Interstate Natural Gas Association of America

MEMORANDUM

Date: My 22, 2006
To: RGGI Staff Working Group
FR: Lisa S, Beal, Director, Environment & Construction Policy
RE: RGGI Draft model Rule

INGAA is a non-profit trade association representing virtually all interstate natural gas transmission pipeline companies operating in the United States and interprovincial pipelines operating in Canada, as well as natural gas companies in Mexico and Europe. INGAA's U.S. members operate over 200,000 miles of pipeline and related facilities and account for over 90 percent of all natural gas transported and sold in interstate commerce.

INGAA has worked extensively with stakeholders throughout the RGGI process and appreciates this opportunity to comment on the draft model rule. The RGGI model rule could potentially lay the groundwork for future regional, state and possibly federal GHG programs so it is important that the program be structured and implemented as efficiently as possible.

The INGAA comments will focus on offsets and in particular, natural gas transmission projects. INGAA congratulates the Governors for including natural gas projects as potential offsets as ensuring a broad and sufficient supply of offsets is critical for the RGGI program to achieve its goals in a cost-effective manner. While clear rules and processes are needed, we caution against adopting overly restrictive eligibility requirements such as financial additionality.

INGAA's key points are as follows:

1. The natural gas transmission offset program should be designed as a straightforward and efficient process that does not restrict participation and avoids overly complex procedural requirements such as financial additionality
2. The model rule should consider the use of performance measures to determine additionality which would avoid cumbersome and time-consuming case-by-case project reviews.
3. The offset program should only consider regulatory additionality. However, regulatory additionality should not have retroactive applicability after an investment has been made.
4. Offsets within the natural gas transmission industry should not be limited to methane reductions. Other GHG reductions, such as CO2 releases from gas processing, offer potential offset creation opportunities.
5. There is a need to develop a standardized protocol for quantifying emissions for the purposes of offsets. INGAA welcomes the opportunity to work with RGGI and other stakeholders to create a credible, efficient, simple protocol for natural gas transmission and distribution emission offsets and urges RGGI to incorporate INGAA's 2005 guidelines for estimating emissions from natural gas transmission and storage.

If you have any question. Please feel free to contact me at (202) 216-5935 or lbeal@ingaa.org.

Lisa S Beal

Lisa S. Beal
Director, Environment & Construction Policy

1.0 Introduction

INGAA offers these comments to the Regional Greenhouse Gas Initiative (RGGI) in its development of the RGGI model rule. RGGI stands to create a model rule that may be replicated by other regulating entities at the local, state and possibly federal level. Our comments will focus on the offset provisions. It is imperative that application of the rule to offsets generated by the natural gas transmission industry is based on standardized principles and practices that incentivize CO2 Equivalent (CO2-e) reductions in the industry, are cost effective for all parties, and create a system that can be accepted by other regulating entities. Rules should be based on uniform performance measures rather than more cumbersome and costly case-by-case analysis. INGAA advocates that establishment of clear rules and processes for the creation of offsets is critical in order to provide certainty to investors that fungible offsets will result from project investments, and therefore to incentivize offset project development. The purpose of this paper is to articulate the natural gas transmission industry concerns and proposals regarding GHG offsets.

2.0 Natural Gas Transmission Offset Opportunities

Offsets are a key component of any GHG program since many GHG sources cannot be reached easily through a conventional cap and trade program. The design of offset programs in some regulatory schemes has been bogged down due to overly complex procedural requirements or over-zealous theoretical considerations (e.g., financial additionality) that have little or no bearing on companies selecting the most appropriate emission reduction or offset strategy. INGAA supports straightforward and standardized offset creation procedures with appropriate safeguards.

In general projects or performance based standards should follow the principles laid out in the WBCSD/WRI GHG Project Protocol and ISO Part 3 guidelines.

To generate GHG offsets, the project should be:

1. Real - A discrete reduction of actual greenhouse gas emissions resulting from specific and identifiable actions.
2. Quantified - Calculated using real data and a transparent and replicable methodology.
3. Verified - A third party must authenticate the action and calculations of the Seller and attest to the validity and quantity of reductions.
4. Surplus - Reductions must be excess of any emissions reductions that may be required of the source by existing regulations existing at the time.
5. Unencumbered - Seller must have clear ownership of the emission reductions.

In essence, the offset programs should only consider regulatory additionality, and not stifle implementation and harvesting of extensive, low-cost offsets. Also, no limit should be placed on the use of verifiable offsets since many will be low-cost, effective reductions that can serve to jump-start the allowance trading markets and provide incentives to develop other emission reduction technologies. These offsets should not be subtracted from the overall cap, since they are not part of the baseline calculation used to establish a cap.

RGGI model rules should be flexible enough to consider a performance standard approach to additionality. Under this approach, any project activity that exceeds the performance standards will result in additional offsets. The obvious advantage is that the performance standard based additionality avoids cumbersome and time-consuming case by case project reviews. In addition it provides a consistent and level playing standard to avoid individual baseline scenarios or competitive issues within RGGI states. RGGI should work with appropriate companies and/or trade associations representing the potential "offset" generation sector to address the temporal, spatial and stringency issues associated with development of the appropriate performance standards. It should be noted that several RGGI states, such as New Jersey have experience in development of such standards.

Regulatory additionality should not have retroactive applicability after an investment is made. In order to provide needed investment certainty and ensure access to financing, investments that met a regulatory additional test when project financing is obtained should remain eligible for at least a ten year period, even if a law or rule is changed to make an approved project ineligible going forward. The project sponsor's allowances should not be truncated to receipt of allowances only for the offset reductions that occurred before the law or rule change. After the initial ten year period, the project applicant could re-apply for access to allowances, and project eligibility could be re-evaluated at that point; the applicant should have the opportunity to update or adapt the project at the point of applying for renewal.

Retroactive regulatory additionality would inject much uncertainty into the value of offset projects; so much so, in fact, that it may be difficult to get the investment community to buy into these concepts to get any project funded. The RGGI Staff Working Group should consult with the investment community on how this restriction of offset projects will affect their viability in the marketplace.

The current RGGI memorandum of understanding (MOU) only recognizes those offsets within the natural gas transmission industry created by the reduction methane emissions from natural gas transmission and distribution. INGAA advocates that RGGI consider similarly meritous other GHG reductions available from natural gas transmission and distribution. High potential reductions are available from efficiency improvement projects that minimize the consumption of natural gas and therefore emissions or reduce CO2 releases from gas processing. Examples of such reduction opportunities *that are additional to methane emission reductions include,* but are not limited to:

- Upgrading to high-efficiency compressors
- Using turbines at compressor stations in lieu of reciprocating engines
- Replacing turbine gas starts
- Installing pneumatic(air) or electric starters

To achieve the emission reductions goals that RGGI aspires to attain, INGAA advocates that RGGI not limit offsets to methane emission reductions alone, but rather consider similar CO2-e emission reductions that can be achieved by the natural gas industry as offsets.

3.0 Industry Benchmarks

Standardized protocols are required to facilitate *cost effective* certification of natural gas transmission offsets in the RGGI program. To this extent the GHG protocol (Part 2) and the ISO Part 3 provides general guidelines related to project level quantification and accounting. There are several established protocols for inventorying CO2-equivalent (CO2-e) emissions from natural gas transmission, including tools for calculating combustion emissions, and fugitive and direct methane emissions. These protocols are also useful for calculating CO2, CH4, and other GHG emission *reductions* associated with vented gas or combustion. Project-specific protocols to quantify CO2 captured from vent gas are also in use. While existing protocols can be used to quantify fugitive and vented emissions, the referenced emissions factors are not granular enough to calculate fugitive or vented emission *reductions* when the project involves “in-kind” system upgrades. INGAA’s recommendations to address this challenge are presented below.

3.1 Emission Quantification. Existing protocols include the protocol published by the Gas Research Institute (now Gas Technology Institute) and EPA in 1996[1], the American Petroleum Institute (API) Protocol[2]published in 2004, and the INGAA September 2005 estimation guidelines[3] which have been shared with RGGI and CCAR. The API and INGAA emission calculation guidelines draw their emissions quantification approaches for fugitive and vented methane emissions predominantly from the GRI/EPA body of work. This emissions quantification approach is to multiply an activity factor (such as number of components or length of pipe) by an emission factor. While the GRI/EPA emission factors stand as the most robust data currently available, INGAA is working with the Federal EPA and other segments of the oil and gas industry to review and update emission factors as needed. INGAA would welcome the opportunity to share our analysis of industry emission factors with RGGI.

INGAA recognizes that use of a standardized protocol will reduce implementation costs for participating companies, verifiers, and RGGI administrators. We welcome the opportunity to work with RGGI and other stakeholders to create a credible, efficient, simple protocol for natural gas transmission and distribution emission offsets. We recommend that the existing INGAA guidelines be used to inform the standard protocol for calculating CO2-e emission reductions from natural gas transmission emission reduction projects. However, neither this nor any other existing standard can be used to quantify emission reductions associated with system upgrades related to pipe or component replacement with newer condition, same material components or pipe. Specifically the existing quantification protocols for fugitive or vented emissions rely on emission factors that vary by component type and material, but not by age, manufacturer or company. Therefore if a system is upgraded by replacing worn components with new, in-kind components, the same emission factor applies and no reduction in emissions would be shown in a calculation.

3.2 Project Baselines: Determining the reference case or baseline for a project is key for demonstrating environmental improvements and quantifying the emission offsets achieved. There are several practices for establishing a baseline. Such baselines may be project-specific or based on more general performance standards, aka benchmarks. Per the WRI/WBCSD GHG Protocol for Project Accounting, project specific baselines may be an assumption of continuation of current activities or implementation of an alternative project to achieve the same end service, or implementation of the same technologies/practices used in the project activity. INGAA advocates that assuming a continuation of current activities with the same type of end service is the most efficient and accurate method for establishing project baselines. However, given the current obstacles to efficient estimation of in-kind upgrade fugitive or vented emissions improvements, we suggest that benchmark standards (performance standard baseline emissions) be established for most common in-kind replacement projects. These benchmarks will obviate the need for project proponents to perform costly and time consuming direct measurements to estimate baseline conditions and for RGGI to engage technical expertise to perform time-consuming review of each project-specific baseline scenario. Therefore INGAA recommends that project baselines be based on an assumption of the continuation of current

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[1] 1Gas Research Institute (GRI) and US Environmental Protection Agency (EPA). *Methane Emissions from the Natural Gas Industry*, Volumes 1 through 13, GRI-94/0257 and EPA-600/R-96-080, June 1996. www.gastechnology.org

[2] American Petroleum Institute, *Compendium of Greenhouse Gas Methodologies for the Oil and Gas Industry*, February 2004.

[3] Interstate Natural Gas Association of America, *Greenhouse Gas Emission Estimation Guidelines for Natural Gas Transmission and Storage, Volume 1 – GHG Emission Estimation Methodologies and Procedures (GHG Guidelines),September 2005. (see Attachment A).*

activities except in cases of in-kind system upgrades in which case the baseline will be based on a benchmark emission rate

4.0 Eligibility and Additionality

Additionality is the sense that a GHG project “would lead to reductions in emissions that are additional to any that would occur in the absence of the project activity". INGAA is concerned that overly strict additionality criteria will disincentivize project activity. Specific concerns and recommendations follow.

4.1 Eligibility. INGAA supports the concept that Performance Standards (a.k.a. Business as Usual or BaU Standards) could be established for various projects. Anything above those standards would then be eligible. RGGI could consider development of “offset standards” for various components encompassing best practice standards. The following list is not comprehensive, but derives itself from the highly successful EPA Gas STAR program.

Current Standard	**Offset Standard**
Replace gas turbine starters – turbine and gas engine application	Install electric or compressed air powered starters
For reciprocating compressors – vent compressor piping after shutdown	Install gas recovery system
Replace comp. cylinder unloaders	Install efficiency no bleed unloaders with multiple seals on shaft
Use of standard flat face reciprocating compressors packing	Install low emissions packing
For reciprocating engines operating w/o A/F ratio controller	Install A/F controller that is mapped to minimize fuel burned
Vent or blow down line to weld connection for new customer	Eliminate vented emissions by utilizing a hot tap[4] for in-service connections
Vent or blow down line to cut out section of pipeline due to damage	Utilize pump down to lower gas line pressure before maintenance
Vent or blow down line to cut out section of pipeline due to damage	For “smaller” exterior pipeline damage, utilize composite wraps thus eliminating need to vent any gas
Use of gas assisted glycol pumps	Replace with electric or instrument air driven

We would propose that RGGI would maintain a public process to evolve a list like this as common practices change. INGAA further asserts that projects may, but should not be required to generate reductions for more than one year.

[4] A connection made to a (live) pipeline while the line is under pressure or in service. Special procedures are required to open the pipe without leaking any gas.

4.2 Regulatory Additionality. While regulatory additionality, also termed "surplus" precludes crediting of emission reductions that are achieved as a direct consequence of meeting a regulatory requirement, it should not preclude emission reductions achieved through voluntary actions. Emission reductions achieved as a direct consequence of voluntary efforts or meeting voluntary commitments are considered surplus and should be allowed as offsets. Such voluntary efforts may include voluntary partnerships with local, state or federal government, voluntary registries or exchanges, commitments to shareholders and other stakeholders, commitments to industry associations, other externally or internally established reduction goals or voluntary reduction actions.

INGAA supports the requirement that offsets should demonstrate regulatory additionality to the extent that GHG reductions are specifically required by a federal, state or local rule. Non-GHG regulatory requirements (eg NOx reduction) that have ancillary benefits of GHG reduction should not be precluded by additionality rules.

4.3 Financial/Investment Additionality. INGAA is strongly opposed to the inclusion of financial or investment additionality as criteria for offsets as the inevitable unintended consequences of this ill-defined concept will result in disincentives for the development of offset projects. Financial additionality in this context refers to whether project investment would have taken place in the absence of the credits garnered by the project through RGGI, or at least that the project is economically less attractive than other alternatives without the credits. We are opposed to any proposal that would require that projects demonstrate such financial additionality in order to qualify as offsets. We feel that there is no simple, fair and effective mechanism for evaluating financial additionality.

Consider the Kyoto Protocol's Clean Development Mechanism (CDM) as an example of the limitations of attempting to impose financial additionality criteria. CDM additionality requirements, such as the requirement to "Determine whether the proposed project activity is economically or financially less attractive than other alternatives without the revenue from the sale of certified emission reductions (CERs)" is overly restrictive and burdensome to implement. Meeting these requirements imposes substantial transaction costs on project participants, and substantial administrative costs on the CDM administering entity, the CDM Executive Board. The International Emissions Trading Association (IETA) reflects that the many complications of the CDM rules are stifling project proposals, noting that: the "*current approach, which emphasizes rigor at the expense of pragmatism, stifles projects with good environmental and development benefits from being implemented. This occurs either because projects do not make it through the lengthy process or because developers are discouraged by the CDM's overly complex and unpredictable procedures."*[5] In response to a call from the CDM Executive Board for recommendations, several commenters, including the Government of Canada and the World Bank suggested that efficiency could be improved and transaction costs reduced if the CDM created a list of eligible project types instead of applying detailed additionality criteria.[6] Similarly, use of the Performance Standard approach we have described in 4.1 will result in clear environmental additionality, while avoiding the costs and complications of financial additionality rules.

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5 IETA, *Greenhouse Gas Market 2005, The rubber hits the road*, 2006.

6 See http://cdm.unfccc.int/public_inputs/meth_add_tool/index.html for both Government of Canada and World Bank Submissions on Additionality to the Executive Board of the Clean Development Mechanism, March 2006.

5.0 Other Key Recommendations

Other key considerations for the final RGGI Model Rule include considerations for geography-based incentives for offsets, verification, and registration and trading of emission offsets.

5.1 Verification. INGAA recommends that RGGI establish a single, cost effective verification protocol that includes a verification guideline and generic checklists, as well as a template for verification reports. This verification protocol will allow third party verifiers to work in a consistent manner, ensuring project developers fair and equal treatment. INGAA recommends that offsets be certified based on an annual estimate of reductions achieved. Certification of offsets for emission reductions should be determined by verification of emission reductions achieved against baseline within the project boundaries per an established monitoring and verification protocol. Monitoring and verification protocols should be definitive enough to certify emission reductions achieved over the term of a project's life.

5.2 Assignment of Offset Value. Complying with the RGGI Memorandum of Understanding (MOU) assignment of higher offset value for reductions within signatory states as opposed to reductions outside of signatory states is inconsistent with the intent of the program; to reduce GHG emissions, and unnecessarily limits the opportunity for achieving cost-effective GHG reductions. Furthermore, INGAA does not believe there is an environmental justification for differentiating a GHG reduction based on location within or outside the boundaries of the RGGI region. Because natural gas transmission reductions may be achieved in systems that cross from non-signatory states to signatory states, we advocate that natural gas transmission projects that occur on any system that directly enters a signatory state be allocated offsets equal to that allocated to projects wholly occurring within signatory states.

5.3 Certification and Trading of Emission Offsets. In order for the RGGI offsets program to achieve its goals, INGAA recognizes that there needs to be an active market for offsets, thereby driving investment in emission reduction projects. To establish a robust, active market, there must be clear rules defining offsets, clear rules to certify offsets, and clarity on the use of certified offsets in the RGGI program. INGAA feels that implementation of the recommendations presented in this paper will best ensure that eligible offsets from the natural gas transmission industry are real, surplus, verifiable, permanent and enforceable.

INGAA recommends that RGGI establish clear rules on the definition and certification of offsets, and that such rules are simple, consistent, and cost effective for both project developer and RGGI certifying body to implement. To facilitate fair, consistent and cost effective certification, RGGI should establish a single certifying body rather than individual state-based certifiers. Certification should rely in part on establishment of monitoring and verification protocols that are consistent with the protocols recommended in Section 3 of this paper.

INGAA recommends that RGGI establish a transparent system to register or otherwise pre-approve offset projects prior to project implementation and the creation of reductions. Pre-approval should be based on preliminary review of certification criteria, and represent an assessment from RGGI that if the project performs as described in the pre-approval application, RGGI will certify project reductions as offsets. Such pre-approvals will increase market certainty with regards to the future creation of RGGI-eligible offsets from such projects, thereby driving investment and project development.

INGAA advocates that RGGI-certified offsets should be 100% fungible with RGGI program allowances. This will establish buyer certainty, i.e. reduce buyer liability, and increase demand for certified offsets. Increasing the demand for certified offsets will serve to increase investment and project development.

ATTACHMENT A

Interstate Natural Gas Association of America

Greenhouse Gas Emission Estimation Guidelines for Natural Gas Transmission and Storage, Volume 1 – GHG Emission Estimation Methodologies and Procedures (GHG Guidelines)

September 2005

GREENHOUSE GAS
EMISSION ESTIMATION GUIDELINES
FOR NATURAL GAS TRANSMISSION AND STORAGE

VOLUME 1 – GHG EMISSION ESTIMATION METHODOLOGIES AND PROCEDURES

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1.0 INTRODUCTION

Volume 1 of the INGAA Greenhouse Gas (GHG) Emissions Estimation Guideline for Natural Gas Transmission and Storage Document (GHG Estimation Guidelines or Guidelines), presents a compilation of estimation methods for assessing carbon dioxide, methane, and nitrous oxide emissions from combustion and non-combustion sources at natural gas transmission and storage facilities. The Guidelines are intended to be a living document and are designed as a detailed reference for developing a GHG inventory for use by both practitioners and managers. The methodologies, procedures, and examples outlined in this Volume are intended to address the majority of the GHG emission sources from the transmission and storage sector. However, the Guidelines are intended as guidance for constructing an inventory for gas transmission and storage sources – but not a prescriptive approach for developing estimates. Other approaches and emission factors are available that are not presented in this document.

Section 1 of this document provides background on the technical elements associated with completing the GHG estimates, and Sections 2 through 4 present emission factors and emission estimation methods for the primary source types that may be encountered in the natural gas transmission and storage sector of the natural gas industry. Some alternative methods or approaches for assessing emissions from these sources are also discussed. The source types considered include:

- Combustion sources including fleet and construction mobile sources,
- Fugitive emissions from equipment and piping leaks, and
- Process venting and non-routine releases

If a company participates in a voluntary reporting program, the program may include reporting of indirect emission associated with purchased electricity, as well as other criteria. In this situation, the reporting program will likely identify methods for estimating indirect emissions, and emission estimation approaches for indirect emissions are not included in this document.

1.1 Natural Gas Transmission and Storage Overview

The natural gas industry encompasses a breadth of operations, starting with discovery and production of natural gas and culminating with combustion (or feedstock use) by the end user. The primary natural gas industry sectors are typically classified as:

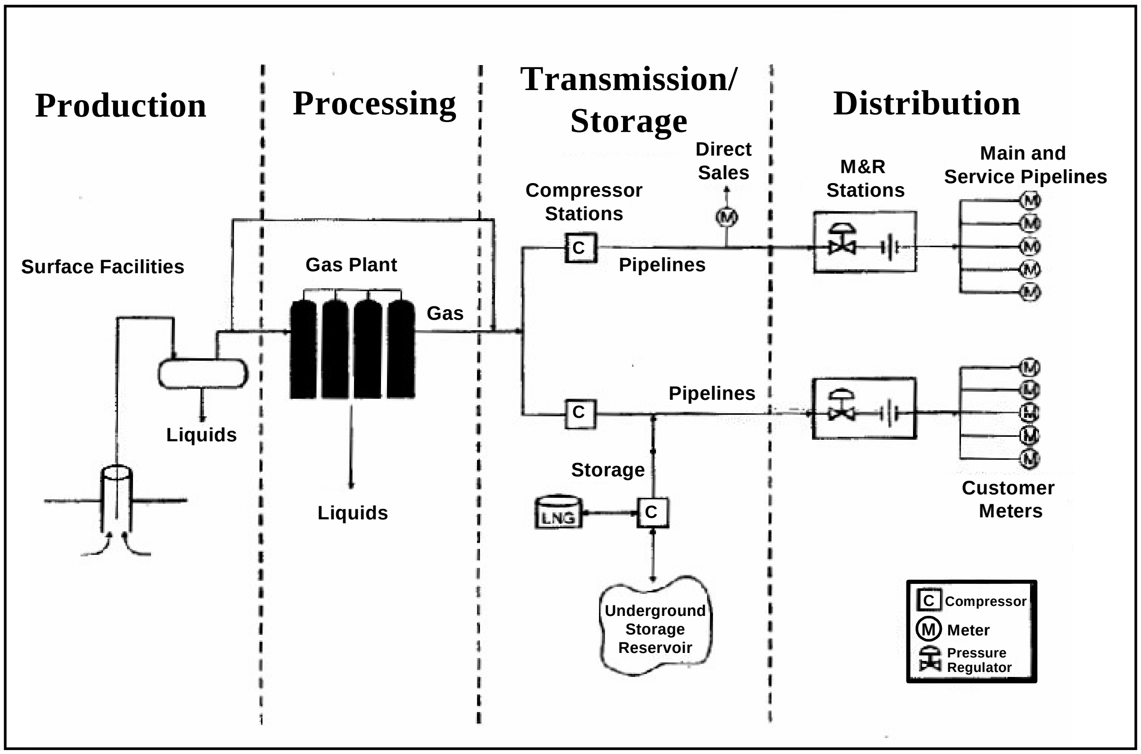
- Exploration and production;
- Natural gas processing;
- Transmission and storage; and
- Distribution.

The natural gas transmission and storage sector is addressed in this document. The U.S. transmission and storage sector includes about 2000 compressor stations, 200,000 miles of high-pressure interstate pipeline, and 300 underground storage facilities. The primary facilities and equipment include interstate natural gas pipelines, compressor stations, metering and regulator stations, and storage fields. A diagram of the complete natural gas system, including the transmission and storage sectors, is shown in Figure 1-1. This figure is from a study completed by the Gas Research Institute and U.S. EPA.

This document addresses emission estimates from the equipments, processes, and activities typical for the transmission and storage. Upstream processes (e.g., from E&P or natural gas processing) may be co-located or adjacent to transmission facilities, but estimation techniques for these activities (e.g., associated with gas or liquid processing other than dehydration) are not included herein, nor are downstream (distribution sector) equipment and processes.

Other resources are available to provide estimates from other natural gas industry sectors, including the American Petroleum Institute (API) *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry* (API Compendium), GRI-GHGCalc™ software, and commercial consulting services or software.

Figure 1-1. Diagram of the Primary Sectors in the Natural Gas Industry. [1]



For GHG estimates from natural gas processes, both GRI-GHGCalc and the gas transmission and storage section of the API Compendium are primarily based upon data from a 1990's collaborative project funded by the Gas Research Institute (GRI) and U.S. EPA[1] (GRI/EPA Study). For the most part, other available calculation tools for natural gas processes also rely primarily upon the GRI/EPA Study.

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[1] GRI and EPA co-published multi-volume reports, *Methane Emissions from the Natural Gas Industry*. Figure from Report Numbers: GRI-94/0257, EPA-600/R-96-080a.

The sector boundaries for transmission and storage are based upon commonly identified points within the natural gas system. The "entrance" to the gas transmission sector is identified as the point of custody transfer from a natural gas processing plant into an interstate gas transmission pipeline (or the point of custody transfer from a producing field or liquefied natural gas (LNG) terminal if natural gas processing to meet pipeline transportation specifications is not required). Thus, natural treatment devices common to a processing plant (e.g., sulfur removal, liquids fractionation) are not addressed in this document. The transfer point out of this sector is the entrance to the pipeline of the local distribution company for delivery to end use customers, or delivery point to the end user if an interstate pipeline is a direct supplier (e.g., natural gas supply for a large utility). Gas storage facilities include both above-ground LNG facilities and below-ground storage caverns and formations.

1.2 Greenhouse Gases and Global Warming Potential

The "greenhouse effect" is the phenomenon where atmospheric gases absorb and trap the terrestrial radiation leaving the Earth's surface – thus causing a warming effect on earth. The greenhouse effect is primarily from CO_2 and water vapor, along with other trace gases in the atmosphere. A number of gases are typically considered as anthropogenic GHGs, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons (e.g., C_nF_{2n+2} compounds), and sulfur hexafluoride. For emissions from oil and natural gas systems, CO_2, methane, and nitrous oxide are typically reported, as these are the emissions that are released from combustion sources and natural gas processes. Changes in the atmospheric concentration of GHGs may affect the energy balance between the land, the seas, the atmosphere, and space. A measure of such changes in the energy available to the system from a gas is termed "radiative forcing", and, holding everything else constant, atmospheric increase of a GHG produces positive radiative forcing.

GHGs can contribute to the greenhouse effect both directly and indirectly. A "direct" contribution is from a gas that is itself a greenhouse gas, while indirect radiative forcing occurs when the original gas undergoes chemical transformations in the atmosphere to produce other greenhouse gases, when a gas influences the atmospheric lifetimes of other gases, and/or when a gas affects processes that alter the atmospheric radiative balance of the earth.

The indirect CO_2 produced by the oxidation of non methane volatile organic compounds (NMVOC) in the atmosphere has not been included in many estimation methodologies and is not contained within this document. NMVOCs do not represent a single molecular species, but instead a wide range of volatile hydrocarbon species with varying molecular weights and carbon contents. The latest Intergovernmental Panel on Climate Change (IPCC) documentation seeks to include other hydrocarbon emissions by accounting for the carbon content by species profile (percent carbon in NMVOC by mass) multiplied by the ratio of molecular weight of carbon dioxide to carbon. Estimates for these emissions may become standardized in the future, but there inclusion is not warranted at this time.

Global Warming Potential (GWP) is the index that has been developed to compare different GHGs on a common reporting basis. CO_2 is used as the reference gas to compare the ability of a particular gas to trap atmospheric heat relative to CO_2. The IPCC defines GWP as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kg of a substance relative to 1 kg of the reference gas (i.e., GWP is weight-based, not volume-based). Thus, GHG emissions are commonly reported as CO_2 equivalents (e.g., tonnes of CO2eq, where a tonne is 1000 kg). Since GWP is a time-integrated factor, the GWP for a particular gas is dependent upon the time period selected. A 100-year GWP is the standard that has been broadly adopted for GHG reporting, and will serve as the basis for the INGAA GHG Estimation Guideline. While only three GHGs are the focus of reporting from natural gas systems, GWP values are listed in Table 1-1 for these gases along with some common HFCs and CFCs, and SF_6.

Table 1-1. Global Warming Potentials (100 Year Time Horizon, 1996 IPCC)

Gas	GWP
Carbon dioxide (CO_2)	1
Methane (CH_4)	21
Nitrous oxide (N_2O)	310
HFC-23	11,700
HFC-32	2,800
HFC-125	1,300
HFC-134	3,800
HFC-236	6,300
CF_4	6,500
C_2F_6	9,200
C_4F_{10}	7,000
C_6F_{14}	7,400
SF_6	23,900

The GWPs in Table 1-1 are from the IPCC 1996 Second Assessment Report (SAR). In 2001, the IPCC Third Assessment Report (TAR) was adopted. The TAR updated the GWPs based on the most recent scientific data. This update included a revision to the radiative forcing effect of CO2. Thus, since CO_2 is the reference gas, other GWPs were affected by this change alone. Additional data and information based on a specific gas could also affect the GWP of a particular GHG. For the three GHGs which include reporting methods in this document, the SAR and TAR GWPs are presented in Table 1-2.

Table 1-2. GWP (100-year) for CO_2, Methane, and N_2O from 1996 SAR and 2001 TAR

GHG	GWP (SAR)	GWP (TAR)
Carbon dioxide (CO_2)	1	1
Methane (CH_4)	21	23
Nitrous oxide (N_2O)	310	296

These updated GWPs have not been commonly applied in inventories and reporting protocols to date. Thus, for the purposes of this document, the GWPs from the original 1996 SAR will be used. If the reporting convention changes, this can be readily addressed in an inventory by updating the methane and N_2O GWP conversion factors in inventories.

CO_2 is a direct emission from combustion sources. Emission estimates for gas transmission and storage are available based on fuel usage from combustion equipment such as internal combustion engines and turbines used to drive natural gas compressors, boilers/heaters used for facility process heat demands, glycol dehydrator reboilers, and on-site electrical generators. For natural gas transmission and storage facilities, the primary challenge in developing a GHG inventory is the estimation of methane emissions, which are especially important for natural gas systems due to the GWP of methane.

1.3 GHG Emissions Estimation Methodologies – Quantification Steps

For developing an inventory, emission estimates are developed based on an emission factor approach, as follows:

$$\text{Emission Rate} = \text{Emission Factor} \quad \text{X} \quad \text{Activity Data}$$

Depending upon the "tier" for the estimate, the activity data could be very general (e.g., miles of pipeline, number of compressor stations), or more specific (e.g., equipment specific fuel consumption, number of leak components in a facility).

In Sections 2 through 4, emission factors and activity data are provided for the various emission sources in gas transmission and storage. It is important to recognize that the identified emission estimation guidelines are presented as an available approach based on published literature. These guidelines should not be viewed as prescriptive, and operators developing an inventory may choose alternative approaches or emission factors. When using these guidelines, where multiple options are available (e.g., based on the decision trees for combustion emissions), operators will need to identify the methodology appropriate to meet their inventory objectives that considers the available activity data information.

To report the complete company inventory, emission estimates from individual processes, equipment, and facilities will be aggregated. A company will need to decide the implementation approach for preparing a rolled up inventory, and define responsibilities for compiling and inputting activity data, calculating emissions, and rolling up the equipment and facility-level emissions into a corporate report.

1.4 Emission Sources

The primary emission sources for natural gas transmission and storage include: CO_2 emissions from combustion sources; methane emissions (i.e., lost and unaccounted for gas) from fugitive emissions, and venting or purging associated with standard practices, maintenance, or upset events. Sources associated with each of these emission types are itemized below. Detailed methodologies for calculating emissions from the different source types follows in Sections 2 through 4. As noted in Section 1.1, indirect emissions are not addressed in this document.

1.4.1 Combustion Emissions

Emissions of CO_2, methane, and N_2O are reported from combustion sources, including:

- IC engine and gas turbine compressor drivers,
- IC engine and gas turbine generators,
- Dehydrator reboilers,
- Facility boilers or process heaters,
- Flares or incinerators,
- Company fleet vehicles.

1.4.2 Vented Emissions

Vented methane emissions come from a variety of process equipment and operational practices. Note that process venting and maintenance venting (e.g., purge/blowdown) are included under fugitives for IPCC and some other reporting guidelines. These emissions can comprise a significant portion of GHG emissions from transmission and storage. Emission sources include:

- Dehydrator vents,
- Compressor vents,
- Pneumatic devices (isolation valves and control loops),
- Purge or blowdown from routine operations or upsets, including:
    - Pipeline venting,
    - Compressor station venting,
    - Storage facility venting,
    - M&R station venting,
    - Pigging and inspection,
    - "Pull Backs" or venting associated with water removal.

1.4.3 Fugitive Emissions

Fugitive GHG emissions are methane leaks from pipelines and system components such as compressor seals, pump seals, valve packings, and flanges and piping connectors. Currently, the emission sources and activity data basis for fugitive emissions are based upon primary equipment that includes subcomponents, such as:

- Piping and associated components,
- Compressors,

- M&R stations (meter stations, interconnects, farm taps, receipt/sales meter stations, border meter stations, gate stations),
- Storage well components, and
- Organic liquids storage tanks.

1.4.4 Other Emissions

Additional emissions that are not categorized with the emission sources above may also be included in the inventory. These emissions include optional emissions and emissions from non-routine activities. These sources are not documented in this Gudeline document, but example sources include:

- Other emissions (e.g., business travel, employee commuting, outsourced activities),
- Non-routine maintenance activities,
- Anaerobic water treatment, and
- Remediation.

1.5 Tiered Approaches

As methods for GHG inventory development continue to evolve, a "tiered" emission calculation approach has been commonly applied based on varying levels of detail associated with user input data on equipment and processes. Higher tier emission estimates require more detailed data and typically generate emission estimates with better accuracy and precision. Tier 1 represents the most broad emissions estimate, and requires the least input information. Tier 2 and Tier 3 require progressively more data, but result in a higher quality GHG inventory. In Section 4, a calculation is completed for an example facility that demonstrates the differences in the estimates for Tier 1, 2, and 3.

This discussion of "Tiers" for emission estimates should not be confused with the IPCC use of the term "tier". IPCC provides direction for preparing a national level GHG inventory, and uses "tier" to discuss quality control procedures, with tier 1 referring to general inventory QC procedures and tier 2 referring to source category specific procedures. These INGAA Guidelines use emission estimation "tiers" to refer to the progression in activity data detail required for the GHG estimate, with higher tiers typically providing a higher quality estimate for a particular source type.

The Tier-based hierarchy for this document can be considered as follows:

- Tier 1: General estimate with minimal inputs required (e.g., emission factor based on miles of pipeline used to estimate the GHG inventory).
- Tier 2: Data requirements and emission factors based on facility level data or the largest emission sources at a site.
- Tier 3: Data requirements and emissions based on process operation or equipment level information at a site.
- Additional Tiers (e.g., Tier 3+, Tier 4, and beyond) involve emission determinations that require additional data – and higher costs for inventory development. These approaches are

typically beyond the current practices for inventory development. The approaches also require thorough documentation to ensure that an external reviewer/auditor can understand and validate the estimation.

Note that in completing calculations, emission estimates may use different Tiers for different emission types. For example, based on available activity data, combustion emissions may be estimated using an approach commensurate with Tier 3, while vented emissions may be determined using Tier 2. However, it is important to understand that within a category of emissions (e.g., vented emissions) only a single Tier should be used, and all of the activity data required within the Tier needs to be considered. While similar activity data may serve multiple Tiers, in stepping up in Tiers (e.g., Tier 2 to Tier 3), the emission factors have been developed such that the factor is Tier-specific and encompasses emissions associated with a different array of emission points/sources within the respective emission category.

When considering different Tiers for emission estimates, it is also important to understand that while emission factor accuracy generally improves within an emission category (e.g., vented) for progressive Tiers, comparing Tiers for different source types or different pollutants does not provide an indication of the relative accuracy of the estimates. For example, an emission estimate using the same Tier for different source categories (e.g., Tier 2 combustion CO_2 versus Tier 2 vented methane) has different accuracy due to the inherent nature of the emission sources and the associated default emission factors (as well as the accuracy of the activity data count). In this example, combustion CO2 calculations are typically the most straightforward and accurate, while fugitive emissions are associated with higher uncertainty. In addition, the same Tier emission factor for different pollutants within a source category (e.g., Tier 2 combustion CO_2 versus combustion N_2O) may have very different accuracies. So, the Tier rating scheme is not an absolute indicator of the fidelity of an estimate, but rather an indicator of progressively better emission factors within an individual source category for a specific GHG.

Because the calculation is relatively straightforward, a higher Tier estimate may be possible for combustion CO_2 emissions (e.g., calculation based on fuel consumption and fuel analysis). For other GHG emission estimates, a Tier 3 or lower estimate is the current approach typically applied. Migration beyond Tier 3 estimates will likely occur over time. Such estimates will require more detailed process and equipment activity data in conjunction with more specific emission factor data. This document focuses on Tier 1 through 3 emission estimates. For activities where the path forward is apparent, issues or data needs associated with a Tier 3+ or Tier 4 estimate are also discussed.

1.6 Emission Factors

Emissions factors present mass of GHG emissions (CO_2, methane, or N_2O in this Estimation Guideline) per unit of activity, where the activity is typically a process rate or equipment count. (For example, lb of CO_2 per MMBtu of natural gas combusted, kg of methane leaks per number of reciprocating compressors.) The emission factors presented in Sections 2 through 4 of this document present current factors from the literature, but are not intended to be prescriptive or encompass the breadth of emission factors available. In general, for natural gas systems, most of the factors have been derived from the GRI / EPA Study completed in the mid-1990's.

Emission factors present a "typical" or "average" emission rate based on the industry norm. These are often referred to as "default" emission factors. The uncertainty associated with the factor depends upon both the application and the technical limitations associated with the dataset that forms the basis of the factor. The uncertainty also depends on the accuracy of the measurement methods associated with the emissions and activity data. For example, combustion CO_2 emission factors are more accurate due to the relative simplicity of the CO_2 emission determination, while fugitive methane emissions have a higher uncertainty due to the complexity of directly measuring fugitive emissions as well as facility-to-facility differences.

The INGAA GHG Estimation Guidelines are not intended to limit the ability of a company to use emission factors or emission estimation methods alternative to those included in this document. For example, a particular company or site may have actual emissions that vary from the "norm" represented by the emission factor and choose to use alternative approaches or emission factors. In fact, if circumstances indicate an issue with available emission factors (or the estimation method) for a particular application, a company may be better served to choose an alternative to the published emission factors – such as site-specific data. In any case, a GHG inventory should include documentation of the basis for the emission estimates.

1.7 Activity Data

Multiple estimation methods are available to estimate emissions for sources and processes. For example, multiple tiers are available, and some processes provide more than one estimation methodology for a Tier 2 or Tier 3 estimate. Based on available activity data – and the quality of the data, a company can decide which estimation approach most effectively meets its needs.

Regardless of the tier or estimation method selected, a certain amount of source and activity data will be collected to support inventory development. Data collection concerns include inventory completeness, accuracy (e.g., eliminate double counting and transcription errors), emission factor and activity data matching, and documentation and recordkeeping. This generally requires the active engagement of personnel with a good working knowledge of the equipment and facilities involved, and of the associated operations and engineering terminology.

Examples of supporting data and information that may be used for activity data include:

- Process operating conditions (e.g., gas compositions, temperatures, pressures and flows);
- Maintenance records;

- Supply medium used for gas-operated devices (e.g. natural gas versus compressed air engine starters);
- Piping materials;
- Operating and maintenance practices and schedules (e.g., depressurization of idle compressors); and,
- Annual updates of equipment installed and decommissioned.

The specific activity data for transmission and storage GHG estimates are identified in the sections that follow. In compiling activity data for inventory development, a company may consider not only the current inventory (e.g., the initial inventory), but also the procedures that are necessary to ensure efficient collection of the same data in subsequent years. In developing initial inventories, activity data deficiencies or gaps could be identified so that process improvements can be considered for subsequent or updated inventories.

2.0 COMBUSTION SOURCES

Greenhouse gases are emitted from combustion equipment used at natural gas transmission and storage facilities, and combustion emissions include the three GHGs addressed in the INGAA GHG Estimation Guidelines – CO_2, methane (CH_4), and N_2O. CO_2 is formed from the oxidation of fuel carbon, CH_4 is a product of incomplete natural gas combustion – typically CH_4 in the fuel escapes oxidation, and N_2O is formed by oxygen-nitrogen reactions that are promoted by cooler flame temperatures. The combustion equipment typically employed at these natural gas facilities includes:

- Stationary sources firing natural gas (processed/pipeline quality), diesel fuel, and gasoline:
  - External combustion sources: boilers and heaters;
  - Gas turbines: simple-cycle; and
  - Reciprocating internal combustion engines (ICEs): Natural gas-fired 2-stroke lean burn, 4-stroke lean burn, and 4-stroke rich burn, and diesel fired.
- Incinerators and flares.

Mobile source emissions (i.e., fleet vehicles and construction equipment) are included at the end of this section.

2.1 Emissions Estimation Methodologies Overview

GHG emissions from a single combustion source or group of sources (facility) can be directly measured or estimated from a source-specific emission factor (EF) and corresponding activity data (AD). The general equation for this estimation, as discussed in Section 1.3, is:

$$\text{Emissions}_{GHG} \text{ (mass/unit time)} = AD * EF \qquad \text{Eqn. 2-1}$$

The Activity Data is equipment, process, or facility data per unit time and the Emission Factor is GHG mass or volume per process, equipment, or facility data increment. Increased emissions estimation accuracy requires more detailed data and calculations. In Sections 3 and 4, vented and fugitive emissions are discussed. These non-combustion emission categories are natural gas industry-specific and published data is limited. For combustion equipment, available GHG literature includes considerably more data and detailed methods for estimating emissions from combustion. For example, while leading reporting/accounting documents such as the World Resources Institute and World Business Council for Sustainable Development (WRI/WBCSD) GHG Protocol (WRI/WBCSD GHG Protocol) do not offer methods for natural gas system estimates of vented or fugitive emissions, supplements are available that specifically address combustion emissions.

2.1.1 Emission Tiers for Combustion

A general hierarchy of emissions estimation approaches, in order of increasing accuracy for a specific source type (i.e. decreasing uncertainty), is as follows:

- Tier 1. Emissions estimated using system or facility-level Tier 1 EFs based on GHG emissions per unit production or other facility data (e.g., for natural gas transmission, volume of gas transmitted or facility pipeline length) and a corresponding AD. There is a unique EF for each GHG. The EF * AD calculation provides an estimate of the GHG emissions from combustion for an entire facility, company, or industry;
- Tier 2. Emissions estimated using facility-level Tier 2 EFs based on total fuel combusted in a facility and a corresponding AD. There is a unique EF for each GHG and fuel type. The EF * AD calculation provides an estimate of the GHG emissions from combustion of the fuel type for an entire facility;
- Tier 3. Emissions estimated using equipment-level Tier 3 EFs based on total fuel combusted in a piece of equipment and a corresponding AD. There is a unique EF for each GHG, fuel type, and combustion technology category (e.g. 2-stroke lean burn ICEs, boilers < 100 MMBtu). The EF * AD calculation provides an estimate of the GHG emissions from combustion of the fuel type in a piece of equipment (or bank of similar equipment).

For Tiers 1 through 3, the emission factor is a published "default" factor based on typical characteristics. For combustion, activity data and operating information may be available to conduct a more refined emission estimate. An example of a "Tier 3+" or "Tier 4" level estimate follows:

- Emissions for CH_4 and N_2O are estimated using equipment-level EFs based on total fuel combusted in a piece of equipment and a corresponding AD. There is a unique EF for each GHG, fuel type, and equipment make. The EF is derived from combustion equipment manufacturer data or emissions monitoring/testing of the specific equipment model. The EF * AD calculation provides an estimate of the GHG emissions from combustion of the fuel type in the equipment of the defined make and model.
- For CO_2, emissions are estimated using facility or equipment-level (or equipment bank) fuel usage and fuel quality data based on analysis of facility natural gas. The metered fuel consumption, in conjunction with the natural gas carbon content provides the ability to accurately estimate CO_2 emissions based on the carbon content of the fuel.

In this scenario, methane and N_2O would be estimated based on fuel usage (Activity Data) and an emission factor. The fidelity of the available emission factor would indicate the relative "Tier" of this estimate – e.g., a Tier 3 estimate based on an average default emission factor would be most likely. The CO_2 estimate approach above is one of several in the available literature. The CO_2 estimation hierarchy is discussed further below. In general, because fuel consumption and fuel quality data are more accessible, CO_2 estimates from combustion can be completed with a higher degree of certainty than GHG emissions such as those from fugitive releases or venting.

In the future, the accessibility of operational data (i.e., fuel consumption and fuel analysis) and emission measurements associated with combustion equipment may provide the opportunity for very refined emission estimates for CO_2, CH_4 and N_2O for combustion equipment.

Calculation procedures using EFs and ADs for Tiers 1 and 2 are detailed below, along with discussion of estimation approaches that address Tier 3 level estimates and beyond.

2.1.2 Data Conventions

Combustion emission factors in the literature are typically reported in tonnes (i.e., metric tons) per MMBtu, tonnes/terajoule (TJ), and the original units reported in the referenced source. In the Tables below, the following conventions are used to convert the emission factors from the referenced source units to tonnes/MMBtu and tonnes/TJ.

- Fuel Heating Value – Emission factors are reported based on the fuel's higher heating value (HHV). Fuel heating values listed in Table 2-1 were used unless otherwise noted. A factor of 0.9 was used to convert lower heating value (LHV) based EFs to HHV-based EFs for natural gas unless otherwise noted:

  $EF_{HHV} = 0.9 * EF_{LHV}$ Eqn. 2-2

  A factor of 1.05 was used to convert LHV-based EFs to HHV based EFs for liquid fuels – diesel fuel and gasoline unless otherwise noted:

  $EF_{HHV} = EF_{LHV}/1.05$ Eqn. 2-3

- Standard Gas Conditions - The ideal gas law:

  $PV = nRT$ Eqn. 2-4

  Where: P = pressure (in atm, psia, or kPa)
  V = volume (ft^3, cm^3)
  n = number of gmoles or lbmoles
  R = 10.73 psi ft^3/lbmole ºR, 0.73 atm ft^3/lbmole ºR, 82.06 atm cm^3/gmole K
  T = temperature (ºR, K)

  is used to convert gas volumes to a mass or weight basis. Standard gas conditions include a temperature of 60 ºF/15.6 ºC and a pressure of 1 atm /14.696 psia/101.325 kPa These conditions give a standard volume of 379.3 standard cubic feet (scf)/lbmole or 23.685 liters/gmole.

- Fuel Properties – Default fuel heating values, densities, and carbon contents are listed in Table 2-1 from common references. These values are available for use if actual fuel data is not available. In addition, in some cases EF conversion is needed to obtain consistent engineering units. If the reference source identified the fuel properties, the referenced values were used for conversion. In cases where reference fuel properties were not available, Table 2-1 values were used for EF conversions and calculations

Table 2-1. Densities, Heating Values, and Carbon Content for Fuels

Fuel	Density	HHV	LHV	Carbon, % by Weight	Ref
Diesel	7.06 lb/gal	$5.83*10^6$ Btu/bbl	$5.55*10^6$ Btu/bbl	87.3	A
Gasoline/ Petrol	6.17 lb/gal	$5.46*10^6$ Btu/bbl	$5.19*10^6$ Btu/bbl	85.5	A, B
Kerosene	6.76 lb/gal	$5.67*10^6$ Btu/bbl	$5.39*10^6$ Btu/bbl	87	A, B
Natural Gas (processed/pipeline)	1 lb/23.8 scf	1020 Btu/scf	918 Btu/scf	76	C
Natural Gas (raw/unprocessed)	~1 lb/19 scf	1240 Btu/scf [D]	1110 Btu/scf [D]	~77	D

HHV – Higher Heating Value
LHV – Lower Heating Value

A. EPA AP-42, Appendix A, Miscellaneous Data Conversion Factors, 1995.
B. North American Combustion Handbook, Volume I: Combustion Fuels, Stoichiometry, Heat Transfer, Fluid Flow, 3rd Ed., 1986.
C. EPA AP-42, Section 1.4, Natural Gas Combustion, 1998
D. Canadian Association of Petroleum Producers (CAPP), Calculating Greenhouse Gas Emissions, CAPP Publication No. 2003-03, April 2003.

2.1.3 Emission Factor Selection Criteria

Emission factor alternatives are much more abundant for combustion than for the other emission categories characteristic of gas transmission and storage. A three step process was used to identify the most appropriate EFs for estimating GHG emissions from natural gas transmission and storage combustion systems:

1. Documents with GHG EF and emissions estimation methodologies were reviewed. Emission estimation methodologies were documented and EFs tabulated for CO_2, CH_4, and N_2O. Entries also included fuel type and heating value, combustor type and specifications (design, applicable operating conditions (e.g. load range), etc.), air pollution controls (APCs), EF rating, reference (if EF originated from another document), and other applicable information.

2. All EFs were converted to common activity factors of tonne/MMBtu and tonne/TJ based on HHV for comparison purposes. If insufficient data (e.g. HHV) were provided to perform the conversion calculations, default values from Table 2-1 were applied.

3. Common EFs (based on GHG, fuel, combustion technology, etc.) were compared to determine the factor most applicable to natural gas transmission and storage facilities. Quite often EFs were redundant, i.e., EFs in a recent report had been referenced from a previous

report. In these instances, the original reference was cited. Selection of the most applicable EFs was based on the following criteria, generally in the order presented:

- Quality rating – for example, AP-42 EF quality ratings or reported uncertainties. The AP-42 ratings methodology is presented in Appendix C-3;
- Specificity to natural gas transmission and storage facilities;
- Specificity to the United States - it was generally assumed that US based EFs are more pertinent to natural gas transmission and storage facilities than foreign based EFs, particularly for fuel sensitive EFs such as CO_2;
- EF development methodology - for example, GHG directly measured or estimated from another measurement (e.g. N_2O assumed to be 1.5% of NOx);
- Age - it was generally assumed that newer EFs are based on more recent and more reliable data;
- Availability and expected accuracy of Activity Data; and,
- Consistency with other reported EFs (is it an outlier and why?).

A number of available references in the literature include emission factors and estimation methods for combustion. Thus, the emission factors presented in this section include identification of the specific reference. For later sections (e.g., venting and fugitives), the available emission factors are very limited and based on a few key studies or reports. Thus, the literature reference is identified, but less reference detail is provided in the emission factor tables in the sections that address GHG from sources other than stationary combustion.

2.2 Stationary Source CO_2 Emission Estimation Methodologies

Fuel carbon is almost completely oxidized to CO_2 during combustion, irrespective of the combustor type. The complete combustion equation for a hydrocarbon is:

$$CxHyOz + (x + y/4 - z/2)\ O2 = xCO2 + y/2\ H2O \qquad \text{Eqn. 2-5}$$

Therefore, if fuel consumption for a facility, equipment bank (e.g., compressor building), or individual unit is known or can be reasonably estimated, CO_2 emissions can be estimated from the fuel consumption, known or estimated fuel composition (carbon content), and a carbon oxidation factor. If the activity data is at the facility level and a default fuel analysis is used, this is the Tier 2 approach for CO_2 emissions estimation. If equipment specific fuel use and fuel analysis is used, this estimate of CO_2 would be "Tier 4".

Figures 2-1 and 2-2 outline the methodology for estimating CO_2 emissions from combustion at a natural gas transmission or storage facility, including the approach for determining which Tier to use for estimating a facility's fuel consumption and CO_2 emissions. The total consumption of each fuel fired at a facility must be determined (diesel fuel, natural gas, and/or gasoline). The Figures 2-1 and 2-2 hierarchy identifies fuel consumption estimation methods consistent with different "Tiers" of emissions estimates. This approach is based on the hierarchy provided in the International Petroleum Industry Environmental Conservation Association (IPIECA) "*Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions*" (IPIECA Guidelines).

Figure 2-1. CO_2 Emissions Estimation Overview

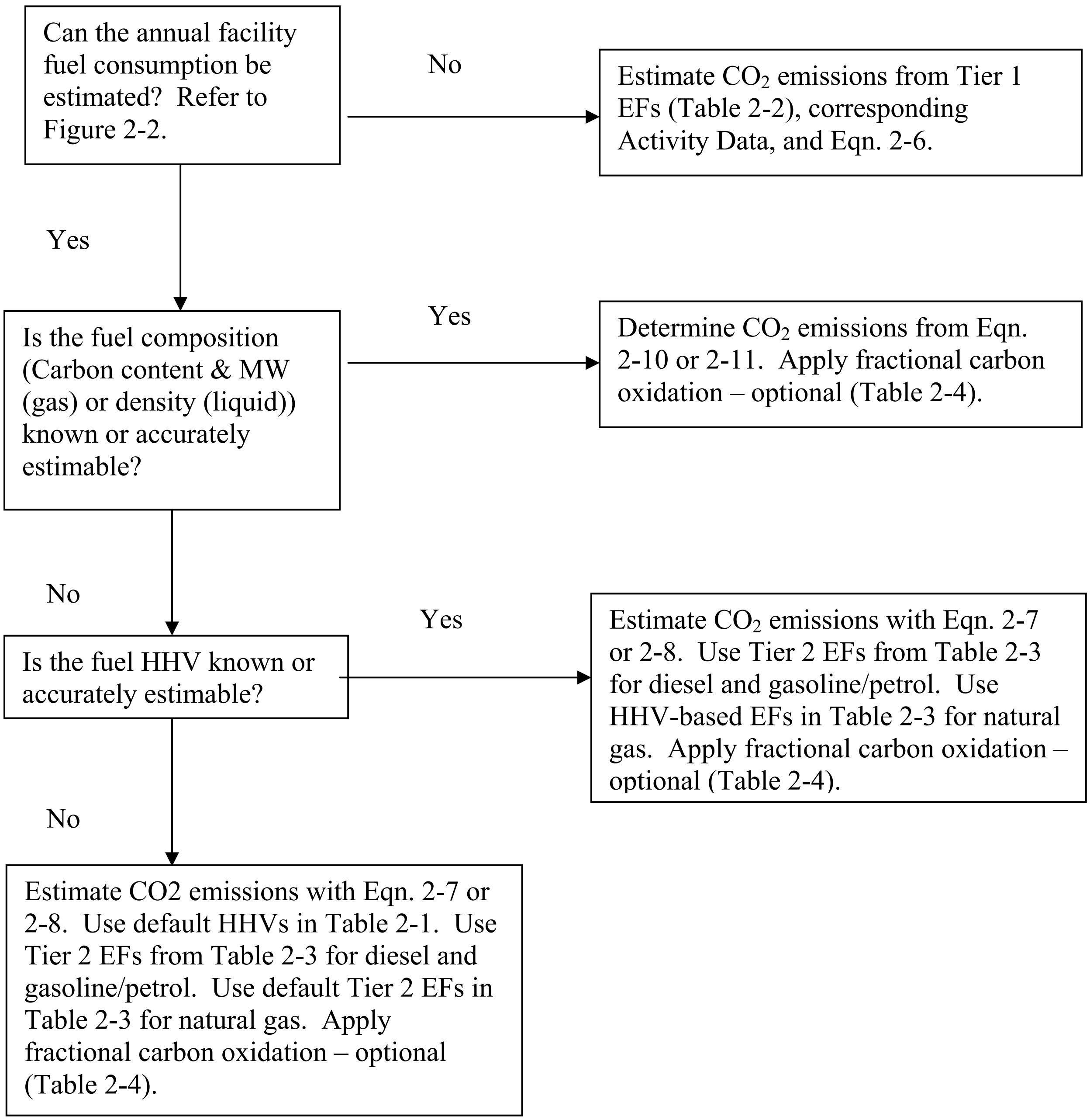
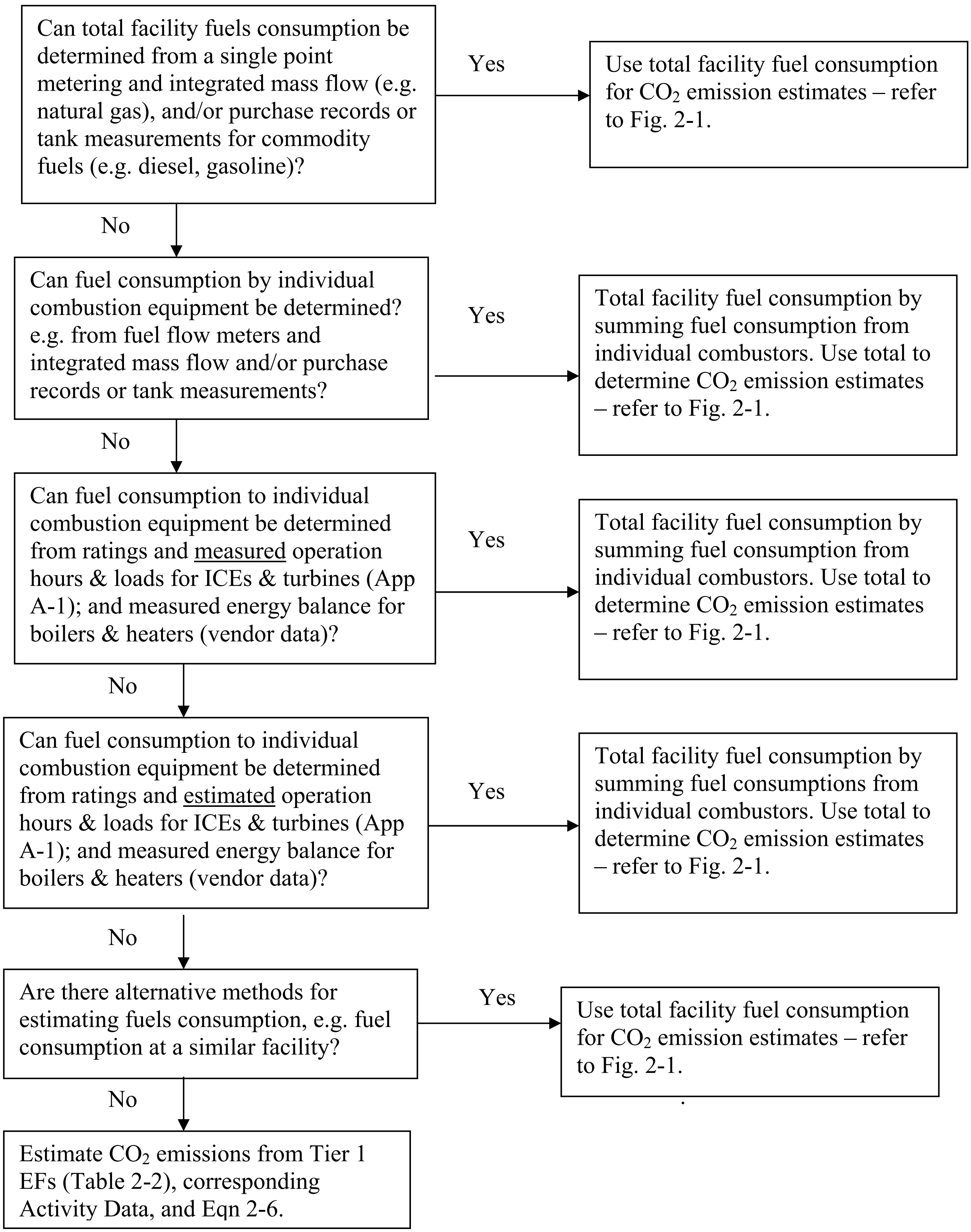


Figure 2-2. CO_2 Emissions Estimation Fuel Consumption Determination



2.2.1 CO_2 Emissions Estimates Using Tier 1 Emission Factors

Tier 1 CO_2 emissions are estimated from a Tier 1 CO_2 emission factor and corresponding activity data as shown in equation 2-6. Table 2-2 lists Tier 1 CO_2 emission factors. These emission factors are from GRI-GHGCalc™.

tonnes CO_2 = Activity Data * EF Eqn. 2-6

where: tonne CO_2 = estimated annual CO_2 emissions from combustion (tonne/yr)
Activity data = transmission pipeline length or storage stations

Table 2-2. Tier 1 CO2 Emission Factors for Combustion

Segment	Activity Data	GHG	EF	EF Units	Reference
Transmission	Transmission pipeline length	CO_2	2.3 E+2	Tonne/mile-yr	GRI 2001
Storage	Storage stations	CO_2	2.4 E+2	Tonne/station-yr	GRI 2001

GRI – GRI-GHGCalc Version 1.0 Emission Factor Documentation, July 2001

2.2.2 CO2 Emissions Estimates Using Tier 2 Emission Factors

If the annual fuel consumption can be estimated, fuel composition (carbon content and molecular weight/density) is not known and the fuel heating value is known or can be reasonably estimated, then annual CO_2 emissions are estimated using an EF from Table 2-3 and equation 2-7 for natural gas and equation 2-8 for liquid fuels. If the fuel is natural gas, then a heating value based EF from Table 2-3 is available.

$tonneCO2_j$ = Activity Data * EF * COX Eqn. 2-7

where: $tonneCO2_j$ = estimated annual facility CO_2 emissions from combustion of fuel j (tonne/yr)
Activity Data = Q_{GFj} * HHV_{Gj} * 10^{-6} = MMBtu/yr
Q_{GFj} = scf fuel j combusted at facility/yr
HHV_{Gj} = Btu/scf fuel j
10^{-6} = MMBtu/10^6 Btu
EF = tonnes CO_2/MMBtu
COX = COX is the fractional carbon oxidation factor. The use of COX is optional, a conservative approach is to assume 100% carbon oxidation to CO_2 (i.e. COX = 1.0). COX values are listed in Table 2-4.

$tonneCO2_j$ = Activity Data * EF * COX Eqn. 2-8

where: Activity Data = Q_{LFj} * HHV_{Lj} * 10^{-6} = MMBtu/yr
Q_{LFj} = gal fuel j combusted/yr
HHV_{Lj} = Btu/gal fuel j

Total facility CO_2 emissions are the sum of emissions from each fuel combusted per equation 2-9.

$$\text{tonnes CO2} = \sum \text{tonneCO2}_j \qquad \text{Eqn. 2-9}$$

where: j = number of different fuels combusted at facility
tonne CO2 = estimated annual facility CO_2 emissions (tonne/yr)

If the annual fuel consumption can be estimated, but the fuel composition (carbon content and molecular weight) is not known, and the fuel heating value is not known or cannot be reasonably estimated, then CO_2 emissions are estimated using an EF from Table 2-3, a default heating value from Table 2-1, and equation 2-7 for natural gas and equation 2-8 for liquid fuels. Table 2-3 includes default EFs for both pipeline and raw natural gas.

Table 2-3. Tier 2 CO_2 Emission Factors for Combustion.

Fuel	Activity Data	GHG	EF	EF Units	Reported EF (Units)	Reference
Diesel	MMBtu/yr	CO_2	7.4 E-2	tonne/MMBtu	Calculation	Table 2-1
Gasoline/Petrol	MMBtu/yr	CO_2	6.8 E-2	tonne/MMBtu	Calculation	Table 2-1
NG: Default – Pipeline/Processed	MMBtu/yr	CO_2	5.2 E-2	tonne/MMBtu	Calculation	Table 2-1
NG: HHV = 975 – 1000 Btu/scf	MMBtu/yr	CO_2	5.4 E-2	tonne/MMBtu	54.01 (tonne/10^9 Btu)	EIA 2004
NG: HHV = 1000 – 1025 Btu/scf	MMBtu/yr	CO_2	5.3 E-2	tonne/MMBtu	52.91 (tonne/10^9 Btu)	EIA 2004
NG: HHV = 1025 – 1050 Btu/scf	MMBtu/yr	CO_2	5.3 E-2	tonne/MMBtu	53.06 (tonne/10^9 Btu)	EIA 2004
NG: HHV = 1050 – 1075 Btu/scf	MMBtu/yr	CO_2	5.3 E-2	tonne/MMBtu	53.46 (tonne/10^9 Btu)	EIA 2004
NG: HHV = 1075 – 1100 Btu/scf	MMBtu/yr	CO_2	5.4 E-2	tonne/MMBtu	53.72 (tonne/10^9 Btu)	EIA 2004
NG: HHV > 1100 Btu/scf; Default – Raw/Unprocessed	MMBtu/yr	CO_2	5.5 E-2	tonne/MMBtu	14.92 (MMTC/10^{15} Btu)	EIA 2002

EIA 2004 - Energy Information Administration (EIA). Documentation for Emissions of Greenhouse Gases in the United States 2002, (Washington, DC, January 2004).
EIA 2002 - Energy Information Administration (EIA). Emissions of Greenhouse Gases in the United States 2001, DOE/EIA-0573(2001), December 2002.

2.2.3 CO_2 Emissions Estimates Determined from Fuel Consumption and Composition

If the annual fuel consumption can be estimated and the fuel composition (carbon content and molecular weight/density) is known, then CO_2 emissions are estimated using a mass balance approach shown with equation 2-10 for natural gas and equation 2-11 for liquid fuels.

$$\text{tonne } CO2_j = 4.38 * 10^{-6} * Q_{GFj} * MW_{Fj} * C_j \text{ wt\%}/100 * COX \qquad \text{Eqn. 2-10}$$

Where: $\text{tonne}CO2_j$ = estimated annual CO_2 emissions from combustion of fuel j (tonne/yr)
Q_{GFj} = scf fuel j combusted/yr
MW_{Fj} = fuel molecular weight = lb fuel j/lbmole fuel j
C_j wt%/100 = carbon weight percent/100 = lb C/lb fuel j
$4.38 * 10^{-6}$ = Mol Vol (lbmole fuel/379.3 scf fuel) * 1/MW_C (lbmole C/12 lb C) * lbmole CO_2/lbmole C * MW_{CO2} (44 lb CO_2/lbmole CO_2) * tonne/2204.6 lb

$$\text{tonne}CO2_j = 1.66 * 10^{-3} * Q_{LFj} * \rho_{LFj} * C_j \text{ wt\%}/100 * COX \qquad \text{Eqn. 2-11}$$

Where: Q_{FLj} = gal fuel j combusted/yr
ρ_{LFj} = fuel density = lb fuel j/gal fuel j
$1.66 * 10^{-3}$ = 1/MW_C (lbmole C/12 lb C) * lbmole CO_2/lbmole C * MW_{CO2} (44 lb CO_2/lbmole CO_2) * tonne/2204.6 lb

Total facility CO_2 emissions are the sum of emissions from each fuel combusted per equation 2-9.

Procedures for calculating fuel molecular weight and carbon weight percent are presented in Appendix C-2.

Table 2-4. Fractional Carbon Oxidation Factors

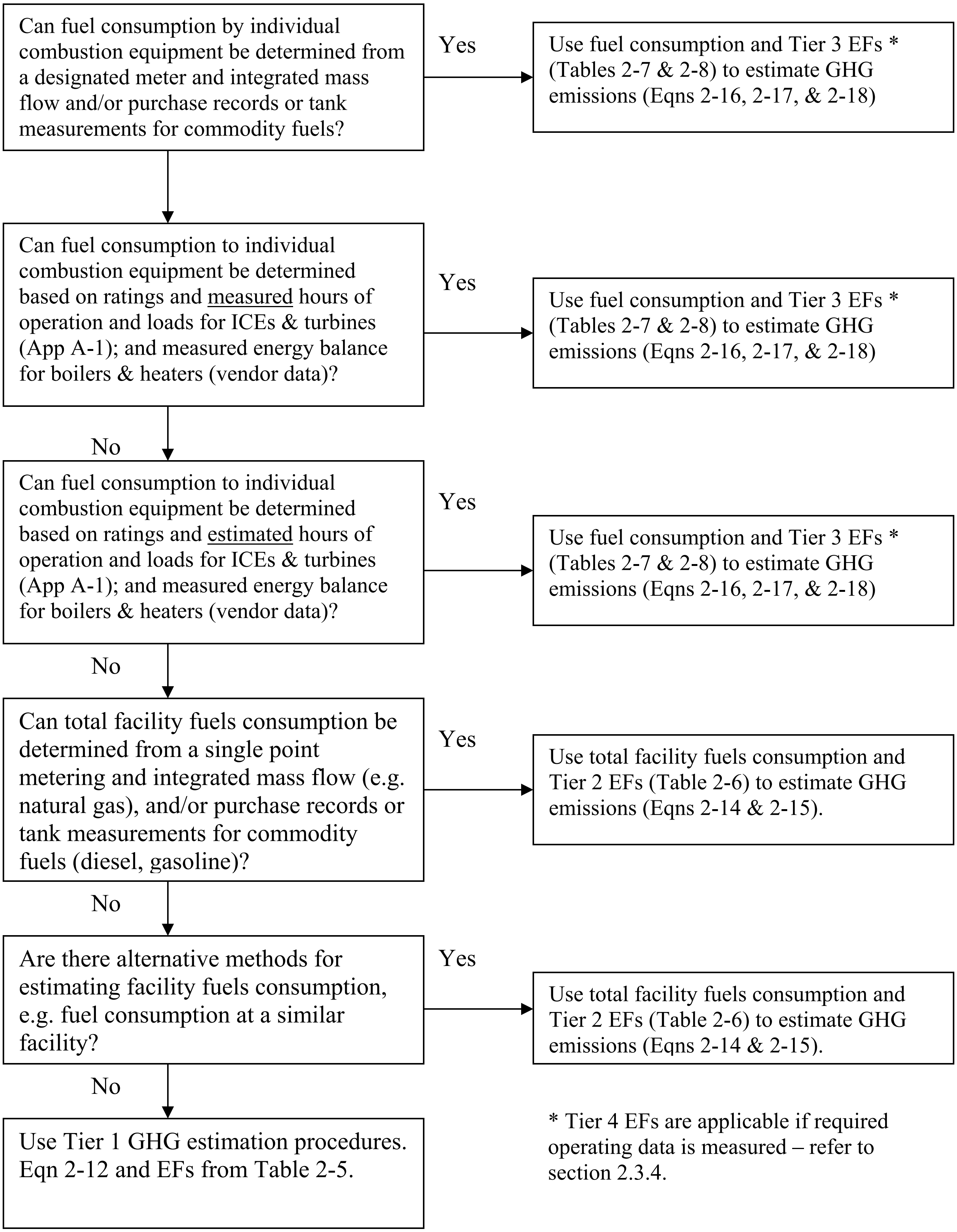
Fuel	Fraction of Fuel C Oxidized (COX)	Reference
Diesel	0.99	EIIP 1999, IPPC 1996
Gasoline	0.99	EIIP 1999, IPPC 1996
Natural Gas	0.995	EIIP 1999, IPPC 1996

EIIP 1999 - EIIP, Guidance for Emissions Inventory Development, Volume II: Estimating Greenhouse Gas Emissions, EIIP Greenhouse Gas Committee, October 1999.
IPPC 1996 - Intergovernmental Panel on Climate Change (IPCC). Greenhouse Gas Inventory Reference Manual: IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, 1996

2.3 Stationary Source CH_4 and N_2O Emission Estimation Methodologies

While CO_2 emissions are primarily determined by fuel consumption and carbon content and are irrespective of combustor type, CH_4 and N_2O emissions are impacted by equipment type, design, air pollution controls, operation, age, and maintenance, as well as fuel properties. Therefore, more detailed, equipment specific emissions estimation methodologies may be considered for CH_4 and N_2O. Figure 2-3 outlines the methodology for estimating CH_4 and N_2O emissions. Tier 3 emissions estimates are used if fuel consumption by individual combustion equipment can be estimated. If detailed information about combustion equipment's make, model, and operation are available, it may be possible to apply a Tier 4 emission factor. If fuel consumption by individual equipment cannot be estimated and total facility fuel combustion by fuel type can be estimated, then a Tier 2 emissions estimate can be used; however, if the facility fuel consumption cannot be reasonably estimated, then a Tier 1 methodology should be used.

Figure 2-3. CH_4 and N_2O Emissions Estimation Overview



2.3.1 CH_4 and N_2O Emissions Estimates Using Tier 1 Emission Factors

Tier 1 GHG emissions are estimated from a Tier 1 GHG emission factor and corresponding activity data as shown in equation 2-12. This emissions estimate is for the entire facility.

tonnes GHG = Activity Data * EF Eqn. 2-12

Where: GHG = CH_4 or N_2O
tonnes GHG = estimated annual GHG emissions from combustion (tonne/yr)
Activity data = transmission pipeline length or storage stations

Tonnes of CO_2 equivalents are estimated using equation 2-13.

tonnes CO2eq = tonnes GHG * GWP Eqn. 2-13

Where: tonnes CO2eq = estimated annual emissions of the GHG as CO_2 equivalents (tonne/yr)

Table 2-5 lists Tier 1 emission factors for CH_4 and N_2O.

Table 2-5. Tier 1 CH_4 and N_2O Emission Factors for Combustion

Operation	Activity Data	GHG	EF	EF Units	Reference
Transmission	Transmission pipeline length (miles)	CH_4	2.2 E-1	Tonne/mile-yr	GRI 2001
Storage	Storage stations (each)	CH_4	2.6 E+1	Tonne/station-yr	GRI 2001
Transmission	Transmission pipeline length (miles)	N_2O	1.9 E-2	Tonne/mile-yr	GRI 2001
Storage	Storage stations (each)	N_2O	8.3 E-2	Tonne/station-yr	GRI 2001

GRI 2001 - GRI GHGCalc Version 1.0 Emission Factor Documentation, July 2001

2.3.2 CH_4 and N_2O Emissions Estimates Using Tier 2 Emission Factors

Tier 2 emissions for a facility are estimated using total facility fuel flow, an EF from Table 2-6 for CH_4 or N_2O, and equation 2-14 for natural gas and equation 2-15 for liquid fuels. If the fuel heating value is not known then a default value from Table 2-1 should be used.

tonnes GHG_j = Activity $Data_{GFj}$ * EF Eqn. 2-14

where: tonnes GHG_j = estimated annual GHG emissions from combustion of fuel j (tonne/yr)

GHG = CH_4 or N_2O
Activity $Data_{GFj} = Q_{GFj} * HHV_{GFj} * 10^{-6}$ (MMBtu/yr)
Q_{GFj} = scf fuel j combusted at facility/yr
HHV_{GFj} = Btu/scf fuel j
$10^{-6} = MMBtu/10^6$ Btu

tonnes GHG_j = Activity $Data_{LFj}$ * EF   Eqn. 2-15

where: Activity $Data_{LFj} = Q_{LFj} * HHV_{LFj} * 10^{-6}$ (MMBtu/yr)
Q_{LFj} = gal fuel j combusted at facility/yr
HHV_{LFj} = Btu/gal fuel j

GHG emissions as CO_2 equivalents can be determined from equation 2-13. Total estimated annual GHG emissions from combustion are the sum of emissions from each fuel combusted per equation 2-9.

Table 2-6. Tier 2 CH_4 and N_2O Emission Factors for Combustion

Fuel	Activity Data	GHG	EF	EF Units	Reported EF (Units)	Reference
Diesel	MMBtu/yr	CH_4	3.0 E-6	tonne/MMBtu	3 (kg/TJ) (LHV)	IPCC 1996
Diesel	MMBtu/yr	N_2O	6.0 E-7	tonne/MMBtu	0.6 (kg/TJ) (LHV)	IPCC 1996
Gasoline/Petrol	MMBtu/yr	CH_4	3.0 E-6	tonne/MMBtu	3 (kg/TJ) (LHV)	IPCC 1996
Gasoline/Petrol	MMBtu/yr	N_2O	6.0 E-7	tonne/MMBtu	0.6 (kg/TJ) (LHV)	IPCC 1996
Natural Gas	MMBtu/yr	CH_4	9.5 E-7	tonne/MMBtu	1 (kg/TJ) (LHV)	IPCC 1996
Natural Gas	MMBtu/yr	N_2O	1.1 E-7	tonne/MMBtu	0.1 (kg/TJ) (LHV)	IPCC 1996

IPCC 1996 - Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (Reference Manual)

2.3.3 CH_4 and N_2O Emissions Estimates Using Tier 3 Emission Factors

Tier 3 emissions for individual combustion equipment are estimated using a generic combustion technology-based EF from Table 2-7 for CH_4 or Table 2-8 for N_2O and equation 2-16 for natural gas, equation 2-17 for liquid fuels, and equation 2-18 to total the facility emissions for each GHG. If the fuel heating value is not known then a default value from Table 2-1 should be used.

tonnes GHG_{ij} = Activity $Data_{GFij} * EF_{ij}$ Eqn. 2-16

where: tonnes GHG_{ij} = annual GHG emissions from equipment i firing fuel j (tonne/yr)
GHG = CH_4 or N_2O
Activity $Data_{GFij} = Q_{GFij} * HHV_{GFj} * 10^{-6}$ = MMBtu/yr of fuel j fired in equipment i;

$Q_{GFi,j}$ = scf of gaseous fuel j combusted in equipment i/yr
HHV_{GFj} = Btu/scf fuel j
10^{-6} = MMBtu/10^6 Btu
$EF_{i,j}$ = GHG emission factor for equipment i firing fuel j (tonne/MMBtu)

tonnes GHG_{ij} = Activity $Data_{LFij}$ * $EF_{i\,j}$ Eqn. 2-17

where: Activity $Data_{LFij}$ = Q_{LFij} * HHV_{LF} * 10^{-6} = MMBtu/yr of fuel j fired in equipment i;
Q_{LFij} = gal liquid fuel j combusted in equipment i/yr
HHV_{LFj} = Btu/gal fuel j

Tonnes of CO_2 equivalents are estimated using equation 2-13.

The total estimated annual GHG emissions from combustion are the sum of emissions from the individual combustion equipment.

tonnes GHG = $\sum$ tonnes GHG_{ij} (summed over equipment i and fuels j) Eqn. 2-18

where: tonnes GHG = estimated annual GHG emissions from combustion (tonne/yr)

Table 2-7. Tier 3 CH_4 Emission Factors for Combustion

Fuel	Comb Tech	Activity Data	GHG	EF	EF Units	Reported EF (Units)	Reference
Diesel	ICE (>600 hp)	MMBtu/ yr	CH_4	3.7 E-6	tonne/ MMBtu	8.1E-3 lb/MMBtu	AP42 (10/96)
Diesel	ICE (<600 hp)	MMBtu/ yr	CH_4	4.0 E-6	tonne/ MMBtu	4 g/GJ (LHV)	CORINAIR90
Diesel	Boiler, Ext Combustion	MMBtu/ yr	CH_4	1.7 E-7	tonne/ MMBtu	3.8E-4 lb/MMBtu	AP42 (9/98)
Diesel	Gas Turbine	MMBtu/ yr	CH_4	ND	tonne/ MMBtu	ND	AP42 (4/00)
Gasoline/ Petrol	ICE 4-Stroke	MMBtu/ yr	CH_4	3.9 E-5	tonne/ MMBtu	3.9 E+1 kg/TJ (LHV)	EEA/CITEPA (CORINAIR94)
Gasoline/ Petrol	ICE 2-Stroke	MMBtu/ yr	CH_4	1.2 E-4	tonne/ MMBtu	1.2 E+2 kg/TJ (LHV)	EEA/CITEPA (CORINAIR94)
NG	ICE 4- Stroke Rich Burn	MMBtu/ yr	CH_4	1.0 E-4	tonne/ MMBtu	2.3E-1 lb/MMBtu	AP42 (8/00)
NG	ICE 4- Stroke Lean Burn	MMBtu/ yr	CH_4	5.7 E-4	tonne/ MMBtu	1.25 lb/MMBtu	AP42 (8/00)
NG	ICE 2-Stroke Lean Burn	MMBtu/ yr	CH_4	6.6 E-4	tonne/ MMBtu	1.45 lb/MMBtu	AP42 (7/00)
NG	ICE Large Dual Fuel	MMBtu/ yr	CH_4	2.4 E-4	tonne/ MMBtu	240 g/GJ (LHV)	IPCC 1996
NG	Gas Turbine	MMBtu/ yr	CH_4	3.9 E-6	tonne/ MMBtu	8.6E-3 lb/MMBtu	AP42 (4/00)
NG	Boiler (< 300 MW), Ext Combustion	MMBtu/ yr	CH_4	1.0 E-6	tonne/ MMBtu	2.26E-3 lb/MMBtu	AP42 (7/98)
NG	Boiler (> 300 MW), Ext Combustion	MMBtu/ yr	CH_4	1.3 E-6	tonne/ MMBtu	1.4 kg/TJ (LHV)	IPCC 1996

AP-42 - US EPA Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, AP-42 (GPO 055-000-005-001), US EPA OAQPS, Fifth Edition, January 1995 with Supplements A, B, and C, 1996; Supplement D, 1998 errata updated 4/28/00; Supplement E, 1999, and Supplement F, 2000

CORINAIR 94 (Core Inventory Air), European Topic Centre on Air Emissions, CORINAIR 1994 Inventory, European Environment Agency (1998)

CORINAIR 90, European Topic Centre on Air Emissions, CORINAIR 90 Summary Report

Table 2-8. Tier 3 N_2O Emission Factors for Combustion

Fuel	Comb Tech	Activity Data	GHG	EF	EF Units	Reported EF (Units)	Reference (Notes)
Diesel	ICE (>600 hp)	MMBtu/yr	N_2O	2.2 E-6	tonne/ MMBtu	3.03E-7 (tonne/gal)	Env Canada 2003 (A)
Diesel	ICE (<600 hp)	MMBtu/yr	N_2O	1.1 E-5	tonne/ MMBtu	1.0 E-2 (tonne/TJ)	Env Canada 2003
Diesel	Boiler, Ext Combustion	MMBtu/yr	N_2O	8.6 E-7	tonne/ MMBtu	1.9E-3 (lb/MMBtu)	AP42 (4/00)
Diesel	Gas Turbine	MMBtu/yr	N_2O	ND	tonne/ MMBtu	ND	AP42 (4/00)
Gasoline / Petrol	ICE 4-Stroke	MMBtu/yr	N_2O	9.0 E-7	tonne/ MMBtu	1.17E-7 (tonne/gal)	Env Canada 2003 (B)
NG	ICE 4- Stroke Rich Burn	MMBtu/yr	N_2O	4.5 E-7	tonne/ MMBtu	4.0 E-4 (tonne/TJ)	GTI 2002, API 1999
NG	ICE 4- Stroke Lean Burn	MMBtu/yr	N_2O	1.4 E-6	tonne/ MMBtu	1.3 E-3 (tonne/TJ)	GTI 2002, API 1999 (C)
NG	ICE 2-Stroke Lean Burn	MMBtu/yr	N_2O	2.3 E-6	tonne/ MMBtu	2.1 E-3 (tonne/TJ)	GTI 2002, API 1999 (C)
NG	Gas Turbine	MMBtu/yr	N_2O	3.8 E-6	tonne/ MMBtu	4 (g/GJ) (LHV)	Stewart 1998
NG	Gas Turbine w/ SCR	MMBtu/yr	N_2O	1.4 E-5	tonne/ MMBtu	1.3 E-2 (tonne/TJ)	GTI 2002, API 1999
NG	Gas Turbine w/ DLNB	MMBtu/yr	N_2O	3.8 E-6	tonne/ MMBtu	4 (g/GJ) (LHV)	Stewart 1998
NG	Gas Turbine w/ Water Inj	MMBtu/yr	N_2O	2.8 E-6	tonne/ MMBtu	3 (g/GJ) (LHV)	Stewart 1998
NG	Gas Turbine w/ Steam Inj	MMBtu/yr	N_2O	2.8 E-6	tonne/ MMBtu	3 (g/GJ) (LHV)	Stewart 1998
NG	Boiler Ext Combustion	MMBtu/yr	N_2O	9.8 E-7	tonne/ MMBtu	2.16E-3 (lb/MMBtu)	AP42 (7/98)
NG	Boiler w/ LNB	MMBtu/yr	N_2O	2.8 E-7	tonne/ MMBtu	6.27E-4 (lb/MMBtu)	AP42(7/98) CAPP 2003

AP-42 - US EPA Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, AP-42 (GPO 055-000-005-001), US EPA OAQPS, Fifth Edition, January 1995 with Supplements A, B, and C, 1996; Supplement D, 1998 errata updated 4/28/00; Supplement E, 1999, and Supplement F, 2000

Environment Canada 2003 - Environment Canada, Canada's Greenhouse Gas Inventory 1990-2001, Greenhouse Gas Division, Environment Canada, August 2003.

GTI 2002 - Nitrous Oxide Emissions form Natural Gas-Fired Reciprocating Internal Combustion Engines, Draft Memorandum, GTI, January 2002.

API - *Characterization of Emissions from Oil and Gas Production Combustion Units,* Draft Report, 7/99.

Stewart 1998 - R Stewart (1998) A Survey of Gaseous Emissions to Atmosphere from UK Gas Turbines. AEA Technology Environment, UK.

CAPP 2003 - Canadian Association of Petroleum Producers (CAPP) Guide: Calculating Greenhouse Gas Emissions, April 2003

A. Diesel HHV = 5.75; B. gas HHV = 5.46; C. Based on DL

2.3.4 CH_4 and N_2O Emissions Estimates – Moving Beyond Tier 3

Tier 4 (or perhaps more appropriately Tier 3+) emission factors have greater specificity than Tier 3 emission factors by considering parameters, such as equipment make, model, operating conditions, air pollution controls, age and maintenance history. These factors can impact GHG emissions. For the purposes of this discussion, an "operating condition" can be any of the aforementioned parameters that can impact emissions from an individual combustor, including age, maintenance, and actual operating point or range. For example, emissions from a combustor may be expected to change as the equipment ages or as operating hours accumulate from the most recent maintenance; thus, an "operating condition" could be an age range or range of operating hours since the most recent maintenance. The key point is that the parameter differentiates GHG emissions from the combustion equipment.

Tier 4 emission factors are typically provided by equipment manufacturers or developed from emissions testing data. Published Tier 4 emission factors are scarce and beyond the scope of this guidance document; however, it is anticipated that Tier 4 emission factors will become more prevalent as GHG emissions data are collected in the support of emission inventories development and more precise data are warranted. Therefore, Tier 4 emissions estimation procedures are presented along with selected published Tier 4 emission factors.

Tier 4 emissions for individual combustion equipment are estimated using equipment fuel consumption activity data and a Tier 4 emission factor. The primary differences between a Tier 3 and a Tier 4 emissions estimation are: 1.) a piece of equipment's emission factor will depend on the equipments make, model, age, etc, rather than just the combustion technology category (e.g. 4-cycle ICE); and 2.) more than one EF may apply to a piece of equipment over a data collection period if its operation varies sufficiently to impact emissions.

Tier 4 emissions for individual combustion equipment are estimated using equation 2-18 for natural gas, equation 2-19 for liquid fuels, and equation 2-20 to total the facility emissions for each GHG.

At this time, Tier 4 emission factors are not available for all types of equipment. An example of Tier 4 emissions factors for Waukesha ICEs are listed in Table 2-9. For such an estimate, if the fuel heating value is not known, then a default value from Table 2-1 should be used.

$$\text{tonnes } GHG_{ijk} = \text{Activity Data}_{GFijk} * EF_{ijk} \qquad \text{Eqn. 2-19}$$

where: tonnes GHG_{ijk} = estimated annual emissions of GHG from equipment i firing fuel j at operating condition k (tonne/yr)

Activity $Data_{GFijk} = Q_{GFijk} * HHV_{GFj} * (10^{-6}$ MMBtu/Btu) = MMBtu/yr of fuel j fired in equipment i at operating condition k;

Q_{GFijk} = scf of gaseous fuel j combusted in equipment i at operating condition k /yr

HHV_{GFj} = Btu/scf fuel j

EF_{ijk} = GHG emission factor; equipment i firing fuel j at operating condition k (tonne/MMBtu) tonnes GHG_{ijk} = Activity $Data_{LFilk}$ * $EF_{i,jk}$ Eqn. 2-20

where: Activity $Data_{LFijk} = Q_{LFijk} * HHV_{LFj} * 10^{-6}$ = MMBtu/yr of fuel j fired in equipment i at operating condition k;
Q_{LFijk} = gal liquid fuel j combusted in equipment i at operating condition k /yr
HHV_{LFj} = Btu/gal fuel j

tonnes of CO_2 equivalents are estimated using equation 2-13.

The total estimated annual GHG emissions from combustion are the sum of emissions from the individual combustion equipment.

tonnes GHG = $\sum$ tonnes GHG_{ijk};
(sum for equipment i, fuels j, operating conditions k) Eqn. 2-21

where: tonnes GHG = estimated annual GHG emissions from combustion (tonne/yr)

Table 2-9. Selected Tier 4 GHG Emission Factors for Waukesha ICEs Combustion

Model	Operating Condition (A)	Activity Data	GHG	EF (B)	EF Units	Reported EF (Units) (C)	Reference (Notes)
AT25GL	Standard	MMBtu/ yr	CH_4	5.7 E-3	tonne/ MMBtu	6.03 (g/kWh)	CAPP 2003 (B)
AT25GL	Standard	MMBtu/ yr	N_2O	2.8 E-5	tonne/ MMBtu	0.030 (g/kWh)	CAPP 2003 (B)
AT25GL	Ultra Lean	MMBtu/ yr	CH_4	3.9 E-3	tonne/ MMBtu	4.16 (g/kWh)	CAPP 2003 (B)
AT25GL	Ultra Lean	MMBtu/ yr	N_2O	2.4 E-5	tonne/ MMBtu	0.025 (g/kWh)	CAPP 2003 (B)
F 1197G G	Lowest Manifold/ Best Power	MMBtu/ yr	CH_4	3.2 E-3	tonne/ MMBtu	3.35 (g/kWh)	CAPP 2003 (B)
F 1197G G	Lowest Manifold/ Best Power	MMBtu/ yr	N_2O	1.9 E-4	tonne/ MMBtu	0.20 (g/kWh)	CAPP 2003 (B)
F 1197G G	Equal NOx & CO	MMBtu/ yr	CH_4	2.5 E-3	tonne/ MMBtu	2.61 (g/kWh)	CAPP 2003 (B)
F 1197G G	Equal NOx & CO	MMBtu/ yr	N_2O	2.6 E-4	tonne/ MMBtu	0.28 (g/kWh)	CAPP 2003 (B)
F 1197G G	Catalytic Conv.	MMBtu/ yr	CH_4	2.5 E-3	tonne/ MMBtu	2.61 (g/kWh)	CAPP 2003 (B)
F 1197G G	Catalytic Conv.	MMBtu/ yr	N_2O	2.6 E-4	tonne/ MMBtu	0.27 (g/kWh)	CAPP 2003 (B)
F 1197G G	Standard/ Best Economy	MMBtu/ yr	CH_4	1.2 E-3	tonne/ MMBtu	1.27 (g/kWh)	CAPP 2003 (B)
F 1197G G	Standard/ Best Economy	MMBtu/ yr	N_2O	4.2 E-4	tonne/ MMBtu	0.44 (g/kWh)	CAPP 2003 (B)

Canadian Association of Petroleum Producers (CAPP) Guide: Calculating Greenhouse Gas Emissions, April 2003

A. Carburetor Setting
B. Reported emission factor units converted to tonne/MMBtu assuming thermal efficiency of 0.31. Waukesha engine specifications are thermal efficiencies of 0.28 – 0.31 for naturally aspirated engines and 0.31 – 0.36 for lean burn engines.
C. Reported emission factors units. N_2O emission factor estimated as 0.015 * NO_x EF.

2.4 Flare GHG Emission Estimation Methodologies

Figure 2-4 outlines the methodology for estimating GHG emissions from combustion flares. The ideal approach is to use either emissions test data from the flare or a flare of the same design and operation, or to use flare manufacturer emissions data. These data are typically not available, and emissions may be estimated using equations 2-21 to 2-23. These equations assume that industry flares have a combustion efficiency of 98%, with 2% uncombusted CH_4 (per the guidance in CAPP 2003 and Alberta EUB 2001). If the flare gas composition is not known, one of the generic compositions in Table 2-10 may be used.

Flaring is an "event-based" activity typically associated with an emission that would be otherwise "vented". This estimate is based on estimates of event volumes and does not use the standard "EF * AD" calculation approach. Conversions factors are integrated into the equation below. See Section 3 for discussions on estimation of event volumes.

$$\text{tonnes CO2} = 5.16 * 10^{-5} * Q_{FG} * \text{C mole ratio} \qquad \text{Eqn. 2-22}$$

Where: tonnes CO2 = annual CO_2 emissions from flaring (tonne/yr)
Q_{FG} = Volume Gas Flared (scf/yr)
C mole ratio = $\sum$(lbmole HC/lbmole gas * lbmoles C/lbmole HC)
$5.16 * 10^{-5}$ = 1/Molar Volume (lbmole/379.3 scf) * Combustion Efficiency (0.98) * 1 lbmole CO2/lbmole C * MW_{CO2} (44 lb/lbmole) * tonne/2204.6 lb

$$\text{tonnes CH4} = 3.83 * 10^{-7} * Q_{FG} * CH_4 \text{ mole fraction} \qquad \text{Eqn. 2-23}$$

Where: tonnes CH4 = annual CH_4 emissions from flaring (tonne/yr)
Q_{FG} = Volume Gas Flared (scf/yr)
CH_4 mole fraction = lbmole CH4/lbmole gas
$3.83 * 10^{-7}$ = 1/Molar Volume (lbmole/379.3 scf) * 0.02 (% Uncombusted CH_4/100) * MW_{CH4} (16 lb/lbmole) * tonne/2204.6 lb

$$\text{tonnes } N_2O = \text{Activity Data} * \text{EF} \qquad \text{Eqn. 2-24}$$

Where: tonnes N_2O = annual N_2O emissions from flaring (tonne/yr)
Activity Data = Q_{FG} = Volume Gas Flared (scf/yr)
EF = $1.0 * 10^{-10}$ tonne N_2O/scf

The N_2O emissions calculation is based on an emission factor of $1.0 * 10^{-10}$ tonne/scf of flare gas combusted (CAPP 2003, Alberta EUB 2001) and was derived from NOx emissions data with the estimation that N_2O equals 1.5% of NOx.

Tonnes of CO_2 equivalents for CH_4 and N_2O are estimated using equation 2-13.

Figure 2-4. Overview of Flares GHG Emissions Estimation

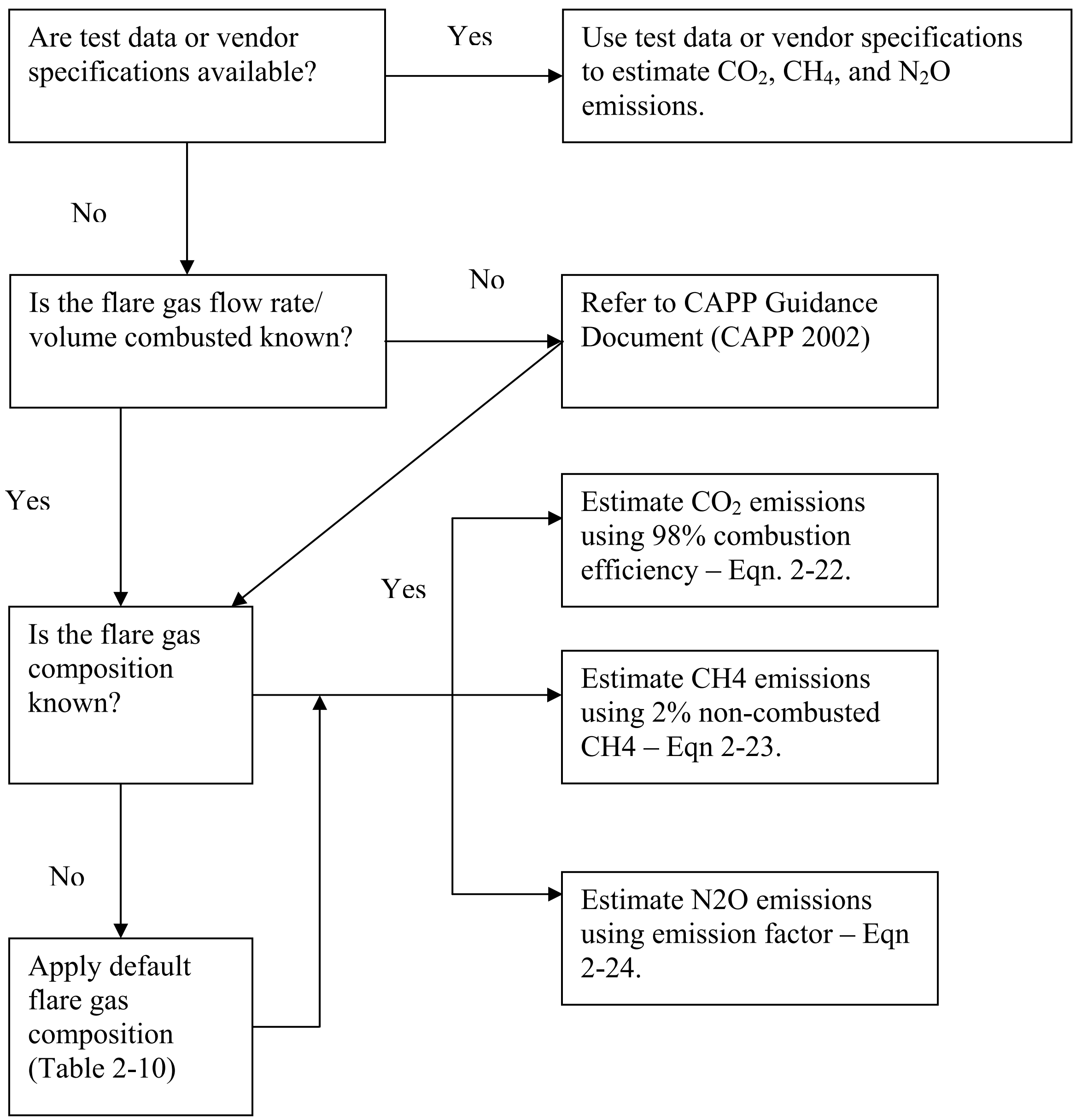


Table 2-10. Generic Natural Gas Compositions

Gas Component	Unprocessed/Raw Gas (mole %) (A)	Processed/Pipeline Gas (mole %) (B)
CH_4	80	91.9
C_2H_6	15	-
C_3H_8	5	-
NMHC – not specified	-	6.84
N_2	-	0.68
CO_2	-	0.58
C mole ratio = ∑(lbmole HC/lbmole gas * lbmoles C/lbmole HC)	1.25	1.06 (C)

A. CAPP 2003 - Canadian Association of Petroleum Producers (CAPP) Guide: Calculating Greenhouse Gas Emissions, April 2003
B. IPPC 2000 – IPCC Good Practice Guidance and Uncertainty management in National Greenhouse Gas Inventories, Chapter 2 (Energy), Table 2.16, page 2.87, May 2000
C. Assumed unspecified NMHC is C_2H_6.

2.5 Incinerator GHG Emission Estimation Methodologies

Typically, an incinerator will operate by co-firing a waste gas stream with a supplemental fuel. The supplemental fuel will be natural gas at most transmission and storage facilities. Estimation of GHG emissions from the incinerator can be accomplished by first estimating CH_4 and CO_2 emissions from the waste stream using a mass balance approach and then from the supplemental fuel using either a mass balance or emission factor approach.

Step 1. Estimate the CH_4 and CO_2 mass emissions from the waste gas stream. This requires an estimation of the average waste gas stream composition. This estimation can be based on waste gas analyses, process data, and/or engineering judgment – and the approach is similar to the discussion regarding Equation 2-22 above.

$$\text{tonnes } CO2_{WG} = 5.26 * 10^{-5} * Q_{WG} * \text{C mole ratio} * DE/100 \qquad \text{Eqn. 2-25}$$

Where: tonnes $CO2_{WG}$ = estimated annual CO_2 emissions from waste gas combustion (tonne/yr)
Q_{WG} = Volume Waste Gas (scf/yr)
C mole ratio = lbmole C/lbmole waste gas = C mole%/100
DE = incinerator destruction efficiency (%)
$5.26 * 10^{-5}$ = 1/Molar Volume (lbmole/379.3 scf) * 1 lbmole CO2/lbmole C * MW_{CO2} (44 lb/lbmole) * tonne/2204.6 lb

Procedures to determine C mole ratio from a gas composition are in Appendix C-2.

$$\text{tonnes } CH4_{WG} = 1.91 * 10^{-5} * Q_{WG} * CH_4 \text{ mole fraction} * (1 - DE/100) \qquad \text{Eqn. 2-26}$$

Where: tonnes $CH4_{WG}$ = estimated annual CH_4 emissions from waste gas combustion (tonne/yr)
CH_4 mole fraction = lbmole CH_4/lbmole waste gas
$1.91 * 10^{-5}$ = 1/Molar Volume (lbmole/379.3 scf) * MW_{CH4} (16 lb/lbmole) * tonne/2204.6 lb

A destruction efficiency of 98% is commonly assumed if the destruction efficiency is not known or an estimate cannot be determined or provided by the supplier of the incinerator.

Step 2. Estimate the CH_4 and total CO_2 mass emissions from the supplemental fuel. If the fuel composition is known, then the CO_2 emissions can be estimated using equation 2-10. If the fuel composition is not known, then the CO_2 emissions can be estimated using equation 2-7 and an emission factor from Table 2-3. CH_4 emissions can be estimated using equation 2-16 (assuming the supplemental fuel is natural gas) and an emission factor from Table 2-7 for CH_4 (Boilers (<300 MW), External Combustion).

Step 3. Estimate the total CH_4 and total CO_2 mass emissions from both the waste gas and supplemental fuel firing by adding the results from Step 1 and Step 2.

Step 4. Estimate the total N_2O emissions using the sum of the annual heat rates (MMBtu/yr) for the waste gas and the supplemental fuel, equation 2-16, and an emission factor from Table 2-8 for N_2O (Boilers (<300 MW), External Combustion).

Tonnes of CO_2 equivalents for CH_4 and N_2O are estimated using equation 2-13.

2.6 Mobile Sources and Fleet Vehicles

Greenhouse gas emissions from highway vehicles are determined from miles driven and emission factors based on GHG emissions per mile. Table 2-11 lists mileage based emission factors for different gasoline and diesel powered vehicle classes. Equation 2-27 determines annual GHG emissions for each vehicle class.

$$\text{tonnes } GHG_{VCi} = \text{Activity Data}_{VCi} * EF_{GHG,VCi} \qquad \text{Eqn. 2-27}$$

Where: GHG = CO_2, CH_4, or N_2O
VC = vehicle class
tonnes GHG_{VCi} = emissions of GHG from vehicle class i (tonne/yr)
Activity $Data_{VCi}$ = total annual mileage for all vehicles in vehicle class i (miles/yr)
$EF_{GHG,VCi}$ = Emission Factor for vehicle class i (tonne/mile)

CO_2 emission factors are based on the "default" vehicle class miles per gallon (mpg) listed in Table 2-11. The CO_2 emission factors ($EF_{CO2,i\ default}$) can be adjusted for "actual" mpg's using the following equation.

$$EF_{CO2,i\ actual} = EF_{CO2,i\ default} * (\text{default mpg/actual mpg}) \qquad \text{Eqn. 2-28}$$

The total annual vehicle fleet GHG emissions are the sum of emissions from the individual vehicle classes.

$$\text{tonnes GHG} = \sum \text{tonnes}_{VCi}; \text{ (summed over vehicle classes i)} \qquad \text{Eqn. 2-29}$$

Table 2-11. Mobile Source Highway Vehicles GHG Emission Factors

Vehicle Class	APC [a]	Fuel	mpg	tonne / mile [b]			Notes	Ref
				CO_2	CH_4	N_2O		
Gasoline Auto	LEV	Gasoline[c]	26	3.4E-4			1	
Gasoline Auto	LEV	Gasoline			1.7E-8	2.2E-8	2	A
Gasoline LDT	LEV	Gasoline	14	6.3E-4			1	
Gasoline LDT	LEV	Gasoline			2.2E-8	1.5E-8	2	A
Gasoline HDV	All	Gasoline	6	1.5E-3			1	
Gas HDV LEV	LEV	Gasoline			4.3E-8	2.9E-8	3	A
Gas HDV T1	EPA Tier 1	Gasoline			6.6E-8	1.8E-7	3	A
Diesel Auto	All	Diesel	24	4.3E-4			1	
Diesel Auto AC	Advanced Control (AC)	Diesel			5E-10	1.0E-9	4	A
Diesel Auto MC	Moderate Control MC)	Diesel			5E-10	1.0E-9	4	A
Diesel Auto UC	Uncontrolled (UC)	Diesel			6E-10	1.2E-9	4	A
Diesel LDT	All	Diesel	15	6.9E-4			1	
Diesel LDT AC	Advanced Control	Diesel			5E-10	1.5E-9	4	A
Diesel LDT MC	Moderate Control (MC)	Diesel			5E-10	1.4E-9	4	A
Diesel LDT UC	Uncontrolled	Diesel			6E-10	1.7E-9	4	A
Diesel HDV	All	Diesel	7	1.5E-3			1	
Diesel HDV AC	All	Diesel			5.1E-9	4.8E-9	4	A
Motorcycles	All	Gasoline	60	1.5E-4			1	
Motorcycles UC	Uncontrolled	Gasoline			9.0E-8	8.7E-9	5	A
Motorcycles NC	Non-catalyst Controls (NC)	Gasoline			6.7E-8	6.9E-9	5	A

[a] Appendix C-4 includes a discussion of vehicle emission controls.
[b] Table 2-11 Emission Factors are based on a recent EPA study that presents current U.S. factors. These factors differ from those in other sources such as the IPCC Protocol and API Compendium.
[c] Gasoline or Petrol

APC – Air Pollution Controls; HDV – Heavy Duty Vehicle; LDT – Light Duty Truck; LEV – Low Emission Vehicle; mpg – miles per gallon; AC – Advanced Control; UC – Uncontrolled; NC – Non-catalyst Controls

Notes and References for Table 2-11:

A. US Emissions Inventory 2005: Inventory of US Greenhouse Gas Emissions and Sinks: 1990 - 2003, EPA 430-R-003, US Environmental Protection Agency, Washington, D.C., (April 2005)
1. Tonne/mile based on fuel properties listed in Table 2-13 and tabulated mpg
2. Greater than 99% of Vehicle Class miles in 2003 from vehicles equipped with LEV technology.
3. 65% of HDV miles in 2003 from vehicles equipped with EPA Tier 1 emissions control technology and 65% of HDV miles in 2003 from vehicles equipped with LEV.
4. UC technology for Model Years 1966-1982, MC technology for Model Years 1983-1995; AC technology for Model Years 1996-2002.

2.7 Construction Equipment

Greenhouse gas emissions from non-highway construction equipment are determined from fuel consumption and fuel consumption-based emission factors per equation 2-30. Table 2-12 lists fuel consumption based emission factors for gasoline and diesel powered construction equipment.

$$\text{tonnes } GHG_{CEj} = \text{Activity Data}_{CEj} * EF_{GHGCEj} \qquad \text{Eqn. 2-30}$$

Where: $GHG = CO_2$, CH_4, or N_2O
CE = construction equipment
tonnes GHG_{CEj} = GHG emissions from construction equip. firing fuel j (tonne/yr)
Activity $Data_{CEj}$ = total annual use of fuel j in CE (gal/yr)
EF_{GHGCEj} = GHG emission factor for CE firing fuel j (tonne/gal)

The total construction equipment GHG emissions are the sum of emissions from combustion of the different fuels.

$$\text{tonnesGHGe}_{CE} = \sum \text{tonnesGHGe}_{CEj}; \text{ (summed over fuels j)} \qquad \text{Eqn. 2-31}$$

Table 2-12. Mobile Source Construction Equipment GHG Emission Factors

Fuel	tonne/gal			Notes	Reference
	CO_2	CH_4	N_2O		
Gasoline/Petrol	8.8E-3	5.0E-7	2.2E-7	1	A
Diesel	1.0E-2	5.8E-7	2.6E-7	1	A

A. US Emissions Inventory 2005: Inventory of US Greenhouse Gas Emissions and Sinks: 1990 - 2003, EPA 430-R-003, US Environmental Protection Agency, Washington, D.C., (April 2005)
1. Tonne/gal based on fuel properties listed in Table 2-1 and EFs of 0.08 g N_2O/kg fuel and 0.180 g CH_4/kg/fuel for both gasoline and diesel.

Table 2-13: Fuel Properties used for Vehicle Emission Factor Conversion to Tonnes

Fuel	Density		Higher Heating Value		Lower Heating Value		Carbon	Ref.
	lb/gal	kg/m^3	Btu/bbl	Joule / m^3	Btu/bbl	Joule / m^3	% by wt.	
Diesel	7.06	846.1	$5.83 * 10^6$	$3.82 * 10^{10}$	$5.55 * 10^6$	$3.62 * 10^{10}$	87.3 (B)	A
Gasoline	6.17	739.3	$5.46 * 10^6$	$3.62 * 10^{10}$	$5.19 * 10^6$	$3.44 * 10^{10}$	85.5 (B)	A, B
Kerosene	6.76 (B)	810	$5.67 * 10^6$ (A)	$3.76 * 10^{10}$ (A)	$5.39 * 10^6$	$3.57 * 10^{10}$		A, B
Natural Gas (methane)	0.042 lb/ft3	0.673	1,020 Btu/ft^3	$3.80 * 10^7$	918 Btu/ft^3	$3.42 * 10^7$	76	C

A. EPA AP-42, Appendix A, Miscellaneous Data Converstion Factors, 1995.
B. North American Combustion handbook, Volume I: Combustion Fuels, Stoichiometry, Heat Transfer,Fluid Flow, 3rd Ed., 1986.
C. EPA AP-42, Section 1.4, Natural Gas Combustion, 1998

3.0 VENTED SOURCES

Methane emissions from venting differ from fugitive emissions in that these emissions are typically a deliberate action associated with plant activities, or are produced when emergency situations require or produce a rapid reduction in process pressures. Vented GHGs can be a continuous emission, be sporadic, or occur with a less than annual frequency. Vented emissions take place either in known locations such as in the case of process vents, or at the location of an accidental release. Vented emissions can vary significantly in size, scope and severity. Examples of sources of vented emissions include:

- Glycol dehydrator process vents (Section 3.2);
- Pneumatic devices such as valve actuators, controllers, isolation valves, and pneumatic pumps (detailed in Section 3.3);
- Planned or non-routine maintenance venting or blowdown (Section 3.4).

Vented emissions have been considered in a number of prior greenhouse gas guidance documents. These available studies provide tiers or accuracy levels of vented emissions. Based on the GRI/EPA Study, vented emissions comprise 28.3% of the total methane emissions for the transmission and storage sector. (33.0 +/- 33.9 BSCF out of a total of 116.5 +/- 58 BSCF.)

Natural gas powered pneumatic instrument controllers and valve actuators were collectively the largest source of methane emissions in the U.S. national methane inventory. Default emission factors are based on data collected in the 1992 and reported in the GRI/EPA study. These data may no longer represent industry averages (e.g., as presented in default emission factors) as many high bleed devices have been systematically replaced with low or no bleed devices.

Minimization of vented emissions often requires variation of the process that produces the emissions, or addition of control equipment. For instance, control equipment might include the replacement of a natural gas driven pneumatic controller with an air actuated controller, or the addition of a low pressure flare system for tank vents and pressure relief valve systems. Other reductions in vented emissions can be achieved with different work practices, such as reducing pipeline pressures prior to releasing gas pursuant to a pipeline repair project.

Since combustion emission factors have broad applicability across industrial sectors, many accounting and reporting protocols include emission estimation guidelines for combustion. The primary emission factors for combustion are identified in Section 2. Default methods and emissions factors are commonly applied. In the gas transmission and storage sector, vented and fugitive emission factors and estimation methods are more specifically related to the natural gas sector – especially for GHG venting. Thus, in addition to presenting emission estimation methodology that includes default emission factors, this section briefly discusses the different available sources of emissions data for vented emissions from transmission and storage activities.

It is important to differentiate between fugitive emissions (see Section 4) and vented emissions. Pipeline blowdown events, whether deliberate for operating purposes (such as to reduce pipeline pressure or a post-maintenance purge), or unintentional as the result of an upset condition (such as depressurization of a pipeline section to facilitate emergency repairs), are classified as vented or accidental emissions.

Similarly, losses associated with pressure safety relief valve operation, preventing overpressure events (includes closed systems routed to control devices such as flares) are also included in the vented emissions section. However, gas "passing" relief valve seals, also referred to as "valve blow-by", that occurs following a relief valve operation event due to improperly reseated valve surfaces (e.g. chattering or malfunctioning relief valve resulting from sealing surfaces that are not properly mated), are considered fugitive emissions.

3.1 Emission Tiers and Basis of Default Emission Factors

A number of resources were reviewed in assembling the information for Section 3. Reporting/accounting protocols and other internationally recognized documents (e.g., the WRI/WBCSD GHG Protocol, IPIECA Guidelines, IPCC guidelines) refer readers to details in documents such as the API Compendium for determining sector-specific emissions. Background references that consider gas industry vented emissions include:

- GRI / EPA Study: The data from this report continue to be used for emission factors for vented emissions from gas transmission and storage.
- GRI-GHGCalc™ software: The emission factors for all tiers are from the GRI/EPA study, with some supplementary data. Version 1.2 of the software includes different factors for U.S. and Canadian operations.
- API Compendium: GRI/EPA study data are used, and emission factors are presented with different units than factors using the same data in GHGCalc. As discussed further below, the API Compendium is primarily throughput based, while the GHGCalc™ approach is primarily equipment based. Both approaches primarily use the GRI/EPA data and thus have similar uncertainty in the emission factors.
- IPCC Guidelines: Emission factors are included in the 1996 guidelines. IPCC factors are intended for national-level emission estimates. Emission factors are presented for different geographical regions, including a single emission factor for the U.S. and Canada. The source for this data is the October 1992 U.S. EPA Report, *US Anthropogenic Methane Emissions in the United States. Estimates for 1990: Report to the Congress.*
- Australian Greenhouse Office: This document includes vented emission factors for gas processing plants and emission factors related to flaring, but does not present emission factors for transmission or storage. The AGO presents one emission factor that captures vented, fugitive and combustion GHGs from all oil and gas industry sectors in a single "full fuel cycle" emission factor.

While the second and third tier of emission factors can give a more detailed emissions estimate for vented emissions, many venting events are directly tied to company practices. Thus, to obtain a more accurate GHG emission estimate for vented emissions from a specific plant or company, a fourth tier estimate may be desired (i.e., and engineering estimate of the event) – for at least some activities (e.g., blowdowns or maintenance related venting). This section provides examples of Tier 4 estimates for vented emissions.

Process and event specific emission factors are presented in sections below for vented emissions. A Tier 1 estimate of vented emissions is intended to address all of the subset of activities that are identified in the activity-specific sections that follow. Thus, the Tier 1 estimation approach is presented separately from the facility level and equipment level methodologies. Two Tier 1 emission factors are available from the established literature.

3.1.1 Vented Emissions – Calculation Methods and Conversion Factors

GHG emissions from vented sources based on default emission factors (Tiers 1 – 3) are calculated using the standard equation of:

$$\text{Tonne GHG} = AF \times EF \times CF \qquad \text{Eqn. 3-1}$$

where: AF is the Activity Factor,
EF is the Emission Factor from each source,
CF is the conversion factor to convert to tonne/year.

Vented sources usually emit methane from natural gas, but also include CO_2 from natural gas. For gases other than CO_2 it is necessary to modify equation 3-1 to include the Global Warming Potential, according to equation 3-2. For reporting purposes for methane, both tonnes CH_4 and tonnes CO2eq should be calculated, and Equation 3-1 leads to:

$$\text{Tonne CO2eq} = AF \times EF \times CF \times GWP \qquad \text{Eqn. 3-2}$$

where: GWP is 21 for CH_4.

Default emission factors presented in the sections that follow include different units for the emissions, such as mass based (lb) or volume based (SCF). The emission factors in this section are given in lbs/year, scf/year or MMscf/year. The factors to convert these units to tonnes/year are as follows:

Greenhouse Gas	Emission Factor Units	Conversion factor to tonne/year
CH_4	lb/year	4.54E-4
CH_4	scf/year	1.9E-5
CH_4	MMscf/year	19
CO_2	lb/year	4.54E-4
CO_2	scf/year	5.2E-5
CO_2	MMscf/year	52

3.1.2 Tier 1 Emission Estimate – Vented Emissions

Tier 1 emission estimates are intended as a qualitative assessment of emissions. Tier 1 default emissions factors are based on a high-level indicator of corporate activity, and do not consider factors such as equipment age, type, or size. Vented emissions are related to activities and practices that can significantly differ for different companies or even at different facilities within the same company, including the use of pneumatic devices, and practices for blowdown and process venting. In addition, default Tier 1 emission factors are based on historical datasets and do not account for operating practices that many companies have implemented in recent years, such as the replacement of pneumatic devices with low or no-bleed alternatives. Thus, the user should understand the limitations of a Tier 1 estimate of vented emissions to those circumstances where Tier 2 or Tier 3 activity data are not available.

The Tier 1 emission factor is based on data from the GRI/EPA study and follow-up work completed with GRI Canada to expand GHGCalc™ to consider Canadian data. The Tier 1 emission factors for transmission and for storage vented emissions are presented in Table 3-1.

Table 3-1: Tier 1 Emission Factors for Vented Emissions.

Tier	Segment	Activity Data	GHG	Emission Factor	EF Units
1	Transmission	Pipeline length	CH_4	3,944	lb/mile-yr
1	Storage	Storage Stations	CH_4	479,000	lb/station-yr

A Tier 1 annual vented emissions estimate reported as CH4 is calculated according to equation 3-1. CO2eq is calculated per equation 3-2. The example is shown here:

tonnes CO2eq = EF * Activity Data * GWP (i.e., 21) * CF (i.e., 1 tonne/2204.6 lbs)

For clarity, some users of this document may be familiar with an IPCC emission factor for this emission category. Note that the IPCC emission factor is commensurate with a “rolled up” Tier 1 estimate of emissions from processing, transmission (including storage), and distribution. The factor is intended for national level estimates and is based on an energy “consumption” metric (i.e., kilograms per petajoule (equivalent to a thousand trillion joules or roughly 30 million kilowatt-hours of gas consumed). Thus, this factor has limited utility for company-specific estimates and is not presented in this document. The IPCC guidelines are being updated with release planned in 2006. The update will likely include emission factors based on units that can be applied to a Tier 1 estimate.

3.2 Dehydrator Process Vents

Methane emissions can occur in association with venting from glycol dehydrator units. Most water is removed from natural gas with a separator located in the producing field or at the entrance to a processing plant. Further drying of natural gas may be required to meet pipeline specifications, and glycol dehydration units are the most prevalent equipment type used. Dehydrators are abundant in the gas production and processing sectors, but can also be located at transmission and storage facilities. In a glycol dehydrator, the glycol absorbs water, but will also absorb methane (and CO_2) from the gas stream. Upon regeneration of the glycol, these absorbed gases are released and vented. Regeneration of the glycol is completed using combustion to heat the water-rich glycol in the reboiler. Combustion emissions can be calculated using the procedures in Section 2. If a more refined (i.e., Tier 4) estimate is desired, emissions of absorbed methane can be calculated using software, such as the GRI-GLYCalc™ program. Since GLYCalc may already be used to estimate other emissions (e.g., HAPs or VOCs), methane data may be readily accessible to the operator.

GHGCalc™ includes the same emission factors for Tiers 2 and 3 for dehydrator methane emissions, which are based on the GRI/EPA study (volume 14). The API Compendium also includes sector specific emissions factors from the GRI/EPA study. These factors are based on natural gas specific density and percent methane that are "typical" for the natural gas industry. Alternatively, the API Compendium also lists factors developed by industry based on the 1998 GRI report, *Investigation of Condenser Efficiency for HAP Control from Glycol Dehydrator Vent Streams* (GRI-98-0073). These emission factors include emissions from gas assisted pumps used to convey the glycol (discussed further below). In addition, factors are presented that include consideration of whether a gas-water flash separator is present upstream of the dehydrator. Since these factors are more intrinsic to operations upstream of gas transmission, the associated emission factors choices are not presented here and the reader is referred to Section 5 of the API Compendium.

Based on the available data, the default emission factors for vented emissions from glycol dehydration are presented in Table 3-2. GHGCalc includes the same emission factors for Tier 2 or Tier 3. The methane emission factor is based on an assumption of 93.4% methane in the natural gas.

Table 3-2: Tier 2 or 3 Emission Factor for Glycol Dehydrator Vented CH_4 Emissions.

Tier	Segment	Activity Data	GHG	Emission Factor	EF Units
2 or 3	Transmission	Annual natural gas processed (MMSCF/yr)	CH_4	3.96	lbs CH_4 per MMSCF gas
2 or 3	Storage	Annual natural gas processed (MMSCF/yr)	CH_4	4.95	lbs CH_4 per MMSCF gas

Emissions are calculated using equation 3-1 and 3-2.

If glycol is pumped using a pneumatic device such as a Kimray pump, then the pump emissions need to be determined as well. To estimate dehydrator vent emissions using a Tier 4 estimate, the unit could be modeled using GLYCalc™ or similar process simulators. In addition, using actual natural gas methane content rather than the default value from the reference would improve the estimate (i.e., multiply the emissions by the ratio of the actual methane content as a percentage (or an assumed methane content if an actual measurement is not available) and divide by 93.4, the assumed percentage used to develop this emission factor).

3.3 Pneumatic Devices

Natural gas wells, compressor stations, meter and regulator stations, and treatment plants are often located in places where there is not access to electricity from the main grid or other on-site electrical power available. Thus, natural gas can be used to drive pneumatic equipment, including valve actuators, liquid pumps, and control devices such as tank level controllers. Venting of the motive gas constitutes a GHG emission.

A pneumatic device is a mechanical device operated by compressed air or natural gas. Some of these devices discharge the power gas (also called supply gas) to the atmosphere. There are few pneumatic devices associated with the pipeline. Within compressor stations and storage facilities, pneumatic devices include, for example, gas-actuated isolation valves and continuous bleed controllers.

In estimating emissions from pneumatic devices, it is important to recognize that many companies have replaced vented pneumatics in recent years. For example, many U.S. companies that participate in the EPA Natural Gas STAR program have reduced methane emissions by upgrading pneumatic devices. Thus, if an initial GHG inventory is being developed based on current practice that includes minimal or no vented emissions from pneumatic devices, it is possible that development of the GHG inventory for a historical base year will require special attention to this topic to ensure that operational changes are addressed.

3.3.1 Controllers and Valve Actuators

Each time a pneumatic valve is actuated, natural gas is vented (unless it is recovered). The amount of natural gas vented depends on the valve type, valve size, and frequency of activation. Pneumatic devices can be continuous bleed devices in which case a small flowrate of natural gas is continually vented, or intermittent devices. For more accurate Tier 3 estimates, pneumatic counts by type are required. If a pneumatic device is typically inactive, the device may be excluded from the total device count. If a company is conducting a system-wide inventory, compiling a device count may be onerous. An approach to estimating pneumatic device counts is provided in Section 3.3.2. If an actual count is not attained, the relative amplitude of these emissions based on the estimated count can be judged to determine whether additional effort is necessary to complete a rolled up accounting of device count by facility.

Key types of pneumatic controllers and actuators include:

- Continuous Bleed Pneumatics: Controllers are used in the natural gas industry to regulate level, flowrate, temperature, or pressure. Throttling control is carried out by orifice-flapper controllers that have continuous or intermittent bleed. Other types will bleed during the activation cycle. The methane emissions depend on the gas supply methane content and pressure, the type of controller, and the number of activations.
- Turbine Valve Operator: Turbine operators are usually attached to gate valves. Natural gas is emitted through a small rotating "turbine", which is attached to gears that move the valve stem. Natural gas is vented when the valve is actuated. Methane emissions depend on the gas characteristics, valve type, age, maintenance history, and number of actuations.

- Pneumatic Valve Operator: A displacement-based valve operator is normally used to turn plug valves or ball valves. The natural gas can exert pressure directly on the actuator element, or it can exert a force on hydraulic fluid that in turn exerts a force on the valve actuator. Natural gas is emitted when the valve is actuated.

The available emission factors for pneumatic actuators/controllers are based on the GRI/EPA Study. Table 3-3 presents Tier 2 and Tier 3 emission factors for transmission and storage, as presented in GHGCalc™. The same emission factors are presented in the literature for transmission and storage, while different emission factors are provided for other sectors. The Tier 2 emission factor does not differentiate between the different actuators, while Tier 3 requires device count by type. The mass-based emission factor is based on 93.4 volume percent methane in natural gas, and can be adjusted to an alternative factor based on a measured natural gas methane concentration for a specific facility.

Table 3-3: Transmission and Storage Methane Emission Factors for Pneumatic Actuators and Controllers.

Tier	Segment	Activity Data	Emission Source	Gas	EF	Units
2	Trans. or Storage	Device count	Gas-Operated Pneumatics Actuators or Controllers	CH_4	6,847	lb/device-yr
3	Trans. or Storage	Device count	Continuous Bleed Pneumatics	CH_4	19,620	lb/device-yr
3	Trans. and Storage	Device count	Pneumatic/Hydraulic Valve Operator	CH_4	221.9	lb/device-yr
3	Trans. and Storage	Device count	Turbine Valve Operator	CH_4	2,665	lb/device-yr

To calculate annual tonnes of CH_4 and CO2eq, see equations 3-1 and 3-2. If device count cannot be determined, see Section 3.3.3 for estimating device counts.

3.3.2 Isolation Valves and Station Control Loops

Compressor stations usually have emergency shutdown systems and emergency blowdown systems. A critical component of this system is to isolate the compressor station before the station is blown down. The isolation valve or pipeline gate valve is usually a pneumatic device. If this valve is natural gas driven, then it will also emit greenhouse gas. A Tier 3 emission factor is presented in Table 3-4. This emission factor is based on Canadian data as presented in GHGCalc™ version 1.2.

Meter and pressure regulation (M&R) stations include transmission to transmission stations as well as transmission to customer stations. The majority of losses at M&R stations are due to fugitive and pneumatic devices. For delivery to distribution companies, the isolation valve for these stations may be operated by the transmission or storage company, and the vented gas needs to be included in the emission inventory as appropriate. The emission factor in Table 3-4 is from GHGCalc™, where it was presented as a Distribution sector factor, but it can be applied to transmission, depending upon owner/operator of the facility and reporting convention.

Level controllers and pressure control devices can be electronic or driven pneumatically by air or natural gas. Typically larger compressor stations have a separate compressed air system for these devices, but small plants and those in remote locations may use natural gas. Newer equipment tends to use electronic controllers eliminating the need for natural gas emissions. A key point for these control loops is that the natural gas to drive the pneumatics in the system is often taken from the compressor fuel line. If this is the case, then care must be taken to ensure that the gas is considered a methane emission, not a CO_2 emission from the compressor. The difference in global warming potential between CO_2 and methane is a factor of twenty-one. Thus, if this vented gas is improperly considered a combustion emission, then the greenhouse gas emissions will be underreported. A Tier 3 emission factor is presented in Table 3-4 based on Canadian data as presented in GHGCalc version 1.2.

Similar to compressor station control loops, metering and regulator stations have control loops to maintain levels and flowrates. These control loops are pneumatic devices that can be air or natural gas driven. Emissions from natural gas driven pneumatics need to be included in the emission inventory if the station is operated by the transmission or storage company. The emission factor in Table 3-4 is from GHGCalc™ and presented as a Distribution sector factor, but it can be applied to transmission, depending upon owner/operator of the facility and reporting convention.

Table 3-4. CH_4 Emission Factors from Pneumatic Driven Isolation Valves and Control Loops.

Tier	Segment	Activity Data	Emission Source	Gas	EF	Units
3	Transmission or Storage	Device count	Isolation Valve Operator	CH_4	810.5	lb/device-yr
3	Transmission or Storage	Device count	M&R Station Isolation Valve	CH_4	796	lb/device-yr
3	Transmission	Device count	Compressor Stn Control Loop	CH_4	8,023	lb/device-yr
3	Transmission or Storage	Device count	M&R Station Control Loop	CH_4	7,584	lb/device-yr

To calculate annual tonnes of CH_4 and CO2eq, see equations 3-1 and 3-2.

3.3.3 Estimation of Pneumatic Device Count

To simplify obtaining activity factors (pneumatic device counts at each pipeline and storage compressor location), two methods of estimating the average number of pneumatic devices per compressor engine are outlined below. If this estimate is used in lieu of an actual count, the relative contribution of these emissions should be assessed in the final rolled up inventory to determine the need to develop a more specific accounting of the number of pneumatic devices.

The first method is based on first principles and is highly dependent on the age of the engine and whether the facility utilizes instrument air or gas in their pneumatic controls. The second is based on data obtained by GRI during field surveys for the GRI/EPA Study and is representative of a wide range of engine types and ages.

- Method 1: 5 pneumatic devices per engine; ±5 (100 percent uncertainty)

  An estimate of device count per engine can be assessed based on an understanding of applications of these devices. For a three stage compressor, there is typically a scrubber before the first stage, before the second stage and before the third stage. Each scrubber would have three level control loops, one for a dump valve, one for a high alarm and one for a high-high shutdown. In addition, other configurations used include a single fuel gas scrubber for all the compressors, which would also have three level control devices.

  Also, there may be a flow controller or a pressure controller, and in rare cases an automatic louver on the engine cooling radiator. For newer compressor installations, high alarms and high-shutdown pneumatic devices have been replaced by electronics.

- Method 2: 10 pneumatic devices per engine ± 5 (50% Uncertainty)

  An estimate of device count per engine can be developed based on statistics from the GRI/EPA Study. From the GRI/EPA Study (Volume 12 of 14: Pneumatic Devices, June 1996, Methane Emissions from the Natural Gas Industry; Page 62), the average number of pneumatic devices per station is 40 ± 37% for the transmission and storage sector. Of the 40 pneumatic valves, 6.25 are turbine devices, 20.9 are rotary vane, and 12.9 are continuous bleed. The number of devices per site is based on the total number of devices observed during site visits. The confidence bound on the number of devices per station was determined based on the spread of site data.

  There are an estimated 2,175 ± 8% transmission and storage stations nationally based on 1,700 compressor stations, 386 underground storage stations, and 89 LNG storage stations. From GRI/EPA Study (Volume 5 of 14: Activity Factors, Page 68), the number of reciprocating engines is estimated at 6,785 in the transmission sector and 930 in the storage sector for a total of 7,715 ± 10% engines. The estimated number of turbines in the transmission sector is 681, with 136 in the storage sector for a total of 817 ± 10% turbines. The resulting estimated total count for all engines and turbines in the transmission and storage sector is 8,532 units ± 9.1%.

  An average number of engines and turbines per station can be derived by dividing this total count by the estimated number of stations (i.e. 8,532/2,175 = 3.9 engines and turbines per station). Using the average pneumatic devices per station (40) divided by the average engine/turbine count per station (3.9) results in:

  = 40 (avg. device count) / 3.9 (avg. engine/turbine count) = 10 pneumatic devices/engine

3.3.4 Pneumatic Pumps

Chemical injection pumps are used to deliver a measured quantity of chemicals into wells and into pipelines to ensure that corrosion of the pipe or well is minimized. These pumps can be electric or air driven. At remote sites, this is often not practical, and high pressure natural gas is used as a motive source. Chemical injection pumps can be piston or diaphragm pumps.

Gas-assisted glycol (Kimray) pumps are used to move glycol solutions through the glycol dehydrator process when electric or air driven pumps are not available or practical. If natural gas is used as the motive force, then methane is emitted when the natural gas is vented.

These pumps are common in oil and gas production fields, but less prevalent in facilities that offer electrical service – and have limited application in gas transmission and storage. Vented gas from pneumatic pumps can be recovered (e.g., in a vapor recover system and sent to a low pressure flare), but is typically vented to the atmosphere. Vented emissions of greenhouse gas from these pumps is dependent on pump size / rate, type, frequency of use, gas supply pressure and gas methane composition. Emission estimates are available based on emission factors from the GRI/EPA Study. In addition, the API Compendium offers "integrated" emission factors that consider dehydrator methane venting, flash tank application to the dehydration process, and Kimray pump usage. Since these process approaches are not typical for "downstream" gas transmission and storage facilities, the reader is referenced to Section 5 of the API Compendium for the methodology.

The GRI/EPA Study (volume 13) present emission factors for pneumatic chemical injection pumps. The factors are based on "production segment" natural gas containing 78.8 volume percent methane. In Table 3-5, the emission factors are based directly on the GRI/EPA Study factors, but adjusted to consider natural gas containing 90% methane. The precision value is from the GRI/EPA report. In addition, GHGCalc presents an emission factor for the storage sector based on data from the GRI/EPA Study. This factor can also be used for transmission.

Table 3-5: Emissions Factors for Pneumatic Chemical-Injection Pumps and Kimray Pumps.

Tier	Segment	Activity Data	Emission Source	Gas	EF	Units
3	Trans. or Storage	Pump count and usage	Piston Pump	CH_4	56*	SCF CH_4 per pump-day
3	Trans. or Storage	Pump count and usage	Diaphragm Pump	CH_4	509*	SCF CH_4 per pump-day
3	Storage	Gas volume dehydrated	Kimray Pump (dehydrator)	CH_4	7.5	lb/MMSCF

* This emission factor is adjusted from the value in the GRI/EPA Study (78.8% methane), which is based on E&P segment gas quality, to account for higher CH_4 content in pipeline natural gas (90% methane was assumed for this calculation).

To calculate annual tonnes of CH_4 or CO2eq for pumps, see equations 3-1 and 3-2.

Alternatively, to conduct a Tier 4 estimate, pump specifications can be used along with site-specific data. For example, a pump injecting corrosion inhibiting chemicals into a pipeline that operates annually could determine an accurate estimate based on pump characteristics including:

- Equipment stroke rate (e.g., 20 injections per hour),
- Pump volume specification (e.g., 0.75 liters (standard) per cycle),
- Average natural gas methane content (e.g., 90%).

The emission calculation would determine the annual volume emitted based on the specifications above, then convert to tonnes CO2eq using the standard SCF methane to tonnes CO2eq conversion presented elsewhere in this document.

3.4 Blowdown and Maintenance Related Events

Blowdowns or system venting can occur to prepare a pipeline or equipment for maintenance/inspection, in association with an emergency shutdown event, or from release of pressure relief devices. In estimating annual greenhouse gas emissions, default emission factors are available. However, these releases are related to discrete events (e.g., scheduled inspection), which is difficult to capture in an average or default emission estimation methodology. The factors provided are based on studies and represent "typical" activities for transmission and storage activities. As an alternative to providing estimates based on the default emission factors, a company can provide a Tier 4 estimate by maintaining records of the events that constitute planned or emergency venting for the pipeline, compressor stations, or storage facilities. The amount of annual GHG emissions depends upon the summation of event specific releases, and characteristic parameters include the volume of the pipeline segment or size of the unit being blown down, the pressure of the system, the gas composition, and the frequency of events.

Emission factors for blowdown are available for the pipeline, compressor stations, storage facilities, and M&R stations, as shown in Table 3-6. The emission factors available are at the facility level. This is typically commensurate with a Tier 2 estimate, but is categorized as Tier 3 in GHGCalc™. A calculation should be completed for each of the application "activities" in Table 3-6 – i.e., total vented emissions are the cumulative of the estimate from blowdown within a compressor station, pipeline blowdown, M&R station blowdown, and storage facility blowdown.

Available data for transmission and storage is based on the GRI/EPA study as summarized in GHGCalc. The emission factor for M&R Station blowdowns is also in GHGCalc, but based on a Canadian study by URS Corporation. The alternative Tier 4 approach requires calculation and aggregation of event specific emissions based on the physical characteristics of the system and the gas released, as discussed further below.

The emission factors in Table 3-6 are based on natural gas methane content of 93.4 volume percent and can be adjusted based on an actual/measured value for a particular facility or pipeline.

Table 3-6: Emissions Factors for Blowdown and Equipment Venting Events.

Tier	Segment	Activity Data	Emission Source	Gas	EF	Units
3	Transmission	Station Count	Blowdown & Venting	CH_4	223,758	lb/station-yr
3	Transmission	Pipeline Length	Pipeline Blowdown	CH_4	1729	lb/mile-yr
3	Transmission	M&R Station Count	Blowdown & Venting	CH_4	29,817	lb/station-yr
3	Storage	Storage Facility Count	Blowdown & Venting	CH_4	184,000	lb/station-yr
3	Storage	Pipeline Length	Pipeline Blowdown	CH_4	13	lb/mile-yr

To calculate annual tonnes of CH_4 and CO2eq, see equations 3-1 and 3-2.

3.4.1 Tier 4 GHG Emission Estimation for Event-Based Venting

As noted above, the applicability of the default emission factors are dependent upon the practices of a particular company relative to the “average” represented by the companies that are included in the projects that provided the emission factor datasets. Company-to-company or year-to-year variability in event-related emissions are difficult to determine. As GHG reporting (and reductions) mature in the long term, the emissions associated with blowdown, maintenance, emergency venting, etc. will likely be addressed based on a specific record of each event, calculation of event emissions, and summation of events for the year.

This will require a record of the characteristics of the affected equipment. For example, for blowdown of a length of pipeline, the operator would calculate emissions based on the pipeline length (to block valve), pipeline diameter, line pressure, and natural gas methane content. Since event-specific emission tracking at the Tier 4 level is the only viable alternative to facility-level default estimates for blowdown and non-routine releases, additional example scenarios and calculations are provided. The first example is a rather simple event based on volumes of a pig received. The second event is a more complicated calculation associated with gas vented for blowdown of a compressor.

Example 1: Methane emissions from pigging operations

Scenario: A pig receiver or pig catcher is to be depressurized to allow the pig to be removed. Example input data for this event-specific analysis includes: The pig receiver has a 4 meter long section of 18” OD pipe, and a 5 meter section of 24” OD pipe. The line pressure is 630 psig, and the temperature of the gas is 60 ^{o}F. The gas is 85% methane by volume.

The emissions calculation for this event includes the following assumptions and calculations:

- Assuming schedule 80 pipe, the ID of the 18”OD and 24” OD pipe sections are 16.124” and 21.562” ID, and the cross sectional areas are 1.418 ft^2 and 2.536 ft^2 (0.1317 m^2 and 0.2356 m^2), respectively.
- The volumes of the two sections are 0.527 m^3 and 1.178 m^3 – total volume of 1.705 m^3.
- The pressure in the line is 630 psig, or 644.7psia. The line pressure equates to 4,445,078 Pa. The temperature of the gas in the line is 60 ^oF or 288.7 K. Using the ideal gas law, the number of moles of gas in the line is 3157.2 gmoles.
- Methane is 85% of the gas, or 2,683.6 gmoles. The molecular weight of methane is 16.042 g/mole. So the total methane vented is 2683.6 x 16.042 = 43,051g or 43.051 kg.
- Converting to CO2eq (methane GWP of 21, 1000 kg/tonne) = 0.904 tonnes CO2eq

<u>Example 2: Methane emissions from a compressor blowdown</u>

Scenario: A compressor and engine are to be taken down for maintenance from a fully loaded condition. The fuel gas to the engine and the natural gas to the engine are to be shut off and the engine and compressors fully vented before maintenance occurs. The gas and fuel gas have the same composition of 85% methane.

Example input data for this event-specific analysis includes detailed information for the multiple “volumes” that are vented.

- The compressor is a two stage compressor with three cylinders on each stage. The first stage compressors have a volume of 531 cubic inches, and the second stage have a volume of 270 cubic inches. The suction pressure is 140 psi, the interstage pressure is 330 psi and the discharge pressure is 630 psi. The suction temperature is 60 ^oF, the inter-stage temperature is 172 ^oF, and the discharge temperature is 150 ^oF.
- The engine that drives the compressor has 12 cylinders, with a compression ratio of 9.2, a bore size of 14 inches and a stroke of 14 inches. The fuel gas enters the cylinder through a 2 inch line at 65 psi. Each cylinder has 3 feet of the 2 inch line that ties into a common 2 inch header on each side of the compressor. There is 10 feet of 2 inch line from the header to the fuel gas shutoff valve.
- The first stage consists of 4 meters of an 18” line from a shut off valve to an inlet scrubber, and a 20” suction bottle that is 3 meters in length. The first stage discharge bottle is 4m in length and 20” in diameter. The discharged gas from the first stage travels through 20 meters of 12” line to a cooler. From the cooler the gas travels through 30m of 8” pipe to a scrubber which is 2.5m tall and 40cm in diameter. The gas travels to a 3 meter long second stage suction bottle which is 12” in diameter.
- The second stage discharge bottle is 18 inches in diameter and is 4.5 meters long. Gas travels from the discharge bottle down 20 meters of 8” pipe to a second stage cooler. From the outlet of the cooler there is 5m of 8” pipe before a valve.

The “event” calculation requires a stepwise approach to address all of the gas volumes that are released. The input data has a mixture of English and SI units, which is common in practice. To be consistent all calculations of methane volumes will be carried out in SI units. Since there are three different pressures in the compressor, and one for the fuel gas, the volume at each pressure will need to be calculated.

The emission calculations include:

- Volume of Fuel Gas: There is 46 feet of 2 inch line between the last valve on the fuel gas line and the cylinders. Assuming schedule 40, the ID of the pipe is 2.067 inches. This gives a total volume of 1.07 cubic feet. At 65 psi, assuming ideal gas this is 94.7 grams of methane vented.
- Volume at Suction Pressure: The volume in the first stage compressor is 531 cubic inches. So for three compressors this is 0.92 cubic feet. The suction scrubber is 2 meters tall and has an internal diameter of 40 cm, giving an internal volume of 0.251m^3. Assuming schedule 80 for the 18" pipe and 20" suction bottle gives volumes for these two sections of 0.527 and 0.489 cubic meters respectively. The total volume of gas at 140 psi vented from the inlet line, suction scrubber, suction bottle and three compressor cylinders is 1.294 m^3. At 140 psi, and assuming ideal gas law then this equates to a methane emission of 7.84 kg.
- Volume at Interstage Pressure: The volume in each second stage compressor is 270 cubic inches. So for three compressors this is 0.0133 cubic meters. The suction scrubber is 2.5 meters tall and has an internal diameter of 40 cm, giving an internal volume of 0.314 m^3. Assuming schedule 80 for the 8" and 12" line and second stage suction scrubber gives volumes for these three sections of 0.884, 1.311 and 0.314 cubic meters respectively. The total volume of gas at 330 psi vented from the piping, second stage suction scrubber, first stage discharge bottle and three compressor cylinders is 3.371 m^3. At 330 psi, and assuming ideal gas law then this equates to a methane emission of 37.44 kg.
- Volume at Discharge Pressure: The volume of the second stage discharge bottle is 0.734 m^3. The volume of the 20 meters of 8 inch pipe to the cooler is 0.589 m^3. At a pressure of 620 psi, this corresponds to 28.031 kg of methane.

  Total Amount of Methane and CO2eq Vented: The total amount of methane vented is the sum of each section. That gives a total methane emission of 73.40 kg or 161.7 pounds. Note that in the calculation the cooler volume was not included but this could be calculated if the number of tubes in the cooler and the internal diameter of the tubes were known. Converting to CO2eq = 1.54 tonnes CO2eq from the compressor blowdown.

These two example calculations are illustrative of event-based venting calculations. If a company selects an event-based approach rather than using default factors, a system will need to be implemented to ensure that all such blowdown events – from planned or emergency activities – are logged and associated emissions are calculated and reported.

3.5 Non-routine Activities: Sporadic or Intermittent Event-Based Emissions

In the transmission and storage sector, a non-routine activity is usually associated with a discrete or intermittent event associated with a particular activity. The term "non-routine" does not imply that the event is unusual or atypical, but rather that the activity is sporadic or intermittent and not associated with continuous process operations. The GHG emissions from non-routine activities are typically a venting of gas from the pipeline or affected piece of equipment. For example, venting to enable repair of the equipment or an accidental release.

The default emission factors provided in this section may not reflect the practices that are used by a company to manage releases from operational events. To provide a better estimate, an engineering calculation approach is needed. Examples of the types of activities that can result in a discrete, event-based release include:

- Planned maintenance of a section of pipeline or piece of equipment such as an internal combustion engine compressor driver, such as equipment turnaround;
- Unplanned maintenance of pipeline or equipment to address a required repair;
- Release of a pressure relief valve (PRV);
- Purging of newly installed lines;
- Abandonment of pipeline or facility equipment;
- Pigging (release at the pig catcher);
- Dig-ins.

The emissions from these events need to be included in the company GHG inventory. The tier-based emission factors provide an approach for calculating emissions. However, "industry-average" emission factors cannot be expected to capture company-specific approaches to handling vented emissions, and may by highly inaccurate. The alternative is for a company to determine the emissions associated with each discrete event, and document the basis for the determination. Example calculations in above indicate the types of facility and process information needed to complete calculations for vented emissions. In addition, a company can consider specific issues related to in-house procedures. For example, a facility may capture "purged" gas and route it to a flare. In this case, the GHG contribution to the inventory is decreased because methane, which has a higher global warming potential, is converted to CO_2 during combustion in the flare.

To better understand emissions accounting for ***non-routine*** events, issues to consider for several types of emissions venting events follow:

- Pig traps

  Pigs are used to clean pipelines of water, condensate, dirt, rust, or hydrates that have been deposited or condensed in the pipe, and "smart pigs" can inspect internal surfaces. The GHGs vented from a pigging event will vary depending on the length and diameter of pipe cleaned, the line pressure, and the equipment connected to the pig receiver or pig catcher – and the practices of the operator. Some systems send the gas that arrives ahead of the pig to a separator and the natural gas (and GHG) is not vented. Others send the gas to a flare, while others vent it to the atmosphere. To remove the pig, it is necessary to vent and purge the pig receiver. The volume of gas released depends on the volume of gas in the pig receiver, the pressure in the line and the composition of the gas. An example of such a calculation for a pig receiver is provided in Example 1 in Section 3.4.1.

- Overhauls

  Periodically, equipment will be partially or totally disassembled for repair and replacement of worn parts. In particular, rotating/reciprocating equipment, such as compressors and compressor drivers require scheduled overhaul. This requires that the natural gas in the units to be completely vented and purged before maintenance can occur. An example calculation is provided as Example 2 in Section 3.4.1. Restart of the unit will also vent greenhouse gas as the unit needs to be purged of air before being connected to the pipeline.

- Event-based Flaring

  If a facility includes the ability to route gases to flare, then GHG emissions are reduced due to the conversion of methane in the natural gas to CO_2 during the combustion process. In general, flares are highly efficient at burning gas, and the specific assumptions associated with combustion efficiency and residual methane emissions are presented in Section 2.4.

For a flaring event, the total volume of gas routed to flare needs to be determined. In some facilities, a flow meter may be used to provide a volumetric measurement. In the absence of a measurement, the volume associated with the flaring event should be determined based on an engineering calculation (see Section 2.4).

4.0 FUGITIVE SOURCES

40 CFR Part 63.2 defines *fugitive emissions* as those emissions from a stationary source that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. Fugitives refer to unintentional leaks from sealed surfaces and threaded components including piping and associated equipment components.

Fugitive emissions are a major component of GHG emissions from natural gas systems. Thus, in addition to identifying emission estimation methods, this section provides background on this emission source and the unique issues associated with estimation or measurement of fugitive emissions. Following the background material, this section presents methods for estimating CH_4 and CO_2 emissions from fugitive sources in the transmission and storage sector. In addition to Tier 1 through 3 estimation approaches based on default emission factors, a section is included that discusses approaches for estimating emissions that are facility specific and go beyond a Tier 3 estimate.

4.1 Background on Fugitive Emission Sources and GHG Estimation

Common examples of fugitive emission sources include, but are not limited to:

- Block valves;
- Control valves;
- Valve stem and bodies;
- Pump seals;
- Compressor seals;
- Sight Glass
- Sample connections;
- Flare stack connectors and flanges;
- Atmospheric Organic Liquid Storage Tank Hatches and Pressure Relief Vents
- Meters
- Instrumentations seals and packing;
- Pressure relief valves to atmosphere;
- Equipment and piping flanges and connectors;
- Screwed connections and instrumentation fittings;
- Open ended lines;
- Diaphragm Pressure Regulators;
- Unions;
- Process drains
- Underground pipelines (resulting from corrosion, faulty connection, etc.).
- Drains

Leakage may be caused by a number of factors. However, a number of components, such as mechanical seals, are designed to leak a small amount in order to remove heat and debris from the contact the surfaces. Alternative seal designs can be implemented for some services which do not normally transmit any hydrocarbons directly to the atmosphere (i.e., leaked fluid can be collected and directed to a control device such as a flare or fuel gas system).

Fugitive emissions from oil and natural gas systems are often difficult to accurately quantify. This is largely due to the diversity of the industry, the large number and variety of potential emission sources, the wide variations in emission-control levels associated with inspection and repair programs, and the limited availability of facility-specific emission source data. In addition, the historical methods for measuring fugitive emissions include a large inherent uncertainty, counter to the expectations for accuracy associated with emission measurement. Fundamental emission estimation issues for fugitive emissions for the transmission and storage sector include:

- The use of simple volume-based emission factors introduces large error;
- The application of default system-wide emission factor and activity data consistent with current accepted practices introduces significant errors due to potential differences in facility type (e.g. integral compressors tend to have a higher leak potential), age, maintenance practices and frequency, throughput, etc.
- The application of rigorous bottom-up approaches requires expert knowledge and detailed data that may be difficult and costly to obtain and implement;
- Measurement programs can be time consuming and costly to perform;
- Attempts to estimate leakage for pipeline systems using available information such as lost and unaccounted for (LAUF) data are bounded by issues associated with meter accuracy and the large volumes of gas throughput at a facility relative to the fugitive releases. For example, for a transmission station throughput of 500 million standard cubic feet per day, the lost and unaccounted for (LAUF) based on meter accuracy of ±0.25% could result in ± 1,250,000 SCF/day – which may be the same order of magnitude as "actual" fugitive losses and cannot be differentiated due to limitations in measurement specifications.

Fugitive pipeline leaks typically consist of emissions from above ground or buried valves and other fittings/components attached to the pipelines. These include threaded or screwed (i.e. non-welded) connectors between two pipeline segments or joints and permeation of gas through the pipe wall (associated with plastic pipe). Pipe wall losses are most commonly associated with structural failures such as cracks or corrosion normally caused by operational wear and pipe material degradation. The two variables effecting pipeline leak rates are pipeline service type (i.e. transmission, distribution, or service line) and the pipe length. While service type is important for distribution (where plastic pipe is more prevalently used in certain geographical areas), that is not the case for transmission and storage

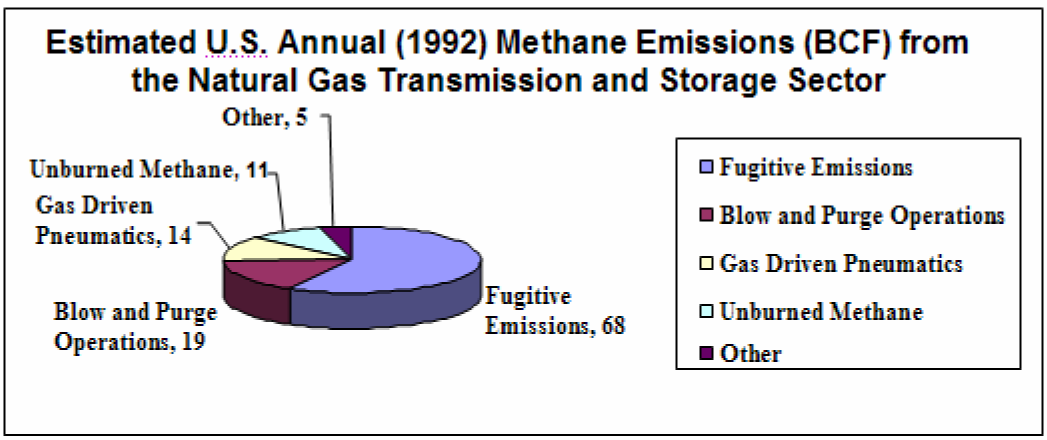
As noted in Section 3, it is important to differentiate between fugitive emissions and vented emissions. Pipeline blowdown events, whether deliberate for operating and maintenance purposes or unintentional as the result of an upset condition, are vented emissions (see Section 3), as are losses associated with release of a pressure safety relief valve resulting from an overpressure protection event. However, gas "passing" relief valve seals, also referred to as "valve blow-by", that occurs following an overpressure protection event due to improperly re-seated valve surfaces (e.g. chattering or malfunctioning relief valve resulting from sealing surfaces that are not properly mated), ***are*** considered fugitive emissions.

Data on fugitive equipment leaks of CO_2 are generally disregarded, since CO_2 emissions are more commonly associated with combustion sources. Formation CO_2 is typically removed from natural gas by the sweetening units at gas processing plants (e.g., amine unit acid gas releases are a point source of and CO_2). GHGs released to the atmosphere from such processes, including fugitive leaks in the process lines, are addressed in natural gas production and processing guideline documents such as the API Compendium. However, a portion of CH_4 emitted from underground pipeline leaks is oxidized to form CO_2 as it migrates through the soil to the surface and may be included in the inventory if adequate activity data exist.

4.2 Brief Summary of Key Conclusions from the Literature

Figure 4-1, illustrates that fugitive emissions are the single largest ***methane*** emission source for the transmission and storage sector. Fugitives account for 58% of the CH_4 emissions from transmission and storage. These data were taken from the GRI/EPA Study on natural gas industry baseline emissions. Nearly 90% of these industry-wide emissions result from compressor component leakage including the suction, discharge and blowdown valves, pressure relief valves, and compressor seals. Thus, compressor count and use of reciprocating versus rotating equipment has a significant effect on facility GHG emissions.

Figure 4-1. CH_4 Source Apportionment for Transmission and Storage Sector.



Many components leak to some extent. However, only a few percent of the total population of sources at a site may leak sufficiently to require repair or replacement. A facility is considered to be well maintained and fugitive equipment leaks properly controlled if the number of defined leakers is less than two percent of the total number of potential sources.

The following are some of the noteworthy characteristics of fugitive equipment leaks:

- There is a strong correlation between the rate of leakage and the type of service (e.g., gas/vapor and light liquid/two-phase streams) (Wetherold and Provost, 1979). However, there is no clear relationship between the size of a component and the rate of leakage (U.S. EPA, 1983).

- The potential for leakage increases with operating pressure and ambient temperature, but is generally independent of operating temperature or elevation above grade (Langley et al., 1981).

- Pipeline leak calculations do not include pipeline operating pressure or diameter as a variable, since the leaked volumes do not vary significantly with these two parameters (Campbell et al., 1996).

- Control valves have a greater potential for leakage than block valves. For block valves, the gate design has the most potential for leakage, while plug and ball designs have the least potential.

- Off-line compressor units that have been depressurized and are left open to the atmosphere through the vent line leak more than ones that have not been depressurized or that are online (especially for reciprocating compressors) (Hummel et al., 1996). In the first case, the leakage is past the seats of upstream and downstream block valve. In the latter case, it is past the seat of the blowdown valve.

- Repaired components usually achieve a normal leak potential if the leaks do not recur during the first few weeks after repair (Eaton et al., 1980).

- The majority of fugitive emissions (42 percent of total emissions measured) resulted from the single largest source at each of the 183 sites surveyed (Ross and Picard, 1996). Similar trends have also been observed in the U.S.

- Components in vibration, high-use, or heat-cycle gas service typically are the most leak prone. Fugitive sources tend to be continuous emitters and individual leakers typically have low emission rates.

- Integral compressors tend to have more fugitive losses than separable compressors, and IC engine-driven compressor have more losses than turbine-driven compressors. This is partly due to fewer components and the associated opportunity for leakage on the fuel gas system for the turbines.

- Process instrument diagram (P&ID) and mechanical flow diagrams can be used to count process units, but often do not reflect actual component or equipment counts (e.g., valves, flanges and fittings) except for very simple installations.

- While there may be tendency to trivialize smaller fugitive sources, due to the large population of these components and operating service, the total emissions from these components may be significant.

4.3 Emission Estimation Methodologies

In selecting a fugitive emissions estimate methodology, proper consideration should be made regarding the availability and quality of data and desired inventory accuracy. Although burden and cost are an important consideration, the desired accuracy must ultimately be balanced against the available data. If the available data will not support an estimate of the desired accuracy, additional data gathering and measurement activities may be required. More rigorous approaches go beyond Tier 3 and require fugitive monitoring data and calculations at the component level. Due to the large uncertainty associated with fugitive emission measurement and standardized calculations based on "best practice" correlation equations, even estimates that go beyond Tier 3 can have a large uncertainty. The use of company-specific data will provide an improved estimate as compared to industry average activity and emission factor data.

Tier 2 and 3 emission factors are continuously being updated and modified to reflect new measurement data, incorporation of state-of-the-art technologies, and improved test methods. Literature review should be conducted regularly to ensure that the best available factors are being used. Documentation of the data set relied upon to produce the emission factor(s) is recommended to ensure inventory transparency.

A number of emission factors and correlation equations have been developed for estimating fugitive equipment leaks. Presented in the sections below are emission estimation methodologies based on four categories. In addition to Tiers 1 through 3, several approaches are discussed for Tier 3+ or Tier 4 estimates, which require more equipment and component level detail. Example calculations are provided in Section 4.8 that demonstrates how the GHG estimation calculations are completed for the different tiers for the same source.

The basic advantages and disadvantages of each method are summarized in Table 4-1 below. The Tier 1 and 2 factors offer the lowest fidelity estimates with the largest uncertainties. Tier 3 and Tier 3+ fugitive emissions estimates require a component count by type. Section 4.6 provides several estimation methods for deriving component counts that range from industry average values to actual facility counting (tallies) and/or field verification.

Table 4-1: Summary of the Procedures for Estimating/Measuring Emissions Due to Fugitive Equipment Leaks.

Technique	Information Requirements	Advantages	Disadvantages	Relative Accuracy
Facility Throughput or Station Number Based Estimate	• Facility throughput and storage station counts.	• Simple with minimal effort. • Quick & low cost	• Very poor accuracy (several orders of magnitude for individual facilities). Errors decrease with increasing numbers of components. • Does not account for control efforts.	Least
Facility Throughput with Meter and Compressor Station Count Delineation	• Facility throughput and meter station count.			
Screening Methodologies: - Leak/No-leak Factors - Stratified Factors - Published Leak-rate Correlations - Custom Leak-rate Correlations	• Equipment inventory. • Leak survey results.	• Identifies leaking components. • Control efforts reflected in results.	• Labor intensive. • Moderate costs. • Poor to moderate accuracies (±300 percent at best).	Most
Screening Coupled with Direct Measurements for Significant Leakers: - Hi-Flow Sampler - Bagging	• Equipment inventory. • Leak survey results.	• Identifies leaking components. • Excellent accuracy (potentially ±15 percent). • Control efforts reflected in results.	• Labor intensive. • Moderate to high costs.	

4.3.1 Tier 1 Emission Estimate – Pipeline Length or Station Count Basis

As discussed elsewhere in this document, Tier 1 estimates are considered a high-level approach that provides a more qualitative value. A Tier 1 estimate is based on a very broadly based default emission factor. This method ***only*** requires pipeline length or storage station counts. The Tier 1 estimate provides a first-order means of estimating total fugitive emissions and an *indication* of the fugitive emissions from a facility. The Tier 1 estimate also results in the largest estimate uncertainty of any method. Significant uncertainty arises when broadly applying ***industry average leak statistics*** to a facility that may have significantly different maintenance practices, age of equipment, temporal or seasonal variations in sources, equipment specifications and design standards.

These "industry-average" emission and activity factors have been developed through correlating throughput with pipeline length (inherently assumes a number of fugitive components per length of pipeline) or total storage facility counts to industry average fugitive loss estimates. This base estimation technique is only useful when attempting to calculate emissions from a facility that has yet to be constructed, compiled by a third party for the purpose of preparing regional or national inventories and where no additional data are present, or as an initial indicator of facility fugitive source contributions.

Because fugitive emissions represent the largest source of methane losses from transmission and storage, care must be taken when applying this overly simplistic approach. Errors from this approach are typically as high as several orders of magnitude and may be higher if the facility is not representative of industry averages. The Tier 1 emission factors for transmission and for storage fugitive emissions are presented in Table 4-2. These factors are from GHGCalc^{TM} based on data from the GRI/EPA Study.

Table 4-2: Tier 1 Emission Factors for Fugitive Emissions.

Segment	Activity Data	GHG	EF*	EF Units
Transmission	Pipeline length	CH_4[1]	7,923	lb CH_4/mile-yr
Transmission (CO_2 from CH_4 oxidation)[3]	Pipeline length	CO_2	7.59	lb CO_2/mile-yr
Transmission (CO_2 from pipeline leaks)	Pipeline length	CO_2[2]	466.7	lb CO_2/mile-yr
Storage	Storage Stations	CH_4[1]	1,489,000	lb CH_4/station-yr

[1] Assumes 93.4 vol% methane in natural gas.

[2] Assumes 2% CO_2 in natural gas.

[3] Methane emitted from buried pipelines is partially oxidized to form CO_2 as it passes through the surrounding soil.

Note the different emission factor units in Table 4-2 (i.e., pounds of CO_2 or pounds of methane). GHG emissions are calculated by multiplying the Activity Data by the Emission Factor. Adjusting the methane emission for GWP provides a CO_2 equivalent estimation.

4.3.2 Tier 2 Emission Estimate – Facility and Compressor Count Basis

This method relies on correlating industry-average fugitive GHGs with pipeline length and includes a further delineation of either compressor station or meter and regulator station counts. This method incorporates additional activity factors but retains most of the uncertainty and error associated with the application of industry average data. This method is an improvement over the Tier 1 throughput based factors. Errors from this approach are typically as high as several orders of magnitude and may be higher if the facility is not representative of industry averages.

The Tier 2 emission factors for transmission and for storage fugitive emissions are presented in Table 4-3. For the storage industry segment, fugitive emission factors are calculated based on the number of centrifugal and reciprocating compressors, and the storage station count. The fugitive emission factors for reciprocating and centrifugal compressors are the same for Tier 2 and Tier 3. These factors are from GHGCalc™, and the associated GRI/EPA Study.

Table 4-3: Tier 2 Emission Factors for Fugitive Emissions.

Segment	Activity Data	GHG	EF*	EF Units
Transmission	Compressor station count	CH_4	1,259,400	lb CH_4/station-yr
Transmission	Compressor Station Count	CO_2	72,747	lb CO_2/station-yr
Transmission	Meter/Regulator station count	CH_4	2,533	lb CH_4/station-yr
Transmission	Meter/Regulator station count	CO_2	146.34	lb CO_2/station-yr
Transmission	Pipeline length	CH_4	23.08	lb CH_4/mile-yr
Transmission (CO_2 from CH_4 oxidation)	Pipeline length	CO_2	7.59	lb CO_2/mile-yr
Transmission (CO_2 from pipeline leaks)	Pipeline length	CO_2	1.52	lb CO_2/mile-yr
Storage	Reciprocating compressor count	CH_4	325,400	lb CH_4/comp.-yr
Storage	Centrifugal compressor count	CH_4	471,100	lb CH_4/comp.-yr
Storage	Storage Stations	CH_4	398,000	lb CH_4/station-yr

*Based on 93.4 vol% methane and 2% CO_2 in natural gas.

GHG emissions are calculated by multiplying the Activity Data by the Emission Factor and adjusting for GWP for methane emissions. Each of the processes identified in the table must be included in the estimate with emissions summed for the various source types within the segment. Note that the Tier 1 factors in Table 4-2 are based on roll-up of the Tier 2 factors and consideration of industry average statistics for equipment/facility count and pipeline length. Also note that for Tier 2, transmission estimates are based on facility/pipeline level activity data, while storage estimates are based on both facility and equipment level activity data.

4.3.3 Tier 3 Emission Estimate

The Tier 3 estimate approach using default emission factors is based on more facility level detail than Tier 2. However, the same arguments still apply regarding uncertainty: fugitive emissions are inherently uncertain and the use of default emission factors results in an estimate that includes large uncertainty. The emission factors for Tier 3 are from the GRI/EPA Study and are presented in Table 4-4 for transmission and Table 4-5 for storage.

Table 4-4: Tier 3 Emission Factors for Fugitive Emissions from Transmission.

Segment	Activity Data	GHG	EF*	EF Units
Transmission	Compressor station count	CH_4	135,260	lb CH_4/station-yr
Transmission	Reciprocating compressor count	CH_4	249,810	lb CH_4/comp.- yr
Transmission	Reciprocating compressor count	CO_2	14429.9	lb CO_2/comp.- yr
Transmission	Centrifugal compressor count	CH_4	467,660	lb CH_4/comp.- yr
Transmission	Centrifugal compressor count	CO_2	27013.67	lb CO_2/comp.- yr
Transmission (Farm taps or direct sales)	Meter/Regulator station count	CH_4	480.8	lb CH_4/station-yr
Transmission (Farm taps or direct sales)	Meter/Regulator station count	CO_2	27.77	lb CO_2/station- yr
Transmission (Trans. interconnects)	Meter/Regulator station count	CH_4	61,390	lb CH_4/station-yr
Transmission (Trans. interconnects)	Meter/Regulator station count	CO_2	3546.1	lb CO_2/station- yr
Transmission	Cast Iron pipeline length	CH_4	10,079	lb CH_4/mile-yr
Transmission (CO_2 from CH_4 oxidation)	Cast Iron pipeline length	CO_2	18,710	lb CO_2/mile-yr
Transmission (CO_2 from pipeline leaks)	Cast Iron pipeline length	CO_2	994	lb CO_2/mile-yr
Transmission	Protected steel pipeline length	CH_4	15.1	lb CH_4/mile-yr
Transmission (CO_2 from CH_4 oxidation)	Protected steel pipeline length	CO_2	1.3	lb CO_2/mile-yr
Transmission (CO_2 from pipeline leaks)	Protected steel pipeline length	CO_2	0.9	lb CO_2/mile-yr
Transmission	Unprotected steel pipeline length	CH_4	276	lb CH_4/mile-yr
Transmission (CO_2 from CH_4 oxidation)	Unprotected steel pipeline length	CO_2	13.9	lb CO_2/mile-yr
Transmission (CO_2 from pipeline leaks)	Unprotected steel pipeline length	CO_2	16.6	lb CO_2/mile-yr
Transmission	Plastic Pipeline length	CH_4	22.5	lb CH_4/mile-yr
Transmission (CO_2 from CH_4 oxidation)	Plastic Pipeline length	CO_2	1.3	lb CO_2/mile-yr
Transmission (CO_2 from pipeline leaks)	Plastic Pipeline length	CO_2	1.4	lb CO_2/mile-yr

*Based on 93.4 vol% methane and 2% CO_2 in natural gas.

Table 4-5: Tier 3 Emission Factors for Fugitive Emissions from Storage.

Segment	Activity Data	GHG	EF*	EF Units
Storage	Storage station count	CH_4	331,401	lb CH_4/station-yr
Storage	Reciprocating compressor count	CH_4	325,376	lb CH_4/comp.-yr
Storage	Centrifugal compressor count	CH_4	471,098	lb CH_4/comp.-yr
Storage	Storage well count	CH_4	1764	lb CH_4/well-yr
Storage	Gathering pipeline length	CH_4	23.1	lb CH_4/mile-yr
Storage (CO_2 from CH_4 oxidation)	Gathering pipeline length	CO_2	7.6	lb CO_2/mile-yr
Storage (CO_2 from pipeline leaks)	Gathering pipeline length	CO_2	1.5	lb CO_2/mile-yr

*Based on 93.4 vol% methane and 2% CO_2 in natural gas.

4.4 Tier 3+ Facility-Specific Estimates – Screening-based Methodologies

It is commonly accepted that fugitive emission are difficult to accurately estimate. Even regulatory based requirements for control of fugitive releases (e.g., VOC regulations) are based upon methods with large uncertainties. While default emission factors are the accepted approach for GHG estimates for fugitive emissions, alternative and improved fugitive emission estimation methods will continue to be explored. Ultimately, facility measurements (and possibly development of company-specific emission factors based on a measurement program) may provide a solution. It is feasible to implement these programs because of recent advances in leak measurement technology and best practices that provide the opportunity to cost effectively recover product that is otherwise lost. However, at this time a number of approaches to “Tier 3+” emission estimates for fugitive emissions are under consideration. This section discusses a number of these options. Over the next few years, many of these options may prove ineffective or be supplanted with other alternatives – such as improved emission factors based on a growing database of emissions information from measurement programs.

A screening-based approach to emission estimation requires that a full leak detection program be conducted at the subject facility; that is, all equipment and components with the potential for fugitive leaks are screened. Although methane losses are unregulated, VOC leaks in some processes at upstream facilities are regulated, and associated leak detection requirements for regulated VOC streams form the basis for screening-based approaches to fugitive methane releases. Screening based approaches are typically chosen where companies voluntarily opt into leak detection and repair (LDAR) or Directed Inspection and Maintenance (DI&M) programs. LDAR / DI&M programs are targeted toward improving a facilities loss control and profit margins while also having an added benefit of reducing GHGs. Direct measurement of leaker emissions allows prioritization of the repairs (largest most cost-effective sources addressed first) and potentially allows for more efficient and reliable emissions quantification.

The U.S. EPA Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017, Nov. 1995) provides a guideline document for acceptable approaches for generating process unit-specific emission estimates. This document serves as the foundation for the screening-based methodologies. All of the screening based methods require implementation of EPA Method 21 – which uses an instrument such as an Organic Vapor Analyzer to "sniff" components and measure the hydrocarbon concentration of a leak. The leaks are then categorized based on the measured concentration. Discussed below are four screening-based approaches from the EPA report:

- Leak /no-leak Emission Factors;
- Three-stratum Emission Factors;
- Leak-rate Correlations; and
- Unit-specific Leak-rate Correlations.

Approaches for completing component counts are discussed in Section 4.7.

4.4.1 Leak/no-leak Emission Factors

This method offers some refinement over applying an average emission factor approach by allowing some adjustment for individual unit conditions and operation differences. Screening values must be classified as either leaking (e.g.., has a maximum screening value of 10,000 ppm or more) or non-leaking (e.g., has a maximum screening value of less than 10,000 ppm), and categorized by type of component and type of service.

This method relies upon establishing a part per million by volume leak definition (typically 10,000 ppmv) and component by component screening (sniffing with an organic vapor analyzer) against this leak definition to determine whether a leak exists. When applying this approach it is assumed that components having screened values larger than the leak definition have different average emission rates as compared to components with screening levels less than this level.

Table 4-6 is taken from Canadian data and provides the leak, no leak emission factor for the transmission source of interest. Significant differences exist between the Canadian and the U.S. gas transmission systems. Primarily, the Canadian system is newer and relies upon turbines as the prime movers whereas the U.S. system primarily relies upon IC engines.

Implementation of this procedure requires counts for the various types of components. The components are classified as "leak" or no-leak" depending upon the screening value from the inspection program. Then, the count for each component type is determined for both the "leak" and "no leak" categories. The appropriate emission factor from Table 4-6 is applied for the count of each component type and leak class. The GHG emissions are the cumulative sum from all components, corrected for the methane content of the natural gas.

Note that the emission factors in Table 4-6 for gas transmission systems are based on measurement of total organic emissions (i.e., total hydrocarbon measurement). To calculate fugitive methane emissions for a facility, the gas composition must be known (or assumed), as molecular weight (MW) and volume percent methane are used in the calculation. If a gas analysis is not available, the default of 93.4 vol% methane may be assumed, along with a MW ratio of 16/17 (methane Mw / natural gas Mw).

The calculated kilograms of emissions from Table 4-6 are converted to kilograms of methane as follows:

$$CH_4\ (kg) = Gas\ (kg) * Mw_{,CH4} / Mw_{,gas} * Vol\%_{CH4} /100 \qquad \text{Eqn. 4-1}$$

Where Gas (kg) = Emission calculated based on the emission factor from the Table and the associated activity data.

$Mw_{,CH4}$ = Methane molecular eight (i.e., 16),

$Mw_{,gas}$ = Natural gas molecular weight (based on analysis or assumption of 17 for natural gas),

$Vol\%_{CH4}$ = Volume percent methane in natural gas (based on analysis or assumption of 93.4 vol%).

Multiply by GWP of 21 and divide by 1000 for tonnes of CO_2eq.

4.4.2 Three-Stratum Emission Factors

The basic assumptions inherent in use of the three-stratum emission factor method are the same as those presented for the leak/no-leak method. Use of the three-stratum factors offers an additional improvement over the use of the leak/no-leak factors through the creation of additional ranges.

Sources are categorized into three ranges of screening values as follows:

<u>Screening Value Range (ppmv)</u>

- 0 to 1,000
- 1,001 to 10,000
- Greater than 10,000 ppmv (also known as a pegged source)

Table 4-7 provides a summary of three stratum emissions factors by component type for the transmission sector. As with Table 4-6, the average emission factors presented in Table 4-7 for gas transmission systems are based on measurement of total organic emissions (i.e., total hydrocarbon measurement). The calculated kilograms of emissions should be corrected to account for the methane content of the gas stream using equation 4-1.

Table 4-6: Leak/No-Leak CH_4 Emission Factors for Estimating Fugitive Leaks.

Gas Transmission Facilities						
Source		Number of Sources	Percent of Sources	Emissions (kg/hr/src)	95% Confidence Limits	
					Lower	Upper
Connector[1]	No Leak	44512	98.79	0.0000338	0.0000271	0.0000406
	Leak	556	1.21	0.01856	0.01465	0.02247
Block Valve[2]	No Leak	5907	96.02	0.0006132	0.0	0.001342
	Leak	245	3.98	0.03895	0.02728	0.05062
Control Valve[3]	No Leak	233	85.35	0.01006	0.007532	0.01259
	Leak	40	14.65	0.07581	0.0	0.1706
Pressure Relief Valve	No Leak	63	33.87	0.0006471	0.0	0.001537
	Leak	123	66.13	0.3814	0.0	0.8673
Regulator	No Leak	108	83.72	0.0000398	0.0000175	0.0000474
	Leak	21	16.28	0.01977	0.004751	0.03439
Orifice Meter[4]	No Leak	83	79.81	0.001925	0.0006846	0.003165
	Leak	21	20.19	0.0088	0.004936	0.01286
Other Flow Meter[5]	No Leak	259	97.37	0.0000037	0.0000016	0.0000059
	Leak	7	2.63	0.0002064	0.0	0.0006932
Station or Pressurized Compressor Blowdown System[6]	No Leak	27	26.47	0.0006213	0.0	0.001641
	Leak	75	73.53	1.274	0.4989	2.049

Source: Ross and Picard (1996), Table 4, page 13.

1 Includes flanges, threaded connections and mechanical couplings.

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

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

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

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

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

Table 4-7: Three-Stratum Emission Factors for Estimating Fugitive Leaks

Gas Transmission Facilities						
Source		Number of Sources	Percent of Sources	Emissions (kg/hr/src)	95% Confidence Limits	
					Lower	Upper
Connector[1]	<1000	44207	98.1	0.0000032	0.000003	0.0000033
	1000-10000	305	0.7	0.004480	0.003623	0.005337
	>10000	556	1.2	0.01856	0.01465	0.02247
Block Valve[2]	<1000	5803	94.3	0.0005027	0.0	0.001242
	1000-10000	104	1.7	0.006782	0.003705	0.009858
	>10000	245	4.0	0.03895	0.02728	0.05062
Control Valve[3]	<1000	167	61.2	0.000027	0.0000197	0.0000344
	1000-10000	66	24.2	0.03544	0.03020	0.04068
	>10000	40	14.6	0.07581	0.0	0.1706
PRV	<1000	60	32.3	0.0002125	0.0000619	0.003632
	1000-10000	3	1.6	0.009339	0.0	0.04927
	>10000	123	66.1	0.3814	0.0	0.8673
Regulator	<1000	10	26.3	0.0000127	0.0000099	0.0000155
	1000-10000	7	18.4	0.0004301	0.0001985	0.0006618
	>10000	21	55.3	0.01977	0.004751	0.03439

Source: Ross and Picard (1996), Table 7, page 23.

---- No data available.

1 Includes flanges, threaded connections and mechanical couplings.

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

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

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

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

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

7 The Instrument Controller Category accounts for emission from pneumatic control devices that use natural gas as the supply medium.

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

Table 4-7: Three-Stratum Emission Factors For Estimating Fugitive Leaks (cont.)

Source		Number of Sources	Percent of Sources	Emissions (kg/hr/src)	95% Confidence Limits	
					Lower	Upper
Orifice Meter[4]	<1000	67	64.4	0.000032	0.0000198	0.0000442
	1000-10000	16	15.4	0.009850	0.004703	0.01500
	>10000	21	20.2	0.0088	0.004936	0.01286
Other Flow Meter[5]	<1000	258	97.0	0.000003	0.0000014	0.0000045
	1000-10000	1	0.4	0.0002000	----	----
	>10000	7	2.6	0.0002064	0.0	0.0006932
Station or Pressurized Compressor Blowdown System[6]	<1000	25	24.5	0.000023	0.000001	0.000045
	1000-10000	2	2.0	0.008100	----	----
	>10000	75	73.5	1.274	0.4989	2.049
Compressor Blowdown System - Depressurized Reciprocating	<1000	4	26.67	0.0	0.0	0.0
	1000-10000	---	----	----	----	----
	>10000	11	73.33	3.200	1.245	5.155
Compressor Blowdown System - Depressurized Centrifugal	<1000	7	38.89	0.0	0.0	0.0
	1000-10000	----	----	----	----	----
	>10000	11	61.11	1.200	0.0	2.422
Open-Ended Line	<1000	173	27.0	0.0000288	0.0000161	0.0000415
	1000-10000	6	0.9	0.002533	0.0001628	0.004904
	>10000	463	72.1	0.1158	0.05458	0.1770
Instrument Controller[7]	<1000	----	----	----	----	----
	1000-10000	----	----	----	----	----
	>10000	17	100.0	0.4681	0.09325	0.8429
Compressor Seal - Reciprocating[8]	<1000	5	13.9	0.00056	0.0	0.002115
	1000-10000	----	----	----	----	----
	>10000	31	86.1	0.7682	0.4865	1.049
Compressor Seal - Centrifugal[8]	<1000	1	4.8	0.0000075	----	----
	1000-10000	----	----	----	----	----
	>10000	20	95.2	0.8546	0.2469	1.462

*see footnotes above

4.4.3 Leak-Rate Correlations

The leak rate correlation approach predicts the mass emission rate as a function of the screening value (ppmv) for a particular component type. The primary difference between this approach and leak/no leak and stratum methods is that correlation equations are conducted on an individual component basis, rather than in large groups. The use of this approach is a considerable refinement over the available emission-factor methods and will provide more accurate estimates of component leak emissions than the other methods discussed above in which constants are applied over discrete ranges of screening values. The level of uncertainty in the total emissions estimated by this approach is a function of the number of components considered and the percentage of pegged (> 10,000 ppmv) sources.

The general form of the correlation equation given by the two-constant relation is:

$$Log(ER) = B_0 + B_1 \, Log(SV) \qquad \text{Eqn. 4-2}$$

where:

B_0, B_1 = model parameters as given in Table 4-8,
ER = leak rate in (kg/h/source), and
SV = maximum screening value above background measured using a detector calibrated to methane (ppm)

Table 4-8: Correlation Parameters for Estimating Leak Rates from Components

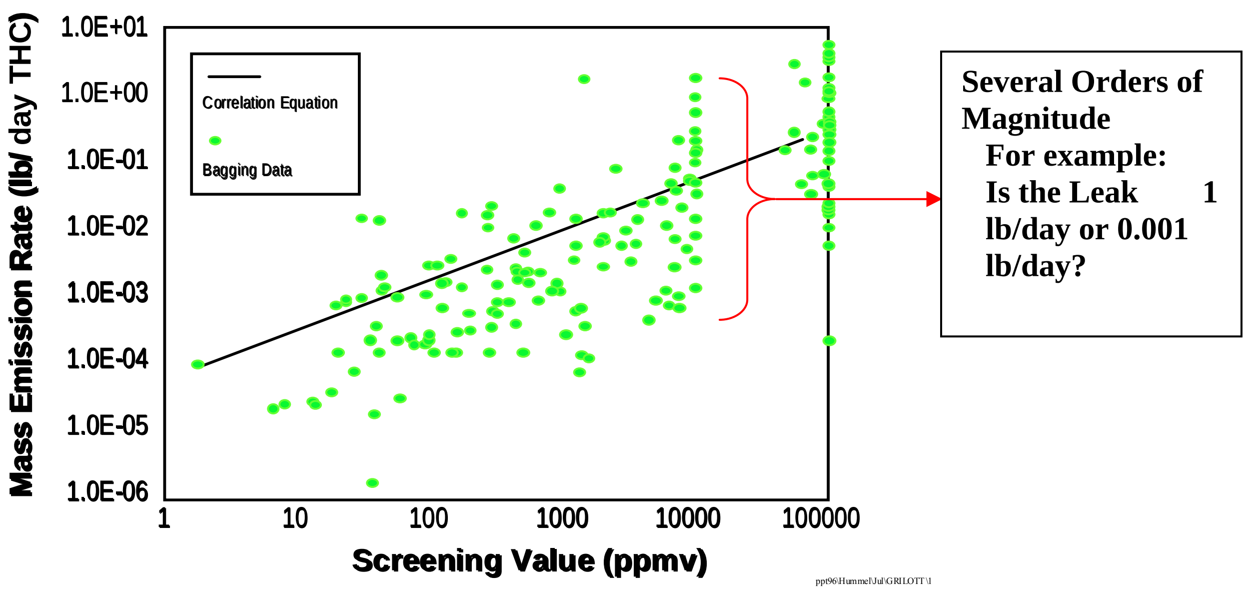
Source	B_0	B_1	Number of Sources	Correlation (R^2)
Connectors[1]	-5.9147	0.75	305	0.71
Valves[1]	-6.0399	0.83	369	0.67
Open-Ended Lines[2]	-6.9586	1.28	64	0.44
Pressure Relief Devices[2]	-5.1479	0.91	29	0.46
Pressure Regulators[2]	-6.4821	0.91	35	0.58

1 The correlation for this source is based on screening and bagging data collected by Ross and Picard (1996), by Environment Canada (Williams, 1996), and data collected for U.S. EPA (1995).
2 The correlation for this source is based on screening and bagging data collected by Ross and Picard (1996) and Environment Canada (Williams, 1996).

Despite the fact that leak rate correlations provide an improved estimate approach relative to other options discussed above, concentration is a poor surrogate for the actual leak rate. Recent studies that have investigated the effectiveness of leak detection and repair programs have shown that under U.S. EPA Method 21 guidelines, up to 10 times as many leaks are repaired than would be necessary to obtain a significant reduction in emissions. Also, the conventional approach does not provide an accurate measurement of either the baseline emissions from the facility or the amount of emissions reduced (error is ± 300%). Leak based correlation equations can also result in large emissions uncertainties and estimate errors. The uncertainties in this method are typically ± two orders of magnitude, but can be as great as three to four orders of magnitude. This is demonstrated based on measured leak rate data from EPA shown in Figure 4-2 plotted with the emission estimate determined from the correlation equation. Historically, difficulties in measuring leaks (i.e., leak “bagging” studies) limited the ability to conduct direct measurements and necessitated the development of the alternative approaches discussed in this section.

Concentration values measured using Method 21 are plotted against the leak rate in Figure 4-2. The data scatter is more than ± two orders of magnitude relative to the correlation equation estimate. Consequently, by repairing all components that screen above 10,000 parts per million, resources are wasted on repairing components with extremely small leaks, while some components that screen less than 10,000 parts per million are not fixed even though they have a significant leak rate.

Figure 4-2: Leak Rate versus Concentration and Correlation Equation Estimate.



Additionally, the maximum concentration for the correlation equations is a screening concentrations of 10,000 or 100,000 parts per million. Any leak above these screening concentrations has the same estimated leak rate (known as a “pegged source” emission factor). Many leaks screen above these concentration thresholds, but since the mass emission rate is actually low in some cases, the leaks may not be cost effective to repair. In recent years, DI&M programs have proven that this is true in the natural gas industry.

4.4.4 Unit-Specific Leak-Rate Correlations

Mass emission rates determined by either bagging or High Volume Sampler (e.g., HiFlow Sampler™) measurements may be combined with the associated screening value to develop a process unit-specific relationship between concentration and mass emissions. The EPA Leak Detection Protocol identifies the procedures to develop a correlation equation specific to a particular facility process that can then be applied to this process-type. To develop unit-specific leak-rate correlations it is necessary to compile a sufficient number of data points to surround the desired screening range for each target component and service category. For additional details on developing a unit-specific leak-rate correlations, refer the EPA Leak Protocol for Equipment Leak Emission Estimates.

4.5 Other Tier 3+ Emission Estimation Approaches

In addition to the screening-based approaches in Section 4.4, additional approaches for fugitive emission estimation that go beyond the current Tier 3 approach are available, including:

- Selectively incorporate measured data with Tier 3 estimates.

  Combining the Tier 3 emission factors with measured data from a transmission or storage facility should significantly improve the quality of the estimate. Key sources of leakage can be targeted for measurement (e.g. compressor seals and vents, fuel gas systems and scrubbers, gas operated starters, etc.) and integrated with the Tier 3 EF to refine estimates and reduce uncertainties.

- Screening coupled with direct measurement of emissions from significant leakers.

  Experience has shown that the few leakers (e.g., screening value > 10,000 ppm) which occur at a facility (i.e., typically, 3 to 6 percent of the component population) contribute nearly all (i.e., 90 to 95 percent) of the fugitive emissions from components in gas service. Once a component count has been established at the facility, a leak survey may be conducted using screening tools such as remote passive infrared camera technologies, soap solution (i.e. bubble test), and ultrasonic techniques. After a leak is identified based on the screening value, it can be quantified using high volume sampler methods. The actual measured values can be used to construct site-specific emissions data and can be appended as subsequent surveys are conducted improving the EF uncertainty. The emission factors for non-leakers (e.g.., screening value < 10,000 ppm) are applied to the rest of the components. Once a thorough assessment has been completed, a basis exists for simplifying the approach and better allocating resources in the future to best reduce uncertainties in the results.

- Develop equipment specific leak rate data for all fugitive sources.

  Measured leak rate data can be used to develop equipment-specific emission factors. These factors can be used system wide provided that they are representative of the target source, operating range or envelope, and are in similar service, utilization, and load, and are close in age. This requires the development of adequate datasets for devising the emission factors, and determining the frequency of follow-up inspection to ensure that the “current” equipment status (e.g., leak frequency and distribution) conforms to the basis of the emission factor. This would be a time intensive effort – but may be viable within the context of a DI&M program to reduce LAUF and GHGs – and may be requisite in a future-year GHG trading program.

4.6 Activity Data for Fugitive Emission Estimates

The activity data requirements for fugitive estimates are identified in the sections above. As improvements in the emissions estimates are sought and higher tiers desired, additional data and information will be required. Table 4-9 summarizes the required transmission sector activity data by Tier. Table 4-10 summarizes the storage sector activity data by tier.

Table 4-9: Required Transmission Sector Fugitive Emissions Activity Data by Estimation Tier.

Tier 1	Tier 2	Tier 3
Pipeline length	Pipeline length	Pipeline length by material type: unprotected steel, protected steel, plastic, and cast iron
	Compressor station count	Compressor engine count by type: reciprocating and centrifugal
	M&R station count	M&R station count by type: farm tap/direct sales and transmission interconnects
		Transmission compressor station count

Table 4-10: Required Storage Sector Fugitive Emissions Activity Data by Estimation Tier.

Tier 1	Tier 2	Tier 3
Storage station count	Storage station count	Storage station count
	Compressor count by type: reciprocating and centrifugal	Compressor engine count by type: reciprocating and centrifugal
		Storage well count
		“Gathering” pipeline length

4.7 Estimating Component Counts

For improved Tier 3+ fugitive estimation methods, an inventory of equipment components must first be developed for each target facility or installation. This may be accomplished through actual site surveys. Alternatively, counts may be taken from process flow diagrams and bills of materials. Although adequate for small, relatively simple installations (e.g., receipt meter stations and farm taps), drawings and bills of materials probably lack sufficient detail for larger facilities (e.g., border meter stations, compressor stations). Again, for large installations, actual field counts are more accurate (especially on threaded piping and pre-packaged process units such as compressor units).

Table 4-11 presents several methods for determining component counts in order of accuracy and reliability.

Table 4-11: Methods for Deriving Component Counts

Method	Associated Tier	Accuracy & Reliability
Estimate Component Counts Based On Facility Size (Total HP, Throughput, etc.)	1	Least
Estimate Component Counts Based on National or Industry Average Number of Components per Emission Source	2	
Default Equipment Schedules	2+	
Extrapolated Facility Measurement Program Data	2+	
Counts from P&ID drawings plus Audits for Selected Leak Prone Equipment	3	
Complete Facility Survey and Component Audit	3+	Most

4.7.1 Issues and Considerations for Developing Component Counts

A GRI/U.S.EPA report from 2002 (*Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants*) identified a significant underestimate of components at each of four facilities surveyed. In addition to the facilities lacking an accurate component count, initial estimates provided by the sites were on average, 40 percent lower, than the physical counts developed during site visits.

This report and other experience indicate:

- The use of experienced process engineers when conducting facility audits and component counting allows for increased efficiency and dramatically reduces errors resulting from improperly eliminating components or including components in non-GHG streams (e.g. compressed air, liquid service, cooling water, electrical conduit, etc.).

- Process and Instrument (P&ID) drawings may not be current and often do not reflect recent changes, additions, modifications and "as-built" conditions. The lack of accurate or detailed design drawings may significantly impact the accuracy of the inventory. "Field audits" of component estimates would likely improve accuracy.
- Audits should not only rely on estimates of component sizes but should frequently include measured data. A tape measure or similar, will greatly improve the accuracy of the count by size categories.
- Actual component counting activities may be simplified by counting components on a single source and multiplying by the number of similar sources.
- Limiting the size of components to ½" or greater may ignore potential sources of methane emissions at a facility. Tubing connections are frequently thought to be unimportant contributors to the inventory due to the size and nature of these components. However, these connections may leak an appreciable amount of methane and where appropriate should be included in the component counts.

In general, the cost for developing and documenting average facility level component counts is offset by reduced product losses within the initial year of implementing a directed inspection and maintenance (DI&M) program. However, a decision is required on whether the gains in accuracy justify the cost of additional data gathering.

In the absence of actual component counts, the default equipment schedules in Table 4-12 may be used to develop an equipment inventory. Similarly, Section 3.3.3 provides an example for estimating pneumatic devices on compressor engines.

Table 4-12: Default Equipment Schedule

Component	Transmission Facilities						
	Border Meter Station[2]	Receipt/ Sales Meter Station[2]	Farm Tap[1]	Reciprocating Compressor Unit[3]	Centrifugal Compressor Unit[3]	Compressor Station Yard Piping[4]	Compressor Discharge Cooler[5]
Connectors	100	95	60	317	476	747	2 937
Control Valves	0	0	----	10	3	----	----
Open-Ended Lines	4	10	0	5	10	36	----
Pressure Relief Devices	1	3	2	1	3	3	----
Pressure Regulators	1	2	4	1	3	7	----
Block Valves	35	27	11	36	106	227	19
Blowdown Lines	0	----	----	----	----	11	----
Orifice Meters	1	1	----	----	----	----	----
Other Flow Meters	0	----	0	----	----	----	----
Instrument Controllers	0	----	----	----	----	2	----

Source: Ross and Picard (1996), Table 8, page 27.

1 Number of components per meter set (for residential, commercial and industrial meter sets) or site (for district and gate stations).
2 Number of components per meter run.
3 Number of components per compressor unit.
4 Number of components per compressor station. For a station with 2 reciprocating units the total number of connectors would be 2*317 + 747 = 1381.
5 Number of components associated with discharge coolers at compressor stations. If the station has discharge coolers, add these additional components.

4.8 Example Fugitive Emission Calculations

This section presents fugitive emission estimation for an example gas transmission segment using the methods from Tiers 1, 2, and 3. The results from this example illustrate the more conservative nature of Tier 1 and Tier 2 estimates.

An example of a simple Tier 1 average emission factor for the transmission sector is presented below.

Example Operation

Company XYZ owns and operates a cathodically protected 1,245 mile steel transmission pipeline consisting of:

- Six booster stations consisting of:
  - Booster Station #1 - four reciprocating compressors totalling 10,000 HP;
  - Booster Station #2 - Two 5000 HP centrifugal compressors
  - Booster Station #3 - Five 2000 HP reciprocating compressors
  - Booster Station #4 - Two reciprocating compressors totalling 7,000 HP and one 3000 HP centrifugal compressor;
  - Booster Station #5 - same as Booster station #1
  - Booster Station #6 - same as Booster Station #2
- 23 M&R Stations (2 transmission interconnects and 21 direct sales)
- 2 Storage Stations with 2 – 2500 HP reciprocating compressors and 1 – 2500 HP centrifugal compressor
- 3 storage wells with 5 miles of gathering pipeline
- "Normal" gas composition (i.e. 93.4% CH_4 and 2% CO_2)
- Annual volume of gas moved = 1.5 TCF
- Assume a 100 year GWP of 21 for methane

Calculate the *Tier 1 fugitive* emissions for these operations.

Tier 1 - Transmission

Activity Factor * Emission factor = Emission Rate

1,245 miles of transmission pipeline * 7,923 lb CH_4 per mile-year = 9,864,135 lb CH_4/Year (9,864,135/2204.6 = 4,474.3 tonnes CH_4/Year

1,245 miles of transmission pipeline *7.59 lb CO_2 (oxidation) per mile-year = 9,449.6 lb CO_2/Year = 4.3 tonnes CO_2/Year from oxidation

1,245 miles of transmission pipeline * 466.72 lb CO_2 (leak) per mile-year = 581,066.4 lb CO_2/Year = 263.5 tonnes CO_2/Year

CH_4 fugitives*GWP + CO_2 from oxidation + CO_2 fugitive leaks = CO2eq TPY from Transmission Sources

(4474.3*21)+4.3+263.5 = 94,228 tonnes CO2eq from Transmission Sources

Tier 1 - Storage

Activity Factor * Emission factor = Emission Rate

2 Storage Stations * 1,489,000 pounds per station per year = 2,978,000 lbs CH_4 / Year = 1,350.8 tonnes CH_4

21*1,350.5 = 28,367 tonnes CO2eq from Storage Sources

Combining both Transmission and Storage yields:

94,228 tonnes CO2eq from Transmission Sources + 28,367 tonnes CO2eq from Storage Sources

= ***122,595 tonnes CO2eq (Tier 1 estimate)***

<u>Calculate the *Tier 2 fugitive* emissions for these same operations and contrast the answer to the tier 1 estimate.</u>

Tier 2 - TRANSMISSION

Activity Factor * Emission factor = Emission Rate

1,245 miles of transmission pipeline * 23.08 lb CH_4 per mile-year = 28,735 lb CH_4/Year (28,735/2204.6 = 13.03 tonnes CH_4/Year

1,245 miles of transmission pipeline *7.59 lb CO_2 (oxidation) per mile-year = 9,449.6 lb CO_2/Year = 4.3 tonnes CO_2/Year from oxidation

1,245 miles of transmission pipeline * 1.52 lb CO_2 (leaks) per mile-year = 1,892.4 lb CO_2/Year = 0.86 tonnes CO_2/Year

23 M&R stations * 2533 lb CH_4 per Station per year = 26.4 tonnes CH_4/Year

23 M&R stations* 146.34 lb CO_2 per station per year = 1.53 tonnes CO_2/year

6 Compressor stations * 1,259,400 lb CH_4/station per year = 3,427.6 tonnes CH_4/Year

6 Compressor Stations*72,747 lb CO_2 per station per year = 198 tonne CO_2/year

CH_4 fugitives*GWP + CO2 from oxidation + CO_2 fugitive leaks = CO2eq TPY from Transmission Sources

(21 *(13.03+26.4+3,427.6)) + 4.3+0.86 +1.53 +198 = 73,012 tonnes CO2eq (***Tier 2***)

Or a 21,216 tonnes CO2eq less than the ***Tier 1*** transmission estimate

Tier 2 - STORAGE

Activity Factor * Emission factor = Emission Rate

2 Storage Stations * 398,000 pounds per station per year = 796,000 lbs CH_4 / Year = 361 tonnes CH_4

2 reciprocating compressors *325,400 lbs CH_4 per compressor per year = 650,800 lbs CH_4 per year = 295.2 tonnes CH_4

1 centrifugal compressor * 471,100 lbs CH_4 per compressor per year = 471,100 lbs CH_4 per year = 213.7 tonnes CH_4

(21*(361+ 295.2 + 213.7)) = 18,266 tonnes CO2eq from Storage Sources (***Tier 2***)

Or a 10,101 tonnes CO2eq less than the ***Tier 1*** storage estimate

Combining both Transmission and Storage yields:

73,012 tonnes CO2eq from Transmission Sources + 18,266 tonnes CO2eq from Storage Sources

= ***91,278 tonnes CO2eq (Tier 2 estimate)***

Calculate the *Tier 3 fugitive* emissions for these same operations and contrast the answer to the Tier 1 estimate.

Tier 3- TRANSMISSION

Activity Factor * Emission factor = Emission Rate

Station Number	Reciprocating Engine Count	Centrifugal Compressor Count
1	4	
2		2
3	5	
4	2	1
5	4	
6		2
Total	*15*	*5*

1,245 miles of protected steel transmission pipeline * 15.13 lb CH_4 (leak) per mile-year = 18,837 lb CH_4/Year = 8.5 tonnes CH_4/Year

1,245 miles of transmission pipeline * 1.287 lb CO_2 (oxidation) per mile-year = 1,602 lb CO_2/Year = 0.7 tonnes CO_2/Year from oxidation

1,245 miles of transmission pipeline * 0.9185 lb CO_2 (leaks) per mile-year = 1,143.5 lb CO_2/Year = 0.5 tonnes CO_2/Year from leaks

21 M&R (direct sales) stations * 480.8 lb CH_4 per Station per year = 10,097 lb CH_4/Year = 4.6 tonnes CH_4/Year

21 M&R (direct sales) stations * 27.77 lb CO_2 per Station per year = 0.26 tonnes CO_2 /Year

2 M&R (trans. interconnects) stations * 61,390 lb CH_4 per Station per year = 122,780 lb CH_4/Year = 55.7 tonnes CH_4/Year

2 M&R (trans. interconnects) stations * 3546.1 lb CO_2 per Station per year = 3.2 tonnes CO_2/Year

6 Compressor stations * 135,260 lb CH_4/station per year = 368 tonnes CH_4/Year

15 Reciprocating Compressors * 249,810 lb CH_4 per Station per year = 1699.7 tonnes CH_4/Year

15 Reciprocating Compressors * 14,429.9 lb CO_2 per Station per year = 98.2 tonnes CO_2/Yr

5 Centrifugal Compressors * 467,660 lb CH_4 per Station per year = 1060.6 tonnes CH_4/Year
5 Centrifugal Compressors * 27013.67 lb CO_2 per Station per year = 61.3 tonnes CO_2 /Year

CH_4 fugitives*GWP + CO_2 from oxidation + CO_2 fugitive leaks = CO2eq TPY from Transmission Sources

(21 *(8.5+4.6+55.7+368+1699.7+1060.6)) + 0.7+0.5 +98.2+61.3+0.26+3.2 = 67,303 tonnes CO2eq (***Tier 3***)

Or a 5,709 tonnes CO2eq less than the ***Tier 2*** transmission estimate

Tier 3 - STORAGE

Activity Factor * Emission factor = Emission Rate

3 Storage Wells * 1,764 pounds CH_4 per well per year = 5,292 lbs CH_4 / Year = 2.4 tonnes CH_4

2 Storage Stations * 331,401 pounds CH_4 per station per year = 662,802 lbs CH_4 / Year = 300.6 tonnes CH_4

2 reciprocating compressors * 325,376 lbs CH_4 per compressor per year = 650,752 lbs CH_4 per year = 295.1 tonnes CH_4

1 centrifugal compressor * 471,098 lbs CH_4 per compressor per year = 471,098 lbs CH_4 per year = 213.7 tonnes CH_4

5 miles of gathering pipeline * 23.08 lb CH_4 (leaks) per mile per year = 115.4 lbs CH_4 per year = 0.05 tonnes CH_4

5 miles of gathering pipeline * 7.589 lb CO_2 (oxidation) per mile per year = 37.9 lbs CO_2 per year = 0.02 tonnes CO_2

5 miles of gathering pipeline * 1.522 lb CO_2 (leaks) per mile per year = 7.61 lbs CO_2 per year = 0.003 tonnes CO_2

(21*(2.4+ 300.6 + 295.1+213.7+0.05))+0.02+0.003 = 17,049 tonnes CO2eq (***Tier*** 3) from Storage Sources

Or a 1,217 tonnes CO2eq less than the ***Tier 2*** storage estimate

Combining both Transmission and Storage yields:

67,303 tonnes CO2eq from Transmission Sources + 17,049 tonnes CO2eq from Storage Sources

= ***84,352 tonnes CO2eq***

EXAMPLE SUMMARY

Tier	Transmission	Storage	Total
1	94,228	28,367	122,595
2	73,012	18,266	91,278
3	67,303	17,049	84,352

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Appendix B: Unit Conversion Table for GHG Calculations

Metric to English Conversion Table for Common Units

g methane	=	0.052	scf Methane
tonne	=	2204.62	lb
kg	=	2.2046	lb
km	=	0.6213	mile
m^3	=	35.3147	ft^3
m^3	=	0.0353	Mscf
mbar	=	0.014504	psi
MW	=	1341.02	hp (international)
J	=	0.000947	BTU
Gg/PJ	=	2.3279	lb/MMBTU
Gg/yr/$10^6 m^3$ gas withdrawn	=	0.0624	lb/yr/ft^3 gas withdrawn
Gg/yr/km	=	3548366	lb/yr/mile
kg CO2eq/GJ	=	2.3279	lb CO2eq/MMBTU
kg CO2eq/kwh	=	1.6439	lb CO2eq/hp-hr
m^3/component-yr	=	0.035	Mscf/Component-yr
m^3/km/mbar/y	=	3918.92	ft^3/mile/psi/yr
m^3/km-yr	=	0.057	Mscf/mile-yr
m^3/MW/yr	=	0.0263	ft^3/hp/yr
m^3/plant-yr	=	0.035	Mscf/plant-yr
tonne/compressor-hr	=	2204.62	lb/compressor-hr
tonne/km-hr	=	3548.4	lb/mile-hr
tonne/PJ	=	0.002328	lb/MMBTU
tonne/station-hr	=	2204.62	lb/station-hr
tonne/well-hr	=	2204.62	lb/well-hr
tonnes/compressor-yr	=	2204.622	lb/compressor-yr
tonnes/km-yr	=	3548.4	lb/mile-yr
tonnes/MMm^3	=	62.43	lb/$MMft^3$
tonnes/Station	=	2204.623	lb/station
tonnes/station-yr	=	2204.6226	lb/station-yr
tonnes/well-yr	=	2204.6226	lb/well-yr

Conversion for Global Warming Potential

tonnes CO2eq = $\text{tonnes}_{gas} * \text{GWP}_{gas}$

where,

tonnes CO2eq	=	Tonnes (i.e., metric tons = 1000 kg) carbon equivalent
tonnes_{gas}	=	Tonnes of emissions of the GHG gas
GWP_{gas}	=	Global Warming Potential of the gas (e.g., 21 for methane)

Appendix C: Support Information for Combustion Emissions

Appendix C-1: Energy Output to Input Conversions for Prime Movers

Annual heat input to an ICE or turbine employed as a prime mover can be estimated from the combustion equipment output power using a thermal efficiency factor. If the thermal efficiency of a device is known (e.g. has been measured or provided by the manufacturer), equation C1-1 can be used to estimate the annual heat input for an ICE or turbine based on the output power.

Annual Heat Input (MMBtu/yr) = $2.55\ 10^{-3} * P * L * H * 1/\eta$ Eqn. C1-1

Where: 2.55 E-3 = 2,554.4 (Btu/hp-hr) * MMBtu/10^6 Btu (MMBtu/hp-hr)
P = horsepower rating at 100% load (hp)
L = average annual fractional operating load = average operating hp/P
H = annual operating hours (hr/yr)
η = thermal efficiency at average operating load ($0 < \eta < 1.0$)

If the thermal efficiency is not known, equation C1-2 can estimate the annual heat input for an ICE or turbine based on the output power and a default output/input conversion factor.

Annual Heat Input (MMBtu/yr) = $P * L * H * CF * 10^{-6}$ MMBtu/Btu Eqn. C1-2

Where: CF = power output to energy input conversion factor – refer to Table C1-1 (Btu/hp-hr)

Table C1-1. Power Output to Energy Input Conversions for Prime Movers (API 2004)

		Conversion Factor (HHV Basis)		
Service	**Fuel**	**Btu/kw-hr**	**Btu/hp-hr**	**J (in)/J (out)**
Combined Cycle Turbine	Diesel	12,420	**9,262**	3.64
Gas Turbine	Diesel	14,085	**10,503**	4.13
ICE	Diesel	10,847	**8,089**	3.18
Steam Turbine (Boiler)	Diesel	8,653	**6,543**	2.54
Industrial ICE	Gasoline	9,387	**7,000**	2.75
Combined Heat & Power	NG	5,000 – 6,000	**3,729 – 4,474**	1.47 – 1.76
Combined Cycle Steam Turbine w/Supplemental Firing	NG	10,229	**7,628**	3.00
Combined Cycle Single Shaft	NG	8,952	**6,676**	2.62
Gas Turbine	NG	13,918	**10,379**	4.08
ICE	NG	10,538	**7,858**	3.09
Combined Cycle Combustion Turbine	NG	11,648	**8,686**	3.41
Steam Turbine (Boiler)	NG	10,502	**7,381**	3.08

Sources: American Petroleum Institute (API) "Compendium of Greenhouse Gas Emissions Methodologies For the Oil and Gas Industry" (February 2004);
EIIP, Guidance for Emissions Inventory Development, Volume II: Estimating Greenhouse Gas Emissions, EIIP Greenhouse Gas Committee, October 1999.
EPA, AP-42, Supplements A, B, and C, Table 3.3-1, October 1996.

Appendix C-2: Fuel Composition Conversions: Mole Percentage, Weight Percentage, Carbon Mole Percentage, and Carbon Weight Percentage

Convert between weight % per compound in a mixture and mole % per compound

$mole\%_i = wt\%_i * MW_{mixture}/MW_i$ Eqn. C2-1

Where: $mole\%_i$ = molar percentage of compound i in a mixture
$wt\%_i$ = weight percentage of compound i in a mixture
$MW_{mixture}$ = molecular weight of a mixture (lb/lbmole)
MW_i = molecular weight of compound i (lb/lbmole)

Conversely,

$wt\%_i = mole\%_i * MW_i/MW_{mixture}$ Eqn. C2-2

If the fuel is in the gas phase, then the volume percentage of compound i in a mixture ($vol\%_i$) equals the $mole\%_i$. The molecular weight of a mixture of compounds can be calculated using equation C2-3 and equation C2-4.

$MW_{mixture} = 1/100 * \sum(mole\%_i * MW_i)$, i = 1, # compounds in mixture Eqn. C2-3

$MW_{mixture} = 100 / \sum(Wt\%_i/MW_i)$, i = 1, # compounds in mixture Eqn. C2-4

Table C2-1 lists molecular weights of hydrocarbons and other compounds typically found in fuels and waste gases.

Table C2-1. Molecular Weights of Hydrocarbons and Other Fuel Constituents.

Compound		**Molecular Weight**	**wt%C**
Nitrogen	N_2	28.02	0.0
Oxygen	O_2	32.00	0.0
Water	H_2O	18.02	0.0
Sulfur Dioxide	SO_2	64.06	0.0
Hydrogen Sulfide	H_2S	34.08	0.0
Carbon Monoxide	CO	28.01	42.88
Carbon Dioxide	CO_2	44.01	27.29
Methane	CH_4	16.04	74.88
Ethane	C_2H_6	30.07	79.88
Propane	C_3H_8	44.10	81.70
Butanes	C_4H_{10}	58.12	82.66
Pentanes	C_5H_{12}	72.15	83.23
Hexanes	C_6H_{12}	86.18	83.62
Heptanes	C_7H_{16}	100.21	83.89
Octanes	C_8H_{18}	114.23	84.09
Nonanes	C_9H_{20}	128.25	84.28
Decanes	$C_{10}H_{22}$	142.28	84.41
C_{11+} *	$C_{11}H_{24}$	156.31	84.52

* Assume MW C11+ = MW $C_{11}H_{24}$; wt%C = weight percentage of Carbon in compound

Convert from compound weight % in a mixture to Carbon weight % in a mixture

C_{mix} wt% = $\sum$ [(wt%$_i$/100) * (wt%Ci/100)] * 100; (i = 1, # compounds in mixture) Eqn. C2-5

Where: wt%$_i$ = weight percentage of compound i in a mixture
wt%Ci = weight percentage of C in compound i (Table C2-1)
C_{mix} wt% = weight percentage of C in mixture

Convert from compound mole % in a mixture to Carbon weight % in a mixture

C_{mix} wt% = $\sum$ [(mole%$_i$/100) * $MW_i/MW_{mixture}$ * (wt%Ci/100)] * 100; (i = 1, # compounds in mixture) Eqn. C2- 6

Convert from Carbon weight % in a mixture to Carbon mole % in a mixture

C_{mix} mole% = C wt% * $MW_{mixture}/MW_C$ Eqn. C2- 7

Where: C mole% = molar percentage of Carbon in a mixture
MW_C = molecular weight of Carbon (12.01 lb/lbmole)

Appendix C-3: AP-42 Emission Factor Quality Ratings

A – Excellent. Emission factor is developed from primarily A- and B-rated source test data taken from many randomly chosen facilities in the industry population. The source category population is sufficiently specific to minimize variability.

B – Above Average. Emission factor is developed from primarily A- and B-rated source test data taken from a moderate number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. As with the A-rating, the source category population is sufficiently specific to minimize variability.

C – Average. Emission factor is developed from primarily A- , B-, and C-rated source test data taken from a reasonable number of facilities, and there may be reason to suspect that these facilities do not represent a random sample of the industry. As with the A-rating, the source category population is sufficiently specific to minimize variability.

D – Below Average. Emission factor is developed from primarily A- , B-, and C-rated source test data taken from a small number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. There may also be evidence of variability within the source category population.

E – Poor. Emission factor is developed from primarily C-, and D-rated source test data taken from a very few number of facilities, and there may be reason to suspect the facilities tested do not represent a random sample of the industry. There may also be evidence of variability within the source category population.

U – Unrated. Emission factor is developed from source tests which have not been thoroughly evaluated. Research papers, modeling data, or other sources that may lack supporting documentation. The data are not necessarily "poor', but there is not enough data to rate the factors according to the rating protocol. "U" ratings are commonly found in L&E documents and FIRE rather than AP-42.

Appendix C-4: Gasoline and Diesel Vehicles Emissions Controls

Gasoline Powered Vehicles

Low Emission Vehicle (LEV) **-** This emission standard requires a much higher emission control level than the Tier 1 standard. Applied to light duty gasoline passenger cars and trucks beginning in small numbers in the mid-1990s, LEV includes multi-port fuel injection with adaptive learning , and advanced computer diagnostics systems and advanced and close coupled catalysts with secondary air injection. LEVs as defined here include transitional LEVs (TLEVs), LEVs, ultra-low EVs (ULEVs), and super ultra-low EVs (SULEVs). In this analysis, all categories of LEVs are treated the same due to the fact that there are very limited CH_4 or N_2O emission factor data for LEVs to distinguish among the different types of vehicles.

EPA Tier 1 – This emission standard created through the 1990 amendments to the Clean Air Act limited passenger car NOx emissions to 0.4 g/mile, and HC emissions to 0.25 g/mile. For light duty trucks, this standard set emissions at 0.4 to 1.1 g/mile for NOx and 0.25 to 0.39 g/mile for HCs. Depending on the weight of the truck. Emissions reductions were met through the use of more advanced emission control systems, and applied to light duty gasoline vehicles beginning in 1994. These advanced emission control systems included advance 3-way catalysts, electronically controlled fuel injection and ignition timing, EGR, and air injection.

Non-catalyst: These emission controls were common in gasoline passenger cars and light duty gasoline trucks during model years (1973-1974) but passed out thereafter, in heavy-duty gasoline vehicles beginning in the 1980's, and in motorcycles beginning in 1996. This technology reduces hydrocarbon (HC) and carbon monoxide (CO) emissions through adjustments to ignition timing and air-fuel ratio, air injection into the exhaust manifold, and exhaust gas recirculation (EGR) valves, which also helps meet vehicle NOx standards.

Uncontrolled: Vehicles manufactured prior to the implementation of pollution control technologies are designated as uncontrolled. Gasoline light-duty cars and trucks (pre-1973), gasoline heavy-duty vehicles (pre-1984), diesel vehicles (pre-1983), and motorcycles (pre-1996) are assumed to not have any significant control technologies in place.