

**HANDBOOK FOR ESTIMATING COMBUSTION EMISSIONS
FROM THE OPERATION AND CONSTRUCTION OF
CANADIAN NATURAL GAS SYSTEMS**

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EXECUTIVE SUMMARY

This handbook is presented to assist natural gas companies in quantifying atmospheric emissions from combustion sources at Canadian gas transmission, storage and distribution facilities. Combustion emissions at gas production and processing facilities are specifically excluded - users are referred to the Global Climate Change Voluntary Challenge Guide published by CAPP (1997) to address these sectors.

The specific focus is on the following common combustion emissions:

Greenhouse Gases (GHG)

- carbon dioxide (CO₂),
- methane (CH₄), and
- nitrous oxide (N₂O).

Criteria Air Pollutants

- carbon monoxide (CO),
- nitrogen oxides (NO_x),
- sulphur dioxide (SO₂),
- volatile organic compounds (VOC),
- total organic compounds (TOC), and
- particulate matter (PM).

Additionally, factors for speciation of VOC and TOC emissions (i.e., disaggregation of these emissions according to their individual chemical components) also are provided.

This handbook is presented as a companion volume to a similar document developed for assessing methane emissions from non-combustion sources (i.e., fugitive equipment leaks, process venting and accidental releases) at Canadian natural gas facilities (GRI Canada, 1998). Both handbooks are part of an ongoing commitment by the Canadian gas industry to harmonize its atmospheric-emissions inventorying efforts. The overall aim is to provide a flexible framework in which individual companies may assess their emissions, and to establish a base set of terms, source categories and nomenclature to facilitate inter-company comparisons and allow easy aggregation/disaggregation of the results for future industry reporting initiatives.

Collectively, the two handbooks facilitate, essentially, complete accounting of GHG emissions from natural gas systems, including indirect emissions due to consumption of electricity from fossil-fuelled power plants. Raw CO₂ emitted as a constituent of natural gas losses from non-combustion sources and as a constituent of fuel is omitted for simplification purposes. This is a reasonable approximation in view of the low concentrations of raw CO₂ in commercial natural gas streams (i.e., typically less than about 0.6 mol percent). Additionally, other GHGs besides CO₂, CH₄ and N₂O may be emitted by gas systems (e.g., CFCs of refrigeration systems and SF₆

from electrical equipment) but these are only very minor contributors to total system-wide GHG emissions, and therefore, are also omitted.

The procedures provided for accounting of criteria air pollutants and trace air toxics are basically complete for combustion sources. However, the assessment of TOC, VOC and air toxics from non-combustion sources is not specifically addressed.

The assessment of combustion emissions involves three steps: (1) inventorying of the combustion sources; (2) determining the type, amount and quality of fuel combusted by each source; and (3) quantifying the amount of target emissions produced from this combustion activity. The relative amount of each type of pollutant formed may depend on many factors including: type of fuel or combustible material being burned, type and size of combustion device, type of pollution control features, operating conditions (e.g., air-fuel mixture), percent loading, and number of operating hours since the last maintenance check.

The target source types include natural gas-fuelled compressor engines, process heaters and boilers, thermoelectric generators, small industrial space heaters and portable torches, thermal oxidizers, office water heaters and furnaces, and mobile sources.

While significant effort has been made to be as current and complete as possible, methods for assessing combustion emissions are continually being advanced; particularly with respect to trace organic emissions. Accordingly, this handbook is intended to be a live document that will be updated as warranted.

While some safety and operating issues are briefly discussed in this document, it is not intended for use as a reference in these matters.

Technical and Planning Issues

The discussion of emission management strategies and available emission control technologies is beyond the scope of this handbook. Rather, the handbook simply tries to provide the user with a general understanding of the target emission sources, the key factors affecting formation of the target air pollutants, and the difficulties and uncertainties associated with estimating and measuring these emissions. A summary of the available techniques for estimating and measuring combustion emissions is provided.

An important matter throughout the handbook is the need for good quality assurance (QA)/quality control (QC) measures to ensure reliable results, and the need to consider the potential errors before drawing any conclusions from the results. For instance, the emissions of some pollutants (e.g., NO_x and trace organic compounds) may be very sensitive to small differences in actual operating conditions, practices and equipment features.

While much of the work is of a simple clerical nature and can be assigned to junior personnel, a team approach involving intermediate- and senior-level personnel is required to assure:

- accurate and complete posting of information,
- no double or missed counting, and
- correct selection and application of the applicable assessment methods and related factors.

Collectively, the team needs to be familiar with the target sources, applicable industry terminology, available assessment techniques, and sources of the required infrastructure and activity data.

Assessment Methods

There are a variety of techniques that may be used to either estimate or measure combustion emissions. A simple emission factor approach which relies on default activity levels according to the type and size of combustion source is presented as a first approach to quantifying combustion emissions. More advanced techniques incorporate measurement approaches to develop improved emission factors and/or fuel consumption data, and to address site-specific issues.

Sufficient information is provided on each approach to allow the user to make an informed selection from the available options.

Conclusions

The presented handbook is a general reference document that focuses strictly on the available options for assessing combustion emissions at gas transmission, storage and distribution facilities. Rather than try and establish minimum standards and reporting formats, the document simply delineates all reasonable options, and provides sufficient perspective and background information to allow users to make their own informed decisions. The presented options include, but are not limited to, use of emission factors through to direct measurement techniques.

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GLOSSARY

TRANSMISSION FACILITIES

- Block Valve Station - A block valve used to isolate a segment of the main transmission pipeline for tie-in or maintenance purposes. Block valves are located at distances of 25 to 80 km along each line to limit the amount of piping that may need to be depressurized for tie-ins and maintenance, and to reduce the amount of gas that would be lost in the event of a line break.
- Booster Station - A facility where gas pressure is increased to overcome friction losses through a pipeline. Centrifugal or axial compressors are most commonly used in these applications. A station typically comprises several units in series or parallel, as well as the necessary suction and discharge piping. Many booster stations also have discharge coolers to reduce the viscosity of the compressed gas and thereby to increase the efficiency of gas transmission.
- Border Meter Station - A meter station where custody of the gas is transferred from one gas transmission system to another at a provincial or national boundary. These stations are usually larger than normal meter stations. Typically, they have 10 to 20 large diameter meter runs (16" to 20" lines) and no pressure regulation.
- Compressor Station - A facility where gas pressure is increased to allow the gas to enter into a higher pressure pipeline system (i.e., feed rather than booster service). Both centrifugal and reciprocating compressor units may be used in these applications. However, use of reciprocating compressors is most common. A station typically comprises several units in series or parallel, as well as the necessary suction and discharge piping. Many compressors also have discharge coolers to reduce the viscosity of the compressed gas and thereby to increase the efficiency of gas transmission.
- Control Valve Station - A modulating valve that controls either the flow rate or pressure through the pipeline. In the latter case, this facility is often referred to as a regulator station. Usually, high pressure gas from the pipeline is used as the supply medium needed to energize the valve actuator.
- Transmission Farm Tap - Direct gas sales from a transmission pipeline to an individual customer, usually in rural areas where access to gas distribution system is not available. These facilities have usually only pressure

regulating equipment (gas might be provided free of charge as a consideration for an easement, or the meter is located by the residence as part of the customer meter set).

Receipt Meter Station - A meter station for measuring the amount of gas being supplied by a given source (e.g. gas processing plant or a gas battery) to a gas transmission system.

Sales Meter Station - A meter station for measuring the amount of gas being withdrawn from a gas transmission system by a customer (e.g. gas distribution system, farm or industrial end user). It might include pressure regulating equipment.

Storage - Most transmission systems incorporate the use of storage caverns or spheres to help balance daily and seasonal variations in loads, and, therefore, are able to operate at nearly full capacity much of the time.

Storage Well - A well through which natural gas may be either injected or removed from an underground storage cavern. The overall storage system would typically be connected to a gas transmission system.

Transmission Pipeline - A pipeline used to transport processed but unodourized natural gas to market (i.e., to gas distribution systems and major industrial customers). Most transmission pipelines also have some farm taps which provide gas to farmers located along the pipeline in areas where service from distribution systems is not readily available.

The pipelines are usually constructed of steel, although aluminum is used for some lower pressure applications (generally up to 500 psig). The pipe sizes range from 60.3 mm to 1219.2 mm O.D. (2 to 48 NPS), with the mid-range sizes most common. The operating pressures typically range from 1380 to over 6900 kPa_g (200 to 1000+ psig).

For the purposes of calculating methane emissions from transmission pipelines, all small associated facilities such as valve assemblies or pig traps are considered to be part of the pipeline.

Transmission Stations - Transmission stations are stations associated with transmission pipelines and handle unodourized gas. They meter and/or regulate

the gas pressure. They consist of Receipt/Sales Stations, Border Meter Stations and Transmission Farm Taps.

DISTRIBUTION FACILITIES

Commercial Meter Set - Customer metering facilities for gas sales to a commercial customer. They include both pressure regulation and measurement. The regulator reduces the pressure from distribution pressure to 1.7 kPa_g (0.25 psig) or often a higher pressure, typically not in excess of 140 kPa_g (20 psig).

Gate Station - A distribution facility located adjacent to a transmission facility where gas is odourized and flows through a splitter system for distribution to different districts or areas. The inlet gas is often metered, heated, and the pressure reduced. These stations may have multiple metering and pressure regulating runs.

Distribution Farm Tap - A small pressure regulating station located in rural or semi-rural areas on high-pressure pipelines flowing odourized gas. It usually only regulates the pressure down to a distribution pressure, and often, does not include metering equipment.

Distribution Mains - Distribution mains deliver odourized gas to the customers. They range in size from ¾ NPS in rural distribution to 24 NPS, with the most common being 2 to 8 NPS. Systems constructed of plastic pipe (mostly polyethylene, but also P.V.C. or some other plastics), typically, are operated at pressures of up to 690 kPa_g (100 psig), although there are polyethylene resins that allow operation at pressures slightly over 700 kPa_g (100 psig). Higher pressure steel pipelines (either with or without cathodic protection) flowing odourized gas are considered distribution mains in this document. A few older systems constructed of cast iron also exist.

For the purpose of calculating methane emissions from distribution mains, all small associated facilities, such as isolation valves, are considered to be part of the main.

Distribution Stations - Stations associated with the distribution mains that handle odourized natural gas. By function they include gate stations, district regulating stations, distribution farm taps and industrial meter sets.

District Regulating Stations - A secondary regulating facility located downstream of a gate station on gas distribution systems where gas pressure is further reduced (usually to about 400 kPa_g [60 psig] but sometimes only

to 1200 kPa_g [175 psig], depending on the company).

Industrial Meter Set - Metering facility that transfers gas from the distribution system to a large industrial customer. Typically, gas is supplied at intermediate or high pressure (400 to 3000 kPa_g [60 to 435 psig] or more), and is metered and pressure regulated.

Miscellaneous Pipeline Equipment - Aboveground or exposed equipment components (e.g., isolation/block valves, pressure-relief valves, connectors, etc.) used on the pipeline that do not occur at an actual distribution station. Buried components are deemed to be part of the piping.

Residential Meter Set - Customer metering facilities for gas sales to a residential customer. They include both pressure regulation and measurement. The regulator typically reduces pressure from distribution pressure to 1.7 kPa_g (0.25 psig).

EQUIPMENT

Dehydrator - A dehydration unit located at sales or purchase station. Its role is to control hydrates rather than final treatment to meet sales specifications.

Line Heater - An indirectly fired heater used to heat the fluid in the pipeline to above hydrate or freezing temperatures.

Direct-fired Heater The combustion gases occupy most of the heater volume and heat the process stream contained in pipes arranged in front of refractory walls (the radiant section) and in a bundle in the upper portion (the convective section). Convective heaters are a special application in which there is only a convective section.

Firetube Heaters The combustion gases are contained in a firetube that is surrounded by a liquid that fills the heater shell. This liquid may be either the process stream or a heat medium that surrounds the coil bundle containing the process stream. Common applications are indirect-fired water-bath heaters (line heaters) and glycol reboilers.

EMISSIONS TERMINOLOGY

Air Toxics - Air pollutants that are either known or believed to have an adverse effect on human health. For many such compounds 15-minute, 1-hour and 8-hour occupational exposure limits have been

established but acceptable limits for prolonged low-concentration exposure are uncertain.

Acid Precipitation -

Acid precipitation (or acid rain) results from the atmospheric emission of SO_x and NO_x . Both types of pollutants are products of combustion. In the air, these substances react with atmospheric moisture to produce sulphuric (H_2SO_4) and nitric acid (HNO_3), respectively. Eventually, these are carried to earth by precipitation (rain or snow).

The precursors of acid rain may produce respiratory and other internal disease when inhaled in high concentrations. Also, acid rain has potentially serious indirect effects on human health. The two major concerns regarding indirect health effects are: (1) the leaching of toxic chemicals by acidified waters leading to contamination of drinking water supplies, and (2) the contamination of edible fish by toxic chemicals, principally mercury. Acid rain has also been known to damage aquatic ecosystems (National Research Council, 1981).

Combustion Efficiency -

The extent to which all input combustible material has been completely oxidized (i.e., to produce H_2O , CO_2 and SO_2). Complete combustion is often approached but is never actually achieved. The main factors that contribute to incomplete combustion include thermodynamic, kinetic, mass transfer and heat transfer limitations. In fuel rich systems, oxygen deficiency is also a factor.

Criteria Air Pollutants -

Pollutants for which ambient air quality objectives have been promulgated. These typically include SO_2 , NO_x , PM, and CO. Additionally, VOCs also may be a criteria air pollutant in some jurisdictions.

Destruction Efficiency -

The extent to which a target substance present in the input combustibles has been destroyed (i.e., converted to intermediate, partially-oxidized and fully-oxidized products of combustion).

Global Warming
Potential (GWP) -

The amount of radiative forcing on the climate produced per unit mass of a specific greenhouse gas relative to that produced by CO_2 . For example, CO_2 has a GWP of 1 while CH_4 and N_2O have GWPs of 21 and 310, respectively. These values include both

direct and indirect effects.

Greenhouse Gases -

These are substances that cause radiative forcing on the climate (i.e., contribute to global warming) when emitted into the atmosphere. Current focus is on those greenhouse gases increasing in atmospheric concentrations due to human activities, primarily CO_2 , CH_4 , CFC and N_2O .

Continued global warming could be expected to result in a significant rise in the present sea level, altered precipitation patterns and changed frequencies of climatic extremes. The potential effects of these changes include altered distribution and seasonal availability of fresh water resources, reduced crop yields and forest productivity and increased potential for tropical cyclones.

Heat Rate -

The amount of heat energy (based on the net or lower heating value of the fuel) which must be input to a combustion device to produce the rated power output. Heat rate is usually expressed in terms of net $\text{J/kW}\cdot\text{h}$.

Kinetics and
Thermodynamics -

Thermodynamic equilibrium defines the maximum extent to which a chemical reaction such as combustion may proceed (i.e., the point at which there is no further tendency for change).

Chemical kinetics determine the rate at which a chemically reacting system will approach the point of thermodynamic equilibrium.

Methane Content of
Natural Gas -

Volume of methane contained in a unit volume of natural gas at 15°C 101.325 kPa.

Nitrogen Oxides (NO_x) -

The total of all forms of oxidized nitrogen at a given measurement point. The primary form of NO_x emitted by combustion devices is NO_2 ; however, other forms may include NO , N_2O , NO_3 , N_2O_4 and N_2O_5 . Convention is to express total NO_x in terms of equivalent NO_2 .

There are three mechanisms for formation of NO_x in combustion processes: thermal fixation of nitrogen from the combustion air (thermal NO_x), oxidation of fuel-bound nitrogen compounds (chemical NO_x), and the formation of CN compounds in the flame

zone which subsequently react to form NO (prompt NO_x). Thermal NO_x is the predominant form of NO_x produced from natural gas combustion. The conditions that govern the formation of thermal NO_x are the peak temperature, residence time at the peak temperature and the availability of oxygen while that temperature exists.

Fuel-bound nitrogen is an important source of NO_x where appreciable amounts of such fuels are used. The extent of conversion of fuel-bound nitrogen to NO is nearly independent of the parent fuel molecule, but is strongly dependent on the local combustion environment and on the initial amount of fuel-bound nitrogen.

Prompt NO_x is associated with the combustion of hydrocarbons. The maximum formation of prompt NO_x is reached on the fuel-rich side of stoichiometric, it remains high through a fuel-rich region, and then drops off sharply when the fuel-air ratio is about 1.4 times the value at stoichiometric.

NO_x controls can be classified into types: post combustion methods and combustion control techniques. Post combustion methods address NO_x emissions after formation while combustion control techniques prevent the formation of NO_x during the combustion process. Post combustion methods tend to be more expensive than combustion control techniques.

Post combustion control methods include selective non-catalytic reduction, and selective catalytic reduction.

Combustion control techniques depend on the type of combustion device and fuel. Nonetheless, they generally are designed to achieve lower combustion temperatures without significantly affecting combustion efficiency and power output, and to avoid/minimize the use of nitrogen containing fuels.

Particulate Matter (PM) -

Particulate matter is that portion of the flue gas which exists as a solid or liquid droplet when it leaves the stack and cools to ambient conditions. Carbonaceous particulate that forms from gas-phase processes is generally referred to as soot, and that developed from pyrolysis of liquid hydrocarbon fuels is referred to as coke or cenospheres.

The potential for particulate emissions is generally dependent on

the composition of the fuel and the type of combustion device. Combustion of natural gas produces very small amounts of particulate emissions compared to other types of fuels. Nonetheless, the amount of particulate emissions will tend to increase with the molecular weight of the gas. Also, reciprocating engines produce the most particulate matter while heaters and boilers produce the least. Most of the particulate matter emitted by reciprocating engines is reportedly due to lubricating oil leakage past the piston rings.

Particulate emissions generally are classified as PM, PM₁₀, PM_{2.5} and PM₁ according to the maximum diameter of the material, namely, total PM, and PM with a diameter less than 10, 2.5 and 1 microns, respectively. PM₁₀ and smaller particulate matter are of greatest concern because of their ability to bypass the body's natural filtering system.

Photochemical Oxidants -

Photochemical oxidants are a class of pollutants produced by the reaction of VOCs and NO_x in the presence of solar radiation which accumulate in the air near ground level. Ozone (O₃) is the principal oxidant produced; however, significant levels of peroxyacetyl nitrate (PAN) and nitrogen dioxide (NO₂) also occur.

Exposure to increased ozone concentrations can cause short-term impairment of the respiratory system and is suspected of playing a role in the long-term development of chronic lung disease.

Damage to vegetation caused by ozone is reported (Wilson et al., 1984) to be greater than that caused by commonly occurring air contaminants such as SO₂, NO₂, or acidic precipitation. Also, elevated ozone concentrations produce smog and cause deterioration and cracking of rubber products.

Power Output -

For engines it is the net shaft power available after all losses and power take-offs (e.g., ignition-system power generators, cooling fans, turbo chargers and pumps for fuel, lubricating oil and liquid coolant) have been subtracted. For heaters and boilers it is the net heat transferred to a target process fluid or system.

Products of Incomplete Combustion -

These are any compounds, excluding CO₂, H₂O, SO₂, HCl and HF, that contain C, H, S, Cl or F and occur in the flue gas stream. These compounds may result from thermodynamic, kinetic or transport limitations in the various combustion zones. All input combustibles are potential products of incomplete combustion.

Intermediate substances formed by dissociation and recombination effects may also occur as products of incomplete combustion (CO is often the most abundant combustible formed).

Standard Reference Conditions -

Most equipment manufacturers reference flow, concentration and equipment performance data at ISO standard conditions of 15°C, 101.325 kPa, sea level and 0.0 percent relative humidity.

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

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

Sulphur Oxides (SO_x) -

Usually almost all sulphur input to a combustion process as part of the fuel or waste materials being burned is converted to SO_x. Only a few percent of the available sulphur is emitted as sulphate particulate and other products of incomplete combustion. The produced SO_x is comprised mostly of SO₂ (typically 95 percent) with the rest being SO₃. For simplification purposes it is assumed throughout this document that all input sulphur is converted to SO₂.

Thermal Efficiency -

The percentage or portion of input energy converted to useful work or heat output. For combustion equipment, typical convention is to express the input energy in terms of the net (lower) heating value of the fuel. This results in the following relation for thermal

$$\eta = \text{Thermal Efficiency} = \frac{\text{Useful Work / Heat Output}}{\text{Net Heat / Energy Input}} \times 100\%$$

ency:

Alternatively, thermal efficiency may be expressed in terms of energy losses as follows:

$$\eta = \left(1 - \frac{\Sigma \text{Energy Losses}}{\text{Net Heat / Energy Input}} \right) \times 100\%$$

Losses in thermal efficiency occur due to the following potential factors:

- exit combustion heat losses (i.e, residual heat value in the exhaust gases),
- air infiltration,
- incomplete combustion, and
- mechanical losses (e.g., friction losses and energy needed to run cooling fans and lubricating-oil pumps).

Total Hydrocarbons -

All compounds containing at least one hydrogen atom and one carbon atom.

Total Volatile Organic Compounds (TOC) -

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

Volatile Organic Compounds (VOC) -

Any compound of carbon, excluding carbon monoxide, and carbon dioxide, which participates in atmospheric chemical reactions. This excludes methane, ethane, methylene chloride, methyl chloroform, many fluorocarbons, and certain classes of per fluorocarbons.

LIST OF ACRONYMS

AGA	-	American Gas Association
BSFC	-	Brake-Specific Fuel Consumption
CAPP	-	Canadian Association of Petroleum Producers
CCME	-	Canadian Council of Ministers of the Environment
CGA	-	Canadian Gas Association
CSA	-	Canadian Standards Association
EC	-	Environment Canada
EPA	-	Environmental Protection Agency
GHG	-	Greenhouse Gases
GRI	-	Gas Research Institute
GTC	-	Gas Technology Canada
HAP	-	Hazardous Air Pollutant
HEL	-	Higher Explosive Limit
LEL	-	Lower Explosive Limit
NBS	-	National Bureau of Standards
NMVOG	-	Non-methane Volatile Organic Compound
PM	-	Total Suspended Particulate Matter
PM ₁	-	Particulate Matter $\leq 1 \mu\text{m}$ in Aerodynamic Diameter
PM _{2.5}	-	Particulate matter $\leq 2.5 \mu\text{m}$ in Aerodynamic Diameter
PM ₁₀	-	Particulate matter $\leq 10 \mu\text{m}$ in Aerodynamic Diameter
POM	-	Polycyclic Organic Matter
ppm	-	Parts Per Million
THC	-	Total Hydrocarbons
U.S. EPA	-	U.S. Environmental Protection Agency
VCR	-	Voluntary Challenge and Registry
VOC	-	Volatile Organic Compound
TOC	-	Total Organic Compounds
TNMOC	-	Total Non-methane Organic Compounds

CONVERSIONS

USEFUL CONVERSION FACTORS		
Physical Quantity	SI to English Conversion	English to SI Conversion
Length	1 m = 3.2808 ft 1 km = 0.6213712 mi	1 ft = 0.3048 m 1 mi = 1.609344 km
Area	1 m ² = 10.7639 ft ²	1 ft ² = 0.092903 m ²
Volume	1 m ³ = 35.3134 ft ³ 1 L = 0.2641720 U.S. gal	1 ft ³ = 0.02837 m ³ 1 U.S. gal = 3.785412 L
Velocity	1 m/s = 3.2808 ft/s 1 km/h = 0.6213712 mph	1 ft/s = 0.3048 m/s 1 mph = 1.609344 km/h
Density	1 kg/m ³ = 0.06243 lbm/ft ³	1 lbm/ft ³ = 16.018 kg/m ³
Force	1 N = 0.2248 lb _f	1 lb _f = 4.4482 N
Mass	1 kg = 2.20462 lb _m	1 lb _m = 0.45359737 kg
Pressure	1 kPa = 0.145038 psi 1 kPa = 4.01474" WC	1 psi = 6.89476 kPa 1" WC = 0.249082 kPa
Energy	1 kJ = 0.94783 Btu	1 Btu = 1.05504 kJ
Power	1 W = 3.4121 Btu/h 1 kW = 1.3405 hp	1 Btu/h = 0.29307 W 1 hp = 0.746 kW
Heat Flux/Unit Area	1 W/m ² = 0.317 Btu/h·ft ²	1 Btu/h·ft ² = 3.154 W/m ²
Heat Flux/Unit Length	1 W/m = 1.0403 Btu/h·ft	1 Btu/h·ft = 0.9613 W/m
Heat Generation/Unit Volume	1 W/m ³ = 0.096623 Btu/h·ft ³	1 Btu/h·ft ³ = 10.35 W/m ³
Energy/Unit Mass	1 kJ/kg = 0.4299 Btu/lb _m	1 Btu/lb _m = 2.326 kJ/kg
Specific Heat	1 kJ/kg·°C = 0.23884 Btu/lb _m ·°F	1 Btu/lb _m ·°F = 4.1869 kJ/kg·°C
Thermal Conductivity	1 W/m·°C = 0.5778 Btu/h·ft·°F	1 Btu/h·ft·°F = 1.7307 W/m·°C
Convective Heat Transfer Coefficient	1 W/m ² ·°C = 0.1761 Btu/h·ft ² ·°F	1 Btu/h·ft ² ·°F = 5.6782 W/m ² ·°C

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1.0 INTRODUCTION

This handbook presents a detailed compendium of the available methods for assessing emissions of greenhouse gases, criteria air pollutants and trace organic compounds from combustion sources associated with natural gas transmission, storage and distribution systems. It is designed as a detailed reference guide for use by both management and practitioners. It identifies and describes the different types of sources to be considered, delineates the basic steps involved in inventorying the target emissions, highlights important quality control/quality assurance matters to be considered, and provides practical information for designing an overall assessment strategy best suited to a company's particular needs and circumstances. Moreover, it establishes a general source classification scheme to facilitate inter-company comparisons and easy aggregation/disaggregation of data for future industry reporting initiatives.

A glossary of key terms and common acronyms is provided at the front of the handbook, along with a summary of common unit conversion factors.

General information concerning planning and designing of a combustion emissions inventory is presented in Section 2 along with the reference emission-source classification scheme.

Section 3 describes the generalized approach to assessing emissions from a combustion device, while Sections 4 to 10 provide supplemental source-specific information. The source types considered include: natural gas-fuelled compressor engines, process heaters and boilers, thermal oxidizers, industrial space heaters and torches, thermoelectric generators, and mobile sources. Section 11 provides procedures for estimating indirect emissions associated with the consumption of electric power produced by fossil-fuelled power plants.

All references cited in this handbook are listed in Section 12. A bibliography of some additional useful references is presented in Section 13.

Useful physical properties of combustible gases and combustion products are given in the Appendices. The appendices also present properties of selected process fluids for use in estimating fuel consumption based on actual process heating or work done, a summary of standard source test methods and a summary of available emission factors for specific makes and models of compressor engines.

2.0 DEVELOPMENT OF A COMBUSTION EMISSIONS INVENTORY

To help ensure complete and reliable results, the assessment effort must be conducted in a thorough and well-organized manner. Accordingly, this section delineates the important matters to be considered in planning the development of a methane emissions inventory. As well, it documents the general classification of gas transmission and distribution facilities. Except for a few minor differences, this section is consistent with Section 2 of the companion handbook for methane emission from non-combustion sources.

2.1 General Planning Considerations

Typically, the work may be divided into the following basic tasks, as presented in the general order of occurrence:

- establish the study area, reference period and specific objectives to be achieved,
- assemble a study team with the requisite expertise and resources,
- prepare an inventory of the target infrastructure and operations in the study region,
- formulate an appropriate methodology for assessing the target emissions from these sources,
- detail the sources sufficiently for application of the selected emission assessment procedures and classification of the results (e.g., determine types of combustion devices, their rated power output, actual load and utilization factors, emission controls, measured facility-specific fuel consumption data and/or sufficient data to prorate/estimate source-specific fuel consumption data),
- conduct field inspection and sampling campaigns as may be needed to provide the required information,
- prepare a computer application to manage and process the collected data,
- identify trends and anomalies in the emission results,
- quality assurance/quality control (QA/QC),
- prepare a final report on the results and document information (especially data sources and contacts) that may be useful in any future updates of the work, and
- develop recommendations for senior management.

However, some of these task may be combined, depending on the actual scope of work and resources available.

2.1.1 Objectives. The first step is to clearly establish the specific objectives to be achieved. This will often dictate the best approach to be taken and allow proper planning of the proposed work.

Typical objectives may be as follows:

- Assess total company-wide combustion emissions as an indication of environmental performance, and to fulfil obligations made to the global climate change voluntary challenge and registry program.
- Conduct a statistical sampling/measurement campaign to determine company-specific emission factors for selected key types of sources.
- Assess emissions from a single facility to investigate the possible need for control measures.
- Establish accurate emission rates from specific sources to engineer appropriate control measures.
- Evaluate operational improvements.

2.1.2 Study Team. Personnel and technical requirements are most demanding the first time an assessment is undertaken. Thereafter, the process is greatly simplified, provided the initial efforts have been properly documented.

One of the main difficulties is identifying resources and information available within the company that may be useful for the proposed undertaking. This usually requires a certain amount of research by someone with a good overall knowledge of the company and its operations, and an understanding of the target sources and proposed assessment techniques.

Custom software applications may need to be developed to access electronic information and convert it to a useable format. Hardcopy data should be entered into a data base system or spreadsheet application for efficient management and processing. Facility inspections and emission measurement programs may be warranted.

While much of the work may often be done by junior personnel, the work also requires the overview and involvement of senior personnel. As well, a range of technical support services may be required.

2.1.3 Delineation of Process Infrastructure and Operations. Major facilities and installations are usually readily identified through a variety of sources including engineering, operations and accounting departments. However, minor facilities (e.g., line heaters, space heaters, etc.) and mobile sources may be more difficult to document.

2.1.4 Emissions Assessment Protocol. The development of a company-specific protocol document is an effective mechanism for substantiating the specific information sources, factors, methodologies and QA/QC procedures used, or to be used. Moreover, it provides a clear road map for those charged with performing the required emissions assessment work, and facilitates careful planning of the work to be performed.

It is especially needed where the emissions assessment is to be conducted on a regular or frequent basis, and can provide a sound basis for monitoring changes in emissions.

2.1.5 Data Collection. Regardless of the techniques employed, a certain amount of source and activity data must be collected to support the assessment effort. The key issues are to ensure completeness, accuracy (i.e., no double counting) and correct posting of the information. This generally requires personnel with a good working knowledge of the equipment and facilities involved, and of the associated operations and engineering jargon.

Compilation of the required source data usually means developing a detailed inventory of sources by facility or installation. This may include major point sources (e.g., compressor engines and process heaters or boilers) through to the, often, many minor sources (space heaters, portable fired equipment and mobile sources). A thorough approach is needed to ensure adequate accounting of total emissions. While there is a natural tendency to trivialize smaller sources, these, due to their numbers and periods of activity, may often be significant total contributors. Therefore, they should not be disregarded unless their collective contribution to total methane emissions is proven to be negligible. Conversely, once a thorough assessment has been done, a basis exists for simplifying the approach and better allocating resources in the future to best reduce uncertainties in the results.

Many companies use computerized inspection-and-maintenance information management systems. These can be a very reliable means of counting major and critical-service components (e.g., compressor units, process heaters and boilers, etc.). Also, some departments within a company may maintain databases of certain types of equipment or facilities for their own specific needs (e.g., tax accounting, production accounting, insurance records, quality control programs, safety auditing, license renewals, etc.). Some effort should be made to flush out and identify these pools of potentially useful information.

The required activity data may include the following:

- measured volumes of natural gas taken from the process,
- flared waste-gas volumes,
- fuel purchases (e.g., propane, gasoline, diesel, aviation fuel, etc.),
- fuel analyses,
- process operating conditions that may be used to infer the work being done by combustion devices (e.g., gas compositions, temperatures, pressures and flows), and
- operations and maintenance records.

Other data that may be needed are listed below:

- engine nameplate data,
- source emission control features,
- sulphur content of the fuels consumed,
- types of heat medium fluids being used, and
- annual update of new equipment installed.

Typical difficulties that may be encountered in attempting to utilize available data are as follows:

- converting electronic data to a consistent or convenient format,
- reliable and accurate data entry,
- verification of database accuracies and completeness,
- possible development of special applications to perform custom retrievals of information from existing applications (this almost always involves more work than initially expected), and
- prorating total facility fuel consumption to the individual pieces of combustion equipment.

2.1.6 Field Work. The primary objective of the field work is to ensure complete and accurate results. However, important elements to be considered in any field work are planning, organization, logistics (e.g., transportation, accommodation, available times), anticipation of potential difficulties and safety issues, contingencies or flexibility to respond to specific difficulties that may arise (e.g., poor weather conditions), and good communication and coordination of activities with site personnel. The work may be divided into the following general tasks:

- development of a realistic scope of work and work schedule,
- contingency planning,

- preparation of check lists and data collection sheets,
- mobilization,
- site indoctrination and orientation,
- receipt of work permits,
- interviews with site personnel regarding operating practices and design features that either contribute to or help reduce combustion emissions,
- completion/verification of the site description,
- recording of nameplate data for the target combustion sources,
- setup and check-out of the required measurement equipment,
- performance of actual measurements and inspections,
- recording of applicable process conditions at the time of the measurements,
- return of work permits, and
- demobilization.

Where practicable, operations personnel responsible for the target facilities and installations should be involved in the work to ensure that emission sources are correctly identified, and that the operating status and state of equipment are interpreted properly. This is especially important at larger more-complex facilities.

The use of checklists and proper data collection sheets is essential to ensuring that all the necessary information is collected. Moreover, it promotes an efficient and systematic approach to performing the necessary work.

Developing a good overview description of a facility's process infrastructure and surroundings helps provide useful perspective for subsequent interpretation of the results. A photographic essay of the facilities and work performed is particularly useful for this purpose. Some considerations and suggestions regarding the use of cameras are as follows:

- Flash cameras are not allowed in hazardous locations.
- Prepare a written log of each photograph, preferably as the pictures are being taken or shortly thereafter.
- If multiple facilities or installations are to be visited, tag the start of photographs at each by taking a picture of the entrance sign.

2.1.7 Data Management and Processing. The most practicable means of handling and processing the compiled data is to enter it into either a spreadsheet program (e.g., Lotus 123, Excel, or QuattroPro) or a data management system (e.g., dBASE, Paradox, FoxPro, Access, or Oracle), as appropriate. Typically, spreadsheets are best suited to managing small to moderate amounts of information, and for performing relatively basic calculations. The ability to use multiple sheets in a single file and to link files helps make

it easy to organize and structure a spreadsheet application. Additionally, most personnel will be knowledgeable on the use of spreadsheet programs, and minimal effort is required to quickly produce presentation-quality output. For large amounts of information or many types of data, however, spreadsheets tend to be an inefficient means of data management and quickly become cumbersome and unwieldy to use. Furthermore, if extensive use is made of cell programming features, a spreadsheet application may become very difficult to modify or update without introducing errors, and will generally be more difficult to debug than a comparable database application. Greater use of macro programming features and linking of external applications to spreadsheet cells can mitigate some of these problems but soon it still is better to be using a data management system.

The use of a database application enables complex information retrievals and custom reporting of information that simply would not be practicable with a spreadsheet program. Information may be arranged into logical groupings (or tables) that may be linked together to create a relational database. This allows efficient storage of information and makes it easier to manage the data. Furthermore, it is much easier to rearrange information and insert or delete fields as a project evolves than with a spreadsheet. Overall, databases tend to be easier to maintain and support than spreadsheets, as the applications become more sophisticated.

A big disadvantage of data management systems is the need for more specialized user training. A data management system is most useful and productive where the user is competent in its programming features. Many data management systems offer an interactive environment that is easy to master, thus, allowing a novice to quickly begin doing useful work. However, interactive usage is very restrictive, much more susceptible to human error, and, for other than simple tasks, is far less efficient than using the system's programming features to develop scripts. Scripts may be continually reused and are readily debugged.

Additionally, a data management system, while able to do very sophisticated information retrievals, requires considerable more effort than a spreadsheet to prepare presentation quality output. Often it is easier to output the data to another program for preparation of presentation graphs and tables.

In general, if there is any uncertainty at the start of a project about whether to use a spreadsheet or data management system, then the latter should be chosen. The amount of information to be collected and the complexities of managing it almost always exceeds expectations.

2.1.8 Data Analysis. A typical exercise in any emissions assessment effort is to summarize the results in charts and tables. The following are some specific matters to consider in reviewing the results:

- look for cost effective opportunities to reduce emissions and improve the quality of the developed estimates,
- the greatest sources of emissions do not necessarily offer the most cost-effective opportunities for emissions control, and
- look for opportunities to adjust the assessment strategy for future efforts so that uncertainties are minimized for the available resources.

2.1.9 Quality Assurance/Quality Control (QA/QC). As a basic QA/QC measure, it is important that the results be reviewed by senior operations, engineering and environmental personnel to help ensure that there are no errors, omissions or double counting. Any apparent anomalies in the data should be investigated so they can be fully understood and properly explained.

As part of this process, it is useful to compare the results against any previous baseline data as well as with other relevant corporate, industry and national inventories. Moreover, the results should be put in context relative to current corporate and regulatory objectives.

Other appropriate QA/QC measures may include the following:

- ensure that the reference year for the presented results is clearly stated,
- ensure that the sources of all source, activity and emission factor data as well as calculation procedures and test methods are identified and properly referenced (both for the benefit of future updates and to provide a clear trail for resolving anomalies),
- check for recent updates or improvements in calculation procedures and related factors being used,
- check for inconsistencies,
- rank sources to help identify anomalies,
- ensure that emissions have been adjusted to reflect actual fuel consumption (i.e., hours of operation, work being done, and thermal efficiencies of the combustion equipment) and check these data to ensure that they have not been simply carried forward from a previous year rather than properly updated,
- check to ensure that point source contributions have been subtracted out from area source category totals where appropriate,
- document any extrapolations from previous results and check that all applicable source categories have been corrected to the current reference year,
- subject a reasonable cross section of the targeted sources to a detailed procedures check, and
- document any recent operational improvements and upgrades.

The actual QA/QC measures used in conducting the emissions assessment or preparing

the emissions inventory should be fully documented.

2.1.10 Reporting. The following is a suggested list of matters to be addressed in the developed final emissions-assessment report:

- The method of assessment should be fully documented.
- The emissions should, to the extent practicable, be compared to results in preceding years back to the baseline year of 1990.
- The expected accuracy of the results should be stated and the areas of greatest uncertainty clearly noted. This is critical for proper interpretation of the results and any claims of net reductions.
- Specific measures taken to reduce methane emissions should be described.
- A discussion of the differences between the previous year and the current year's estimates if applicable.
- An effort should be made to put the estimated amount of emissions in proper context relative to the amount of gas handled, and the distances the gas is transported.
- Some effort to forecast future emissions should be made.

Companies that elect to participate in Canada's Voluntary Challenge and Registry (VCR) Program may find detailed information on this initiative at the following Internet address: www.vcr-mvr.ca. Alternatively, companies may contact Voluntary Challenge and Registry Inc. at the address below:

Voluntary Challenge and Registry Inc.
170 Laurier Avenue W., Suite 600
Ottawa, Ontario
K1P 5V5

Telephone: (613) 565-5151
Fax: (613) 565-5743
E-mail: info@vcr-mvr.ca

As a first step, participants are encouraged to submit a letter of intent confirming a commitment to limit or reduce greenhouse gases from their operations. This is followed by an action plan and subsequent progress reports. A Participant's Handbook and

Addendum is available at the VCR web site; it gives detailed information on how to report greenhouse gas emission reduction plans and actions.

2.2 Source Classification Scheme

The use of a consistent source-classification scheme across the gas industry is necessary to allow meaningful comparisons of results between companies, and to facilitate easy aggregation of results for future industry and national reporting initiatives. It is recognized that many companies already have their own in-house terminology and definitions, and that certain industry standards (e.g., CSA Z662-96 Oil and Gas Pipeline Systems) and government regulations establish their own values. The scheme presented here is intended to achieve a reasonable balance between existing corporate, industry and government naming conventions, as well as to provide a logical grouping of sources according to functionality, industry sector, and type of facility.

All facilities that handle unodourized pipeline gas are arbitrarily deemed to be in gas transmission service, and if the pipeline gas is odourized the facilities are deemed to be in distribution service. To characterize the different facilities and installations generally according to logical type and size, the following classifications shall be used:

Distribution

- Protected Steel Mains and Service Lines
- Unprotected Steel Mains and Service Lines
- Plastic Mains and Service Lines
- Cast Iron Mains
- Copper-tubing Service Lines
- Gate Stations
- District Regulating Stations
- Distribution Farm Taps
- Industrial Meter Stations
- Commercial Meter Sets
- Residential Meter Sets
- Miscellaneous Pipeline Equipment
- Mobile Sources

Transmission

- Protected Steel Pipelines
- Unprotected Steel Pipelines
- Border Meter Stations
- Receipt Meter Stations
- Sales Meter Stations
- Transmission Farm Taps

- Block Valve Stations
- Control Valve Stations
- Compressor and Booster Stations
 - Reciprocating Compressor Units
 - Centrifugal Compressor Units
 - Compressor Discharge Coolers
 - Compressor Station Yard Piping
- Mobile Sources

2.3 Uncertainties

The potential sources of uncertainties in an emissions inventory may include the following:

- inherent uncertainties of the selected estimation techniques,
- missing or incomplete information regarding the source population and activity levels,
- measurement errors,
- poor understanding of temporal and seasonal variations in the sources, and
- data entry and calculation errors.

The first two items are likely to be the greatest sources of error, although all are potentially noteworthy.

In general, the procedures documented in this handbook represent a range of simple (or first-order) through to best-available measurement and estimation techniques. However, many of these methods, particularly those specific to estimating trace organic emissions, are still undergoing significant refinement. The published emission factors are frequently updated as the science evolves.

3.0 GENERALIZED ASSESSMENT APPROACH

The common approach for determining emissions from combustion sources, and which is taken here, is to apply appropriate emission factors to fuel consumption or equivalent activity data. The use of emission measurement approaches is presented in the context of developing improved emission factors and activity data as companies may deem appropriate. The application of measurement techniques and continuous emission monitoring systems as a routine emissions assessment approach generally is not practicable due to the specific costs (e.g., \$2 500 to \$10 000 or more per source), the large numbers of sources and the distribution of these sources amongst many widely-distributed small to medium sized facilities. Furthermore, complex numerical models have been developed by researchers for modelling various types of dynamic combustion processes. However, while useful for research and some design purposes, they are not readily available and their predictions are not yet reliable enough for general emission assessment activities.

The following subsections present the general procedures for applying the emission factor approach and provide some discussion of supplemental measurement techniques that may be considered. All source-specific considerations and factors are presented in Sections 4 to 10 which follow. Form 3.0-1 summarizes the key steps in assessing the emissions from individual sources and aggregating the results. Estimation of indirect emissions due to electric power consumption is addressed in Section 11.

In the general literature, emissions and combustion equipment parameters may be expressed in a wide range of units, formats, classifications and terminology. In the current document every effort has been made to maintain a consistent convention to allow convenient comparisons and aggregation of results, and to be reasonably consistent with the more common conventions used by governments and other industries. Consumption of gaseous fuels or combustibles is expressed in terms of the gross (or higher) heating value of the material in units of GJ; this is common practice for gas purchases and sales. Liquid fuels are expressed on a volume basis in units of litres. Emission factors are expressed on a fuel-consumption basis in units of ng/J or ng/L as appropriate. The conversion table presented at the front of this handbook may be used to convert available data to these units as needed.

Calculation Form 3.0-1**ASSESSMENT OF COMBUSTION EMISSION
FROM A SINGLE SOURCE*****General Steps***

Step No.	Description	Default Values ¹
1	Record the target type of pollutant (e.g., N ₂ O, VOC, benzene, etc.)	Not Applicable
2	Record the associated facility classification.	See Section 2.2
3	Record the Source Type (e.g., reciprocating compressor engine, catalytic heater, etc).	Not Applicable
4	Determine annual fuel consumption (i.e., measured value if available or else estimated value).	See Section 3.1
5	Select or develop appropriate emission factor ¹ .	See Sections 4 to 10 and 14.3.
6	Calculate emissions based on results from Steps (4) and (5).	See Section 3.2
7	Repeat Steps 2 to 6 for all sources and aggregate the results.	Tonnes/y

¹ The presented data are based on national averages and, for improved accuracy, should be replaced with company-specific or unit-specific values where available.

3.1 Determination of Fuel Consumption

In most cases, natural gas taken from the process will be the principal type of fuel used for stationary combustion devices, while purchased liquid fuels will be mostly used for mobile sources (e.g., construction equipment and motor vehicles). Purchased propane may be used for motor vehicles and for portable heaters and torches.

The following subsections address methods for estimating and prorating fuel gas consumption. It is assumed that the volumes of liquid fuels and propane consumed may be readily determined and prorated from financial accounting records. This may require some assumptions regarding the average fuel price during the period of interest.

3.1.1 Fuel Consumption Based on Maximum Rated Power Output. In the absence of any better information, the fuel gas consumption by a stationary or portable combustion device may be estimated based on its maximum rated power output, the heating value of the fuel and an appropriate thermal efficiency, load factor and operating factor as given by the following equation:

$$e_F = k_L \cdot \frac{t_O}{8760} \cdot \left(\frac{100 \text{ HHV}_F}{\eta \text{ LHV}_F} \right) \cdot e_{\text{sub max}} \cdot g_c$$

where,

e_F	=	rate of fuel consumption expressed as an energy flow rate and based on the higher heating value of the gas (GJ/y),
e_{max}	=	maximum rated power output of the combustion device (kW),
k_L	=	fractional loading of the combustion device when it is operating (dimensionless) (see Table 2 for default values),
t_O	=	number of hours during the year that the device is actually operating (h) (see Table 3 for default values),
η	=	thermal efficiency of the device based on the net heat/energy input rate (percent) (see Table 1 for default values),
HHV_F	=	higher (gross) heating value of the fuel gas (MJ/m^3) (see Section 14.1),
LHV_F	=	lower (net) heating value of the fuel gas (MJ/m^3) (see Section 14.1), and
g_c	=	factor to convert from units of kJ/s to GJ/y,
	=	31.536.

Values of the thermal efficiency may be determined from the operating manual for the device, and estimates of the load and operating factors may be obtained through discussions with operations personnel responsible for the target facility. In the absence of such data, default values may be taken from the Tables 1 to 3, respectively. Procedures

for calculating the net and gross heating value of a fuel or combustion material are provided in Section 14.1 of the appendices.

- 3.1.2 Fuel Consumption Based on Actual Work or Heat Output** This is similar but opposite to the approach taken in Section 3.1.1. Here, rather than estimating fuel gas consumption based on the available power output of a device, fuel consumption is determined based on the actual work or heat output as indicated by available process data (e.g., temperatures, pressures and flows) and allowing for the efficiency of the device. The calculation procedures and process data required depend on the type of combustion device, and are delineated in Sections 4 to 9, accordingly.

Equipment manufacturers typically report specific fuel requirements based on the net heating value of the fuel rather than the gross heating value as considered herein. Consequently, if fuel consumption is estimated from equipment performance curves, the results must be converted to a gross-heating-value basis for use with the equations and emission factors provided in this document.

- 3.1.3 Proration of Total Measured Fuel Usage to Individual Devices** While, most types of gas facilities carefully measure and record actual volumes of fuel gas consumed, usually only total site-wide fuel consumption is tracked. Accordingly, if fuel gas is supplied to multiple combustion devices at a site, it is necessary to prorate the site total back to the individual end uses since this can significantly affect the estimated amount of emissions (for example, reciprocating engines will produce significantly more NO_x emissions per unit of fuel consumption than will a process heater). At some locations it also may be necessary to discount measured fuel consumption to account for non-combustion uses (e.g., instrument gas, compressor starter gas, purge gas, etc.). The fuel gas consumption for a given device may be determined using the following equation:

$$e_{Fi} = e'_{Fi} \cdot k_N$$

where,

e_{Fi}	=	estimated fuel gas consumption (GJ/y) by combustion device i,
e'_{Fi}	=	theoretical fuel gas consumption (GJ/y) by combustion device i,
k_N	=	normalization correction factor (dimensionless).

Table 1. Typical input heat rates and thermal efficiencies (based on the net heating value of the fuel) for different types and sizes of natural gas-fuelled equipment.			
Source Type	Maximum Rated Power Output (kW)	Input Heat Rate (kJ/kW·h)	Thermal Efficiency (percent)
Reciprocating Engines	<325	12 857	28 ¹
	325 to 600	11 250	32 ¹
	600 to 2250	10 000	36 ¹
	>2250	9 474	38 ¹
Turbine Engines	All	10 909	33 ²
Industrial and Commercial Heaters and Boilers	<375 (Natural Draft)	4 736	76 ³
	<375 (Forced Draft)	4 500	80 ²
	≥375	4 500	80 ²
Residential Water Heaters	All	7 500	48 ⁴
Residential Furnaces	All	5 143	70 ⁵
Catalytic Heaters	Vented Outdoors	4 500	80 ⁶
	Vented Indoors	3 600	100
Thermoelectric Generators	All	100 000	3.6 ²

1 Adapted from Perry and Chilton (1973).

2 Estimated based on a review of current manufacturer's data for selected units.

3 Adapted from Fig 8-30 of GPSA Engineering Data Book, Volume 1, tenth Edition, 1987.

4 Adapted from Geller (1988).

5 Adapted from Baumeister et al. (1978).

6 Catalytic heaters emit radiant heat and discharge thermal heat with the combustion products. Thus, the thermal efficiency of a catalytic heater depends on the ability of the room to absorb the radiant heat (i.e., on the absorptivity of the objects in the room). Based on discussions with one major manufacturer of catalytic heaters used in process buildings, actual unit efficiencies may range from 50 to 80 percent. Although, a value of 80 percent is typically used for design purposes.

Table 2. Estimated load factors for combustion devices during actual running/firing periods ¹ .	
Source Type	Load Factor (k_L) (Fraction of Maximum Rated Power Output)
Reciprocating Engines	0.65
Turbine Engines	0.75
Industrial and Commercial Heaters and Boilers	1.0
Residential Water Heaters	1.0
Residential Furnaces	1.0
Catalytic Heaters	1.0
Thermoelectric Generators	1.0

1 Based on engineering estimates and personal experience.

Table 3. Typical portion of the time combustion devices are actually running/operating.

Source Type	Fractional Time In Operation	Annual Operating Hours
Reciprocating Engines	0.79 ¹	6920
Turbine Engines	0.81 ¹	7096
Industrial and Commercial Heaters and Boilers	0.50 ²	4380
Residential Water Heaters	0.17 ³	1489
Residential Furnaces	0.25 ⁴	2190
Catalytic Heaters	0.50 ⁵	4380
Thermoelectric Generators	0.95 ⁶	8322

1 Mean of data collected by Legge and Baker (1987) for equipment at oil and gas facilities in Alberta.

2 Arbitrarily determined based on typical sizing practice for the types of applications usually encountered at gas facilities.

3 Based on hot water usage only during normal day-time working hours (i.e., 8 hours per day for 5 days per week), and an assumed 50 percent duty during this period.

4 Based on use only during the colder half of the year and on an assumed 50 percent duty during this period.

5 Based on use only during the colder half of the year and on an assumed 100 percent duty during this period.

6 Based on use an assumed 100 percent duty except for a 2 to 3 week shutdown period each year.

$$k_N = \frac{e_F - \sum e'_{F_{NC}}}{\sum e'_{F_C}}$$

The value of k_N is determined using the following equation:
where,

- e_F = total measured fuel gas usage at the site (GJ/y),
 $\sum e'_{F_C}$ = sum of the calculated/theoretical fuel gas usage by each combustion device at the site (GJ/y), and
 $e'_{F_{NC}}$ = calculated/theoretical fuel gas usage by all non-combustion devices at the site (GJ/y) (see the methane emissions handbook for estimation of these gas amounts).

3.2 Determination of Emissions

Once fuel consumption is determined, the amount of a target pollutant i emitted may be determined using the following equation:

$$E_i = 10^{-6} \cdot e_{F_i} \cdot EF_i \cdot \left(1 - \frac{EC_i}{100}\right)$$

where,

- e_{F_i} = estimated fuel gas consumption (GJ/y for gas fuels or L/y for liquid fuels) by combustion device i ,
 E_i = emissions of pollutant i from the specified source (t/y),
 EF_i = appropriate factor for emissions of pollutant i from the specified type of source (ng/J for gas fuels or g/L for liquid fuels), and
 EC_i = overall efficiency of control equipment provided on the specified source for reducing emissions of pollutant i (percent).

Values of EF may be obtained from the manufacturer (see Section 14.3 of the appendices) or from the average values presented in Sections 4 to 9. For improved accuracy, values may be determined through actual testing of sample units. Details of these options and specific matters to be considered are presented in the subsections below. Values of EC should be obtained from

the manufacturer or through actual source testing. In the absence of any data it should be assumed that the target sources have no special controls (i.e., the value of EC should be set to zero).

3.2.1 Average Emission Factors Average emission factors typically are developed and published by environmental agencies and industry associations. In theory, they are a statistical value that may be expected to provide reasonable results when applied to a large population of the applicable sources (e.g., for company, regional and national emission inventories). However, they are not normally intended for application to individual or small numbers of sources.

In reality, the reliability of an average emission factor in a given application depends on the specific pollutant or pollutants of interest, and the type of source. For instance, the values for CO₂ emissions will tend to be quite accurate (even for individual sources) due to the usually low variance in carbon content of a specific fuel type and the good conversion of this material to CO₂ in most combustion processes (i.e., good combustion efficiencies). Similarly, factors for SO₂ emissions will be quite reliable if the sulphur content of the fuel is accurately known. Factors for CO, methane, VOCs and PM are less reliable. Factors for individual trace organic species and for NO_x are least reliable due to the particular sensitivity of these emissions to even slight changes in operating conditions and equipment features, especially for reciprocating engines. For example, Table 4 shows the variability in NO_x emission factors for individual reciprocating compressor engines tested at gas facilities in Alberta. Those units that had the greatest NO_x emission factors tended to be located at larger facilities with full-time onsite maintenance staff, and were best tuned (i.e., were achieving the most complete combustion). Table 5 shows much better agreement between power output and the emission factor, although still significant variability for NO_x factors determined for individual natural gas-fuelled turbine engines.

The average emission factor values presented in Sections 4 to 10 are the best values known to be available at the time this handbook was prepared. However, average factors are continually being updated to reflect the development and penetration of new combustion technologies as well as impacts of increasing performance standards and regulatory control requirements. Accordingly, periodic checks for the existence of new more applicable emission factors should be undertaken by the assessment team.

U.S. EPA maintains perhaps the largest source of published emission factors. Its compilation of common air pollutants is published in AP-42 (U.S. EPA, 1995). AP-42 also provides some discussion of the common emission controls available for the sources considered, including the typical effectiveness of these controls. Additionally, a broad range of compound-specific air emission factors are presented in U.S. EPA's FIRE data system, Version 5.1b (Radian Corporation, 1995). An important feature of FIRE is the user's ability to enter their own emission factors into the system and submit data to U.S. EPA for evaluation and inclusion in the FIRE repository system. Submitted data are

evaluated by U.S. EPA for use in revising rated factors in the FIRE system.

Table 4. NO _x emission factors determined for natural gas-fuelled reciprocating engines in Alberta, 1985 October 7 to 1986 February 12 ¹ .		
Test Number	Maximum Rated Power Output (kW)	Determined Emission Factor (ng/J)
1	600	84
2	820	2 797
3	600	148
4	895	83
5	480	323
6	1200	715
7	1500	719
8	820	218
9	930	3 412
10	1500	2 554
11	1120	1 341
12	1120	504
Average Emission Factor ² = 1075 ng/J		
Emission Factor Precision ² = 1.101		

- 1 Source: Picard, D.J., D.G. Colley and D.H. Boyd. 1987. Design of the Emission Inventory: Emission Inventory of Sulphur Oxides and Nitrogen Oxides in Alberta. A report prepared by Western Research for the Alberta/Government Acid Deposition Research Program. Table 6. Page 34.
- 2 When characterizing a class of emission sources in terms of a single representative emission factor, the normal practice is to take the average of the available data and indicate the precision of these data as has been done above. The use of this approach implies that the data are normally distributed. The data presented here, however, are not normally distributed, as indicated by the quoted precision which implies that some 20 percent of all sources are negative. Use of the average value may therefore be inappropriate. Alternatively, the geometric mean is 540 ng/J, the median is 610 ng/J.

Table 5. NO _x emission factors determined for natural gas-fuelled turbine engines in Alberta, 1985 November 14 to 1986 January 13 ¹ .		
Test Number	Maximum Rated Power Output (kW)	Determined Emission Factor (ng/J)
1	18 540	124
2	17 310	123
3	9 025	47
4	25 975	73
5	8 690	98
6	2 650	176

Average Emission Factor = 107 ng/J
Emission Factor Precision = 0.422

1 Source: Picard, D.J., D.G. Colley and D.H. Boyd. 1987. Design of the Emission Inventory: Emission Inventory of Sulphur Oxides and Nitrogen Oxides in Alberta. A report prepared by Western Research for the Alberta/Government Acid Deposition Research Program. Table 6. Page 34.

U.S. EPA also maintains the SPECIATE database, Version 1.5 (Radian Corporation, 1993), which contains typical composition profiles that may be used to speciate total estimated particulate or VOC emissions. The current system has about 700 chemical speciation profiles for various stationary mobile source categories. About 352 of these are VOC profiles for 31 industrial and non-industrial source categories. Emission estimates based on compound-specific emission factors are considered to be more reliable than equivalent estimates based on the speciate approach.

Electronic copies of the latest versions of AP-42, FIRE data system and SPECIATE may be obtained through U.S. EPA's ClearingHouse for Inventory and Emission Factors (CHIEF), an electronic bulletin board service (BBS) located on U.S. EPA's Technology Transfer Network (TTN). The CHIEF BBS also has a separate, but complimentary, feature called Fax CHIEF which allows documents to be downloaded to a Fax machine; this is particularly useful for documents and graphics which are not otherwise available in electronic format.

Access to CHIEF BBS can be obtained through either direct dial-up ports or the Internet via the World Wide Web. The dial-port telephone number is (919) 541-5742. Modem speeds up to 14.4 kbps are supported. The World Wide Web address is www.epa.gov/ttn/chief. Fax CHIEF may be accessed at (919) 541-5626 or -0548.

Both TTN and Fax CHIEF are free except for the cost of actually accessing the system (e.g., telephone charges, communication software, modem, etc.). In the case of Fax CHIEF, a user must dial in using the voice communication option of their fax machine, and then respond to the subsequent voice queries by keying in appropriate codes. Once this interactive session has been completed, and the desired documents specified, the user must switch their fax machine to data receiving mode. Fax CHIEF then will start transmitting the document over the line as part of the same call. Thus, any toll charges are paid for by the user. A maximum of 2 documents may be requested during any single call.

3.2.2 Manufacturer's Emission Factors. Many manufacturers provide unit-specific emission factors, as well as performance curves for estimating fuel consumption at different operating conditions. The emission factors normally are developed based on optimum factory conditions and usually only for criteria and a few key non-criteria air pollutants. So, they should be applied with some caution. Nonetheless, where manufacturer's data are available, it is generally preferable to using industry average factors.

A summary of much of the available manufacturer's emissions and fuel efficiency data is provided for the targeted types of combustion equipment in Sections 14.3 of the appendices.

The manufacturer's emission factors provided herein are expressed on a fuel-

consumption basis, and where given in units of energy, are based on the gross heating value of the fuel. This is consistent with the convention used by most environmental agencies. However, the factors given in a manufacturer's product literature are normally expressed based on either the net heating value of the fuel or the net power output of the combustion device. Consequently, appropriate conversion factors may need to be applied to such data for use with the equations and factors provided herein.

3.2.3 Development of Emission Factors From Analysis of Fuel and Flue Gases This approach is the simplest means of determining the actual emission factor for a given combustion source. It requires sampling and analysis of both the exhaust/flue gas and the fuel. The target device should be allowed to reach steady state at normal operating conditions before the samples are collected. For reciprocating engines one manufacture recommends waiting until after the unit has run for 500 to 1000 hours before doing any emissions tests. CO and HC may decrease by as much as 5 to 10 percent from engines tested with only 0 to 10 hours on them. The measurements should be made as close to the stack outlet as possible. This avoids missing the maximum conversion of CO and HC to CO₂ and H₂O.

The analysis results first are used to solve for the stoichiometric coefficients a, b and c in the following generalized combustion reaction:



where the analyses are expressed on either a mass or mole basis (which ever basis chosen must be maintained throughout the emission factor determination procedures). The composition of air (on a dry basis) may be taken as 20.95 mol percent O₂, 78.09 mol percent N₂, 0.93 mol percent Ar and 0.03 mol percent CO₂. To solve for a, b and c, a mass/mole balance is done on the three primary atomic components of the flue gas (usually, carbon, nitrogen and oxygen).

The emission factor for a given pollutant i then follows from the relation below:

$$EF_i = g_c \cdot \frac{b y_{Flue_i}}{HHV_F \text{ or } V_F}$$

where,

g_c = appropriate unit conversion factor need to achieve an emission factor in units of ng/J (for gas fuels) or g/L (for liquid fuels),

- b = stoichiometric coefficient determined from equation (5),
 y_{Flue} = mass or mole fraction (as appropriate) of component i in the flue gas,
 HHV_F = higher heating value of the fuel per mole or unit mass (as appropriate) (see Section 14.1), and
 V_F = volume of fuel gas per unit mass or mole (as appropriate) (see Section 14.1).

The heating value term in the above equation applies if the emission factor is being developed for a combustion device that burns fuel gas and the volume term applies for a device that consumes liquid fuel.

3.2.4 Development of Emission Factors From Complete Source Tests. The preferred method for determining emission factors is to simultaneously measure fuel gas consumption and emission rates and then determine the ratio of these two streams and apply appropriate unit conversion factors. This of course requires that a dedicated and reliable fuel gas meter either exists or may readily be installed for the target source, and that reasonable access is available to perform a proper stack survey. Unless the facility has been designed to include such provisions, it is usually becomes a very difficult and expensive matter to do this later.

Standard methods for performing stack surveys for specific air pollutants are usually established by provincial regulatory agencies and by Environment Canada. U.S. EPA's standard test methods normally are also accepted; a summary of these is provided in the appendices.

4.0 NATURAL GAS-FUELLED COMPRESSOR ENGINES

The following sections characterize typical natural gas compressor engines, delineate the procedures for assessing fuel consumption by these sources, and summarize the applicable emission factors.

A sample calculation sheet for estimating emissions of greenhouse gases from fuel consumption by compressor engines is provided on Form 4-1. The form is based on the use of equation (4).

4.1 Source Characterization

Both reciprocating and turbine engines are used as prime movers for natural gas compressor units.

4.1.1 Reciprocating Engines. Natural gas-fuelled reciprocating engines used in compressor applications may range in size from about 30 to 3500 kW, and typically operate at speeds of 800 to 1800 rpm. Some low-speed (i.e., 360 to 525 rpm) single-cylinder and two-cycle units also are available. Engines used in transmission applications typically are in the range of 1000 to 3000 kW while those used in distribution service are less than 1000 kW.

Reciprocating engines are available in both naturally-aspirated (NA) and turbocharged-aftercooled (TA) configurations. Additionally, both high and low compression ratio versions are available for most engines. The high compression ratio pistons are used on TA engines to reduce brake-specific fuel consumption (BSFC) and emissions, but can only burn a vary narrow range of fuels. The low compression ratio pistons are used on both TA and NA standard engines.

Any combination of aspiration type, compression ratio, fuel composition and emission control technology can change the rating of a given engine. So, it is important to be aware of the actual configuration of each target unit so the correct performance and emissions data can be applied.

Actual engine power output may vary by up to ± 3 percent from nameplate value on a new engine. Additionally, derations may need to be applied to account for differences between the actual site conditions (i.e., altitude and ambient temperature) and the manufacturer's standard reference conditions. Naturally aspirated engines are affected more by departures from the manufacturer's standard reference conditions than are turbocharged engines. This is a result of the turbocharger's ability to compensate for low ambient pressures and the aftercooler's ability to maintain a constant air inlet temperature. Derations also may be required if low heating value fuels are used (e.g., all naturally aspirated engines and engines operating at altitudes above 1500 m). Altitude and low heating-value fuel derations are cumulative.

Calculation Form 4-1

**GREENHOUSE GAS EMISSIONS FROM
COMPRESSOR ENGINES**

Source	Total Fuel Consumption (GJ/y or L/y)	Pollutant	Emission Factor (ng/J or g/L)	g _c	Emissions (t/y)	GWP (t/t)	CO ₂ -E Emissions (t/y)
Reciprocating Engines		CO ₂		10 ⁻⁶		1	
		CH ₄		10 ⁻⁶		21	
		N ₂ O		10 ⁻⁶		310	
Turbine Engines		CO ₂		10 ⁻⁶		1	
		CH ₄		10 ⁻⁶		21	
		N ₂ O		10 ⁻⁶		310	
TOTAL GREENHOUSE GAS EMISSIONS FROM COMPRESSOR ENGINES							

Typically, turbocharged-aftercooled ratings apply to 1500 m and 25°C. Naturally aspirated engines apply to 150 m and 30°C. For applications above these limits potential power outputs must be derated 3 percent per 300 m and 1.7 percent per 5°C.

Optimum combustion conditions (maximum power) are obtained when the air-fuel ratio is close to stoichiometric. Current natural gas engines are generally designed to run lean. The excess air promotes more complete combustion of the fuel which helps to improve fuel efficiencies and reduce the thermal load on the engine. Fuel efficiency varies as a function of actual power output and engine speed.

Unfortunately, the conditions which tend to promote maximum power output and fuel efficiency also create the highest combustion temperatures which promotes the formation of NO_x emissions. The common method to limit emissions on gas engines is called lean burn, a technology which was developed in the 1980s. Lean-burn engines use the turbocharger to run 50 to 100 percent excess air (above the stoichiometric requirement) through the combustion chamber. Excess air reduces combustion temperatures resulting in lower NO_x but higher CO and total hydrocarbons (THCs) when compared with the rich-burn engine. It is critical to maintain a nearly constant air-fuel ratio in order to maintain emission levels of an engine.

There are various types of after-treatment that may be applied to natural gas engines. The most common is non-selective catalytic reduction (NSCR). This technique is used with rich-burn engines and requires an air-fuel ratio control system for proper operation. The air-fuel ratio is adjusted to provide excess CO relative to NO_x levels. The catalyst uses the CO to reduce the NO_x to N₂ and CO₂. According to one manufacturer, common NO_x emission reduction levels are 90 percent of typical rich-burn values, and higher excess CO levels will produce 95 to 98 percent reduction of NO_x. However, in the latter case, additional air must be injected into the exhaust stream and a second catalyst must be installed to reduce the excess CO to CO₂.

Selective catalytic reduction (SCR) can be applied to lean-burn gas engines to reduce NO_x. Ammonia is injected into the exhaust stream to selectively reduce NO_x to N₂. These SCR systems currently are expensive, and therefore, are not often used.

The preferred method for monitoring gas engine emissions is periodic measurement of excess oxygen in the exhaust. The oxygen content in the exhaust of a lean-burn engine is easily correlated with the NO_x output of the engine. When the exhaust oxygen to NO_x correlation is made, on site, the engine NO_x emissions can be maintained from that point with exhaust oxygen measurements. Oxygen content can be monitored easily with an oxygen meter or via the engine air-fuel ratio control system (if it is exhaust-oxygen based).

4.1.2 Gas Turbines Stationary gas turbine engines are available in sizes up to a current maximum capacity of 220 MW but typical sizes tend to be in the range of 1 to 25 MW for most industrial applications. In the gas industry they tend to be used in processing and transmission rather than distribution applications.

The rated thermal efficiency of turbine engines is typically 30 to 35 percent and can be as high as 42 percent for new gas turbine models. The input heat rates required to achieve the manufacturer's published power outputs for each unit are referenced at standard conditions and on the net heating value of the fuel, and must be derated to site conditions. Differences in ambient air temperature, altitude, barometric pressure and humidity should all be accounted when making these adjustments. No power correction is normally required.

The gas turbine, in general, is a low emitter of exhaust gas pollutants relative to reciprocating engines in similar service (e.g., methane emissions are roughly an order of magnitude lower for gas turbines than for similarly rated reciprocating engines). This is because the fuel is burned with ample excess air to ensure essentially complete combustion at all but minimal load conditions.

The amount of NO_x emissions produced by turbine engines is a function of the fuel burned, firing temperature, exhaust discharge temperature and residence time in the combustion zone. Since the trend towards high turbine efficiencies leads to higher pressure ratios and firing temperatures, the emission rates of NO_x are higher for these units.

The normal method for reducing NO_x formation in turbines is to reduce combustion temperatures. Maintaining an operating temperature in the combustors at 1500°C or below virtually eliminates production of NO_x; however, this is not achievable by conventional combustion control methods such as steam or water injection, or premixing air and natural gas prior to entering the combustor (this process is referred to as lean premix or dry-low-NO_x [DLN]). Presently, the low combustion temperatures are only achieved through catalytic combustion (e.g., the XONON combustion system by Catalytica Combustion Systems Inc.).

The most common post-combustion NO_x reduction treatment is selective catalytic reduction (SCR). This reduces NO_x emissions approximately 80 percent, but is expensive and requires the operator to store large quantities of ammonia.

4.2 Assessment of Fuel Consumption

In the absence of measured fuel consumption data, estimates may be developed based on either the maximum rated power output of the unit or on the actual work done by the unit as

determined from available process data. General procedures for applying the first technique are presented in Section 3.1.1. The remainder of this section delineates the latter approach for specific application to reciprocating and centrifugal compressors. If there are multiple combustion sources at the site with notably different emission factors and only total site-wide fuel consumption is measured, it will be necessary to prorate this fuel to the individual sources. This may be done by estimating fuel consumption for each source and then adjusting these values so that the sum matches the total measured fuel rate. Procedures for making these adjustments are presented in Section 3.1.3.

Fuel consumption by a single compressor unit may be estimated by backcalculation based on the amount of work done on the process gas with specific allowances for mechanical losses of the compressor and the thermal efficiency of the prime mover. The primary equation to be solved is given below:

$$e_F = \frac{100 \cdot HHV_F (e_G + e_L)}{\eta \cdot LHV_F} \cdot \frac{t_{subO}}{8760} \cdot g_c$$

where,

e_F	=	rate of fuel consumption expressed as an energy flow rate and based on the higher heating value of the gas (GJ/y),
e_G	=	total rate of compression work done on the process gas (kJ/s),
e_L	=	mechanical losses by the compressor (kJ/s),
η	=	thermal efficiency of the prime mover at actual site operating conditions (percent) (see Section 14.3 for selected manufacturer's values or Table 1 for default values),
HHV_F	=	higher (gross) heating value of the fuel gas (MJ/m ³) (see Section 14.1),
LHV_F	=	lower (net) heating value of the fuel gas (MJ/m ³) (see Section 14.1), and
t_O	=	number of hours during the year that the device is actually operating (h) (see Table 3 for default values),
g_c	=	factor to convert from units of kJ/s to GJ/y,
	=	31.536

The mechanical losses of the compressor (e.g., bearing and seal losses) can be roughly computed from Schael's equation:

$$e_L = (e_G)^{0.4}$$

The heating values may be determined for the fuel gas composition using the procedures given in Section 14.1 of the Appendices. The thermal efficiency of the compressor may either be taken from the default values given in Table 1, or more preferably, determined from the manufacturer's performance curves or the manufacturers data presented in Section 14.3. The rate of work done by the compressor on the process gas may be estimated by assuming an isentropic process across each stage of compression. The following equation may then be applied:

$$e_G = \sum_{i=1}^{i=n} e_{G_i}$$

where i denotes a particular stage of compression and n denotes the total number of compression stages. Centrifugal compressors are treated as though they have only a single stage.

The gas power for a given stage i is calculated using the following relation:

$$e_{G_i} = \dot{m} \frac{(Z_1 + Z_2) R T_1}{2 M} \frac{\gamma}{(\gamma - 1)} \left[\left(\frac{P_2}{P_1} \right)^{(\gamma-1)/\gamma} - 1 \right]$$

where,

- \dot{m} = mass flow rate of process gas through the compression stage (kg/s),
- M = molecular weight of the gas,
- R = universal gas constant,
= 8.3145 kPa·m³/(kmol·K),
- T_1 = inlet temperature to the compressor stage (K),
- P_1 = inlet pressure to the compressor stage (kPa),
- P_2 = outlet pressure from the compressor stage (kPa),
- Z_1 = compressibility factor of the gas at the inlet conditions (see Section 14.1 in the appendices),
- Z_2 = compressibility factor of the gas at the outlet conditions (see Section 14.1 in the appendices), and
- γ = specific heat ratio of the process gas (i.e., C_p/C_v) (see Section 14.1 in the appendices).

The value of \dot{m} may be determined using the equation below:

$$\dot{m} = Q_{STP} \cdot \frac{P_{STP} M}{R T_{STP}}$$

where,

- Q_{STP} = volumetric flow rate of process gas through the compression stage reference at standard conditions of 15°C and 101.325 kPa (m³/s),
 P_{STP} = standard pressure (kPa),
 = 101.325 kPa, and
 T_{STP} = standard temperature (K),
 = 288.15 K.

4.3 Assessment of Emissions

Atmospheric emissions from compressor engines may be estimated in accordance with the procedures presented in Section 3.2. Tables 6 and 7 present average emission factors for common air pollutants and trace organic compounds, respectively, for natural-gas fuelled reciprocating engines. Corresponding factors are presented for natural gas-fuelled turbines in Tables 8 and 9 (common air pollutants), Table 10 (trace organic compounds), and Table 11 (trace metallic substances). Actual manufacturer's data and available test data for specific makes and models of compressor engines are provided in Section 14.3 of the appendices.

Pollutant	2-Stroke Lean-Burn (ng/J)	2-Stroke Clean-Burn (ng/J)	4-Stroke Lean-Burn (ng/J)	4-Stroke Rich-Burn (ng/J)	4-Stroke Clean-Burn (ng/J)
NO _x	1306	139	1560 (358) ³	1855 (202) ⁴	55
N ₂ O	ND	ND	ND	ND	ND
CO	131	148 (12) ²	131	759 (236) ⁴	223
CO ₂ ⁵	49 300	49 300	49 300	49 300	49 300
SO ₂ ⁶	0.25	0.25	0.25	0.25	0.25
TOC	885	801	464	148	1096
VOC	97	37	33	12	39
Methane	759	717	413	131	969
PM ₁₀ (Total)	ND	12.3	4.3	5.6	7.1
PM ₁₀ (Filterable)	ND	0.20	0.033	0.32	0.11
Inorganic Condensable PM ⁷	ND	2.0	2.4	2.1	3.5
Organic Condensable PM ⁷	ND	10.1	1.9	3.2	3.5

ND - No data.

- 1 Adapted from U.S. EPA (1997): Draft Supplement to Compilation of Air Pollutant Emission Factors, Volume 1 - Stationary Point and Area Sources. Table 3.2-1 to 3.2-5.
- 2 With catalytic oxidation.
- 3 With SRC control.
- 4 With NSCR control.
- 5 Based on 99.5 percent conversion of the fuel carbon to CO₂ for natural gas. The fuel carbon content is based a typical natural gas composition at the Alberta/Saskatchewan border.
- 6 Assumes the sulphur content of natural gas is 70.6 grains/10³ m³.
- 7 Considered less than 1 µm in aerodynamic diameter.

Table 7. Emission factors for trace organic air pollutants from stationary natural gas-fuelled reciprocating engines¹.

Pollutant	2-Stroke Lean-Burn (ng/J)	2-Stroke Clean-Burn (ng/J)	4-Stroke Lean-Burn (ng/J)	4-Stroke Rich-Burn (ng/J)	4-Stroke Clean-Burn (ng/J)
1,1,2,2 Tetrachloroethane	ND	2.6e-2	1.4e-2	1.2e-2	2.0e-2
1,1,2 Trichloroethane	ND	1.6e-2	8.0e-3	7.6e-3	1.3e-2
1,1 Dichloroethane	ND	1.6e-2	7.2e-3	7.2e-3	1.2e-2
1,2,3- Trimethylbenzene	1.5e-2	ND	ND	ND	ND
1,2,4 Trimethylbenzene	5.9e-2	1.3e-2	7.6e-3	ND	5.1e-3
1,3,5 Trimethylbenzene	7.6e-3	ND	1.5e-2	ND	ND
2,2,4 Trimethylpentane	2.1e-1	ND	ND	ND	ND
2-Methylnaphthalene	1.2e-2	ND	ND	ND	ND
1,2-Dichloroethane	ND	1.3e-2	7.2e-3	7.2e-3	1.2e-2
1,2-Dichloropropane	ND	1.8e-2	8.4e-3	8.0e-3	1.3e-2
1,3-Butadiene	ND	5.9e-2	ND	ND	ND
1,3-Dichloropropene	ND	1.7e-2	8.0e-3	8.0e-3	1.3e-2
2,2,4- Trimethylpentane	ND	8.0e-2	1.4e-1	ND	4.6e-2
2-Methylnaphthalene	ND	2.0e-3	ND	ND	2.4e-2
Acenaphthene	7.6e-4	1.5e-4	ND	ND	8.9e-4
Acenaphthylene	1.88e-3	4.6e-4	ND	ND	3.9e-3
Acetaldehyde	3.9e+1	1.5e+0	1.8e+0	1.4e+0	1.6e+0

Acrolein	3.5e+0	1.9e+0	ND	7.6e-1	1.8e+0
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Continued

Pollutant	2-Stroke Lean-Burn (ng/J)	2-Stroke Clean-Burn (ng/J)	4-Stroke Lean-Burn (ng/J)	4-Stroke Rich-Burn (ng/J)	4-Stroke Clean-Burn (ng/J)
Anthracene	4.1e-4	9.3e-5	ND	ND	5.9e-4
Benz(a)anthracene	2.1e-4	3.7e-5	ND	ND	1.9e-4
Benzene	1.3e+0	2.8e-1	1.6e-1	8.4e-1	2.7e-1
Benzo(a)pyrene	ND	2.4e-5	ND	ND	ND
Benzo(b)fluoranthene	ND	3.7e-5	ND	ND	8.0e-5
Benzo(e)pyrene	ND	1.0e-4	ND	ND	1.9e-4
Benzo(g,h,i)perylene	ND	1.1e-4	ND	ND	1.9e-4
Benzo(k)fluoranthene	ND	1.8e-5	ND	ND	ND
Biphenyl	1.7e-3	ND	9.3e-2	ND	ND
Butane	2.0e+0	ND	2.3e-1	ND	ND
Butyraldehyde	2.1e-1	8.0e-1	1.1e-2	2.1e-2	5.9e-2
Carbon Tetrachloride	ND	2.4e-2	1.1e-2	1.1e-2	1.9e-2
Chlorobenzene	ND	1.8e-2	8.4e-3	8.0e-3	1.3e-2
Chloroform	ND	1.9e-2	8.9e-3	8.4e-3	1.4e-2
Chrysene	4.2e-4	7.6e-5	ND	ND	4.6e-4
Cyclohexane	1.3e-1	ND	ND	ND	ND
Cyclopentane	3.8e-2	5.1e-2	1.2e-1	ND	4.2e-2
Ethane	2.9e+1	4.6e+1	1.9e+1	ND	9.7e+1
Ethylbenzene	2.8e-2	1.6e-2	1.5e-2	9.7e-3	1.9e-2

Ethyl Dibromide	ND	2.9e-2	1.4e-2	1.3e-2	2.2e-2
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Continued

Pollutant	2-Stroke Lean-Burn (ng/J)	2-Stroke Clean-Burn (ng/J)	4-Stroke Lean-Burn (ng/J)	4-Stroke Rich-Burn (ng/J)	4-Stroke Clean-Burn (ng/J)
Fluoranthene	2.0e-4	2.8e-4	ND	ND	7.6e-4
Fluorene	1.1e-3	2.6e-4	4.2e-3	ND	1.9e-3
Formaldehyde	3.2e+1	1.7e+1	1.3e+1	7.6e+0	2.2e+1
Indeno(1,2,3-c,d) pyrene	ND	4.2e-5	ND	ND	ND
Isobutane	1.6e+0	ND	ND	ND	ND
Methanol	1.2e+0	8.4e-1	5.1e-1	1.3e+0	1.5e+0
Methylcyclohexane	1.2e-1	2.1e-1	6.7e-1	ND	1.6e-1
Methylene Chloride	ND	9.7e-2	9.7e-3	2.1e-2	1.0e-2
n-Hexane	2.4e-1	3.4e-1	3.5e-1	ND	2.9e-1
n-Nonane	5.9e-3	2.7e-2	5.9e-2	ND	1.9e-2
n-Octane	1.6e-2	8.0e-2	2.0e-1	ND	4.6e-2
n-Pentane	6.3e-1	7.6e-1	8.4e-1	ND	6.7e-1
Naphthalene	5.5e-2	8.0e-3	4.6e-3	4.0e-2	9.3e-2
Perylene	ND	2.1e-5	ND	ND	ND
Phenanthrene	2.0e-3	8.9e-4	ND	ND	5.1e-3
Phenol	1.8e-2	ND	1.1e-2	ND	ND
Propane	1.2e+1	1.3e+1	1.3e+1	ND	1.0e+1
Pyrene	3.2e-4	4.2e-4	ND	ND	9.7e-4

Styrene	1.9e-2	1.6e-2	7.2e-3	7.6e-3	1.3e-2
Toluene	5.1e-1	8.4e-2	2.0e-1	2.8e-1	2.2e-1
Vinyl Chloride	ND	9.7e-3	4.6e-3	4.6e-3	7.6e-3

Continued

Table 7. Emission factors for trace organic air pollutants from stationary natural gas-fuelled reciprocating engines ¹ (concluded).					
Pollutant	2-Stroke Lean-Burn (ng/J)	2-Stroke Clean-Burn (ng/J)	4-Stroke Lean-Burn (ng/J)	4-Stroke Rich-Burn (ng/J)	4-Stroke Clean-Burn (ng/J)
Xylenes	1.9e-1	2.0e-2	6.7e-2	8.9e-2	7.6e-2

¹ Adapted from U.S. EPA (1997): Draft Supplement to Compilation of Air Pollutant Emission Factors, Volume 1 - Stationary Point and Area Sources. Table 3.2-1 to 3.2-5.

Technology	NO _x (ng/J)	N ₂ O (ng/J)	CO (ng/J)	CO ₂ ⁴ (ng/J)
Uncontrolled	173	ND	37 ³	49 300
With Water/Steam Injection	67	ND	3.2	49 300
Lean-Premix Turbines	34	ND	2.1	49 300

ND - No data.

- 1 Adapted from U.S. EPA (1998): Draft Supplement to Compilation of Air Pollutant Emission Factors, Volume 1 - Stationary Point and Area Sources. Table 3.1-1.
- 2 Only tests with 90 to 100 percent loads were considered for CO and NO_x. NO_x emissions decrease at lower load conditions, while CO emissions increase at lower load conditions. Test data indicate that as much as 30 percent NO_x reduction and 200 percent CO increase are possible when the unit load is reduced to 75 percent.
- 3 CO emissions varied widely for the units tested. The range of emission factors calculated for CO was 0.4 to 211 ng/J with O₂ levels of 14.8 percent to 17.5 percent.
- 4 Based on 99.5 percent conversion of the fuel carbon to CO₂ for natural gas. The fuel carbon content is based a typical natural gas composition at the Alberta/Saskatchewan border.

Pollutant	Emission Factor (ng/J)
CO ₂ ²	49 300
Lead	<0.0067
N ₂ O	ND
PM ³	3.1
PM (Condensable) ⁴	1.7
PM (Filterable) ⁴	1.4
SO ₂ ⁵	0.25
CH ₄ ⁶	3.31
THC ⁷	3.6
VOC ⁷	1.2
NMHC ⁷	0.29

ND - No data.

1 Adapted from U.S. EPA (1998): Draft Supplement to Compilation of Air Pollutant Emission Factors, Volume 1 - Stationary Point and Area Sources. Table 3.1-2.

2 Based on 99.5 percent conversion of the fuel carbon to CO₂ for natural gas. The fuel carbon content is based a typical natural gas composition at the Alberta/Saskatchewan border.

3 PM emission factor determined using EPA Method 5.

4 All PM (total, condensable and filterable) is assumed to be less than 2.5 µm in diameter. Therefore, the PM emission factors presented here may be used to estimate PM_{2.5} or PM₁₀ emissions. Total PM is the sum of the filterable and condensable PM. Condensed PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

5 Assumes the sulphur content of natural gas is 70.6 grains/10³ m³.

6 Calculated as the difference between THC and NMHC emission factors.

7 Only tests with 90 to 100 percent loads were considered for VOC, THC and NMHC.

Pollutant	Emission Factor (ng/J)
1,3-Butadiene	<0.00019 ²
Acetaldehyde	0.034
Acrolein	0.0033
Benzene	0.059
Ethylbenzene	0.010
Formaldehyde	1.43
Naphthalene	0.059
NDMA ³	<0.000097 ²
NMOR ³	<0.000097 ²
PAHs ³	0.076
Propylene Oxide	<0.012 ²
Toluene	0.055
TMA ³	<0.000072 ²
Xylene	0.011

- 1 Adapted from U.S. EPA (1998): Draft Supplement to Compilation of Air Pollutant Emission Factors, Volume 1 - Stationary Point and Area Sources. Table 3.1-3.
- 2 Emission factor based on one half the detection limits and not on measured values. Expected emissions are lower than the presented emission factor.
- 3 NDMA is N-nitrosodimethylamine, NMOR is N-nitrosomorpholine, PAH is polycyclic aromatic hydrocarbon, TMA is trimethylamine.

Table 11. Emission factors for metallic hazardous air pollutants from natural gas-fuelled turbines ¹ .	
Pollutant	Emission Factor (ng/J)
Arsenic	0.000021
Cadmium	<0.00035 ²
Chromium VI	<0.00055 ²
Lead	<0.0067 ²
Manganese	<0.00067 ²
Mercury	0.00019

1 Adapted from U.S. EPA (1998): Draft Supplement to Compilation of Air Pollutant Emission Factors, Volume 1 - Stationary Point and Area Sources. Table 3.1-3.

2 Emission factor based on one half the detection limits and not on measured values. Expected emissions are lower than the presented emission factor.

5.0 NATURAL GAS-FUELLED PROCESS HEATERS AND BOILERS

This category includes boilers, choke heaters, line heaters, reboilers and utility heaters. These are mainly indirect fired units. A schematic diagram of a typical line heater is shown in Figure 1.

The assessment of emissions from small industrial space heaters and portable torches, thermal electric generators, thermal oxidizers, and office heaters and boilers is discussed in Sections 6 to 9, respectively.

A sample calculation sheet for estimating emissions of greenhouse gases from fuel consumption by all these sources is provided on Form 5-1. The form is based on the use of equation (4).

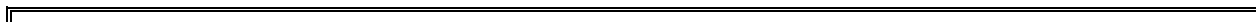
5.1 Source Characterization

Two general types of fired heaters and boilers are used in the natural gas industry (GPSA, 1987): watertube and firetube. Watertube units are designed to pass water through the inside of heat transfer tubes while the outside of the tubes is heated by direct contact with the hot combustion gases and through radiant heat transfer. Firetube units are designed such that the hot combustion gases flow through tubes which heat a liquid circulated outside of the tubes. Firetube boilers range in duty from 10 kW (e.g., small utility heaters) to 3 500 kW (e.g., gas pipeline line heaters). The design, controls, and operation of firetube heaters varies widely from very simple natural draft designs to well-instrumented forced air units. Good fuel efficiency is achieved through low stack temperatures, low excess air, and insulation of the unit. An efficiency verification test is usually done using the stack loss method described in Section 5.2. Full efficiency tests are done in accordance with ASME/ANSI Boiler test Code 4.1.

Basic design features may include:

- multi-pass fire tubes,
- forced or natural draft combustion air systems,
- smaller units (10 to 75 kW) tend to have on-off firing while larger units often have full modulation firing,
- air dampers may include single-blade, rotary and multi-blade designs,
- only the larger sizes of boilers would tend to have any kind of NO_x control. These may include low-NO_x burners and internal flue gas recirculation (FGR). Post combustion control techniques generally are not used on boilers with energy inputs less than 30 MW.

A boiler's excess air supply provides for safe operation above stoichiometric conditions. A typical burner is usually set up with 10 to 20 percent excess air (2 to 4 percent O₂). NO_x controls that require higher excess air levels can result in fuel being used to heat the air rather than transferring it to usable energy.



Calculation Form 5-1**GREENHOUSE GAS EMISSIONS FROM
HEATERS, BOILERS AND THERMAL OXIDIZERS**

Source	Total Fuel Consumption (GJ/y or L/y)	Pollutant	Emission Factor (ng/J or g/L)	g_c	Emissions (t/y)	GWP (t/t)	CO ₂ -E Emissions (t/y)
Process Heaters and Boilers		CO ₂		10 ⁻⁶		1	
		CH ₄		10 ⁻⁶		21	
		N ₂ O		10 ⁻⁶		310	
Catalytic Heaters		CO ₂		10 ⁻⁶		1	
		CH ₄		10 ⁻⁶		21	
		N ₂ O		10 ⁻⁶		310	
Portable Torches		CO ₂		10 ⁻⁶		1	
		CH ₄		10 ⁻⁶		21	
		N ₂ O		10 ⁻⁶		310	
Thermoelectric Generators		CO ₂		10 ⁻⁶		1	
		CH ₄		10 ⁻⁶		21	
		N ₂ O		10 ⁻⁶		310	
Flares		CO ₂		10 ⁻⁶		1	
		CH ₄		10 ⁻⁶		21	
		N ₂ O		10 ⁻⁶		310	
Incinerators		CO ₂		10 ⁻⁶		1	
		CH ₄		10 ⁻⁶		21	
		N ₂ O		10 ⁻⁶		310	
Furnaces		CO ₂		10 ⁻⁶		1	
		CH ₄		10 ⁻⁶		21	
		N ₂ O		10 ⁻⁶		310	
Hot Water		CO ₂		10 ⁻⁶		1	

heaters							
		CH ₄		10 ⁻⁶		21	
		N ₂ O		10 ⁻⁶		310	
TOTAL GREENHOUSE GAS EMISSIONS FROM HEATERS, BOILERS AND THERMAL OXIDIZERS							

Figure 1

Process Heaters

5.2 Assessment of Fuel Consumption

In the absence of measured fuel consumption data, estimates may be developed based on either the maximum rated power output of the unit or on the actual work done by the unit as determined from available process data. General procedures for applying the first technique are presented in Section 3.1.1. The remainder of this section delineates the latter approach for specific application to process heaters and boilers. If there are multiple combustion sources at the site with notably different emission factors and only total site-wide fuel consumption is measured, it will be

necessary to prorate this fuel to the individual sources. This may be done by estimating fuel consumption for each source and then adjusting these values so that the sum matches the total measured fuel rate. Procedures for making these adjustments are presented in Section 3.1.3.

Fuel consumption by a single heater or boiler may be estimated based on the actual heat transferred to the process (as indicated based on available process operating data), the thermal efficiency of the unit, and the annual operating hours. For heaters or reboilers the following

$$e_F = \dot{m} c_p (T_i - T_o) \cdot \frac{100}{\eta} \cdot \frac{t_o}{8760} \cdot g_c$$

equation may be solved:

where,

e_F	=	rate of fuel consumption expressed as an energy flow rate and based on the higher heating value of the gas (GJ/y),
\dot{m}	=	mass flow rate of the process fluid being heated (kg/s),
c_p	=	specific heat capacity of the process fluid (kJ/kg·C),
T_i	=	cold inlet temperature of the process fluid (°C),
T_o	=	hot outlet temperature of the process fluid (°C),
η	=	thermal efficiency of the heater or boiler (percent),
t_o	=	annual operating hours (h), and
g_c	=	factor to convert from units of kJ/s to GJ/y,
	=	31.536

Specific heat values for selected common process fluids (e.g., natural gas, water, aqueous glycol solutions, and DowTherm) are provided in Section 14.1 of the appendices. Default values for the thermal efficiency and annual operating hours are provided in Tables 1 and 3 in Section 3.2. As well, Table 12 provides additional efficiency data for specific types of applications. Furthermore, unit-specific thermal efficiencies may be readily determined for heaters and boilers using the stack loss method. This simple approach determines energy efficiency as being 100 percent minus the heat lost via flue gases. This requires measuring the flue gas temperature at or near the outlet of the final heat-transfer section, measuring either the oxygen or carbon dioxide concentration in the flue gases, and then looking up the corresponding thermal efficiency using

the efficiency tables provided Section 14.1 of the appendices.

Heater Type	Bath Temperature (°C)	Stack Temperature (°C)	Thermal Efficiency (percent)
Water Bath	80 to 90	400 to 480	76 to 82
50 % Ethylene Glycol	90 to 95	425 to 480	76 to 80
Low Pressure Steam	118 to 121	425 to 480	76 to 80
Hot Oil	150 to 290	480 to 590	71 to 76
TEG Reboiler	175 to 205	425	75 to 80

1 Adapted from Fig 8-30 of Gas Processors Suppliers Association (GPSA) Engineering Data Book, Volume 1, tenth Edition, 1987.

For steam boilers equation (12) must be changed to the following form:

$$e_F = \dot{m} (h_i - h_o) \cdot \frac{100}{\eta} \cdot \frac{t_o}{8760} \cdot g_c$$

where h_i and h_o are the inlet and outlet enthalpies (kJ/kg) of the water/steam. These values must be determined from available steam tables.

5.3 Assessment of Emissions

Atmospheric emissions from heaters and boilers may be estimated in accordance with the procedures presented in Section 3.2. Average emission factors for natural gas -fuelled heaters and boilers are presented in Tables 13 and 14 (common air pollutants), Table 15 (trace organic compounds), and Table 16 (trace metallic substances). Table 17 presents some additional factors presented by one manufacturer for common air pollutants from low-NO_x natural gas-fuelled heaters and boilers.

Emission factors for common air pollutants from propane- and butane-fuelled heaters and boilers are presented in Table 18.

Table 13. Emission factors for nitrogen oxides (NO _x) and carbon monoxide (CO) from natural gas-fuelled heaters and boilers ¹ .					
Source Types	Size (MW)	Emission Controls	NO _x (ng/J) ²	CO (ng/J)	CO ₂ ⁴ (ng/J)
Wall-fired Units	>29	Uncontrolled - Pre-NSPS ³	118	35	49 550
		Uncontrolled - Post-NSPS ³	80	35	49 550
		Controlled - Low NO _x Burners	59	35	49 550
		Controlled - Flue Gas Recirculation	42	35	49 550
	≤29	Uncontrolled	42	35	49 550
		Controlled - Low NO _x Burners	21	35	49 550
		Controlled - Low NO _x Burners/Flue Gas Recirculation	13	35	49 550
Tangential-Fired Units	All	Uncontrolled	72	10	49 550
		Controlled - Flue Gas Recirculation	32	41	49 550
Residential Furnaces	<0.088	Uncontrolled	40	17	49 550

1 Adapted from U.S. EPA (1998): Compilation of Air Pollutant Emission Factors, Volume 1 - Stationary Point and Area Sources. Table 1.4-1.

2 Expressed as NO₂. For large and small wall-fired boilers with SNCR control, apply a 24 percent reduction to appropriate NO_x emission factor. For tangential-fired boilers with selective non-catalytic reduction (SNCR) control, apply a 13 percent reduction to the appropriate NO_x emission factor.

3 NSPS = New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 73 MW of heat input that commenced construction modification or reconstruction after August 17, 1971, and units with heat input capacities between 29 and 73 MW that commenced construction modification or reconstruction after June 19, 1984.

4 Based on approximately 100 percent conversion of fuel carbon to CO₂.

Pollutant	Emission Factor (ng/J)
CO ₂ ²	49 550
Lead	0.0002
N ₂ O (Uncontrolled)	0.93
N ₂ O (Controlled-low-NO _x burner)	0.27
PM (Total) ³	3.2
PM (Condensable) ³	2.4
PM (Filterable) ³	0.80
SO ₂ ⁴	0.25
TOC	4.6
Methane	0.97
VOC	2.3

PM - Particulate Matter

TOC - Total Organic Compound

VOC - Volatile Organic Compound

1 Adapted from U.S. EPA (1998): Compilation of Air Pollutant Emission Factors, Volume 1 - Stationary Point and Area Sources. Table 1.4-1.

2 Calculated based on 100 percent conversion of fuel carbon to CO₂ for a typical natural gas composition at the Alberta/Saskatchewan border.

3 All PM (total, condensable and filterable) is assumed to be less than 1.0 micrometres in diameter. Therefore, the PM emission factors presented here may be used to estimate PM₁₀, PM_{2.5} and PM₁ emissions. Total PM is the sum of the filterable and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

4 Assumes the sulphur content of natural gas is 70.6 grains/10³ m³.

Table 15. Emission factors for selected trace organic compound emissions from natural gas-fuelled heaters and boilers ¹ .		
CAS No.	Pollutant	Emission Factor (ng/J)
91-57-6	2-Methylnaphthalene	1.0e-5
56-49-5	3-Methylchloranthrene 7,12-dimethylbenz(a)anthracene	<7.6e-7 <6.7e-6
83-32-9	Acenaphthene	<7.6e-7
203-96-8	Acenaphthylene	<7.6e-7
120-12-7	Anthracene	<1.0e-6
56-55-3	Benz(a)anthracene	<7.6e-7
71-43-2	Benzene	8.9e-4
50-32-8	Benzo(a)pyrene	<5.1e-7
205-99-2	Benzo(b)fluoranthene	<7.6e-7
191-24-2	Benzo(g,h,i)perylene	<5.1e-7
205-82-3	Benzo(k)fluoranthene	<7.6e-7
106-97-8	Butane	8.9e-1
218-01-9	Chrysene	7.6e-7
53-70-3	Dibenzo(a,h)anthracene	<5.1e-7
25321-22-6	Dichlorobenzene	5.1e-4
74-84-0	Ethane	1.3
206-44-0	Fluoranthene	1.3e-6
86-73-7	Fluorene	1.2e-6
50-00-0	Formaldehyde	3.2e-2
110-54-3	Hexane	7.6e-1
193-39-5	Indeno(1,2,3-cd)pyrene	<7.6e-7

91-20-3	Naphthalene	2.6e-4
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Continued ...

Table 15. Emission factors for selected trace organic compound emissions from natural gas-fuelled heaters and boilers ¹ (Concluded).		
CAS No.	Pollutant	Emission Factor (ng/J)
109-66-0	Pentane	1.1
85-01-8	Phenanathrene	7.2e-6
74-98-6	Propane	6.7e-1
129-00-0	Pyrene	2.1e-6
108-88-3	Toluene	1.4e-3

1 Adapted from U.S. EPA (1998): Compilation of Air Pollutant Emission Factors, Volume 1 - Stationary Point and Area Sources. Table 1.4-3.

CAS No.	Pollutant	Emission Factor (ng/J)
7440-38-2	Arsenic	8.4e-5
7440-39-3	Barium	1.9e-3
7440-41-7	Beryllium	<5.1e-6
7440-43-9	Cadmium	4.6e-4
7440-47-3	Chromium	5.9e-4
7440-48-4	Cobalt	3.5e-5
7440-50-8	Copper	3.6e-4
7439-96-5	Manganese	1.6e-4
7439-97-6	Mercury	1.1e-4
7439-98-7	Molybdenum	4.6e-4
7440-02-0	Nickel	8.9e-4
7782-49-2	Selenium	<1.0e-5
7440-62-2	Vanadium	9.7e-4
7440-66-6	Zinc	1.2e-2

1 Adapted from U.S. EPA (1998): Compilation of Air Pollutant Emission Factors, Volume 1 - Stationary Point and Area Sources. Table 1.4-4.

Table 17. Manufacturer's emission factors for common air pollutants from natural gas-fuelled commercial firetube boilers for different NO _x control levels.					
Pollutant	Emission Factors (ng/J)				
	Uncontrolled ¹	60 ppm ² NO _x	30 ppm ² NO _x	25 ppm ² NO _x	20 ppm ² NO _x
CO	64	64	17/47 ³	17/47 ³	64
CO ₂ ⁴	49 550	49 550	49 550	49 550	49 550
NO _x	52	30	15	13	10
THC	6.9	6.9	6.9	6.9	6.9
PM	4.3	4.3	4.3	4.3	4.3

1 Equivalent to a NO_x value of 100 ppm.

2 ppm levels are given on a dry volume basis and corrected to 3 percent oxygen (15 percent excess air).

3 The low CO value applies when the boiler is operated at greater than 50 percent of rated capacity, and the higher CO value applies to all lesser load values.

4 Calculated based on 100 percent conversion of fuel carbon to CO₂ for a typical natural gas composition at the Alberta/Saskatchewan border.

Pollutant	Butane-Fuelled Units ²				Propane-Fuelled Units ²			
	Industrial (3 to 30 MW)		Commercial (0.1 to 3 MW)		Industrial (3 to 30 MW)		Commercial (0.1 to 3 MW)	
	(ng/J)	(g/L)	(ng/J)	(g/L)	(ng/J)	(g/L)	(ng/J)	(g/L)
PM ³	2.5	0.07	2.1	0.06	2.8	0.07	1.9	0.05
SO ₂ ⁴	423 x S	0.011 x S	423 x S	0.011 x S	417 x S	0.012 x S	417 x S	0.012 x S
NO _x ⁵	87	2.5	63	1.8	90	2.3	66	1.7
N ₂ O	3.8	0.1	3.8	0.1	4.3	0.1	4.3	0.1
CO ₂ ⁶	59 700	1710	59 700	1710	59 200	1500	59 200	1500
CO	15	0.43	9	0.25	15	0.38	9	0.23
TOC	2.3	0.07	2.3	0.07	2.3	0.06	2.3	0.06
CH ₄	0.97	0.02	0.97	0.02	0.97	0.02	0.97	0.02

- 1 Adapted from U.S. EPA (1998): Compilation of Air Pollutant Emission Factors, Volume 1 - Stationary Point and Area Sources. Table 1.4-5.
- 2 Based on a gross heating value of 28.718 MJ/m³ for liquid butane and 25.394 MJ/m³ for liquid propane. Assumes emissions (except SO₂ and NO_x) are the same, on a heat input basis, as for natural gas combustion. The NO_x emission factors have been multiplied by a correction factor of 1.5, which is the approximate ratio of propane/butane NO_x emissions to natural gas NO_x emissions.
- 3 Filterable particulate matter (PM) is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. For natural gas, a fuel with similar combustion characteristics, all PM is less than 10 µm in aerodynamic equivalent diameter (PM₁₀).
- 4 S equals the sulphur content of the of the fuel expressed in grains/100 ft³ of vapour.
- 5 Expressed as NO₂.
- 6 Assuming 99.5 percent conversion of fuel carbon to CO₂.

6.0 **SMALL INDUSTRIAL SPACE HEATERS AND PORTABLE TORCHES**

This category includes portable propane heaters and torches and catalytic heaters.

6.1 **Source Characterization**

6.1.1 Catalytic Heaters. Catalytic heaters are an intrinsically-safe panel-style unit frequently used to provide space heating in hazardous indoor process areas as well as in many non-classified indoor or enclosed industrial areas. As shown in Figure 1, fuel enters a gas-tight pan through an orifice in the back and is dispersed through a pre-heated catalyst pad at the face of the unit. Oxygen from the ambient air diffuses through the catalyst pad from the front and oxidation of the fuel occurs inside the catalyst pad at a temperature below the normal ignition temperature of the fuel (i.e., there is no flame). A vent system to collect the resulting exhaust gases and discharge them outside is usually an optional item. Many companies simply allow the exhaust gases to discharge inside the building (especially if the building has a high ventilation rate).

Because of the low combustion temperatures in catalytic heaters, NO_x emissions should be lower than in equivalent gas fired heaters. However, data to confirm this are not known to be available.

Catalytic heaters typically are rated at 15.77 kW/m². The units are designed to emit primarily radiant heat. The remainder of the heat produced from the fuel is emitted as hot exhaust gases.

6.1.2 Portable Torches. Portable propane and butane torches are often used in winter maintenance work and for field installation of heat-shrink coatings. Additionally, they are sometimes used as duct heaters for space heating of temporarily enclosed construction/maintenance work areas. While some sites may own several of these types of units, most often they are simply rented when required.

6.2 **Assessment of Fuel Consumption**

The fuel consumption rate of catalytic heaters normally is given as part of the nameplate information on the unit. Contrary to other types of combustion devices, the rated heat output is usually the same as the required heat input and is based on the higher heating value of the fuel. However, this should be confirmed with the manufacturer.

For portable propane or butane torches and heaters it is assumed financial records should usually be available to indicate annual fuel consumption. Alternatively, fuel volumes may be estimated based on the size and number of propane and butane bottles owned or leased and the frequency at which they are typically refilled.

6.3 Assessment of Emissions

Atmospheric emissions from space heaters and torches may be estimated in accordance with the procedures presented in Section 3.2. In the absence of more source-specific values, the average emission factors presented in Section 5.3 for residential furnaces and commercial heaters should be used as appropriate.

7.0 THERMOELECTRIC GENERATORS

7.1 Source Characterization

Thermoelectric generators are used to supply low-voltage DC electricity for low-power-requirement applications such as instrumentation, telemetry systems, heat tape, lighting and cathodic protection at some small facilities where economic access to the electric utility grid is unavailable (i.e., in remote or inaccessible areas). These are highly reliable semiconductor devices which have no moving parts and produce electric power by the direct conversion of heat into electricity (see Figure 2). A steady power level is produced by maintaining a temperature difference across the hot side (540°C) and the cool side (140°C) of a thermopile. The thermopile is constructed of an assembly of semi-conductor thermoelectric elements.

Combustion of natural gas or propane provides the heat while natural convection provides the cooling required to create the required temperature differential.

There are three main parts to a thermoelectric generator: burner (or heat source), sealed thermopile (energy conversion device), and cooling fins (heat sink). The unit is sized to be able to provide the maximum required power level at the maximum ambient temperature.

Thermoelectric generators typically range in size from 15 to 550 W and provide output power at 6.7, 12, 24, or 48 VDC. The thermal efficiency of these units is very low; typically about 3.6 percent for the most common unit sizes (i.e., 30 and 60 W sizes).

7.2 Assessment of Fuel Consumption

In the absence of a dedicated fuel gas meter or equivalent means of tracking actual fuel consumption, it is reasonable to assume simple on/off operation of the unit. Thus, when it is operating it will be consuming the maximum rated fuel consumption rate specified by the manufacturer, and when it is off it will not be consuming any fuel. The maximum fuel consumption is typically provided as part of the nameplate information on the unit and also may be obtained directly from the manufacturer.

Table 19 summarizes rated fuel consumption rates for different sizes of thermoelectric generators manufactured by one popular manufacturer.

7.3 Assessment of Emissions

Atmospheric emissions by thermoelectric generators may be estimated in accordance with the procedures presented in Section 3.2. In the absence of more source-specific values, the average emission factors presented in Section 5.3 for residential furnaces and commercial heaters should be used as appropriate (i.e., depending on the type of fuel consumed).

Figure 2

Schematic of a typical thermoelectric generator.

Rated Electric Power Output (W)	Overall Thermal Efficiency ² (percent)	Input Heat Rate ² (MJ/h)
15	2.5	2.12
30	3.6	2.97
60	3.6	6.08
120	3.6	12.02
220	2.8	27.86
550	2.9	67.87

1 Based on data published by one popular supplier of thermoelectric generators.

2 Based on the net heating value of the input fuel.

8.0 THERMAL OXIDIZERS

8.1 Source Characterization

Thermal oxidizers are combustion devices used to dispose of waste streams. These devices may include conventional open-flame flare systems, enclosed flares and incinerators. Enclosed flares and incinerators are distinguished by their use of a refractory-line chamber to contain the flame heat to create a finite post flame combustion zone. Enclosed flare systems differ from incinerators in terms of the amount and type of control systems provided. An enclosed flare either has no special controls or only stack-top temperature control. An incinerator has at least stack-top temperature and oxygen control and may also feature a continuous stack emission monitoring system.

Properly designed and operated open-flame flares are able to achieve a destruction efficiency of 98 percent, while enclosed flares and incinerators are able to achieve destruction efficiencies of greater than 99 percent. However, recent work by Strosher (1996) has shown that, for open flares, actual combustion efficiencies may be substantially lower. Differences between the destruction efficiency and the combustion efficiency are due to the formation of products of partial or incomplete combustion. The amount and types of incomplete combustion products formed is depended on a number of factors including: burner/flare tip design, exit velocities, wind conditions, amount of condensation or liquid carry-over through to the flare tip, and the waste gas composition. Presently, there is no reliable means of predicting such emissions, and the assessment of these emissions through measurements is difficult and currently is deemed to be impractical. However, the potential for products of incomplete combustion is more apt to be an issue when burning heavier molecular weight streams as may be encountered at oil and gas production facilities, than the dry natural gas streams normally handled by gas transmission and distribution systems.

At gas facilities open-flame flare systems are primarily used for disposal of waste gas volumes from purging and blowdown events, and generally are only used if the gas is odourized or is sour. Otherwise, common practice for many companies is to dispose of the waste gas by controlled venting. Small enclosed flares or incinerators are sometimes used to dispose of compressor packing-case or seal vent gas.

8.2 Assessment of Fuel Consumption

For all forms of thermal oxidizers it will be necessary to determined the total volumes of combustibles being disposed (i.e., fuel/pilot gas plus waste gas). If used and not measured, pilot gas may be assumed to be in the order of 11.7 kJ/s during operating periods. Waste gas volumes, if not measured, may be estimated based on the applicable procedures presented in the methane emissions handbook (GRI Canada, 1998).

8.3 Assessment of Emissions

Atmospheric emissions from thermal oxidizers may be estimated in accordance with the procedures presented in Section 3.2. Emissions from enclosed flare systems and incinerators may be assessed using the emission factors presented in Section 5.3 for equivalent process heaters and boilers. For conventional flare systems, specific emission factors have been published by U.S. EPA (1991) for quantification of some of the primary pollutants formed. These factors are presented in Tables 20 and 21. The first table gives the factors for the major pollutants. The second table provides factors for the major components of the total hydrocarbon fraction in the combustion gases. Although the factors are determined from tests using heavier-than-methane hydrocarbons, they may still be useful for obtaining rough estimates of the amount of emissions from natural gas flaring.

Component	Emission Factor (ng/J)
THC ³	60
CO ₂ ⁴	48 560
CO	159
NO _x	29
N ₂ O	ND
Soot ⁵	157

ND - No data.

1 Adapted from Table 13.5-1 of AP-42 (U.S. EPA, 1991).

2 Based on tests using crude propylene containing 80% propylene and 20% propane.

3 Measured as methane equivalent.

4 Calculated based on an overall carbon balance for a typical natural gas composition at the Alberta/Saskatchewan border, and assuming 98 percent conversion of fuel carbon to CO₂.

5 Estimated based on a total carbon balance assuming all soot is essentially carbon. Typical soot concentration values are: nonsmoking flares, 0 µg/L; lightly smoking flares, 40 µg/L; average smoking flares 177 µg/L; and heavily smoking flares, 274 µg/L.

Component	Composition	
	Average (Volume %)	Range (Volume %)
Methane	55	14 to 83
Ethane/Ethylene	8	1 to 14
Acetylene	5	0.3 to 23
Propane	7	0 to 16
Propylene	25	1 to 65

1 Taken from Table 11.5-2 of AP-42 (U.S. EPA, 1991).

2 The composition presented is an average of a number of test results obtained under the following sets of

conditions: steam-assisted flare using high heating-value feed; steam-assisted using low heating-value feed; air-assisted flare using high heating-value feed; and air-assisted using low heating -value feed. In all tests, waste gas was a synthetic gas consisting of a mixture of propylene and propane.

9.0 OFFICE HEATERS AND BOILERS

9.1 Source Characterization

Residential style furnaces and hot water heaters may often be used to service non-classified indoor areas at gas facilities (e.g., office buildings and warehouses). These would normally be natural gas-fuelled units, but propane-fuelled units may also be encountered (particularly in any portable trailers that may be used on site).

Current top-rated gas furnaces have efficiency ratings of 90 to 97 percent, compared to efficiency ratings of 60 to 65 typical of furnaces produced prior to about 1980 (Geller, 1988). Typical efficiencies of gas water heaters are in the 47 to 50 percent range.

The standard gas-fired heaters and furnaces are natural draft units. The more efficient ones are equipped with increased heat exchanger surface area and either a downstream induced-draft blower or an upstream forced-draft blower to promote increased turbulence in the heat exchanger section and thereby improved heat transfer. The use of an induced-draft blower also allows excess air to be drawn into the flue gases prior to venting. The additional air cools the flue gases after leaving the heat exchange section to low enough temperatures so that standard plastic piping can be used for venting. This eliminates any problems with corrosion and plastic piping is often cheaper and easier to install than sheet metal or masonry chimneys.

The highest-efficiency units are designed to achieve either near or full condensing of the flue gases. Full-condensing units have flue gas temperatures less than the dew point (55 to 60°C) of the flue products, and are designed to allow for condensing in both the heat exchanger and the vent system. Near condensing systems are designed and operated to allow condensation in only the vent system and not the heat exchanger. The thermal efficiency of fully condensing systems can be as high as 99 percent; for near condensing water heaters, it is generally between 84 and 90 percent.

As of February 3, 1995, new automatic operating gas-fired central forced-air furnaces that use natural gas or propane and have an input of not more than 117.23 kW typically are required by Natural Resources Canada to have a thermal efficiency of at least 80 percent. However, this does not include furnaces for mobile homes and recreation vehicles.

9.2 Assessment of Fuel Consumption

In the absence of measured fuel consumption data, it is recommended that estimates be developed for each unit based on its maximum rated power output, thermal efficiency and annual operating hours as described in Section 3.1.1. More rigorous approaches could be taken but are not warranted due to the low contribution of these sources to total industry- or company-wide combustion emissions.

The measurement of individual unit energy efficiencies may be done using CGA Method P.2-1991 (Testing method for measuring annual fuel utilization efficiencies of residential furnaces and boilers).

9.3 Assessment of Emissions

Atmospheric emissions by office heaters and boilers may be estimated in accordance with the procedures presented in Section 3.2. In the absence of more source-specific values, the average emission factors presented in Section 5.3 for residential furnaces and commercial heaters should be used as appropriate (i.e., depending on the type of fuel consumed).

10.0 MOBILE SOURCES

This category accounts for atmospheric emissions from fuel usage by on-road and off-road vehicles as well as aircraft. A sample calculation sheet for estimating emissions of greenhouse gases from fuel consumption by mobile sources is provided on Form 10-1. The form is based on the use of equation (4).

10.1 Source Characterization

Mobile sources may include, company motor vehicle fleets, corporate aircraft, and motorized off-road inspection, construction and maintenance equipment (e.g., quads, backhoes, bulldozers, cranes, etc.). The various fuel types may include gasoline, propane, compressed natural gas, methanol, diesel, and aviation gas. As illustrated in Figure 3, there typically are three types of emissions that may be attributed to mobile sources: evaporative, refuelling and exhaust. Evaporative losses occur for liquid fuels which are stored at atmospheric conditions. They can account for the majority of the total hydrocarbon pollution from current cars on hot days. The various mechanisms for evaporative losses include diurnal temperature and barometric pressure changes, running losses (the hot engine can vaporize fuel when the engine is running), hot soak (the engine remains hot for a period of time after the car is turned off, and the fuel evaporation from dissipation of residual engine heat continues for some time while the vehicle is parked).

Refuelling emissions may include the displacement of vapours from the fuel tank during fill with liquid fuels, spillage/leakage, and losses of residual material in fuel transfer lines upon completion of a fill event.

The amount and type of exhaust emissions will depend on a number of factors including,

- type of mobile source,
- type of fuel,
- engine size,
- operating conditions (air-fuel ratio, percent load, and ambient temperature), and
- pollution control features.

10.2 Assessment of Fuel Consumption

Fuel consumption by mobile sources is best assessed based on available receipts and accounting records. However, it may be possible to obtain reasonable estimates for some types of mobile sources based on operating hours or distances travelled. Such consumption factors should be determined in consultation with the applicable equipment manufacturers.

Calculation Form 10-1

**GREENHOUSE GAS EMISSIONS FROM
MOBILE SOURCES**

Source	Fuel Type	Total Fuel Consumption (GJ/y or L/y)	Pollutant	Emission Factor (ng/J or g/L)	g _c	Emissions (t/y)	GWP (t/t)	CO ₂ -E Emissions (t/y)
Autos			CO ₂		10 ⁻⁶		1	
			CH ₄		10 ⁻⁶		21	
			N ₂ O		10 ⁻⁶		310	
Light Duty Trucks			CO ₂		10 ⁻⁶		1	
			CH ₄		10 ⁻⁶		21	
			N ₂ O		10 ⁻⁶		310	
Heavy Duty Trucks			CO ₂		10 ⁻⁶		1	
			CH ₄		10 ⁻⁶		21	
			N ₂ O		10 ⁻⁶		310	
Off-Road Equipment			CO ₂		10 ⁻⁶		1	
			CH ₄		10 ⁻⁶		21	
			N ₂ O		10 ⁻⁶		310	
Aircraft			CO ₂		10 ⁻⁶		1	
			CH ₄		10 ⁻⁶		21	

			N ₂ O		10 ⁻⁶		310	
TOTAL GREENHOUSE GAS EMISSIONS FROM MOBILE SOURCES								

Figure 3

Typical contributions to atmospheric emissions from mobile sources.

10.3 Assessment of Emissions

Atmospheric emissions from mobile sources may be estimated in accordance with the procedures presented in Section 3.2. In the absence of more source-specific values, the average emission factors presented in Table 22 for different conventional liquid fuels, source categories and vehicle types may be used as appropriate. Additional factors are provided in Tables 23 and 24 for natural gas-fuelled vehicles and in Table 25 for LPG-fuelled vehicles.

Fuel	Source Category	Vehicle Type	Control Technology	CO ₂ (g/L)	CH ₄ (g/L)	N ₂ O (g/L)
Motor Gasoline	On-Road	Autos	New Advanced 3-way Catalyst	2 360	0.24	0.45
			Aged Advanced 3-way Catalyst	2 360	0.24	1.65
			Early 3-way Catalyst	2 360	0.37	0.43
			Oxidation Catalyst	2 360	0.53	0.45
			Non-Catalyst	2 360	1.03	0.23
		Light-Duty Trucks	New Advanced 3-way Catalyst	2 360	0.37	0.45
			Aged Advanced 3-way Catalyst	2 360	0.37	1.65
			Early 3-way Catalyst	2 360	0.48	0.43
			Oxidation Catalyst	2 360	0.46	0.45
			Non-Catalyst	2 360	0.88	0.23

Continued ...

Table 22 Emission factors for liquid gasoline fuelled on-road, off-road, air and marine transport sources ¹ (Continued).						
Fuel	Source Category	Vehicle Type	Control Technology	CO ₂ (g/L)	CH ₄ (g/L)	N ₂ O (g/L)
Motor Gasoline (Continued)	On-Road (Continued)	Heavy-Duty Trucks	3-way Catalyst	2 360	0.28	1.65
			Non-Catalyst	2 360	0.49	0.23
			Uncontrolled	2 360	0.76	0.23
	Off-Road	Ground, Non-Rail	All	2 360	0.19	0.23
Diesel Oil	On-Road Transport	Light-Duty Automobiles	Advanced Controlled	2 730	0.10	0.40
			Moderate Controlled	2 730	0.070	0.40
			Uncontrolled	2 730	0.052	0.40
		Light-Duty Trucks	Advanced Controlled	2 730	0.078	0.40
			Moderate Controlled	2 730	0.052	0.40
			Uncontrolled	2 730	0.087	0.40
		Heavy-Duty Trucks	Advanced Controlled	2 730	0.16	0.40
			Moderate Controlled	2 730	0.20	0.40
			Uncontrolled	2 730	0.23	0.40

Continued ...

Fuel	Source Category	Vehicle Type	Control Technology	CO ₂ (g/L)	CH ₄ (g/L)	N ₂ O (g/L)
Diesel Oil (Continued)	Off-Road Transport	Ground, Non-Rail	All	2 730	0.26	0.40
Aviation Gasoline	Air Transport	All	All	2 330	2.19	0.23
Aviation Turbo	Jet Air Transportation	All	All	2 550	0.08	0.25

1 Source: Environment Canada. 1997. Trends in Greenhouse Gas Emissions 1990-1995. Tables 6 and 7. Page 1-5 to 1-6.

Vehicle Type	Emission Controls	NO _x (ng/J)	CH ₄ (ng/J)	NMVOC (ng/J)	CO (ng/J)	N ₂ O (ng/J)	CO ₂ (ng/J)
Passenger Cars	Advanced	190	260	18	110	ND	49 300
	Uncontrolled	340	570	80	650	ND	49 300
Heavy-Duty Vehicles (Stoichiometric Engines)	Advanced	230	270	18	90	ND	49 300
	Uncontrolled	315	550	80	660	ND	49 300
Heavy-Duty Vehicles	Advanced	240	240	27	90	ND	49 300

(Lean Burn Engines)							
	Uncontrolled	1150	500	100	400	ND	49 300

ND - No data.

Source: Adapted from Table 1-43 of the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories, and converted to a gross heating value basis.

Vehicle Type	Emission Controls	NO _x (g/L)	CH ₄ (g/L)	NMVOC (g/L)	CO (g/L)	N ₂ O (g/L)	CO ₂ (g/L)
Passenger Cars	Advanced	4.50	0.30	2.2	2.7	ND	1 520
	Uncontrolled	8.99	0.76	15.0	34.3	ND	1 520
Heavy-Duty Vehicles (Stoichiometric Engines)	Advanced	5.69	0.30	1.5	2.2	ND	1 520
	Uncontrolled	8.53	0.61	11.9	35.9	ND	1 520

ND - No data.

Source: Adapted from Table 1-44 of the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories.

11.0 INDIRECT EMISSIONS FROM ELECTRIC POWER CONSUMPTION

Consumption of electric power is an indirect source of atmospheric emissions in cases where the power has been generated from fossil-fuel based processes. Most provinces have a mix of both fossil-fuel and nonfossil-fuel based power plants (e.g., wind, hydroelectric and nuclear power) that produce into the utility grid. As well, most provinces are both importers and exporters of electric power. So, it is often difficult to determine the true source of electric power that may be drawn from the utility grid. Nonetheless, some province-specific factors are available which reflect the average emissions per unit of electric energy consumed (i.e., power produced minus line/transmission losses). These are summarized in Table 25 and may be used along with available power consumption data and the following equation to estimate indirect emissions in each province:

$$E_i = 10^{-6} \cdot e_E \cdot EF_i$$

where,

E_i = emissions of pollutant i due to consumption of electric power in the specified province (t/y),

e_E = annual electric power usage within the specific province (kW·h), and

EF_i = appropriate factor for emissions of pollutant i (g/kW·h).

More specific emission factors often may be obtained directly from the applicable power companies. Additionally, detailed summaries of a user's electric power consumption are also usually available from the individual power companies. Otherwise, electric power consumption may be determined from available financial records.

A sample calculation sheet for estimating indirect emissions of greenhouse gases from use of electric power from the electric utility grid is provided on Form 11-1. The form is based on the use of equation (14).

Table 25. Emission factors for indirect-emissions due to consumption of electric power from the public utility system that has been generated at fossil-fuelled power plants.							
Province	CO ₂ (g/kW·h)	CO (g/kW·h)	NO _x (g/kW·h)	N ₂ O (g/kW·h)	CH ₄ (g/kW·h)	NMVOC (g/kW·h)	SO ₂ (g/kW·h)
AB ¹	1025	0.141	2.043	0.013	2.098	ND	2.874
BC ²	38	ND	ND	0.0165	0.0018	ND	ND
SK ³	882	ND	ND	0.0692	0.012	ND	ND
MB ⁴	5.7	ND	ND	0.0002	0.0002	ND	ND
ON ⁵	220 ⁷	ND	ND	ND	ND	ND	ND
NS ⁶	844.2	ND	ND	0.0013	ND	ND	ND

ND - No Data

1 Source: CPA. 1991. Integrated Air Emissions Trade-offs Study. Table 2.2.2. Page 2.3.

2 Estimated based on forecast 1998 information available in BC Hydro's 1997 greenhouse gas emissions report to the Voluntary Challenge Registry.

3 Estimated based on forecast 1998 information available in SaskPower's 1997 greenhouse gas emissions report to the Voluntary Challenge Registry.

4 Estimated based on forecast 1998 information available in Manitoba Hydro's 1997 greenhouse gas emissions report to the Voluntary Challenge Registry.

5 Estimated based on forecast 1998 information available in Ontario Hydro's 1997 greenhouse gas emissions report to the Voluntary Challenge Registry.

6 Estimated based on forecast 1998 information available in Nova Scotia Power's 1997 greenhouse gas emissions report to the Voluntary Challenge Registry.

7 Values are for equivalent CO₂ emissions.

Calculation Form 11-1

**INDIRECT GREENHOUSE GAS EMISSIONS FROM
ELECTRIC POWER CONSUMPTION**

Source	Total Power Usage (kW·h)	Pollutant	Emission Factor (g/kW·h)	g _c	Emissions (t/y)	GWP (t/t)	CO ₂ -E Emissions (t/y)
		CO ₂		10 ⁻⁶		1	
		CH ₄		10 ⁻⁶		21	
		N ₂ O		10 ⁻⁶		310	
		CO ₂		10 ⁻⁶		1	
		CH ₄		10 ⁻⁶		21	
		N ₂ O		10 ⁻⁶		310	
		CO ₂		10 ⁻⁶		1	
		CH ₄		10 ⁻⁶		21	
		N ₂ O		10 ⁻⁶		310	
		CO ₂		10 ⁻⁶		1	
		CH ₄		10 ⁻⁶		21	
		N ₂ O		10 ⁻⁶		310	
		CO ₂		10 ⁻⁶		1	
		CH ₄		10 ⁻⁶		21	
		N ₂ O		10 ⁻⁶		310	

TOTAL INDIRECT GREENHOUSE GAS EMISSIONS FROM ELECTRIC POWER CONSUMPTION	
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14.0 APPENDICES

14.1 Physical Properties of Selected Compounds

14.2 U.S. EPA Test Methods

14.3 Emission Factors for Specific Makes and Models of Equipment

14.1 PHYSICAL PROPERTIES OF SELECTED COMPOUNDS

This section contains the following information:

General Compound-Specific Properties

General physical properties of selected compounds are summarized in Table 26. The higher and lower heating values of a multi-component gas may be calculated using the following equation:

$$HHV = \sum_{i=1}^{i=n} HHV_i \cdot y_i$$

and ,

$$LHV = \sum_{i=1}^{i=n} LHV_i \cdot y_i$$

where,

HHV _i	=	higher (gross) heating value of the component i (MJ/m ³),
LHV _i	=	lower (net) heating value of the component i (MJ/m ³),
n	=	number of components,
y _i	=	mole fraction of component i,

Natural Gas

The following properties of typical processed natural gas are provided:

- compressibility factors and specific heat ratios at various temperatures and pressures (see Table 27), and
- specific heat at various temperatures and pressures (see Table 28).

The presented values are calculated using the Peng and Robinson (1976) equation of state for the typical gas compositions noted at the bottom of the tables.

Glycol Solutions

The following properties of aqueous glycol solutions are provided (Dow Chemical Company, 1989):

- specific heats (see Table 29), and
- densities (see Table 30).

Dowtherm Solutions

The following properties of common Dowtherm heat-transfer mediums are provided (Dow Chemical Company, 1993):

- specific heat and density of conventional Dowtherm heat transfer fluids (see Table 31) and
- specific heat and density of glycol-based Dowtherm solutions (see Table 32).

Thermal Efficiencies Based on Stack-Loss Method

Tables 33 to 35 may be used to look-up thermal efficiencies of natural gas- propane- and butane-fuelled heaters and boilers based on the exit flue gas temperature from the final heat exchanger section and the O₂ or CO₂ content of the flue gas. The presented values are calculated using the Peng and Robinson (1976) equation of state.

Gas	Formula	Specific Gravity	Net Heating Value ¹ At 15°C	Gross Heating Value ¹ (at 15°C)		Air Required for Combustion (m ³ /m ³)	Flammability Limits ¹ (Volume percent in Air)	
				Gas (MJ/m ³)	Liquid (MJ/L)		Lower	Higher
Methane	CH ₄	0.5550	33.936	37.694	---	9.53	5.00	15.00
Ethane	C ₂ H ₆	1.0460	60.395	66.032	18.458	16.67	3.22	12.45
Propane	C ₃ H ₈	1.5470	86.456	93.972	25.394	23.82	2.37	9.50
n-Butane	C ₄ H ₁₀	2.0710	112.384	121.779	28.718	30.97	1.86	8.41
i-Butane	C ₄ H ₁₀	2.0710	112.031	121.426	27.621	30.97	1.86	8.41
n-Pentane	C ₅ H ₁₂	2.4906	138.380	149.654	30.709	38.11	1.40	7.80
i-Pentane	C ₅ H ₁₂	2.4906	138.044	149.319	30.333	38.11	1.40	7.80
Hexane	C ₆ H ₁₄	2.9749	164.402	177.556	32.091	45.26	1.25	6.90
Heptane	C ₇ H ₁₆	3.4591	190.398	205.431	33.095	52.41	1.00	6.00
Octane	C ₈ H ₁₈	3.9432	216.374	205.132	32.809	59.55	0.84	3.20
Carbon Monoxide	CO	0.9670	11.959	11.959	---	2.39	12.50	74.20
Carbon Dioxide	CO ₂	1.5194	0	0	0	---	---	---

Continued ...

Gas	Formula	Specific Gravity	Net Heating Value ¹ At 15°C	Gross Heating Value ¹ (at 15°C)		Air Required for Combustion (m ³ /m ³)	Flammability Limits ¹ (Volume percent in Air)	
			Gas (MJ/m ³)	Gas (MJ/m ³)	Liquid (MJ/L)		Lower	Higher
Hydrogen	H ₂	0.0696	10.230	12.091	---	2.39	4.00	74.20
Hydrogen Sulphide	H ₂ S	1.1764	21.912	23.791	---	7.20	4.30	45.50
Oxygen	O ₂	1.1047	0	0	0	---	---	---
Nitrogen	N ₂	0.9672	0	0	0	---	---	---
Air	O ₂ , N ₂ Ar & CO ₂	1.0000	0	0	0	---	---	---

1 Source: GPSA. 1980. SI Engineering Data Book. Figure 16-1. Page 16-4.

14.2 U.S. EPA TEST METHODS

Listed below is a complete summary of all test methods, conditional test methods and performance specifications for continuous emission monitoring systems documented by U.S. EPA's Measurement Technical Information Centre. While not all these methods are necessarily relevant to combustion sources it is appropriate to include them all for completeness.

STANDARD TEST METHODS

- Method 1 - Sample and Velocity Traverses for Stationary Sources
- Method 1A - Sample and Velocity Traverses for Stationary Sources with Small Stacks or Ducts
- Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube)
- Method 2A - Direct Measurement of Gas Volume Through Pipes and Small Ducts
- Method 2C - Determination of Stack Gas Velocity and Volumetric Flow Rate from Small Stacks or Ducts (Standard Pitot Tube)
- Method 2D - Measurement of Gas Volume Flow Rates in Small Pipes and Ducts
- Method 2E - Determination of Landfill Gas Production Flow Rate
- Method 3 - Gas Analysis for the Determination of Dry Molecular Weight
- Method 3A - Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources (Instrumental Analyzer Procedure)
- Method 3B - Gas Analysis for the Determination of Emission Rate Correction Factor or Excess Air
- Method 3C - Determination of Carbon Dioxide, Methane, Nitrogen, and Oxygen From Stationary Sources.
- Method 4 - Determination of Moisture Content in Stack Gases
- Method 5 - Determination of Particulate Emissions from Stationary Sources
- Method 5A - Determination of Particulate Matter Emissions from the Asphalt Processing and Asphalt Roofing Industry
- Method 5B - Determination of Nonsulfuric Acid Particulate Matter from Stationary Sources
- Method 5D - Determination of Particulate Matter Emissions from Positive Pressure Fabric Filters
- Method 5E - Determination of Particulate Emissions from Wool Fibreglass Insulation Manufacturing Industry
- Method 5F - Determination of Nonsulfate Particulate Matter from Stationary Sources
- Method 6 - Determination of Sulfur Dioxide Emissions from Stationary Sources
- Method 6A - Determination of Sulfur Dioxide, Moisture, and Carbon Dioxide Emissions From Fossil-Fuel Combustion Sources
- Method 6B - Determination of Sulfur Dioxide and Carbon Dioxide Daily Average Emissions from Fossil Fuel Combustion Sources
- Method 6C - Determination of Sulfur Dioxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)
- Method 7 - Determination of Nitrogen Oxide Emissions from Stationary Sources

- Method 7A - Determination of Nitrogen Oxide Emissions from Stationary Sources (Ion Chromatographic Method)
- Method 7B - Determination of Nitrogen Oxide Emissions from Stationary Sources (Ultraviolet Spectrophotometry)
- Method 7C - Determination of Nitrogen Oxide Emissions from Stationary Sources Alkaline-Permanganate/Colorimetric Method
- Method 7D - Determination of Nitrogen Oxide Emissions from Stationary Sources Alkaline-Permanganate/Ion Chromatographic Method
- Method 7E - Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Procedure)
- Method 8 - Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources
- Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources
- Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources
- Method 101 - Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants (Air Streams)
- Method 101A - Determination of Particulate and Gaseous Mercury Emissions from Sewage Sludge Incinerators
- Method 102 - Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants (Hydrogen Streams)
- Method 108B - Determination of Arsenic Content In Ore Samples From Nonferrous Smelters
- Method 108C - Determination of Arsenic Content In Ore Samples From Nonferrous Smelters
- Method 10A - Determination of Carbon Monoxide Emissions in Certifying Continuous Emission Monitoring Systems at Petroleum Refineries
- Method 11 - Determination of Hydrogen Sulfide Content of Fuel Gas Streams in Petroleum Refineries
- Method 12 - Determination of Inorganic Lead Emissions from Stationary Sources
- Method 13A - Determination of Total Fluoride Emissions from Stationary Sources (SPADNS Zirconium Lake Method)
- Method 13B - Determination of Total Fluoride Emissions from Stationary Sources (Specific Ion Electrode Method)
- Method 14 - Determination of Fluoride Emissions from Potroom Roof Monitors for Primary Aluminum Plants
- Method 15 - Determination of Hydrogen Sulfide, Carbonyl Sulfide, and Carbon Disulfide from Stationary Sources
- Method 16 - Semicontinuous Determination of Sulfur Emissions from Stationary Sources
- Method 16A - Determination of Total Reduced Sulfur Emissions from Stationary Sources (Impinger Technique)
- Method 17 - Determination of Particulate Matter Emissions from Stationary Sources
- Method 18 - Measurement of Gaseous Organic Compound Emissions by Gas Chromatography
- Method 19 - Determination of Sulfur Dioxide Removal Efficiency and Particulate, Sulfur Dioxide and Nitrogen Oxides Emission Rates from Electric Utility Steam Generators

- Method 20 - Determination of Nitrogen Oxides, Sulfur Dioxide, and Oxygen Emissions from Stationary Gas Turbines
- Method 201 - Determination of PM₁₀ Emissions (Exhaust Gas Recycle Procedure)
- Method 201A-Determination of PM₁₀ Emissions (Constant Sampling Rate Procedure)
- Method 202 - Determination of Condensable Particulate Emissions from Stationary Sources
- Method 203A Visual Determination of Opacity of Emissions from Stationary Sources for Time-Averaged Regulations
- Method 203B Visual Determination of Opacity of Emissions From Stationary Sources for Time-Exception Regulations
- Method 203C Visual Determination of Opacity of Emissions From Stationary Sources for Instantaneous Limitation Regulations.
- Methods 204- Criteria For and Verification of a Permanent or Temporary Total Enclosure
- Method 204A Volatile Organic Compounds Content in Liquids Input Stream
- Method 204B Volatile Organic Compounds Emissions In Captured Stream
- Method 204C Volatile Organic Compounds Emissions In Captured Stream (Dilution Technique)
- Method 204D Volatile Organic Compounds Emissions in Fugitive Stream From Temporary Total Enclosure
- Method 204E Volatile Organic Compounds Emissions in Fugitive Stream from Building Enclosure
- Method 204F Volatile Organic Compounds Content In Liquid Input Stream (Distillation Approach)
- Method 21 - Determination of Volatile Organic Compound Leaks
- Method 22 - Visual Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares
- Method 24 - Determination of Volatile Matter Content, Water Content, Density, Volume Solids, and Weight Solids of Surface Coatings
- Method 24A - Determination of Volatile Matter Content and Density of Printing Inks and Related Coatings
- Method 25 - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon
- Method 25A- Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer
- Method 25C- Determination of Nonmethane Organic Compounds (NMOC) In Landfill Gases
- Method 25D - Determination of the Volatile Organic Concentration of Waste Samples
- Method 26 - Determination of Hydrogen Chloride Emissions From Stationary Sources
- Method 26A - Determination of Hydrogen Halide and Halogen Emissions from Stationary Sources - Isokinetic Method
- Method 27 - Determination of Vapor Tightness of Gasoline Delivery Tank Using Pressure Vacuum Test
- Method 28 - Certification and Auditing of Wood Heaters
- Method 28A - Measurement of Air To Fuel Ratio and Minimum Achievable Burn Rates for Wood-Fired Appliances
- Method 29 (DRAFT) - Determination of Metals Emissions from Stationary Sources
- Method 301- Field Validation of Pollutant Measurement Methods from Various Waste Media

- Method 303- Determination of Visible Emissions From By-Product Coke Oven Batteries
 Method 303A- Determination of Visible Emissions From Nonrecovery Coke Oven Batteries
 Method 304- Method for the Determination of Biodegradation Rates of Organic Compounds
 Method 304A - Determination of Biodegradation Rates of Organic Compounds (Vent Option)
 Method 304B Determination of Biodegradation Rates of Organic Compounds (Scrubber Option)
 Method 305 - Measurement of Emissions of Potential of Individual Volatile Organic
 Compounds in Waste
 Method 306 - Determination of Chromium Emissions from Decorative and Hard Chromium
 Electroplating and Anodizing Operations
 Method 306A Determination of Chromium Emissions from Decorative and Hard Chromium
 Electroplating and Anodizing Operations
 Method 306B Surface Tension Measurement for Tanks Used at Decorative Chromium
 Electroplating and Anodizing Facilities
 Method 307 - Determination of Emissions from Solvent Vapor Cleaners Using a Liquid Level
 Procedure

CONDITIONAL TEST METHODS

- (1) Determination of Butadiene Emissions
- (2) Determination of Particulate Matter (Screening Procedure)
- (3) Determination of Particulate Matter (Modified High Volume Sampling Procedure)
- (4) Determination Of Hydrogen Chloride Emissions From Stationary Sources
- (6) Determination of Chromium Emissions from Chromium Electroplaters
- (7) Verification of Gas Dilution Systems for Field Instrument Calibrations
- (9) Protocol For The Field Validation of Stationary Source Emissions
- (10) Determination of Perchloroethylene Content of Wet Waste Materials From Filters and Still Bottoms
- (11) Determination of Halogenated Organics from Stationary Sources
- (13) Revisions to Method 101A - Determination of Particulate and Gaseous Mercury Emissions from Stationary Sources
- (14) Determination of Benzene Matter Emissions from Stationary Sources
- (15) Performance Specifications for Volatile Organic Compound Continuous Emission Monitoring Systems in Stationary Sources
- (16) Performance Specifications for Gas Chromatographic Continuous Emission Monitoring Systems in Stationary Sources
- (17) Determination of Volatile Organic Content for Ultraviolet Radiation-Cured Coatings
- (19) Direct Measurement of Gas Velocity and Volumetric Flowrate Under Cyclonic Flow Conditions (Propeller Anemometer)

CEMS PERFORMANCE SPECIFICATIONS

- PS 2 - Specifications and Test Procedures for SO₂ and NO_x Continuous Emission Monitoring Systems in Stationary Sources
- PS 3 - Specifications and Test Procedures for O₂ and CO₂ Continuous Emission Monitoring Systems in Stationary Sources
- PS 4 - Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources
- PS 4A Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources
- PS 5 - Specifications and Test Procedures for TRS Continuous Emission Monitoring Systems in Stationary Sources
- PS 6 - Specifications and Test Procedures for Continuous Emission Rate Monitoring Systems in Stationary Sources
- PS 7 - Specifications and Test Procedures for Hydrogen Sulfide Continuous Emission Monitoring Systems In Stationary Sources

14.3 EMISSION FACTORS FOR SPECIFIC MAKES AND MODELS OF EQUIPMENT

Tables 36 and 37 summarize the available emission factors for specific makes and models of natural gas-fuelled reciprocating compressor engines. Tables 38 and 39 provide the corresponding information for natural gas-fuelled turbine compressor engines. The presented values are taken directly from the manufacturer's product literature and from their Internet Web sites. As well, some third-party test data compiled are included. All data have been corrected to a gross-heating-value basis.