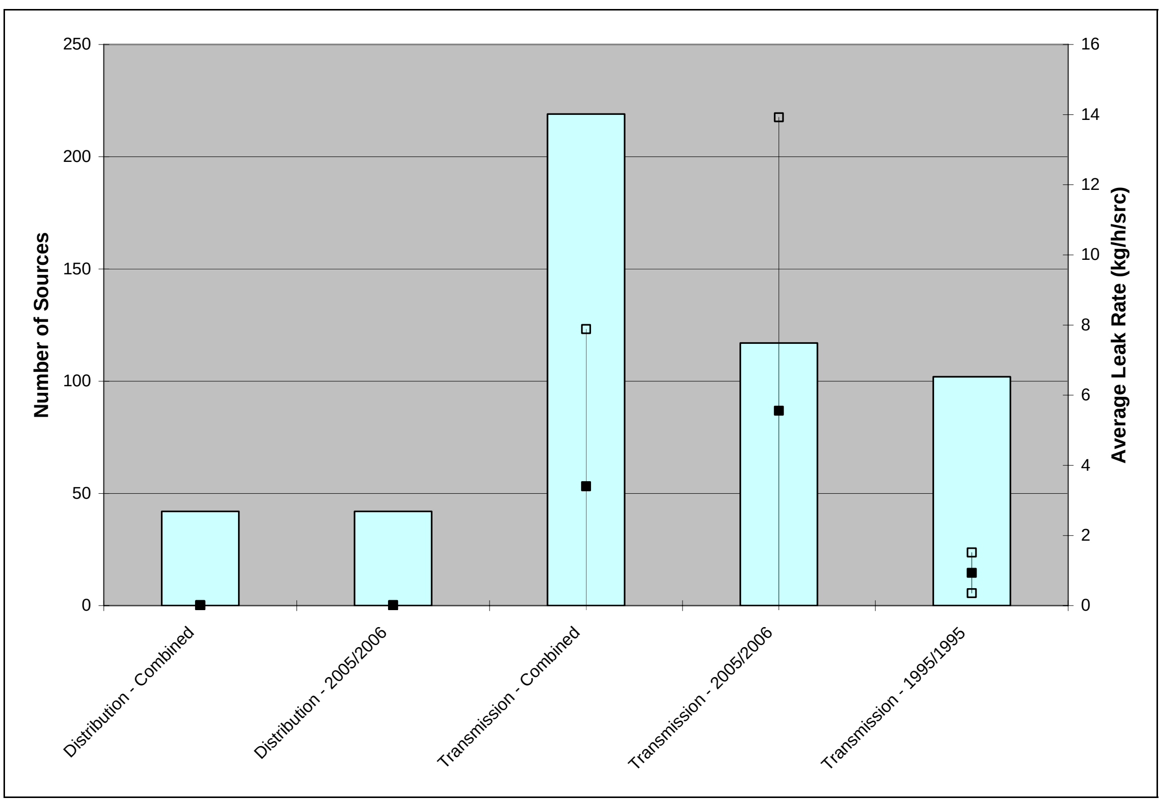


Figure A-6 Average Emission Factors – Blowdown

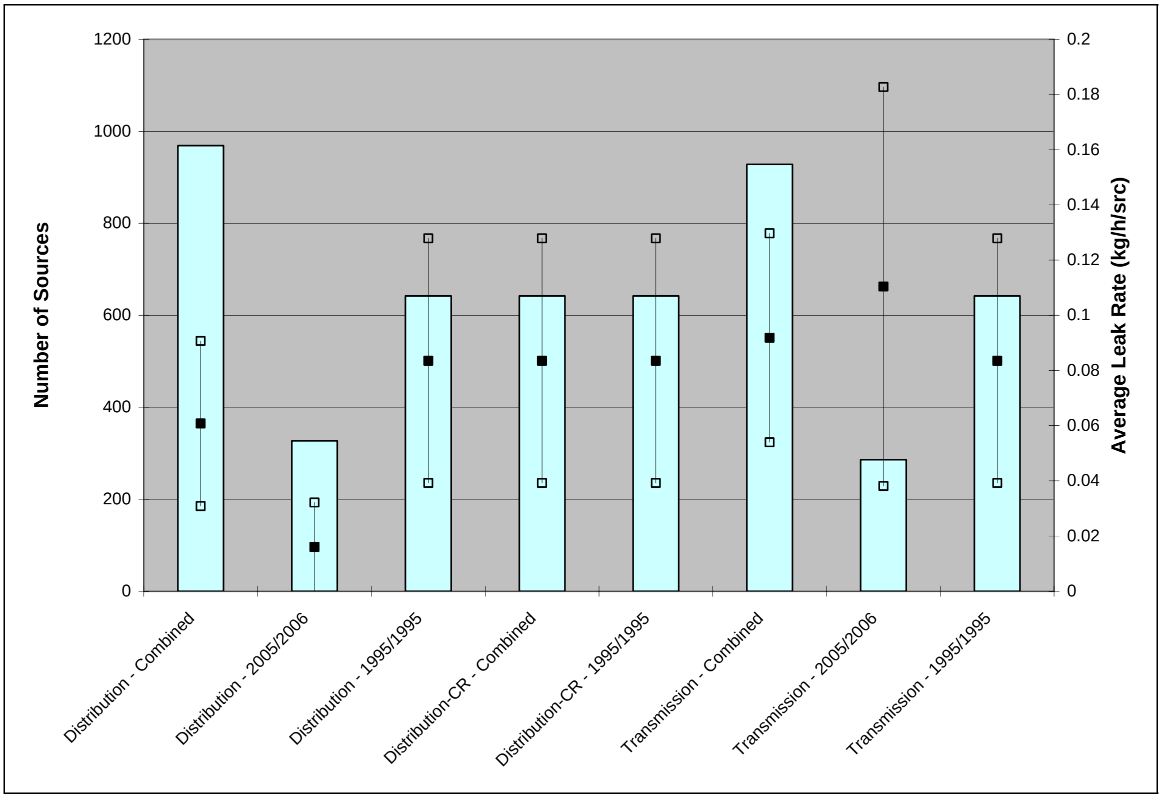


Figure A-7 Average Emission Factors – Open-Ended Line

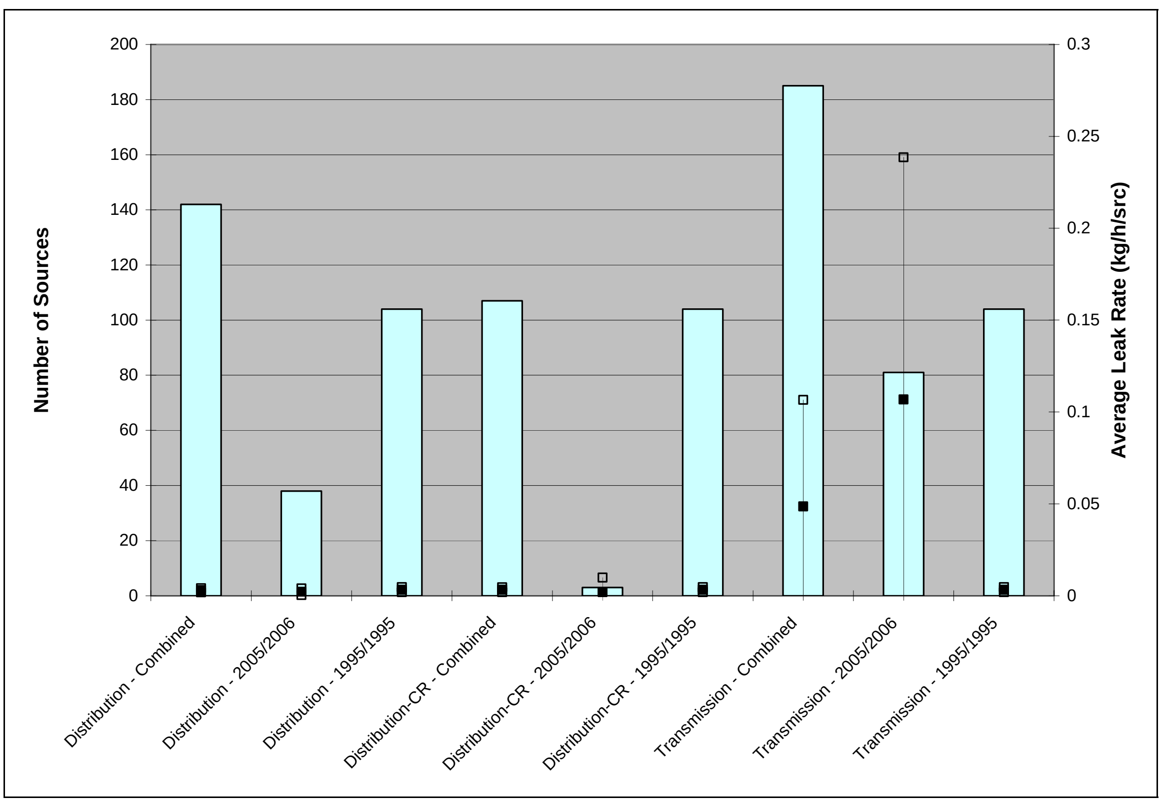


Figure A-8 Average Emission Factors – Orifice Meter

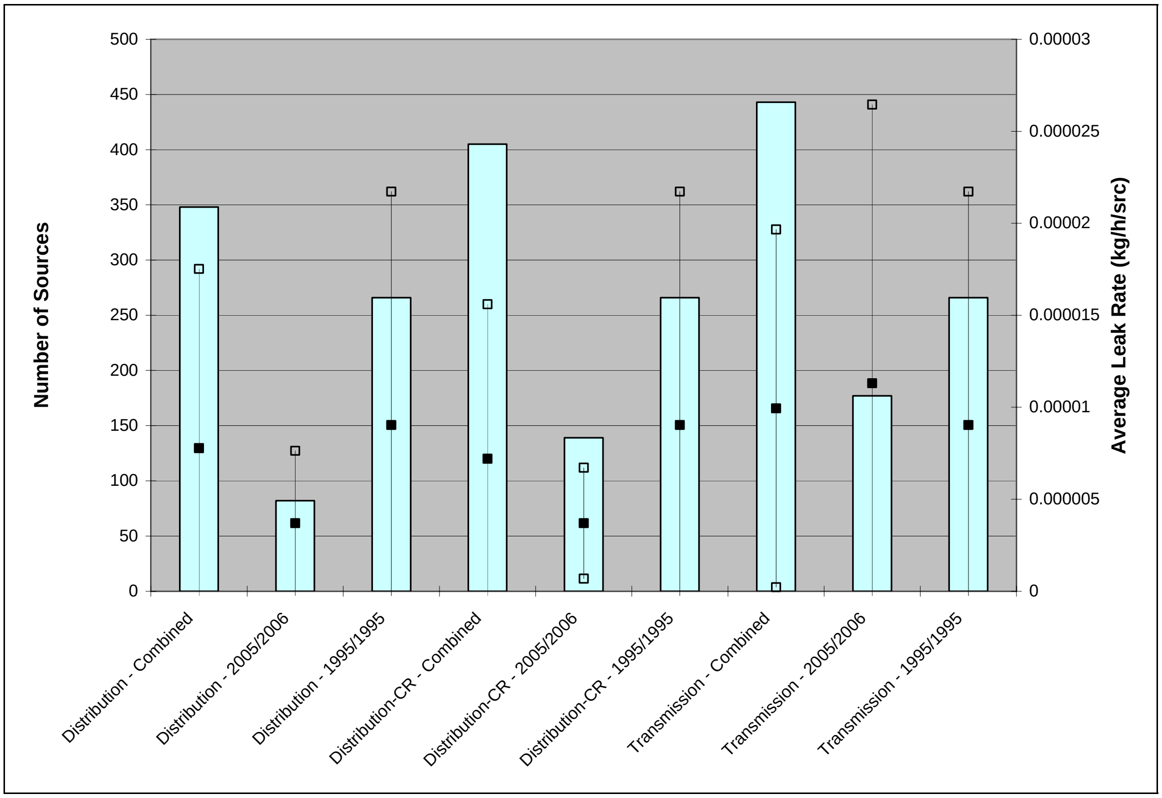


Figure A-9 Average Emission Factors – Other Flow Meter

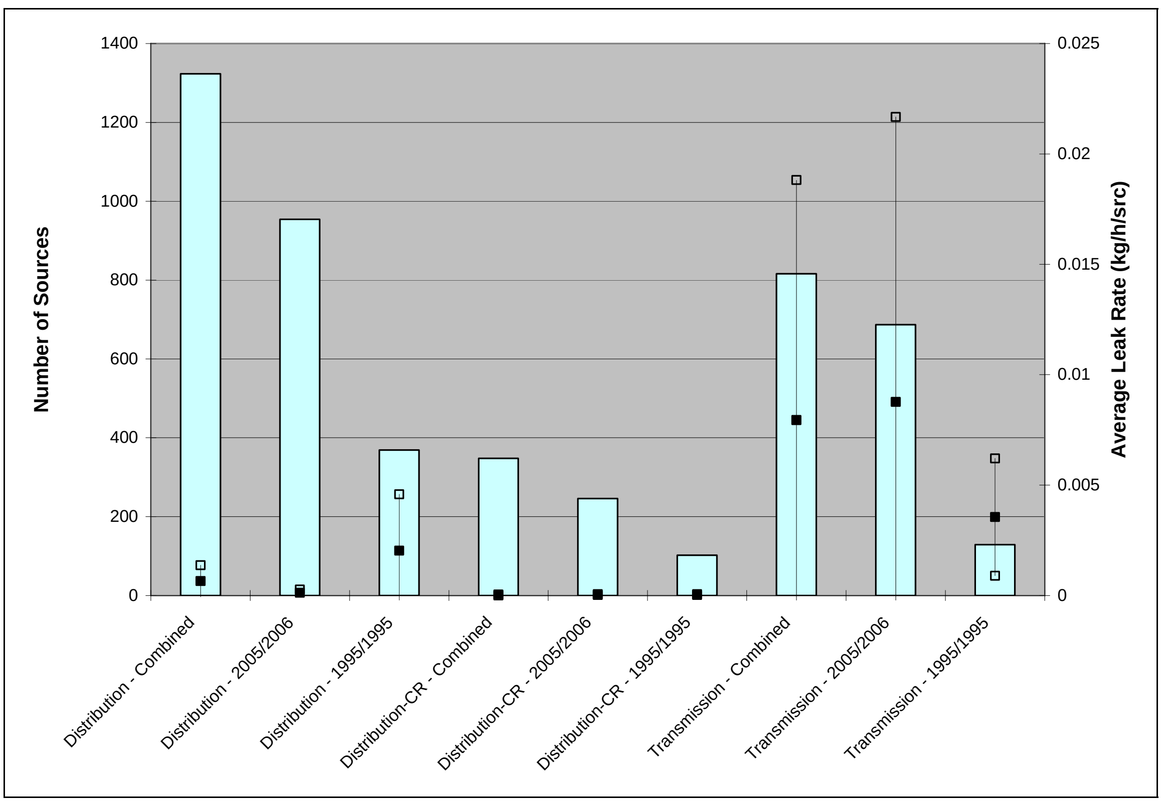


Figure A-10   Average Emission Factors – Pressure Regulator

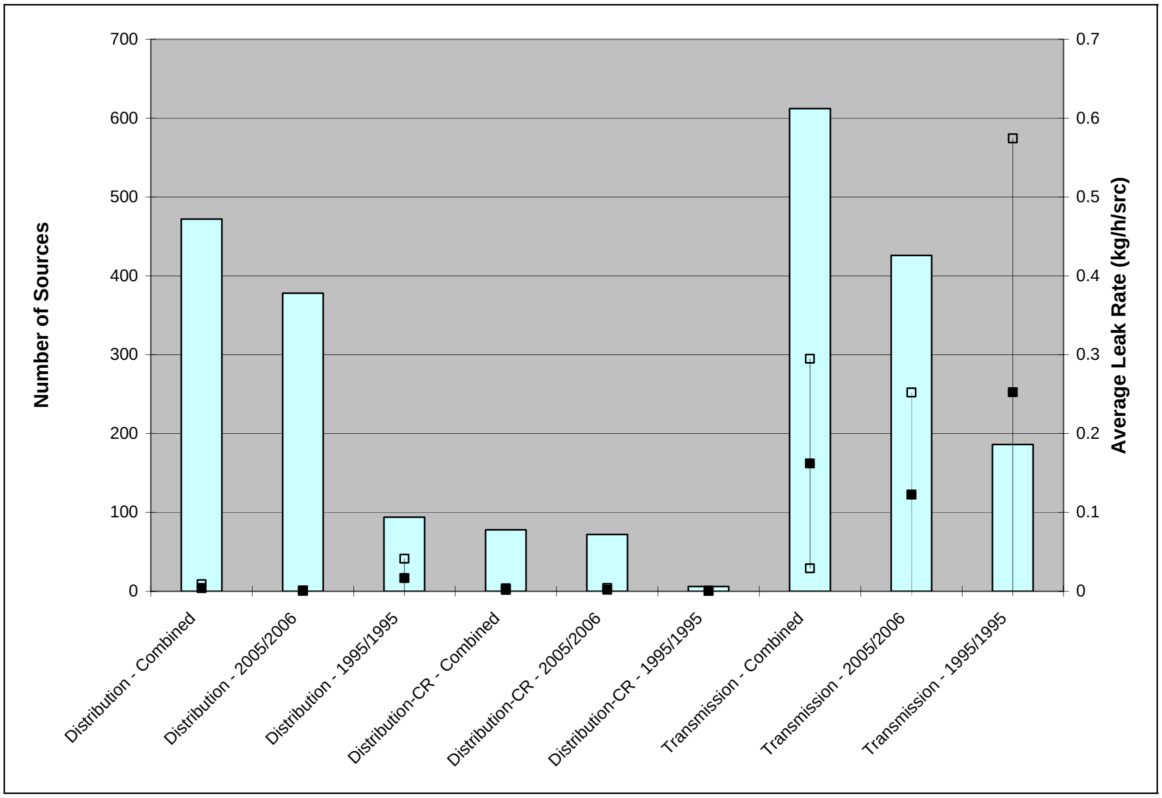


Figure A-11 Average Emission Factors – Pressure Relief Valve

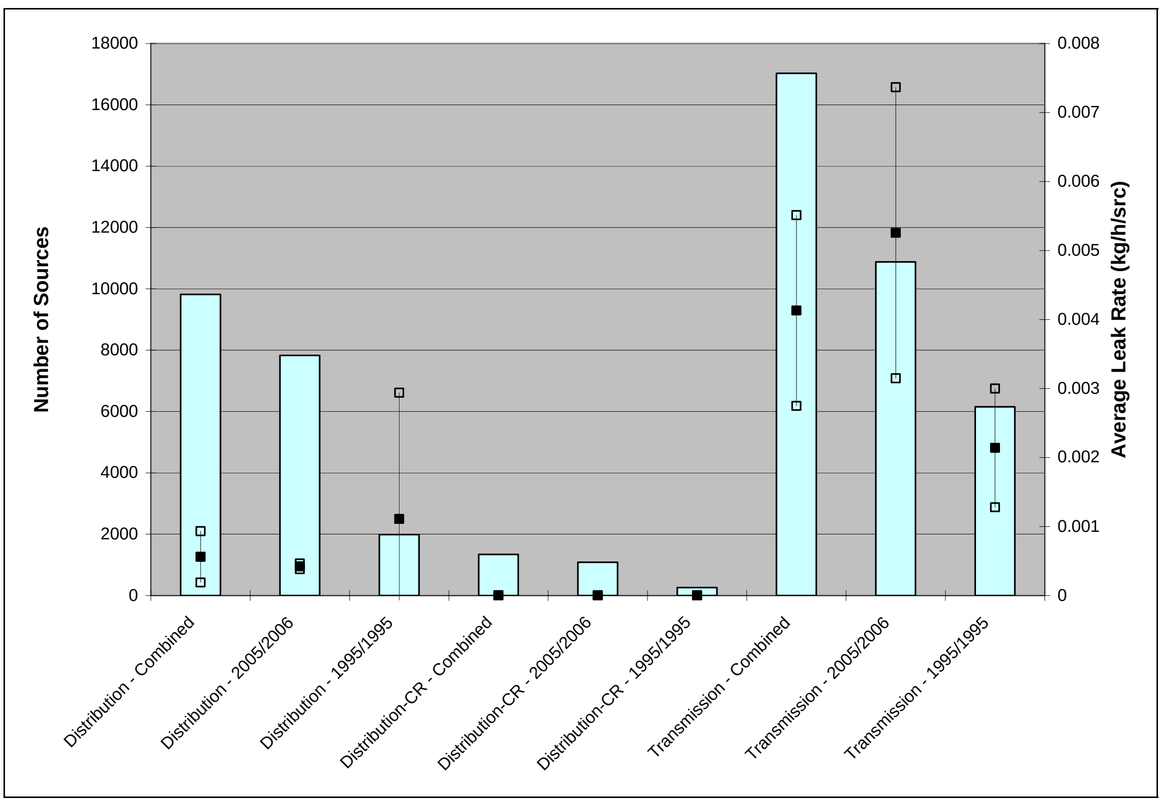


Figure A-12 Average Emission Factors – Valve

Appendix B: Comparison of Average Emission Factors from Published Sources to Current Study by Component Type

The figures in this appendix provide a graphical comparison of the average emission factors developed based on a statistical analysis of combined data set of leak measurement and component counts collected during several field measurement programs, to those from the 1995/1996 and the 2005/2006 data sets and to published sources. The 95 percent confidence intervals on the average emission factors developed for the Canadian natural gas transmission and distribution industry are incorporated via whisker plots. This comparison is presented in tabular form in Table 3-2. To illustrate the relative magnitude of the emission factors for various component categories, the first figure shows the average factors for all categories on a Cartesian scale. The following four figures offer the emission factor comparisons on log scales in order to expand the emission rate range for various component categories.

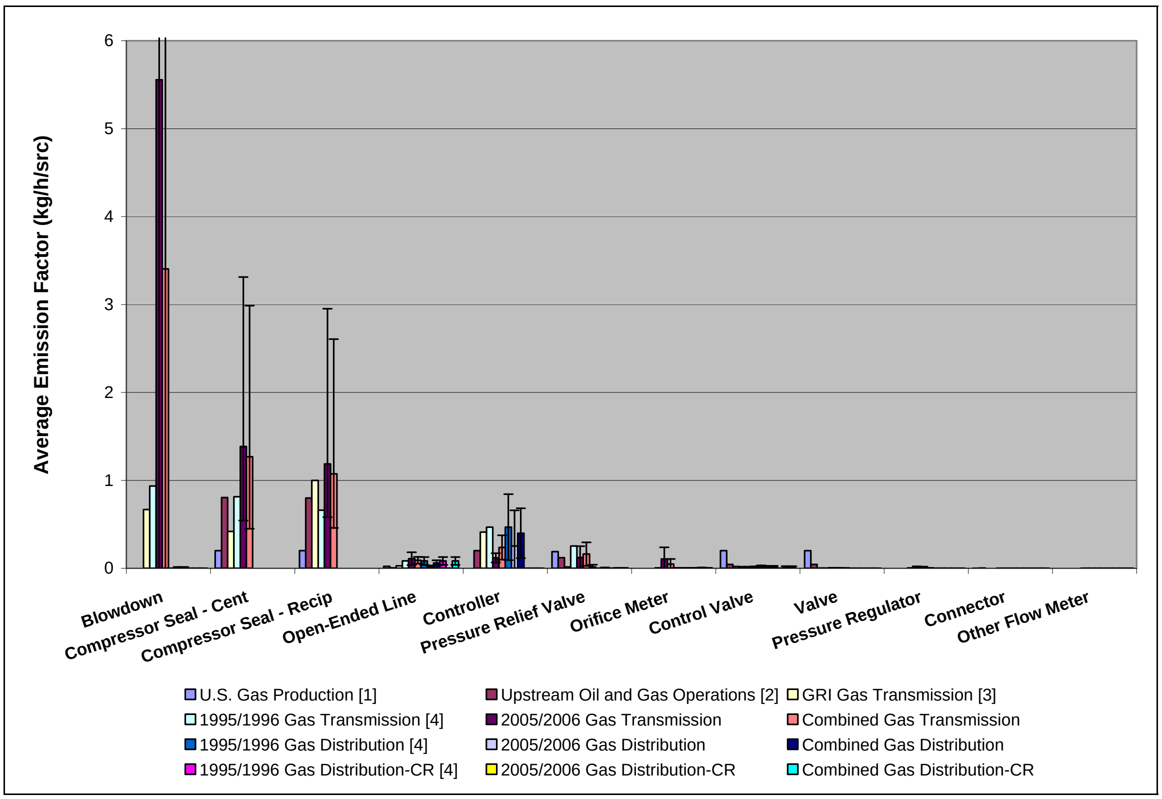


Figure B-1 Comparison of Average Emission Factors – All Equipment Components

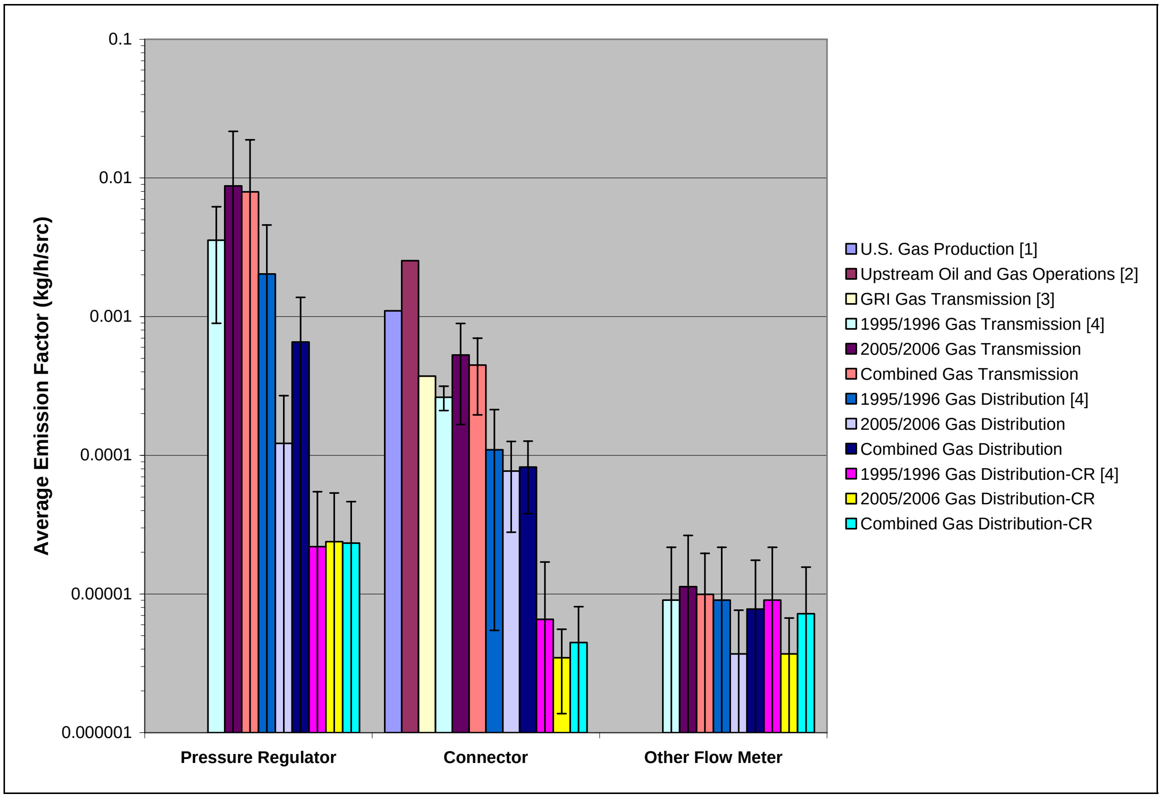


Figure B-2 Comparison of Average Emission Factors – Pressure Regulator, Connector and Other Flow Meter

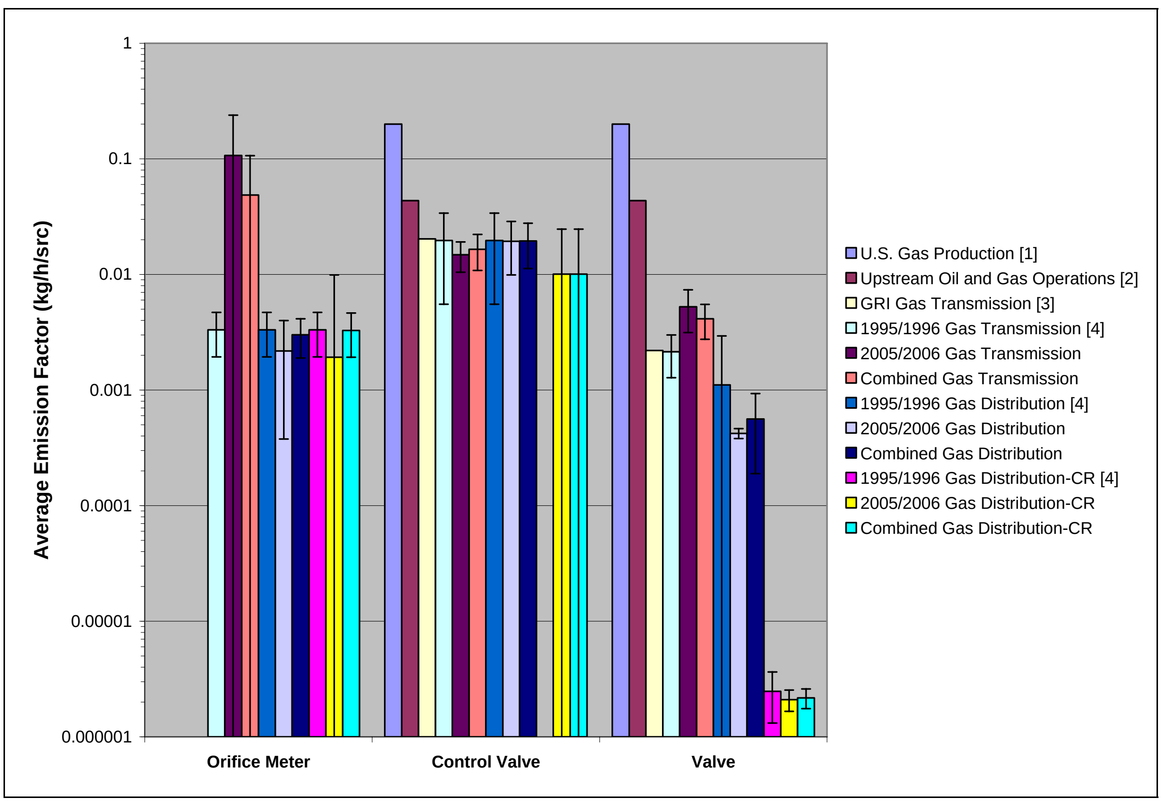


Figure B-3 Comparison of Average Emission Factors – Orifice Meter, Control Valve and Valve

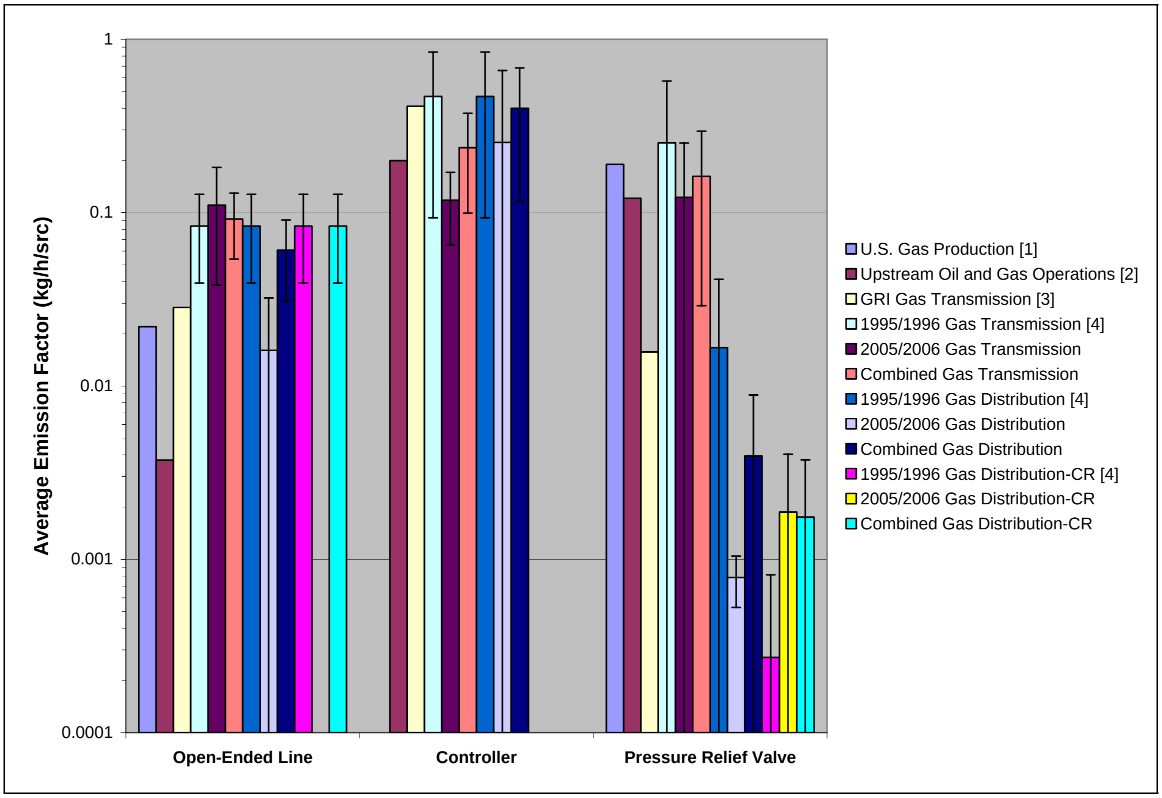


Figure B-4 Comparison of Average Emission Factors – Open-Ended Line, Controller and Pressure Relief Valve

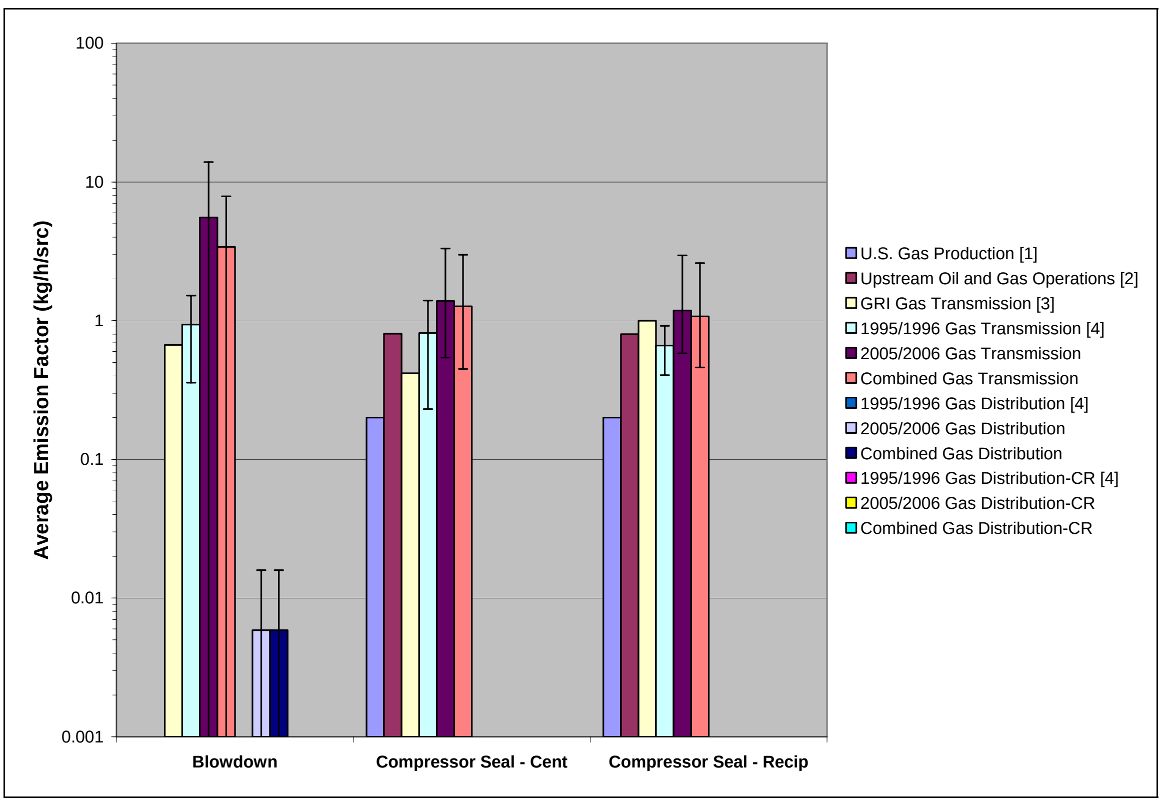


Figure B-5 Comparison of Average Emission Factors – Blowdown, Centrifugal Compressor Seal and Reciprocating Compressor Seal

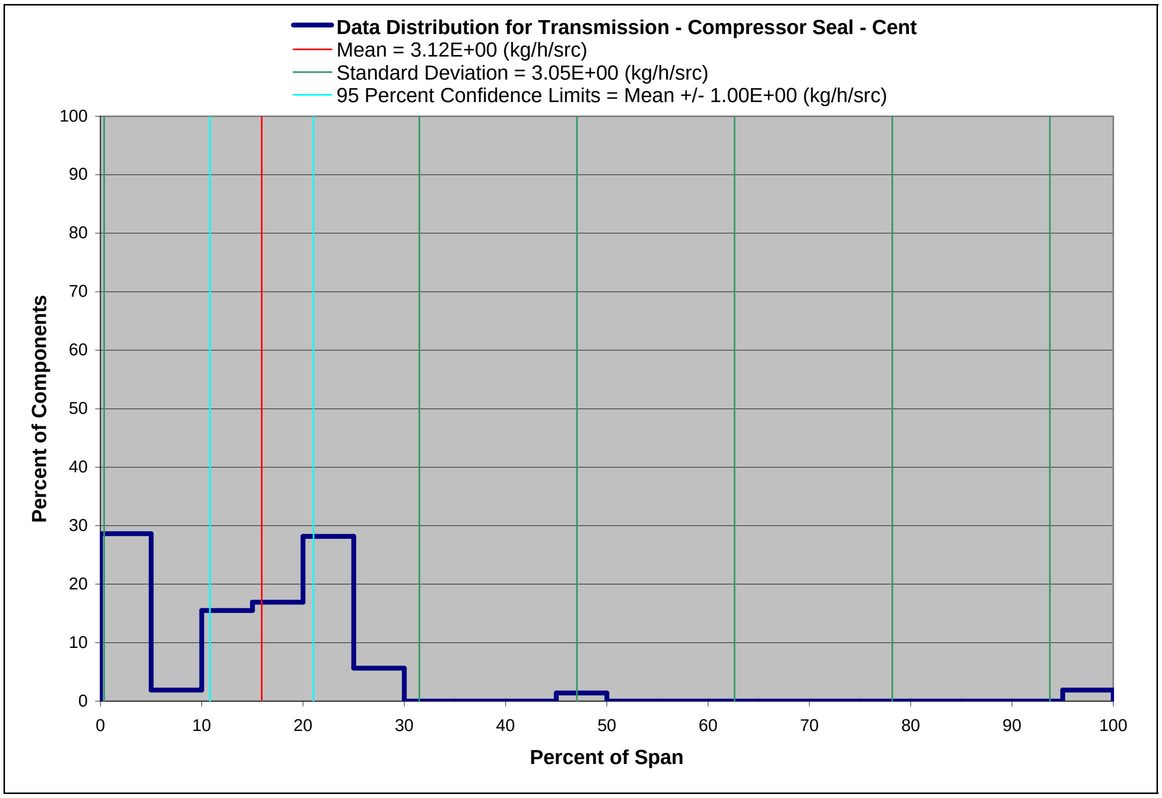


Figure C-1 Transmission Leaker Data Distribution – Centrifugal Compressor Seals

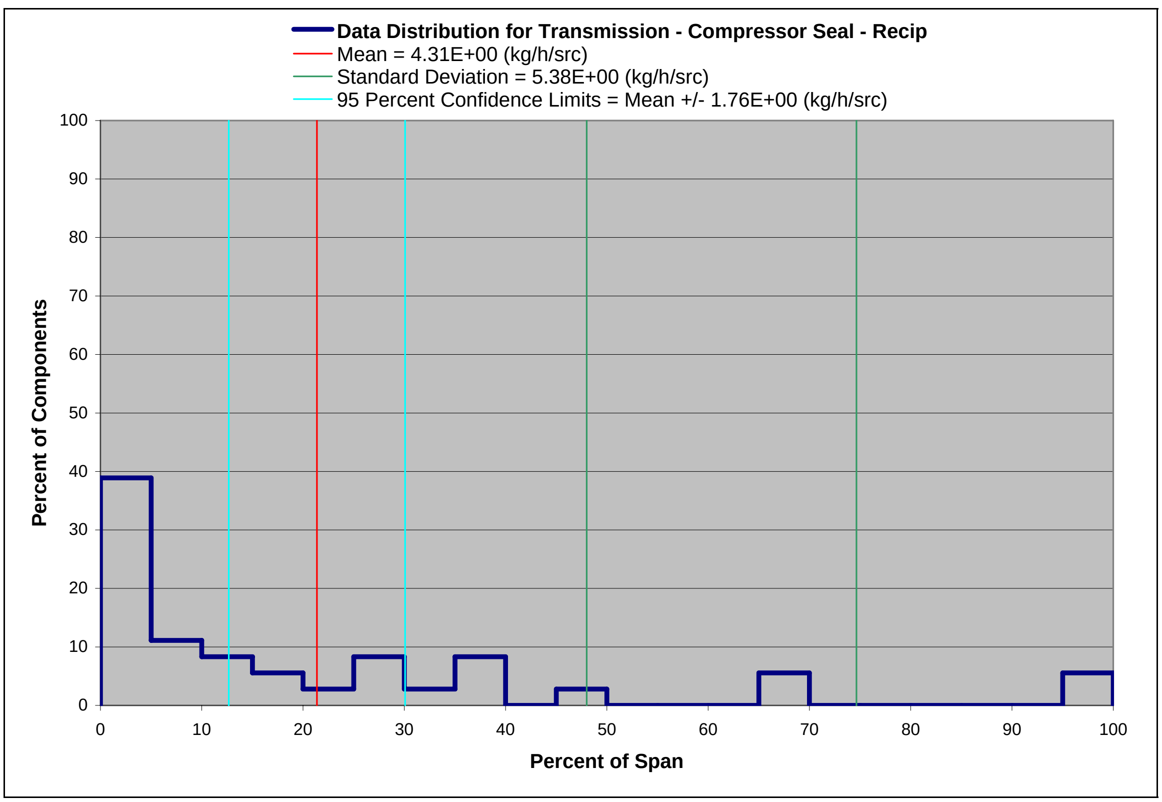


Figure C-2 Transmission Leaker Data Distribution – Reciprocating Compressor Seals

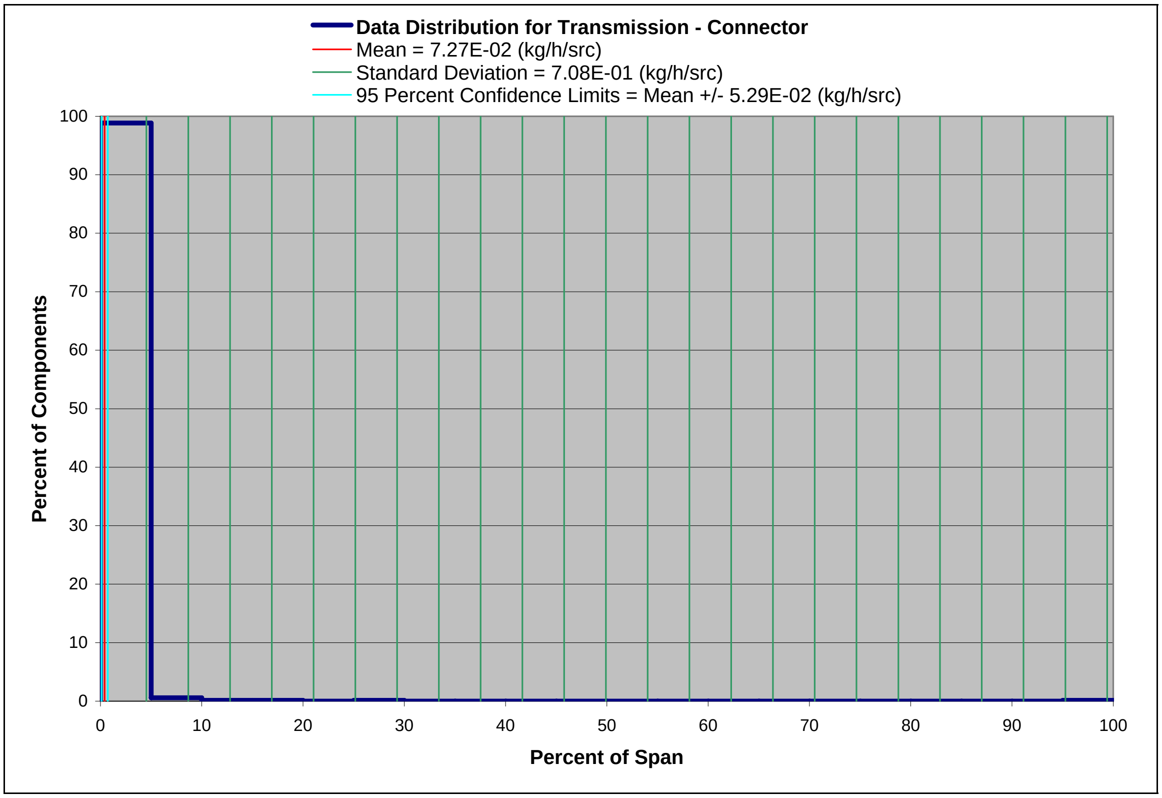


Figure C-3 Transmission Leaker Data Distribution – Connector

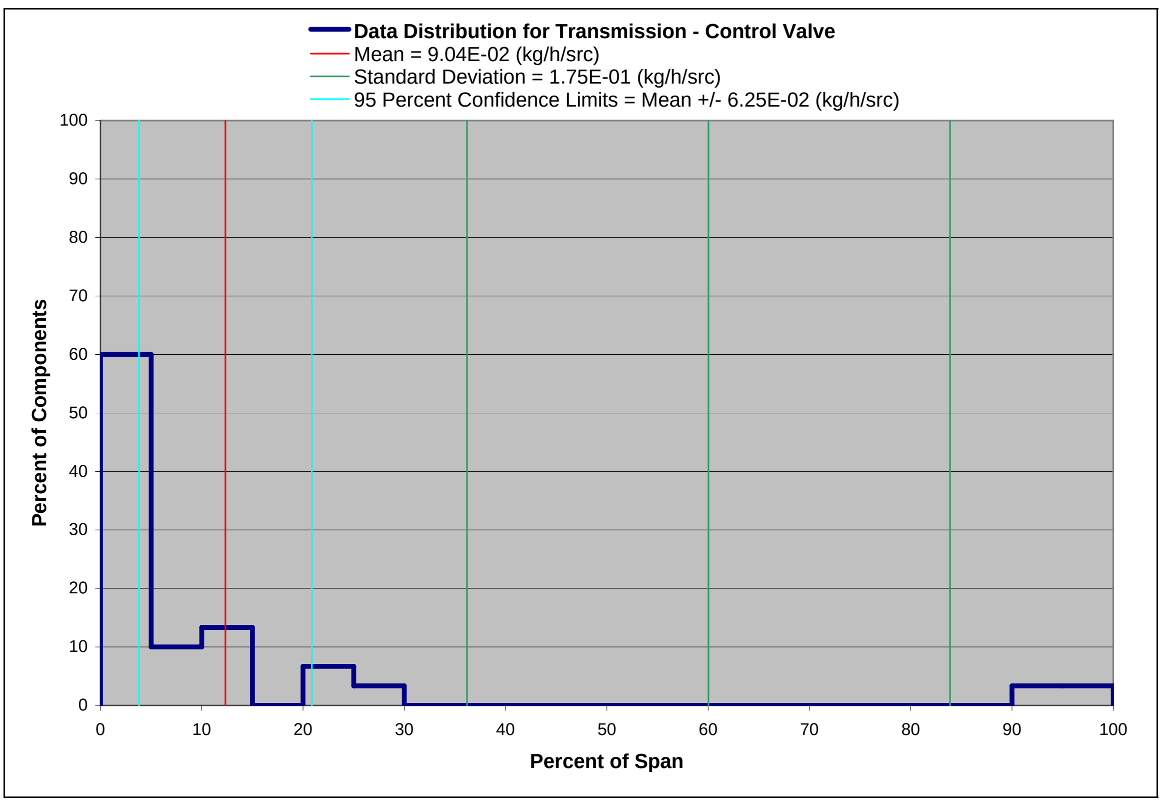


Figure C-4 Transmission Leaker Data Distribution – Control Valve

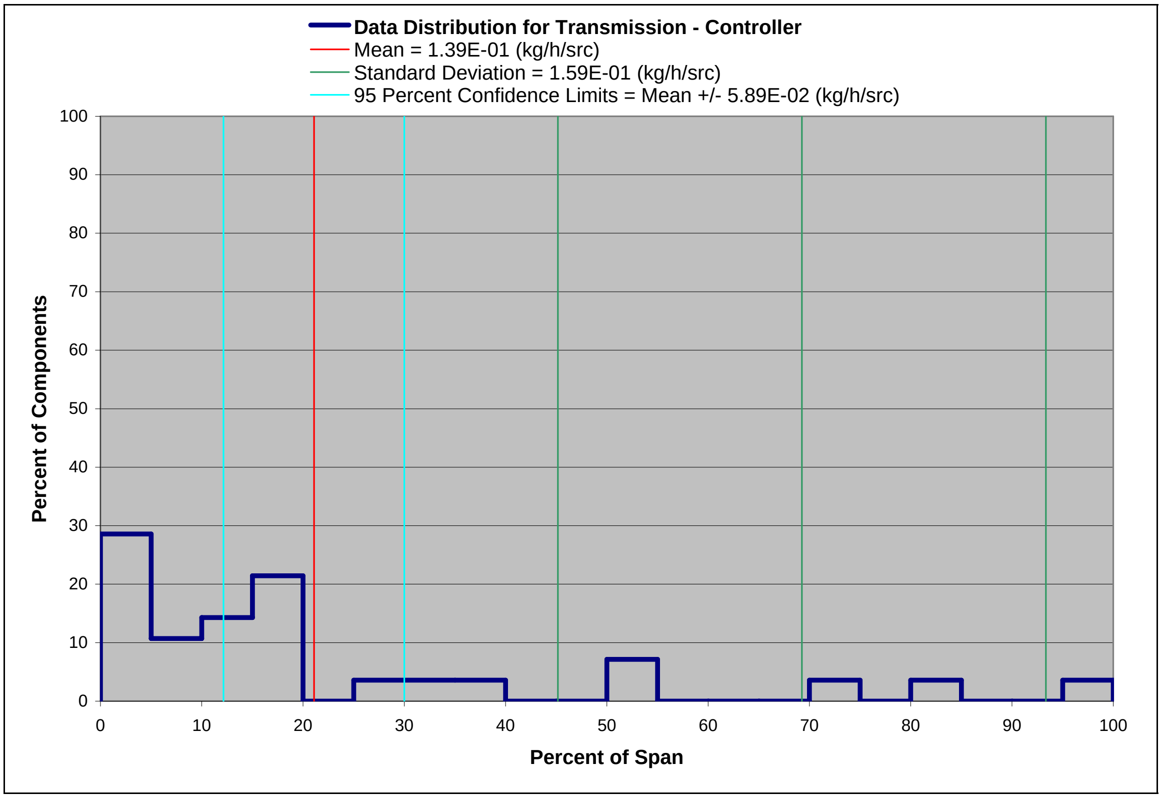


Figure C-5 Transmission Leaker Data Distribution – Controller

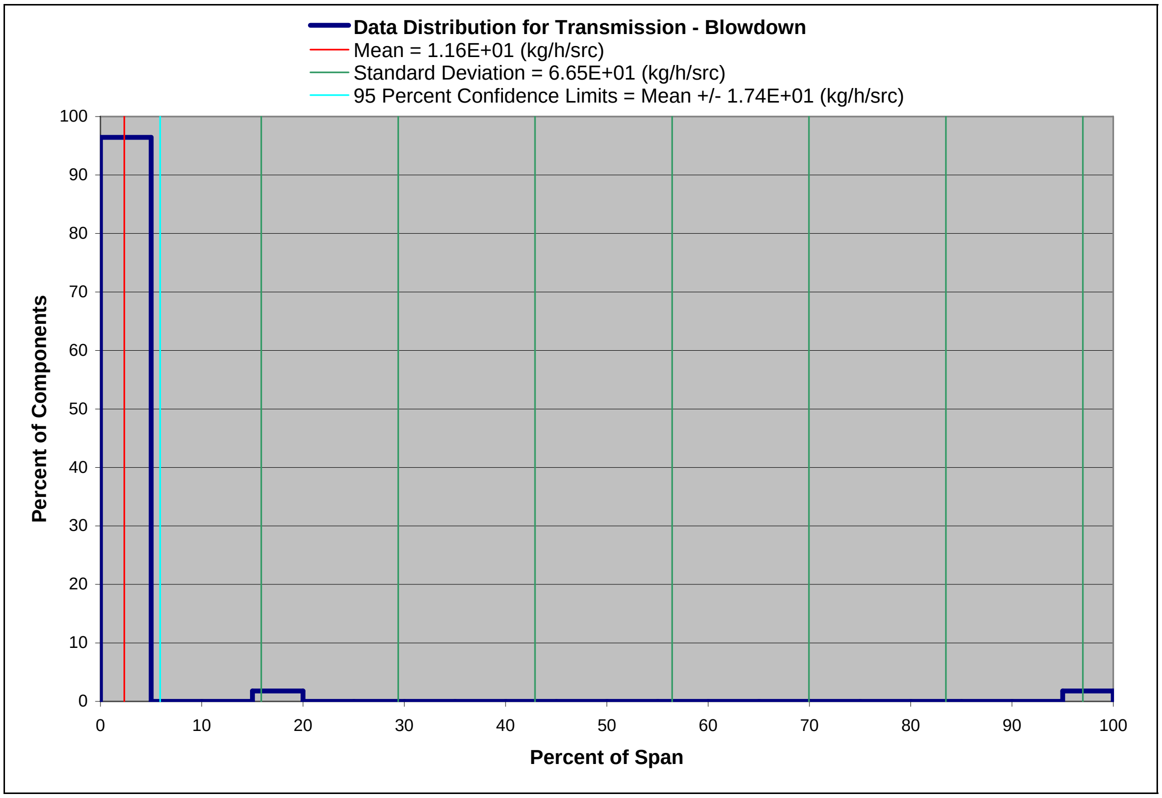


Figure C-6 Transmission Leaker Data Distribution – Blowdown

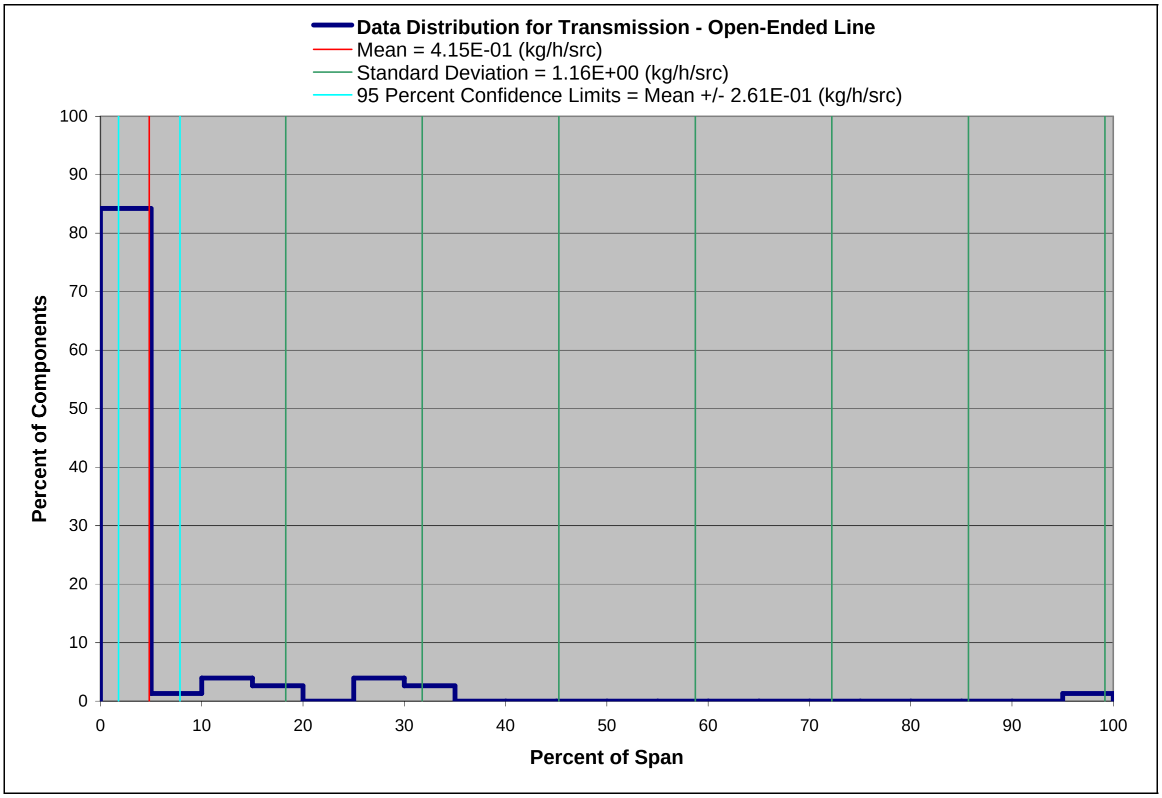


Figure C-7 Transmission Leaker Data Distribution – Open-Ended Line

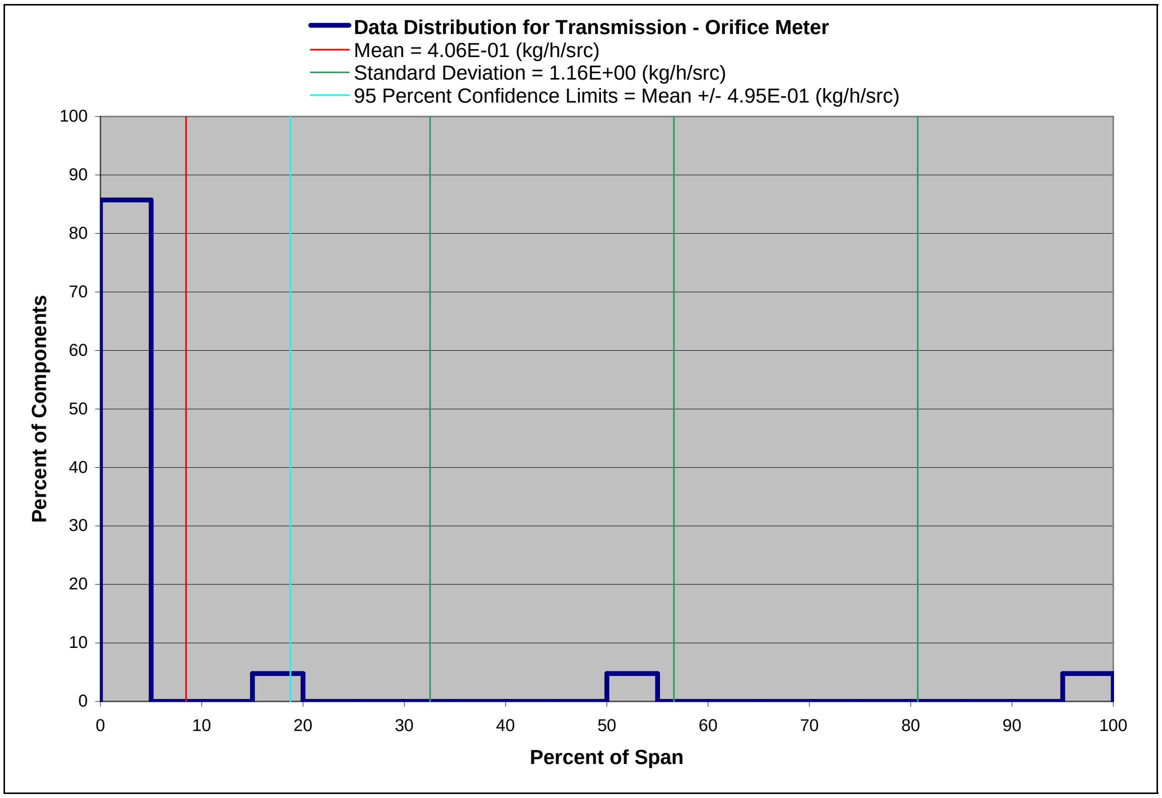


Figure C-8 Transmission Leaker Data Distribution – Orifice Meter

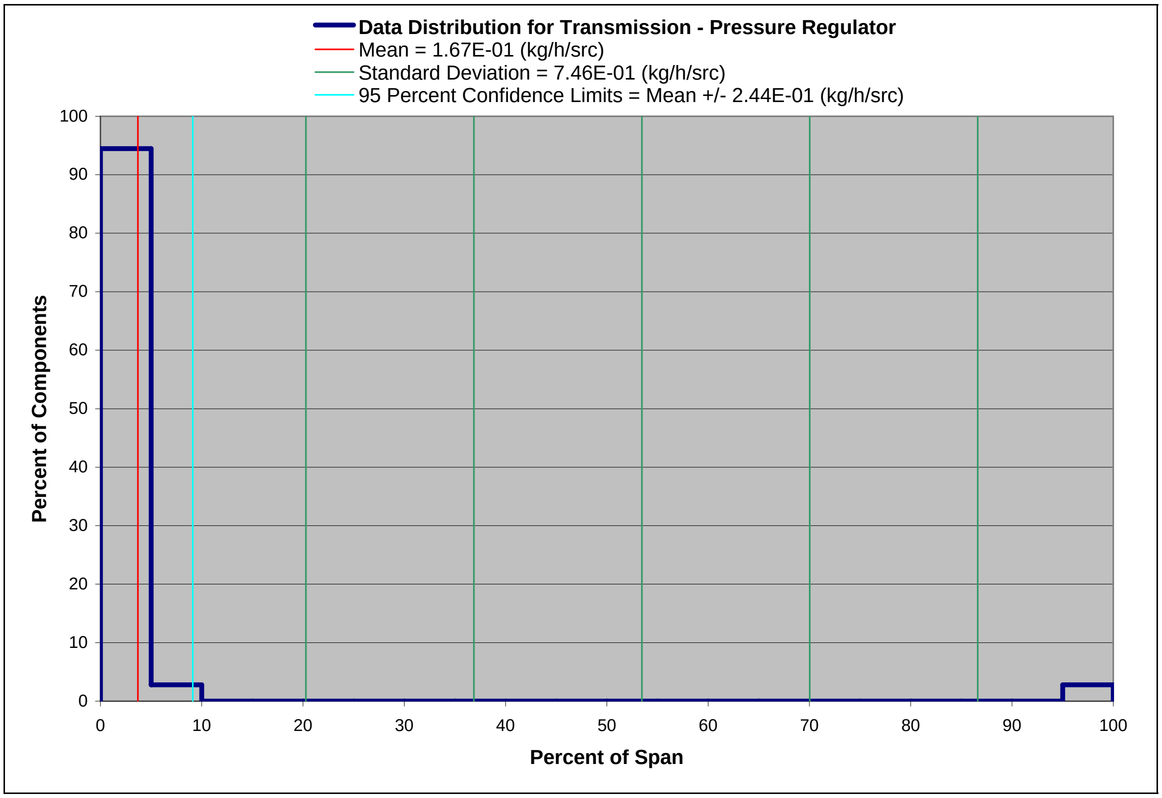


Figure C-9 Transmission Leaker Data Distribution – Pressure Regulator

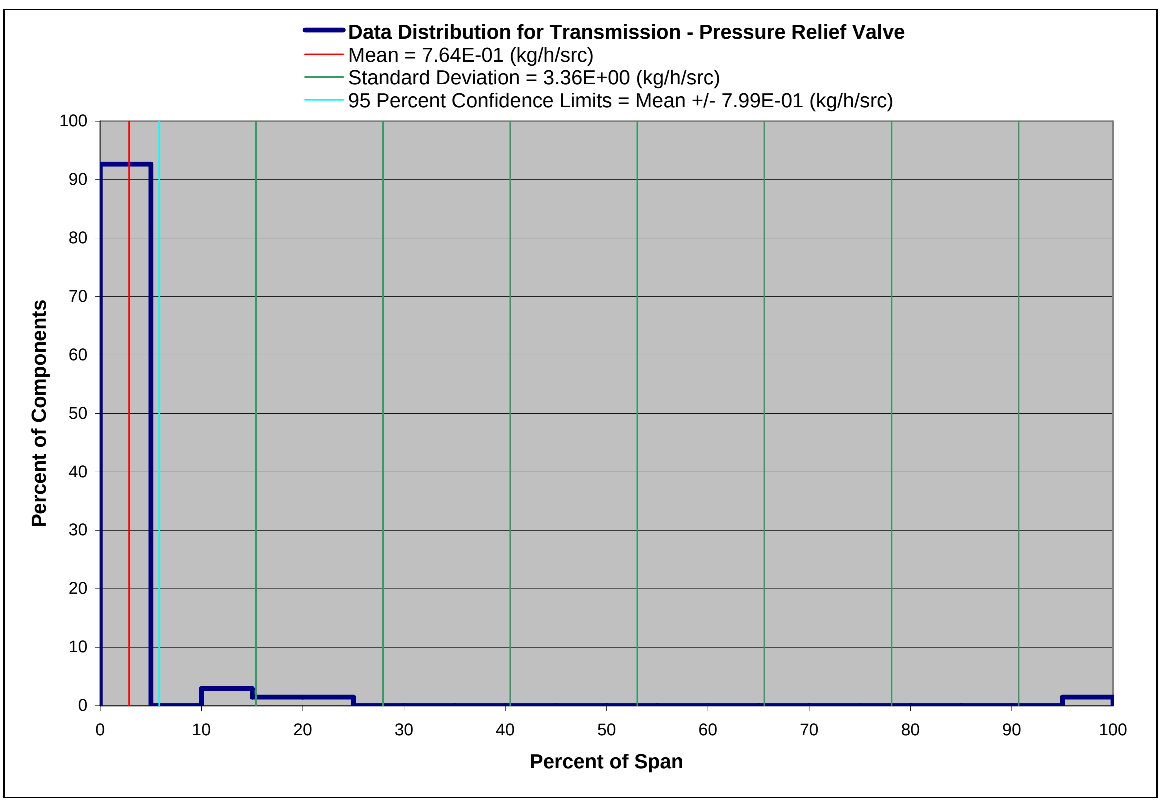


Figure C-10 Transmission Leaker Data Distribution – Pressure Relief Valve

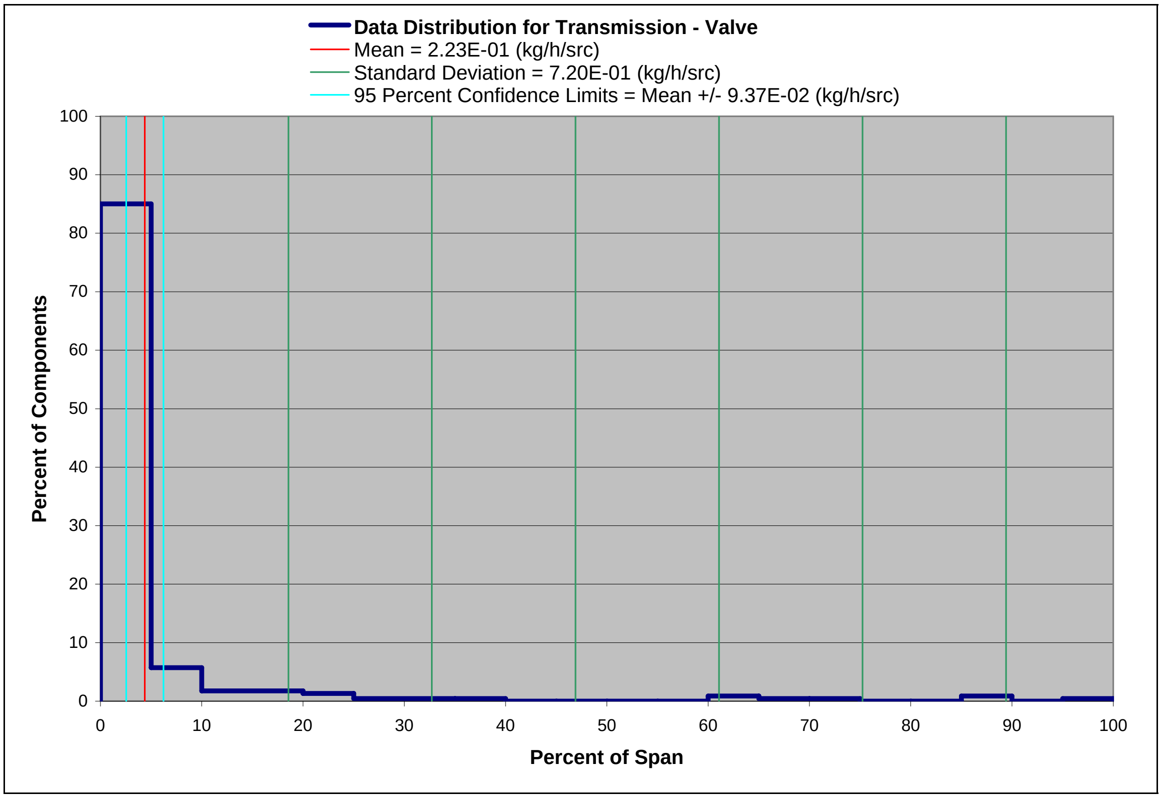


Figure C-11 Transmission Leaker Data Distribution – Valve

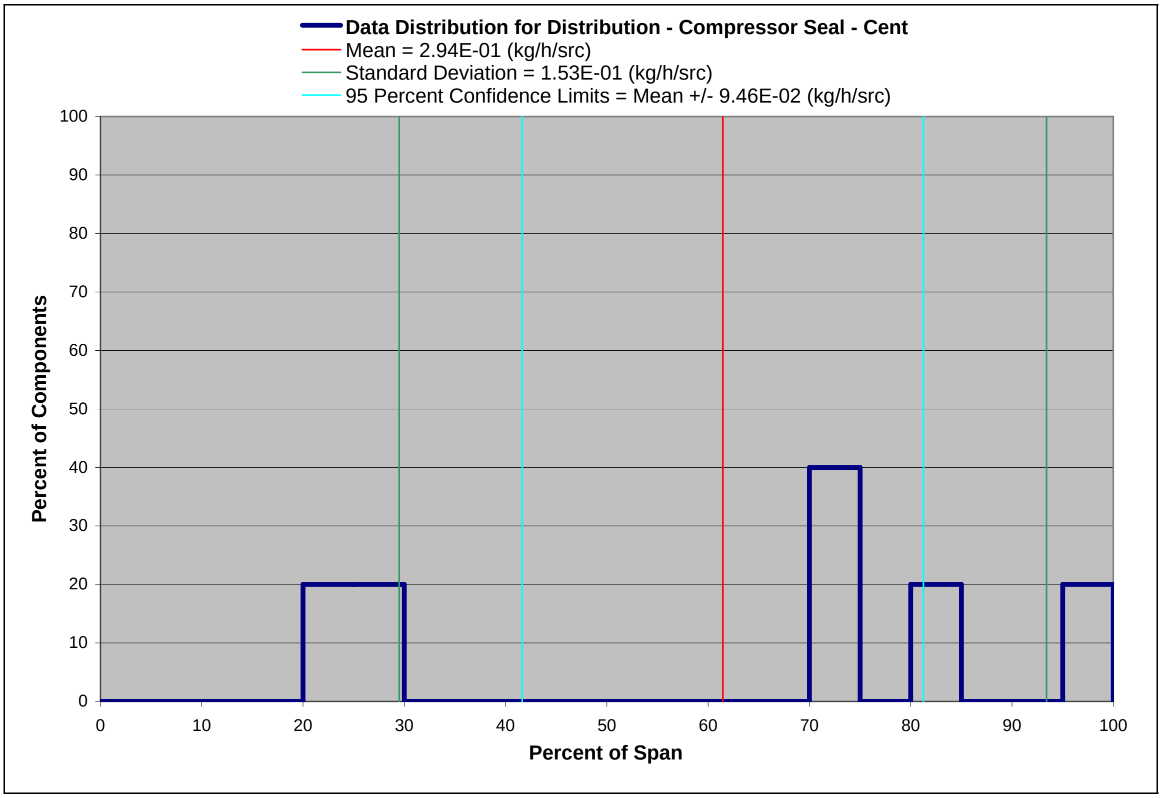


Figure C-12 Distribution Leaker Data Distribution – Centrifugal Compressor Seals

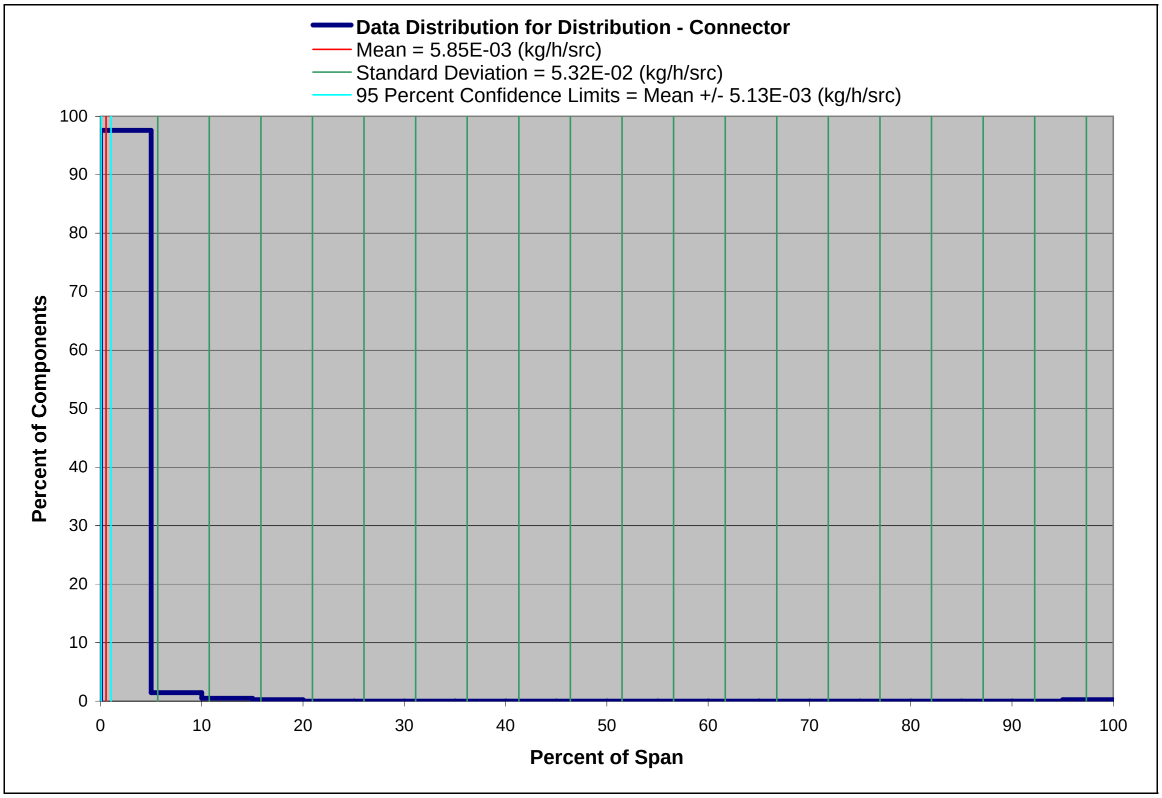


Figure C-13 Distribution Leaker Data Distribution – Connector

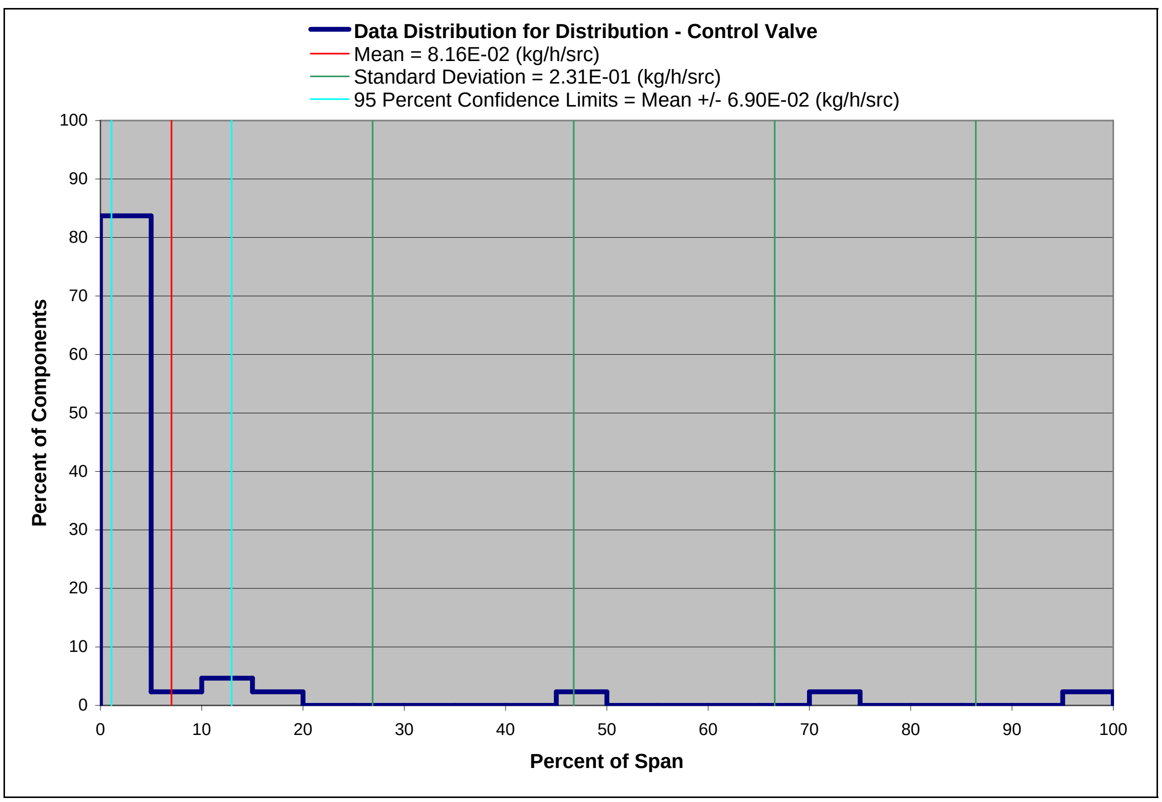


Figure C-14 Leaker Data Distribution – Control Valve

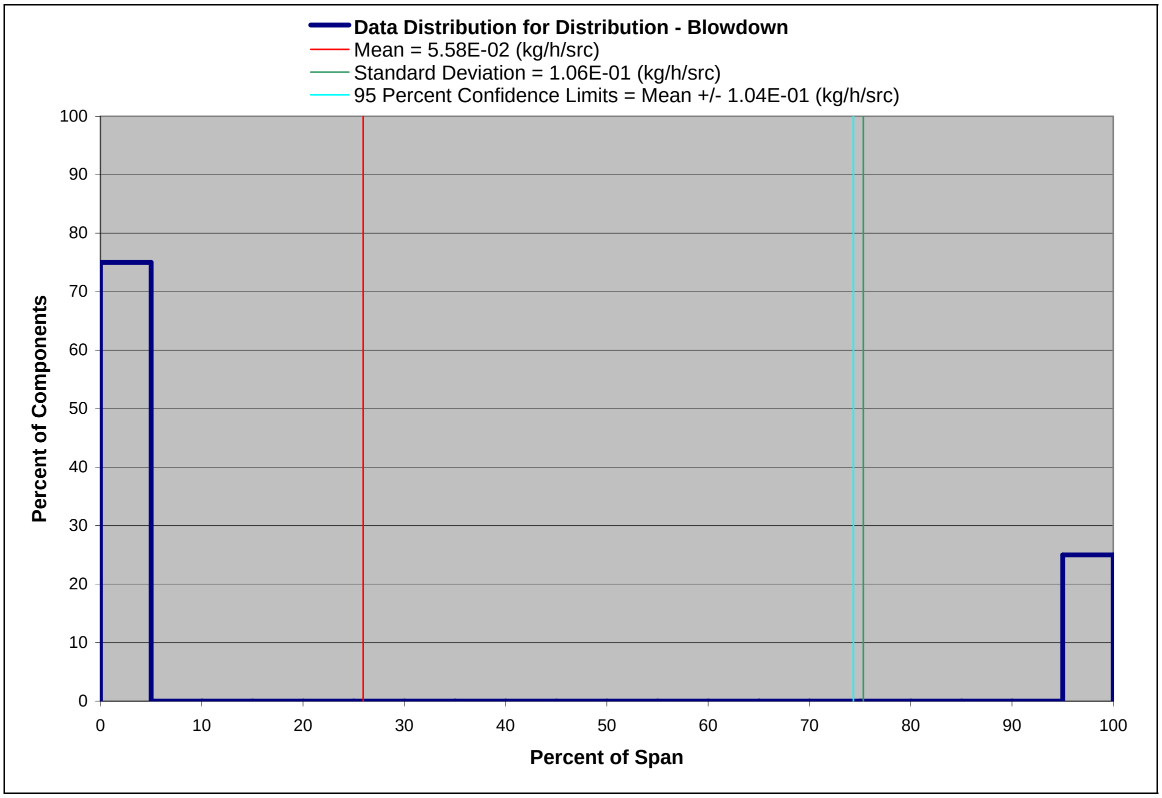


Figure C-15 Distribution Leaker Data Distribution – Blowdown

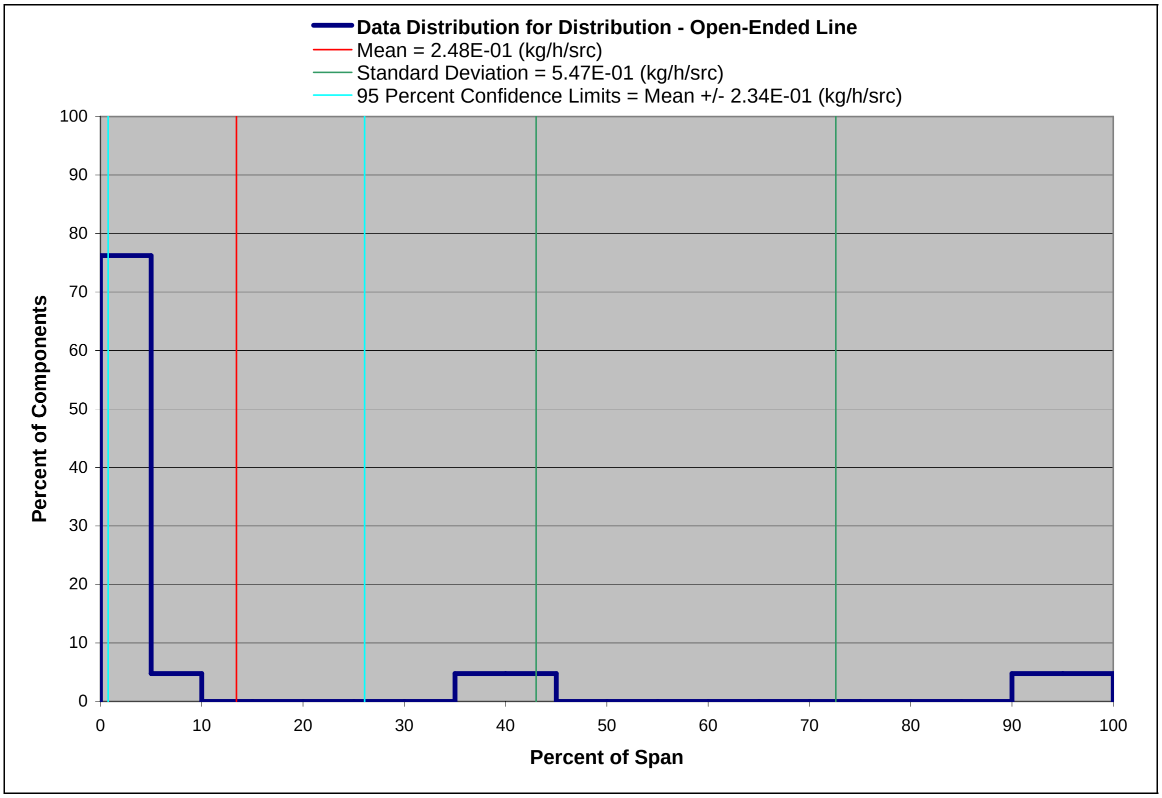


Figure C-16 Distribution Leaker Data Distribution – Open-Ended Line

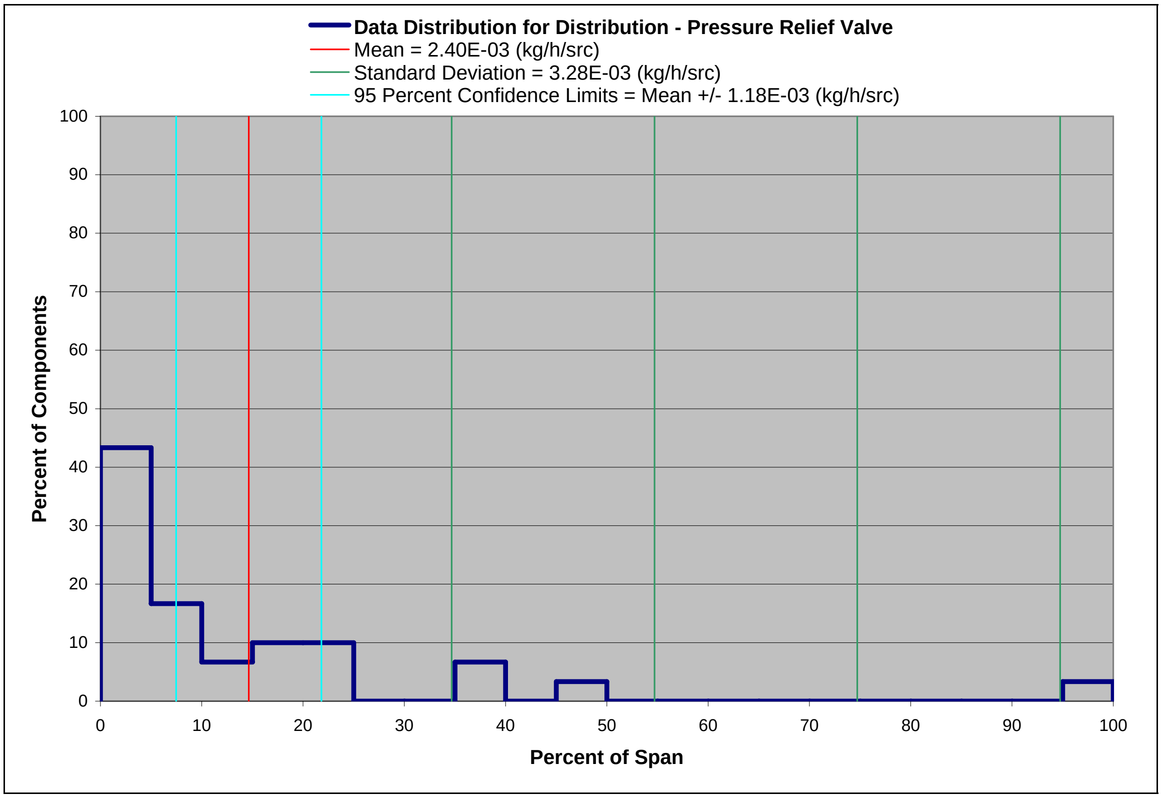


Figure C-17 Distribution Leaker Data Distribution – Pressure Relief Valve

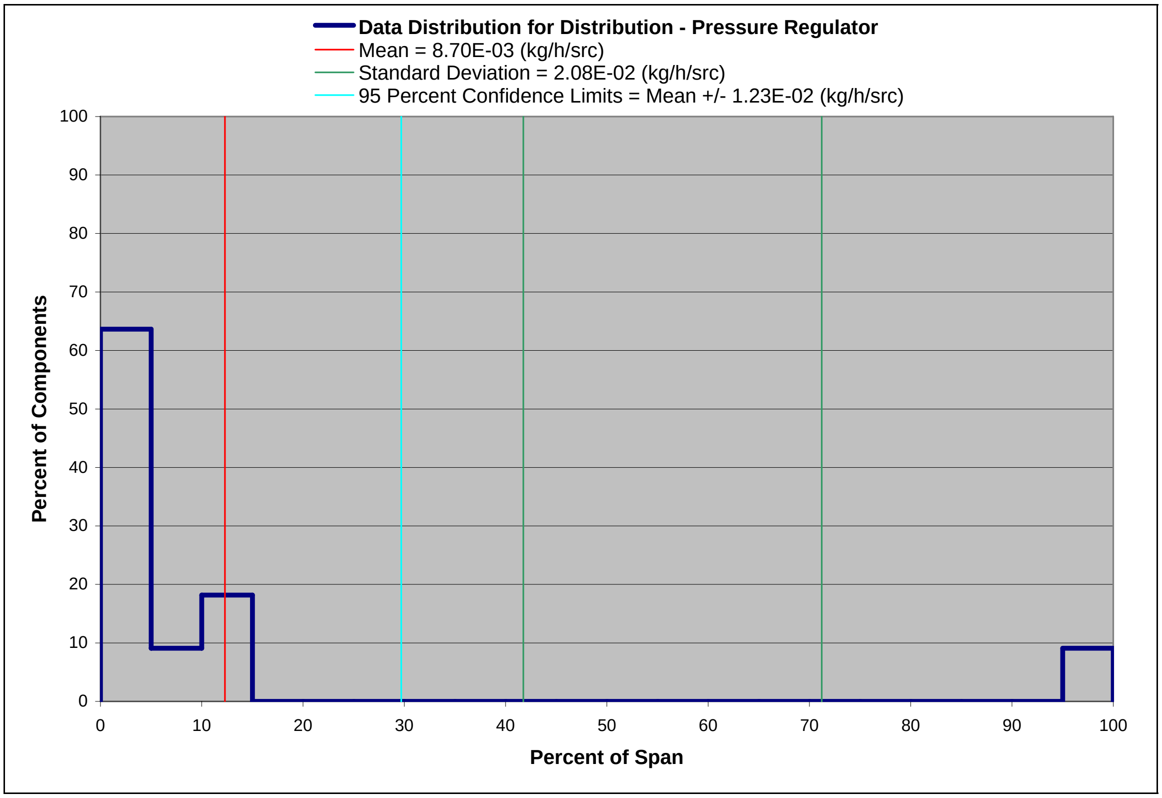


Figure C-18 Distribution Leaker Data Distribution – Pressure Regulator

Appendix D: Cumulative Leak Contributions

The following graphs for each equipment component type show the cumulative contribution of each leaking equipment component to emissions from that source category. When the leakers are ranked from largest to smallest, as on these graphs, it becomes apparent that the top 10 percent of leakers typically contribute approximately 90 percent of the emissions. While this does vary somewhat by component category, the majority of the emissions in all component categories are contributed by a relatively small fraction of the leaking component population. Only the data from the surveyed transmission facilities are presented by way of example, as the cumulative leak contribution graphs for components at distribution facilities are analogous.

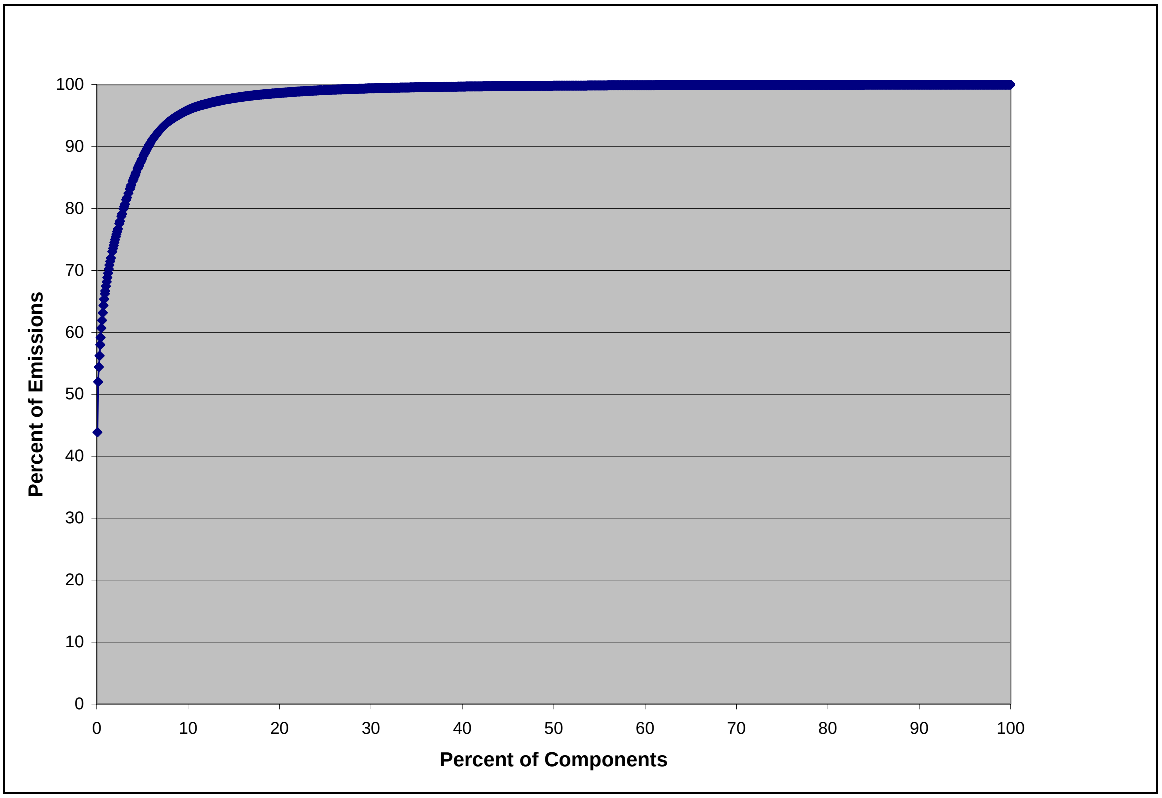


Figure D-1 Cumulative Leak Contributions for Transmission Facilities – All equipment components

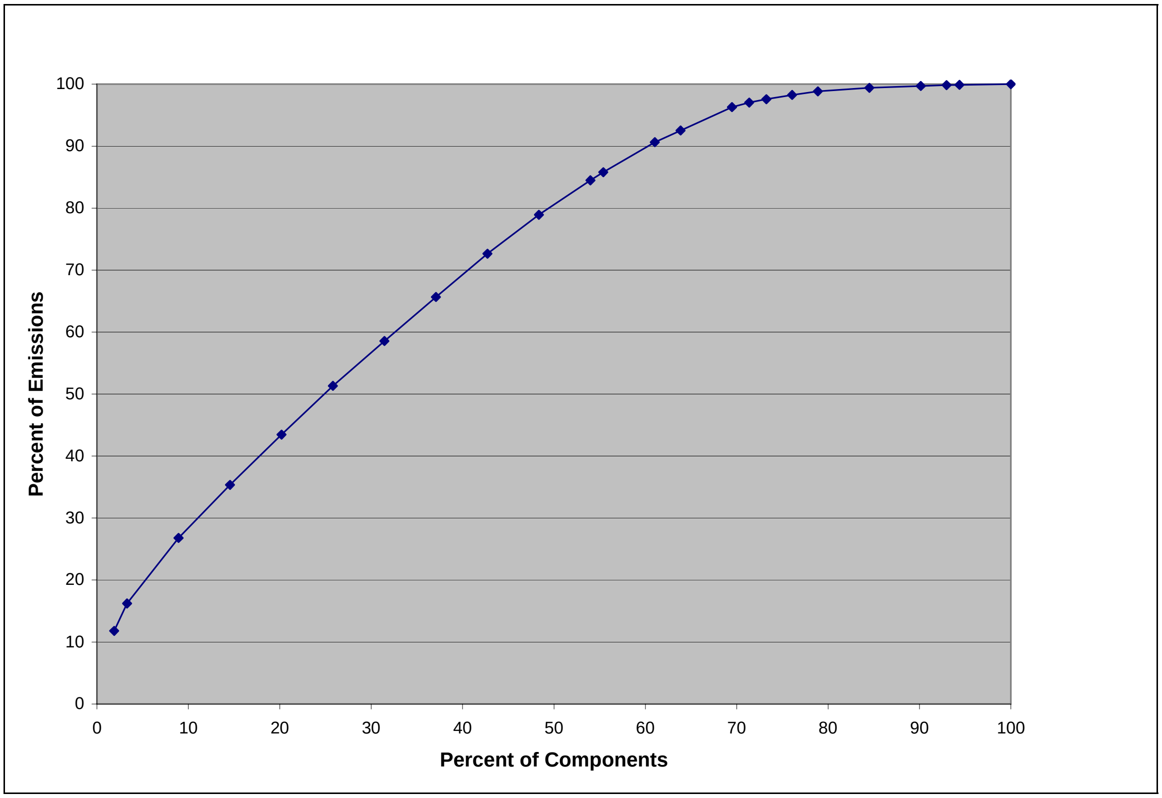


Figure D-2 Cumulative Leak Contributions – Transmission – Centrifugal Compressor Seals

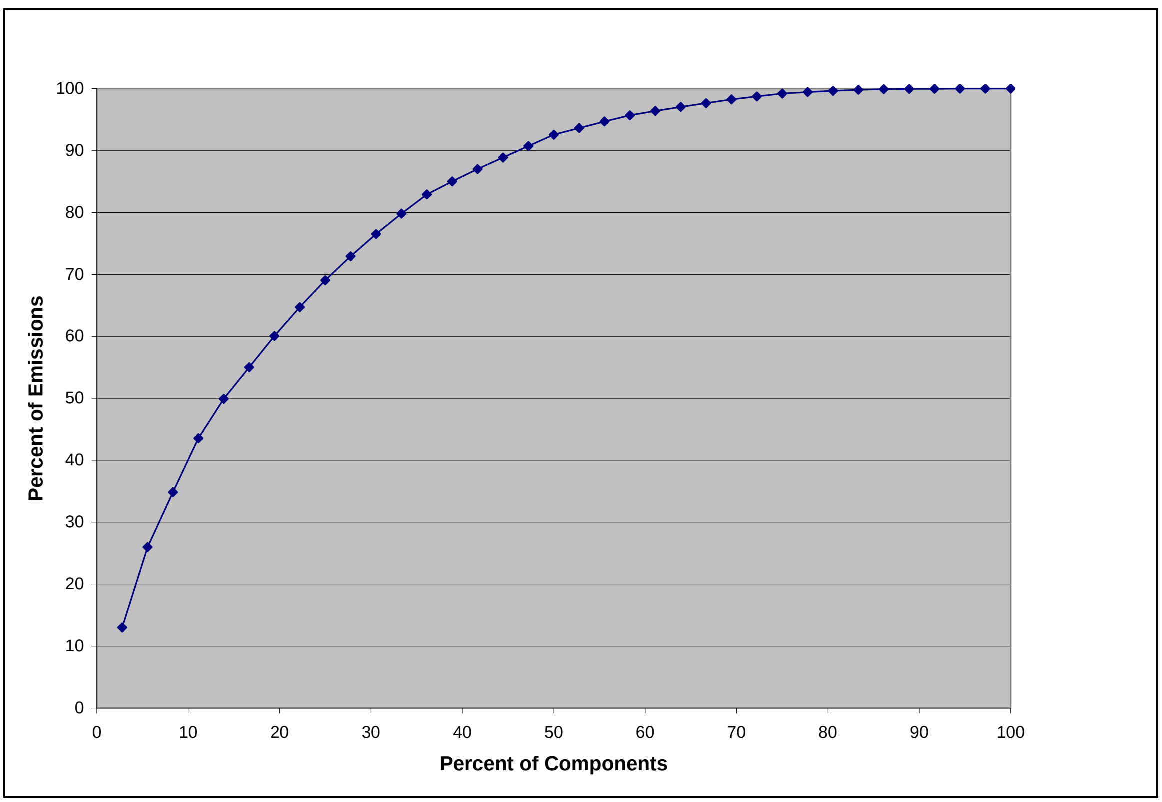


Figure D-3 Cumulative Leak Contributions – Transmission – Reciprocating Compressor Seals

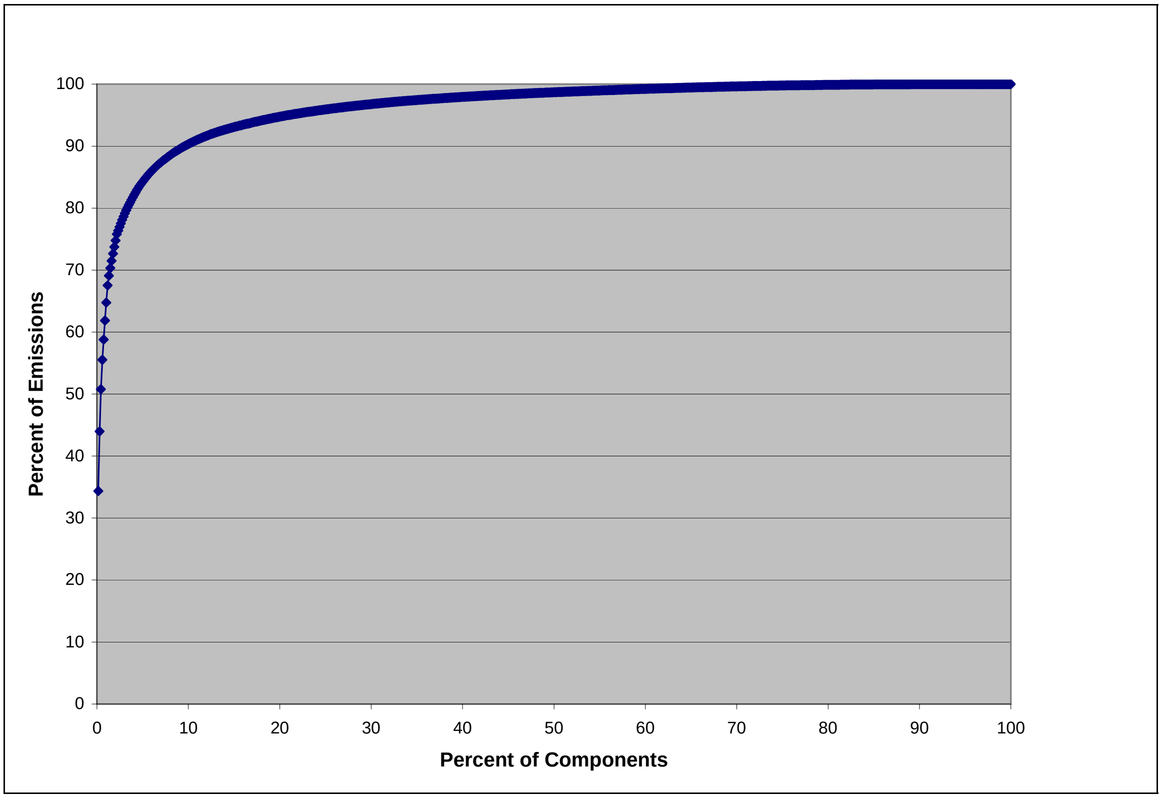


Figure D-4 Cumulative Leak Contributions – Transmission – Connector

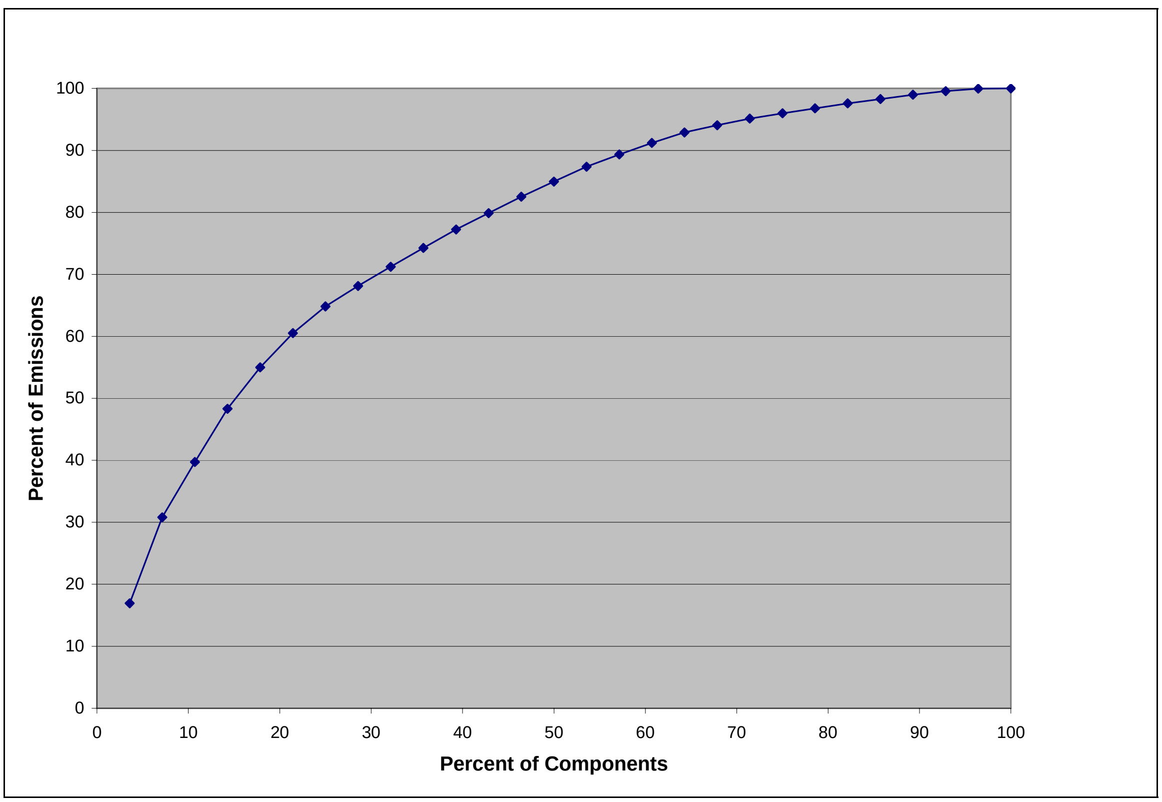


Figure D-5 Cumulative Leak Contributions – Transmission – Controller Vent

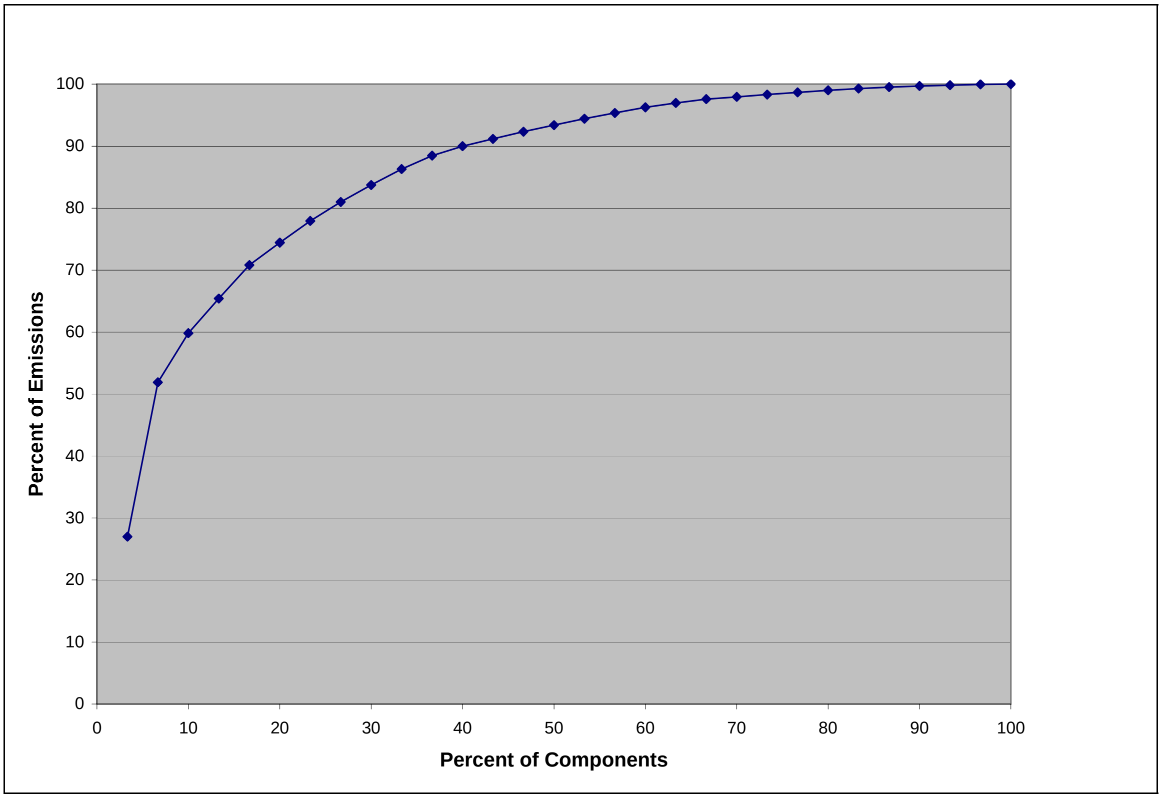


Figure D-6 Cumulative Leak Contributions – Transmission – Control Valve

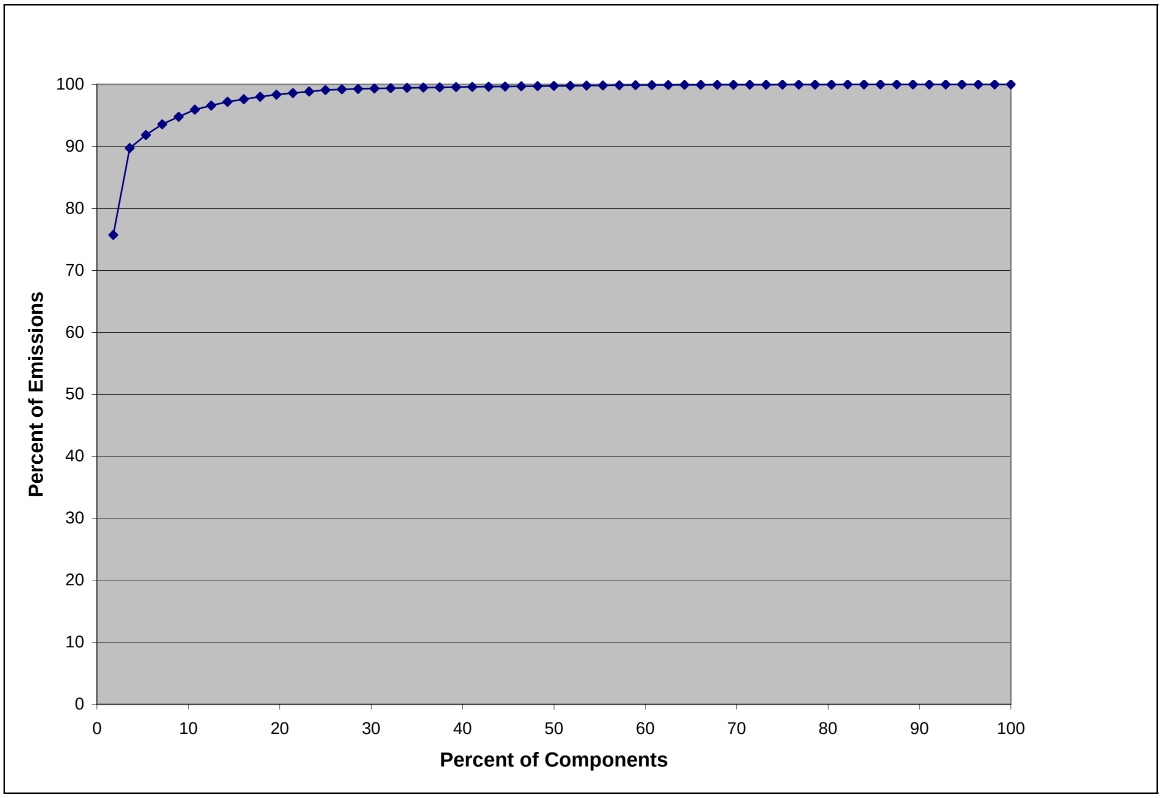


Figure D-7 Cumulative Leak Contributions – Transmission – Blowdown

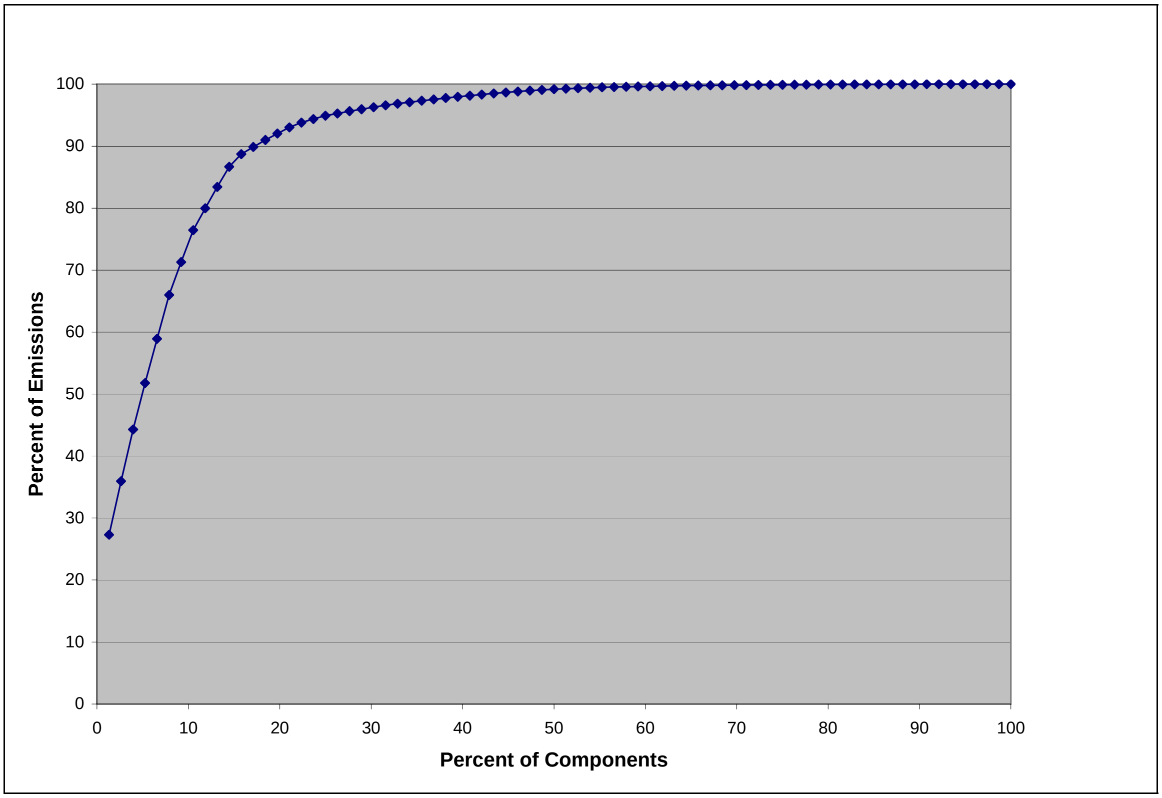


Figure D-8 Cumulative Leak Contributions – Transmission – Open-Ended Line

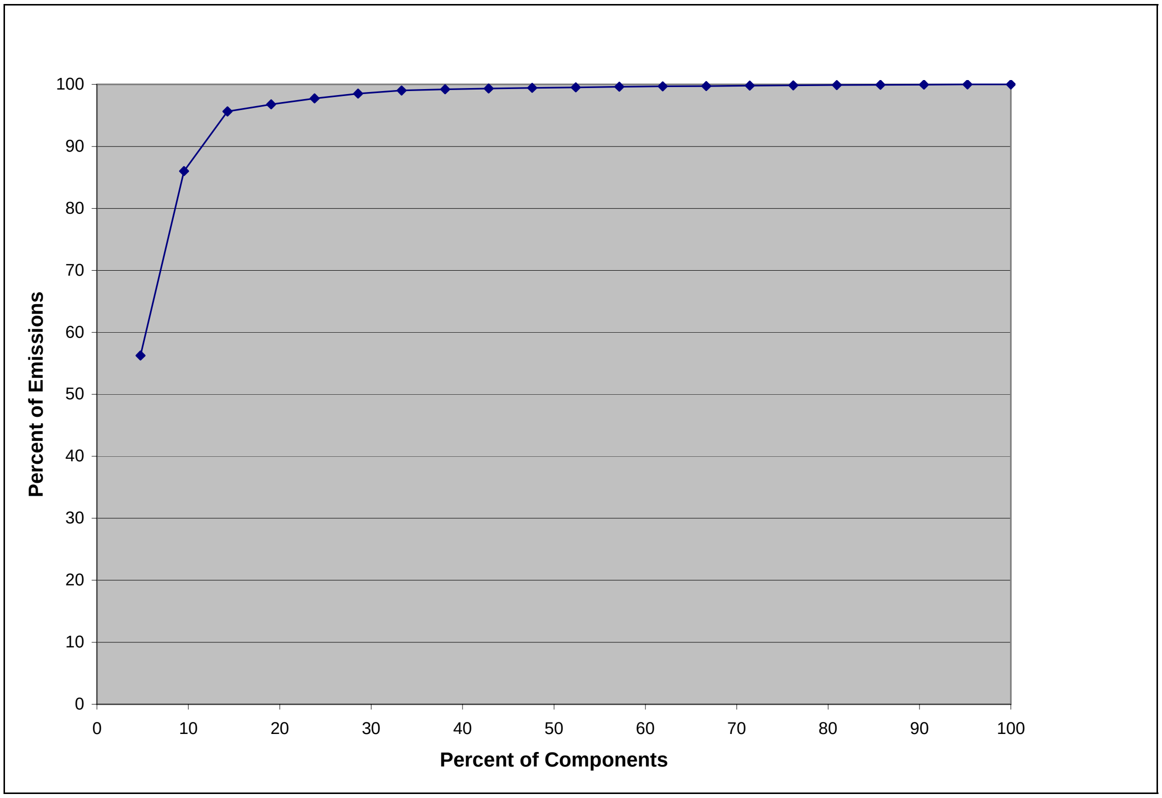


Figure D-9 Cumulative Leak Contributions – Transmission – Orifice Meter

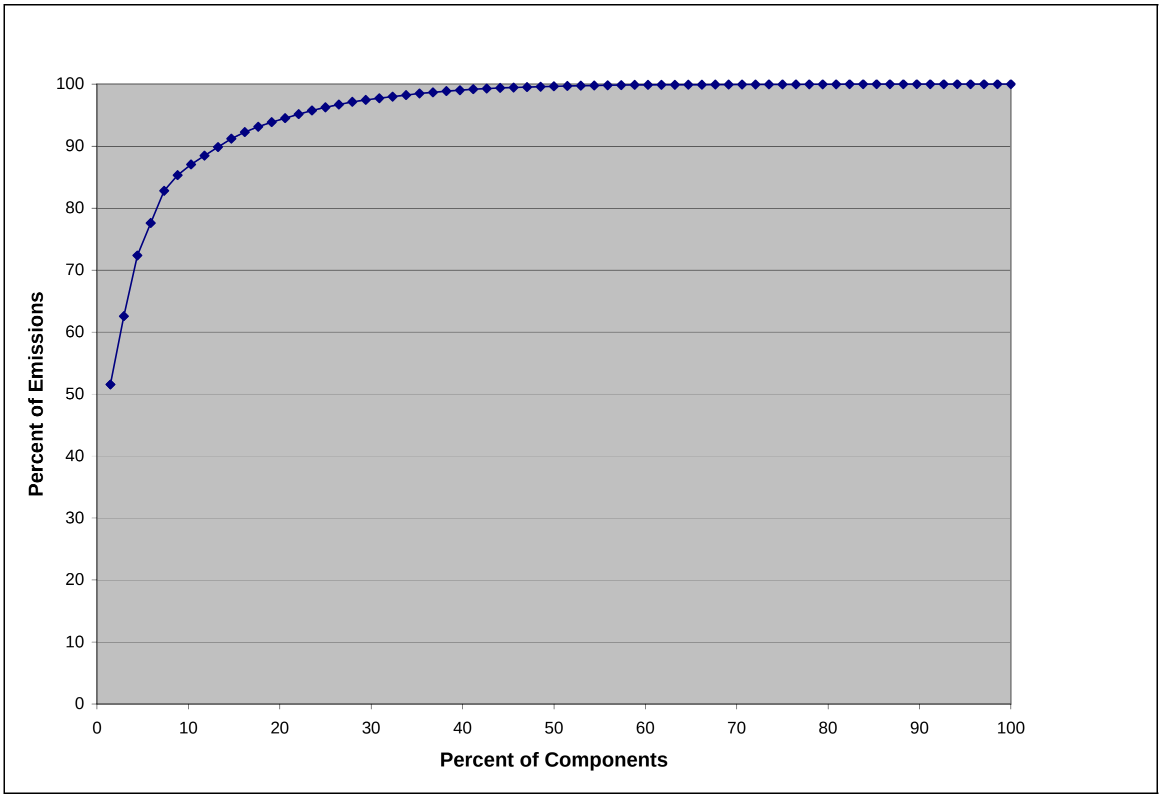


Figure D-10 Cumulative Leak Contributions – Transmission – Pressure Relief Valve

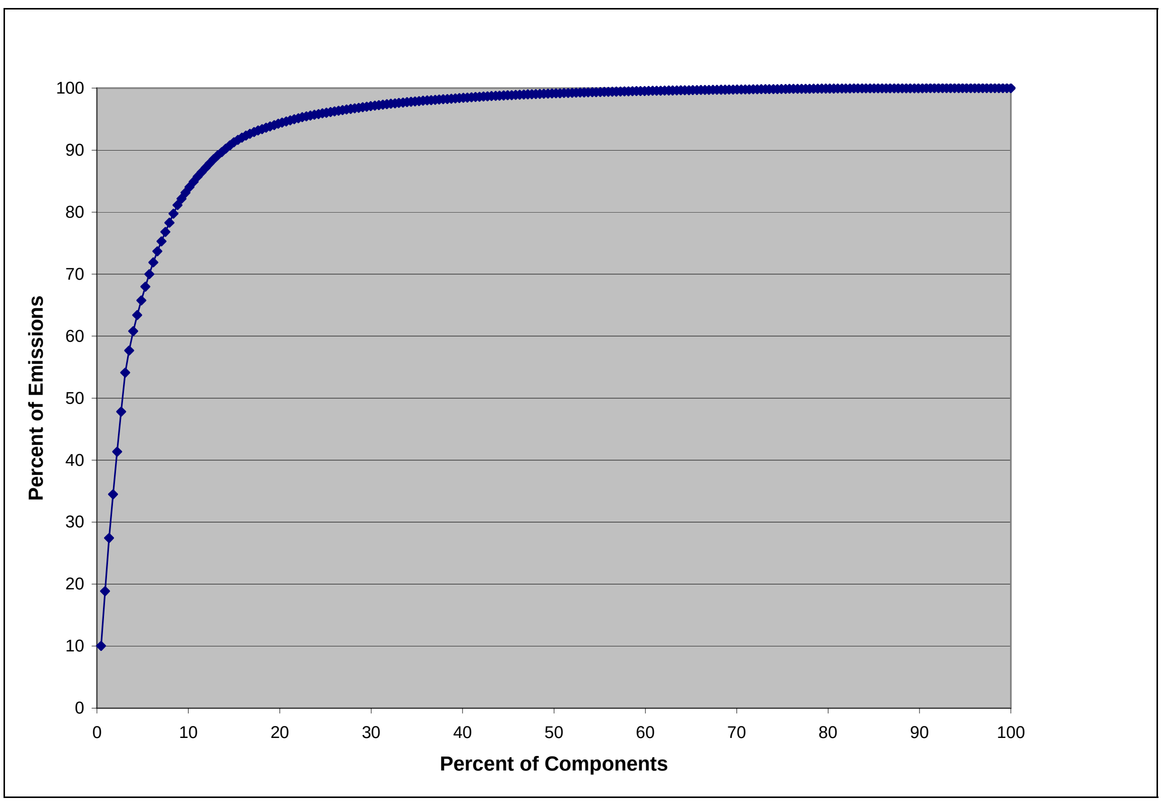


Figure D-11 Cumulative Leak Contributions – Transmission – Valve

Appendix E: Default Component Counts and Confidence Intervals

The following tables present the default component count data and the 95 percent confidence limits (CL) on each value, along with the number of facilities or units surveyed. The 1995/1996 data set does not contain the detail required to evaluate confidence limits on the component counts; consequently, the counts presented are based on the 2005/2006 and independent company study data only.

As has been noted, component counts can vary significantly based on a number of factors. The results of component counts at the surveyed facilities show that certain component categories may not be present at all facilities of a given type. In these cases a fractional activity factor results. To avoid confusion associated with fractional activity factors, entries in the table have been rounded to generate integer values. In cases of fractional activity factors less than 0.5, a value of zero has been entered to indicate that the component may be encountered infrequently at facilities of the given type. Since these fractional component types do not make a significant contribution of overall emissions, the impact on large scale emission inventories is considered extremely small.

Table E-1 Confidence Limits on Equipment Schedules for Gas Transmission Facilities Based on 2005/2006 Measurement Campaign and Independent Company Studies Data Set.

Component		Receipt / Sales Meter Station	Mainline Block Valve	Reciprocating Compressor Unit	Centrifugal Compressor Unit	Compressor Station Yard Piping	Compressor Discharge Cooler
Facilities Surveyed		168	13	25	29	21	9
Compressor Seal – Centrifugal	Average	–	–	–	2	–	–
	Upper CL	–	–	–	–	–	–
	Lower CL	–	–	–	–	–	–
Compressor Seal – Reciprocating	Average	–	–	4	–	–	–
	Upper CL	–	–	5	–	–	–
	Lower CL	–	–	4	–	–	–
Connector	Average	33	200	256	502	950	3527
	Upper CL	46	317	347	576	1210	4537
	Lower CL	20	84	165	429	689	2517

Table E-1 Confidence Limits on Equipment Schedules for Gas Transmission Facilities Based on 2005/2006 Measurement Campaign and Independent Company Studies Data Set.

Component		Receipt / Sales Meter Station	Mainline Block Valve	Reciprocating Compressor Unit	Centrifugal Compressor Unit	Compressor Station Yard Piping	Compressor Discharge Cooler
Control Valve	Average	0	0	1	5	13	0
	Upper CL	0	1	2	6	22	1
	Lower CL	0	0	0	4	4	0
Controller	Average	0	0	0	0	1	–
	Upper CL	0	0	0	0	1	–
	Lower CL	0	0	0	0	0	–
Blowdown	Average	0	0	0	1	4	–
	Upper CL	0	0	0	1	5	–
	Lower CL	0	0	0	1	3	–
Open-Ended Line	Average	0	1	0	4	6	2
	Upper CL	0	1	0	6	9	3
	Lower CL	0	1	0	3	3	1
Orifice Meter	Average	0	–	1	0	2	–
	Upper CL	0	–	1	0	4	–
	Lower CL	0	–	0	0	0	–
Other Flow Meter	Average	1	0	–	0	1	–
	Upper CL	1	0	–	1	2	–
	Lower CL	1	0	–	0	0	–
Pressure Regulator	Average	1	2	2	5	15	0
	Upper CL	1	5	3	6	20	1
	Lower CL	1	0	2	3	10	0
Pressure Relief Valve	Average	0	0	2	3	8	0
	Upper CL	1	0	2	4	10	1
	Lower CL	0	0	1	2	5	0
Valve	Average	7	36	22	120	217	33
	Upper CL	9	53	27	140	289	46
	Lower CL	5	18	17	101	145	20

Table E-2	Confidence Limits on Equipment Schedules for Gas Distribution Facilities and Meter/Regulation Stations Based on 2005/2006 Measurement Campaign and Independent Company Studies Data Set.									
Component		**Industrial Meter Set**	**Gate Station**	**District Regulator Station**	**Border Meter Station**	**Mainline Block Valve**	**Reciprocating Compressor Unit**	**Centrifugal Compressor Unit**	**Compressor Station Yard Piping**	**Compressor Discharge Cooler**
Facilities Surveyed		15	30	32	6	22	2	12	9	7
Compressor Seal – Centrifugal	Average	–	–	–	–	–	–	2	–	–
	Upper CL	–	–	–	–	–	–	–	–	–
	Lower CL	–	–	–	–	–	–	–	–	–
Compressor Seal – Reciprocating	Average	–	–	–	–	–	5	–	–	–
	Upper CL	–	–	–	–	–	–	–	–	–
	Lower CL	–	–	–	–	–	–	–	–	–
Connector	Average	111	353	181	381	142	163	430	1172	527
	Upper CL	152	427	248	–	207	–	523	1546	626
	Lower CL	70	280	113	–	77	–	336	799	428
Control Valve	Average	0	2	1	1	1	1	5	19	0
	Upper CL	1	3	1	–	3	–	6	31	0
	Lower CL	0	0	0	–	0	–	4	7	0
Controller	Average	–	0	–	–	0	–	–	–	–
	Upper CL	–	0	–	–	0	–	–	–	–
	Lower CL	–	0	–	–	0	–	–	–	–
Blowdown	Average	–	–	–	0	–	1	1	3	–
	Upper CL	–	–	–	–	–	–	1	7	–
	Lower CL	–	–	–	–	–	–	0	0	–
Open-Ended Line	Average	–	0	0	4	1	4	5	22	–
	Upper CL	–	1	1	–	1	–	8	37	–
	Lower CL	–	0	0	–	0	–	2	8	–
Orifice Meter	Average	0	1	0	–	0	1	0	1	–
	Upper CL	0	1	0	–	0	–	1	2	–
	Lower CL	0	0	0	–	0	–	0	0	–
Other Flow Meter	Average	1	1	0	1	0	–	1	1	–
	Upper CL	2	1	0	–	1	–	1	2	–
	Lower CL	1	0	0	–	0	–	0	0	–

Table E-2 Confidence Limits on Equipment Schedules for Gas Distribution Facilities and Meter/Regulation Stations Based on 2005/2006 Measurement Campaign and Independent Company Studies Data Set.

Component		Industrial Meter Set	Gate Station	District Regulator Station	Border Meter Station	Mainline Block Valve	Reciprocating Compressor Unit	Centrifugal Compressor Unit	Compressor Station Yard Piping	Compressor Discharge Cooler
Pressure Regulator	Average	4	12	8	8	2	1	3	18	–
	Upper CL	6	14	10	–	4	–	4	27	–
	Lower CL	2	10	5	–	1	–	1	8	–
Pressure Relief Valve	Average	0	3	2	3	1	2	2	18	1
	Upper CL	1	3	2	–	3	–	3	36	1
	Lower CL	0	2	1	–	0	1	1	0	0
Valve	Average	26	64	40	62	33	20	83	222	14
	Upper CL	37	80	53	–	54	–	102	321	19
	Lower CL	15	49	27	–	13	–	64	122	8

Table E-3	Confidence Limits on Equipment Schedules for Gas Distribution Commercial and Residential Meter Sites Based on 2005/2006 Measurement Campaign Data Set.			
Component		**Residential Meter Set**	**Commercial Meter Set**	**Farm Tap**
Facilities Surveyed		44	35	18
Connector	Average	48	82	48
	Upper CL	69	100	60
	Lower CL	27	65	35
Control Valve	Average	0	0	0
	Upper CL	0	0	0
	Lower CL	0	0	0
Orifice Meter	Average	–	0	–
	Upper CL	–	0	–
	Lower CL	–	0	–
Other Flow Meter	Average	1	2	0
	Upper CL	2	3	1
	Lower CL	1	1	0
Pressure Regulator	Average	2	3	2
	Upper CL	2	5	3
	Lower CL	1	2	2
Pressure Relief Valve	Average	0	1	2
	Upper CL	0	2	3
	Lower CL	0	0	1
Valve	Average	8	14	13
	Upper CL	13	18	18
	Lower CL	4	10	7

Appendix F: Changes observed from 1995/1996 to 2005/2006 data sets

The tables in this appendix offer a comparison, by industry sub-sector, of the average emission factors and confidence limits based on the 1995/1996 data set, the 2005/2006 measurement campaign and independent company studies data set and the combined data set.
In addition, tabular summaries of the magnitude of changes between the 1995/1996 study and subsequent measurement work, in terms of number of sources encountered, leak frequencies and average emissions are provided.

Table F-1 Comparison of Average Emission Factors (kg TOC/h/source) for Gas Transmission Facilities.

	Combined Data Set				2005/2006 Measurement Campaign + Independent Company Studies				1995/1996 Study			
Component Category	Number of Sources	Average Emission Factor	Upper CL	Lower CL	Number of Sources	Average Emission Factor	Upper CL	Lower CL	Number of Sources	Average Emission Factor	Upper CL	Lower CL
Compressor Seal - Cent	79	1.617E+00	2.181E+00	1.053E+00	58	1.908E+00	2.634E+00	1.182E+00	21	8.139E-01	1.397E+00	2.307E-01
Compressor Seal - Recip	149	1.203E+00	1.714E+00	6.908E-01	113	1.375E+00	2.042E+00	7.074E-01	36	6.616E-01	9.184E-01	4.048E-01
Connector	145829	4.471E-04	6.985E-04	1.957E-04	100761	5.297E-04	8.928E-04	1.667E-04	45068	2.624E-04	3.146E-04	2.102E-04
Control Valve	782	1.650E-02	2.219E-02	1.082E-02	509	1.479E-02	1.911E-02	1.048E-02	273	1.969E-02	3.387E-02	5.514E-03
Controller	50	2.371E-01	3.747E-01	9.941E-02	33	1.181E-01	1.708E-01	6.532E-02	17	4.681E-01	8.429E-01	9.330E-02
Blowdown	219	3.405E+00	7.885E+00	0	117	5.556E+00	1.392E+01	0	102	9.369E-01	1.516E+00	3.576E-01
Open-Ended Line	928	9.183E-02	1.297E-01	5.395E-02	286	1.104E-01	1.827E-01	3.816E-02	642	8.354E-02	1.279E-01	3.924E-02
Orifice Meter	185	4.863E-02	1.066E-01	0	81	1.068E-01	2.386E-01	0	104	3.313E-03	4.694E-03	1.932E-03
Other Flow Meter	443	9.942E-06	1.966E-05	2.223E-07	177	1.131E-05	2.645E-05	0	266	9.034E-06	2.172E-05	0
Pressure Regulator	816	7.945E-03	1.882E-02	0	687	8.770E-03	2.167E-02	0	129	3.552E-03	6.208E-03	8.949E-04
Pressure Relief Valve	612	1.620E-01	2.950E-01	2.906E-02	426	1.225E-01	2.520E-01	0	186	2.524E-01	5.744E-01	0
Valve	17029	4.131E-03	5.514E-03	2.748E-03	10877	5.257E-03	7.366E-03	3.148E-03	6152	2.140E-03	3.000E-03	1.280E-03

Table F-2 Changes from 1995/1996 to 2005/2006 Gas Transmission Data Sets				
	Percent Change from 1995/1996 to 2005/2006			
Component Category	**Number of Sources Surveyed**	**Leak Frequency**	**Leaker Emission Factor**	**Average Emission Factor**
Compressor Seal - Cent	176	-35	260	134
Compressor Seal - Recip	214	-63	462	108
Connector	124	-45	292	102
Control Valve	86	-60	19	-25
Controller	94	-15	-70	-75
Blowdown	15	-35	811	493
Open-Ended Line	-55	-63	259	32
Orifice Meter	-22	28	4519	3124
Other Flow Meter	-33	-79	554	25
Pressure Regulator	443	-68	743	147
Pressure Relief Valve	129	-76	100	-51
Valve	77	-48	473	146

Table F-3	Comparison of Average Emission Factors (kg TOC/h/source) for Gas Distribution Facilities and Meter/Regulation Stations.											
	Combined Data Set				2005/2006 Measurement Campaign + Independent Company Studies				1995/1996 Study			
Component Category	Number of Sources	Average Emission Factor	Upper CL	Lower CL	Number of Sources	Average Emission Factor	Upper CL	Lower CL	Number of Sources	Average Emission Factor	Upper CL	Lower CL
Compressor Seal - Cent	24	1.223E-01	1.927E-01	5.191E-02	24	1.223E-01	1.927E-01	5.191E-02	–	–	–	–
Compressor Seal - Recip	9	5.600E-04	1.789E-03	0	9	5.600E-04	1.789E-03	0	–	–	–	–
Connector	52051	8.227E-05	1.266E-04	3.792E-05	43466	7.687E-05	1.258E-04	2.791E-05	8585	1.096E-04	2.138E-04	5.472E-06
Control Valve	605	1.949E-02	2.771E-02	1.127E-02	332	1.933E-02	2.875E-02	9.903E-03	273	1.969E-02	3.387E-02	5.514E-03
Controller	25	3.997E-01	6.836E-01	1.158E-01	8	2.544E-01	6.599E-01	0	17	4.681E-01	8.429E-01	9.330E-02
Blowdown	42	5.878E-03	1.591E-02	0	42	5.878E-03	1.591E-02	0	–	–	–	–
Open-Ended Line	969	6.077E-02	9.068E-02	3.086E-02	327	1.606E-02	3.216E-02	0	642	8.355E-02	1.279E-01	3.924E-02
Orifice Meter	142	3.011E-03	4.131E-03	1.890E-03	38	2.182E-03	3.987E-03	3.771E-04	104	3.313E-03	4.694E-03	1.932E-03
Other Flow Meter	348	7.777E-06	1.752E-05	0	82	3.700E-06	7.634E-06	0	266	9.034E-06	2.172E-05	0
Pressure Regulator	1323	6.549E-04	1.375E-03	0	954	1.218E-04	2.695E-04	0	369	2.033E-03	4.584E-03	0
Pressure Relief Valve	472	3.944E-03	8.865E-03	0	378	7.860E-04	1.044E-03	5.283E-04	94	1.664E-02	4.127E-02	0
Valve	9817	5.607E-04	9.322E-04	1.892E-04	7832	4.217E-04	4.629E-04	3.805E-04	1985	1.109E-03	2.940E-03	0

Table F-4 Changes from 1995/1996 to 2005/2006 Gas Distribution Data Sets				
	Percent Change from 1995/1996 to 2005/2006			
Component Category	Number of Sources Surveyed	Leak Frequency	Leaker Emission Factor	Average Emission Factor
Compressor Seal - Cent	–	–	–	–
Compressor Seal - Recip	–	–	–	–
Connector	406	17	-55	-30
Control Valve	22	-12	8	-2
Controller	-53	-50	9	-46
Blowdown	–	–	–	–
Open-Ended Line	-49	-91	114	-81
Orifice Meter	-63	-48	-50	-34
Other Flow Meter	-69	-100	-100	-59
Pressure Regulator	159	-75	-79	-94
Pressure Relief Valve	302	-50	-98	-95
Valve	295	-58	-81	-62

Table F-5	**Comparison of Average Emission Factors (kg TOC/h/source) for Commercial and Residential Gas Distribution Sites.**											
	Combined Data Set				**2005/2006 Measurement Campaign + Independent Company Studies**				**1995/1996 Study**			
Component Category	**Number of Sources**	**Average Emission Factor**	**Upper CL**	**Lower CL**	**Number of Sources**	**Average Emission Factor**	**Upper CL**	**Lower CL**	**Number of Sources**	**Average Emission Factor**	**Upper CL**	**Lower CL**
Connector	8616	4.467E-06	8.112E-06	8.226E-07	5846	3.469E-06	5.567E-06	1.371E-06	2770	6.573E-06	1.701E-05	0
Control Valve	8	1.006E-02	2.466E-02	0	8	1.006E-02	2.466E-02	0	–	–	–	–
Open-Ended Line	642	8.355E-02	1.279E-01	3.924E-02					642	8.355E-02	1.279E-01	3.924E-02
Orifice Meter	107	3.274E-03	4.630E-03	1.919E-03	3	1.925E-03	9.913E-03	0	104	3.313E-03	4.694E-03	1.932E-03
Other Flow Meter	405	7.203E-06	1.560E-05	0	139	3.700E-06	6.714E-06	6.861E-07	266	9.034E-06	2.172E-05	0
Pressure Regulator	348	2.329E-05	4.633E-05	2.410E-07	246	2.383E-05	5.352E-05	0	102	2.197E-05	5.464E-05	0
Pressure Relief Valve	78	1.749E-03	3.747E-03	0	72	1.872E-03	4.034E-03	0	6	2.717E-04	8.144E-04	0
Valve	1340	2.173E-06	2.593E-06	1.753E-06	1081	2.100E-06	2.540E-06	1.660E-06	259	2.478E-06	3.641E-06	1.315E-06

Table F-6	**Changes from 1995/1996 to 2005/2006 Commercial and Residential Gas Distribution Data Sets**			
	Percent Change from 1995/1996 to 2005/2006			
Component Category	**Number of Sources Surveyed**	**Leak Frequency**	**Leaker Emission Factor**	**Average Emission Factor**
Connector	111	-66	13	-47
Control Valve	–	–	–	–
Open-Ended Line	–	–	–	–
Orifice Meter	-97	-100	-100	-42
Other Flow Meter	-48	-100	-100	-59
Pressure Regulator	141	-94	1747	9
Pressure Relief Valve	–	–	–	–
Valve	317	-100	-100	-15

Appendix G: Measured Emissions from 2005/2006 Field Campaign

Emissions from fugitive equipment leaks identified and measured during the 2005/2006 field campaign total 13,536 × 10^3 m^3/yr of lost product. The estimated value of these losses is $2,250,000 CDN/yr based on a natural gas value of $4.45 CDN/GJ. Table F-1 provides a summary of the measured emissions by type of facility, while Table F-2 lists the top 20 leaks encountered during the survey, along with the volume and value of product lost. Both tables indicate the significant contribution compressor stations, both odourized and unodourized, make to the overall emissions from the Canadian natural gas transmission and distribution industry. Compressor stations account for 98 percent of overall leakage and all 20 of the top leakers encountered during the 2005/2006 emission survey were located at compressor stations.

Table G-1 2005/2006 Measured Emissions by Facility Type

Facility Type	Hydrocarbon Leak Rate (m^3/hr)	Contribution of Overall Leakage (%)
Compressor Stations [1]	1513.7	97.96
Gate / Regulation Stations	14.61	0.95
Block / Control Valve Stations	13.11	0.85
Receipt / Meter Stations	3.66	0.24

[1] Includes two LNG storage facilities.

Table G-2 Top Twenty Leakers from 2005/2006 Emissions Survey

Facility Type	Process Unit	Source	Hydrocarbon Leak Rate (m^3/hr)	Value of Lost Product ($/yr)
Compressor Stn.	Station Blowdown	Blowdown	656.2	$956,700
Compressor Stn.	Cyclone Separator	Blowdown	121.7	$177,378
Compressor Stn.	Station Blowdown	Pressure Relief Valve	35.7	$52,098
Compressor Stn.	Recip. Compressor	Compressor Seal	28.8	$41,970
Compressor Stn.	Recip. Compressor	Compressor Seal	28.8	$41,970
Compressor Stn.	Filter Unit	Connector - Filter Cover	22.9	$33,392
Compressor Stn.	Recip. Compressor	Compressor Seal	19.5	$28,475
Compressor Stn.	Recip. Compressor	Compressor Seal	19.2	$28,025
Compressor Stn.	Station Fuel Gas Vent	Blowdown	18.3	$26,640
Compressor Stn.	Cent. Compressor	Compressor Seal	17.4	$25,367
Compressor Stn.	Compressor Blowdown	Blowdown	15.9	$23,241
Compressor Stn.	Cent. Compressor	Compressor Seal	15.8	$22,994
Compressor Stn.	Recip. Compressor	Compressor Seal	14.0	$20,449
Compressor Stn.	Cent. Compressor	Compressor Seal	12.8	$18,619
Compressor Stn.	Cent. Compressor	Compressor Seal	12.1	$17,642
Compressor Stn.	Cent. Compressor	Compressor Seal	11.7	$17,103
Compressor Stn.	Discharge Cooler	Open-Ended Line	11.6	$16,939
Compressor Stn.	Recip. Compressor	Compressor Seal	11.3	$16,403
Compressor Stn.	Cent. Compressor	Compressor Seal	10.7	$15,545
Compressor Stn.	Cent. Compressor	Compressor Seal	10.6	$15,435

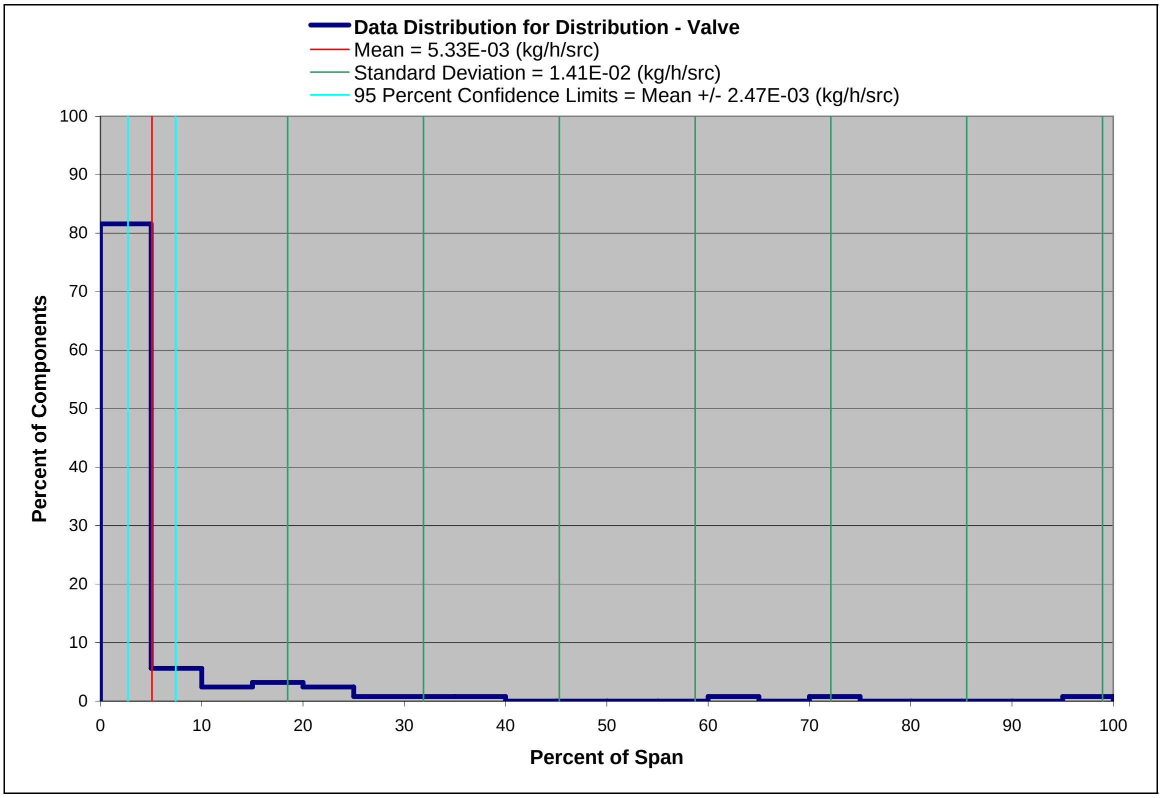


Figure C-19 Distribution Leaker Data Distribution – Valve

Attachment C

Statistical Analysis of Leak Rates and Sample Size Requirements, El Paso Corporation, 2009

El Paso Corporation
Statistical Analysis of Leak Rates and Sample Size Requirements

Goal

The goal of this analysis was to derive the required sample size of the number of compressors to be monitored/measured to attain a given level of quality of total system fugitive emissions estimates for reciprocating and centrifugal compressors under various operating conditions. The general steps in the analysis include:

- statistical modeling of leakage emissions by source component
- combining the source components into typical compressor types
- performing simulation modeling of total compressor emissions under the different operating conditions using various sample sizes and system populations
- calculating the compressor sample size required for various total system populations in order to estimate total system emissions within 20% given a 90% confidence interval

Data Overview

Actual measurements of fugitive leak rates for various components were analyzed. The data set used was a compiled set of available data for the El Paso pipelines. These leak rates were categorized by generic component description and by operating condition. Consistent with existing literature, it was found that the majority of the fugitive emissions due to leakage at the facilities in the database came from the following components under the associated operating conditions:

	Compressor Operating Condition		
Component	*Running*	*Idle/Pressurized*	*Blown Down*
Unit Pressure Relief Valve (Vent)	x		
Unit Blow Down Valve (Vent)	x	x	
Unit Block Valves (Vent)			x
Total Rod Seal Leak Rate	x	x	

Data for these components were then used to model the total emissions rates for each compressor.

Statistical Representation

For each of the component/compressor operating condition combinations, a probability distribution was fitted to the historical fugitive leak rate data. Crystal Ball was used to determine which probability distribution had the best fit using the Chi-Square goodness of fit test. In general, the Weibull distribution represented most of the data best and was used to model all the leak rate probability distributions. Table 1 is an example of the output of the goodness of fit test for the Unit Blow Down Valve (Vent) component in the “Running” condition. The bars represent the actual measured data, while the green line is the fitted Weibull distribution.

Table 1 – Example of Distribution for Unit Blow Down Valves in “Running” Mode

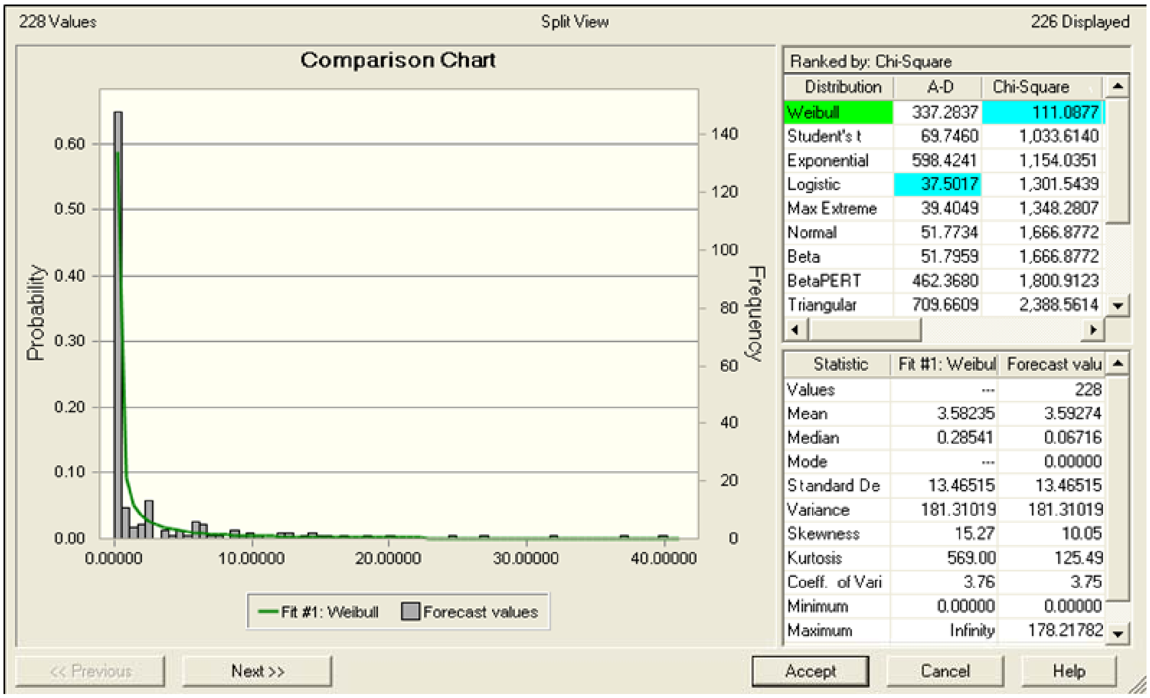


Table 2 provides a summary for the data. It shows the total number of data points, the means and standard deviations, and the Weibull distribution parameters. Total combined pipeline data statistics are shown as well as statistics by individual pipeline.

Data for the individual pipelines tended to be somewhat less variable relative to their means (average 230% for TGP and SNG) than for the total El Paso pipeline system data combined (average 290%). The variability in the data will have an effect on the confidence intervals and therefore on the sample size requirements. However, only TGP consistently had a sufficient amount of data since it is more difficult to fit a reasonable probability distribution to data points of limited size. Therefore, a comparison will be made between using the El Paso combined pipeline data and the data for TGP, representing an individual pipeline.

Table 2 - Data Summary Table

Component	Unit Blow Down Valve (Vent)		Total Rod Seal Leak Rate		Unit Block Valves (Vent)	Unit Pressure Relief Valve (Vent)
Operating Condition	*Running*	*Idle/Pressurized*	*Running*	*Idle/Pressurized*	*Blown Down*	*Running*
All Leak Rates in scfm						
Total System						
Number of Data Points	228	140	1433	542	131	34
Mean	3.59	1.51	1.97	2.19	9.64	0.23
Standard Deviation	13.47	4.32	4.51	4.19	21.41	1.01
Standard Deviation %	375%	286%	229%	191%	222%	439%
Weibull Distribution						
Scale factor	0.79	0.52	0.95	1.3216	4.82	0.04
Shape factor	0.3607	0.4217	0.4912	0.5608	0.5012	0.3358
TGP						
Number of Data Points	139	113	929	485	71	25
Mean	2.88	1.77	1.57	2.30	9.49	0.29
Standard Deviation	5.79	4.73	2.92	4.37	10.77	1.18
Standard Deviation %	201%	267%	186%	190%	113%	407%
Weibull Distribution						
Scale factor	1.6292	0.6762	0.9906	1.3982	3.2214	0.0579
Shape factor	0.5385	0.4407	0.5756	0.5634	0.5502	0.3489
Sonat						
Number of Data Points	18	13	151	51	26	6
Mean	10.03	0.88	3.46	1.30	7.88	0.10
Standard Deviation	41.98	1.97	7.73	1.79	11.40	0.25
Standard Deviation %	419%	224%	223%	138%	145%	250%
Weibull Distribution						
Scale factor	1.7609	n/a	1.68	1.0933	6.4436	n/a
Shape factor	0.3389	n/a	0.4957	0.7461	0.7156	n/a
EPNG						
Number of Data Points	15	0	157	0	12	0
Mean	13.76	n/a	3.30	n/a	7.26	n/a
Standard Deviation	16.04	n/a	8.18	n/a	5.80	n/a
Standard Deviation %	117%	n/a	248%	n/a	80%	n/a
Weibull Distribution						
Scale factor	n/a	n/a	2.8116	n/a	n/a	n/a
Shape factor	n/a	n/a	0.9608	n/a	n/a	n/a
CIG/WIC						
Number of Data Points	0	0	40	0	1	0
Mean	n/a	n/a	3.40	n/a	n/a	n/a
Standard Deviation	n/a	n/a	2.98	n/a	n/a	n/a
Standard Deviation %	n/a	n/a	88%	n/a	n/a	n/a
Weibull Distribution						
Scale factor	n/a	n/a	2.8116	n/a	n/a	n/a
Shape factor	n/a	n/a	0.9608	n/a	n/a	n/a

Simulation Modeling

Once the probability distribution of the fugitive leak rates for each of the components was established, random leak rates could be generated for each of those components. Combining the random leak rates according to number of components in a typical reciprocating or centrifugal compressor then gives the total simulated emissions due to leakage for that compressor type. Table 3 indicates the typical component counts used for each compressor type:

Table 3- Typical Component Count Used in the Analysis

Component	Compressor Type *Reciprocating*	*Centrifugal*
Unit Pressure Relief Valve (Vent)	1	0

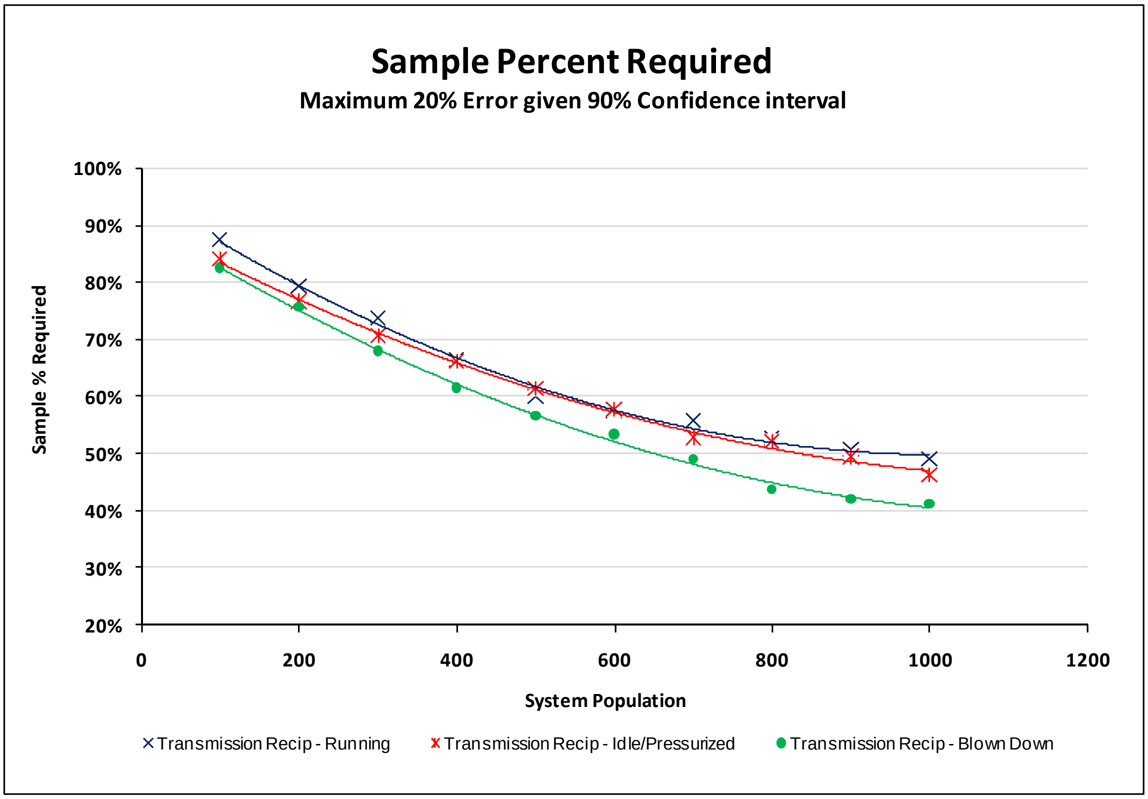
Unit Blow Down Valve (Vent)	1	1
Unit Block Valves (Vent)	1	1
Total Rod Seal Leak Rate	3.3	1.5

To determine the effect of sampling only a portion of the total system compressor population on an emissions estimate, simulations were run for various total system populations from 100 to 1,000, in increments of 100. For each system population increment, samples were drawn from 20% to 80% in increments of 20%. The mean emissions for the sample population (equivalent to what would be reported) were then compared to the means for the total population (equivalent to what would be actually emitted) by calculating the difference, or error, in the two emission rates. From the simulations, an error distribution could be established. Since the errors follow a normal distribution (central limit theorem), a 90% confidence interval could be constructed using the standard deviations of the errors. The difference between the mean and the 5^{th} or 95^{th} percentile (representing the two-tailed 90% confidence interval) would then represent the range in error that could occur in any particular sample given that level of confidence.

<u>Results</u>

The charts below show the 90% confidence interval errors for various population sizes and sample percentages for a reciprocating compressor in each of the operating conditions. Curves based on both the TGP data and the El Paso System combined data are shown. The lighter weight curve represents the combined system results, and the heavier weight curve represents the TGP results.

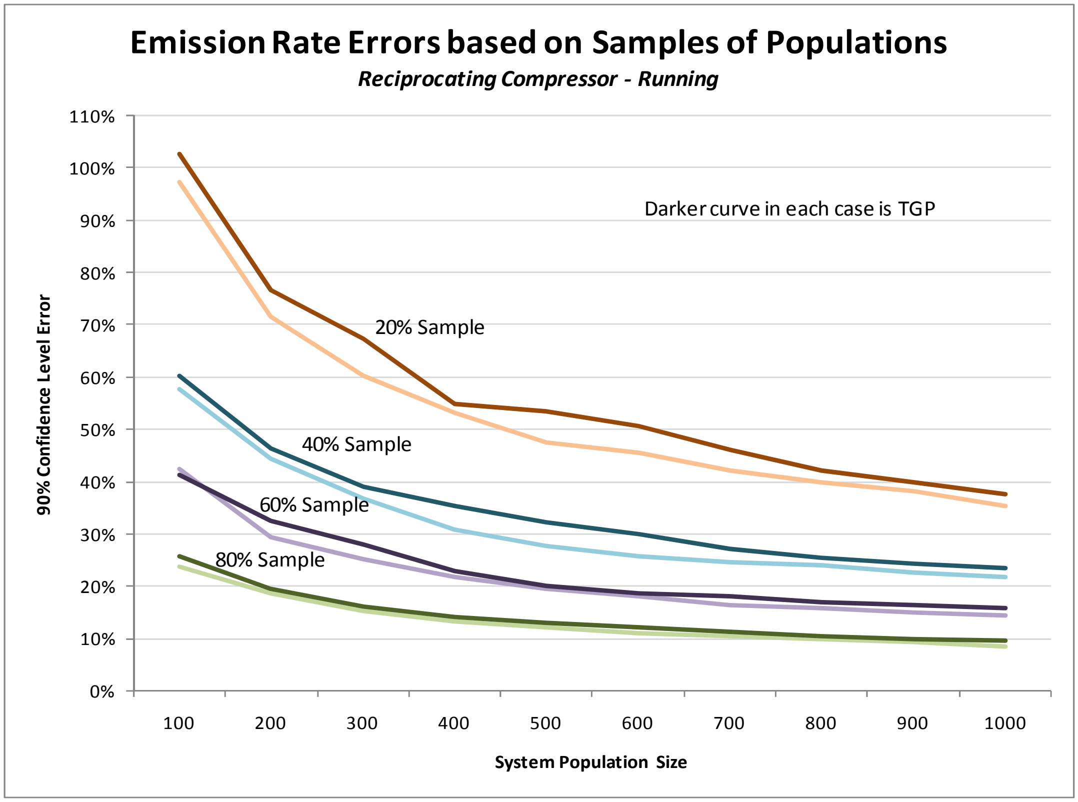
In all cases, even for the smaller 20% sample sizes, the mean error, which would indicate the difference between the emissions that would be reported and the actual emissions, was essentially zero. The most it was off was 3%. As a result, over time, the reported emissions would be equal the actual emissions, even though in any one year, the difference could be higher or lower by up to 20%. This also supports the use of the two-tailed confidence interval.



A similar analysis was performed using the component counts for a centrifugal compressor. The sampling requirements were slightly less than those for the reciprocating compressor; therefore the charts above would represent the controlling case regardless of compressor type.

Below is the curve fitted through the data for the reciprocating compressor in the running condition, which is the highest curve from Figure 4, therefore requiring the highest sample percentages. A few additional data points were also analyzed and added to extend the curve up to 8,800 compressors, which represents the total number of transmission and storage compressors nationwide, according to latest published GRI data. Figure 5 shows the extended fitted curve and the equation representing this curve.

Figure 5



Emission Rate Errors based on Samples of Populations
Reciprocating Compressor - Running
Darker curve in each case is TGP
20% Sample
40% Sample
60% Sample
80% Sample
90% Confidence Level Error
110%
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
100
200
300
400
500
600
700
800
900
1000
System Population Size

Figure 1

Figure 2

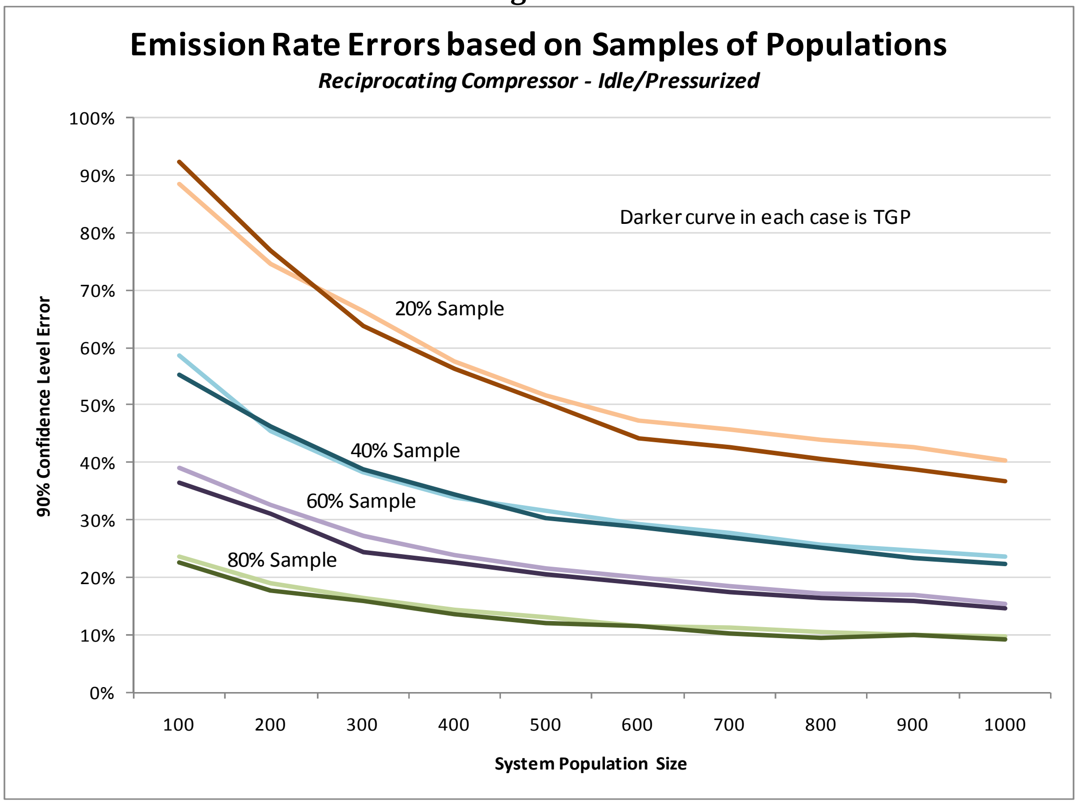
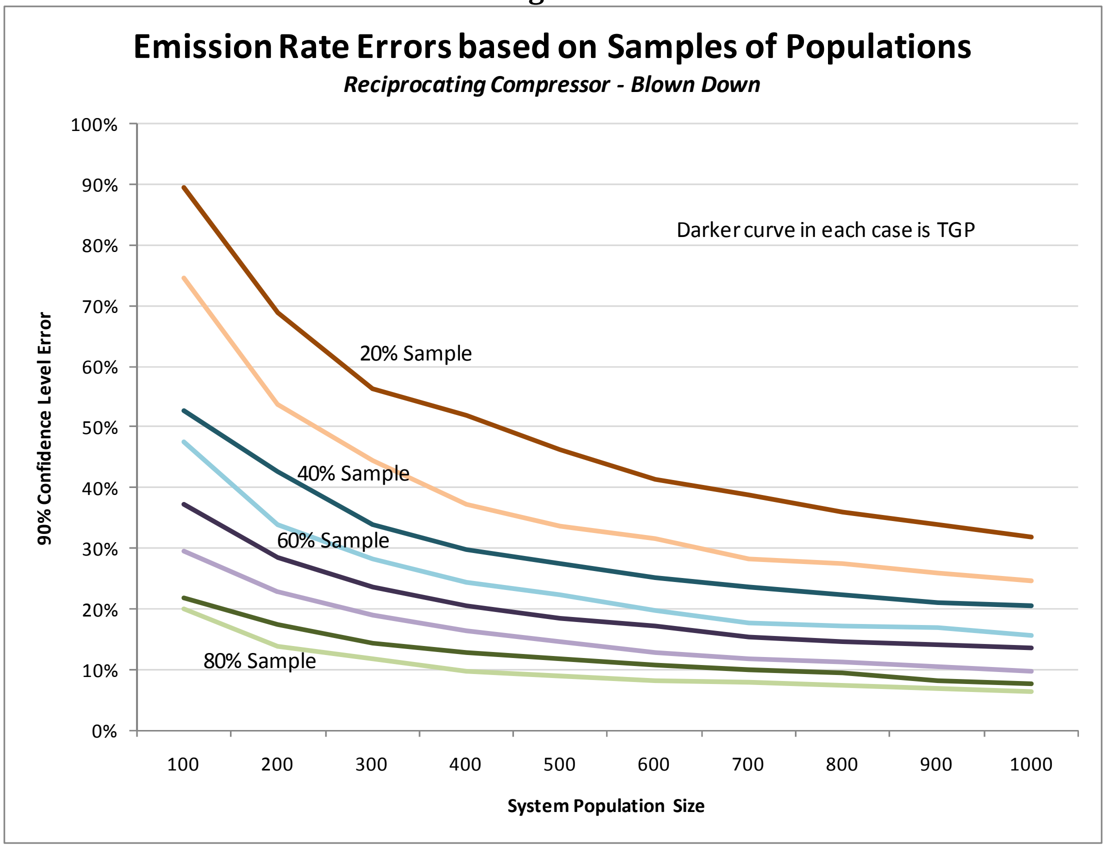

Emission Rate Errors based on Samples of Populations
Reciprocating Compressor - Idle/Pressurized
Darker curve in each case is TGP
20% Sample
40% Sample
60% Sample
80% Sample
90% Confidence Level Error
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
100
200
300
400
500
600
700
800
900
1000
System Population Size

Figure3



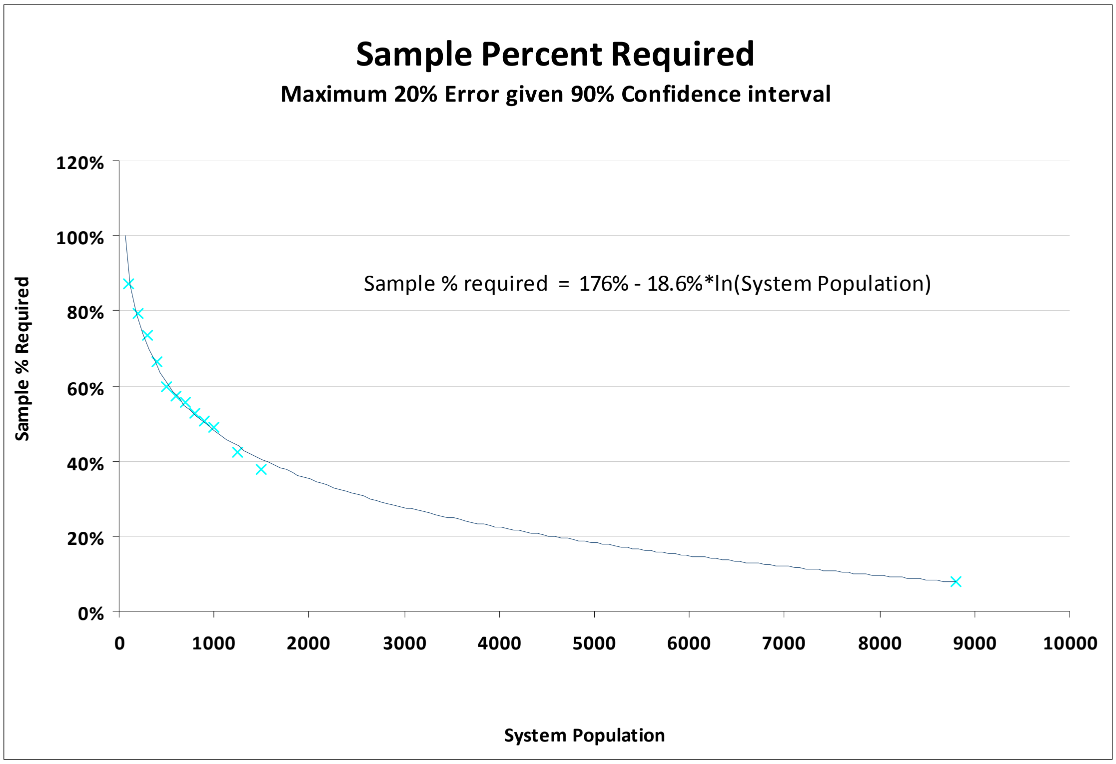
As an example, say we have a reciprocating compressor in the running mode (Figure 1). If the total population of reciprocating compressors in the system is equal to 900, we can find the percent of those compressors that would be required to be sampled in order to limit the error in emissions to 20%, given a 90% level of confidence. Using the TGP curve in Figure 1, for 900 compressors and a 40% sample size, the error would be 24%, and for a 60% sample size the error would be 16%. So for a 20% error, the sample required would be somewhere in between, or approximately 50% by interpolation. Therefore, a total of 450 reciprocating compressors would be required to be sampled. The emissions based on this sample of 450 compressors (reported) would then be within 20% of the emissions for the total system population of 900 compressors (actual), given a 90% confidence interval.

Similarly, if the total population of the system is 300 compressors, then about 74% of the compressors would need to be sampled, or about 222 compressors to achieve a 20% error at 90% confidence interval.

Notice that the number of compressors required to be sampled varies with the total system population size, so the smaller the system, the fewer number of compressors that need to be sampled. However, the sample size will be a larger percentage of the total number of compressors in the system.

Figure 4 summarizes the sampling requirements to limit the error to 20% with a confidence level of 90%. Since the TGP curves in the charts above tended to be higher, indicating greater sampling requirements, only the TGP curves were used to generate the Figure below. Note that the pressurized conditions (running or idle/pressurized) are more restrictive than the unpressurized condition (blown down).

Figure 4



So in order to obtain a ± 20% estimate of total emissions industry wide (8,800 compressors), given a 90% level of confidence, a sample size of only 8% would be required. To give an idea of the sensitivity of the error to sample size, increasing the sample to 20% would reduce the emissions estimate error to ± 13%, given a 90% level of confidence.

Since Figure 5 was based on the high case, which was for reciprocating compressors in the running mode, the effect of a mix of compressors and operating modes was also investigated. For the 8,800 compressor population case, another simulation was run based roughly on El Paso's average mix of compressor types and operating modes. This mix includes approximately 80% reciprocating/20% centrifugal compressors, with the average operating mode split between 40% pressurized and 60% unpressurized.

The results of the simulation show that a smaller sample size of 4% would be required to limit the error to ± 20%, and if a 20% sample size were to be used, the error would be limited to ± 10%, given a 90% level of confidence. Therefore, including the compressor type and operating mode in the sampling has the effect of reducing the required sample size, or improving upon the estimates for a fixed sample size.

Conclusion

The number of compressors required to be monitored/measured to attain a ± 20% estimate, given a 90% level of confidence, of total system fugitive emissions for reciprocating and centrifugal compressors under various operating conditions was determined. This means that, with 90% confidence, the most that the reported emissions could be above or below actual emissions would be 20%. This sample size requirement is dependent on the total system population of compressors. The formula developed is:

Sample % required = 176% - 18.6% * ln(Total system population)

Although the size is dependent on the pipeline, type of compressor, and operating condition, the highest case was used to develop this curve and is therefore applicable for any compressor type and operating condition. Including the compressor type and operating condition has the effect of reducing the sample size required, or improving upon the reported emissions estimate for a given sample size. Using El Paso’s mix of compressors and average operating mode, a sample size of 20% would limit the error for the transmission and storage industry to $\pm$ 10%.