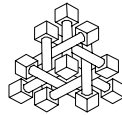


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# Greenhouse Gas (GHG) Verification Guideline Series

## Natural Gas Compressor Leak Mitigation Technologies

Prepared by:



Southern Research Institute

October 1999



Under a Cooperative Agreement with  
U.S. Environmental Protection Agency

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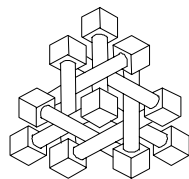
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**Greenhouse Gas (GHG) Verification Guideline Series**  
**Natural Gas Compressor Leak Mitigation Technologies**



**Prepared by:**  
**Southern Research Institute**  
**Greenhouse Gas Technology Verification Center**  
**Post Office Box 13825**  
**Research Triangle Park, NC 27709 USA**

October 1999  
Version 1.1



**SOUTHERN RESEARCH**  
**I N S T I T U T E**

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## FORWARD

The U.S. Environmental Protection Agency (U.S. EPA) has created the Environmental Technology Verification (ETV) Program to facilitate the deployment of promising environmental technologies. Under this program, third-party performance testing of environmental technology is conducted by independent Verification Organizations under strict U.S. EPA quality assurance guidelines. Southern Research Institute (SRI) is one of nine independent Verification Organizations operating under the ETV Program, and SRI operates the Greenhouse Gas Technology Verification Center (the Center). With full participation from technology providers, purchasers, and other stakeholders, the Center develops testing protocols, and conducts technology performance evaluation in field and laboratory settings. The testing protocols are developed and peer reviewed with input from a broad group of industry, research, government, and other stakeholders. After their development, the protocols are field-tested, often improved, and then made available to interested users via Guideline Series reports such as this one. Typically, verifications conducted by the Center involve substantial measurements, so an effort is made here to recommend only the most important measurements for the guideline.

Guidelines for verifying greenhouse gas (GHG) emission reductions for two types of technologies used in the natural gas transmission industry are presented here. One technology reduces and recycles methane leaks from natural gas compressor rod packing, while the other reduces rod packing leaks when compressors are in standby operating mode. The guideline includes two different levels of emission reduction determination: the Verification Guideline and the Simplified Guideline. As the name implies, the Simplified Guideline is an easy and low cost alternative to the Verification Guideline, but emission reduction estimates are less representative of individual sites, and contain greater uncertainty because site-specific measurements are not used. The Verification Guideline requires the collection of field measurements, produces emission reduction results that have less uncertainty, provides a means to quantify uncertainty, and requires more resources and time to implement. Since some readers may choose to use only portions of this document, the authors felt it necessary to repeat some key information in several different locations. As a result, readers of the entire document may experience some redundancy.

It is not the intent of the Center that these guidelines become accepted as a national or international standard. Rather, a significant effort has been devoted to their development, field trial, and improvement; and this experience and data are recognized as potentially valuable to others interested in GHG technology evaluation. There are procedures and measurement instruments that are not specified here, but that may provide high quality results. Instrument descriptions and recommendations presented in this document do not constitute an endorsement by the Center or the U.S. EPA. Readers should be aware that use of this guideline is voluntary, and that the Center is not responsible for liabilities that result from its use.

Finally, the Center continues to conduct verifications in the natural gas industry, and will update this guideline with new findings as warranted. Updates can be obtained on-line at the Center's Web site ([www.sri-rtip.com](http://www.sri-rtip.com)) or at the U.S. EPA ETV Web site ([www.epa.gov/etv](http://www.epa.gov/etv)).

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## ACKNOWLEDGEMENTS

The Greenhouse Gas Technology Verification Center wishes to thank all participants in the field verifications used to prepare this guideline, including participating natural gas producers and transmitters, technology vendors, host site operators, and others. We thank the staff and employees of ANR Pipeline Company for their invaluable service in hosting two tests, in particular, Mr. Curtis Pedersen. Thanks are also extended to Mr. Gary Swan (CMS Panhandle Eastern Pipeline Company) and Mr. John Snow (Hanover Compressor Co.) for reviewing and helping us improve our test plans and reports. The Center also wishes to thank the staff and employees of Enron Gas Pipeline Group and its affiliate, Transwestern Pipeline Company for hosting one field verification. Key individuals from these firms include Mr. William Kendrick, Mr. James Peterson, Mr. Richard Jolly, Mr. Jonny Hendricks, Mr. Howard Begay, Mr. Calvin Largo, and Mr. Korey Kruse. A special thanks is extended to Mr. Michael Terraso of Enron Gas Pipeline Group for his assistance in establishing several tests conducted by the Center. We wish to thank the vendor participants for their help and support throughout the planning and execution of the testing including Mr. Robert Borders of C. Lee Cook, Mr. James Maholic of France Compressor Products, and Mr. Harold Johnson of A&A Environmental Seals, Inc.

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## ACRONYMS

Bcf/yr	Billions of Cubic Feet Per Year
BDV	Blow-Down Volume
°C	Degrees Celsius
cfm	Cubic Feet Per Minute
CH <sub>4</sub>	Methane
ECG	Emission Containment Gland
ETV	Environmental Technology Verification
°F	Degrees Fahrenheit
fpm	Feet Per Minute
GRI	Gas Research Institute
GHG	Greenhouse Gas
H <sub>2</sub> O	Water
Hp	Horsepower
IC Engine	Internal Combustion Engine
K	Kelvin
LDL	Lower Detection Limit
LFE	Laminar Flow Element
ml/min	Millimeters per Minute
nat gas	Natural Gas
NIST	National Institute of Standards and Technologies
prv	Pressure Relief Valve
psig	Pounds per Square Inch Gauge
PVC	Polyvinyl Chloride
scf	Standard Cubic Feet
scfm	Standard Cubic Feet per Minute
sec	Second
SOP	Standard Operating Procedure
SRI	Southern Research Institute
Temp.	Temperature
TG/year	Teragrams per Year
the Center	Greenhouse Gas Technology Verification Center
uv	Unit Valve
US	United States
U.S. EPA	U.S. Environmental Protection Agency

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## 1.0 BACKGROUND

### 1.1 ETV PROGRAM DESCRIPTION

The U.S. Environmental Protection Agency's (U.S. EPA) Office of Research and Development has created the Environmental Technology Verification (ETV) Program to facilitate the deployment of promising environmental technologies. Under this program, third-party performance testing of environmental technology is conducted by independent Verification Organizations. Their goal is to objectively and systematically evaluate technology performance under strict U.S. EPA quality assurance guidelines. The U.S. EPA's Air Pollution Prevention and Control Division has selected Southern Research Institute (SRI) as the independent Verification Organization for greenhouse gas (GHG) mitigation and monitoring technologies. Since late 1997, SRI has conducted GHG technology verifications through its Greenhouse Gas Technology Verification Center (the Center), located in Research Triangle Park, NC. With full participation of technology providers and users, the Center develops testing plans and conducts field and laboratory verifications. The test results are analyzed, peer reviewed, and then distributed to industry, government, vendor, and other groups interested in the data. In addition, the verification protocols are field-tested, usually improved or streamlined, and then made available to interested users via Guideline Series reports.

The Center is one of nine independent Verification Organizations operating under the ETV program. These organizations are identified in Table 1-1, along with the 13 technology areas currently being evaluated under the ETV program. The verification process consists of developing verification protocols, conducting field tests, collecting and interpreting field and other data, reporting findings, and seeking guidance and peer review from industry and other stakeholders. Performance evaluations are conducted according to externally reviewed Test Plans, established protocols for quality assurance, and direct U.S. EPA quality assurance oversight.

**Table 1-1. Nine ETV Verification Organizations**

<b>Name</b>	<b>ETV Technology Focus Areas</b>	<b>Location of Partner</b>
Battelle Memorial Institute	Advanced Monitoring Systems	Columbus, OH
California EPA	Pollution Prevention (P2) Recycling Waste Treatment Systems	Sacramento, CA
Civil Engineering Research Foundation	Broad and Open Mandate	Washington, DC
Concurrent Technologies Corp. (2 pilots)	(1) P2 Innovative Coating Equipment (2) P2 Metal Finishing Technologies	Johnstown, PA
NSF International (3 pilots)	(1) Drinking Water Systems (2) Source Water Protection Technologies (3) Wet Weather Flow Technologies	Ann Arbor, MI
Oak Ridge National Laboratory	Site Characterization and Monitoring Technologies	Oak Ridge, TN
Research Triangle Institute (2 pilots)	(1) Air Pollution Control Technology (2) Indoor Air Products	Research Triangle Park, NC
Sandia National Laboratory	Site Characterization and Monitoring Technologies	Albuquerque, NM
Southern Research Institute	Greenhouse Gas Mitigation and Monitoring Technologies	Research Triangle Park, NC

Two volunteer Stakeholder groups guide the Center. These groups offer advice on technologies most appropriate for verification testing, recommend verification strategies, provide field testing host sites, help disseminate verification results, and provide peer review of Test Plans and Verification Reports. The Center's Executive Stakeholder Group consists of national and international experts in the areas of climate science, policy, and technology. It also includes industry trade organizations, environmental technology finance groups, international institutions, and various government organizations.

In March 1998 the Executive Stakeholder Group recommended that technologies applicable to the natural gas industry are good candidates for independent testing by the Center. This led to the identification and verification testing of three gas industry GHG mitigation technologies. The verification guidelines presented in this document were developed in support of these performance verification tests. These tests have occurred at three separate industrial sites in the western and eastern United States.

## 1.2 GAS INDUSTRY EFFORT AND VERIFICATION SCOPE

To conduct verification testing in the natural gas industry, the Center established an Oil and Gas Industry Stakeholder Group. Members of the Executive Stakeholder Group are listed in Table 1-2a, along with a listing of the Oil and Gas Industry Stakeholder Group in Table 1-2b. The Oil and Gas Industry Stakeholder Group consists of representatives from the oil and gas production sectors, gas transmission, oil refining, storage, and other sectors. Technology manufacturers, service providers, consultants, and government organizations are also included. In a June 1998 meeting in Houston, Texas, the Oil and Gas Industry Stakeholder Group voiced support for the Center's mission, identified a need for independent third-party verification, prioritized specific technologies for testing, and identified verification test parameters that are of most interest to technology purchasers. They also indicated that technologies that capture and utilize methane leaks from natural gas compressor rod packing are of great interest to technology purchasers.

<b>Stakeholder Name</b>	<b>Affiliation</b>
Samuel Baldwin	DOE's National Renewable Energy Laboratory
Johannes Heister	The World Bank
Frank Joshua	United Nations-UNCTAD
Jim Kerstetter	Washington State University-Energy Program
Dina Kruger	USEPA - OAR
Mike Marvin	Business Council for Sustainable Energy
Alan Miller	The World Bank's Global Environmental Facility
Stu Nagourney	NJ Dept. of Environmental Protection
Rhone Resch	The Natural Gas Supply Association
Jeff Seabright	USAID
Jane Siegel	US Dept. of Commerce
Michael Terraso	Enron Pipeline Co.
Michael Walsh	Environmental Financial Products
Mike Winka	NJ Dept. of Environmental Protection



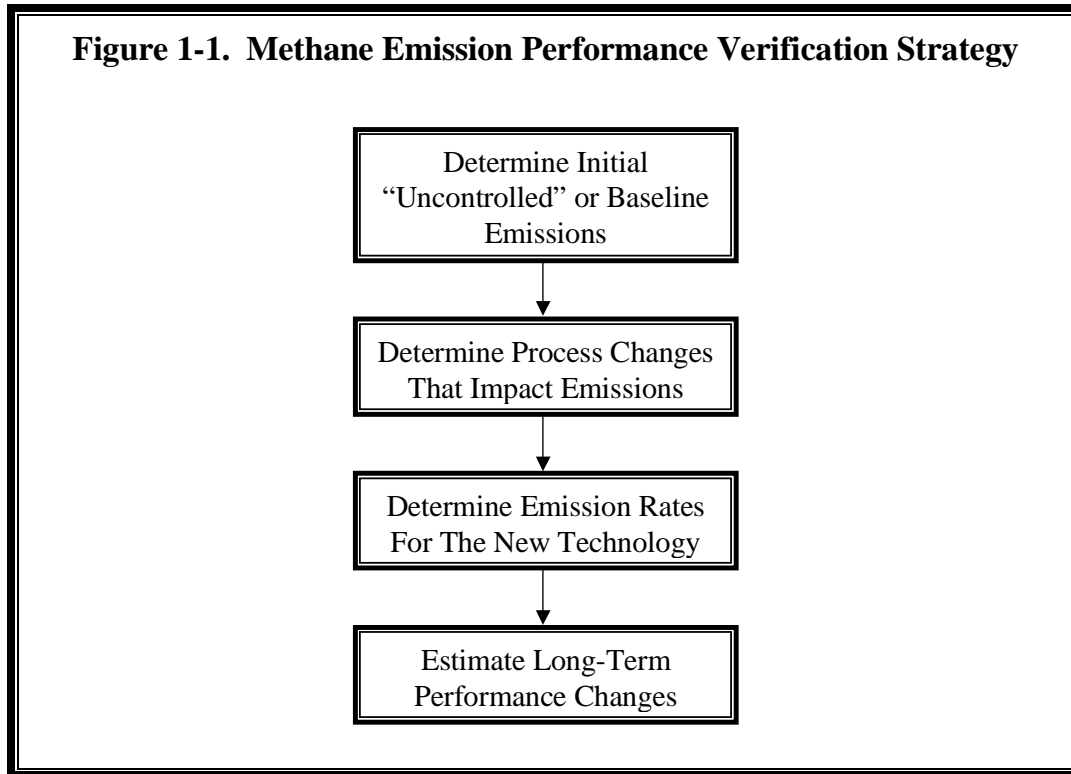
<b>Table 1-2b. The Oil and Gas Industry Stakeholder Group</b>	
<b>Stakeholder Name</b>	<b>Affiliation</b>
John Alderman	Cornerstone Environmental
Bob Borders	C. Lee Cook
William Doyle	Marathon Oil
Jesse Fredrick	WZI, Inc.
Richard Garrett	Rotor-Tech, Inc.
Michael Garvey	Becker Precision Equipment
Douglas Gifford	Zero-Seal Technologies
Patrick Grizzle	Oryx Energy
Paul Gunning	USEPA-Natural Gas STAR Program
Bud Johnson	A&A Environmental Seals
Bill Kendrick	Enron Gas Pipeline Co.
Vick Newsom	Amoco Corp.
Greg Nizich	USEPA-OAQPS
Bob Parr	T.F. Hudgins, Inc.
Vernon Scheivelbein	Texaco, EDTP
John Seymour	Southern Natural Gas Co.
Andy Shah	Conoco
Brian Shannon	ARCO
John Snow	Hanover Compressor Co.

In the natural gas industry, large gas-fired engines provide the mechanical energy needed to drive natural gas compressors. These compressors are used to transport natural gas through high-pressure national gas transmission pipelines. In the US, fugitive natural gas leaks from these compressors represent a major source of methane emissions, and a significant loss of economic and natural resources (EPA 1996a). The Center has developed verification protocols for testing technologies that mitigate natural gas leaks from compressor operations, and once developed, these protocols were proved during field verifications. This proving process resulted in the improvement and streamlining of protocols for technologies that mitigate methane emissions from leaking compressor rod packing.

Protocols for verifying GHG emission reductions for two types of compressor leak mitigation technologies are presented in this guideline document. One technology collects natural gas leaks from compressor rod packing, allowing it to be used as fuel in the gas-fired engines operating on the pipeline. The other technology reduces or eliminates rod packing leaks when the compressor is in standby operating mode. Standby operating mode is commonly encountered in the industry, and is done to ensure compressors can quickly return to operation in response to changing pipeline demand. These technologies, and the industry to which they apply, are discussed in more depth in Section 2.0.

Figure 1-1 shows the general verification approach used here. It also identifies the general sequence of activities that occur, beginning with determining uncontrolled or baseline emissions. This important first step is needed to determine the level of emissions reduction achieved by a technology, and is accomplished by establishing credible and defensible baseline operating and emission conditions. The use of one of the technologies addressed here may be accompanied by changes in facility operating procedures, and these changes will increase

and decrease several different GHG emission sources. Because of this, emissions associated with the new technology, and any emission changes caused by operational changes, are addressed (see steps 2 and 3 in Figure 1-1).



This guideline document includes two different levels of emission estimation: the Verification Guideline and the Simplified Guideline. The Verification Guideline relies on the collection of site-specific field measurements, and produces results that are more representative and contain less uncertainty than the Simplified Guideline. It also provides a means for quantifying uncertainty due to measurement error, and addressing site-specific emission rate variability. The Verification Guideline is patterned after the field verifications conducted by the Center, although the level of testing and redundant sampling has been reduced to support the development of a more practical guideline. The Verification Guideline requires more resources and time to implement and may be most appropriate for users conducting technology characterizations or other assessments where uncertainty must be reduced and quantified.

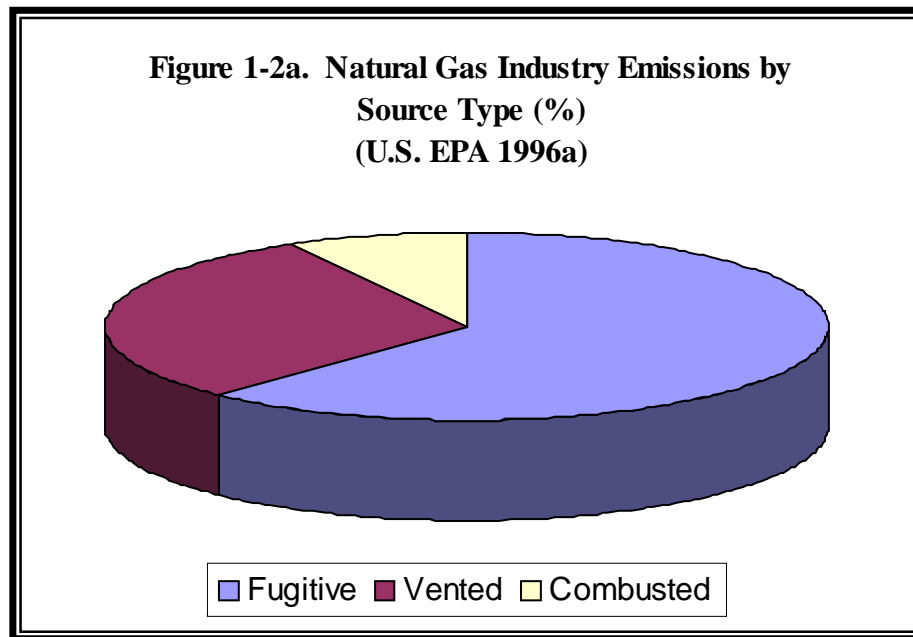
The Simplified Guideline is easier and less costly to use, but produces results that contain greater uncertainty than the Verification Guideline. It relies on the use of generic emission factors, so site-specific measurements are not required. Because of this, the Simplified Guideline produces emission approximations only, and is not suitable for conducting rigorous technology verification. It may be most appropriate for users interested in conducting emission inventory, technology feasibility, or similar assessments. It may also be used as a reasonableness check on results obtained from the Verification Guideline. It is recommended that users of the Simplified Guideline read the Verification Guideline before proceeding.

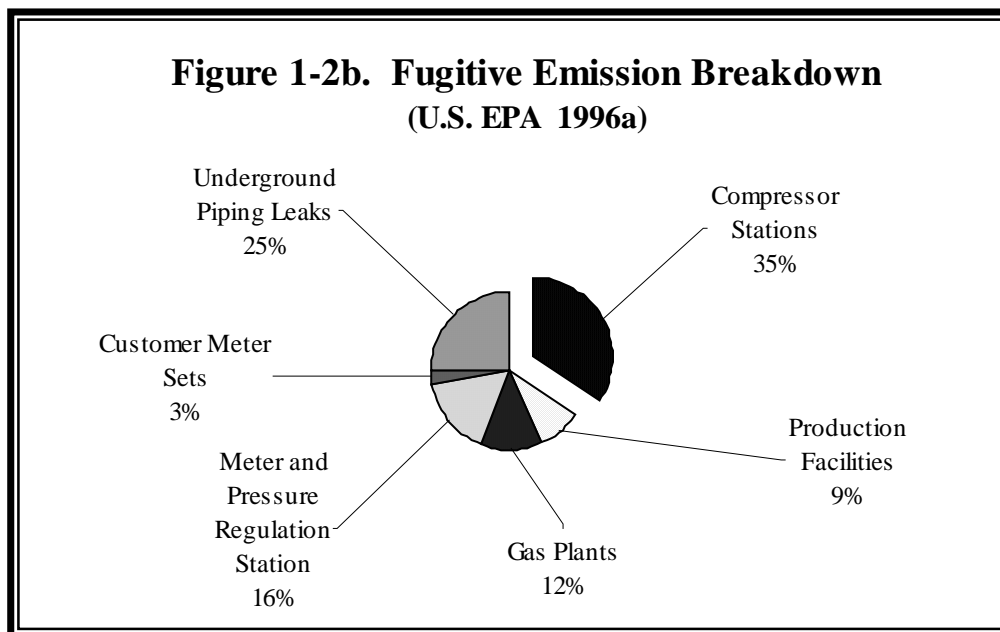
The Center continues to conduct technology verifications in the natural gas industry, and plans to update guidelines related to this increase soon. Specifically, new data on long-term rod packing emission profiles will be added to this guideline soon after three long-term compressor verifications are completed (estimated early 2000). Updates of this document can be obtained on-line at the Center's Web site ([www.sri-rtp.com](http://www.sri-rtp.com)), or at the U.S. EPA ETV Web site ([www.epa.gov/etv](http://www.epa.gov/etv)).

### 1.3 NATURAL GAS INDUSTRY BACKGROUND

Methane emissions from the oil and gas industries contribute significantly to global methane emissions; i.e., about 51 TG/year of methane in 1990, or 14 percent of global anthropogenic emissions (EPA 1994). A study conducted by the U.S. EPA Office of Research and Development and the Gas Research Institute suggests that a large fraction of these emissions occur at natural gas compressor stations in the US (EPA 1996a).

Figure 1-2a shows that "fugitive" emissions from the gas industry are significant, while Figure 1-2b shows that the combined sources at natural gas compressor stations account for a significant fraction of this "fugitive" category (EPA 1996a). In 1992, emissions from transmission compressor stations accounted for approximately 16 percent (507 Bcf/yr) of the total emissions from the natural gas industry. Of this total, reciprocating compressor units accounted for over 75 percent (37.8 Bcf/yr) of the emissions. This suggests a potential exists for reciprocating compressor operators to simultaneously reduce emissions and increase profitability via product recovery.





Methane leaks from reciprocating compressors occur from blow-down valves, rod packing, compressor isolation valves, pressure relief valves, and several other small fugitive emission sources (e.g., valve stems, pump seals, connections and fittings). This guideline focuses on technologies that reduce methane emissions from rod packing, although as explained later, emissions from all of the sources identified earlier are addressed. Rod packing emissions can occur when compressors are in operation, or in some cases, when they are placed into standby operation. The technologies addressed here examine both compressor operating conditions.

In the natural gas industry, gas compressors are used in many different sectors (i.e., production, processing, transmission, and storage). Gathering compressors are used in production fields to collect and transport natural gas from wells to processing plants where impurities such as water, oil, and hydrogen sulfides are removed. In the natural gas transmission sector, compressors are used to transport gas from processing plants to distribution centers. In the storage sector, compressors are used for injection and withdrawal from storage systems. Manufacturers of reciprocating compressors include Ariel, Clark, Cooper, Ingersoll-Rand, Worthington, and others. There are many different models and sizes, but the basic function is the same regardless of their size. The technologies addressed here are directly applicable to the natural gas transmission sector, although they may also be applicable to compressors used in other sectors.

The following section presents more detailed background information on the emissions characteristics of compressor systems. This is followed by a description of the GHG emission control technologies examined here.

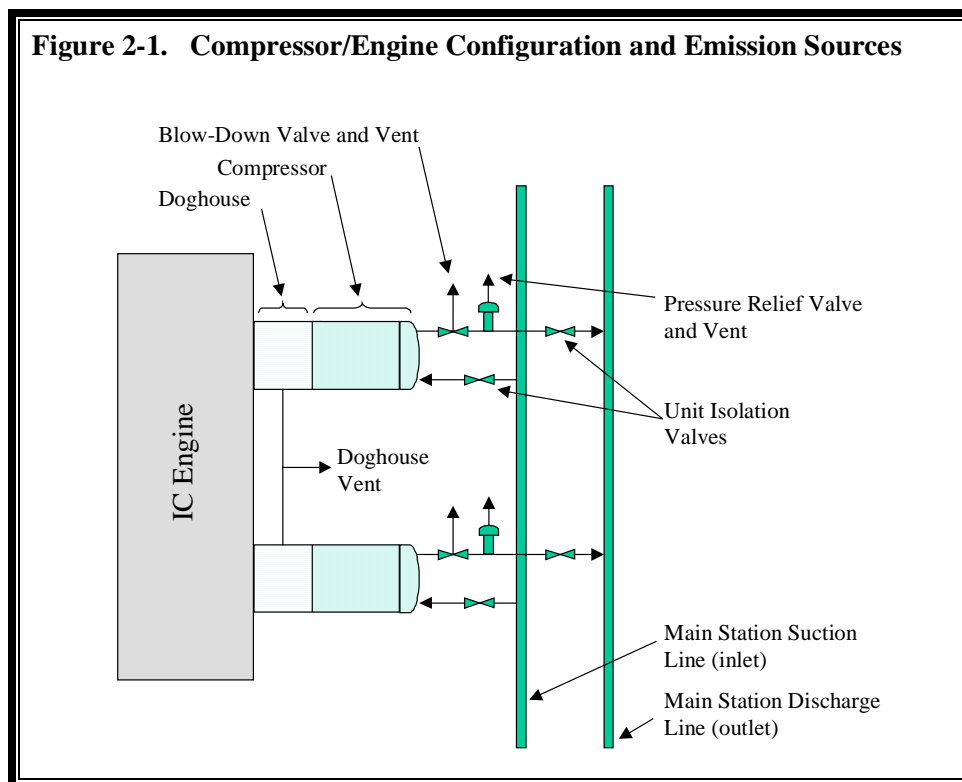
## 2.0 MITIGATION TECHNOLOGY DESCRIPTIONS

Prior to describing the technologies for which verification guidelines are provided, the following technical information is presented to describe the compressor related emission sources.

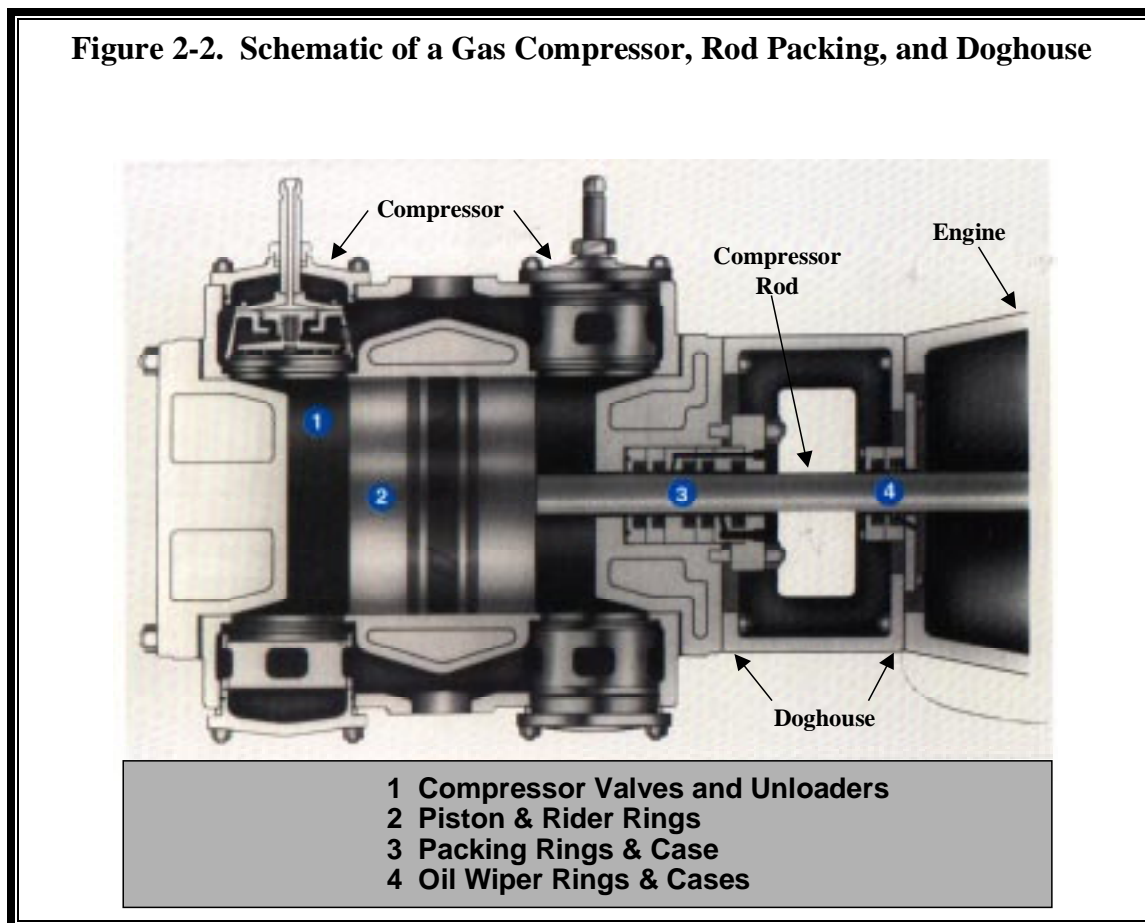
### 2.1 EMISSION SOURCE DESCRIPTION

It is estimated that 7,480 transmission compressors operate in the US, and that methane emissions from the compressor units are 45.3 Bscf in 1992 (EPA 1996b). About 80 percent of these emissions are from reciprocating compressor units (EPA 1996a). Figure 2-1 is a diagram of a typical engine and reciprocating compressor system used at natural gas transmission stations in the US. In the drawing, an internal combustion engine (IC engine), which is fueled by natural gas, provides the mechanical energy needed to drive the compressor. The engine and compressor are linked by a steel connecting rod that transmits the engine power to the compressor. The rod is connected to the engine crank shaft, passes through an enclosure referred to as the distance piece or doghouse, then connects to a piston in the compressor housing. Transmission compressor rods vary in size from 2 inches in diameter to about 4.5 inches in diameter, and are equipped with packing or seals which inhibit leakage from the compressor. Continuous leaks usually flow from the packing into the doghouse, and then to the atmosphere via the doghouse vent. Several compressors are connected to one engine.

Figure 2-1 shows that emission sources at compressor operations include: (1) releases and leaks from the pressure relief valve, (2) continuous leaks from rod packing into the doghouse vent, (3) continuous leaks from the closed blow-down valve, (4) intentional release of system pressure before unit shutdown via the blow-down valve, (5) continuous leaks from the closed unit isolation valves during shutdown (again, via the open blow-down valve), and (6) miscellaneous fugitive leaks from fittings, flanges, pump seals, valve stems, etc.



A large source of natural gas emissions from compressor operations is the leakage associated with operating and standby-mode compressor rod packing. In general, compressor packing provides a seal around the rod shaft, keeping high-pressure gas contained in the compressor from leaking into the atmosphere. An expanded view of a typical compressor/doghouse arrangement is shown in the cutaway drawing in Figure 2-2, including the packing case, identified as location No. 3. The packing consists of one or more sealing rings contained within a case that serves several functions, including: lubrication, venting, purging, cooling, temperature and pressure measurement, leakage measurement, rod position detection, and sealing for standby mode operations (GRI 1997). In conventional packing, the sealing rings are configured in series to successively restrict the flow of gas into the doghouse. The sealing rings are held in separate grooves or “cups” within the packing case, and are free to move laterally along with the rod, and free to “float” within the grooves. The doghouse is shown between locations 3 and 4 in Figure 2-2.



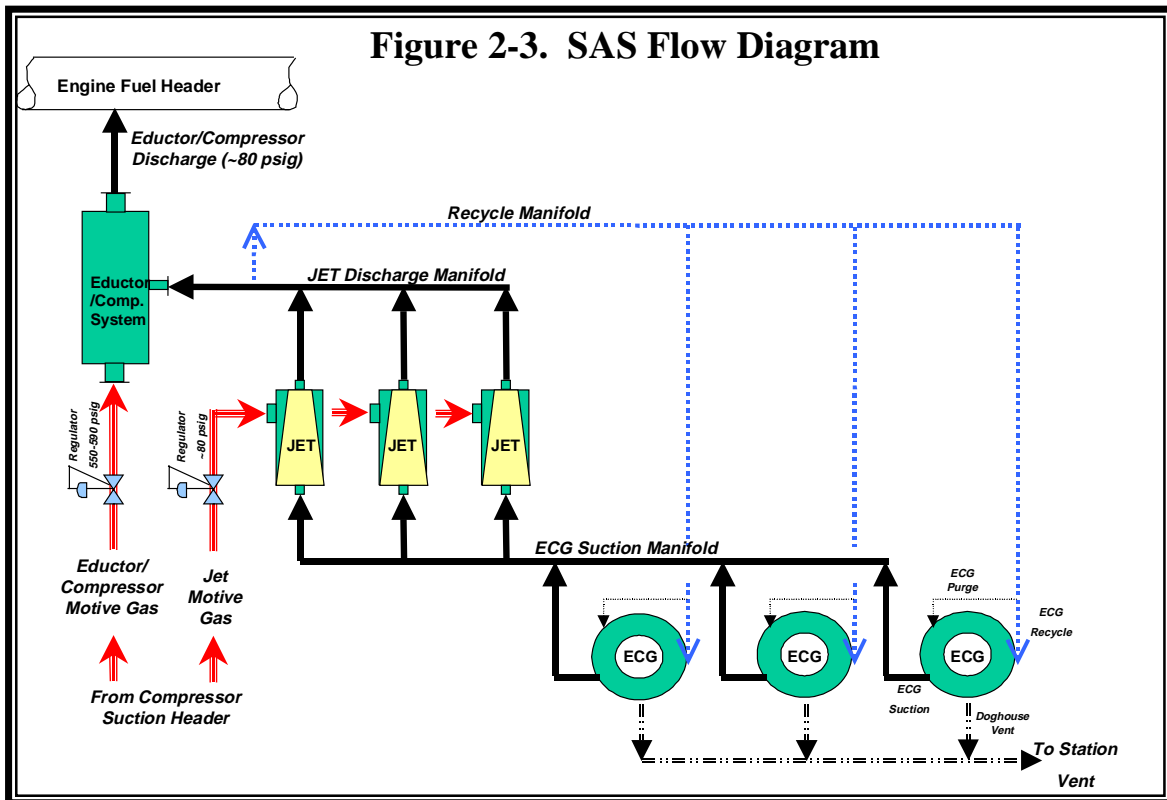
## 2.2 ROD PACKING LEAK CONTAINMENT DEVICES

Technologies that reduce or eliminate leaks from rod packing may be used by the natural gas industry to recover lost product. If natural gas leaks can be reduced or recovered, GHG emission reductions will occur, lost profits will be recovered, and natural resources will be conserved.

There are several vendors of technologies which claim to reduce rod packing emissions. The verification procedure outlined in this guideline document is based on methods developed to verify the performance of one vendor’s technology; the Seal Assist System (SAS). The SAS, developed and sold by A&A Environmental Seals, Inc. of La Marque, Texas, captures natural gas from leaking rod packing, and routes the collected gas to the existing compressor engine for combustion. Differences among leak containment technologies could impact how verification is conducted, so readers with technologies that differ significantly from the SAS should assess the need to alter the guidelines presented here. To provide an understanding of the SAS technology design and operation, a description is provided below.

The SAS is a secondary containment device designed to prevent compressor rod packing leaks from escaping into the atmosphere (Mathis et al. 1998). The SAS allows existing rod packing leaks to continue, but the leaking gas is channeled within an emissions containment gland, then routed to equipment that can recover and reuse the collected gas. Captured gas is collected, recompressed by an eductor/compressor, then routed into the existing compressor engine fuel line for use.

Figure 2-3 is a schematic of the SAS system. It consists of four primary components: the Emission Containment Gland (ECG), the Jets, the recycle stream, and an eductor/compressor which pressurizes the collected gas to engine fuel line pressure. The ECG bolts over the face of an existing rod packing located in the doghouse. The ECG contains a 3.5” annulus area which isolates the rod emissions from the doghouse atmosphere. Suction is provided on the ECG by the action of the jets, and sufficient gas is directed back through a recycle line, to produce an ECG operating pressure slightly less than atmospheric pressure. If the compressor remains pressurized during standby, the system can continue to collect gas.



### 2.3 ROD PACKING STATIC SEALING DEVICES

Gas leakage can occur from compressor rod packing while the compressor is in operation, and in some cases, when the compressor is in standby-mode. Based on EPA/GRI study, reciprocating compressors in the gas transmission sector were operating 45 percent of the time in 1992 (EPA 1996b). This indicates that 55 percent of the time was devoted to standby operations and maintenance and repair. If rod leaks during standby operations are reduced or eliminated, significant gas savings and emissions reductions can occur.

Compressor shutdown and standby procedures vary from station to station. Some operators depressurize and blow-down all pressure from a compressor before standby. Others depressurize the compressor to a lower but elevated pressure, while still others maintain full pressure during standby. Maintaining pressure facilitates a more efficient and timely compressor startup.

If pressure is maintained, emissions from the rod packing and other sources will continue. For transmission pipeline operators, these leaks can represent a significant loss of revenue, and in response to this, vendors offer technologies to reduce or eliminate standby leaks. For rod packing, this class of technologies is referred to as static seals, in reference to the static operating mode a compressor must maintain during standby operations. There are two different types of static sealing technologies verified by the Center, and both represent a modification to a standard packing case (i.e., special static sealing systems are added to the case). One system is a pneumatically activated tertiary seal that can be activated when shutdown occurs, either manually or automatically (C. Lee Cook Division, Dover Corporation). The other is designed to provide additional sealing automatically once compressor shutdown occurs (France Compressor Products). Other static seal designs may exist, but these two designs are briefly described below.

France Compressor Products (Newtown, PA) offers the Emissions Packing system to reduce leakage during standby periods. The Emissions Packing appears identical to a conventional rod packing (see Figure 2-2), with the exception that the final conventional seals or rings are replaced with a France “T-cup” system. The France “T-Cup” contains two spring-loaded pressure plates in addition to the six sealing rings typically contained in a conventional packing. The spring-loaded pressure plate and the remaining three conventional rings in the “T-cup” are intended to provide a positive and continuous seal during standby periods. The pressure plate is a two piece radial cut ring, with several compression springs equally spaced around the ring. This exerts a force parallel to the rod and according to France Compressor Products, while the compressor is in an standby and pressurized state, the spring-loaded pressure plate exerts a force in the direction of the conventional rings. This causes the adjacent rings to mate together, reducing packing leaks. To allow room for the addition of the pressure plates, the Emissions Packing contains one less ring set than a conventional packing.

The Static Pac™ is a gas leak containment device designed to prevent rod packing leaks from escaping into the doghouse, and thus, to the atmosphere during compressor standby periods. The system is offered by C. Lee Cook (Louisville, KY). The Static Pac™ system is installed in a conventional packing case by replacing several rings (typically 2) in the low-pressure side of the packing case (side nearest the doghouse). Upon shutdown of the compressor, the compressor control system activates the Static Pac™, which uses pressurized gas to move a piston along the outer shell of the Static Pac™ seal. This wedges a lip seal into contact with the rod, inhibiting packing leaks into the doghouse. When the actuating pressure is lowered, the piston retracts, releasing the Static Pac™ seal.

The two static seal technologies described here require modification of a conventional packing case, resulting in a “missing seal”. It has been speculated that an increase in rod emissions may occur during compressor operation as a result of this missing seal. Evaluations conducted by the Center are still ongoing, but preliminary results indicate this is not a significant factor for these systems while compressors are running.

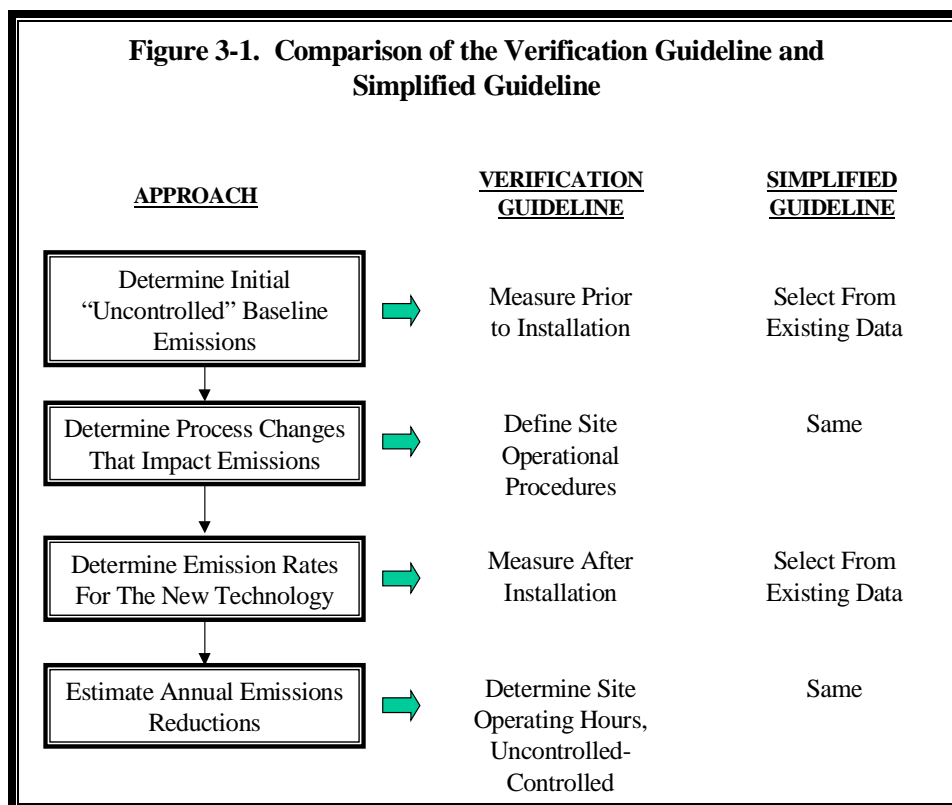


### 3.0 VERIFICATION GUIDELINE

#### 3.1 INTRODUCTION

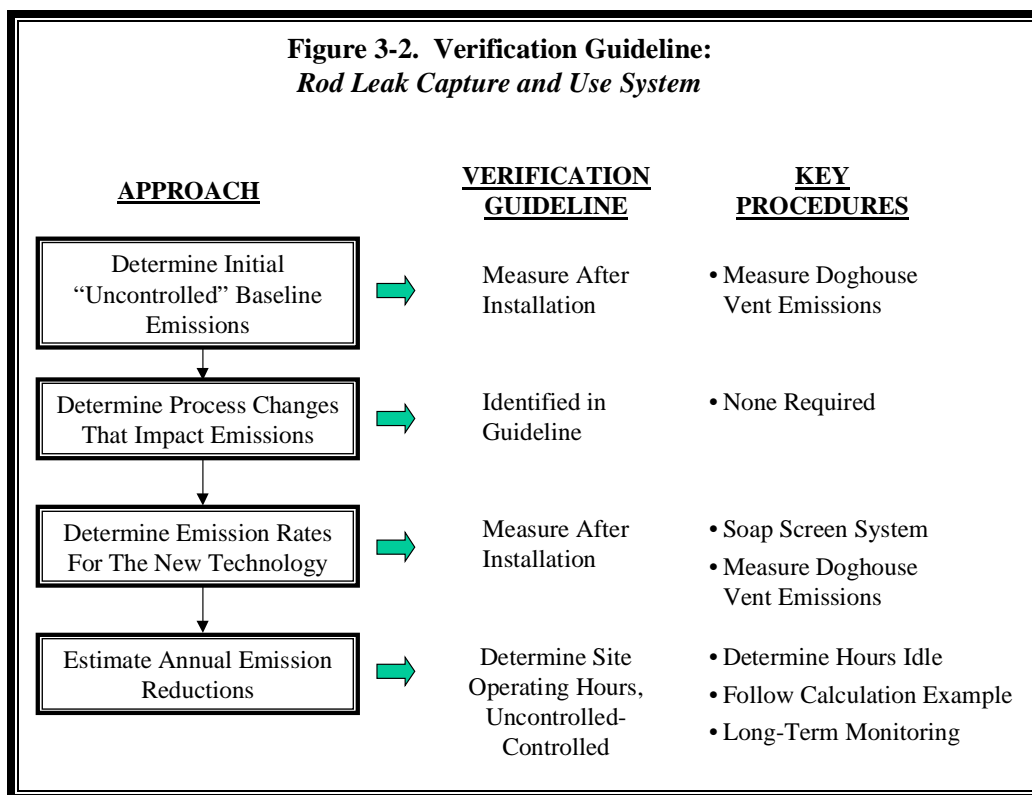
The guidance in this document is based on three separate field verifications conducted at three natural gas transmission stations in the United States. Although the guidance has been “field tested”, it may not be applicable to all compressor operations, particularly those where compressor operations differ from those in the United States. This guideline should also be considered dynamic, since the Center continues to conduct technology verifications within the natural gas industry, and this document will be updated regularly to include new findings and procedures for new technologies. Updates of this document can be obtained on-line at the Center’s Web site ([www.sri-rtp.com](http://www.sri-rtp.com)) or the U.S. EPA ETV Web site ([www.epa.gov/etv](http://www.epa.gov/etv)).

Following the planning, execution, and post-field-data analysis phases of each verification, the Center identified field or other procedures that performed poorly or were marginally necessary, and then revised the protocol. Any procedural changes instituted from this effort are included here. The guideline includes two different levels of emission reduction determination: the Verification Guideline, described here, and the Simplified Guideline, described in Section 4.0. As the name implies, the Simplified Guideline is easier and less costly to use, but it contains greater uncertainty since site-specific emission measurements are not required. The Verification Guideline relies on site-specific field measurements, and as such, produces results which are more representative of the site under evaluation. In the Verification Guideline, uncertainty due to emission measurement error is quantified, and procedures for addressing site-specific emission rate variability are proposed. Figure 3-1 illustrates the primary differences between the Verification Guideline and the Simplified Guideline. It is recommended that before the Simplified Guideline is used, the reader review and understand the more comprehensive Verification Guideline presented in Sections 3.2 and 3.3.



### 3.2 VERIFICATION GUIDELINE: ROD PACKING LEAK CAPTURE DEVICES

The rod packing and leak capture technologies were described in Section 2.2. Figure 3-2 shows the procedures for determining GHG emission reductions for rod packing leak capture devices under the Verification Guideline. The following sections describe each procedure, which if executed properly, should produce verified emission reduction values for this technology. With the use of this procedure; error bounds, due to uncertainty in the measurements collected, can be assigned to the emission reduction. This addresses measurement errors, but not other sources of uncertainty such as emission rate variability due to diurnal temperature changes, emission increases due to packing wear over time, emission variability due to differences in operating practices, and other site-specific factors. Several of these factors are addressed in the guideline by providing procedures for quantifying emission changes due to these factors. Finally, because of the nature of this technology, process changes that could alter GHG emissions do not appear to occur (SRI 1999a). Thus, this step in the verification approach outlined in Figure 3-2 is not addressed further.

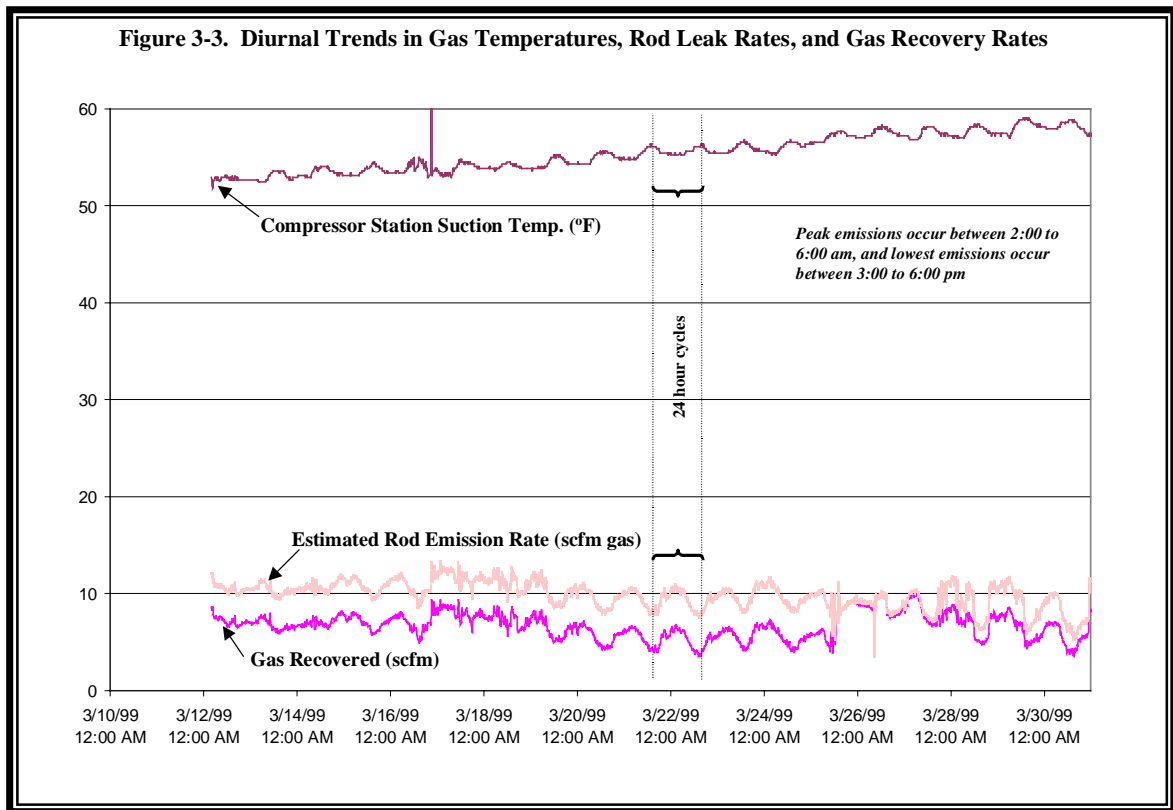


#### 3.2.1 Determining Uncontrolled Emission Rates

It is likely that, concurrent with installing the control technology, new rod seals will be retrofitted into the existing packing case. Rod seals wear over time, and as this occurs, natural gas emission rates, and control system emission reductions will increase. Establishing a profile for this changing leak rate is the subject of later sections. In this section, methods for determining uncontrolled emissions at the time of installation are described. By subtracting the emissions after installation from the uncontrolled emissions at the time of installation, the initial emission reduction can be determined. Dividing this value by the uncontrolled emission rate and multiplying by 100 yields the initial percent reduction.

If the packing seals are new, some packing break-in time should be allowed before testing begins. Packing manufacturers can be consulted for an appropriate break-in time, or, based on the limited experience of the Center, 40 hours at compressor operation should be sufficient. Uncontrolled emissions can then be measured with the Flow Tube procedure specified in Appendix A-1 after installation of the leak capture device. Other instruments and procedures could be applied, such as the GRI High Flow Sampler, but only the Flow Tube procedure is addressed in this guideline. The following discussion outlines the procedure for determining uncontrolled emissions.

Emissions data for the combined flow from three uncontrolled compressor rod seals are shown in Figure 3-3. These data are not intended to represent industry averages, so caution in their use is advised. However, it does show that there can be a relationship between emissions, time of day, and temperature of the natural gas entering the station. It is clear that a 24-hour emission cycle can occur, although not always, so preliminary Flow Tube sampling should be conducted at several different times over a 24-hour period to determine what site-specific patterns and variability, if any, occurs. To accomplish this, a pre-test site visit should be conducted, during which preliminary Flow Tube measurement and other pre-test coordination activities occur. Once this is done, it is recommended that the Flow Tube procedure be repeated at least three separate times over one 24-hour period (one Flow Tube quantification involves the collection of ten 16-second average values). Prior to any sampling, execute the Flow Tube procedure calibration specified in Appendix A-1. Specific sampling locations and procedures are discussed later in this section. Based on the one example in Figure 3-3, sampling is recommended during the mid-morning peak (about 9:00am), mid-afternoon average (about 2:00pm), and late afternoon low (about 5:00pm). These times may vary from site-to-site.



If significant variability is observed in the measured emission rates, additional Flow Tube measurements should be conducted. To provide guidance on assessing rod packing emission variability, 340 individual Flow Tube

samples were compiled for ten different compressors tested by the Center (i.e., 10- to 16-second average emission rate values). Table 3-1 shows the average uncontrolled emission rates for each packing tested. These emission rates were determined by collecting a series of Flow Tube measurements (i.e., greater than two discrete sets of ten 16-second averaged values each) and then averaging all emission rates in the series. The average standard deviation for each series is also calculated.

The compressors represented in Table 3-1 are mostly large units (4.0 to 4.5 inch rods) with dry seals. As would be expected, standard deviation increases with emission rate, but standard deviation, as a percentage of the average emissions, is below 10 percent for all compressors, and is usually between about 2 and 5 percent. If standard deviation, expressed as a percentage of the mean, emissions is consistently higher than 5 percent, consideration should be given to the collection of more than three Flow Tube measurements.

<b>Unit Rod Size (inch)</b>	<b>Compressor ID</b>	<b>Average Emission (scfm)</b>	<b>Average Standard Deviation And Number of Samples (scfm)/(No.)</b>
4.5	K-3-A	25.82	1.29 / 3
4.5	K-2-C	14.21	0.23 / 3
4.0	B-1-A	0.75	0.03 / 30
4.0	B-1-B	0.58	0.02 / 44
4.0	B-2-A	1.24	0.01 / 44
4.0	B-2-B	1.34	0.02 / 41
4.0	C-1-A	0.39	0.03 / 44
4.0	C-1-B	0.57	0.01 / 44
4.0	C-2-A	1.11	0.05 / 45
4.0	C-2-B	0.83	0.03 / 45

After data collection is complete, each set of values should be compared for general consistency, and after identifying and addressing any suspect data, the results are averaged to yield an overall average emission rate for the uncontrolled rod packing.

Uncontrolled emissions should be measured at each rod packing/ECG assembly in a sequential manner, then summed across all compressors associated with a single engine. To accomplish this, it will be necessary for the technology installers to provide a bypass valve on each ECG suction line assembly (see Figure 2-3). When activated, this valve should isolate the ECG from the suction line, allowing rod packing emissions to be vented directly to the atmosphere. Before doing this, it is also necessary to close the valves associated with the ECG's connection to the recycle line and the purge line (if present). After these two valves are closed, the bypass valve can be opened, allowing uncontrolled rod packing emissions collected by the system to be routed directly into the Flow Tube. After uncontrolled emission measurements are completed, and while the bypass valve is open to the atmosphere, the doghouse vent should be checked for evidence that the tertiary ECG seal is leaking. If it is, doghouse vent emissions should be measured with three Flow Tube quantifications, averaged, and then added to the uncontrolled emissions determined as described above.

As shown in Appendix A-1, the Flow Tube is a 2 to 3 foot straight plastic pipe that contains a sensitive vane anemometer near the outlet. With this device, it is possible to measure the velocity of natural gas within the straight pipe accurately, reliably, and over a large range of flows. Coupled with a multi-point calibration chart,

the velocity measured by the Flow Tube can be converted directly into a flow rate of natural gas at standard conditions. Prior to using the Flow Tube, a hydrocarbon analyzer is used to measure gas concentrations in the flow stream. This is done to ensure explosive gas mixtures are not be allowed to enter the Flow Tube during sampling (i.e., explosion hazard exists with 5 to 15 percent of methane in air).

After connecting the Flow Tube directly to the bypass valve, the connection should be verified as leak tight by sealing the end of the Flow Tube with duct tape, and soap screening all connections. Soap screening is conducted by placing dish soap into a spray bottle of water (1 percent solution), and then saturation spraying areas thought to be the exact point of the leak. Based on laboratory evaluations conducted by the Center, bubbles will form at the leak site with even small leaks (i.e., 0.04 scfm or larger), providing an efficient visual means for identifying leak location and significance (SRI 1996). The results of the soap screening should be recorded, and any leaks found repaired and re-tested.

Information needed to assemble, calibrate, and use the Flow Tube are presented in Appendix A-1: Flow Tube Standard Operating Procedure (SOP). The SOP describes instrumentation and calibration procedures for both the Flow Tube and the hydrocarbon analyzer. It also shows calculations needed to convert Flow Tube velocities into emission rates. The SOP describes field operational procedures, and presents sample calibration and field data log forms and results. Although the procedure described is specific to the measurement of emissions from doghouse vents, it is similar to that required to measure uncontrolled emissions from valves and other sources described later.

An alternate method for measuring uncontrolled emissions is to install in-line gas flow meters into the leak mitigation technology's gas collection system (e.g., mass flow or laminar flow meters). Both Flow Tube and in-line meters have been used by the Center to perform technology verifications. With the SAS technology, two meters would be needed; one between the recycle line and the eductor/compressor inlet, and one on the motive gas line of the jet assembly (see Figure 2-3). The difference between the two meters represents the emission reduction for the technology. Although this method can provide reliable and continuous data for long-term monitoring or other purposes, it may be more costly to implement and maintain. In addition, the SAS technology normally operates under slight negative pressure, and a concern exists that this could increase the flow of gas from the leaking packing seals. If this were the case, emission reductions obtained with in-line flow meters would be biased high. The Center is addressing this issue, and will revise this guideline when reliable results are obtained.

### 3.2.2 Determining Controlled Emission Rates

Several sources of emissions from the installed control system are identified here, and methods for determining the emission rates are described. The sum of the emission rates determined from these sources represent the total average emission rate for the overall control system on one compressor. Emission from all compressors on a single engine may be summed to represent total controlled emissions.

Once the entire control system has been installed and pressure tested, GHG emissions can be determined. A potential source of emissions includes fugitive leaks from connections, seals, jet assemblies, the eductor assembly, valve stems, pressure and other taps, and capped pipe ends. These components are usually leak tight due to the severe safety hazard that leaks pose within the confines of the compressor building. The procedure recommended here is to soap screen all GHG control system components, including those listed above and others with a potential to leak (e.g., any non-welded connection or seal where high-pressure gas is involved). Any leaks found should be recorded then repaired before proceeding. Once repairs have been verified with a second soap screening, emissions from these sources can be considered to be zero. If repairs are not possible, U.S. EPA Protocol for Equipment Leak Estimates (EPA 1995) procedures can be applied to "bag" the leaking component, and directly measure the leak rate. This U.S. EPA protocol is not described here, but detailed

guidance is available at the following U.S. EPA Web site: [www.epa.gov/ttn/chieff/fyi.html](http://www.epa.gov/ttn/chieff/fyi.html). This U.S. EPA protocol can be costly to implement unless an on-site gas chromatograph already operates at the testing site. It poses several measurements challenges, and may produce results with greater uncertainty than the Flow Tube.

A second potentially significant source of emissions from the GHG control system is associated with the ECG, which attaches to the face of the rod packing case within the doghouse (see Figure 2-2). With the SAS system, a tetariary seal is located on the ECG to prevent rod leaks from entering the doghouse. When control system pressure increases, gas leaks can occur in significant quantities, and as a result, it is recommended that emission rate measurements be conducted on the doghouse vent using the Flow Tube. The procedure should begin only after ensuring that the doghouse vent is the only means for gas to escape the doghouse. To accomplish this, use the hydrocarbon analyzer described in Appendix A-1 to screen all doghouse flanges, seals, connections, inspection door covers, and other areas where gas could leak into the compressor house. If concentrations above 500 ppm total hydrocarbons are observed, a leak is likely present and should be repaired before proceeding. Also, a restriction (cap or oil trap) should be placed on the doghouse oil drain line to prevent gas from escaping by this route. Once this is complete, the Flow Tube procedure should be executed as described in Appendix A-1, and three separate quantifications should be conducted.

The final source of GHG emissions associated with the gas collected by the GHG control system are combustion-related emissions from burning the collected gas. However, this does not represent an actual increase in GHG emissions, since the engine would have burned natural gas anyway to meet the gas compression demand of the station. These emissions are not counted against the technology in this guideline.

Emissions from all the sources mentioned above should be measured as many times as the uncontrolled emissions, and at the same time of day. Measurements from each individual source should be averaged and then summed for each individual compressor examined. Results may be aggregated for all compressors on a single engine, or for all compressors examined at the station.

### 3.2.3 Initial Emission Reduction

The term initial emission reduction is defined as the reduction that occurred just after installation and rod seal break-in. Initial emission reduction is determined by subtracting the total control system emissions occurring after installation (determined as described in Section 3.2.2) from the uncontrolled emissions occurring at the time of installation (determined as described in Section 3.2.1). By dividing this difference by the uncontrolled emission rate and multiplying by 100, the initial percent reduction is also determined.

Flow Tube accuracy values, determined as described in Appendix A-1, can be used to place uncertainty bounds on the initial emission reduction due to measurement error. The overall average Flow Tube accuracy can be calculated by averaging the individual calibration point accuracy values, determined as described in the SOP calculations (see Appendix A-1). This overall accuracy can then be used to represent a percentage range of emissions as illustrated below. It should be noted that this does not include potentially significant sources of emission variability that were not adequately captured by the measurements collected (e.g., emission variability brought on by process effects, variability not captured because too few measurements were collected).

- **Initial Emission Reduction = Initial Emission Reduction  $\pm$  (overall average accuracy value) %**

The Flow Tube produces natural gas-based emission values, and these should be converted to methane emissions using natural gas compositional measurements for the site. This is done by multiplying the natural gas-based emissions determined above, by the fraction of methane contained in the natural gas collected by the control system. Pipeline operators routinely measure gas composition using a gas chromatograph, and these

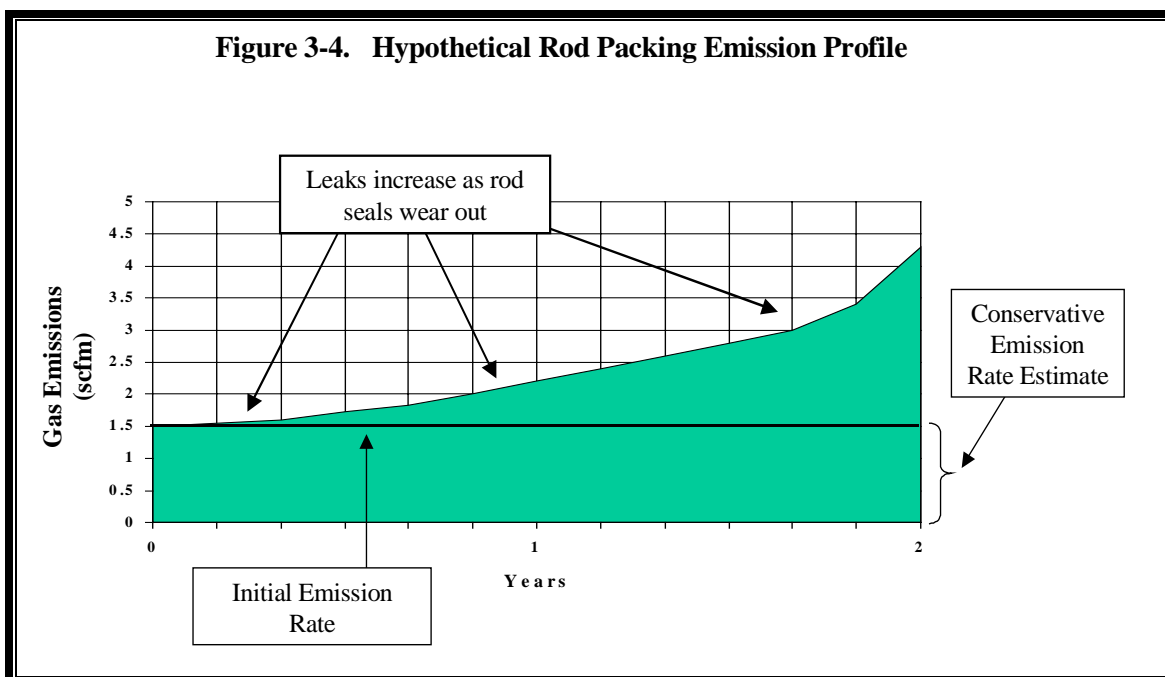
data, along with calibration results, should be obtained from the pipeline operator. When reporting results on a methane basis, errors introduced from this instrument should be added to the uncertainty associated with the Flow Tube, to yield a total uncertainty estimate. This can be accomplished by adding the appropriate accuracy values determined by the pipeline operator to the Flow Tube accuracy values in the expression above.

It should be noted that uncertainty estimated as described above, represents the error introduced by the measurement only. It does not include uncertainty or bias that may be present as a result of measurement infrequency, measurement or calculation errors, environmental or diurnal effects, or other potential biasing factors. These sources of uncertainty can be reduced by proper execution of the Verification Guideline.

### 3.2.4 Annual Emission Reduction

Compressor operating times and shutdown procedures impact the total annual emissions and emission reductions. Compressors that are under repair, depressurized and placed in standby mode, or depressurized and placed out of service, do not liberate packing emissions. Those times where a compressor operates in these modes must be determined using station-supplied records, then subtracted from the total time in a year. The result includes only operating and standby periods in which the compressor was in a pressurized state. The control technology collects gas in both operating and standby mode, so multiplying these times (in minutes) by the initial emission reduction determined as described in Section 3.2.3, yields an estimate of annual emission reductions for the control technology. Of course, if during a pressurized state the non-operating engine does not use the gas collected, these minutes should be subtracted.

The annual emission reduction above is conservative (likely low), because rod packing emission rates may increase over time, influencing the emissions and emission reductions achieved. Figure 3-4 illustrates a rod packing emission profile, and shows how emissions may increase (hypothetical only). Unfortunately, data are not sufficient to support the estimation of packing emission changes over time, and without these data, direct measurements are the only means available to characterize long-term emissions. It is recommended that uncontrolled emissions be measured as outlined in Section 3.2.1 on at least three additional occasions to support the characterization of long-term uncontrolled emission trends (at 7, 14, and 21 months after installation).

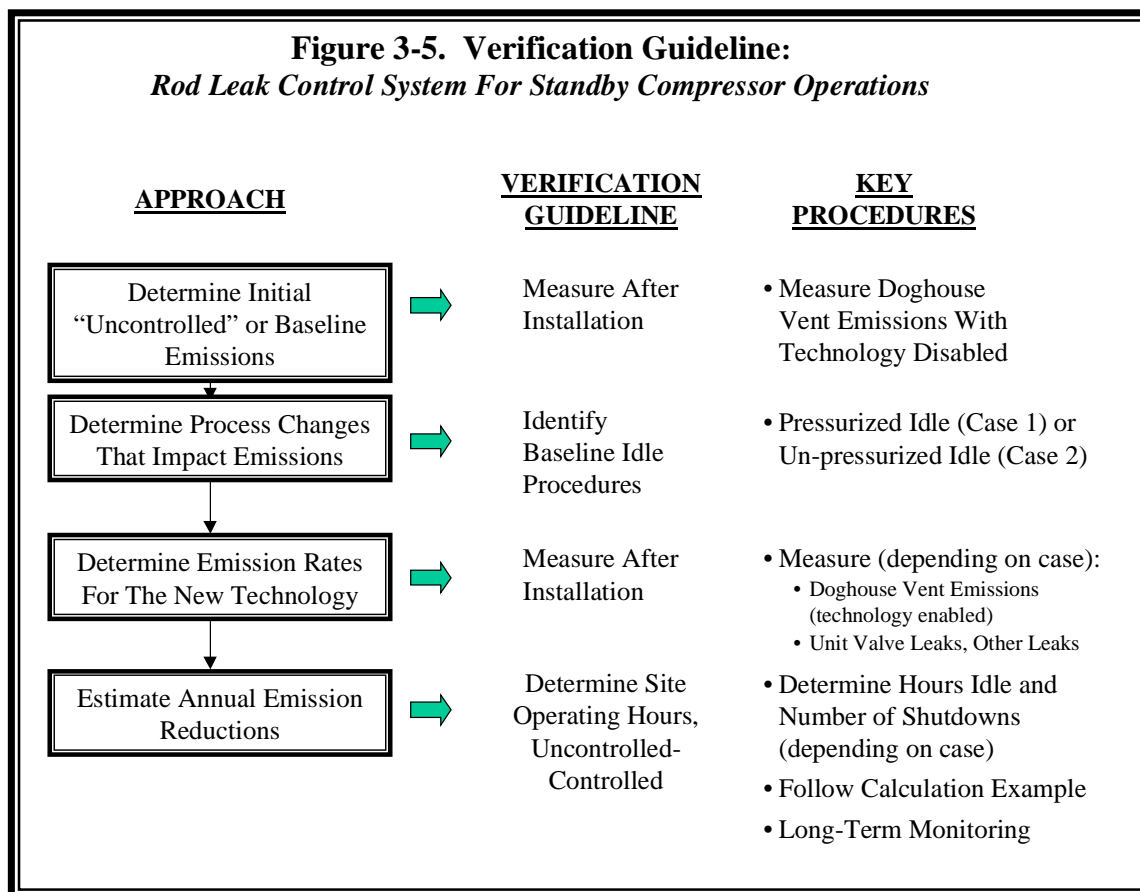


It may be impractical for sites to conduct long-term measurements of uncontrolled emissions, and in these cases, it is recommended that annual emission reductions be determined as described in the first paragraph of this section, and that these values be reported as conservative estimates, subject to later revision. Long-term rod seal measurement data are being collected by the Center for three compressor stations (seven compressors), and these data will be used to develop rod packing emission profiles for these facilities. This data will be included in the guideline once they become available, and may be used to estimate “typical” uncontrolled emission profiles for rod packing.

### 3.3 VERIFICATION GUIDELINE: ROD PACKING STATIC SEALING DEVICES

Rod packing and static sealing technologies were described in Section 2.3. Figure 3-5 shows the procedures recommended for use in the Verification Guideline for static sealing devices. The following sections describe each procedure, which if executed, will produce verified emission reduction values for this technology. As with the previous verification guideline, execution of this procedure will produce error bounds due to measurement uncertainties.

In some cases, use of this technology will be accompanied by a decision to change a compressor’s standby operating procedures. These procedural changes will alter GHG emissions from sources other than those targeted by the control technology, and as such, baseline or uncontrolled emissions will change. Because of this, the verification strategy for static seals is more complex than for the previous technology because additional steps defining baseline conditions have been added to the procedure in Figure 3-5.





The two static seal technologies described earlier require modification of a conventional packing case, resulting in a “missing seal”. It has been speculated that an increase in rod emissions may occur during compressor operation as a result of this missing seal. Industry experience suggests that this does not occur, and the Center’s own limited verification testing indicates that any increase, if present, is likely negligible (SRI 1999b, SRI 1999c). Therefore, testing is not recommended in the guideline to assess the effect that static seals have on normal sealing performance during compressor operation.

### 3.3.1 Establishing Baseline Compressor Standby Conditions

Static seals can reduce emissions during standby operations, and for both technologies examined by the Center, compressors remain pressurized during standby. The annual emission reduction achieved depends on the emissions from the packing before and after installation of the static seals. It also depends on the shutdown procedure used, and the number and duration of shutdowns experienced. For example, a station that currently leaves compressors pressurized during shutdown will experience emission reductions from the decrease in standby packing leaks only. Alternatively, if a station currently blows-down compressors before shutdown (i.e., releases all pressure), it will change to a pressurized shutdown condition after installation. In this case, emission reductions occur from the static seals, and by eliminating blow-down and unit isolation valve emissions. There is however, a potential for increases in emissions at components now exposed to high pressure during standby.

For two of the most commonly used compressor shutdown procedures, Table 3-2 shows the relationship between compressor shutdown procedures and emissions. Depending on the shutdown procedure used before installation of static seals, a change to a pressurized compressor standby may occur. Thus, the table also indicates how compressor emissions may change from the emissions that occurred during the original standby mode. This guideline was developed to allow the characterization of all emissions changes (i.e., those due to the installation of static seals, and those due to the possible adoption of a different shutdown procedure).

<b>Table 3-2. Common Shutdown/Standby Scenarios and Emissions</b>		
<b>Procedure or Emission Source</b>	<b>Case 1</b>	<b>Case 2</b>
<b>--Matrix of Shutdown Procedure Changes--</b>		
Current shutdown Procedure	Pressurized standby with unit valves open or closed	Depressurized standby, blow-down 100% to atmosphere
Procedure with new Static Seals	n/c	Pressurized shutdown
<b>--Matrix of Emissions Changes Due to Shutdown Procedure Changes --</b>		
Rod packing	Decrease	Little or no increase
Blow-down volume	n/c	Eliminated
Unit valve (via open blow-down line)	n/c	Eliminated
Blow-down valve	n/c	Increase
Pressure relief valve	n/c	Increase
Misc. valves, fittings, flanges, seals, stems, etc.	n/c	Increase

NOTES: n/c - no change/effectively no change

The guideline for static seals requires the determination of uncontrolled emissions for one of two standby scenarios. The guideline requires the selection of a scenario that best matches the facility at which emissions are being verified. All possible scenarios are not presented here, but the two that are addressed collectively represent standby practices employed by about 95 percent of the transmission compressors in the US (EPA 1996a). Case 1 should be used if, prior to installation of static seals, the unit was shutdown and left in a fully pressurized state. Case 2 should be used if the compressor was originally depressurized and blown-down before standby. The following describes the Verification Guideline for each case.

### 3.3.2 Case 1 - Initial Emission Reduction

This case represents a compressor that, prior to installation of static seals, maintained full operating pressure during standby operations. This is the same standby operation used after installation, so unit pressure is essentially unchanged, and all other component leak rates can be assumed to remain constant after the installation. In this case, only rod packing emissions will change due to the action of the static seals during standby operations.

To quantify this change in rod packing emissions, Flow Tube emission measurements should be conducted on the doghouse vent. Any leaks past the static seals will pass through the doghouse vent. For control technologies that can be manually engaged and disengaged during standby (e.g., C. Lee Cook Static Pac™), emissions during pressurized standby should be measured while the static seal is engaged (controlled emissions) using the Flow Tube procedure. Immediately following this test, the Flow Tube procedure should be applied again while the system is disengaged (uncontrolled emissions). A minimum of six separate Flow Tube procedures should be completed; three each for the two static seal operational conditions. However, the reader should follow the procedures outlined in Sections 3.2.1 and 3.2.2 when determining the number of tests and testing times for specific sites. If controlled emissions are near zero, the reader should apply the guidance in the SOP that applies to measurements conducted near the LDL of the Flow Tube.

After collecting all field data, the Flow Tube results should be averaged for each test condition. The difference between the two averages should then be calculated (uncontrolled minus controlled) and used to represent initial natural gas emission reduction in scfm. Procedures outlined in Section 3.2.3 can be used to place uncertainty estimates on this value. The Flow Tube produces natural gas emission values that can be converted to methane emissions using natural gas compositional measurements routinely collected by the station operator. Specifically, the methane emission reduction is determined by multiplying the natural gas emission reduction by the fraction of methane measured in the station's natural gas (determined via gas chromatograph). When reporting results on a methane basis, errors introduced from the gas chromatograph procedure should be obtained from the pipeline operator and added to the uncertainty associated with the Flow Tube results.

For technologies that can not be manually disengaged during standby (i.e., France Emissions Packing), a more elaborate procedure may be needed to directly measure uncontrolled emissions. In these cases, the Simplified Guideline may be used, but if less uncertainty is required, consideration should be given to the procedures outlined in the report: *Testing and Quality Assurance Plan for the France Compressor Products Emissions Packing, July 1999* (SRI 1999b, SRI 1999d). This site-specific test plan can be downloaded from the Center's Web site at [www.sri-rtp.com](http://www.sri-rtp.com).

### 3.3.3 Case 1 - Annual Emission Reduction

For static seal technologies applied to a Case 1 baseline operating condition, the amount of time in standby or standby mode are needed to estimate annual emissions and emission reductions. Determination of these times was described in Section 3.2.4. Multiplying these times by the initial emission reduction determined as described in Section 3.3.2 yields an estimate of annual emission reductions of methane or natural gas. As

discussed earlier in Section 3.2.4, this annual emission reduction may be conservative (likely low) because rod packing emission rates may increase over time, increasing the emissions and emission reductions achieved. Long-term emissions data are needed to support the development of actual rod seal emission profiles, and without these data, direct measurements are the only means available with which to characterize long-term emissions. Recommendations in Section 3.2.4 should be followed for conducting these measurements.

It may be impractical for sites to conduct long-term measurements of uncontrolled emissions, and in these cases, it is recommended that the conservative annual emission reductions described above be determined. These values should be reported as conservative estimates, subject to later revision. Data being collected by the Center at three compressor stations will be used to develop long-term rod packing emission profiles, and these data will be included in the guideline once available.

### 3.3.4 Case 2 - Initial Emission Reduction

This case represents a compressor that, prior to installation of static seals, would blow-down from operating pressure to near atmospheric pressure during standby operation. Once installation of the static seals is complete, this unit will operate in a pressurized mode, and emissions from several leaking components will both increase and decrease. A pressurized mode facilitates the efficient startup of the engine/compressor system.

When a compressor blows-down, which is the assumed Case 2 baseline operating condition, the pressure on compressor components is reduced to near atmospheric, and leaks from the rod packing, pressure relief valve, blow-down valve, and miscellaneous components are effectively stopped. On the other hand, leaks from the unit valve seats, which are closed to isolate the compressor from the pipeline system, are released into the compressor system and into the atmosphere via the open blow-down valve vent. After static seals are installed, and a pressurized shutdown begins, the unit valve leaks are stopped, representing an emission reduction which occur in conjunction with the use of the static seals. In addition, the blow-down volume is no longer released, representing an additional emission reduction.

Emissions associated with all of the sources described above are significant, particularly the unit valve emission. Measurements are needed for all sources to support appropriate baseline and emission reduction determinations for Case 2. The measurement procedures are described in Section 3.3.5. Using these procedures, emission rate measurements should be conducted during pressurized standby mode on all components exposed to elevated pressures. These components include the pressure relief valve, the blow-down valve, and miscellaneous flanges, connectors, valves, pump seals, and other potentially leaking components. Once measured, emissions from these devices should be subtracted from the initial emissions reduced by the static seals, to yield a net reduction associated with the static seals. Furthermore, emissions associated with the unit valves and blow-down volume should be added to the reductions associated with the static seals. Determination of the initial emission reduction for the static seals was already described for Case 1 in Section 3.3.2, and the same procedures can be followed here.

Section 3.3.6 presents a mathematical representation of the calculation procedure described above. Because emission changes occur on equipment that serves all compressors on a single engine, Case 2 emission reductions must aggregate to the engine, and not compressor level.

### 3.3.5 Case 2 - Additional Emission Measurements

To measure additional emission sources required for Case 2, manual measurements should be collected on the following sources: unit valve seats, pressure relief valve vent, blow-down valve vent, and miscellaneous components (e.g., fittings, flanges, connections, pump seals, valve stems). The following lists the measurements needed and operating conditions under which testing should be done. About one full day is needed to conduct

one set of measurements on four compressors. Testing of the rod packing emissions were discussed earlier and will not be repeated here.

- With the unit shutdown and pressurized: natural gas leak rates for the pressure relief valve, blow-down valve, and miscellaneous components
- With the unit shutdown and blown-down: natural gas rates for the unit valve (measured at the open blow-down valve line) and the unit valve stem

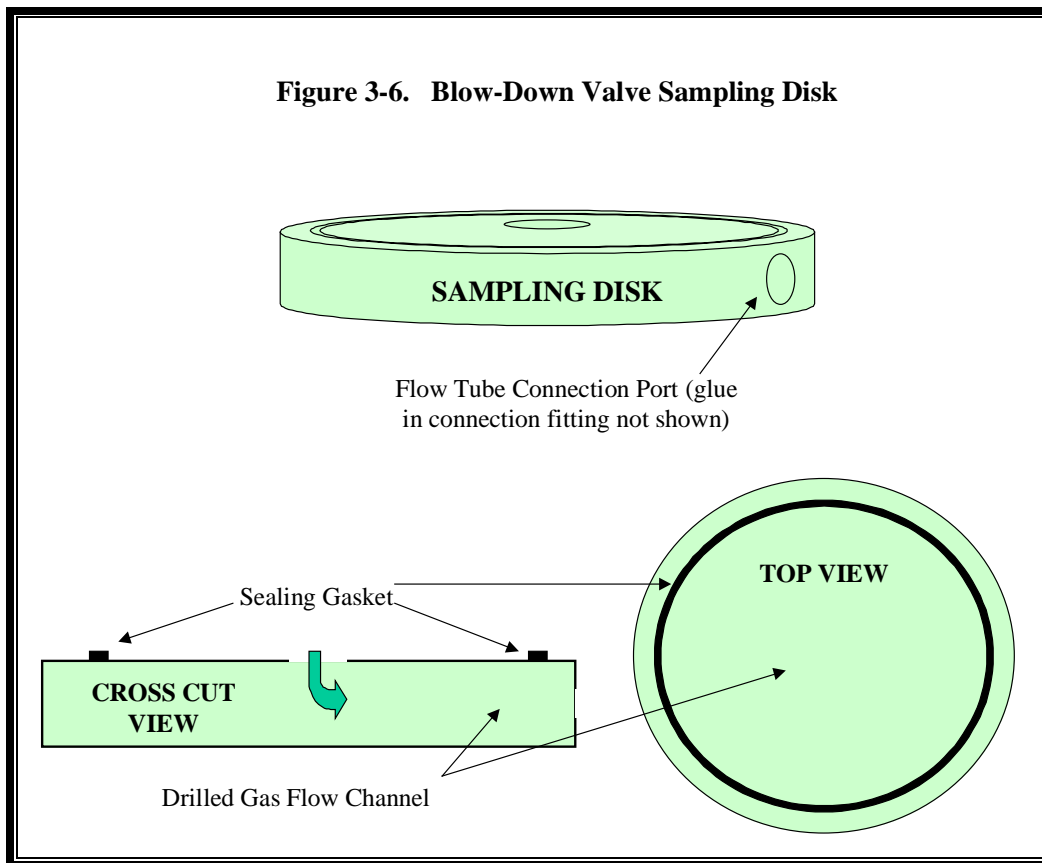
The calculation procedures for using these data, along with site operational hours to determine annual emissions, are described in Section 3.3.6.

### 3.3.5.1 Component Leak Rate Measurements

Pressure relief valves generally vent through a 4- to 6-inch diameter standpipe, with the exit located near the roof of the compressor building. The hydrocarbon analyzer described in Appendix A-1 should first be used at the pipe end to determine if leaks are present, since pressure relief valves are generally leak tight. If significant hydrocarbon concentrations are detected, the Flow Tube procedure should be used to quantify gas flow rates. First, make a leak tight connection between the standpipe and the Flow Tube, then follow the sampling and calibration procedures described in Appendix A-1. Little is known about the variability of emission rates for this source, so it is recommended the guidance on variability specified earlier for rod packing emissions be followed (see Section 3.2.1). A minimum of three separate Flow Tube quantifications should be conducted (one quantification involves ten 16-second average samples as described in Appendix A-1). These should be done as close as possible to the same time used to sample the doghouse vent emissions.

Leak rates for the unit valves should be the highest flows measured. With the blow-down valve open, flow measurements should be conducted with the Flow Tube at the end of the vent pipe for the blow-down valve. This location may be difficult to access without the use of special lifting equipment (e.g., a “cherry picker” boom truck), and an alternative location may be provided at some sites that is more convenient. Specifically, some sites provide a port immediately downstream of the unit valve in the suction and/or discharge line of each compressor. During compressor shutdown, any leaks from the seats of the unit valves will exit through this opened port if the blow-down valves are closed, and the bypass valve has been opened connecting the suction and discharge sides. Another sampling alternative is to use the blowdown valve sample collection procedure described below. Regardless of the sampling location, the Flow Tube should be applied in the same manner as described in Appendix A-1, with sampling frequency and start times consistent with the other sources measured. The anemometer mounted within the Flow Tube has the capacity to measure high flows associated with most unit valves (i.e., a maximum of 6,500 fpm or about 20 cfm). However, a high flow rate calibration chart, similar to the one shown in Appendix A-1, Figure A-2, must be prepared and used for this source.

The leak rate for the blow-down valve can be measured at the blow-down valve vent exit, or by disconnecting the flange located at the exit of the valve. To sample at the flange, it is necessary to unbolt the flange and separate the two sides sufficiently to allow the insertion of a 1 to 1.5 inch thick plastic disk between the flanges. The disk should contain medium thickness gasket material, and channels must be drilled to about a 0.75 inch bore. This will allow the leak to be captured and directed into a small and sensitive low flow rate rotameter (e.g., Dwyer VB Series, 0 to 1000ml/min, published accuracy and precision  $\pm 3$  percent). A diagram of the disk, which can be easily fabricated using readily available materials, is shown in Figure 3-6. A sensitive rotameter is recommended here because the Flow Tube performance begins to deteriorate at the low flow rates expected for blow-down valves (below about 0.3 scfm). The rotameter can be calibrated with the low-flow LFE device described in Appendix A-1, or factory supplied calibrations may be used.



The miscellaneous components consist of pressure and temperature metering taps, fittings that connect the taps to data transmitters, valves used to recover gas for fuel recovery systems, all valve stems, miscellaneous connections and flanges, compressor head seals, pump seals, and any other compressor related component that may leak under pressure. Significant leaks should not be expected at these locations; however, all components should be soap screened, and any leaks found repaired and soap screened again to verify a no leak condition. Any leaks found should be recorded, then repaired before proceeding. Once repairs have been verified with a second soap screening, emissions from these sources can be considered to be zero. If repairs are not possible, U.S. EPA Protocol for Equipment Leak Estimates (EPA 1995) procedures can be applied to “bag” or otherwise enclose the leaking component, and directly measure the leak rate. This U.S. EPA protocol is not described here, but detailed guidance is available at the U.S. EPA Web site [www.epa.gov/ttn/chief/fyi.html](http://www.epa.gov/ttn/chief/fyi.html). This method can be costly to implement, unless an on-site gas chromatograph already operates at the testing site. It poses several measurements challenges, and may produce results with greater uncertainty than the Flow Tube.

### 3.3.5.2 Blow-Down Volume Determination

The blow-down volume represents the gas contained in the test compressor, auxiliary piping, and all components located downstream of the unit valves. During blow-down operations, this gas is allowed to exit through the blow-down valve vent, and dangerous sampling conditions may occur. As such, it is not practical or safe to directly measure the blow-down volume.

Based on design dimensions obtained from the site operator and verified in the field, the total volume present in the equipment that contains the blow-down volume can be reliably calculated. Based on the system pressure at

shutdown, which is measured by existing station pressure sensors, the number of standard cubic feet that occupy this space can be calculated. Given the high pressures, this calculation should include a correction for the compressibility of natural gas (i.e., the Z factor in the non-ideal gas law). With the gas volume converted to standard conditions, the volume of gas that remains within the equipment at ambient pressure should be subtracted (i.e., the volume of the equipment after converting from actual to standard conditions). The resultant represents the total gas released into the atmosphere each time the compressor is depressurized from pipeline to atmospheric pressure.

### 3.3.5.3 Site Operational Data

The number and duration of shutdown and standby periods must be specified to calculate the natural gas reductions for static seals. Generally, transmission compressor operators automatically collect and maintain records that identify daily compressor engine operating hours and the total number of hours the compressor engine was available. These site records, provided by the compressor operator, should be used to determine the number and duration of shutdowns for a full year. Past records of operation for three or more years, may be used to project future shutdown activities for several years into the future. Subtraction of the total available hours from the total operating hours represents the number of hours a compressor was in standby mode or not under repair. The number of shutdowns may not be recorded directly, in which case, they will have to be determined from site logs and/or operator interviews.

### 3.3.6 Case 2 - Annual Emission Reduction

For static seal technologies applied under Case 2, the amount of time in standby mode and the number of shutdowns conducted are used to estimate annual emissions and emission reductions. Determination of these values for a full year was described in the previous section. Multiply these times and number of shutdowns by the emissions and emission reductions determined as described in Sections 3.3.4 and 3.3.5 to determine the annual emission reductions of natural gas for the static sealing system. A mathematical representation of this is shown below for Case 2. The values below are engine-level (not compressor-level) representations of emissions.

$$G2 = BDV * t_{bdv} + Q_{uv} * t - [Q_{prv} + Q_{bdv} + Q_{misc} + Q_s] * t$$

Where,

G2 = natural gas emission reduction over the year of interest for all compressors on the engine of interest, scf

BDV = blow-down volume for all compressors, determined as described in Section 3.3.5.2, scf

Q<sub>uv</sub> = unit valve leak rate measured as described in Section 3.3.5.1, scfm

Q<sub>prv</sub> = pressure relief valve leak rate measured as described in Section 3.3.5.1, scfm

Q<sub>bdv</sub> = blow-down valve leak rate measured as described in Section 3.3.5.1, scfm

Q<sub>misc</sub> = aggregate leak rate for miscellaneous components measured as described in Section 3.3.5.1, scfm

Q<sub>s</sub> = initial natural gas reduction determined for the packing for all compressors measured as described in Section 3.3.4, scfm

t = standby or standby time over the year of interest determined as described in Section 3.3.5.3, minutes

t<sub>bdv</sub> = number of blow-down events occurring over the year of interest as described in Section 3.3.5.3

For the same reasons discussed in Section 3.2.4, this annual emission reduction may be conservative (likely low), because rod packing emission rates may increase over time, influencing the emissions and emission reductions achieved. Long-term emissions data are needed to support the development of actual rod packing emission profiles, and without these data, direct measurements are the only means available to characterize

long-term emissions. Recommendations for conducting these measurements were described in Section 3.2.4, and these procedures should be followed here.

It may generally be impractical for some sites to conduct long-term measurements of uncontrolled emissions, and in these cases, it is recommended that annual emission reductions be determined as described above, and that these values be reported as conservative estimates, subject to later revision. Data being collected by the Center at three compressor stations will be used to develop rod packing emission profiles, and these data will be included in the guideline once available.

The natural gas emission reductions described above can be converted into methane emission reductions using natural gas compositional measurements routinely collected by the pipeline operator. Procedures for making this conversion, and for integrating measurement-related uncertainty into all of the emission reduction estimates, are described in Section 3.2.3.

### 3.4 VERIFICATION GUIDELINE CHECKLIST

#### ROD PACKING LEAK CAPTURE DEVICES

The checklist is for one compressor/ECG. A typical installation would include two or more compressors on one engine, and possibly, several engines at one or more stations. Verifying performance on all compressors using the control device is recommended, since emissions can vary significantly between compressors on the same engine.

##### Determining Uncontrolled Emission Rates (section 3.2.1)

- Install ECG
- ECG installation must allow for a sampling port and isolation of the ECG
- Allow time for emissions to stabilize (40 hours of operation)
- Plan and prepare for measurements
- Obtain or construct measurement apparatus (see Flow Tube SOP in Appendix A)
- Complete calibrations (Flow Tube and gas analyzer – see SOP for details)
- Conduct pre-test site visit to facilitate planning and collect preliminary Flow Tube measurements
- Plan to conduct at least 3 sets of Flow Tube measurements, timed to capture a potential 24-hour diurnal cycle (see guidance and data in Section 3.2.1)
- Conduct measurements
- Refer to SOP for details on conducting a single Flow Tube quantification, which includes ten 16-second average values (See Appendix A)
- Isolate ECG (close suction, recycle and purge valves)
- Measure at the ECG valve sample port, and at the doghouse vent (the sum is the uncontrolled emission rate)
- Validate data
- Examine data for trends or unexpected variability. Attempt to identify causes for outlying data. Screen data and/or repeat measurements as needed.

##### Determining Controlled Emission Rates (Section 3.2.2)

- Plan and prepare for measurements
- Plan to conduct at least 3 sets of Flow Tube measurements, timed to capture a potential 24-hour diurnal cycle (see guidance and data in Section 3.2.1)
- Measurements should be near concurrent with uncontrolled emissions measurements
- Check for fugitive leaks (soap screening)
- Record and repair leaks. If repair is not practical, quantify using EPA protocol (described in Section 3.2.2)
- Measure doghouse vent emissions with control system in operation

- ❑ Ensure that the vent is the sole escape for any ECG leak
- ❑ Cap oil drain or install oil trap
- ❑ Check doghouse access panels, etc. for leaks (sniff using THC analyzer described in Appendix A)
- ❑ Check that packing case vent is routed into the doghouse. If the packing case vent is routed elsewhere, it should be plugged or the emission rate determined
- ❑ Refer to SOP for method details.
- ❑ Validate data
- ❑ Examine data for trends or unexpected variability, attempt to identify causes for outlying data, screen data and/or repeat measurements as needed

#### Initial Emission Reduction (Section 3.2.3)

- ❑ Obtain methane percentage in gas stream from station measurement records, obtain calibration records for GC used by station operators
- ❑ Convert natural gas emissions to methane emissions
- ❑ Calculate difference in controlled and uncontrolled methane emissions
- ❑ Calculate measurement error in emission reduction
  
- ❑ *Alternate method* – Install in-line flow meters on SAS jet manifold gas supply and in the SAS discharge header. The difference between discharge flow and motive gas flow is the system gas recovery. Note, this provides total gas recovery for all ECGs/compressors on the system, not individual ECG or compressor values

#### Annual Emission Reduction (section 3.2.4)

- ❑ Multiply initial emission reduction rate (scfm) by the time (minutes) the compressor is pressurized in a year, and the gas is consumed by an engine
- ❑ The annual emission reduction value can be updated to reflect changes in rod packing sealing performance by obtaining additional measurements further into the life of the packing

## **ROD PACKING STATIC SEALING DEVICES**

Case 1 verifications can be conducted at the compressor level – a single compressor/static seal. Due to the additional component measurements, Case 2 verification must be conducted at the engine level (one engine/all compressors). For Case 2, doghouse vent measurements are required at all compressors on the engine. A typical installation would include two or more compressors on an engine, and several engines at a station. Verifying performance on all compressors using the control device is recommended, since emissions can vary significantly between compressors on the same engine.

#### Establishing Baseline Compressor Standby Conditions (section 3.3.1)

- ❑ Determine applicability of Case 1 or Case 2 verification based on station operations prior to installing the static seal

#### **Case 1—Initial Emission Reduction (section 3.3.2)**

- ❑ Plan and prepare for measurements
- ❑ Obtain or construct measurement apparatus (see Flow Tube SOP in Appendix A)
- ❑ Complete calibrations (Flow Tube and gas analyzer – see SOP for details)
- ❑ Conduct pre-test site visit to facilitate planning and collect preliminary Flow Tube measurements
- ❑ Plan to conduct at least 6 sets of Flow Tube measurements on each doghouse vent (3 controlled, 3 uncontrolled), timed to capture a potential 24-hour diurnal cycle (see guidance and data in Section 3.2.1)
- ❑ Conduct measurements with static seal engaged (controlled) and engine in pressurized/standby mode



- ❑ Conduct measurements with static seal disengaged (uncontrolled), under the same operating condition as above, and immediately before or after controlled emissions measurements
- ❑ Validate data
- ❑ Examine data for trends or unexpected variability, attempt to identify causes for outlying data, screen data and/or repeat measurements as needed
- ❑ Calculate initial emission reduction rate by taking the difference (scfm) (see section 3.3.2)

**Case 1—Annual Emission Reduction (section 3.3.3)**

- ❑ Multiply initial emission reduction rate (scfm) by the time (minutes) the compressor is in standby and pressurized mode throughout a year
- ❑ The annual emission reduction value can be updated to reflect changes in rod packing sealing performance by obtaining additional measurements further into the life of the packing.

**Case 2—Initial Emission Reduction (section 3.3.4)**

- ❑ Note: This section covers the rod packing emission reduction only while later sections cover the other emission sources requiring measurement
- ❑ Plan and prepare for measurements
- ❑ Obtain or construct measurement apparatus (see Flow Tube SOP in Appendix A)
- ❑ Complete calibrations (Flow Tube and gas analyzer – see SOP for details)
- ❑ Conduct pre-test site visit to facilitate planning and collect preliminary Flow Tube measurements
- ❑ Plan to conduct at least 6 sets of Flow Tube measurements (3 controlled, 3 uncontrolled) on each doghouse vent, timed to capture a potential 24-hour diurnal cycle (see guidance and data in Section 3.2.1)
- ❑ Conduct measurements with static seal engaged (controlled) and engine in pressurized/standby mode
- ❑ Conduct measurements with static seal disengaged (uncontrolled), under the same operating condition as above, and immediately before or after controlled emissions measurements
- ❑ Validate data
- ❑ Examine data for trends or unexpected variability. Attempt to identify causes for outlying data. Screen data and/or repeat measurements as needed.

**Case 2--Additional Emission Measurements (section 3.3.5)**

- ❑ Plan and prepare for measurements
- ❑ Plan to make 3 sets of measurements at the same time of day as the doghouse vent measurements
- ❑ Identify Flow Tube access to additional components to be measured (i.e, blow down valve, pressure relief valve, unit valves, and miscellaneous components)
- ❑ Obtain blow down volume from station records
- ❑ Obtain or construct measurement apparatus including the Flow Tube (see Appendix A), rotameter, and accessories needed to attach Flow Tube to leak sources
- ❑ Complete calibrations (Flow Tube and gas analyzer – see SOP for details), note the need for a high flow calibration when using the Flow Tube to measure unit valve emissions
- ❑ Measure blow down valve leak rate – engine standby/pressurized
- ❑ Measure pressure relief valve leak rate – engine standby/pressurized
- ❑ Measure unit valve leak rates (combined) – engine standby/depressurized
- ❑ Measure miscellaneous fugitive leaks – engine standby/pressurized
- ❑ Validate data
- ❑ Examine data for trends or unexpected variability, attempt to identify causes for outlying data, screen data and/or repeat measurements as needed

**Case 2--Annual Emission Reduction (section 3.3.6)**

- ❑ Obtain time that unit is standby/pressurized in a year
- ❑ Determine the number of shutdowns that occurred in a year
- ❑ Calculate emissions reduction using formula in section 3.3.6

## 4.0 SIMPLIFIED GUIDELINE

This document includes two different levels of verification: the Verification Guideline (Section 3.0), and the Simplified Guideline (this section). The Simplified Guideline is a stream-lined alternative to the Verification Guideline. It does not rely on the collection of site-specific measurements data, and is simpler and less costly to use. However, results will contain greater uncertainty because the emission rate estimates used in the Simplified Guideline contain both measurement error and likely representativeness errors due to the use of industry average emission factors (i.e., actual site emissions may be significantly different). The measurement error in the emission factors is unknown, and representativeness uncertainty is site-specific and difficult to generalize. As such, the Simplified Guideline does not contain uncertainty estimating procedures.

The Simplified Guideline may be most appropriate for users conducting emission inventory, feasibility or similar assessments. It may also be used as a reasonableness check on the site-specific results obtained from the Verification Guideline. The discussions in Section 4.0 are abbreviated, and readers should understand the Verification Guideline in Section 3.0 before proceeding.

For the most part, the Simplified Guideline relies on the use of industry average emission factors. These emission factors have not been independently verified by the Center, but most are similar to emission rates measured by the Center at three separate transmission compressor stations in the United States. Where differences occur, they are identified here. The emission factors are described in the following section, after which the Simplified Guideline is presented for rod packing leak containment devices and rod packing static seal technologies.

### 4.1 AVERAGE COMPRESSOR EMISSION PROFILE

Table 4-1 presents industry average emission factors for reciprocating compressors used in the natural gas transmission sector. These values represent uncontrolled emissions of methane from the emission sources previously defined in this document. Several values for non-compressor related emission sources are also presented for comparison and perspective.

<b>Equipment Category</b>	<b>Emission Source Component</b>	<b>Typical Number Per Engine</b>	<b>Average Emission Factor Per Component</b>
Reciprocating Compressor	Rod Packing	3.3	1.0 scfm <sup>2</sup>
	Unit Isolation Valves	2 <sup>1</sup>	8.9 scfm
	Blow-Down Volume	1	26,000 scf/event
	Pressure Relief Valve	1	0.9 scfm
	Miscellaneous Components <sup>3</sup>	1	0.4 scfm
Other Equipment at Compressor Stations	Valves (not control valves)	673	0.0021 scfm
	Pipe Connection	3068	0.0004 scfm

1. This emission factor represents the combined leak from both valves.
2. A more recent report by Radian International (GRI 1997) suggests an average emission rate of 1.9. This study evaluated a larger population than the EPA 1996a study. This value may be used as an alternate if desired, or the average of the two values may be applied.
3. Includes the blow-down valve, other compressor-related valves, flanges, other connectors, pump seals, and sampling connections.
4. Represents blow-down volume for 3.3 compressors per engine (2000 Hp, 600 psi).

Most values presented in Table 4-1 are based on a major US study of methane emissions from the natural gas industry (EPA 1996a, EPA 1996b). The exception is the emission factor presented for the blow-down volume. Blow-down volume emissions were not individually specified in the national study referred to above, so more limited data collected by the Center were used. The value in Table 4-1 is based on four 2000 Hp engine/compressor units tested by the Center, and represents the total blow-down volume for 3.3 compressors on one engine/compressor system (operating pressure equals 600 psig).

Except as cited above, the emission factors in Table 4-1 were developed based on an industry emission characterization program that was jointly sponsored by the Gas Research Institute (GRI) and the U.S. Environmental Protection Agency's Office of Research and Development. In this study, emission measurements were conducted at six different compressor stations, each with multiple engine/compressor units. The objectives of the study were to quantify methane emissions from the natural gas industry in the US, so the industry's contribution to global methane emissions could be reliably determined. To prepare Table 4-1, annual average emission values were converted into short-term emission rates by dividing annual values by the number of minutes in a year and then applying the percentage of the year GRI estimates these components are pressurized and leaking (79.1 percent of the 1992 base year).

Initially, data were collected in the GRI/EPA study to determine if a given emission source was major. For each major category, an initial estimate of the number of sources to be sampled was calculated based on precision goals and the estimated standard deviation for the source category. In an attempt to obtain a representative sampling of companies and geographic locations, sites were selected at random, from a known list of facilities, such as GRI and American Gas Association member companies. Each company contacted was not required to participate, and a complete list of all sources in the US was not generally available; therefore the final set of selected companies was not truly random. Each company that participated in the program selected representative sites for sampling rather than unique facilities.

## 4.2 ROD PACKING LEAK CAPTURE DEVICES

In this section, a method is described for determining annual methane emission reductions for devices that capture and use rod packing leaks as engine fuel. The approach is straight forward, starting with the estimation of uncontrolled emissions over a time period of interest. This technology will generally be installed on each rod packing associated with an engine/compressor unit, and the average uncontrolled emission rate for each packing can be estimated using the emission factor presented in Table 4-1, and/or the alternate factor presented in Footnote 2 to that table. Total uncontrolled emissions for all rod packings on an engine should be summed, and if the number of packings is unknown, then the industry average of 3.3 rods per compressor engine may be used. The emission factor in Table 4-1 is generally representative of industry average values, and covers a range of packing types and ages. As such, uncontrolled emission can be considered to represent emissions immediately after installation through the first few years of operation.

The next step is to estimate the emissions reduced after installation of the technology. In this case, data are limited to 12 measurements conducted by the Center over a four week period on one technology (SRI 1999a). The average emission reduction measured was 70 percent of uncontrolled emissions, so multiplication of the

uncontrolled emission rate from Table 4-1 by 0.7 yields an estimate of the emissions reduced in scfm. Additional long-term data on emission reductions for this technology will become available soon, and will be included here as appropriate.

Compressor operating time also impacts the total annual emissions and emission reductions. Compressors that are under repair, depressurized and placed in standby or standby mode, or depressurized and placed out of service, do not liberate rod packing emissions. The time a compressor operates in these modes must be determined and subtracted from the total hours in the year. The result includes only operating times and times in pressurized standby mode. The technology collects gas in both modes, so multiplying these times, in minutes, by the emission reduction determined as described above, yields an estimate of the annual methane emission reductions for the control technology. Site-specific operational data should be obtained and used as described in Section 3.0, but if specific data are not available, average values can be used based on the population data provided in the national study described earlier (EPA 1996b).

- ◆ Percent of the year a compressor operates = 45.2%
- ◆ Percent of the year a compressor is standby = 54.8%
  - ◆ Standby Pressurized = 33.9%
  - ◆ Standby Depressurized = 20.9%

Based on these data, transmission compressors are pressurized and standby or operating 79.1 percent of the time. Since these are the two modes the technology reduces emissions under, multiplication of the emission reduction determined as described above (in scfm) by 0.791 times the total number of minutes in a year, yields an estimate of the annual methane emission reduction for the technology.

### 4.3 ROD PACKING STATIC SEALING DEVICES

#### 4.3.1 Determining Baseline Conditions

Static sealing technologies can reduce emissions during standby operations. For the two technologies verified by the Center, compressors are intended to remain pressurized during standby (after installation). Of course, the amount of methane reduced depends on the emission rates for the compressor packing; both before and after installation of the static seals. But, it can also depend on the shutdown procedures used, and the number and duration of shutdowns experienced. For example, a station that currently leaves compressors pressurized during standby will achieve reductions in rod packing leaks only. Alternatively, if a station currently blows-down compressors before standby (i.e., releases all pressure), it will change to a pressurized standby condition after installation. In this case, gas savings occur by eliminating blow-down emissions and unit isolation valve leaks. There is, however, a potential for increases in emissions at components now exposed to high pressure during standby.

For two of the most commonly used compressor shutdown procedures, Table 4-2 shows the relationship between compressor shutdown procedure and emissions. Depending on the shutdown procedure used before installation of the static seals, use of new static seals may be accompanied by a change to a pressurized compressor standby condition. The table indicates how compressor emissions may change as a result of this new condition, and in doing so, provides a template for the Simplified Guideline. This guideline allows the characterization of all emissions changes (i.e., those due to the installation of static seals, and those due to the possible adoption of a different shutdown procedure).

<b>Table 4-2. Common Shutdown Scenarios and Emissions</b>		
<b>Procedure or Emission Source</b>	<b>CASE 1</b>	<b>CASE 2</b>
<b>--Matrix of Shutdown Procedure Changes--</b>		
Current shutdown procedure	Pressurized shutdown with unit valves open or closed	Blow-down/100% vent to atmosphere
Procedure with new Static Seals	n/c	Pressurized shutdown
<b>--Matrix of Emissions Changes Due to Shutdown Procedure Changes--</b>		
Rod seals	Decrease	Little or no increase
Blow-down volume	n/c	Decrease
Unit valve seat (via open blow-down line)	n/c	Eliminated
Blow-down valve	n/c	Eliminated
Pressure relief valve	n/c	Increase
Misc. valves, fittings, flanges, stems, etc.	n/c	Increase

NOTES: n/c - no change/effectively no change

The guideline for static seals requires the determination of uncontrolled emissions for one of two shutdown scenarios. The guideline requires the selection of a scenario which best matches the facility of interest. All possible scenarios are not presented here, but two are used that collectively represent shutdown practices employed by about 95 percent of the transmission compressors in the US (EPA 1996b). Case 1 should be used if, prior to installation of static seals, the standby procedure used was to shutdown and maintain full pipeline pressure. Case 2 should be used if the compressor was originally depressurized and blown-down before standby. The following describes the Simplified Guideline for estimating methane emission reductions for each case.

#### 4.3.2 Case 1

For static seal technologies, the annual time in standby mode is needed to estimate annual emission reductions. Determination of this value is highly specific-site, and as described in Section 3.0, site-specific data should be obtained and used. If site-specific information is unavailable, values obtained from the national GRI/EPA study, and from two of the Center's verification tests, can be used. Based on data from the national study, transmission compressors are assumed to spend 54.8 percent of the year in standby mode. Assuming, based on the Center's experience, that 6 percent of this standby time is for routine repair and maintenance activities, 48.8 percent of the year is associated with actual standby mode operations.

In Case 1, emission reductions occur due to the action of the static sealing system. No other emission changes occur. To execute the Simplified Guideline for Case 1, multiply the annual number of minutes on standby (e.g., 48.8 percent of the year), by the emissions reduced after installation of the static seals. Few data are available for estimating static seal emission reductions, but one technology's reduction has been verified by the Center, and this single value is used here to support the Simplified Guideline (SRI 1999e). Specifically, the average

emission reduction measured after ten separate measurements was 96 percent, and as such, the uncontrolled emission factors in Table 4-1 should be multiplied by 0.96 to calculate the emissions reduced in scfm.

The user should be aware that, for some static seal technologies, emission reduction performance may be poor. As such, an effort should be made to verify packing emissions in the field after installation. Also, once additional long-term data on emission reductions for this technology become available, it will be included here.

### 4.3.3 Case 2

For Case 2 the situation is more complex. The standby mode has changed to a pressurized state and several other component emissions have changed as a result. The annual time in standby mode, and the annual number of shutdowns conducted, are used to estimate annual emission reductions. Again, these values are highly site-specific, but if this information is unavailable, approximate values obtained from the GRI/EPA study can be used. As done in Case 1, the user should assume that 48.8 percent of the year is associated with actual standby mode operations. The number of shutdown/blow-down events is more difficult to estimate, and the GRI/EPA study reports do not provide specific data. Limited data collected by the Center on four engines for the period from January 1999 to August 1999 were used to estimate an approximate annual number of shutdown/blow-down events. The value estimated, and recommended cautiously for use, is 28.

To execute the Simplified Guideline for Case 2, multiply the annual standby time (minutes) and number of shutdown/blow-down events, by the component-specific emission values obtained from Table 4-1, and the estimated rod seal emission reduction. A mathematical representation of this is shown below for Case 2 as are guidelines for the selection of component-specific emission factors. To estimate the packing emissions reduced after installation of the technology ( $Q_s$  below), the average emission reduction of 96 percent should be used from Case 1. Multiply the uncontrolled emission from Table 4-1 by 0.96 to yield the emissions reduced in scfm.

The user is cautioned to verify packing emissions in the field after installation, and be on the lookout for additional long-term data on emission reductions for this technology to be included here soon.

$$G2 = BDV * t_{bdv} + Q_{uv} * t - [Q_{prv} + Q_{bdv} + Q_{misc} + Q_s] * t$$

Where,

$G2$  = methane emissions reduction over the year of interest, scf

$BDV$  = blow-down volume, determined from Table 4-1, scf

$Q_{uv}$  = unit valve leak rate as determined in Table 4-1, scfm

$Q_{prv}$  = pressure relief valve leak rate as determined in Table 4-1, scfm

$Q_{bdv}$  = blow-down valve leak rate: 0.08 scfm based on Center measurements at two sites

$Q_{misc}$  = aggregate leak rate for miscellaneous components determined from Table 4-1, scfm

$Q_s$  = methane reduction: equal to uncontrolled emissions from Table 4-1, scfm

$t$  = standby time over the year of interest, minutes

$t_{bdv}$  = number of blow-down events occurring over the year of interest

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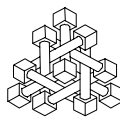


## Appendix A-1: Flow Tube Standard Operating Procedure (SOP)

### STANDARD OPERATING PROCEDURE FOR USING THE FLOW TUBE TO CONDUCT DOGHOUSE VENT MEASUREMENTS

#### Contents:

1. Instrument Descriptions
2. Pre-Test Setup and Calibration Procedures
3. Leak Rate Measurement Procedures



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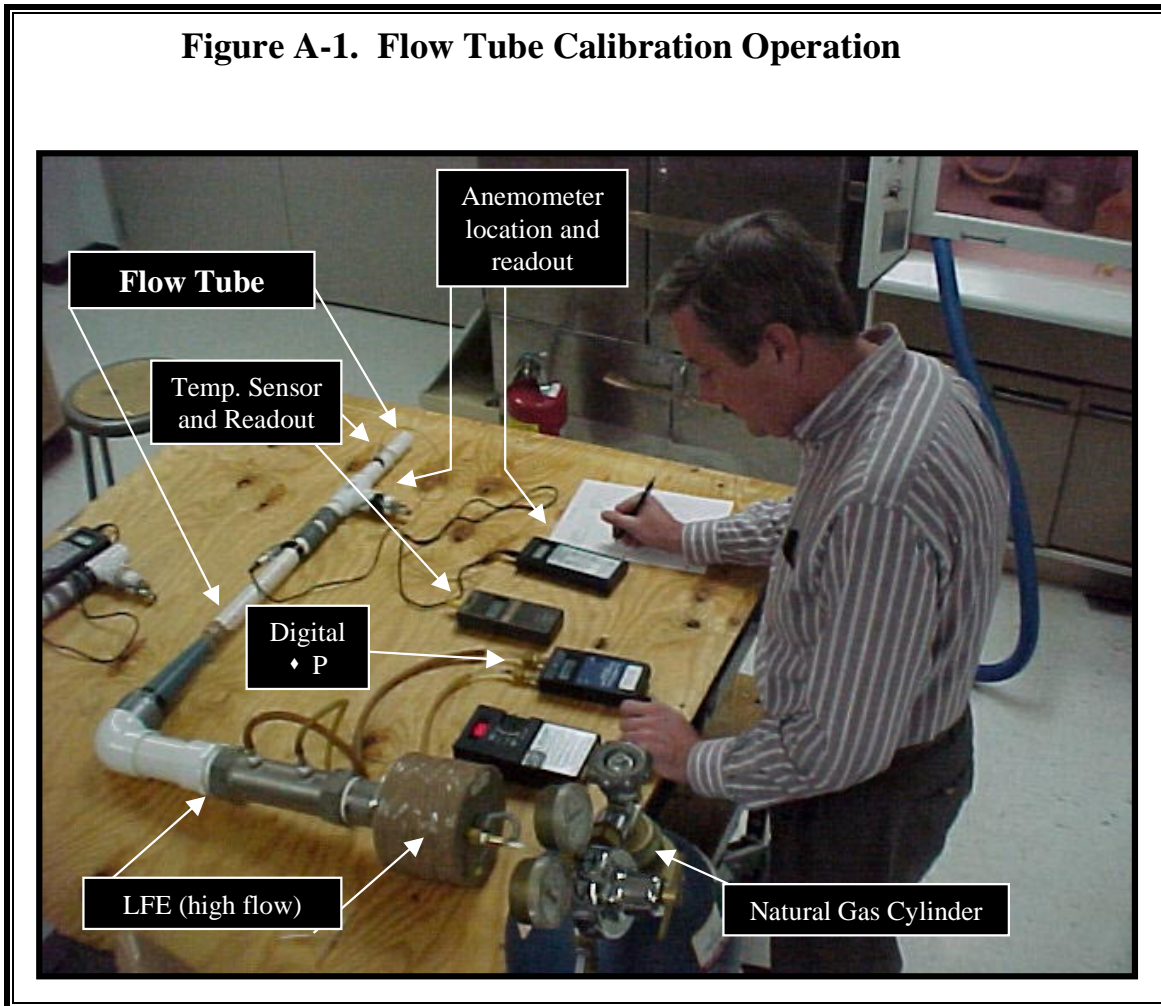
## **I. Instrument Descriptions**

### **Flow Tube**

The Flow Tube, shown in Figure A-1, consists of a vane anemometer housed in a flow straightening PVC tube with an inside diameter of about 1-inch (7/8 inch ID) and an overall length of approximately 30 inches. An anemometer is placed in the tube (Omega Model HH-31A) to measure gas velocity in the range of 60 to 6,800 feet per minute (fpm).

Measured gas velocities are converted to volumetric flow rates by calibrating the anemometer against a laminar flow element (LFE), made by Merriam Company. The Flow Tube calibration is a direct comparison with the laminar flow element, which is traceable to NIST. The calibration is performed prior to each measurement trip at the Center's Research Triangle Park, NC laboratory. It consists of no fewer than five points spanning the flow rate of interest (0.15 scfm to 4 scfm methane for doghouse vents; up to 20 scfm for other sources). A properly calibrated flow tube will provide accurate and reliable readings above flows of about 0.3 scfm of natural gas. Accuracy values ranging from about 0.5 percent to less than 3 percent of actual readings should be anticipated for the Flow Tube based on the Center's experience. Similar accuracy values have been observed at flows as high as about 10 scfm.

As a practical matter, the Flow Tube has a lower detection limit of about 0.14 scfm of natural gas, based on the Center's experience. If during low flow testing it can be visually confirmed that the vane within the Flow Tube is not moving during testing, then the emissions should be reported as zero. If the vane is moving during low flow testing, values below 0.14 scfm natural gas should be approximated to be 0.07 scfm natural gas (corresponds to one-half of the published LDL velocity for the anemometer).

**Figure A-1. Flow Tube Calibration Operation**

### Hydrocarbon Analyzer

A Bascom-Turner CGI-201 hydrocarbon analyzer is used to determine hydrocarbon concentrations. It is capable of detecting 4 to 100 percent total hydrocarbon concentration, with an accuracy of  $\pm 2$  percent of reading. The CGI-201 is calibrated prior to each measurement trip. Calibrations are performed in the laboratory using certified methane standards at 2.5, 25, 50, 75, and 100 percent methane. Calibrations are performed using the calibration apparatus provided by the manufacturer (Part numbers MC-105 and PCA-001), and by following the manufacturer's calibration procedures.

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## **II. PRE-TEST SETUP AND CHECK-OUT PROCEDURES**

Prior to each field measurement trip, perform laboratory calibrations on the Flow Tube and the hydrocarbon analyzer as described below. It is recommended that calibrations be performed upon return from the field, to ensure instrument damage did not occur in transport.

### **Flow Tube Calibration Procedures**

This procedure is specific to the use of a Laminar Flow Element. Other reliable calibration standards are available, and procedures may vary from those presented below if they are used.

Materials required: Flow Tube, Laminar Flow Element or LFE, Omega HH-25 KC temperature transmitter and thermocouple, digital manometer, miscellaneous fittings and hardware.

- Assemble the Flow Tube in-line with the LFE so that the calibration gas can be regulated to flow through both instruments.
- Connect a digital manometer to the LFE. Zero the manometer when no flow is occurring. When gas is allowed to flow through the LFE, the manometer will display a pressure drop across the instrument.
- Connect the temperature transmitter to the in-line thermocouple.
- Record the barometric pressure and the ambient temperature on the log sheet.
- Open the flow regulator on a gas cylinder of methane (about 95 percent) or natural gas, and initiate gas flow into the Flow Tube and the LFE.
- Observe the point where the vane anemometer begins to turn, allowing the readings to stabilize (typically 15 to 20 seconds). Push the 16-sec average button on the vane anemometer transmitter. Record the velocity displayed and the pressure drop shown on the manometer in the log sheet. Record the exit gas temperature.
- Increase the gas flow until pressure drop increases are at intervals of 2.0, 4.0, 5.0, 6.0, and 8.0 inches of water. Record the 16 second average velocity and the temperature of the gas at each pressure interval. A minimum 5 point calibration will be conducted, and this result will be useful for methane gas flows ranging from about 0.5 to 3 scfm. If higher flows are anticipated, a larger LFE should be obtained and the procedure above repeated.
- Repeat the above procedures a second time to achieve a duplicate calibration result (i.e., match the LFE pressure drops from the previous runs). These data will be used to determine precision.
- Determine the slope and y-intercept of the equation that relates gas flows as a function of velocity readings (see analytical procedures below). A straight line relationship has been observed in calibrations conducted by the Center up to flows of about 10 scfm of natural gas. Typical calibration charts are shown in Figure A-1 and A-2. Calculate the accuracy of these measurements, using the calculations presented later in this SOP.

**FLOW TUBE CALIBRATION LOG FORM**

Anemometer Make/Model: \_\_\_\_\_  
Anemometer Serial Number: \_\_\_\_\_  
LFE ID: \_\_\_\_\_  
LFE Calibration Value: Delta P (in H2) = \_\_\_\_\_  
ACFM air = \_\_\_\_\_

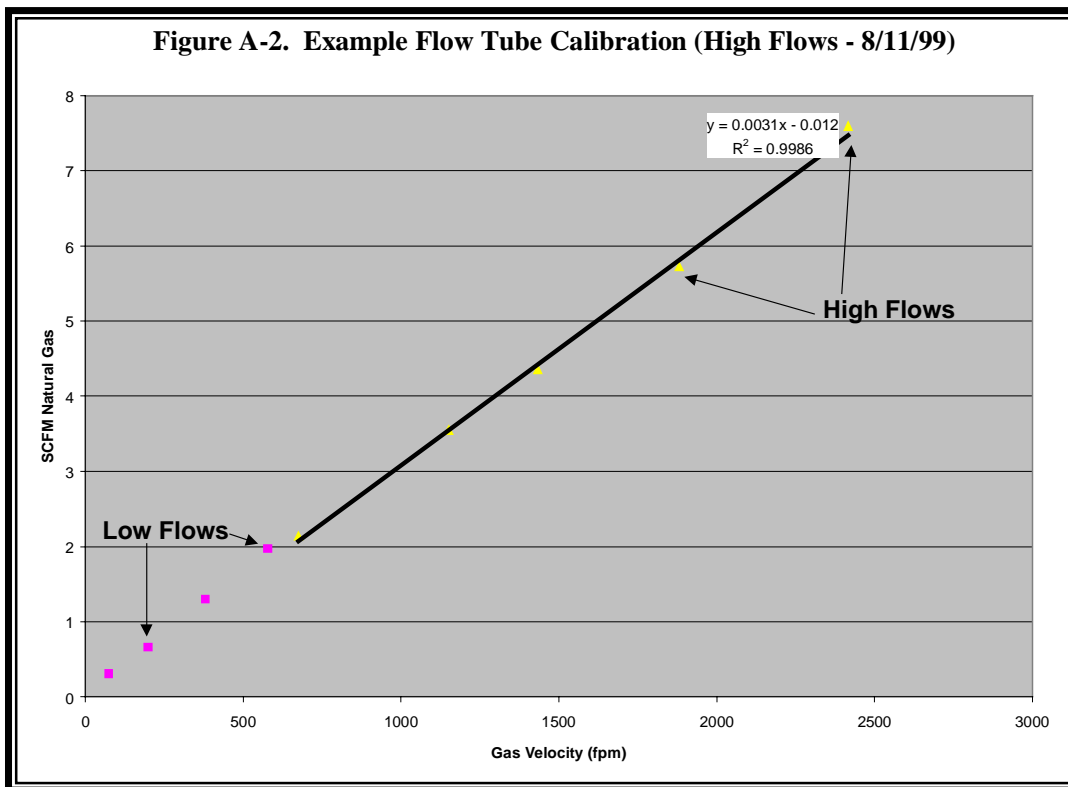
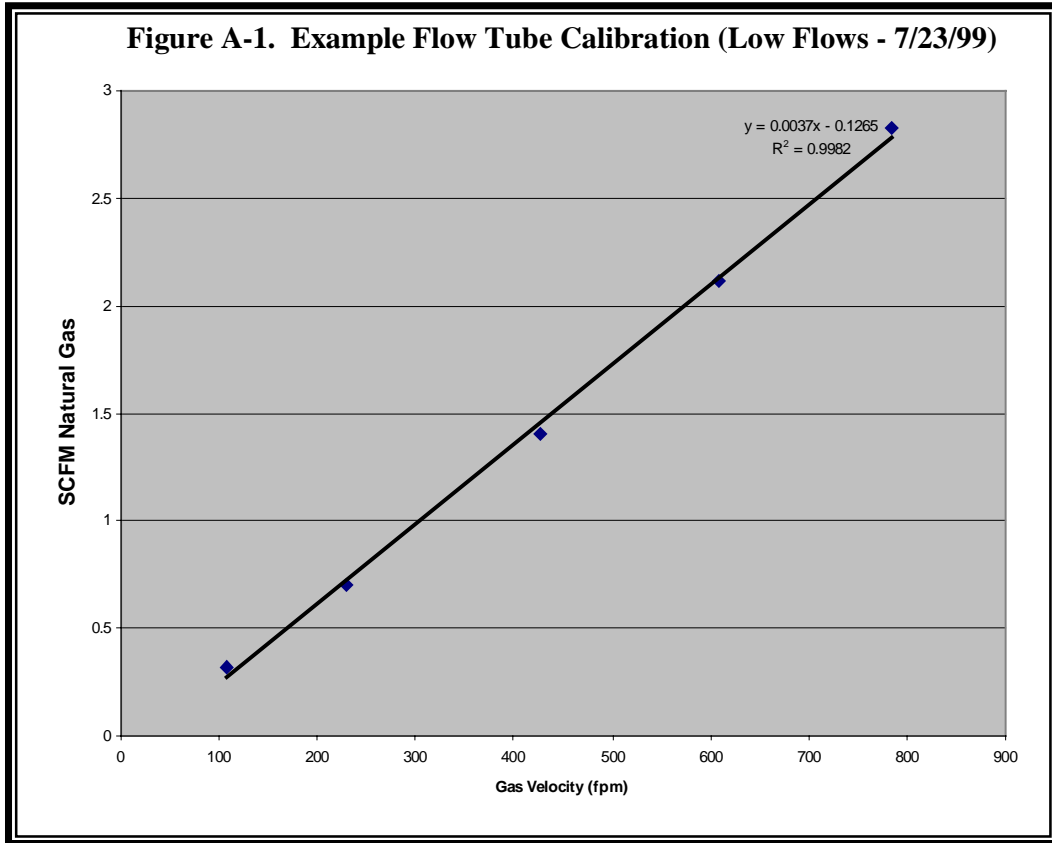
Barometric Pressure: \_\_\_\_\_  
Ambient Temp (K): \_\_\_\_\_  
Calibration Gas: \_\_\_\_\_  
Operator: \_\_\_\_\_  
Date: \_\_\_\_\_

Run 1

Run 2

Anemometer Velocity (fpm)	LFE Delta P (in. H <sub>2</sub> O)	Tube Temp. (K)	Anemometer Velocity (fpm)	LFE Delta P (in. H <sub>2</sub> O)	Tube Temp. (K)





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## CALCULATION OF CALIBRATION FLOWS AND FLOW TUBE ACCURACY

- Using the following equations, determine the flow of air, and then of natural gas (nat gas) at standard conditions for each set of LFE pressure drop readings measured during a calibration.

$$\text{LFE ACFM}_{\text{air}} = [\text{LFE Delta P}] [\text{LFE Cal. ACFM}_{\text{air}} / \text{LFE Cal. Delta P}]$$

Where:

LFE Delta P = pressure drop measured by the digital manometer for the LFE

LFE Cal. ACFM<sub>air</sub> = obtained from calibration certificate of NIST traceable LFE

LFE Cal. Delta P = obtained from calibration certificate of NIST traceable LFE, in H<sub>2</sub>O

$$\text{LFE ACFM}_{\text{nat gas}} = [\text{ACFM}_{\text{air}}] [u_{\text{nat gas}} / u_{\text{air}}]$$

Where:

$u_{\text{nat gas}}$  = viscosity of methane (the major constituent in natural gas) at 20 °C (110 centipoise based on Perry's Chemical Engineer's Handbook)

$u_{\text{air}}$  = viscosity of air at 20 °C (185 centipoise based on Perry's Chemical Engineer's Handbook)

$$\text{LFE SCFM}_{\text{nat gas}} = [\text{ACFM}_{\text{nat gas}}] [P_a / 14.7] [298 / \text{Tube T}]$$

Where:

$P_a$  = atmospheric pressure, psia

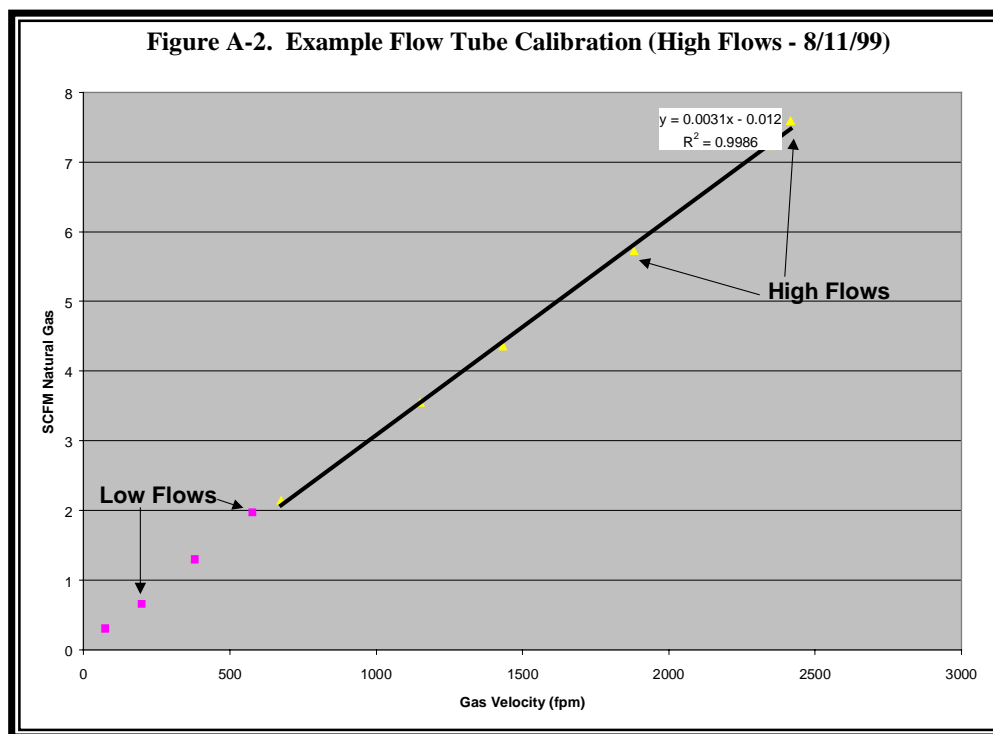
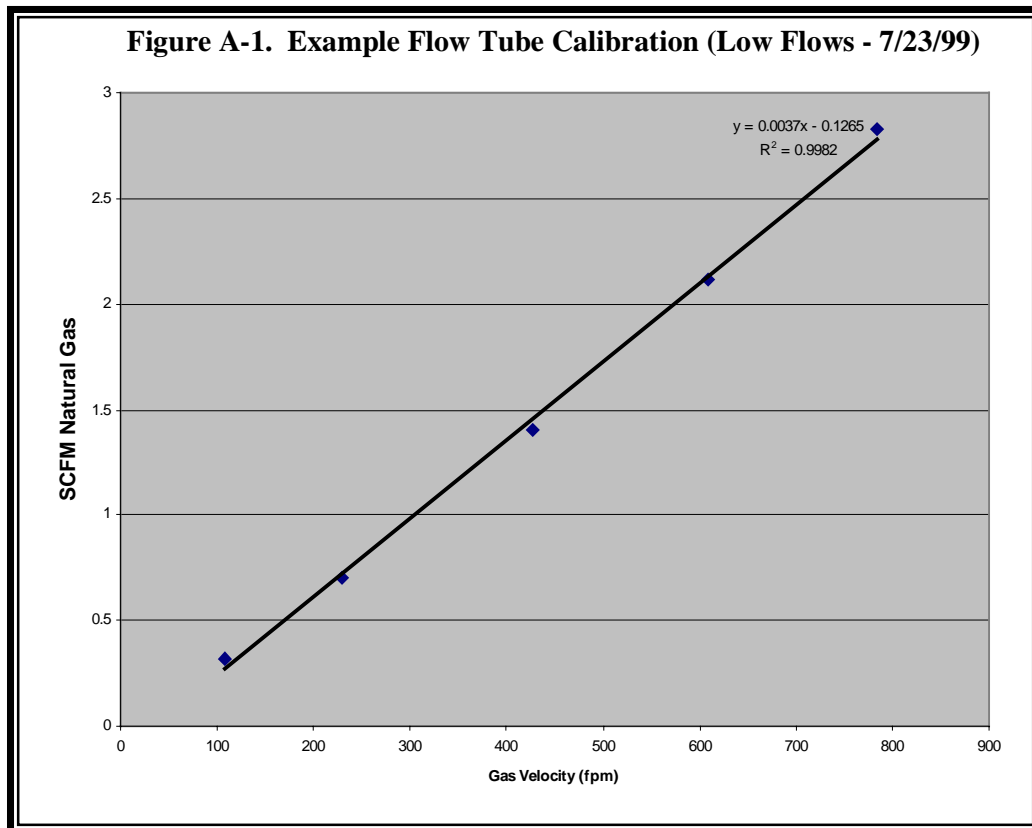
Tube T = gas exit temperature, K

- Generate a linear plot through the calibration points similar to those shown in Figures A-1 and A-2. Plot measured anemometer velocity (**fpm**) on the x-axis and the measured flow of natural gas (**LFE SCFM<sub>nat gas</sub>**) on the y-axis. Perform a least-squares linear regression to obtain the slope (m) and the y-intercept (b). The r-squared values for this equation should be 0.95 or better.
- The following linear equation describes the natural gas flows at the observed anemometer velocity readings. Flow Tube accuracy is determined based on this value and the measured value as shown below.

$$\text{Flow Tube SCFM}_{\text{nat gas}} = m [\text{Anemometer Velocity}] + b$$

$$\text{Accuracy (\%)} = [\text{Flow Tube SCFM}_{\text{nat gas}} - \text{LFE SCFM}_{\text{nat gas}}] / \text{LFE SCFM}_{\text{nat gas}} * 100$$

- Convert flows of natural gas measured in the field into flows of methane using gas compositional data routinely collected by the pipeline operators.





## Hydrocarbon Analyzer Calibration Procedures

These methane meters actually have two sensors including one for low-range methane concentrations (up to 2.5 percent) and another for high-range (up to 100 percent). The two sensors are calibrated separately using clean air (compressed zero air) as a zero reference and five levels of certified methane reference gas including approximately 2.5, 25, 50, 75, and 100 percent methane in balance nitrogen.

Gases are introduced to the meter using a pressure controlled regulator and teflon tube. The tubing incorporates a “T” so that excess calibration gas is dumped to the atmosphere to prevent over pressurizing the meter. The calibration procedure is to zero the sensors first using clean air and adjust (using potentiometer) if necessary. Next, the 2.5 percent reference is introduced and the meter self adjusts its low range sensor response to that gas. The 100 percent reference is next introduced to span the high range sensor. Again, adjustments are made using a potentiometer if necessary to obtain the correct response. Finally, the remaining reference gases are introduced sequentially without making adjustments to the meter to verify linearity.

If proper responses are unobtainable using the potentiometer or the responses are not linear, then either the sensor is replaced or the meter is sent to the manufacturer for service or repair. Calibrations are conducted each time prior to being used in the field.

In the field, the meters are used to determine methane concentrations. Prior to use, the instrument is turned on in the “zero instrument” mode, exposed to clean outdoor air, and allowed to self zero the sensors. The meter is then turned to “read gas” mode and allowed to read the outdoor air to verify the zero reading. The probe tip is manually plugged until the meter displays “bloc” to ensure that the probe is leak free. The meter is then ready for use. Methane concentrations are determined by inserting the probe tip into vent pipes where appropriate, or near suspected leak locations (e.g., flanges, valves, fittings).

**HYDROCARBON ANALYZER CALIBRATION LOG FORM**

Date of Calibration: \_\_\_\_\_  
Operator: \_\_\_\_\_

Barometric Pressure: \_\_\_\_\_  
Ambient Temp: \_\_\_\_\_

Make/Model: \_\_\_\_\_  
Serial Number: \_\_\_\_\_  
Calibration Gas: \_\_\_\_\_

<u>Reference Concentration</u>	<u>Sensor Response Before Adjustments</u>	<u>Sensor Response After Adjustments</u>
_____	_____	_____
_____	_____	_____
_____	_____	_____
_____	_____	_____
_____	_____	_____
_____	_____	_____
_____	_____	_____
_____	_____	_____



### **III. Leak Rate Measurement Field Procedures** **(Compressor Doghouse Vents)**

1. Follow manufacturer's procedures for the hydrocarbon analyzer (auto-zero away from the engine room).
2. Record the following information on the log sheet:

Engine ID	Date
Flow Tube ID	Ambient Temp
Flow Tube Calibration Date	Barometric Pressure
Time	
Rod Number	
Engine Operating Pressure	
3. Disconnect doghouse vent union. Directly attach hydrocarbon analyzer inlet to the open doghouse vent using a leak free connection. Check for leaks by soap screening all connections with a one percent diluted soap solution (place about ¼ cup of dish soap into a spray bottle, then fill with water). Tighten or repair any leaking fittings before proceeding. Plub all drains.
4. Allow a minimum of 30 minutes to purge the doghouse of air, and ensure the exiting gas has a composition which is close to pure natural gas (i.e., between 92 to 98 percent total hydrocarbons). Measure and record hydrocarbon concentration after the purge period is complete. If gas composition is too low, continue the purge and record hydrocarbon readings at five minute intervals. Use extreme caution if gas concentration is in the explosive range (5 to 15 percent of methane in air). If pure natural gas is not measured at the end of the purge period, this is evidence that air is leaking into the doghouse. Locate and repair any leaks before proceeding.
5. Remove the hydrocarbon analyzer and insert temperature probe into the doghouse vent. Measure and record the gas temperature after stable readings are achieved.
6. Remove the temperature probe and attach the Flow Tube to open doghouse vent with a leak tight connection. Again, soap screen all connections.
7. Program the anemometer display to provide 16 sec average velocity readings following the manufacture's instructions.
8. Record 16 sec velocity readings, until a minimum of ten readings are recorded. Continue collecting and recording velocity readings until three adjacent readings are within 5 FPM of each other.
9. Remove the Flow Tube and repeat the procedure if results are highly variable, or trend upward or downward. (consult Section 3.0 for example data). Continue repeating until a reasonably steady state flow rate data set is collected (i.e., the standard deviation from a series of measurements, divided by the average emission rate, is about 7% or less).
10. Use Flow Tube calibration data collected prior to the test to convert these velocity readings directly into natural gas flow rates (scfm). Plot the data, and if normally distributed, determine the average natural gas emission rate.
11. Use natural gas compositional data routinely collected by the pipeline operator, to convert natural gas values determined in step 10 above into methane emission values. Obtain the pipeline operators calibration data used to determine gas composition.
12. Insert the hydrocarbon analyzer, and measure and record the final hydrocarbon concentration.
13. Repeat above procedures for remaining doghouse vents.

**DOGHOUSE VENT MEASUREMENT USING FLOW TUBE  
LOG FORM**

Engine ID: _____	Date: _____	
Flow Tube ID: _____	Ambient Temp: _____	
Flow Tube Calibration Date: _____	Barometric Pressure: _____	
	Operator: _____	
Time: _____		
Rod Number: _____		
Compressor Operating Pressure: _____		
Initial Total Hydrocarbons (%): _____		
Gas Temp (°C): _____		
Leak Rates (16 Sec Avg FPM):		
_____	_____	_____
_____	_____	_____
_____	_____	_____
_____	_____	_____
_____	_____	_____
Final Total Hydrocarbons (%): _____		

