

CHAPTER 4

FUGITIVE EMISSIONS

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Coal Mining

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4 FUGITIVE EMISSIONS

4.1 FUGITIVE EMISSIONS FROM MINING, PROCESSING, STORAGE AND TRANSPORTATION OF COAL

Intentional or unintentional release of greenhouse gases may occur during the extraction, processing and delivery of fossil fuels to the point of final use. These are known as fugitive emissions.

4.1.1 Overview and description of sources

Fugitive emissions associated with coal can be considered in terms of the following broad categories.¹

4.1.1.1 COAL MINING AND HANDLING

The geological processes of coal formation also produce methane (CH₄), and carbon dioxide (CO₂) may also be present in some coal seams. These are known collectively as seam gas, and remain trapped in the coal seam until the coal is exposed and broken during mining. CH₄ is the major greenhouse gas emitted from coal mining and handling.

The major stages for the emission of greenhouse gases for both underground and surface coal mines are:

- **Mining emissions** – These emissions result from the liberation of stored gas during the breakage of coal, and the surrounding strata, during mining operations.
- **Post-mining emissions** – Not all gas is released from coal during the process of coal breakage during mining. Emissions, during subsequent handling, processing and transportation of coal are termed post-mining emissions. Therefore coal normally continues to emit gas *even after it has been mined*, although more slowly than during the coal breakage stage.
- **Low temperature oxidation** - These emissions arise because once coal is exposed to oxygen in air, the coal oxidizes to produce CO₂. However, the rate of formation of CO₂ by this process is low.
- **Uncontrolled combustion** – On occasions, when the heat produced by low temperature oxidation is trapped, the temperature rises and an active fire may result. This is commonly known as uncontrolled combustion and is the most extreme manifestation of oxidation. Uncontrolled combustion is characterised by rapid reactions, sometimes visible flames and rapid CO₂ formation, and may be natural or anthropogenic. It is noted that uncontrolled combustion only due to coal exploitation activities is considered here.

After mining has ceased, **abandoned coal mines** may also continue to emit methane.

A brief description of some of the major processes that need to be accounted for in estimating emissions for the different types of coal mines follows:

UNDERGROUND MINES

Active Underground Coal Mines

The following *potential* source categories for fugitive emissions for active underground coal mines are considered in this document:

Seam gas emissions vented to the atmosphere from coal mine *ventilation air* and *degasification systems*

- Post-mining emissions
- Low temperature oxidation

¹ Methods for determining emissions from *peat extraction* are described in Volume 4 AFOLU Chapter 7 ‘Wetlands’.

- Uncontrolled combustion

Coal mine ventilation air and degasification systems arise as follows:

Coal Mine Ventilation Air

Underground coal mines are normally ventilated by flushing air from the surface, through the underground tunnels in order to maintain a safe atmosphere. Ventilation air picks up the CH₄ and CO₂ released from the coal formations and transports these to the surface where they are emitted to atmosphere. The concentration of methane in the ventilation air is normally low, but the volume flow rate of ventilation air is normally large and therefore the methane emissions from this source can be very significant.

Coal Mine Degasification Systems

Degasification systems comprise wells drilled before, during, and after mining to drain gas (mainly CH₄) from the coal seams that release gas into the mine workings. During active mining the major purpose of degasification is to maintain a safe working atmosphere for the coal miners, although the recovered gas may also be utilised as an energy source. Degasification systems can also be used at abandoned underground coal mines to recover methane. The amount of methane recovered from coal mine degasification systems can be very significant and is accounted for, depending on its final use, as described in Section 4.1.3.2 of this chapter.

Abandoned Underground Mines

After closure, coal mines that were significant methane emitters during mining operations continue to emit methane unless there is flooding that cuts off the emissions. Even if the mines have been sealed, methane may still be emitted to the atmosphere as a result of gas migrating through natural or manmade conduits such as old portals, vent pipes, or cracks and fissures in the overlying strata. Emissions quickly decline until they reach a near-steady rate that may persist for an extended period of time.

Abandoned mines may flood as a result of intrusion of groundwater or surface water into the mine void. These mines typically continue to emit gas for a few years before the mine becomes completely flooded and the water prevents further methane release to the atmosphere. Emissions from completely flooded abandoned mines can be treated as negligible. Mines that remain partially flooded can continue to produce methane emissions over a long period of time, as with mines that do not flood.

A further potential source of emissions occurs when some of the coal from abandoned mines ignites through the mechanism of uncontrolled combustion. However, there are currently no methodologies for estimating potential emissions from uncontrolled combustion at abandoned underground mines.

SURFACE COAL MINES

Active Surface Mines

The *potential* source categories for surface mining considered in this chapter are:

- Methane and CO₂ emitted during mining from breakage of coal and associated strata and leakage from the pit floor and highwall
- Post-mining emissions
- Low temperature oxidation
- Uncontrolled combustion in waste dumps

Emissions from surface coal mining occur because the mined and surrounding seams may also contain methane and CO₂. Although the gas contents are generally less than for deeper underground coal seams, the emission of seam gas from surface mines needs to be taken into account, particularly for countries where this mining method is widely practised. In addition to seam gas emissions, the waste coal that is dumped into overburden or reject dumps may generate CO₂, either by low temperature oxidation or by uncontrolled combustion.

Abandoned Surface Mines

After closure, abandoned or decommissioned surface mines may continue to emit methane as the gas leaks from the coal seams that were broken or damaged during mining. There are at present no methods for estimating emissions from this source.

4.1.1.2 SUMMARY OF SOURCES

The major sources are summarised in Table 4.1.1 below.

TABLE 4.1.1 DETAILED SECTOR SPLIT FOR EMISSIONS FROM MINING, PROCESSING, STORAGE AND TRANSPORT OF COAL		
IPCC code	Sector name	
1 B	Fugitive emissions from fuels	Includes all intentional and unintentional emissions from the extraction, processing, storage and transport of fuel to the point of final use.
1 B 1	<i>Solid Fuels</i>	Includes all intentional and unintentional emissions from the extraction, processing, storage and transport of solid fuel to the point of final use.
1 B a	Coal mining and handling	Includes all fugitive emissions from coal
1 B 1 a i	<i>Underground mines</i>	Includes all emissions arising from mining, post-mining, abandoned mines and flaring of drained methane.
1 B 1 a i 1	<i>Mining</i>	Includes all seam gas emissions vented to atmosphere from coal mine ventilation air and degasification systems.
1 B 1 a i 2	<i>Post-mining seam gas emissions</i>	Includes methane and CO ₂ emitted after coal has been mined, brought to the surface and subsequently processed, stored and transported.
1 B 1 a i 3	<i>Abandoned underground mines</i>	Includes methane emissions from abandoned underground mines
1 B 1 a i 4	<i>Flaring of drained methane or conversion of methane to CO₂</i>	Methane drained and flared, or ventilation gas converted to CO ₂ by an oxidation process should be included here. Methane used for energy production should be included in Volume 2, Energy, Chapter 2 'Stationary Combustion'.
1 B 1 a ii	<i>Surface mines</i>	Includes all seam gas emissions arising from surface coal mining
1 B 1 a ii 1	<i>Mining</i>	Includes methane and CO ₂ emitted during mining from breakage of coal and associated strata and leakage from the pit floor and highwall
1 B 1 a ii 2	<i>Post-mining seam gas emissions</i>	Includes methane and CO ₂ emitted after coal has been mined, subsequently processed, stored and transported.
1 B 1 b	<i>Uncontrolled combustion and burning coal dumps</i>	Includes emissions of CO ₂ from uncontrolled combustion due to coal exploitation activities.

4.1.2 Methodological issues

The following sections focus on methane emissions, as this gas is the most important fugitive emission for coal mining. CO₂ emissions should also be included in the inventory where data are available.

UNDERGROUND MINING

Fugitive emissions from underground mining arise from both ventilation and degasification systems. These emissions are normally emitted at a small number of centralised locations and can be considered as point sources. They are amenable to standard measurement methods.

SURFACE MINING

For surface mining the emissions of greenhouse gases are generally dispersed over sections of the mine and are best considered area sources. These emissions may be the result of seam gases emitted through the processes of breakage of the coal and overburden, low temperature oxidation of waste coal or low quality coal in dumps, and uncontrolled combustion. Measurement methods for low temperature oxidation and uncontrolled combustion are still being developed and therefore estimation methods are not included in this chapter.

ABANDONED MINES

Abandoned underground mines present difficulties in estimating emissions, although a methodology for abandoned underground mines is included in this chapter. Methodologies do not yet exist for abandoned or decommissioned surface mines, and therefore they are not included in this chapter.

METHANE RECOVERY AND UTILISATION

Methane recovered from drainage, ventilation air, or abandoned mines may be mitigated in two ways: (1) direct utilization as a natural gas resource or (2) by flaring to produce CO₂, which has a lower greenhouse warming potential than methane.

TIERS

Use of appropriate tiers to develop emissions estimates for coal mining in accordance with good practice depends on the quality of data available. For instance, if limited data are available and the category is not key, then Tier 1 is *good practice*. The Tier 1 approach requires that countries choose from a global average range of emission factors and use country-specific activity data to calculate total emissions. Tier 1 is associated with the highest level of uncertainty. The Tier 2 approach uses country- or basin-specific emission factors that represent the average values for the coals being mined. These values are normally developed by each country, where appropriate. The Tier 3 approach uses direct measurements on a mine-specific basis and, properly applied, has the lowest level of uncertainty.

4.1.3 Underground coal mines

The general form of the equation for estimating emissions for Tier 1 and 2 approaches, based on coal production activity data *from underground coal mining and post-mining emissions* is given by Equation 4.1.1 below. Methods to estimate emissions from *abandoned* underground mines, included in the guidelines for the first time, are described in detail in Section 4.1.5.

Equation 4.1.1 represents emissions before adjustment for any utilisation or flaring of recovered gas:

<p>EQUATION 4.1.1</p> <p>ESTIMATING EMISSIONS FROM UNDERGROUND COAL MINES FOR TIER 1 AND TIER 2 WITHOUT ADJUSTMENT FOR METHANE UTILISATION OR FLARING</p> <p><i>Greenhouse gas emissions = Raw coal production • Emission Factor • Units conversion factor</i></p>
--

The definition of the *Emission Factor* used in this equation depends on the activity data used. For Tier 1 and Tier 2, the *Emission Factor* for underground, surface and post-mining emissions has units of m³/tonne⁻¹, the same units as in situ gas content. This is because these *Emission Factors* are used with activity data on raw coal production which has mass units (i.e. tonnes). However, the *Emission Factor* and the *in situ* gas content are not

the same and should not be confused. The *Emission Factor* is always larger than the *in situ* gas content, because the gas released during mining draws from a larger volume of coal and adjacent gas-bearing strata than simply the volume of coal produced. For *abandoned underground mines*, the *Emission Factor* has different units, because of the different methodologies employed, see section 4.1.5 for greater detail.

The equation to be used along with Equation 4.1.1 in order to adjust for methane utilisation and flaring for Tier 1 and Tier 2 approaches is shown in Equation 4.1.2.

<p>EQUATION 4.1.2</p> <p>ESTIMATING EMISSIONS FROM UNDERGROUND COAL MINES FOR TIER 1 AND TIER 2 WITH ADJUSTMENT FOR METHANE UTILISATION OR FLARING</p> $CH_4 \text{ emissions from underground mining activities} = \text{Emissions from underground mining } CH_4 + \text{Post-mining emission of } CH_4 - CH_4 \text{ recovered and utilized for energy production or flared}$
--

Emissions from underground mines in equations 4.1.1 and 4.1.2 include abandoned mines (see section 4.1.5) and both go into the total for 1.B. 1.a.i (Underground mines).

Equation 4.1.2 is used for Tiers 1 and 2 because they use *Emission Factors* to account for emissions from coal mines on a national or coal-basin level. The emission factors already include all the methane likely to be released from mining activities. Thus, any methane recovery and utilization must be explicitly accounted for by the subtraction term in Equation 4.1.2. Tier 3 methods involve mine-specific calculations which take into account the methane drained and recovered from individual mines rather than emission factors, and therefore Equation 4.1.2 is not appropriate for Tier 3 methods.

4.1.3.1 CHOICE OF METHOD

UNDERGROUND MINING

Figure 4.1.1 shows the decision tree for underground coal mining activities. For countries with underground mining, and where mine-specific measurement data are available it is *good practice* to use a Tier 3 method. Mine-specific data, based on ventilation air measurements and degasification system measurements, reflect actual emissions on a mine-by-mine basis, and therefore produce a more accurate estimate than using *Emission Factors*.

Hybrid Tier 3 - Tier 2 approaches are appropriate in situations when mine-specific measurement data are available only for a subset of underground mines. For example, if only mines that are considered gassy report data, emissions from the remaining mines can be calculated with Tier 2 emission factors. The definition of what constitutes a gassy mine will be determined by each country. For instance, in the United States, gassy mines refers to coal mines with average annual ventilation emissions exceeding the range of 2 800 to 14 000 cubic meters per day. Emission factors can be based on specific emission rates derived from Tier 3 data if the mines are operating within the same basin as the Tier 3 mines, or on the basis of mine-specific properties, such as the average depth of the coal mines.

When no mine-by-mine data are available, but country- or basin-specific data are, it is *good practice* to employ the Tier 2 method.

Where no data (or very limited data) are available, it is *good practice* to use a Tier 1 approach, provided underground coal mining is not a key sub source category. If it is, then it is *good practice* to obtain emissions data to increase the accuracy of these emissions estimates (see Figure 4.1.1).

POST-MINING

Direct measurement (Tier 3) of all post-mining emissions is not feasible, so an emission factor approach must be used. The Tier 2 and Tier 1 methods described below represent *good practice* for this source, given the difficulty of obtaining better data.

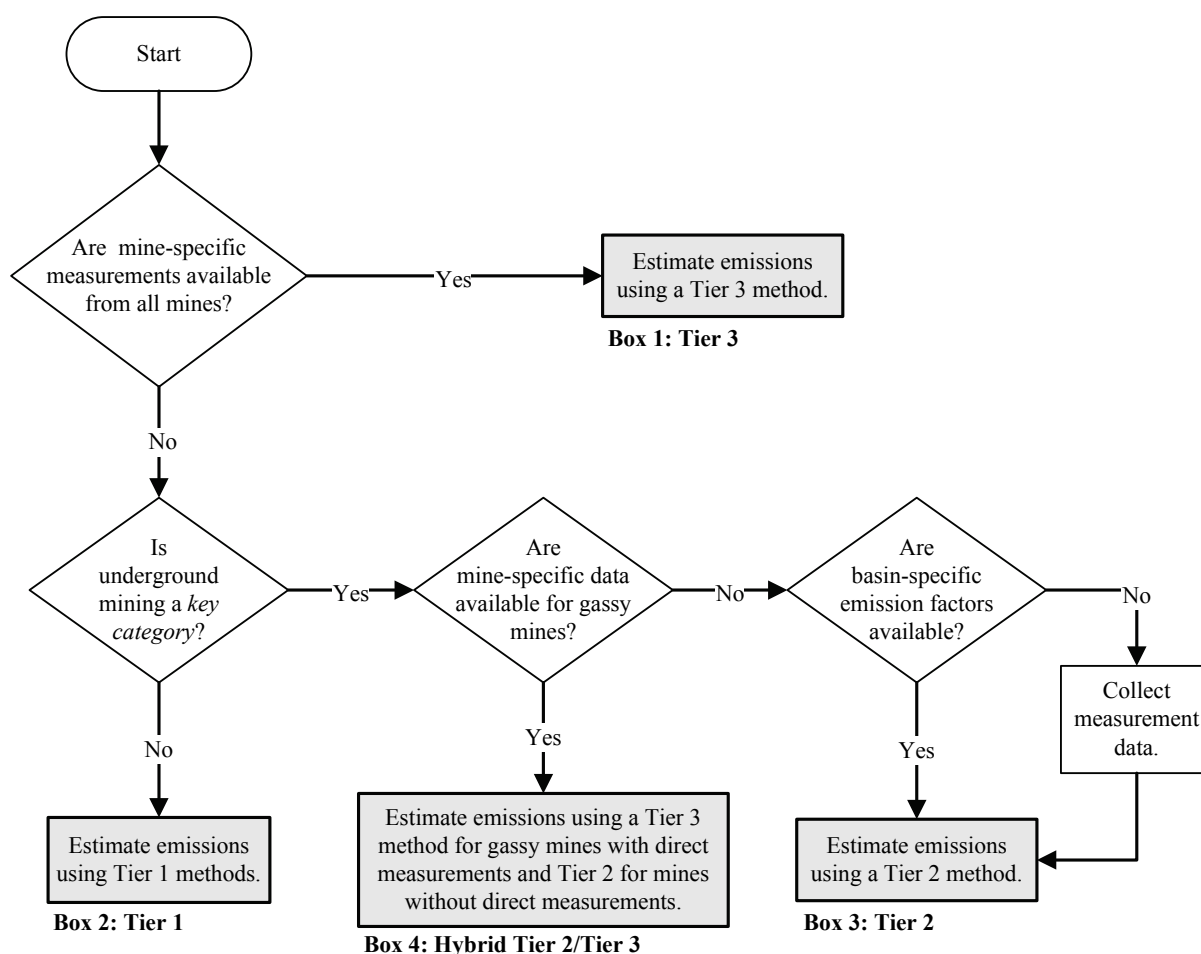
LOW TEMPERATURE OXIDATION

Oxidation of coal when it is exposed to the atmosphere by coal mining releases CO₂. This source will usually be insignificant when compared with the total emissions from gassy underground coal mines. Consequently, no methods are provided to estimate it. Where there are significant emissions of CO₂ in addition to methane in the seam gas, these should be reported on a mine-specific basis.

ABANDONED UNDERGROUND MINES

Fugitive methane emissions from abandoned underground mines should be reported in Underground Mines in IPCC Category 1.B.1.a.i.3, using the methodology presented in Section 4.1.5.

Figure 4.1.1 Decision tree for underground coal mines



Note: See Volume 1 Chapter 4, “Methodological Choice and Key Categories” (noting section 4.1.2 on limited resources) for discussion of key categories and use of decision trees

4.1.3.2 CHOICE OF EMISSION FACTORS FOR UNDERGROUND MINES

MINING

Tier 1 Emission Factors for underground mining are shown below. The emission factors are the same as those described in the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (BCTSRE, 1992; Bibler et al, 1991; Lama, 1992; Pilcher et al, 1991; USEPA, 1993a,b and Zimmermeyer, 1989).

<p>EQUATION 4.1.3</p> <p>TIER 1: GLOBAL AVERAGE METHOD – UNDERGROUND MINING – BEFORE ADJUSTMENT FOR ANY METHANE UTILISATION OR FLARING</p> $CH_4 \text{ emissions} = CH_4 \text{ Emission Factor} \bullet \text{Underground Coal Production} \bullet \text{Conversion Factor}$
--

Where units are:

Methane Emissions (Gg year⁻¹)

CH₄ Emission Factor (m³ tonne⁻¹)

Underground Coal Production (tonne year⁻¹)

Emission Factor:

Low CH ₄ Emission Factor	= 10 m ³ tonne ⁻¹
Average CH ₄ Emission Factor	= 18 m ³ tonne ⁻¹
High CH ₄ Emission Factor	= 25 m ³ tonne ⁻¹

Conversion Factor:

This is the density of CH₄ and converts volume of CH₄ to mass of CH₄. The density is taken at 20°C and 1 atmosphere pressure and has a value of $0.67 \bullet 10^{-6}$ Gg m⁻³.

Countries using the Tier 1 approach should consider country-specific variables such as the depth of major coal seams to determine the emission factor to be used. As gas content of coal usually increases with depth, the low end of the range should be chosen for average mining depths of <200 m, and for depths of > 400 m the high value is appropriate. For intermediate depths, average values can be used.

For countries using a Tier 2 approach, basin-specific emission factors may be obtained from sample ventilation air data or from a quantitative relationship that accounts for the gas content of the coal seam and the surrounding strata affected by the mining process, along with raw coal production. For a typical longwall operation, the amount of gas released comes from the coal being extracted and from any other gas-bearing strata that are located within 150 m above and 50 m below the mined seam (*Good Practice Guidance*, 2000).

POST-MINING EMISSIONS

For a Tier 1 approach the post-mining emissions factors are shown below together with the estimation method:

<p style="text-align: center;">EQUATION 4.1.4</p> <p style="text-align: center;">TIER 1: GLOBAL AVERAGE METHOD – POST-MINING EMISSIONS – UNDERGROUND MINES</p> <p style="text-align: center;"><i>Methane emissions = CH₄ Emission Factor • Underground Coal Production • Conversion Factor</i></p>

Where units are:

Methane Emissions (Gg year⁻¹)

CH₄ Emission Factor (m³ tonne⁻¹)

Underground Coal Production (tonne year⁻¹)

Emission Factor:

Low CH ₄ Emission Factor	= 0.9 m ³ tonne ⁻¹
Average CH ₄ Emission Factor	= 2.5 m ³ tonne ⁻¹
High CH ₄ Emission Factor	= 4.0 m ³ tonne ⁻¹

Conversion Factor:

This is the density of CH₄ and converts volume of CH₄ to mass of CH₄. The density is taken at 20°C and 1 atmosphere pressure and has a value of $0.67 \bullet 10^{-6}$ Gg m⁻³.

Tier 2 methods to estimate post-mining emissions take into account the *in situ* gas content of the coal. Measurements on coal as it emerges on a conveyor from an underground mine without degasification prior to mining indicate that 25-40 percent of the *in situ* gas remains in the coal (Williams and Saghafi, 1993). For mines that practice pre-drainage, the amount of gas in coal will be less than the *in situ* value by some unknown amount. For mines with no pre-drainage, but with knowledge of the *in situ* gas content, the post-mining emission factor can be set at 30 percent of the *in situ* gas content. For mines with pre-drainage, an emission factor of 10 percent of the *in situ* gas content is suggested.

Tier 3 methods are not regarded as feasible for post-mining operations.

EMISSIONS FROM DRAINED METHANE

Methane drained from working (or abandoned) underground (or surface) coal mines can be vented directly to the atmosphere, recovered and utilised, or converted to CO₂ through combustion (flaring or catalytic oxidation) without any utilisation. The manner of accounting for drained methane varies, depending on the final use of the methane.

In general:

- Tier 1 represents an aggregate emissions estimate using emission factors. In general, it is not expected that emissions associated with drained methane would be applicable for Tier 1. Presumably, if methane were being drained, there would be better data to enable use of Tier 2 or even Tier 3 methods to make emissions estimates. However, Tier 1 has been included in the discussion below, in case Tier 1 methods are being used to estimate national emissions where there are methane drainage operations.
- When methane is drained from coal seams as part of coal mining and subsequently flared or used as a fuel, it is *good practice* to subtract this amount from the total estimate of methane emissions for Tier 1 and Tier 2 (Equation 4.1.2). Data on the amount of methane that is flared or otherwise utilised should be obtained from mine operators with the same frequency of measurement as pertains to underground mine emissions generally.
- For Tiers 1 and 2, if methane is drained and vented to the atmosphere rather than utilized, it should not be re-counted as it already forms part of the emissions estimates for these approaches.
- For Tier 3, methane recovered from degasification systems and vented to the atmosphere prior to mining should be added to the amount of methane released through ventilation systems so that the total estimate is complete. In some cases, because degasification system data are considered confidential, it may be necessary to estimate degasification system collection efficiency, and then subtract known reductions to arrive at the net degasification system emissions.
- All methane emissions associated with coal seam degasification related to coal mining activities should be accounted for in the inventory year in which the emissions and recovery operations occur. Thus, the total emissions from all ventilation shafts and from all degasification operations that emit methane to the atmosphere are reported for each year, regardless of when the coal seam is mined through, as long as the emissions are associated with mining activities. This represents a departure from the previous guidelines where the drained methane was accounted for in the year in which the coal seam was mined through.

When recovered methane is utilized as an energy source:

- Any emissions resulting from use of recovered coal mine methane as an energy source should be accounted for based on its final end-use, for example in the Energy Volume, Chapter 2, 'Stationary Combustion' when used for stationary energy production.
- Where recovered methane from coal seams is fed into a gas distribution system and used as natural gas, the *fugitive* emissions are dealt with in the oil and natural gas source category (Section 4.2).

When recovered methane is flared:

- When the methane is simply combusted with no useful energy, as in flaring or catalytic oxidation to CO₂, the corresponding CO₂ production should be added to the total greenhouse gas emissions (expressed as CO₂ equivalents) from coal mining activities. Such emissions should be accounted for as shown by Equation 4.1.5, below. Amounts of nitrous oxide and non-methane volatile organic compounds emitted during flaring will be small relative to the overall fugitive emissions and need not be estimated.

EQUATION 4.1.5

EMISSIONS OF CO₂ AND CH₄ FROM DRAINED METHANE FLARED OR CATALYTICALLY OXIDISED

$$(a) \text{Emissions of CO}_2 \text{ from CH}_4 \text{ combustion} = 0.98 \bullet \text{Volume of methane flared} \bullet \text{Conversion Factor} \\ \bullet \text{Stoichiometric Mass Factor}$$

$$(a) \text{Emissions of unburnt methane} = 0.02 \bullet \text{Volume of methane flared} \bullet \text{Conversion Factor}$$

Where units are:

Emissions of CO₂ from methane combustion (Gg year⁻¹)

Volume of methane oxidised (m³ year⁻¹)

Stoichiometric Mass Factor is the mass ratio of CO₂ produced from full combustion of unit mass of methane and is equal to 2.75

Note: 0.98 represents the combustion efficiency of natural gas that is flared (Compendium of Greenhouse gas Emission Methodologies for the Oil and gas Industry, American Petroleum Institute, 2004)

Conversion Factor:

This is the density of CH₄ and converts volume of CH₄ to mass of CH₄. The density is taken at 20°C and 1 atmosphere pressure and has a value of 0.67•10⁻⁶ Gg m⁻³.

4.1.3.3 CHOICE OF ACTIVITY DATA

The activity data required for Tiers 1 and 2 are raw coal production. If the data on raw coal production are available these should be used directly. If coal is not sent to a coal preparation plant or washery for upgrading by removal of some of the mineral matter, then raw coal production equals the amount of saleable coal. Where coal is upgraded, some coal is rejected in the form of coarse discards containing high mineral matter and also in the form of unrecoverable fines. The amount of waste is typically around 20 percent of the weight of raw coal feed, but may vary considerably by country. Where activity data are in the form of saleable coal, an estimate should be made of the amount of production that is washed. Raw coal production is then estimated by increasing the amount of 'saleable coal' by the fraction lost through washing.

An alternative approach that may be more suitable for mines whose raw coal output contains rock from the roof or floor as a deliberate part of the extraction process, is to use saleable coal data in conjunction with emission factors referenced to the clean fraction of the coal, not raw coal. This should be noted in the inventory.

For the Tier 3 methods, coal production data are unnecessary because actual emissions measurements are available. However, it is *good practice* to collect and report these data to illustrate the relationship, if any, between underground coal production and actual emissions on an annual basis.

High quality measurements of methane drained by degasification systems should also be available from mine operators for mines where drainage is practised. If detailed data on drainage rates are absent, *good practice* is to obtain data on the efficiency of the systems (i.e. the fraction of gas drained) or to make an estimate using a range (e.g. 30-50 percent, typical of many degasification systems). If associated mines have data available these may also be used to provide guidance. Annual total gas production records for previous years should be maintained; these records may be available from appropriate agencies or from individual mines.

Where data on methane recovery from coal mines and utilisation are not directly available from mine operators, gas sales could be used as a proxy. If gas sales are unavailable, the alternative is to estimate the amount of utilised methane from the known efficiency specifications of the drainage system. Only methane that would have been emitted from coal mining activities should be considered as recovered and utilized. These emissions should be accounted for in Volume 2, Chapter 4, Section 4.2, 'Fugitive emissions from oil and natural gas', or if the emissions are combusted for energy, in Volume 2, Chapter 2 'Stationary Combustion'.

4.1.3.4 COMPLETENESS FOR UNDERGROUND COAL MINES

The estimate of emissions from underground mining should include:

- Drained gas produced from degasification systems
- Ventilation emissions
- Post-mining emissions
- Estimates of volume of methane recovered and utilized or flared
- Abandoned underground coal mines (see Section 4.1.5 for methodological guidance)

These sub sources categories are included in the current Guidelines.

4.1.3.5 DEVELOPING A CONSISTENT TIME SERIES

Comprehensive mine-by-mine (i.e. Tier 3) data may be available for some but not all years. If there have been no major changes in the number of active mines, emissions can be scaled to production for missing years, if any. If there were changes in the mine number, the mines involved can be removed from the scaling extrapolation and handled separately. However, care must be taken in scaling because the coal being mined, the virgin exposed coal and the disturbed mining zone each have different emission rates. Furthermore, mines may have a high background emission level that is independent of production.

The inventory guidelines recommend that methane emissions associated with coal seam degasification related to mining should be accounted for in the inventory year in which the emissions and recovery operations occur. This is a departure from previous guidelines which suggested that the methane emissions or reductions only be accounted for during the year in which the coal was produced (e.g. the degasification wells were "mined through.") Thus, if feasible, re-calculation of previous inventory years is desirable to make a consistent time series.

In cases where an inventory compiler moves from a Tier 1 or Tier 2 to a Tier 3 method, it may be necessary to calculate implied emissions factors for years with measurement data, and apply these emission factors to coal production for years in which these data do not exist. It is important to consider if the composition of the mine population has changed dramatically during the interim period, because this could introduce uncertainty. For mines that have been abandoned since 1990, data may not be archived if the company disappears. These mines should be treated separately when adjusting the time series for consistency.

For situations where the emissions of greenhouse gases from active underground mines have been well characterized and the mines have passed from being considered 'active' to 'abandoned', care should be taken so as not to introduce major discontinuities in the total emissions record from coal mining.

4.1.3.6 UNCERTAINTY ASSESSMENT

EMISSION FACTOR UNCERTAINTIES

Emission Factors for Tiers 1 and 2

The major sources of uncertainty for a Tier 1 approach arise from two sources. These are:

- The applicability of global emission factors to individual countries
- Inherent uncertainties in the emission factors themselves

The uncertainty due to the first point above is difficult to quantify, but could be significant. The inherent uncertainty in the emission factor is also difficult to quantify because of natural variability within the same coal region is known to occur.

For a Tier 2 approach, the same broad comments apply, although basin-specific data will reduce the inherent uncertainty in the Emission Factor compared with a Tier 1 approach. With regard to the inherent variability in the Emission Factor, 'Expert Judgement' in the *Good Practice Guidance (2000)* suggested that this was likely to be at least ± 50 percent.

Table 4.1.2 shows the Tier 1 and Tier 2 uncertainties associated with emissions from underground coal mining. The uncertainties for these Tiers are based on expert judgement.

TABLE 4.1.2 ESTIMATES OF UNCERTAINTY FOR UNDERGROUND MINING FOR TIER 1 AND TIER 2 APPROACHES		
Likely uncertainties of coal mine methane Emission factors (Expert judgement - GPG, 2000*)		
Method	Mining	Post-Mining
Tier 2	$\pm 50-75\%$	$\pm 50\%$
Tier 1	Factor of 2 greater or smaller	Factor of 3 greater or smaller
*GPG, 2000 <i>IPCC Good Practice Guidance</i> and Uncertainty Management in National Greenhouse Gas Inventories (2000)		

Tier 3

Methane emissions from underground mines have a significant natural variability due to variations in the rate of mining and drainage of gas. For instance, the gas liberated by longwall mining can vary by a factor of up to two during the life of a longwall panel. Frequent measurements of underground mine emissions can account for such variability and also reduce the intrinsic errors in the measurement techniques. As emissions vary over the course of a year due to variations in coal production rate and associated drainage, *good practice* is to collect measurement data as frequently as practical, preferably biweekly or monthly to smooth out variations. Daily measurements would ensure a higher quality estimate. Continuous monitoring of emissions represents the highest stage of emission monitoring, and is implemented in some modern longwall mines.

Spot measurements of methane concentration in ventilation air are probably accurate to ± 20 percent depending on the equipment used. Time series data or repeat measurements will significantly reduce the uncertainty of annual emissions to ± 5 percent for continuous monitoring, and 10-15 percent for monitoring conducted every two weeks. Ventilation airflows are usually fairly accurately known (± 2 percent). When combining the inaccuracies in emissions concentration measurements with the imprecision due to measurement and calculation of instantaneous measurements, overall emissions for an individual mine may be under-represented by as much as 10 percent or over-represented by as much as 30 percent (Mutmanský and Wang, 2000).

Spot measurement of methane concentration in drained gas (from degasification systems) is likely to be accurate to ± 2 percent because of its higher concentration. Measurements should be made with a frequency comparable to those for ventilation air to obtain representative sampling. Measured degasification flowrates are probably known to be ± 5 percent. Degasification flowrates that are estimated based on gas sales are also likely to have an uncertainty of at least ± 5 percent due to the tolerances in pipeline gas quality.

For a single longwall operation, with continuous or daily emission measurements, the accuracy of monthly or annual average emissions data is probably ± 5 percent. The accuracy of spot measurements performed every two weeks is ± 10 percent, at 3-monthly intervals: ± 30 percent. Aggregating emissions from mines based on the less frequent type of measurement procedures will reduce the uncertainty caused by fluctuations in gas production. However, as fugitive emissions are often dominated by contributions from only a small number of mines, it is difficult to estimate the extent of this improvement.

The uncertainty estimates for underground mines are shown in Table 4.1.3.

TABLE 4.1.3 ESTIMATES OF UNCERTAINTY FOR UNDERGROUND COAL MINING FOR A TIER 3 APPROACH			
Source	Details	Uncertainty	Reference
Drainage gas	Spot measurements of CH ₄ for drainage gas	$\pm 2\%$	Expert judgment (GPG, 2000 [*])
	Degasification flows	$\pm 5\%$	Expert judgment (GPG, 2000)
Ventilation gas	Continuous or daily measurements	$\pm 5\%$	Expert judgment (GPG, 2000)
	Spot measurements every 2 weeks	$\pm 10\%$	Mutmansky and Wang, 2000
	Spot measurements every 3 months	$\pm 30\%$	Mutmansky and Wang, 2000
[*] GPG, 2000 - IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (2000)			

ACTIVITY DATA UNCERTAINTIES

Coal production: Country-specific tonnages are likely to be known to 1-2 percent, but if raw coal data are not available, then the uncertainty will increase to about ± 5 percent, when converting from saleable coal production data. The data are also influenced by moisture content, which is usually present at levels between 5-10 percent, and may not be determined with great accuracy.

Apart from measurement uncertainty, there can be further uncertainties introduced by the nature of the statistical databases that are not considered here. In countries with a mix of regulated and unregulated mines, activity data may have an uncertainty of ± 10 percent

4.1.4 Surface coal mining

The fundamental equation to be used in estimating emissions from surface mining is as shown in Equation 4.1.6.

<p style="text-align: center;">EQUATION 4.1.6</p> <p style="text-align: center;">GENERAL EQUATION FOR ESTIMATING FUGITIVE EMISSIONS FROM SURFACE COAL MINING</p> <p style="text-align: center;"><i>CH₄ emissions = Surface mining emissions of CH₄ + Post-mining emission of CH₄</i></p>

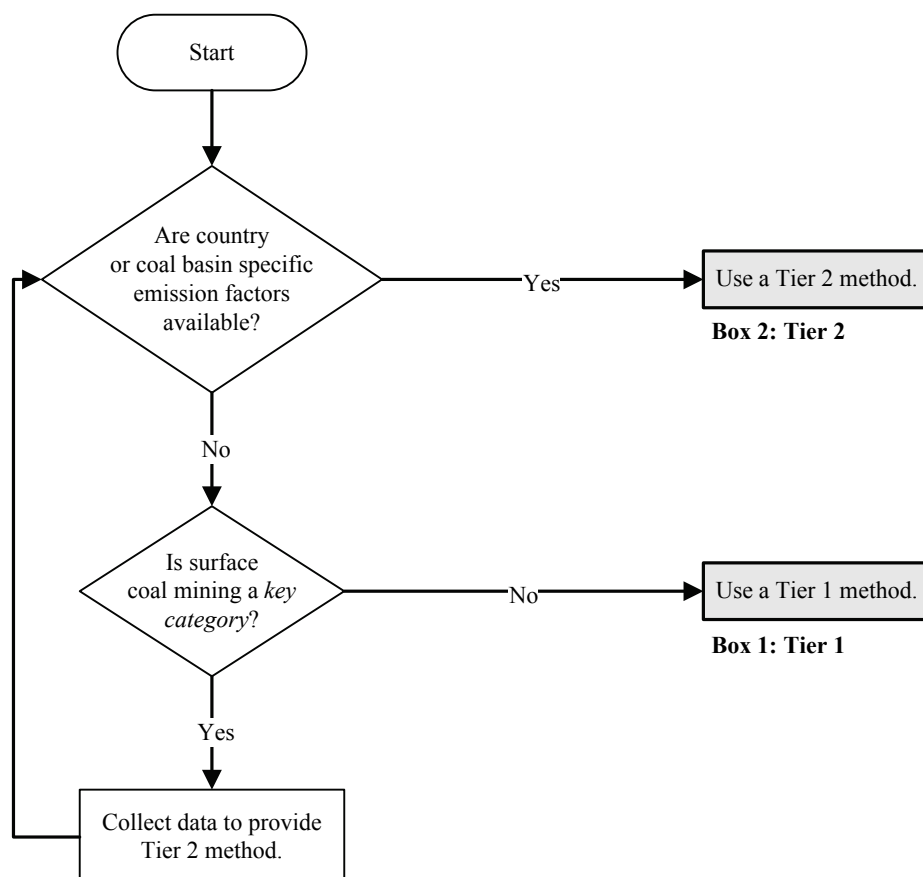
4.1.4.1 CHOICE OF METHOD

It is not yet feasible to collect mine-specific Tier 3 measurement data for surface mines. The alternative is to collect data on surface mine coal production and use emission factors. For countries with significant coal production and multiple coal basins, disaggregation of data and emission factors to the coal basin level will improve accuracy. Given the uncertainty of production-based emission factors, choosing emission factors from the range specified within these guidelines can provide reasonable estimates for a Tier 1 approach.

As with underground mining, direct measurement of post-mining emissions is infeasible so an emission factor approach is recommended. Tier 2 and Tier 1 methods should be reasonable for this source, given the difficulty of obtaining better data.

Oxidation of coal in the atmosphere to produce CO₂ is known to occur at surface mines, but emissions from this are not expected to be significant, especially taking into account the effects of rehabilitation of the waste dumps. Rehabilitation practices, which involve covering the dumps with topsoil and re-vegetation, act to reduce oxygen fluxes into the dump and hence reduce the rate of CO₂ production.

Uncontrolled combustion in waste piles is a feature for some surface mines. However, these emissions, where they occur, are extremely difficult to quantify and it is infeasible to include a methodology.

Figure 4.1.2 Decision tree for surface coal mining

Note: See Volume 1 Chapter 4, “Methodological Choice and Key Categories” (noting section 4.1.2 on limited resources) for discussion of *key categories* and use of decision trees

4.1.4.2 EMISSION FACTORS FOR SURFACE MINING

Although measurements of methane emissions from surface mining are increasingly available, they are difficult to make and at present no routine widely applicable methods exist. Data on *in situ* gas contents before overburden removal are also scarce for many surface mining operations.

The Tier 1 emission factors are shown together with the estimation method in Equation 4.1.7.

EQUATION 4.1.7 TIER 1: GLOBAL AVERAGE METHOD – SURFACE MINES <i>Methane emissions = CH₄ Emission Factor • Surface Coal Production • Conversion Factor</i>
--

Where units are:

Methane Emissions (Gg year⁻¹)

CH₄ Emission Factor (m³ tonne⁻¹)

Surface Coal Production (tonne year⁻¹)

Emissions Factor:

Low CH₄Emission Factor = 0.3 m³ tonne⁻¹

Average CH₄ Emission Factor = 1.2 m³ tonne⁻¹

High CH₄ Emission Factor = 2.0 m³ tonne⁻¹

Conversion Factor:

This is the density of CH₄ and converts volume of CH₄ to mass of CH₄. The density is taken at 20°C and 1 atmosphere pressure and has a value of $0.67 \bullet 10^{-6} \text{ Gg m}^{-3}$.

For the Tier 1 approach, it is *good practice* to use the low end of the specific emission range for those mines with average overburden depths of less than 25 meters and the high end for overburden depths over 50 meters. For intermediate depths, average values for the emission factors may be used. In the absence of data on overburden thickness, it is *good practice* to use the average emission factor, namely 1.2 m³/tonne.

The Tier 2 method uses the same equation as for Tier 1, but with data disaggregated to the coal basin level.

POST-MINING EMISSIONS – SURFACE MINING

For a Tier 1 approach the post-mining emissions can be estimated using the emission factors shown in Equation 4.1.8.

<p>EQUATION 4.1.8</p> <p>TIER 1: GLOBAL AVERAGE METHOD – POST-MINING EMISSIONS – SURFACE MINES</p> <p><i>Methane emissions = CH₄ Emission Factor • Surface Coal Production • Conversion Factor</i></p>

Where units are:

Methane Emissions (Gg year⁻¹)

CH₄ Emission Factor (m³ tonne⁻¹)

Surface Coal Production (tonne year⁻¹)

Emission Factor:

Low CH₄ Emission Factor = 0 m³ tonne⁻¹

Average CH₄ Emission Factor = 0.1 m³ tonne⁻¹

High CH₄ Emission Factor = 0.2 m³ tonne⁻¹

Conversion Factor:

This is the density of CH₄ and converts volume of CH₄ to mass of CH₄. The density is taken at 20°C and 1 atmosphere pressure and has a value of $0.67 \bullet 10^{-6} \text{ Gg m}^{-3}$.

The average emission factor should be used unless there is country-specific evidence to support use of the low or high emission factor.

4.1.4.3 ACTIVITY DATA

As with underground coal mines, the activity data required for Tiers 1 and 2 are raw coal production. The comments relating to coal production data, made for Tier 1 and Tier 2 for underground mining in Section 4.1.3.3 also apply to surface mining.

4.1.4.4 COMPLETENESS FOR SURFACE MINING

The estimate of emissions from surface mining should include:

- Emissions during mining through the breaking of coal and from surrounding strata
- Post-mining emissions
- Waste pile/ overburden dump fires

At present only the first two sources above are taken into account. While there will be some emissions from low temperature oxidation, these are expected to be insignificant for this source.

4.1.4.5 DEVELOPING A CONSISTENT TIME SERIES

There may be missing inventory data for surface mines for certain inventory years. If there have been no major changes in the number of active surface mines, emissions can be scaled to production for the missing years. If there were changes in the number of mines, the mines involved can be removed from the scaling extrapolation

and handled separately. Where new mines have started production in new coalfields, it is important that the emissions applicable to these mines be assessed as each coal basin will have different characteristic in situ gas contents and emission rates.

If coal seam degasification is practiced at surface mines, the methane should be estimated and reported in the inventory year in which the emissions and recovery operations occur.

4.1.4.6 UNCERTAINTY ASSESSMENT IN EMISSIONS

EMISSION FACTOR UNCERTAINTY

Uncertainties in the emissions from surface mines are less well quantified than for underground mining. Briefly, the sources of the uncertainty are the same as described in Section 4.1.3.6 for underground coal mines. However, the variability in the emission factors for large surface mines may be expected to be greater than for underground coal mines, because surface mines can show significant variability across the extent of the mine as a result of local geological features.

Table 4.1.4 shows the Tier 1 and Tier 2 uncertainties associated with surface mining emissions.

TABLE 4.1.4 ESTIMATES OF UNCERTAINTY FOR SURFACE MINING FOR TIER 1 AND TIER 2 APPROACHES		
Likely Uncertainties of Coal Mine Methane Emission Factors for Surface Mining (Expert Judgement*)		
Method	Surface	Post-Mining
Tier 2	Factor of 2 greater or lower	± 50%
Tier 1	Factor of 3 greater or lower	Factor of 3 greater or lower
GPG, 2000 - <i>IPCC Good Practice Guidance</i> and Uncertainty Management in National Greenhouse Gas Inventories (2000)		

ACTIVITY DATA UNCERTAINTY

The comments made for underground mining in Section 4.1.3.6 also apply to surface mining.

4.1.5 Abandoned underground coal mines

Closed, or abandoned, underground coal mines may continue to be a source of greenhouse gas emissions for some time after the mines have been closed or decommissioned. For the purpose of the emissions inventory, it is critical that each mine is classified in one and only one inventory database (e.g., active or abandoned).

As abandoned mines appear in these guidelines for the first time, the Tier 1 and Tier 2 approaches are described in some detail. The Tier 1 and Tier 2 approaches presented below are largely based on an approach originally developed by the USEPA (Franklin et al, 2004) and have been adapted to be more globally applicable. It is anticipated that, where country-specific data exists for abandoned mines, the country-specific data will be used.

The Tier 3 approach provides flexibility for use of mine-specific data. The Tier 3 methodology outlined below has been adapted from the USA methodology (Franklin et al 2004; US EPA 2004). Other relevant work has been sponsored by the UK (Kershaw, 2005), which provides another example of a Tier 3 approach.

4.1.5.1 CHOICE OF METHOD

The fundamental equation for estimating emissions from abandoned underground coal mines is shown in Equation 4.1.9.

<p style="text-align: center;">EQUATION 4.1.9</p> <p style="text-align: center;">GENERAL EQUATION FOR ESTIMATING FUGITIVE EMISSIONS FROM ABANDONED UNDERGROUND COAL MINES</p> $CH_4 \text{ emissions} = \text{Emissions from abandoned mines} - CH_4 \text{ emissions recovered}$

Developing emissions estimates from abandoned underground coal mines requires historical records. Figure 4.1.3 is a decision tree that shows how to determine which Tier to use.

Tier 1 and 2

The two key parameters used to estimate abandoned mine emissions for each mine (or group of mines) are the time (in years) elapsed since the mine was abandoned, relative to the year of the emissions inventory, and emission factors that take into account the mine's gassiness. If applicable and appropriate, methane recovery at specific mines can be incorporated for specific mines in a hybrid Tier 2 – Tier 3 approach (see below).

- Tier 2 incorporates coal-type-specific information and narrower time intervals for abandonment of coal mines.
- Tier 1 includes default values and broader time intervals.

For a Tier 1 approach, the emissions for a given inventory year can be calculated from Equation 4.1.10.

<p>EQUATION 4.1.10</p> <p>TIER 1 APPROACH FOR ABANDONED UNDERGROUND MINES</p> <p><i>Methane Emissions = Number of Abandoned Coal Mines remaining unflooded • Fraction of gassy Coal Mines • Emission Factor • Conversion Factor</i></p>

Where units are:

Methane Emissions (Gg year^{-1})

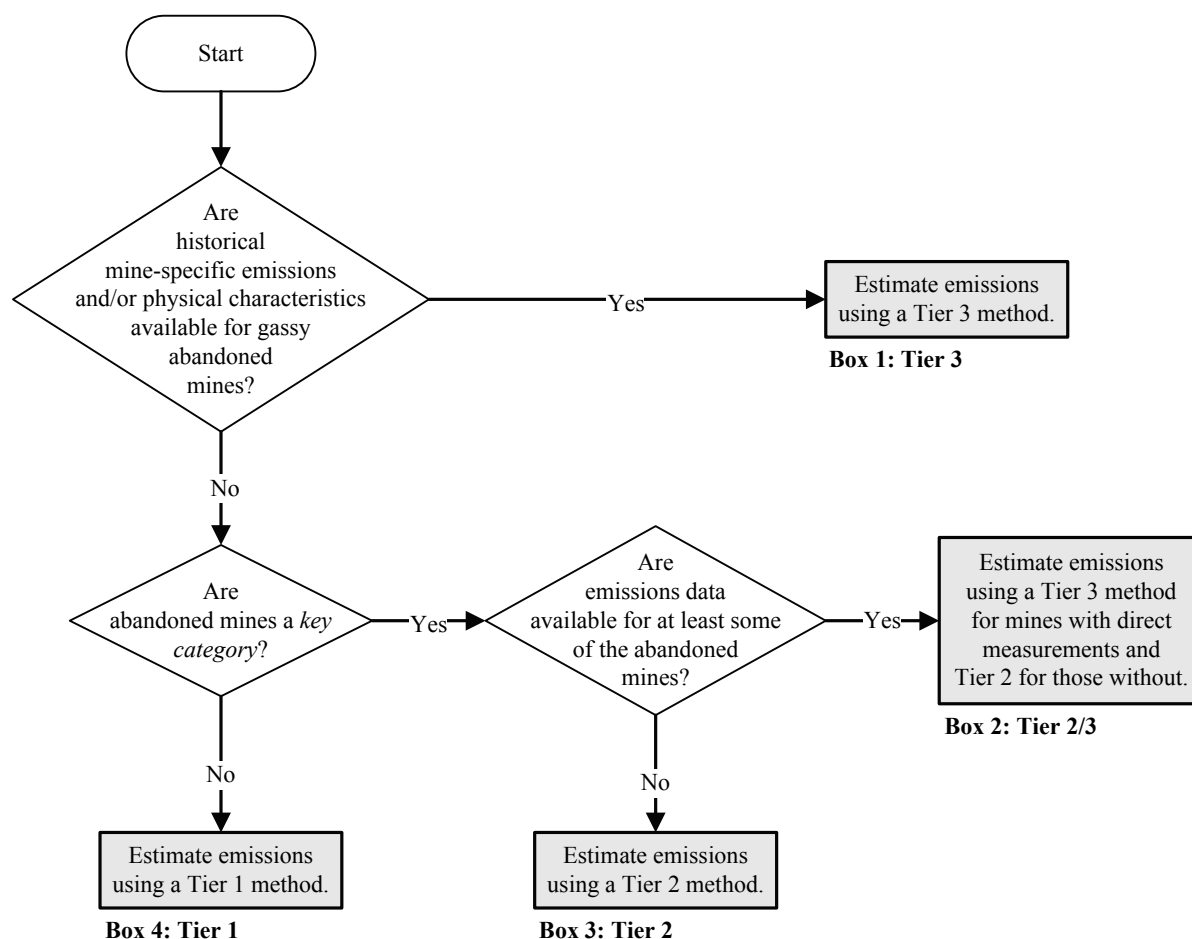
Emission Factor ($\text{m}^3 \text{year}^{-1}$)

Note: the Emission Factor has different units here compared with the definitions for underground, surface and post-mining emissions. This is because of the different method for estimating emissions from abandoned mines compared with underground or surface mining.

This equation is applied for each time interval, and emissions from each time interval are added to calculate the total emissions.

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4 . The density is taken at 20°C and 1 atmosphere pressure and has a value of $0.67 \bullet 10^{-6} \text{ Gg m}^{-3}$.

Figure 4.1.3 Decision tree for abandoned underground coal mines

Note: See Volume 1 Chapter 4, “Methodological Choice and Key Categories” (noting section 4.1.2 on limited resources) for discussion of key categories and use of decision trees

Tier 3

The Tier 3 approaches (Franklin et al, 2004 and Kershaw, 2005) require mine-specific information such as ventilation emissions from the mine when active, characteristics of the mined coal seam, mine size and depth, and the condition of the abandoned mine (e.g., hydrologic status, flooding or flooded, and whether sealed or vented). Each country may generate its own profiles of abandoned mine emissions as a function of time (also known as emission decline curves) based on known national- or basin-specific coal properties, or it may use more generic curves based on coal rank, or measurements possibly in combination with mathematical modelling methods. If there are any methane recovery projects occurring at abandoned mines, data on these projects are expected to be available. A mine-specific Tier 3 methodology would be appropriate for calculating emissions from a mine that has associated methane recovery projects and could be incorporated as part of a hybrid approach with a national level Tier 2 emissions inventory.

In general, the Tier 3 process for developing a national inventory of abandoned mine methane (AMM) emissions consists of the following steps:

1. Creating a database of gassy abandoned coal mines.
2. Identifying key factors affecting methane emissions: hydrologic (flooding) status, permeability mine condition (whether sealed or vented) and time elapsed since abandonment.
3. Developing mine- or coal basin-specific emission rate decline curves, or equivalent models.
4. Validating mathematical models through a field measurement programme.
5. Calculating a national emissions inventory for each year.
6. Adjusting for emissions reductions due to methane recovery and utilization.
7. Determining the net total emissions.

Hybrid Approaches

A combination of different Tier methodologies may be used to reflect the best data availability for different historical periods. For example, for a given country, emissions from mines abandoned in the distant past may need to be determined using a Tier 1 method. For that same country, it may be possible to determine emissions from mines abandoned more recently using a Tier 2 or 3 method if more accurate data are available.

Fully Flooded Mines

It is *good practice* to include mines that are known to be fully flooded in databases and other records used for inventory development, but they should be assigned an emission of zero as the emissions from such mines are negligible.

Emissions Reductions through Recovery and Utilization

In some cases, methane from closed or abandoned mines may be recovered and utilised or flared. Methane recovery from abandoned mines generally entails pumping which increases, or “accelerates”, the amount of methane recovered above the amount that would have been emitted had pumping not taken place.

Under a mine-specific (Tier 3) approach in which emissions decline curves or models are used to estimate emissions, if emissions reductions are less than the projected emissions that would have occurred at the mine had recovery not taken place for a given year, then the emissions reductions from the recovery and utilization should be subtracted from the projected emissions to provide the net emissions. If the methane recovered and utilized in a given year exceeds the emission that would have occurred had recovery not taken place, then the net emissions from that mine for that year are considered to be zero.

If a Tier 3 method is not used (singly or in combination with Tier 2), the total amount of methane recovered and utilized from abandoned mines should be subtracted from the total emissions inventory for abandoned mines, per Equation 4.1.9, subject to the reported emissions being no less than zero. The Tier 3 method should be used where suitable data are available.

4.1.5.2 CHOICE OF EMISSION FACTORS**Tier 1: Global Average Approach – Abandoned Underground Mines**

A Tier 1 approach for determining emissions from abandoned underground mines is described below and is largely based on methods developed by the USEPA (Franklin et al., 2004). It incorporates a factor to account for the fraction of those mines that, when they were actively producing coal, were considered gassy. Thus, this methodology is based on the total number of coal mines abandoned, adjusted for the fraction considered gassy, as described below. Abandoned mines that were considered non-gassy when they were actively mined are presumed to have negligible emissions. In the US methodology, the term gassy mines refers to coal mines that, when they were active, had average annual ventilation emissions that exceeded the range of 2 800 to 14 000 cubic meters per day (m^3/d), or 0.7 to 3.4 Gg per year.

The Tier 1 – approach for abandoned underground coal mines is as follows:

1. Determine the approximate time (year interval) from the following time intervals when gassy coal mines were abandoned:
 - a. 1901 – 1925
 - b. 1926 – 1950
 - c. 1951 – 1975
 - d. 1976 – 2000
 - e. 2001 - present
2. Multiple intervals may be used where appropriate. It is recommended that the number of gassy coal mines abandoned during each time interval be estimated using the smallest time intervals possible based on available data. Ideally, for more recent periods, time intervals will decrease (e.g., intervals of ten years prior to 1990; annual intervals since 1990). Information for different coal mine-clusters abandoned during different time periods should be considered, since multiple time periods may be combined in the Tier 1 approach
3. Estimate the total number of abandoned mines in each time band since 1901 remaining unflooded. If there is no knowledge on the extent of flooding it is *good practice* to assume that 100 percent of mines remain unflooded. For the purposes of estimating the number of abandoned mines, prospect excavations and hand cart mines of only a few acres in size should be disregarded.
4. Determine the percentage of coal mines that would be considered gassy at the time of mine closure. Based on the time intervals selected above, choose an estimated percentage of gassy coal mines from

the high and low default values listed in Table 4.1.5. Actual estimates can range anywhere from 0 to 100 percent. When choosing within the high and low default values listed in Table 4.1.5, a country should consider all available historical information that may contribute to the percentage of gassy mines, such as coal rank, gas content, and depth of mining. Countries with recorded instances of gassy mines (e.g., methane explosions or outbursts) should choose the high default values in the early part of the century. From 1926 to 1975, countries where mines were relatively deep and hydraulic equipment was used should choose the high default value. Countries with deep longwall mines or with evidence of gassiness should choose the high values for the time periods after 1975. The low range of the default values may be appropriate for a given time interval for specific regions, coal basins, or nations, based on geologic conditions or known mining practices.

5. For the inventory year of interest (between 1990 and the present), select the appropriate emissions factor from Table 4.1.6. For example, for mines abandoned in the interval 1901 to 1925 and for the inventory reporting year 2005, the Emission Factor for these mines would have a value of 0.256 million m³ of methane per mine.
6. Calculate for each time band the total methane emissions from Equation 4.1.10 to the inventory year of interest.
7. Sum the emissions for each time interval to derive the total abandoned mine emissions for each inventory year.

TABLE 4.1.5 TIER 1 – ABANDONED UNDERGROUND MINES DEFAULT VALUES - PERCENTAGE OF COAL MINES THAT ARE GASSY		
Time Interval	Low	High
1900-1925	0%	10%
1926-1950	3%	50%
1950-1976	5%	75%
1976-2000	8%	100%
2001-Present	9%	100%

TABLE 4.1.6 TIER 1 – ABANDONED UNDERGROUND MINES EMISSION FACTOR, MILLION M³ METHANE / MINE					
	Interval of mine closure				
Inventory Year	1901 – 1925	1926 – 1950	1951 - 1975	1976 – 2000	2001 – Present
1990	0.281	0.343	0.478	1.561	NA
1991	0.279	0.340	0.469	1.334	NA
1992	0.277	0.336	0.461	1.183	NA
1993	0.275	0.333	0.453	1.072	NA
1994	0.273	0.330	0.446	0.988	NA
1995	0.272	0.327	0.439	0.921	NA
1996	0.270	0.324	0.432	0.865	NA
1997	0.268	0.322	0.425	0.818	NA
1998	0.267	0.319	0.419	0.778	NA
1999	0.265	0.316	0.413	0.743	NA
2000	0.264	0.314	0.408	0.713	NA
2001	0.262	0.311	0.402	0.686	5.735
2002	0.261	0.308	0.397	0.661	2.397
2003	0.259	0.306	0.392	0.639	1.762
2004	0.258	0.304	0.387	0.620	1.454
2005	0.256	0.301	0.382	0.601	1.265
2006	0.255	0.299	0.378	0.585	1.133
2007	0.253	0.297	0.373	0.569	1.035
2008	0.252	0.295	0.369	0.555	0.959
2009	0.251	0.293	0.365	0.542	0.896
2010	0.249	0.290	0.361	0.529	0.845
2011	0.248	0.288	0.357	0.518	0.801
2012	0.247	0.286	0.353	0.507	0.763
2013	0.246	0.284	0.350	0.496	0.730
2014	0.244	0.283	0.346	0.487	0.701
2015	0.243	0.281	0.343	0.478	0.675
2016	0.242	0.279	0.340	0.469	0.652

As abandoned underground mines are included for the first time an example calculation has been included in Table 4.1.7.

TABLE 4.1.7 TIER 1 – ABANDONED UNDERGROUND MINES Example Calculation						
	Interval of mine closure					
	1901 – 1925	1926 – 1950	1951 - 1975	1976 – 2000	2001 – Present	Total for inventory year 2005
Number of mines closed per time band	20	15	10	5	1	
Fraction of gassy mines	0.1	0.5	0.75	1.0	1.0	
Emission factor for Inventory year, 2005 (from Table 4.1.6)	0.256	0.301	0.382	0.601	1.265	
Total emissions (Gg CH ₄ per year from Eqn 4.1.10)	0.34	1.51	1.92	2.07	0.85	6.64

Tier 2 – Country- or Basin-Specific Approach

The Tier 2 approach for developing an abandoned mine methane emission inventory follows a similar approach to Tier 1, but it incorporates country- or basin-specific data. The methodology presented below is intended to utilize coal basin-specific or country-specific data wherever possible (for example, for active mine emissions prior to abandonment, for basin-specific parameters for emissions factors, etc.).

In some cases, default parameters have been provided for these values but these should be used only if country-specific or basin-specific data are not available.

Calculate emissions for a given inventory year using Equation 4.1.11:

<p>EQUATION 4.1.11</p> <p>TIER 2 APPROACH FOR ABANDONED UNDERGROUND MINES WITHOUT METHANE RECOVERY AND UTILIZATION</p> $\text{Methane Emissions} = \text{Number of Coal Mines Abandoned Remaining Unflooded} \bullet \text{Fraction of Gassy Mines} \bullet \text{Average Emissions Rate} \bullet \text{Emission Factor} \bullet \text{Conversion Factor}$
--

Where units are:

Emissions of methane (Gg year^{-1})

Emission Rate ($\text{m}^3 \text{ year}^{-1}$)

Emission Factor (dimensionless, see Equation 4.1.11)

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4 . The density is taken at 20°C and 1 atmosphere pressure and has a value of $0.67 \bullet 10^{-6} \text{ Gg m}^{-3}$

If individual mines are known to be completely flooded, they may be assigned an emissions value of zero. Methane emissions reductions due to recovery projects that utilize or flare methane at abandoned mines should be subtracted from the emissions estimate. For either of these cases, it is recommended that a hybrid Tier 2 – Tier 3 approach be used to incorporate such mine-specific information (see the discussion of methane recovery and utilization projects from abandoned mines, Sections 4.1.5.1 and 4.1.5.3).

The basic steps in the Tier 2 approach for abandoned underground coal mines are as follows:

- Determine the approximate time interval(s) when significant numbers of gassy coal mines were closed. Multiple intervals may be used where appropriate. It is recommended that the number of gassy coal mines abandoned during each time interval be estimated using the smallest time intervals possible based on available data. Ideally, for more recent periods, time intervals will decrease (e.g., intervals of ten years prior to 1990; annual intervals since 1990).
- Estimate the total number of abandoned mines in each time interval selected remaining unflooded. If there is no available information on the flooded status of the abandoned mines, assume 100 percent remain unflooded.
- Determine the number (or percentage) of coal mines that would be considered gassy at the time of mine closure.
- For each time interval, determine the average emissions rate. If country or basin-specific data do not exist, low and high estimates for active mine emissions prior to abandonment can be selected from Table 4.1.8.
- For each time interval, calculate an appropriate emissions factor using Equation 4.1.12, based on the difference in years between the estimated data of abandonment and the year of the emissions inventory. Note that default values for this emissions factor equation are provided in Table 4.1.9, but these default values should be used only where country- or basin-specific information are not available.
- Calculate the emissions for each time interval using Equation 4.1.11.
- Sum the emissions for each time interval to derive the total abandoned mine emissions for each inventory year.

TABLE 4.1.8 TIER 2 – ABANDONED UNDERGROUND COAL MINES DEFAULT VALUES FOR ACTIVE MINE EMISSIONS PRIOR TO ABANDONMENT	
Parameter	Emissions, million m ³ /yr
Low	1.3
High	38.8

EQUATION 4.1.12
TIER 2 – ABANDONED UNDERGROUND COAL MINES EMISSION FACTOR

$$\text{Emission Factor} = (1 + aT)^b$$

Where:

a and b are constants determining the decline curve. Country or basin-specific values should be used wherever possible. Default values are provided in Table 4.1.9, below.

T = years elapsed since abandonment (difference of the mid point of the time interval selected and the inventory year) and inventory year.

A separate emission factor must be calculated for each time interval selected. This emission factor is dimensionless.

TABLE 4.1.9 COEFFICIENTS FOR TIER 2 – ABANDONED UNDERGROUND COAL MINES		
Coal Rank	A	b
Anthracite	1.72	-0.58
Bituminous	3.72	-0.42
Sub-bituminous	0.27	-1.00

Tier 3-Mine-Specific Approach

Tier 3 provides a great deal of flexibility. Directly measured emissions, where available, can be used in place of estimates and calculations. Models may be used in conjunction with measured data to estimate time series emissions. Each country may generate their own decline curves or other characterizations based on measurements, known basin-specific coal properties, and/or hydrological models. Equation 4.1.13 describes one possible, approach.

EQUATION 4.1.13
EXAMPLE OF TIER 3 EMISSIONS CALCULATION – ABANDONED UNDERGROUND MINES

$$\text{Methane Emissions} = (\text{Emission rate at closure} \bullet \text{Emission Factor} \bullet \text{Conversion Factor}) - \text{Methane Emissions Reductions from Recovery and Utilisation}$$

Where units are:

Methane Emissions (Gg year⁻¹)

Emission rate at Closure (m³ year⁻¹)

Emission Factor (dimensionless, see Franklin *et al.*, 2004)

Conversion Factor:

This is the density of CH₄ and converts volume of CH₄ to mass of CH₄. The density is taken at 20°C and 1 atmosphere pressure and has a value of 0.67 • 10⁻⁶ Gg m⁻³.

The basic steps in the Tier 3 methodology involve the following:

- Determine a database of mine closures with relevant geological and hydrological information and the approximate abandonment dates (when all active mine ventilation ceased) consistently for all mines in the country's inventory.

- Estimate emissions based on measured emissions and/or an emissions model. This may be based on the average emission rate at time of mine closure, determined by the last measured emission rate (or preferably, an average of several measurements taken the year prior to abandonment), or estimated methane reserves susceptible to release.
- If actual measurements have not been taken at a given mine, emissions may be calculated using an appropriate decline curve or modelling approach for openly vented mines, sealed mines, or flooded mines. Use the selected decline equation or modelling approach for the mine and the number of years between abandonment and the inventory year to calculate emissions or an appropriate emission factor for each mine.
- Sum abandoned mine emissions to develop an annual inventory.

4.1.5.3 CHOICE OF ACTIVITY DATA

Estimating emissions from abandoned mines requires historical data, rather than current activity data. For Tier 1, country experts should estimate the number of mines abandoned by time interval in Table 4.1.5, on the basis of historical data available from appropriate national international agencies or regional experts.

For Tier 2, the total number of abandoned mines and the time period of their abandonment are required. These data may be obtained from appropriate national, state, or provincial agencies, or companies active in the coal industry. If a country consists of more than one coal region or basin, production and emissions data may be disaggregated by region. Expert judgment and statistical analysis may be used to estimate ventilation emissions or specific emissions based on measurements from a limited number of mines (see Franklin et al (2004)).

For Tier 3, abandoned coal mine emissions estimates should be based on detailed data about the characteristics, data of abandonment and geographical location of individual mines. In the absence of direct measurements of the abandoned mine, Tier 3 emissions factors may be based on mine-specific emissions data, including historical emissions data from degasification and ventilation systems when the mine(s) were active (see Franklin et al, 2004).

EMISSIONS REDUCTIONS FROM METHANE RECOVERY AT ABANDONED MINES

Abandoned mines where recovery and utilisation or flaring of abandoned mine methane is taking place should be accounted for by comparing the amount of methane recovered and utilized with the amount expected to have been emitted naturally. The method for accounting for methane recovered from abandoned coal mines is described in Section 4.1.5.1.

The CO₂ emissions produced from combustion of methane from abandoned mine recovery and utilization projects should be included in the energy sector estimates where there is utilisation, or under fugitive abandoned mine emissions where there is flaring. To make this estimate, abandoned mine methane project recovery or production data may be publicly available through appropriate government agencies depending on the end use. This information may be in the form of metered gas sales and is often publicly available in oil and gas industry or governmental databases. An additional 3 to 8 percent of undocumented abandoned mine methane is typically recovered and used as fuel for compression of the gas. The actual percentage of methane used will depend on the efficiency of the compression equipment. The emissions from this energy use should be reported under Volume 2, Chapter 2 ‘Stationary Combustion’. For projects that use recovered methane from abandoned mines for electricity generation, metered flow rates and compression factors, if available, can be used. If public data accurately reflect electricity produced, then the heat rate or efficiency of the electricity generator can be used to determine its fuel consumption rate.

4.1.5.4 COMPLETENESS

The emissions estimates from abandoned underground mines should include all emissions leaking from the abandoned mines. Until recently, there were no methods by which these emissions could be estimated. *Good practice* is to record the date of mine closure and the method of sealing. Data on the size and depth of such mines would be useful for any subsequent estimation.

4.1.5.5 DEVELOPING A CONSISTENT TIME SERIES

It is unlikely that comprehensive mine-by-mine (Tier 3) data will be available for all years. Therefore, in order to prepare hybrid Tier 2 – Tier 3 inventories, as well as Tier 1 or Tier 2 inventories, the number of abandoned mines may need to be estimated for years for which there are sparse data.

These inventory guidelines recommend that methane emissions associated with abandoned mines should be accounted for in the inventory year in which the emissions and recovery operations occur.

For situations where the emissions of greenhouse gases from active underground mines have been well characterized and the mines have passed from being considered 'active' to 'abandoned', data from the active mine emissions (during the year in which the mine was closed) should be collected. Great care should be taken in transferring mines from the active to the abandoned inventory so that no double-counting or omissions occur.

4.1.5.6 UNCERTAINTY ASSESSMENT

TIER 1

The primary causes of the uncertainty related to the Tier 1 methodology include the following:

- *The global nature of the emission factors.* The range of uncertainty of these emission factors is intentionally large to account for the uncertainty in the determining parameters such as mine size, mine depth, and coal rank.
- *Time of abandonment.* Because emissions from abandoned mines are strongly time dependent, selecting a single interval that best represents the dates of closure for all mines is critical in establishing an emissions rate.
- *The activity data.* Both the number of gassy abandoned mines and the amount of coal that has been produced from gassy mines are strongly country-dependent. The uncertainty will be defined by the availability of historic mining and production records.

The total estimated range of uncertainty associated with Tier 1 estimations will depend on each of the factors discussed above. Actual emissions are likely to be in the range of one-third to three times the estimated emissions value.

TIER 2

The primary causes of uncertainty related to the Tier 2 approaches include the following:

- *The country- or basin-specific emission factors.* Uncertainty is associated with the emission factor decline equations for each coal rank. This uncertainty is a function of the inherent variability of gas content, adsorption characteristics, and permeability within a given coal rank.
- The number of mines producing a given coal rank.
- The number of mines abandoned through time.
- The percentage of gassy mines as a function of time.

The total estimated uncertainty associated with Tier 2 estimations depends on the range of uncertainty associated with each of these factors. These parameters should be more narrowly defined than for Tier 1. Thus, total actual emissions are likely to be in the range of one-half to twice the estimated value.

TIER 3

The primary uncertainties associated with emissions inventories generated using the Tier 3 methodology include the following:

- Active mine emission rate
- Decline curve equation or modelling approach that describes the function relating adsorption characteristics and gas content of the coal, mine size, and coal permeability
- Hydrological status of the abandoned mine (flooded or flooding) and condition (sealed or vented).

The Tier 3 methodology has lower associated uncertainty than Tiers 1 and 2 because the emissions inventory is based either on direct measurements or on mine-specific information including active emission rates and mine closure dates. Although the range of uncertainty associated with estimated emissions from an individual mine may be large (in the ± 50 percent range), summing the uncertainty range of a sufficient number of individual mine emissions actually reduces the range of uncertainty of the final inventory, per the central limits theorem (Murtha, 2002), provided the uncertainties are independent. Given the expected range of the number of abandoned coal mines across different countries, the overall uncertainty associated with Tier 3 methodology for

abandoned mines may vary from ± 20 percent for countries with a large number of abandoned mines to ± 30 percent for a country with a fewer number of abandoned mines whose emissions are included in the inventory.

A combination of different Tiers may be used. For example, the emissions from mines abandoned during the first half of the twentieth century may be determined using a Tier 1 method, while emissions from mines abandoned after 1950 may be determined using a Tier 2 method. The Tier 1 and Tier 2 methods will each have their own uncertainty distribution. It is important to properly sum these distributions in order to arrive at the appropriate range of uncertainty for the final emissions inventory.

4.1.6 Completeness for coal mining

There are three remaining gaps in developing a complete inventory for fugitive emissions from coal mining. These are abandoned surface mines, uncontrolled combustion and CO₂ in coal seam gas.

ABANDONED SURFACE MINES

After closure, emissions from abandoned surface mines may include the following:

- The standing highwall
- Leakage from the pit floor
- Low temperature oxidation
- Uncontrolled combustion

At present, no comprehensive methods to quantify these emissions have been developed and therefore they have not been included in these guidelines. They remain subjects for further research.

EMISSIONS FROM UNCONTROLLED COMBUSTION AND BURNING COAL DEPOSITS

While emissions from this source may be significant for an individual coal mine, it is unclear as to how significant these emissions may be for an individual country. In some countries where such fires are widespread, the emissions may be very significant. There are no clear methods available at present to systematically measure or precisely estimate the activity data, though where countries have data on amounts of coal burned, the CO₂ should be estimated on the basis of the carbon content of the coal and reported in the relevant subcategory of 1.B.1.b. It is noted that uncontrolled combustion only due to coal exploration activities is considered here. Care should be taken to avoid double counting with fugitive CH₄ and low oxidation CO₂ emissions.

CO₂ IN COAL MINE GAS

Countries with data available on CO₂ in their coal mine gas should include it with the sub-category used for the corresponding methane emissions.

4.1.7 Inventory Quality Assurance/Quality Control (QA/QC)

4.1.7.1 QUALITY CONTROL AND DOCUMENTATION

EMISSION FACTORS

- **Quality control**
 - a) Tier 1: reviewing the national circumstances and documenting the rationale for selecting specific values.
 - b) Tier 2: checking the equations and calculations used to determine the emissions factor, and ensuring that sampling follows consistent protocols so that conditions are representative and uniform
 - c) Tier 3: working with mine operators to ensure the quality of data from degasification systems. Individual operating mines should already have in place QA/QC procedures for monitoring ventilation emissions.

- **Documentation**

Provide transparent information on the steps to calculate emissions factors or measure emissions, including the numbers and the sources of any data collected.

ACTIVITY DATA

- **Quality control**

Describe activity data collection methods, including an assessment of areas requiring improvement.

- **Documentation**

- a) Comprehensive description of the methods used to collect the activity data
- b) Discussion of potential areas of bias in the data, including a discussion of whether the characteristics are representative of the country

INVENTORY COMPILER REVIEW (QA)

The inventory compiler should ensure that suitable methodologies are used to calculate emissions from coal mining, including use of the highest applicable Tier for a given country, taking into account what are considered *key category* for that country as well as the availability of data. The inventory compiler should ensure that appropriate emission factors are used. For active underground and surface mines, the best available activity data should be used in accordance with the appropriate Tiers, especially the amount of methane recovered and utilized wherever possible. For abandoned mines, the compiler should ensure the most accurate available historical information is used.

INVENTORY COMPILER QC ON COMPILING NATIONAL EMISSIONS

Methods the inventory compiler can employ to provide quality control for the national inventory may include, for example:

- Back-calculating national and regional emission factors from Tier 3 measurement data, where applicable
- Ensuring that emission factors are representative of the country (for Tier 1 and Tier 2)
- Ensuring that all mines are included
- Comparing with national trends to look for anomalies

EXTERNAL INVENTORY QUALITY ASSURANCE (QA/QC) SYSTEMS

The inventory compiler should arrange for an independent, objective review of calculations, assumptions, and/or documentation of the emissions inventory to be performed to assess the effectiveness of the QC programme. The peer review should be performed by expert(s) who are familiar with the source category and who understand inventory requirements.

4.1.7.2 REPORTING AND DOCUMENTATION

It is *good practice* to document and archive all information required to produce the national emissions inventory estimates as outlined in Volume 1, chapter 8 of the *2006 IPCC Guidelines*.

The national inventory report should include summaries of methods used and references to source data such that the reported emissions estimates are transparent and steps in their calculation may be retraced. However, to ensure transparency, the following information should be supplied:

- Emissions by underground, surface, and post-mining components of CH₄ and CO₂ (where appropriate), the method used for each of the sub-source categories, the number of active mines in each sub-source category and the reasons for the chosen emission factors (e.g. depth of mining, data on *in situ* gas contents etc.). The amount of drained gas and the degree of any mitigation or utilisation should be presented with a description of the technology used, where appropriate.
- Activity data: Specify the amount and type of production, underground and surface coal, listing raw and saleable amounts where available.
- Where issues of confidentiality arise, the name of the mine need not be disclosed. Most countries will have more than three mines, so mine-specific production cannot be back calculated from the emission estimates.

It is important to ensure that in the transition of mines from ‘active’ to ‘abandoned’ each mine is included once and only once in the national inventory.

4.2 FUGITIVE EMISSIONS FROM OIL AND NATURAL GAS SYSTEMS

Fugitive emissions from oil and natural gas systems are accounted for in IPCC subcategory 1.B.2 of the energy sector. For reporting purposes, this subcategory is subdivided as shown in Table 4.2.1. The main distinction is made between oil and natural gas systems, with each being subdivided according to the primary type of emissions source, namely: venting, flaring and all other types of fugitive emissions. The latter category is further subdivided into the different parts (or segments) of the oil or gas system according to the type of activity.

The term fugitive emissions is broadly applied here to mean all greenhouse gas emissions from oil and gas systems except contributions from fuel combustion. Oil and natural gas systems comprise all infrastructure required to produce, collect, process or refine and deliver natural gas and petroleum products to market. The system begins at the well head, or oil and gas source, and ends at the final sales point to the consumer. Emissions excluded from this category are as follows:

- Fuel combustion for the production of useful heat or energy by stationary or mobile sources (see Chapters 2 and 3 of the Energy Volume).
- Fugitive emissions from carbon capture and storage projects, the transport and disposal of acid gas from oil and gas facilities by injection into secure underground formations, or the transport, injection and sequestering of CO₂ as part of enhanced oil recovery (EOR), enhanced gas recovery (EGR) or enhanced coal bed methane (ECBM) projects (see Chapter 5 of the Energy Volume on carbon dioxide capture and storage systems).
- Fugitive emissions that occur at industrial facilities other than oil and gas facilities, or that are associated with the end use of oil and gas products at anything other than oil and gas facilities (see the Industrial Processes and Product Use Volume).
- Fugitive emissions from waste disposal activities that occur outside the oil and gas industry (see the Waste Volume).

Fugitive emissions from the oil and gas production portions of EOR, EGR and ECBM projects are part of Category 1.B.2.

When determining fugitive emissions from oil and natural gas systems it may, primarily in the areas of production and processing, be necessary to apply greater disaggregation than is shown in Table 4.2.1 to account better for local factors affecting the amount of emissions (i.e., reservoir conditions, processing/treatment requirements, design and operating practices, age of the industry, market access, regulatory requirements and the level of regulatory enforcement), and to account for changes in activity levels in progressing through the different parts of the system. The percentage contribution by each category in Table 4.2.1 to total fugitive emissions by the oil and gas sector will vary according to a country’s circumstances and the amount of oil and gas imported and exported. Typically, production and processing activities tend to have greater amounts of fugitive emissions as a percentage of throughput than downstream activities. Some examples of the potential distribution of fugitive emissions by subcategory are provided in the API (2004) Compendium.

4.2.1 Overview, description of sources

The sources of fugitive emissions on oil and gas systems include, but are not limited to, equipment leaks, evaporation and flashing losses, venting, flaring, incineration and accidental releases (e.g., pipeline dig-ins, well blow-outs and spills). While some of these emission sources are engineered or intentional (e.g., tank, seal and process vents and flare systems), and therefore relatively well characterised, the quantity and composition of the emissions is generally subject to significant uncertainty. This is due, in part, to the limited use of measurement systems in these cases, and where measurement systems are used, the typical inability of these to cover the wide range of flows and variations in composition that may occur. Even where some of these losses or flows are tracked as part of routine production accounting procedures, there are often inconsistencies in the activities which get accounted for and whether the amounts are based on engineering estimates or measurements. Throughout this chapter, an effort is made to state the precise type of fugitive emission source being discussed,

and to only use the term fugitive emissions or fugitive emission sources when discussing these emissions or sources at a higher, more aggregated, level.

Streams containing pure or high concentrations of CO₂ may occur at oil production facilities where CO₂ is being injected into an oil reservoir for EOR, ECBM or EGR. They may also occur at gas processing, oil refining and heavy oil upgrading facilities as a by-product of gas treating to meet sales or fuel gas specifications, and at refineries and heavy oil upgraders as a by-product of hydrogen production. Where CO₂ occurs as a process by-product it is usually vented to the atmosphere, injected into a suitable underground formation for disposal or supplied for use in EOR projects. Fugitive CO₂ emissions from these streams should be accounted for under the appropriate subcategories of 1.B.2. Fugitive CO₂ emissions from CO₂ capture should be accounted for in the industry where capture occurs, while the fugitive CO₂ emissions from transport, injection and storage activities should be accounted for separately in category 1.C (refer to Chapter 5).

EOR is the recovery of oil from a reservoir by means other than using the natural reservoir pressure. It can begin after a secondary recovery process or at any time during the productive life of an oil reservoir. EOR generally results in increased amounts of oil being removed from a reservoir in comparison to methods using natural pressure or pumping alone. The three major types of enhanced oil recovery operations are chemical flooding (alkaline flooding or micellar-polymer flooding), miscible displacement (CO₂ injection or hydrocarbon injection), and thermal recovery (steamflood or *in-situ* combustion).

TABLE 4.2.1 DETAILED SECTOR SPLIT FOR EMISSIONS FROM PRODUCTION AND TRANSPORT OF OIL AND NATURAL GAS		
IPCC code	Sector name	Explanation
1 B 2	<i>Oil and Natural Gas</i>	Comprises fugitive emissions from all oil and natural gas activities. The primary sources of these emissions may include fugitive equipment leaks, evaporation losses, venting, flaring and accidental releases.
1 B 2 a	Oil	Comprises emissions from venting, flaring and all other fugitive sources associated with the exploration, production, transmission, upgrading, and refining of crude oil and distribution of crude oil products.
1 B 2 a i	Venting	Emissions from venting of associated gas and waste gas/vapour streams at oil facilities
1 B 2 a ii	Flaring	Emissions from flaring of natural gas and waste gas/vapour streams at oil facilities
1 B 2 a iii	All Other	Fugitive emissions at oil facilities from equipment leaks, storage losses, pipeline breaks, well blowouts, land farms, gas migration to the surface around the outside of wellhead casing, surface casing vent bows, biogenic gas formation from tailings ponds and any other gas or vapour releases not specifically accounted for as venting or flaring
1 B 2 a iii 1	<i>Exploration</i>	Fugitive emissions (excluding venting and flaring) from oil well drilling, drill stem testing, and well completions

TABLE 4.2.1(CONTINUED) DETAILED SECTOR SPLIT FOR EMISSIONS FROM PRODUCTION AND TRANSPORT OF OIL AND NATURAL GAS		
IPCC code	Sector name	Explanation
1 B 2 a iii 2	<i>Production and Upgrading</i>	Fugitive emissions from oil production (excluding venting and flaring) occur at the oil wellhead or at the oil sands or shale oil mine through to the start of the oil transmission system. This includes fugitive emissions related to well servicing, oil sands or shale oil mining, transport of untreated production (i.e. , well effluent, emulsion, oil shale and oilsands) to treating or extraction facilities, activities at extraction and upgrading facilities, associated gas re-injection systems and produced water disposal systems. Fugitive emissions from upgraders are grouped with those from production rather than those from refining since the upgraders are often integrated with extraction facilities and their relative emission contributions are difficult to establish. However, upgraders may also be integrated with refineries, co-generation plants or other industrial facilities and their relative emission contributions can be difficult to establish in these cases
1 B 2 a iii 3	<i>Transport</i>	Fugitive emissions (excluding venting and flaring) related to the transport of marketable crude oil (including conventional, heavy and synthetic crude oil and bitumen) to upgraders and refineries. The transportation systems may comprise pipelines, marine tankers, tank trucks and rail cars. Evaporation losses from storage, filling and unloading activities and fugitive equipment leaks are the primary sources of these emissions
1 B 2 a.iii 4	<i>Refining</i>	Fugitive emissions (excluding venting and flaring) at petroleum refineries. Refineries process crude oils, natural gas liquids and synthetic crude oils to produce final refined products (e.g., primarily fuels and lubricants). Where refineries are integrated with other facilities (for example, upgraders or co-generation plants) their relative emission contributions can be difficult to establish.
1 B 2 a iii 5	<i>Distribution of Oil Products</i>	This comprises fugitive emissions (excluding venting and flaring) from the transport and distribution of refined products, including those at bulk terminals and retail facilities. Evaporation losses from storage, filling and unloading activities and fugitive equipment leaks are the primary sources of these emissions
1 B 2 a iii 6	<i>Other</i>	Fugitive emissions from oil systems (excluding venting and flaring) not otherwise accounted for in the above categories. This includes fugitive emissions from spills and other accidental releases, waste oil treatment facilities and oilfield waste disposal facilities
1 B 2 b	Natural Gas	Comprises emissions from venting, flaring and all other fugitive sources associated with the exploration, production, processing, transmission, storage and distribution of natural gas (including both associated and non-associated gas).
1 B 2 b i	Venting	Emissions from venting of natural gas and waste gas/vapour streams at gas facilities

TABLE 4.2.1(CONTINUED) DETAILED SECTOR SPLIT FOR EMISSIONS FROM PRODUCTION AND TRANSPORT OF OIL AND NATURAL GAS		
IPCC code	Sector name	Explanation
1 B 2 b ii	Flaring	Emissions from flaring of natural gas and waste gas/vapour streams at gas facilities.
1 B 2 b iii	All Other	Fugitive emissions at natural gas facilities from equipment leaks, storage losses, pipeline breaks, well blowouts, gas migration to the surface around the outside of wellhead casing, surface casing vent bows and any other gas or vapour releases not specifically accounted for as venting or flaring.
1B 2 b iii 1	Exploration	Fugitive emissions (excluding venting and flaring) from gas well drilling, drill stem testing and well completions
1B 2 b iii 2	Production	Fugitive emissions (excluding venting and flaring) from the gas wellhead through to the inlet of gas processing plants, or, where processing is not required, to the tie-in points on gas transmission systems. This includes fugitive emissions related to well servicing, gas gathering, processing and associated waste water and acid gas disposal activities
1 B 2 b iii 3	Processing	Fugitive emissions (excluding venting and flaring) from gas processing facilities
1 B 2 b iii 4	Transmission and Storage	Fugitive emissions from systems used to transport processed natural gas to market (i.e., to industrial consumers and natural gas distribution systems). Fugitive emissions from natural gas storage systems should also be included in this category. Emissions from natural gas liquids extraction plants on gas transmission systems should be reported as part of natural gas processing (Sector 1.B.2.b.iii.3). Fugitive emissions related to the transmission of natural gas liquids should be reported under Category 1.B.2.a.iii.3
1 B 2 b iii 5	Distribution	Fugitive emissions (excluding venting and flaring) from the distribution of natural gas to end users
1 B 2 b iii 6	Other	Fugitive emissions from natural gas systems (excluding venting and flaring) not otherwise accounted for in the above categories. This may include emissions from well blowouts and pipeline ruptures or dig-ins
1 B 3	<i>Other emissions from Energy Production</i>	Emissions from geo thermal energy production and other energy production not included in 1.B.1 or 1.B.2

4.2.2 Methodological issues

Fugitive emissions are a direct source of greenhouse gases due to the release of methane (CH₄) and formation carbon dioxide (CO₂) (i.e., CO₂ present in the produced oil and gas when it leaves the reservoir), plus some CO₂ and nitrous oxide (N₂O) from non-productive combustion activities (primarily waste gas flaring). As is done for fuel combustion (see Chapter 1 of this Volume), CO₂ emissions are calculated in Tier 1 assuming that all hydrocarbons are fully oxidized. If information is available on partial oxidation, this can be taken into account in higher Tiers.

Venting comprises all engineered or intentional discharges of waste gas streams and process by-products to the atmosphere, including emergency discharges. These releases may occur on either a continuous or intermittent basis, and may include the following:

- Use of pressurized natural gas instead of compressed air as the supply medium for pneumatic devices (e.g., chemical injection pumps, starter motors on compressor engines and instrument control loops).
- Pressure relief and disposal of off-specification product during process upsets.
- Purging and blowdown events related to maintenance and tie-in activities.

- Disposal of off-gas streams from oil and gas treatment units (e.g., still-column off-gas from glycol dehydrators, emulsion treater overheads and stabilizer overheads).
- Gas releases from drilling, well-testing and pipeline pigging activities.
- Disposal of waste associated gas at oil production facilities and casing-head gas at heavy oil wells where there is no gas conservation or re-injection.
- Solution gas emissions from storage tanks, evaporation losses from process sewers, API separators, dissolved air flotation units, tailings ponds and storage tanks, and biogenic gas formation from tailings ponds.
- Discharge of CO₂ extracted from the produced natural gas or produced as a process byproduct.

Some or all of the vented gas may be captured for storage or utilization. In this instance, the inventory of vented emissions should include only the net emissions to the atmosphere.

Flaring means broadly all burning of waste natural gas and hydrocarbon liquids by flares or incinerators as a disposal option rather than for the production of useful heat or energy. The decision on whether to vent or flare depends largely on the amount of gas to be disposed of and the specific circumstances (e.g., public, environmental and safety issues as well as local regulatory requirements). Normally, waste gas is only vented if it is non-odorous and non-toxic, and even then may often be flared. Flaring is most common at production, processing, upgrading and refining facilities. Waste gas volumes are usually vented on gas transmission systems and may be either vented or flared on gas distribution systems, depending on the circumstances and the company's policies. Sometimes fuel gas may be used to enrich a waste gas stream; so it will support stable combustion during flaring. Fuel gas may also be used for other purposes where it may ultimately be vented or flared, such as purge or blanket gas and supply gas for gas-operated devices (e.g., for instrument controllers). The emissions from these types of fuel uses should be reported under the appropriate venting and flaring subcategories rather than under Category 1.A (Fuel Combustion Activities).

Formation CO₂ removed from natural gas by the sweetening units at gas processing plants and released to the atmosphere is a fugitive emission and should be reported under subcategory 1.B.2.b.i. The CO₂ resulting from the production of hydrogen at refineries and heavy oil/bitumen upgraders should be reported under subcategory 1.B.2.a.i. Care should be taken to ensure that the feedstock for the hydrogen plant is not also reported as fuel in these cases.

Fugitive emissions from oil and natural gas systems are often difficult to quantify accurately. This is largely due to the diversity of the industry, the large number and variety of potential emission sources, the wide variations in emission-control levels and the limited availability of emission-source data. The main emission assessment issues are:

- The use of simple production-based emission factors introduces large uncertainty;
- The application of rigorous bottom-up approaches requires expert knowledge and detailed data that may be difficult and costly to obtain;
- Measurement programmes are time consuming and very costly to perform.

If a rigorous bottom-up approach is chosen, then it is *good practice* to involve technical representatives from the industry in the development of the inventory.

4.2.2.1 CHOICE OF METHOD, DECISION TREES, TIERS

There are three methodological tiers for determining fugitive emissions from oil and natural gas systems, as set out in Section 4.2.2.2. It is *good practice* to disaggregate the activities into Major Categories and Subcategories in the Oil and Gas Industry (see Table 4.2.2 in Section 4.2.2.2), and then evaluate the emissions separately for each of these. The methodological tier applied to each segment should be commensurate with the amount of emissions and the available resources. Consequently, it may be appropriate to apply different methodological tiers to different categories and subcategories, and possibly even include actual emission measurement or monitoring results for some larger sources. The overall approach, over time, should be one of progressive refinement to address the areas of greatest uncertainty and consequence, and to capture the impact of control measures.

Figure 4.2.1 provides a general decision tree for selecting an appropriate approach for a given segment of the natural gas industry. The decision tree is intended to be applied successively to each subcategory within the

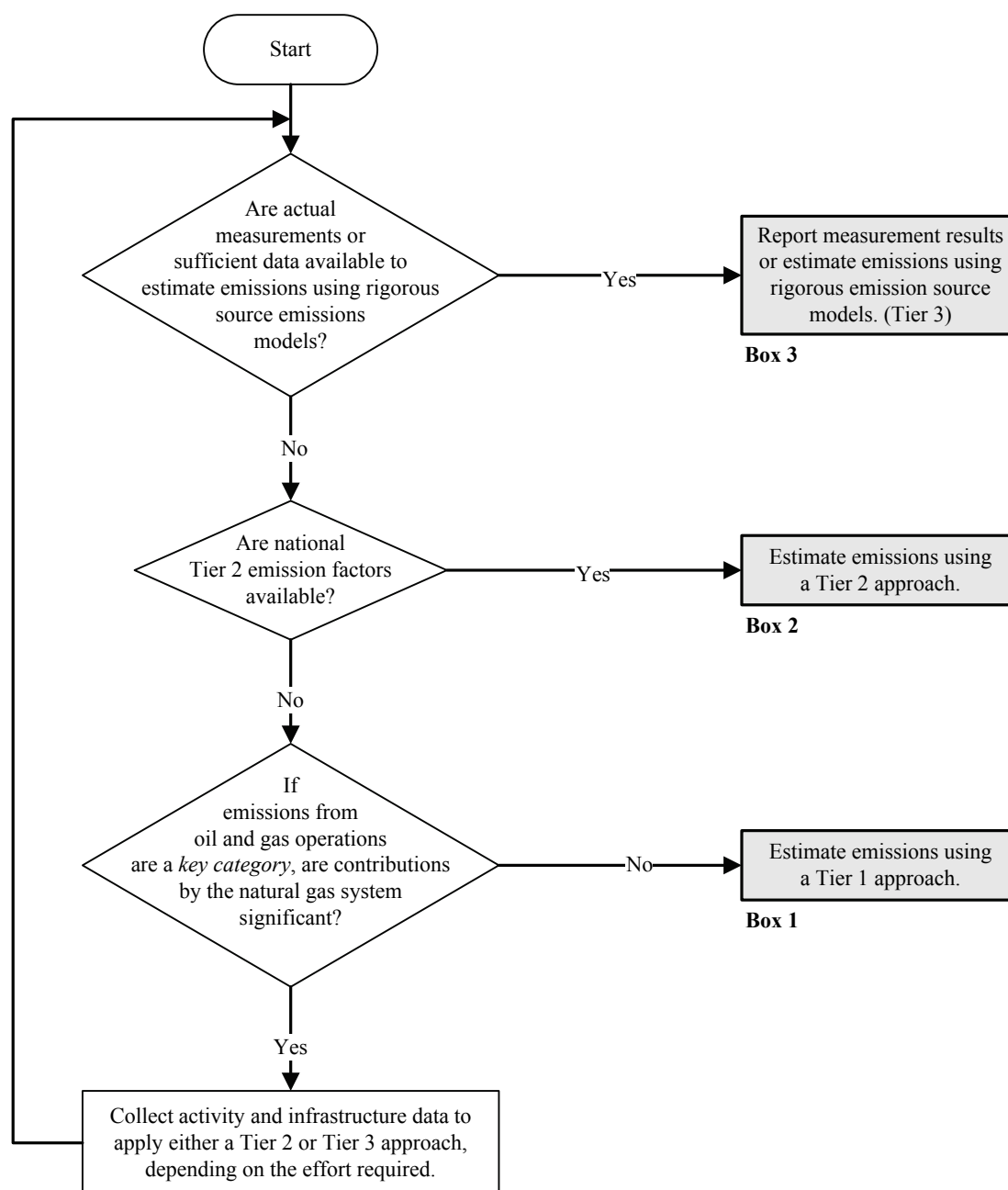
natural gas system (e.g., gas production, then gas processing, then gas transmission, then gas distribution). The basic decision process is as follows:

- check if the detailed data needed to apply a Tier 3 approach are readily available, and if so, then apply a Tier 3 approach (i.e., regardless of whether the category is key and the subcategory is significant), otherwise, if these data are not readily available:
- check if the detailed data needed to apply a Tier 2 approach are readily available, and if so, then apply a Tier 2 approach, otherwise, if these data are not readily available:
- check to see if the category is key and the specific subcategory being considered is significant based on the IPCC definitions of key and significant, and if so, go back and gather the data needed to apply a Tier 3 or Tier 2 approach, otherwise, if the subcategory is not significant:
- apply a Tier 1 approach.

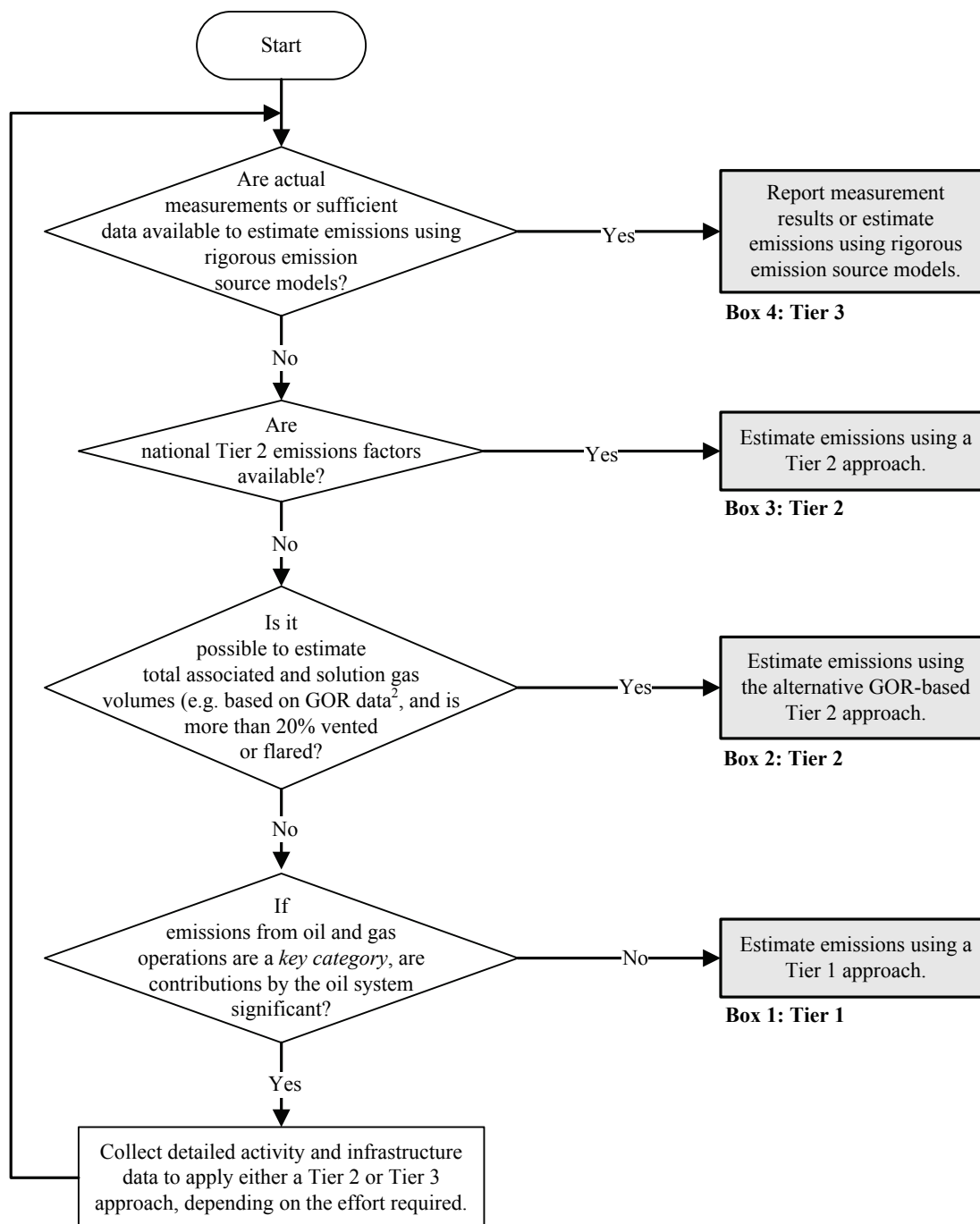
The ability to use a Tier 3 approach will depend on the availability of detailed production statistics and infrastructure data (e.g., information regarding the numbers and types of facilities and the amount and type of equipment used at each site), and it may not be possible to apply it under all circumstances. A Tier 1 approach is the simplest method to apply but is susceptible to substantial uncertainties and may easily be in error by an order-of-magnitude or more. For this reason, it should only be used as a last resort option. Where a Tier 3 approach is used in one year and the results are used to develop Tier 2 emission factors for use in other years, the applied methodology should be reported as Tier 2 in those other years.

Similarly, Figures 4.2.2 and 4.2.3 apply to crude oil production and transport systems, and to oil upgraders and refineries, respectively.

Where a country has estimated fugitive emissions from oil and gas systems based on a compilation of estimates reported by individual oil and gas companies, this may either be a Tier 2 or Tier 3 approach, depending on the actual approaches applied by individual companies and facilities. In both cases, care needs to be taken to ensure there is no omitting or double counting of emissions.

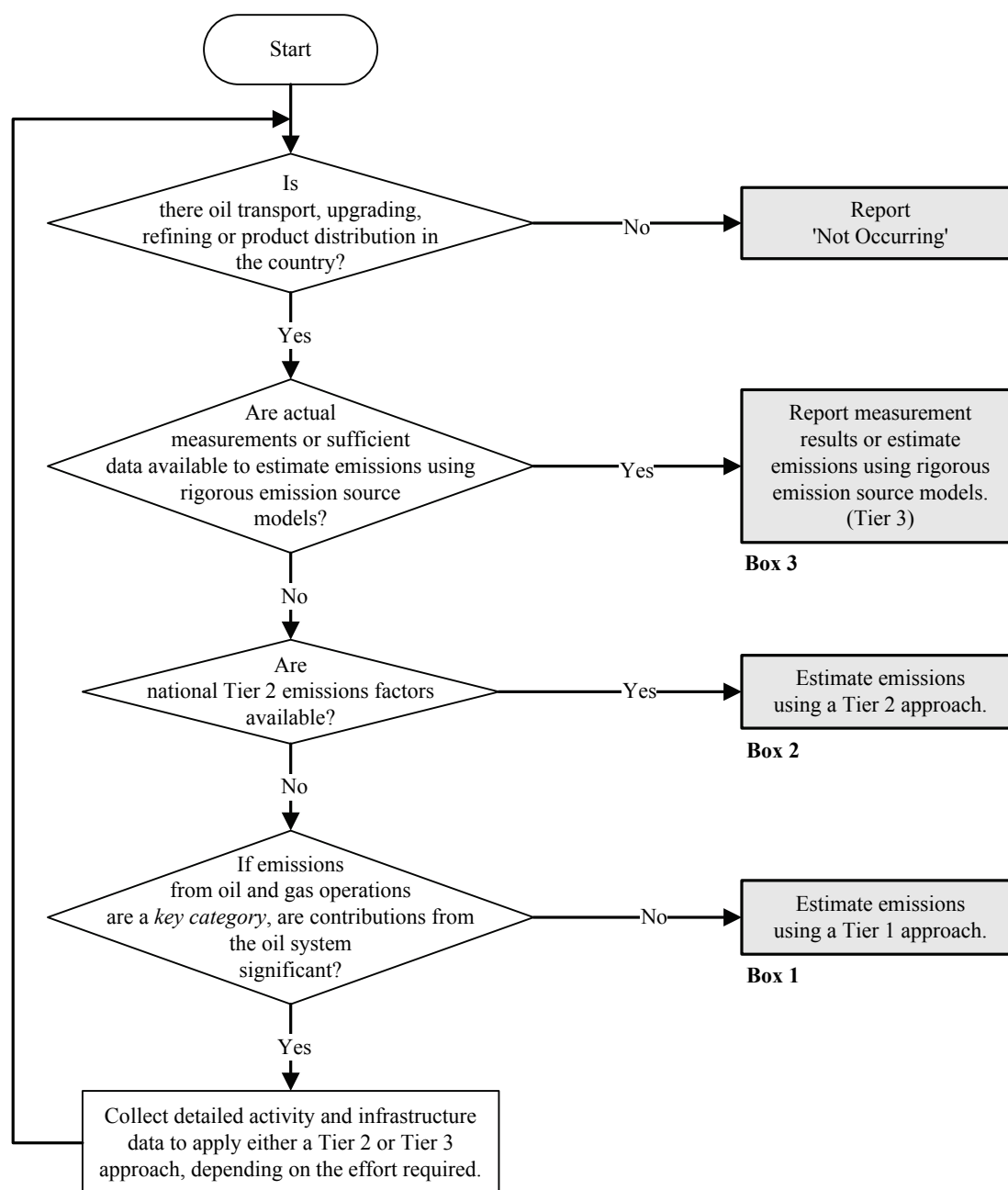
Figure 4.2.1 **Decision tree for natural gas systems**

Note: See Volume 1 Chapter 4, “Methodological Choice and Key Categories” (noting section 4.1.2 on limited resources) for discussion of key categories and use of decision trees

Figure 4.2.2 Decision tree for crude oil production

Note 1: See Volume 1 Chapter 4, “Methodological Choice and Key Categories” (noting section 4.1.2 on limited resources) for discussion of key categories and use of decision trees

Note 2: GOR stands for gas/Oil Ratio (see Section 4.2.2.2).

Figure 4.2.3 Decision tree for crude oil transport, refining and upgrading

Note 1: See Volume 1 Chapter 4, “Methodological Choice and Key Categories” (noting section 4.1.2 on limited resources) for discussion of key categories and use of decision trees

4.2.2.2 CHOICE OF METHOD

The three methodological tiers for estimating fugitive emissions from oil and natural gas systems are described below.

TIER 1

Tier 1 comprises the application of appropriate default emission factors to a representative activity parameter (usually throughput) for each applicable segment or subcategory of a country's oil and natural gas industry and should only be used for non-key sources. The application of a Tier1 approach is done using Equations 4.2.1 and 4.2.2 presented below:

EQUATION 4.2.1
TIER 1: ESTIMATING FUGITIVE EMISSIONS FROM AN INDUSTRY SEGMENT

$$E_{gas, industry segment} = A_{industry segment} \bullet EF_{gas, industry segment}$$

EQUATION 4.2.2
TIER 1: TOTAL FUGITIVE EMISSIONS FROM INDUSTRY SEGMENTS

$$E_{gas} = \sum_{industry segments} E_{gas, industry segment}$$

Where:

$$\begin{aligned} E_{gas, industry segment} &= \text{Annual emissions (Gg)} \\ EF_{gas, industry segment} &= \text{emission factor (Gg/unit of activity),} \\ A_{industry segment} &= \text{activity value (units of activity),} \end{aligned}$$

The industry segments to be considered are listed in Table 4.2.2. Not all segments will necessarily apply to all countries. For example, a country that only imports natural gas and does not produce any will probably only have gas transmission and distribution. The available Tier 1 default emission factors are presented in Tables 4.2.4 and 4.2.5 in Section 4.2.2.3. These factors have been related to throughput, because production, imports and exports are the only national oil and gas statistics that are consistently available. On a small scale, fugitive emissions are completely independent of throughput. The best relation for estimating emissions from fugitive equipment leaks is based on the number and type of equipment components and the type of service, which is a Tier-3 approach. On a larger scale, there is a reasonable relationship between the amount of production and the amount of infrastructure that exists. Consequently, the reliability of the presented Tier 1 factors for oil and gas systems will depend on the size of a country's oil and gas industry. The larger the industry, the more important its fugitive emissions contribution will be and the more reliable the presented Tier 1 emission factors will be.

Besides having a high degree of uncertainty, the Tier 1 approach for oil and natural gas systems does not allow countries to show any real changes in emission intensities over time (e.g., due to the implementation of control measures or changing source characteristics). Rather, emissions become fixed in proportion to the activity levels, and the changes in reported emissions over time simply reflect the changes in activity levels. Tier 2 and 3 approaches are needed to capture real changes in emission intensities. However, going to these higher tier approaches requires considerably more effort and, for Tier 3 approaches, more detailed activity data. The completeness and accuracy of the input information used for higher tier approaches will generally need to be comparable to, or better than, the values of the input information used for the lower methodological tiers in order to achieve more accurate results.

Fugitive greenhouse gas emissions from oil and gas related CO₂ capture and injection activities (e.g., acid gas injection and EOR projects involving CO₂ floods) will normally be small compared to the amount of CO₂ being injected (e.g., less than 1 percent of the injection volumes). At the Tier 1 or 2 methodology levels they are indistinguishable from fugitive greenhouse gas emissions by the associated oil and gas activities. The emission contributions from CO₂ capture and injection were included in the original data upon which the presented Tier 1 factors were developed (i.e., through the inclusion of acid gas injection and EOR activities, along with conventional oil and gas activities, with consideration of CO₂ concentrations in the leaked, vented and flared natural gases, vapours and acid gases). Losses from CO₂ capture should be accounted for in the industry where capture occurs, while losses from, transport, injection and storage activities are assessed separately in Chapter 5.

TABLE 4.2.2
MAJOR CATEGORIES AND SUBCATEGORIES IN THE OIL AND GAS INDUSTRY

Industry Segment	Sub-Categories
Well Drilling	All
Well Testing	All
Well Servicing	All
Gas Production	Dry Gas ^a
	Coal Bed Methane (Primary and Enhanced Production)
	Other enhanced gas recovery
	Sweet Gas ^b
	Sour Gas ^c
Gas Processing	Sweet Gas Plants
	Sour Gas Plants
	Deep-cut Extraction Plants ^d
Gas Transmission & Storage	Pipeline Systems
	Storage Facilities
Gas Distribution	Rural Distribution
	Urban Distribution
Liquefied Gases Transport	Condensate
	Liquefied Petroleum Gas (LPG)
	Liquefied Natural Gas (LNG) (including associated liquefaction and gasification facilities)
Oil Production	Light and Medium Density Crude Oil (Primary, Secondary and Tertiary Production)
	Heavy Oil (Primary and Enhanced Production)
	Crude Bitumen (Primary and Enhanced Production)
	Synthetic Crude Oil (From Oil Sands)
	Synthetic Crude Oil (From Oil Shales)
Oil Upgrading	Crude Bitumen
	Heavy Oil
Waste Oil Reclaiming	All
Oil Transport	Marine
	Pipelines
	Tanker Trucks and Rail Cars
Oil Refining	Heavy Oil
	Conventional and Synthetic Crude Oil
Refined Product Distribution	Gasoline
	Diesel
	Aviation Fuel
	Jet Kerosene
	Gas Oil (Intermediate Refined Products)

- ^a Dry gas is natural gas that does not require any hydrocarbon dew-point control to meet sales gas specifications. However, it may still require treating to meet sales specifications for water and acid gas (i.e. H₂S and CO₂) content. Dry gas is usually produced from shallow (less than 1000 m deep) gas wells.
- ^b Sweet gas is natural gas that does not contain any appreciable amount of H₂S (i.e. does not require any treatment to meet sales gas requirements for H₂S).
- ^c Sour gas is natural gas that must be treated to satisfy sales gas restrictions on H₂S content.
- ^d Deep-cut extraction plants are gas processing plants located on gas transmission systems which are used to recover residual ethane and heavier hydrocarbons present in the natural gas.

TIER 2

Tier 2 consists of using Tier 1 equations (4.2.1 and 4.2.2) with country-specific, instead of default, emission factors. It should be applied to key categories where the use of a Tier 3 approach is not practicable. The country-specific values may be developed from studies and measurement programmes, or be derived by initially applying a Tier 3 approach and then back-calculating Tier 2 emission factors using Equations 4.2.1 and 4.2.2. For example, some countries have been applying Tier 3 approaches for particular years and have then used these results to develop Tier 2 factors for use in subsequent years until the next Tier 3 assessment is performed. In general, all emission factors (including Tier 1 and Tier 2 values) should be periodically re-affirmed or updated. The frequency at which such updates are performed should be commensurate with the rates at which new technologies, practices, standards and other relevant factors (e.g., changes in the types of oil and gas activities, aging of the fields and facilities, etc.) are penetrating the industry. Since new emission factors developed in this manner account for real changes within the industry, they should not be applied backwards through the time series.

An alternative Tier 2 approach that may be applied to estimate the amount of venting and flaring emissions from the production segment of oil systems consists of performing a mass balance using country-specific production volumes, gas-to-oil ratios (GORs), gas compositions and information regarding the level of gas conservation. This approach may be applied using equations 4.2.3 to 4.2.8 below and is appropriate where reliable venting and flaring values are unavailable but representative GOR data can be obtained and venting and flaring emissions are expected to be the dominant sources of fugitive emissions (i.e., most of the associated gas production is not being captured/conserved or utilized). Under these circumstances, the alternative Tier 2 approach may also be used to estimate fugitive greenhouse gas emissions from EOR activities provided representative associated gas and vapour analyses are available and contributions due to fugitive emissions from the CO₂ transport and injection systems are small in comparison (as would normally be expected). Where the alternative Tier 2 approach is applied, any reported venting or flaring data that may be available for the target sources should not also be accounted for as this would result in double counting. However, it is *good practice* to compare the estimated gas vented and flared volumes determined using the GOR data to the available reported vented and flared data to identify and resolve any potential anomalies (i.e., the calculated volumes should be comparable to the available reported data, or greater if these latter data are believed to be incomplete).

Table 4.2.3 shows examples of typical GOR values for oil wells from selected locations. Actual GOR values may vary from 0 to very high values depending on the local geology, state of the producing reservoir and the rate of production. Notwithstanding this, average GOR values for large numbers of oil wells tend to be more predictable. A review of limited data for a number of countries and regions indicates that average GOR values for conventional oil production would usually be in the range of about 100 to 350 m³/m³, depending on the location.

TABLE 4.2.3
TYPICAL RANGES OF GAS-TO-OIL RATIOS FOR DIFFERENT TYPES OF PRODUCTION

Type of Crude Oil Production	Location	Typical GOR Values (m ³ /m ³)	
		Range ⁶	Average
Conventional Oil	Alaska (Prudhoe Bay)	142 to 6234 ^{2,3}	NA
	Canada	0 to 2,000+ ^{1,2}	Not Available (NA)
	Qatar (Onshore, 1 Oil Field)	167 to 184 ⁴	173
	Qatar (Offshore, 3 Oil Fields)	316 to 386 ⁴	333
Primary Heavy Oil	Canada	0 to 325+ ^{1,5}	NA
Thermal Heavy Oil	Canada	0 to 90 ¹	NA
Crude Bitumen	Canada	0 to 20 ¹	NA
¹ Source: Based on unpublished data for a selection of wells in Canada. ² Appreciably higher GOR values may occur, but these wells are normally either classified as gas wells or there is a significant gas cap present and the gas would normally be reinjected until all the recoverable oil had been produced. ³ Source: Mohaghegh, S.D., L.A. Hutchins and C.D. Sisk. 2002. Prudhoe Bay Oil Production Optimization: Using Virtual intelligence Techniques, Stage One: Neural Model Building. Presented at the SPE Annual Technical Conference and Exhibition held in San Antonio, Texas, 29 September–2 October 2002. ⁴ Source: Corporate HSE, Qatar Petroleum, Qatar-Doha 2004. ⁵ Values as high as 7,160 m ³ /m ³ have been observed for some wells where there is a significant gas cap present. Gas reinjection is not done in these applications. The gas is conserved, vented or flared. ⁶ Referenced at standard conditions of 15°C and 101.325 kPa.			

To apply a mass balance method in the alternative Tier 2 approach, it is necessary to consider the fate of all of the produced gas and vapour. This is done, in part, through the application of a conservation efficiency (CE) factor which expresses the amount of the produced gas and vapour that is captured and used for fuel, produced into gas gathering systems or re-injected. A CE value of 1.0 means all gas is conserved, utilized or re-injected and a value of 0 means all of the gas is either vented or flared. Values may be expected to range from about 0.1 to 0.95. The lower limit applies where only process fuel is drawn from the produced gas and the rest is vented or flared. A value of 0.95 reflects circumstances where there is, generally, good access to gas gathering systems and local regulations emphasize vent and flare gas reduction.

EQUATION 4.2.3

ALTERNATIVE TIER 2 APPROACH (EMISSIONS DUE TO VENTING)

$$E_{\text{gas,oil prod, venting}} = GOR \bullet Q_{OIL} \bullet (1 - CE) \bullet (1 - X_{\text{Flared}}) \bullet M_{\text{gas}} \bullet y_{\text{gas}} \bullet 42.3 \times 10^{-6}$$

EQUATION 4.2.4

ALTERNATIVE TIER 2 APPROACH (CH₄ EMISSIONS DUE TO FLARING)

$$E_{CH_4, \text{oil prod, flaring}} = GOR \bullet Q_{OIL} \bullet (1 - CE) \bullet X_{\text{Flared}} \bullet (1 - FE) \bullet M_{CH_4} \bullet y_{CH_4} \bullet 42.3 \times 10^{-6}$$

EQUATION 4.2.5**ALTERNATIVE TIER 2 APPROACH (CO₂ EMISSIONS DUE TO FLARING)**

$$E_{CO_2, oil prod, flaring} = GOR \cdot Q_{OIL} \cdot (1 - CE) \cdot X_{Flared} \cdot M_{CO_2} \cdot [y_{CO_2} + (Nc_{CH_4} \cdot y_{CH_4} + Nc_{NMVOC} \cdot y_{NMVOC})(1 - X_{Soot})] \cdot 4.23 \times 10^{-6}$$

EQUATION 4.2.6**CH₄ EMISSIONS FROM FLARING AND VENTING**

$$E_{CH_4, oil prod} = E_{CH_4, oil prod, venting} + E_{CH_4, oil prod, flaring}$$

EQUATION 4.2.7**CO₂ EMISSIONS FROM VENTING AND FLARING**

$$E_{CO_2, oil prod} = E_{CO_2, oil prod, venting} + E_{CO_2, oil prod, flaring}$$

EQUATION 4.2.8**N₂O EMISSIONS FROM FLARING**

$$E_{N_2O, oil prod, flaring} = GOR \cdot Q_{OIL} (1 - CE) X_{Flared} EF_{N_2O}$$

Where:

$E_{i, oil prod, venting}$	= Direct amount (Gg/y) of GHG gas i emitted due to venting at oil production facilities.
$E_{i, oil prod, flaring}$	= Direct amount (Gg/y) of GHG gas i emitted due to flaring at oil production facilities.
GOR	= Average gas-to-oil ratio (m ³ /m ³) referenced at 15°C and 101.325 kPa.
Q_{OIL}	= Total annual oil production (10 ³ m ³ /y).
M_{gas}	= Molecular weight of the gas of interest (e.g., 16.043 for CH ₄ and 44.011 for CO ₂).
$N_{C,i}$	= Number of moles of carbon per mole of compound i (i.e., 1 for CH ₄ , 2 for C ₂ H ₆ , 3 for C ₃ H ₈ , 1 for CO ₂ , 2.1 to 2.7 for the NMVOC fraction in natural gas and 4.6 for the NMVOC fraction of crude oil vapours)
y_i	= Mol or volume fraction of the associated gas that is composed of substance i (i.e., CH ₄ , CO ₂ or NMVOC).
CE	= Gas conservation efficiency factor.
X_{Flared}	= Fraction of the waste gas that is flared rather than vented. With the exception of primary heavy oil wells, usually most of the waste gas is flared.
FE	= flaring destruction efficiency (i.e., fraction of the gas that leaves the flare partially or fully burned). Typically, a value of 0.995 is assumed for flares at refineries and a value 0.98 is assumed for those used at production and processing facilities.
X_{soot}	= fraction of the non-CO ₂ carbon in the input waste gas stream that is converted to soot or particulate matter during flaring. In the absence of any applicable data this value may be assumed to be 0 as a conservative approximation.
EF_{N_2O}	= emission factor for N ₂ O from flaring (Gg/10 ³ m ³ of associated gas flared). Refer to the IPCC emission factor database (EFDB), manufacturer's data or other appropriate sources for the value of this factor.
42.3×10^{-6}	= is the number of kmol per m ³ of gas referenced at 101.325 kPa and 15°C (i.e. 42.3×10^{-3} kmol/m ³) times a unit conversion factor of 10 ⁻³ Gg/Mg which brings the results of each applicable equation to units of Gg/y.

The values of $E_{CH_4, \text{ oil prod, venting}}$ and $E_{CO_2, \text{ oil prod, venting}}$ in Equations 4.2.6 and 4.2.7 are estimated using Equation 4.2.3.

It should be noted that Equation 4.2.5 accounts for emissions of CO₂ using a similar approach to what is done for fuel combustion in Section 1.3 of the Introduction chapter of the Energy Volume. The term y_{CO_2} in this equation effectively accounts for the amount of raw (or formation CO₂) present in the waste gas being flared. The terms $N_{CH_4} \bullet y_{CH_4}$ and $N_{NMVOC} \bullet y_{NMVOC}$ in Equation 4.2.5 account for the amount of CO₂ produced per unit of CH₄ and NMVOC oxidized.

TIER 3

Tier 3 comprises the application of a rigorous bottom-up assessment by primary type of source (e.g., venting, flaring, fugitive equipment leaks, evaporation losses and accidental releases) at the individual facility level with appropriate accounting of contributions from temporary and minor field or well-site installations. It should be used for *key categories* where the necessary activity and infrastructure data are readily available or are reasonable to obtain. Tier 3 should also be used to estimate emissions from surface facilities where EOR, EGR and ECBM are being used in association with CCS. Approaches that estimate emissions at a less disaggregated level than this (e.g., relate emissions to the number of facilities or the amount of throughput) are deemed to be equivalent to a Tier 1 approach if the applied factors are taken from the general literature, or a Tier 2 approach if they are country-specific values.

The key types of data that would be utilized in a Tier 3 assessment would include the following:

- Facility inventory, including an assessment of the type and amount of equipment or process units at each facility, and major emission controls (e.g., vapour recovery, waste gas incineration, etc.).
- Inventory of wells and minor field installations (e.g., field dehydrators, line heaters, well site metering, etc.).
- Country-specific flare, vent and process gas analyses for each subcategory.
- Facility-level acid gas production, analyses and disposition data.
- Reported atmospheric releases due to well blow-outs and pipeline ruptures.
- Country-specific emission factors for fugitive equipment leaks, unaccounted/unreported venting and flaring, flashing losses at production facilities, evaporation losses, etc.
- The amount and composition of acid gas that is injected into secure underground formations for disposal.

Oil and gas projects that involve CO₂ injection as a means of enhancing production (e.g., EOR, EGR and ECBM projects) or as a disposal option (e.g., acid gas injection at sour gas processing plants) should distinguish between the CO₂ capture, transport, injection and sequestering part of the project, and the oil and gas production portion of the project. The net amount of CO₂ sequestered and the fugitive emissions from the CO₂ systems should be determined based on the criteria specified in Chapter 5 for CO₂ capture and storage. Any fugitive emissions from the oil and gas systems in these projects should be assessed based on the guidance provided here in Chapter 4 and will exhibit increasing concentrations of CO₂ over time in the emitted natural gas and hydrocarbon vapours. Accordingly, the applied emission factors may need to be periodically updated to account for this fact. Also, care should be taken to ensure that proper total accounting of all CO₂ between the two portions of the project occurs.

4.2.2.3 CHOICE OF EMISSION FACTOR

TIER 1

The available Tier 1 default emission factors are presented in Tables 4.2.4 and 4.2.5. All of the presented emission factors are expressed in units of mass emissions per unit volume of oil or gas throughput. While some types of fugitive emissions correlate poorly with, or are unrelated to, throughput on an individual source basis (e.g., fugitive equipment leaks), the correlations with throughput become more reasonable when large populations of sources are considered. Furthermore, throughput statistics are the most consistently available activity data for use in Tier 1 calculations.

Table 4.2.4 should only be applied to systems designed, operated and maintained to North American and Western European standards. Table 4.2.5 generally applies to systems in developing countries and countries with economies in transition where there are much greater amounts of fugitive emissions per unit of activity (often by an order of magnitude or more). The reasons for the greater emissions in these cases may include less stringent design standards, use of lower quality components, restricted access to natural gas markets, and, in some cases,

artificially low energy pricing resulting in reduced energy conservation. Reference should also be made to the IPCC emission factor database (EFDB) since it would contain the values for higher tier emission factors.

TABLE 4.2.4
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS
IN DEVELOPED COUNTRIES^{a,b}

Category	Sub-category ^c	Emission source	IPCC Code	CH ₄		CO ₂ ¹		NMVOC		N ₂ O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
Well Drilling	All	Flaring and Venting	1.B.2.a.ii or 1.B.2.b.ii	3.3E-05	±100%	1.0E-04	±50%	8.7E-07	±100%	ND	ND	Gg per 10 ³ m ³ total oil production
				5.1E-05	±50%	9.0E-03	±50%	1.2E-05	±50%	6.8E-08	-10 to +1000%	Gg per 10 ³ m ³ total oil production
				1.1E-04	±50%	1.9E-06	±50%	1.7E-05	±50%	ND	ND	Gg per 10 ³ m ³ total oil production
Gas Production	All	Fugitives ^d	1.B.2.b.iii.2	3.8E-04 to 2.3E-03	±100%	1.4E-05 to 8.2E-05	±100%	9.1E-05 to 5.5E-04	±100%	NA	NA	Gg per 10 ⁶ m ³ gas production
				7.6E-07	±25%	1.2E-03	±25%	6.2E-07	±25%	2.1E-08	-10 to +1000%	Gg per 10 ⁶ m ³ gas production
Gas Processing	Sweet Gas Plants	Fugitives	1.B.2.b.iii.3	4.8E-04 to 10.3E-04	±100%	1.5E-04 to 3.2E-04	±100%	2.2E-04 to 4.7E-04	±100%	NA	NA	Gg per 10 ⁶ m ³ raw gas feed
		Flaring	1.B.2.b.ii	1.2E-06	±25%	1.8E-03	±25%	9.6E-07	±25%	2.5E-08	-10 to +1000%	Gg per 10 ⁶ m ³ raw gas feed
	Sour Gas Plants	Fugitives	1.B.2.b.iii.3	9.7E-05	±100%	7.9E-06	±100%	6.8E-05	±100%	NA	NA	Gg per 10 ⁶ m ³ raw gas feed
		Flaring	1.B.2.b.ii	2.4E-06	±25%	3.6E-03	±25%	1.9E-06	±25%	5.4E-08	-10 to +1000%	Gg per 10 ⁶ m ³ raw gas feed
		Raw CO ₂ Venting	1.B.2.b.i	NA	NA	6.3E-02	-10 to +1000%	NA	NA	NA	NA	Gg per 10 ⁶ m ³ raw gas feed

TABLE 4.2.4 (CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS
IN DEVELOPED COUNTRIES^{a,b}

Category	Sub-category ^c	Emission source	IPCC Code	CH ₄		CO ₂ ¹		NMVOC		N ₂ O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
Gas Transmission & Storage	Deep-cut Extraction Plants (Straddle Plants)	Fugitives	1.B.2.b.iii.3	1.1E-05	±100%	1.6E-06	±100%	2.7E-05	±100%	NA	NA	Gg per 10 ⁶ m ³ raw gas feed
		Flaring	1.B.2.b.ii	7.2E-08	±25%	1.1E-04	±50%	5.9E-08	±25%	1.2E-08	-10 to +1000%	Gg per 10 ⁶ m ³ raw gas feed
	Default Weighted Total	Fugitives	1.B.2.b.iii.3	1.5E-04 to 10.3E-04	±100%	1.2E-05 to 3.2E-04	±100%	1.4E-04 to 4.7E-04	±100%	NA	NA	Gg per 10 ⁶ m ³ gas production
		Flaring	1.B.2.b.ii	2.0E-06	±25%	3.0E-03	±50%	1.6E-06	±25%	3.3E-08	-10 to +1000%	Gg per 10 ⁶ m ³ gas production
		Raw CO ₂ Venting	1.B.2.b.i	NA	N/A	4.0E-02	-10 to +1000%	NA	N/A	NA	N/A	Gg per 10 ⁶ m ³ gas production
	Transmission	Fugitives ^{dk}	1.B.2.b.iii.4	6.6E-05 to 4.8E-04	±100%	8.8E-07	±100%	7.0E-06	±100%	NA	NA	Gg per 10 ⁶ m ³ of marketable gas
Venting ^{dk}		1.B.2.b.i	4.4E-05 to 3.2E-04	±75%	3.1E-06	±75%	4.6E-06	±75%	NA	NA	Gg per 10 ⁶ m ³ of marketable gas	
	Storage	All ^k	1.B.2.b.iii.4	2.5E-05	-20 to +500%	1.1E-07	-20 to +500%	3.6E-07	-20 to +500%	ND	ND	Gg per 10 ⁶ m ³ of marketable gas

TABLE 4.2.4 (CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS
IN DEVELOPED COUNTRIES^{a,b}

Category	Sub-category ^c	Emission source	IPCC Code	CH ₄		CO ₂ ¹		NMVOC		N ₂ O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
Gas Distribution	All	All ^k	1.B.2.b.iii.5	1.1E-03	-20 to +500%	5.1E-05	-20 to +500%	1.6E-05	-20 to +500%	ND	ND	Gg per 10 ⁶ m ³ of utility sales
				1.1E-04	±100%	7.2E-06	±100%	1.1E-03	±100%	ND	ND	Gg per 10 ³ m ³ Condensate and Pentanes Plus
Natural Gas Liquids Transport	Liquefied Petroleum Gas	All	1.B.2.a.iii.3	NA	NA	4.3E-04	±50%	ND	ND	2.2E-09	-10 to +1000%	Gg per 10 ³ m ³ LPG
				ND	ND	ND	ND	ND	ND	ND	ND	Gg per 10 ⁶ m ³ of marketable gas
Oil Production	Conventional Oil	Fugitives (Onshore)	1.B.2.a.iii.2	1.5E-06 to 3.6E-03	±100%	1.1E-07 to 2.6E-04	±100%	1.8E-06 to 4.5E-03	±100%	NA	NA	Gg per 10 ³ m ³ conventional oil production
		Fugitives (Offshore)	1.B.2.a.iii.2	5.9E-07	±100%	4.3E-08	±100%	7.4E-07	±100%	NA	NA	Gg per 10 ³ m ³ conventional oil production
		Venting	1.B.2.a.i	7.2E-04	±50%	9.5E-05	±50%	4.3E-04	±50%	NA	NA	Gg per 10 ³ m ³ conventional oil production
		Flaring	1.B.2.a.ii	2.5E-05	±50%	4.1E-02	±50%	2.1E-05	±50%	6.4E-07	-10 to +1000%	Gg per 10 ³ m ³ conventional oil production

TABLE 4.2.4 (CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS
IN DEVELOPED COUNTRIES^{a,b}

Category	Sub-category ^c	Emission source	IPCC Code	CH ₄		CO ₂ ¹		NMVOC		N ₂ O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
	Heavy Oil/Cold Bitumen	Fugitives	1.B.2.a.iii.2	7.9E-03	±100%	5.4E-04	±100%	2.9E-03	±100%	NA	NA	Gg per 10 ³ m ³ heavy oil production
		Venting	1.B.2.a.i	1.7E-02	±75%	5.3E-03	±75%	2.7E-03	±75%	NA	NA	Gg per 10 ³ m ³ heavy oil production
		Flaring	1.B.2.a.ii	1.4E-04	±75%	2.2E-02	±75%	1.1E-05	±75	4.6E-07	-10 to +1000%	Gg per 10 ³ m ³ heavy oil production
	Thermal Oil Production	Fugitives	1.B.2.a.iii.2	1.8E-04	±100%	2.9E-05	±100%	2.3E-04	±100%	NA	NA	Gg per 10 ³ m ³ thermal bitumen production
		Venting	1.B.2.a.i	3.5E-03	±50%	2.2E-04	±50%	8.7E-04	±50%	NA	NA	Gg per 10 ³ m ³ thermal bitumen production
		Flaring	1.B.2.a.ii	1.6E-05	±75%	2.7E-02	±75%	1.3E-05	±75%	2.4E-07	-10 to +1000%	Gg per 10 ³ m ³ thermal bitumen production
	Synthetic Crude (from Oilsands)	All	1.B.2.a.iii.2	2.3E-03	±75%	ND	ND	9.0E-04	±75%	ND	ND	Gg per 10 ³ m ³ synthetic crude production from oilsands

TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS IN DEVELOPED COUNTRIES ^{a,b}												
Category	Sub- category ^c	Emission source	IPCC Code	CH ₄		CO ₂ ¹		NMVOC		N ₂ O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
	Synthetic Crude (from Oil Shale)	All	1.B.2.a.iii.2	ND	ND	ND	ND	ND	ND	ND	ND	Gg per 10 ³ m ³ synthetic crude production from oil shale
				2.2E-03	±100%	2.8E-04	±100%	3.1E-03	±100%	NA	NA	Gg per 10 ³ m ³ total oil production
				8.7E-03	±75%	1.8E-03	±75%	1.6E-03	±75%	NA	NA	Gg per 10 ³ m ³ total oil production
		Flaring	1.B.2.a.ii	2.1E-05	±75%	3.4E-02	±75%	1.7E-05	±75	5.4E-07	-10 to +1000%	Gg per 10 ³ m ³ total oil production
Oil Upgrading	All	All	1.B.2.a.iii.2	ND	ND	ND	ND	ND	ND	ND	ND	Gg per 10 ³ m ³ oil upgraded
Oil Transport	Pipelines	All ^k	1.B.2.a.iii.3	5.4E-06	±100%	4.9E-07	±100%	5.4E-05	ND	NA	NA	Gg per 10 ³ m ³ oil transported by pipeline

TABLE 4.2.4(Continued)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS
IN DEVELOPED COUNTRIES^{a,b}

Category	Sub-category ^c	Emission source	IPCC Code	CH ₄		CO ₂ ¹		NMVOC		N ₂ O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
	Tanker Trucks and Rail Cars	Venting ^k	1.B.2.a.i	2.5E-05	±50%	2.3E-06	±50%	2.5E-04	ND	NA	NA	Gg per 10 ³ m ³ oil transported by Tanker Truck
	Loading of Off-shore Production on Tanker Ships	Venting ^k	1.B.2.a.i	ND ^b	ND	ND ^b	ND	ND ^b	ND	NA	NA	Gg per 10 ³ m ³ oil transported by Tanker Ships
Oil Refining	All	All	1.B.2.a.iii.4	2.6x10 ⁻⁶ to 41.0x10 ⁻⁶	±100%	ND	ND	0.0013 ⁱ	±100%	ND	ND	Gg per 10 ³ m ³ oil refined.
Refined Product Distribution	Gasoline	All	1.B.2.a.iii.5	NA	NA	NA	NA	0.0022 ^j	±100%	NA	NA	Gg per 10 ³ m ³ product distributed.
	Diesel	All	1.B.2.a.iii.5	NA	NA	NA	NA	ND	ND	NA	NA	Gg per 10 ³ m ³ product transported.
	Aviation Fuel	All	1.B.2.a.iii.5	NA	NA	NA	NA	ND	ND	NA	NA	Gg per 10 ³ m ³ product transported.
	Jet Kerosene	All	1.B.2.a.iii.5	NA	NA	NA	NA	ND	ND	NA	NA	Gg per 10 ³ m ³ product transported.

**TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS
IN DEVELOPED COUNTRIES^{a,b}**

NA - Not Applicable ND - Not Determined

^a While the presented emission factors may all vary appreciably between countries, the greatest differences are expected to occur with respect to venting and flaring, particularly for oil production due to the potential for significant differences in the amount of gas conservation and utilisation practised.

^b The range in values for fugitive emissions is attributed primarily to differences in the amount of process infrastructure (e.g. average number and sizes of facilities) per unit of gas throughput.

^c 'All' denotes all fugitive emissions as well as venting and flaring emissions.

^d 'Fugitives' denotes all fugitive emissions including those from fugitive equipment leaks, storage losses, use of natural gas as the supply medium for gas-operated devices (e.g. instrument control loops, chemical injection pumps, compressor starters, etc.), and venting of still-column off-gas from glycol dehydrators. The presented range in values reflects the difference between fugitive emissions at offshore (the smaller value) and onshore (the larger value) emissions.

^e 'Flaring' denotes emissions from all continuous and emergency flare systems. The specific flaring rates may vary significantly between countries. Where actual flared volumes are known, these should be used to determine flaring emissions rather than applying the presented emission factors to production rates. The emission factors for direct estimation of CH₄, CO₂ and N₂O emissions from reported flared volumes are 0.012, 2.0 and 0.000023 Gg, respectively, per 10⁶ m³ of gas flared based on a flaring efficiency of 98% and a typical gas analysis at a gas processing plant (i.e. 91.9% CH₄, 0.58% CO₂, 0.68% N₂ and 6.84% non-methane hydrocarbons by volume).

^f The larger factor reflects the use of mostly reciprocating compressors on the system while the smaller factor reflects mostly centrifugal compressors.

^g 'Venting' denotes reported venting of waste associated and solution gas at oil production facilities and waste gas volumes from blowdown, purging and emergency relief events at gas facilities. Where actual vented volumes are known, these should be used to determine venting emissions rather than applying the presented emission factors to production rates. The emission factors for direct estimation of CH₄ and CO₂ emissions from reported vented volumes are 0.66 and 0.0049 Gg, respectively, per 10⁶ m³ of gas vented based on a typical gas analysis for gas transmission and distribution systems (i.e. 97.3% CH₄, 0.26% CO₂, 1.7% N₂ and 0.74% non-methane hydrocarbons by volume).

^h While no factors are available for marine loading of offshore production for North America, Norwegian data indicate a CH₄ emission factor of 1.0 to 3.6 Gg/10³ m³ of oil transferred (derived from data provided by Norwegian Pollution Control Authority, 2000).

ⁱ Estimated based on an aggregated emission factors for fugitive equipment leaks, fluid catalytic cracking and storage and handling of 0.53 kg/m³ (CPPI and Environment Canada, 1991), 0.6 kg/m³ (US EPA, 1995) and 0.2 g/kg (assuming the majority of the volatile products are stored in floating roof tanks with secondary seals) (EMEP/CORINAIR, 1996).

^j Estimated based on assumed average evaporation losses of 0.15 percent of throughput at the distribution terminal and additional losses of 0.15 percent of throughput at the retail outlet. These values will be much lower where Stage 1 and Stage 2 vapour recovery occurs and may be much greater in warm climates.

^k NMVOC values are derived from methane values based on the ratio of the mass fractions of NMVOC to CH₄. Values of 0.0144 kg/kg for gas transmission and distribution, 9.951 kg/kg for oil and condensate transportation and 0.3911 kg/kg for synthetic crude oil production are used.

^l The presented CO₂ emissions factors account for direct CO₂ emissions only, except for flaring, in which case the presented values account for the sum of direct CO₂ emissions and indirect contributions due to the atmospheric oxidation of gaseous non-CO₂ carbon emissions.

Sources: Canadian Association of Petroleum Producers (1999, 2004); API (2004); GRU/US EPA (1996); US EPA (1999).

TABLE 4.2.5
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS
IN DEVELOPING COUNTRIES AND COUNTRIES WITH ECONOMIES IN TRANSITION^{a,b}

Category	Sub-category ^c	Emission source	IPCC Code	CH ₄		CO ₂ ⁱ		NMVOC		N ₂ O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
Well Drilling	All	Flaring and Venting	1.B.2.a.ii or 1.B.2.b.ii	3.3E-05 to 5.6E-04	-12.5 to +800%	1.0E-04 to 1.7E-03	-12.5 to +800%	8.7E-07 to 1.5E-05	-12.5 to +800%	ND	ND	Gg per well drilled
				5.1E-05 to 8.5E-04	-12.5 to +800%	9.0E-03 to 1.5E-01	-12.5 to +800%	1.2E-05 to 2.0E-04	-12.5 to +800%	6.8E-08 to 1.1E-06	-10 to +1000%	Gg per well drilled.
Well Servicing	All	Flaring and Venting	1.B.2.a.ii or 1.B.2.b.ii	1.1E-04 to 1.8E-03	-12.5 to +800%	1.9E-06 to 3.2E-05	-12.5 to +800%	1.7E-05 to 2.8E-04	-12.5 to +800%	ND	ND	Gg/yr per producing or capable well
Gas Production	All	Fugitives ^d	1.B.2.b.iii.2	3.8E-04 to 2.4E-02	-40 to +250%	1.4E-05 to 1.8E-04	-40 to +250%	9.1E-05 to 1.2E-03	-40 to +250%	NA	NA	Gg per 10 ⁶ m ³ gas production
				7.6E-07 to 1.0E-06	±75%	1.2E-03 to 1.6E-03	±75%	6.2E-07 to 8.5E-07	±75%	2.1E-08 to 2.9E-08	-10 to +1000%	Gg per 10 ⁶ m ³ gas production
Gas Processing	Sweet Gas Plants	Fugitives	1.B.2.b.iii.3	4.8E-04 to 1.1E-03	-40 to +250%	1.5E-04 to 3.5E-04	-40 to +250%	2.2E-04 to 5.1E-04	-40 to +250%	NA	NA	Gg per 10 ⁶ m ³ raw gas feed
		Flaring	1.B.2.b.ii	1.2E-06 to 1.6E-06	±75%	1.8E-03 to 2.5E-03	±75%	9.6E-07 to 1.3E-06	±75%	2.5E-08 to 3.4E-08	-10 to +1000%	Gg per 10 ⁶ m ³ raw gas feed
	Sour Gas Plants	Fugitives	1.B.2.b.iii.3	9.7E-05 to 2.2E-04	-40 to +250%	7.9E-06 to 1.8E-05	-40 to +250%	6.8E-05 to 1.6E-04	-40 to +250%	NA	NA	Gg per 10 ⁶ m ³ raw gas feed

TABLE 4.2.5 (CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS
IN DEVELOPING COUNTRIES AND COUNTRIES WITH ECONOMIES IN TRANSITION^{a,b}

Category	Sub-category ^c	Emission source	IPCC Code	CH ₄		CO ₂ ⁱ		NMVOC		N ₂ O		Units of measure
				Value	Uncertainty (%) of value)	Value	Uncertainty (%) of value)	Value	Uncertainty (%) of value)	Value	Uncertainty (%) of value)	
		Flaring	1.B.2.b.ii	2.4E-06 to 3.3E-06	±75%	3.6E-03 to 4.9E-03	±75%	1.9E-06 to 2.6E-06	±75%	5.4E-08 to 7.4E-08	-10 to +1000%	Gg per 10 ⁶ m ³ raw gas feed
		Raw CO ₂ Venting	1.B.2.b.i	NA	NA	6.3E-02 to 1.5E-01	-10 to +1000%	NA	NA	NA	NA	Gg per 10 ⁶ m ³ raw gas feed
	Deep-cut Extraction Plants (Straddle Plants)	Fugitives	1.B.2.b.iii.3	1.1E-05 to 2.5E-05	-40 to +250%	1.6E-06 to 3.7E-06	-40 to +250%	2.7E-05 to 6.2E-05	-40 to +250%	NA	NA	Gg per 10 ⁶ m ³ raw gas feed
		Flaring	1.B.2.b.ii	7.2E-08 to 9.9E-08	±75%	1.1E-04 to 1.5E-04	±75%	5.9E-08 to 8.1E-08	±75%	1.2E-08 to 8.1E-08	-10 to +1000%	Gg per 10 ⁶ m ³ raw gas feed
	Default Weighted Total	Fugitives	1.B.2.b.iii.3	1.5E-04 to 3.5E-04	-40 to +250%	1.2E-05 to 2.8E-05	-40 to +250%	1.4E-04 to 3.2E-04	-40 to +250%	NA	NA	Gg per 10 ⁶ m ³ gas production
		Flaring	1.B.2.b.ii	2.0E-06 to 2.8E-06	±75%	3.0E-03 to 4.1E-03	±75%	1.6E-06 to 2.2E-06	±75%	3.3E-08 to 4.5E-08	-10 to +1000%	Gg per 10 ⁶ m ³ gas production
		Raw CO ₂ Venting	1.B.2.b.i	NA	N/A	4.0E-02 to 9.5E-02	-10 to +1000%	NA	N/A	NA	N/A	Gg per 10 ⁶ m ³ gas production

TABLE 4.2.5 (CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS
IN DEVELOPING COUNTRIES AND COUNTRIES WITH ECONOMIES IN TRANSITION^{a,b}

Category	Sub-category ^c	Emission source	IPCC Code	CH ₄		CO ₂ ⁱ		NMVOC		N ₂ O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
Gas Transmission & Storage	Transmission	Fugitives ^f	1.B.2.b.iii.4	16.6E-05 to 1.1E-03	-40 to +250%	8.8E-07 to 2.0E-06	-40 to +250%	7.0E-06 to 1.6E-05	-40 to +250%	NA	NA	Gg per 10 ⁶ m ³ of marketable gas
		Venting ^g	1.B.2.b.i	4.4E-05 to 7.4E-04	-40 to +250%	3.1E-06 to 7.3E-06	-40 to +250%	4.6E-06 to 1.1E-05	-40 to +250%	NA	NA	Gg per 10 ⁶ m ³ of marketable gas
	Storage	All	1.B.2.b.iii.4	2.5E-05 to 5.8E-05	-20 to +500%	1.1E-07 to 2.6E-07	-20 to +500%	3.6E-07 to 8.3E-07	-20 to +500%	ND	ND	Gg per 10 ⁶ m ³ of marketable gas
Gas Distribution	All	All	1.B.2.b.iii.5	1.1E-03 to 2.5E-03	-20 to +500%	5.1E-05 to 1.4E-04	-20 to +500%	1.6E-05 to 3.6E-5	-20 to +500%	ND	ND	Gg per 10 ⁶ m ³ of utility sales
Natural Gas Liquids Transport	Condensate	All	1.B.2.a.iii.3	1.1E-04	-50 to +200%	7.2E-06	-50 to +200%	1.1E-03	-50 to +200%	ND	ND	Gg per 10 ³ m ³ Condensate and Pentanes Plus
	Liquefied Petroleum Gas	All	1.B.2.a.iii.3	NA	NA	4.3E-04	±100%	ND	ND	2.2E-09	-10 to +1000%	Gg per 10 ³ m ³ LPG
	Liquefied Natural Gas	All	1.B.2.a.iii.3	ND	ND	ND	ND	ND	ND	ND	ND	Gg per 10 ⁶ m ³ of marketable gas

TABLE 4.2.5 (CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS
IN DEVELOPING COUNTRIES AND COUNTRIES WITH ECONOMIES IN TRANSITION^{a,b}

Category	Sub-category ^c	Emission source	IPCC Code	CH ₄		CO ₂ ⁱ		NMVOC		N ₂ O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
Oil Production	Conventional Oil	Fugitives (Onshore)	1.B.2.a.iii.2	1.5E-06 to 6.0E-02	-12.5 to +800%	1.1E-07 to 4.3E-03	-12.5 to +800%	1.8E-06 to 7.5E-02	-12.5 to +800%	NA	NA	Gg per 10 ³ m ³ conventional oil production
		Fugitives (Offshore)	1.B.2.a.iii.2	5.9E-07	-12.5 to +800%	4.3E-08	-12.5 to +800%	7.4E-07	-12.5 to +800%	NA	NA	Gg per 10 ³ m ³ conventional oil production
		Venting	1.B.2.a.i	7.2E-04 to 9.9E-04	±75%	9.5E-05 to 1.3E-04	±75%	4.3E-04 to 5.9E-04	±75%	NA	NA	Gg per 10 ³ m ³ conventional oil production
		Flaring	1.B.2.a.ii	2.5E-05 to 3.4E-05	±75%	4.1E-02 to 5.6E-02	±75%	2.1E-05 to 2.9E-05	±75%	6.4E-07 to 8.8E-07	-10 to +1000%	Gg per 10 ³ m ³ conventional oil production

TABLE 4.2.5 (CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS
IN DEVELOPING COUNTRIES AND COUNTRIES WITH ECONOMIES IN TRANSITION^{a,b}

Category	Sub-category ^c	Emission source	IPCC Code	CH ₄		CO ₂ ⁱ		NMVOC		N ₂ O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
	Heavy Oil/Cold Bitumen	Fugitives	1.B.2.a.iii.2	7.9E-03 to 1.3E-01	-12.5 to +800%	5.4E-04 to 9.0E-03	-12.5 to +800%	2.9E-03 to 4.8E-02	-12.5 to +800%	NA	NA	Gg per 10 ³ m ³ heavy oil production
		Venting	1.B.2.a.i	1.7E-02 to 2.3E-02	-67 to +150%	5.3E-03 to 7.3E-03	-67 to +150%	2.7E-03 to 3.7E-03	-67 to +150%	NA	NA	Gg per 10 ³ m ³ heavy oil production
		Flaring	1.B.2.a.ii	1.4E-04 to 1.9E-04	-67 to +150%	2.2E-02 to 3.0E-02	-67 to +150%	1.1E-05 to 1.5E-05	-67 to +150%	4.6E-07 to 6.3E-07	-10 to +1000%	Gg per 10 ³ m ³ heavy oil production
	Thermal Oil Production	Fugitives	1.B.2.a.iii.2	1.8E-04 to 3.0E-03	-12.5 to +800%	2.9E-05 to 4.8E-04	-12.5 to +800%	2.3E-04 to 3.8E-03	-12.5 to +800%	NA	NA	Gg per 10 ³ m ³ thermal bitumen production
		Venting	1.B.2.a.i	3.5E-03 to 4.8E-03	-67 to +150%	2.2E-04 to 3.0E-04	-67 to +150%	8.7E-04 to 1.2E-03	-67 to +150%	NA	NA	Gg per 10 ³ m ³ thermal bitumen production
		Flaring	1.B.2.a.ii	1.6E-05 to 2.2E-05	-67 to +150%	2.7E-02 to 3.7E-02	-67 to +150%	1.3E-05 to 1.8E-05	-67 to +150%	2.4E-07 to 3.3E-07	-10 to +1000%	Gg per 10 ³ m ³ thermal bitumen production

TABLE 4.2.5 (CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS
IN DEVELOPING COUNTRIES AND COUNTRIES WITH ECONOMIES IN TRANSITION^{a,b}

Category	Sub-category ^c	Emission source	IPCC Code	CH ₄		CO ₂ ⁱ		NMVOC		N ₂ O		Units of measure
				Value	Uncertainty (%) of value)	Value	Uncertainty (%) of value)	Value	Uncertainty (%) of value)	Value	Uncertainty (%) of value)	
	Synthetic Crude (from Oilsands)	All	1.B.2.a.iii.2	2.3E-03 to 3.8E-02	-67 to +150%	ND	ND	9.0E-04 to 1.5E-02	-67 to +150%	ND	ND	Gg per 10 ³ m ³ synthetic crude production from oilsands
				ND	ND	ND	ND	ND	ND	ND	ND	Gg per 10 ³ m ³ synthetic crude production from oil shale
	Default Weighted Total	Fugitives	1.B.2.a.iii.2	2.2E-03 to 3.7E-02	-12.5 to +800%	2.8E-04 to 4.7E-03	-12.5 to +800%	3.1E-03 to 5.2E-02	-12.5 to +800%	NA	NA	Gg per 10 ³ m ³ total oil production
		Venting	1.B.2.a.i	8.7E-03 to 1.2E-02	±75%	1.8E-03 to 2.5E-03	±75%	1.6E-03 to 2.2E-03	±75%	NA	NA	Gg per 10 ³ m ³ total oil production
		Flaring	1.B.2.a.ii	2.1E-05 to 2.9E-05	±75%	3.4E-02 to 4.7E-02	±75%	1.7E-05 to 2.3	±75	5.4E-07 to 7.4E-07	-10 to +1000%	Gg per 10 ³ m ³ total oil production

TABLE 4.2.5 (CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS
IN DEVELOPING COUNTRIES AND COUNTRIES WITH ECONOMIES IN TRANSITION^{a,b}

Category	Sub-category ^c	Emission source	IPCC Code	CH ₄		CO ₂ ⁱ		NMVOC		N ₂ O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
Oil Upgrading	All	All	1.B.2.a.iii.2	ND	ND	ND	ND	ND	ND	ND	ND	Gg per 10 ³ m ³ oil upgraded
Oil Transport	Pipelines	All	1.B.2.a.iii.3	5.4E-06	-50 to +200%	4.9E-07	-50 to +200%	5.4E-05	-50 to +200%	NA	NA	Gg per 10 ³ m ³ oil transported by pipeline
	Tanker Trucks and Rail Cars	Venting	1.B.2.a.i	2.5E-05	-50 to +200%	2.3E-06	-50 to +200%	2.5E-04	-50 to +200%	NA	NA	Gg per 10 ³ m ³ oil transported by Tanker Truck
	Loading of Off-shore Production on Tanker Ships	Venting	1.B.2.a.i	ND ^b	ND	ND ^b	ND	ND	ND	NA	NA	Gg per 10 ³ m ³ oil transported by Tanker Truck
Oil Refining	All	All	1.B.2.a.iii.4	ND	ND	ND	ND	ND	ND	ND	ND	Gg per 10 ³ m ³ oil refined.

TABLE 4.2.5 (CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS
IN DEVELOPING COUNTRIES AND COUNTRIES WITH ECONOMIES IN TRANSITION^{a,b}

Category	Sub-category ^c	Emission source	IPCC Code	CH ₄		CO ₂ ⁱ		NMVOC		N ₂ O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
Refined Product Distribution	Gasoline	All	1.B.2.a.iii.5	NA	NA	NA	NA	ND	ND	NA	NA	Gg per 10 ³ m ³ product transported.
	Diesel	All	1.B.2.a.iii.5	NA	NA	NA	NA	ND	ND	NA	NA	Gg per 10 ³ m ³ product transported.
	Aviation Fuel	All	1.B.2.a.iii.5	NA	NA	NA	NA	ND	ND	NA	NA	Gg per 10 ³ m ³ product transported.
	Jet Kerosene	All	1.B.2.a.iii.5	NA	NA	NA	NA	ND	ND	NA	NA	Gg per 10 ³ m ³ product transported.

**TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS
IN DEVELOPING COUNTRIES AND COUNTRIES WITH ECONOMIES IN TRANSITION^{a,b}**

NA - Not Applicable ND - Not Determined

^a While the presented emission factors may all vary appreciably between countries, the greatest differences are expected to occur with respect to venting and flaring, particularly for oil production due to the potential for significant differences in the amount of gas conservation and utilisation practised.

^b The range in values for fugitive emissions is attributed primarily to differences in the amount of process infrastructure (e.g. average number and sizes of facilities) per unit of gas throughput.

^c 'All' denotes all fugitive emissions as well as venting and flaring emissions.

^d 'fugitives' denotes all fugitive emissions including those from fugitive equipment leaks, storage losses, use of natural gas as the supply medium for gas-operated devices (e.g. instrument control loops, chemical injection pumps, compressor starters, etc.), and venting of still-column off-gas from glycol dehydrators.

^e 'Flaring' denotes emissions from all continuous and emergency flare systems. The specific flaring rates may vary significantly between countries. Where actual flared volumes are known, these should be used to determine flaring emissions rather than applying the presented emission factors to production rates. The emission factors for direct estimation of CH₄, CO₂ and N₂O emissions from reported flared volumes are 0.012, 2.0 and 0.000023 Gg, respectively, per 106 m³ of gas flared based on a flaring efficiency of 98% and a typical gas analysis at a gas processing plant (i.e. 91.9% CH₄, 0.58% CO₂, 0.68% N₂ and 6.84% non-methane hydrocarbons by volume).

^f The larger factor reflects the use of mostly reciprocating compressors on the system while the smaller factor reflects mostly centrifugal compressors.

^g 'Venting' denotes reported venting of waste associated and solution gas at oil production facilities and waste gas volumes from blowdown, purging and emergency relief events at gas facilities. Where actual vented volumes are known, these should be used to determine venting emissions rather than applying the presented emission factors to production rates. The emission factors for direct estimation of CH₄ and CO₂ emissions from reported vented volumes are 0.66 and 0.0049 Gg, respectively, per 106 m³ of gas vented based on a typical gas analysis for gas transmission and distribution systems (i.e. 97.3% CH₄, 0.26% CO₂, 1.7% N₂ and 0.74% non-methane hydrocarbons by volume).

^h While no factors are available for marine loading of offshore production for North America, Norwegian data indicate a CH₄ emission factor of 1.0 to 3.6 Gg/103 m³ of oil transferred (derived from data provided by Norwegian Pollution Control Authority, 2000).

ⁱ The presented CO₂ emissions factors account for direct CO₂ emissions only, except for flaring, in which case the presented values account for the sum of direct CO₂ emissions and indirect contributions due to the atmospheric oxidation of gaseous non-CO₂ carbon emissions.

Sources: The factors presented in this table have been determined by setting the lower limit of the range for each category equal to at least the values published in Table 4.2.4 for North America. Otherwise, all presented values have been adapted from applicable data provided in the 1996 IPCC Guidelines and from limited measurement data available from more recent unpublished studies of natural gas systems in China, Romania and Uzbekistan.

The factors in Table 4.2.4 for North America are derived from detailed emission inventory results for Canada and the United States and, where possible, have been updated from the values previously presented in the IPCC Good Practice Guidance (2000) document to reflect the results of more current and refined emissions inventories. Where applicable, factors from the API Compendium of Emissions Estimating Methodologies for the Petroleum Industry have been indicated.

The factors in Table 4.2.4 are presented as examples and reflect the following practices and state of the oil and gas industry:

- Most associated gas is conserved;
- Sweet waste gas is flared or vented;
- Sour waste gas is flared;
- Many gas transmission companies are voluntarily implementing programmes to reduce methane losses due to fugitive equipment leaks;
- The oil and gas industry is mature and actually in decline in many areas;
- System reliability is high;
- Equipment is generally well maintained and high-quality components are used;
- Line breaks and well blowouts are rare;
- The industry is highly regulated and these regulations are generally well enforced.

The emission factors presented in Table 4.2.5 have been set so that the lower limit of each range is at least equal to the corresponding value from Table 4.2.4. Otherwise, all values have been adapted from the factors presented in the 1996 Revised IPCC Guidelines and from limited measurement data available for several recent unpublished studies of natural gas systems in developing countries or countries with economies in transition. Where ranges in values are presented, these are either based on the relative ranges given in the 1996 Revised IPCC Guidelines or are estimated based on expert judgement and data from unpublished reports.

A similar approach has also been used to estimate the uncertainty values given for the presented emission factors. The large uncertainties given for some of the emission factors reflect the corresponding high variability between individual sources, the types and extent of applied controls and, in some cases, the limited amount of data available. For many source categories (e.g., equipment leaks), the fugitive emissions have a skewed distribution where most of the emissions are emitted by only a small percentage of the population. Where uncertainties are less than or equal to ± 100 percent, a normal distribution has been assumed, resulting in a symmetric distribution about the mean. Wherever the reported uncertainty U percent for a quantity Q is greater than 100 percent, the upper limit is $Q(100+U)/100$ and the lower limit is $100Q/(100+U)$.

TIER 3 AND 2

Emission factors for conducting Tier 3 and Tier 2 assessments are not provided in the IPCC Guidelines due to the large amount of such information and the fact these data are continually being updated to include additional measurement results and to reflect development and penetration of new control technologies and requirements. Rather, the IPCC has developed an Emission Factor Database (EFDB) which will be periodically updated and is available through the Internet at www.ipcc-nggip.iges.or.jp/EFDB/main.php. In addition regular reviews of the literature should still be conducted to ensure that the best available factors are being used. The references for the chosen values should be clearly documented. Typically, emission factors are developed and published by environmental agencies and industry associations. It may be necessary to develop inventory estimates in consultation with these organisations. For example, the American Petroleum Institute (API) maintains a Compendium of Emissions Estimating Methodologies for the Oil and Gas Industry, most recently updated in 2004. The API Compendium is available at:

<http://api-ec.api.org/policy/index.cfm>.

A software tool for estimating greenhouse gas emissions using equations from the API Compendium is available at:

<http://ghg.api.org>

Guidance for estimating greenhouse gas emissions has also been developed by a number of national oil and gas industry associations. Such documents may be useful supplemental references and often provide tiered source-specific calculation procedures. Guidance on inventory accounting principles as they apply to the oil and gas industry, and boundary definitions is available in the Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions (International Petroleum Industry Environmental Conservation Association, 2003):

www.ipieca.org/downloads/climate_change/GHG_Reporting_Guidelines.pdf.

When selecting emission factors, the chosen values must be valid for the given application and be expressed on the same basis as the activity data. It also may be necessary to apply other types of factors to correct for site and regional differences in operating conditions and design and maintenance practices, for example:

- Composition profiles of gases from particular oil and gas fields to correct for the amount of CH₄, formation CO₂ and other target emissions;
- Annual operating hours to correct for the amount of time a source is in active service;
- Efficiencies of the specific control measures used.

The following are additional matters to consider in choosing emission factors:

- It is important to assess the applicability of the selected factors for the target application to ensure similar or comparable source behaviour and characteristics;
- In the absence of better data, it may sometimes be necessary to apply factors reported for other regions that practice similar levels of emission control and feature comparable types of equipment;
- Where measurements are performed to develop new emission factors, only recognised or defensible test procedures should be applied. The method and quality assurance (QA)/quality control (QC) procedures should be documented, the sampled sources should be representative of typical variations in the overall source population and a statistical analysis should be conducted to establish the 95 percent confidence interval on the average results.

4.2.2.4 CHOICE OF ACTIVITY DATA

The activity data required to estimate fugitive emissions from oil and gas activities includes production statistics, infrastructure data (e.g., inventories of facilities/installations, process units, pipelines, and equipment components), and reported emissions from spills, accidental releases, and third-party damages. The basic activity data required for each tier and each type of primary source are summarised in Table 4.2.6, Typical Activity Data Requirements for each Assessment Approach by Type of Primary Source Category.

TIER 1

The activity data required at the Tier 1 level has been limited to information that may either be obtained directly from typical national oil and gas statistics or easily estimated from this information. Table 4.2.7 below lists the activity data required by each of the Tier 1 emission factors presented in Tables 4.2.4 and 4.2.5, and gives appropriate guidance for obtaining or estimating each of the required activity values.

TIER 2

The activity data required for the standard Tier 2 methodological approach is the same as that required for the Tier 1 approach. If the alternative Tier 2 approach described in Section 4.2.2.2 for crude oil systems is used, then additional, more detailed, information is required including average GOR values, information on the extent of gas conservation and factors for apportioning waste associated gas volumes between venting and flaring. This additional information should be developed based on input from the industry.

TABLE 4.2.6 TYPICAL ACTIVITY DATA REQUIREMENTS FOR EACH ASSESSMENT APPROACH FOR FUGITIVE EMISSIONS FROM OIL AND GAS OPERATIONS BY TYPE OF PRIMARY SOURCE CATEGORY		
Assessment Tier	Primary Source Category	Minimum Required Activity Data
3	Process Venting/Flaring	Reported Volumes Gas Compositions Proration Factors for Splitting Venting from Flaring
	Storage Losses	Solution Gas Factors Liquid Throughputs Tank Sizes Vapour Compositions
	Equipment Leaks	Facility/Installation Counts by Type Processes Used at Each Facility Equipment Component Schedules by Type of Process Unit Gas/Vapour Compositions
	Gas-Operated Devices	Schedule of Gas-operated Devices by Type of Process Unit Gas Consumption Factors Type of Supply Medium Gas Composition
	Accidental Releases & Third-Party Damages	Incident Reports/Summaries
	Gas Migration to the Surface & Surface Casing Vent Blows	Average Emission Factors & Numbers of Wells
	Drilling	Number of Wells Drilled Reported Vented/Flared Volumes from Drill Stem Tests Typical Emissions from Mud Tanks
	Well Servicing	Tally of Servicing Events by Types
	Pipeline Leaks	Type of Piping Material Length of Pipeline
	Exposed Oils and/Oil Shale	Exposed Surface Area Average Emission Factors
2	Venting and Flaring from Oil Production	Gas to Oil Ratios Flared and Vented Volumes Conserved Gas Volumes Re-injected Gas Volumes Utilised Gas Volumes Gas Compositions
	All Others	Oil and Gas Throughputs
1	All	Oil and Gas Throughputs

TABLE 4.2.7 GUIDANCE ON OBTAINING THE ACTIVITY DATA VALUES REQUIRED FOR USE IN THE TIER 1 APPROACH TO ESTIMATE FUGITIVE EMISSIONS FROM OIL AND GAS OPERATIONS			
Category	Sub-Category	Required Activity Data Value	Guidance
Well Drilling	All	10 ³ m ³ total oil production	Reference directly from national statistics.
Well Testing	All	10 ³ m ³ total oil production	Reference directly from national statistics.
Well Servicing	All	10 ³ m ³ total oil production	Reference directly from national statistics.
Gas Production	All	10 ⁶ m ³ gas production	Reference directly from national statistics.
		10 ⁶ m ³ gas production	Reference directly from national statistics.
Gas Processing	Sweet Gas Plants	10 ⁶ m ³ raw gas feed	Reference directly from national statistics if total gas receipts by gas plants is reported, otherwise, assume this value is equal to total gas production. Apportion this value accordingly between sweet and sour plants. In the absence of any information to allow such apportioning assume all plants are sweet.
	Sour Gas Plants	10 ⁶ m ³ raw gas feed	
	Deep-cut Extraction Plants (Straddle Plants)	10 ⁶ m ³ raw gas feed	Reference directly from national statistics if total gas receipts by straddle plants located on gas transmission systems is reported, otherwise, assume this value is equal to an appropriate portion of total marketable natural gas. In the absence of any information to make this apportionment, assume there are no straddle plants.
	Default Weighted Total	10 ⁶ m ³ gas production	Reference directly from national statistics.
Gas Transmission & Storage	Transmission	10 ⁶ m ³ of marketable gas	Reference directly from national statistics using the value reported for total net supply. This is the sum of imports plus total net gas receipts from gas fields and processing or reprocessing plants after all upstream uses, losses and re-injection volumes have been deducted.
	Storage	10 ⁶ m ³ of marketable gas	
Gas Distribution	All	10 ⁶ m ³ of utility sales	Reference directly from national statistics if reported if available; otherwise, set equal to the amount of gas handled by gas transmission and storage systems minus exports.
Natural Gas Liquids Transport	Condensate	10 ³ m ³ Condensate and Pentanes Plus	Reference directly from national statistics.
	Liquefied Petroleum Gas	10 ³ m ³ LPG	Reference directly from national statistics.

TABLE 4.2.7(CONTNUED) GUIDANCE ON OBTAINING THE ACTIVITY DATA VALUES REQUIRED FOR USE IN THE TIER 1 APPROACH TO ESTIMATE FUGITIVE EMISSIONS FROM OIL AND GAS OPERATIONS			
Oil Production	Conventional Oil	10 ³ m ³ conventional oil production	Reference directly from national statistics.
	Heavy Oil/Cold Bitumen	10 ³ m ³ heavy oil production	Reference directly from national statistics.
	Thermal Oil Production	10 ³ m ³ thermal bitumen production	Reference directly from national statistics.
	Synthetic Crude (from Oilsands)	10 ³ m ³ synthetic crude production from oilsands	Reference directly from national statistics.
	Synthetic Crude (from Oil Shale)	10 ³ m ³ synthetic crude production from oil shale	Reference directly from national statistics.
	Default Weighted Total	10 ³ m ³ total oil production	Reference directly from national statistics.
Oil Upgrading	All	10 ³ m ³ oil upgraded	Reference directly from national statistics if available; otherwise, set equal to total heavy oil and bitumen production minus any exports of these crude oils.
Oil Transport	Pipelines	10 ³ m ³ oil transported by pipeline	Reference directly from national statistics if available; otherwise set equal to total crude oil production plus imports.
	Tanker Trucks and Rail Cars	10 ³ m ³ oil transported by Tanker Truck	Reference directly from national statistics if available; otherwise, assume (as a first approximation) that 50 percent of the total crude.
	Loading of Off-shore Production on Tanker Ships	10 ³ m ³ oil transported by Tanker Ship	Reference directly from national statistics using the value reported for crude oil exports, and apportion this amount to account for only the fraction exported by tanker ships. While exports may occur by pipeline, tanker ship, or tanker trucks, they will usually be almost exclusively by one of these methods. Tanker ships are assumed to be used almost exclusively for exports.
Oil Refining	All	10 ³ m ³ oil refined.	Reference directly from national statistics if available; otherwise set this value equal to total production plus imports minus exports..
Refined Product Distribution	Gasoline	10 ³ m ³ product distributed.	Reference directly from national statistics if available; otherwise, set it equal to total gasoline production by refineries plus imports minus exports.

TABLE 4.2.7(CONTINUED) GUIDANCE ON OBTAINING THE ACTIVITY DATA VALUES REQUIRED FOR USE IN THE TIER 1 APPROACH TO ESTIMATE FUGITIVE EMISSIONS FROM OIL AND GAS OPERATIONS			
	Diesel	10 ³ m ³ product transported.	Reference directly from national statistics if available; otherwise, set it equal to total gasoline production by refineries plus imports minus exports.
	Aviation Fuel	10 ³ m ³ product transported.	Reference directly from national statistics if available; otherwise, set it equal to total gasoline production by refineries plus imports minus exports.
	Jet Kerosene	10 ³ m ³ product transported.	Reference directly from national statistics if available; otherwise, set it equal to total gasoline production by refineries plus imports minus exports.

TIER 3

Specific matters to consider in compiling the detailed activity data required for use in a Tier 3 approach include the following:

- Production statistics should be disaggregated to capture changes in throughputs (e.g., due to imports, exports, reprocessing, withdrawals, etc.) in progressing through oil and gas systems.
- Production statistics provided by national bureaux should be used in favour of those available from international bodies, such as the IEA or the UN, due to their generally better reliability and disaggregation. Regional, provincial/state and industry reporting groups may offer even more disaggregation.
- Production data used in estimating fugitive emissions should be corrected, where applicable, to account for any net imports or exports. It is possible that import and export data may be available for a country while production data are not; however, it is unlikely that the opposite would be true.
- Where coalbed methane is produced into a natural gas gathering system, any associated fugitive emissions should be reported under the appropriate natural gas exploration and production categories. This will occur by default since the produced gas becomes a commodity once it enters the gas gathering system and automatically gets accounted for the same way gas from any other well does when it enters the gathering system. The fact that gas is coming from a coal formation would only be discernable at a very disaggregated level. Where a coal formation is degassed, regardless of the reason, and the gas is not produced into a gathering system, the associated emissions should be allocated to the coal sector under the appropriate section of IPCC category 1.B.1.
- Vented and flared volumes from oil and gas statistics may be highly suspect since these values are usually estimates and not based on actual measurements. Additionally, the values are often aggregated and simply reported as flared volumes. Operating practices of each segment of the industry should be reviewed with industry representatives to determine if the reported volumes are actually vented or flared, or to develop appropriate apportioning of venting relative to flaring. Audits or reviews of each industry segment should also be conducted to determine if all vented and flared volumes are actually reported (for example, solution gas emissions from storage tanks and treaters, emergency flaring/venting, leakage into vent/flare systems, and blowdown and purging volumes may not necessarily be accounted for).
- Infrastructure data are more difficult to obtain than production statistics. Information concerning the numbers and types of major facilities and the types of processes used at these facilities may often be available from regulatory agencies and industry groups, or directly from the actual companies.
- Information on minor facilities (e.g., numbers of field dehydrators and field compressors) usually is not available, even from oil and gas companies. Consequently, assumptions must be made, based on local design practices, to estimate the numbers of these facilities. This may require some fieldwork to develop appropriate estimation factors or correlations.
- Many companies use computerised inspection-and-maintenance information management systems. These systems can be a very reliable means of counting major equipment units (e.g., compressor units, process heaters and boilers, etc.) at selected facilities. Also, some departments within a company may maintain databases of certain types of equipment or facilities for various internal reasons (e.g., tax accounting,

production accounting, insurance records, quality control programmes, safety auditing, license renewals, etc.). Efforts should be made to identify these potentially useful sources of information.

- Component counts by type of process unit may vary dramatically between facilities and countries due to differences in design and operating practices. Thus, while initially it may be appropriate to use values reported in the general literature, countries should strive to develop their own values.
- Use of consistent terminology and clear definitions is critical in developing counts of facilities and equipment components, and to allow any meaningful comparisons of the results with others.
- Some production statistics may be reported in units of energy (based on their heating value) and will need to be converted to a volume basis, or vice versa, for application of the available emission factors. Typically, where production values are expressed in units of energy, it is in terms of the gross (or higher) heating value of the product. However, where emission factors are expressed on an energy basis it is normally in terms of the net (or lower) heating value of the product. To convert from energy data on a GCV basis to a NCV basis, the International Energy Agency assumes a difference of 5 percent for oil and 10 percent for natural gas. Individual natural gas streams that are either very rich or high in impurities may differ from these average values. Emission factors and activity data must be consistent with each other.
- Oil and gas imports and exports will change the activity levels in corresponding downstream portions of these systems.
- Production activities will tend to be the major contributor to fugitive emissions from oil and gas activities in countries with low import volumes relative to consumption and export volumes. Gas transmission and distribution and petroleum refining will tend to be the major contributors to these emissions in countries with high relative import volumes. Overall, net importers will tend to have lower specific emissions than net exporters.

4.2.2.5 COMPLETENESS

Completeness is a significant issue in developing an inventory of fugitive emissions for the oil and gas industry. It can be addressed through direct comparisons with other countries and, for refined inventories, through comparisons between individual companies in the same industry segment and subcategory. This requires the use of consistent definitions and classification schemes. For example, in Canada, the upstream petroleum industry has adopted a benchmarking scheme that compares the emission inventory results of individual companies in terms of production-energy intensity and production-carbon intensity. Such benchmarking allows companies to assess their relative environmental performance. It also flags, at a high level, anomalies or possible errors that should be investigated and resolved.

The indicative factors presented in Table 4.2.8 may be used to qualify specific methane losses as being low, medium or high and help assess their reasonableness. If specific methane losses are appreciably less than the low benchmark or greater than the high benchmark, this should be explained; otherwise, it may be an indication of possible missed or double counted contributions, respectively. The ranking of specific methane losses relative to the presented indicative factors should not be used as a basis for choosing the most appropriate assessment approach; rather, total emissions (i.e. the product of activity data and emission factors), the complexity of the industry and available assessment resources should all be considered.

Where emission inventories are developed based on a compilation of individual company-level inventories, care should be taken to ensure that all companies are included. Appropriate extrapolations may be needed to account for any non-reporting companies.

TABLE 4.2.8
CLASSIFICATION OF GAS LOSSES AS LOW, MEDIUM OR HIGH AT SELECTED TYPES OF NATURAL GAS FACILITIES

Facilities	Activity data	Yearly emission factors			
		Low	Medium	High	Units of Measure
Production and Processing	Net gas production (i.e. marketed production)	0.05	0.2	0.7	% of net production
Transmission Pipeline Systems	Length of transmission pipelines	200	2 000	20 000	m ³ /km/yr
Compressor Stations	Installed compressor capacity	6 000	20 000	100 000	m ³ /MW/yr
Underground Storage	Working capacity of underground storage stations	0.05	0.1	0.7	% of working gas capacity
LNG Plant (liquefaction or regasification)	Gas throughput	0.005	0.05	0.1	% of throughput
Meter and Regulator Stations	Number of stations	1 000	5 000	50 000	m ³ /station/yr
Distribution	Length of distribution network	100	1 000	10 000	m ³ /km/yr
Gas Use	Number of gas appliances	2	5	20	m ³ /appliance/yr
Source: Adapted by the authors from currently unpublished work by the International Gas Union, and based on data for a dozen countries including Russia and Algeria.					

Smaller individual sources, when aggregated nationally over the course of a year, may often be significant total contributors. Therefore, *good practice* is not to disregard them. 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.

Where a country has estimated its fugitive emissions from part or all of its oil and natural gas system based on a roll-up of estimates reported by individual oil and gas companies, it is *good practice* to document the steps taken to ensure that these results are complete, transparent and consistent across the time series. Corrections made to account for companies or facilities that did not report, and measures taken to avoid missed or double counting (particularly where ownership changes have occurred) and to assess uncertainties should be highlighted.

4.2.2.6 DEVELOPING CONSISTENT TIME SERIES

Ideally, emission estimates will be prepared for the base year and subsequent years using the same method. The aim is to have emission estimates across the time series reflect true trends in greenhouse gas emissions. Emission or control factors that change over time (e.g., due to changes in source demographics or the penetration of control technologies) should be regularly updated and, each time, only applied to the period for which they are valid. For, example, if an emission control device is retrofit to a source then a new emission factor will apply to that source from then onwards; however, the previously applied emission factor reflecting conditions before the retrofit should still be applied for all previous years in the time series. If an emission factor has been refined

through further testing and now reflects a better understanding of the source or source category, then all previous estimates should be updated to reflect the use of the improved factor and be reported in a transparent manner.

Where some historical data are missing, it should still be possible to use source-specific measurement results combined with back-casting techniques to establish an acceptable relationship between emissions and activity data in the base year. Approaches for doing this will depend on the specific situation, and are discussed in general terms in Volume 1 Chapter 5 of the 2006 Guidelines.

If emission estimates are developed based on a roll-up of individual company estimates, greater effort will be required to maintain time series consistency, particularly where frequent facility ownership changes occur and different methodologies and emission factors are applied by each new owner without also carrying these changes back through the time series.

4.2.2.7 UNCERTAINTY ASSESSMENT

Sources of error that may occur include the following:

- Measurement errors;
- Extrapolation errors;
- Inherent uncertainties of the selected estimation techniques;
- Missing or incomplete information regarding the source population and activity data;
- Poor understanding of temporal and seasonal variations in the sources;
- Over or under accounting due to confusion or inconsistencies in category divisions and source definitions;
- Misapplication of activity data or emission factors;
- Errors in reported activity data;
- Missed accounting of intermediate transfer operations and reprocessing activities (for example, re-treating of slop oil, treating of foreign oil receipts and repeated dehydration of gas streams: in the field, at the plant, and then following storage);
- Differences in the effectiveness of control devices, potential deterioration of their performance over time and missed accounting of control measures.

Guidance regarding the assessment of uncertainties in emission factors and activity data are presented in the subsections below.

4.2.2.7.1 EMISSION FACTOR UNCERTAINTIES

The uncertainty in an emission factor will depend both on the accuracy of the measurements upon which it is based and the degree to which these results reflect the average behaviour of the target source population. Accordingly, emission factors developed based on data measured in one country may have one set of uncertainties when the factors are applied in that country and another set of uncertainties when they are applied similarly in a different country. Thus, while it is difficult to establish one set of uncertainties that will always apply, a set of default values has been provided for the default factors provided in Tables 4.2.4 and 4.2.5. These uncertainties are estimated based on expert judgement and reflect the level of uncertainty that may be expected when the corresponding emission factors are used to develop emission estimates at the national level. Use of the presented factors to estimate emissions from individual facilities or sources would be expected to result in much greater uncertainties.

4.2.2.7.2 ACTIVITY DATA UNCERTAINTIES

The percentages cited in this section are based on expert judgement and aim to approximate the 95 percent confidence interval around the central estimate. Gas compositions are usually accurate to within ± 5 percent on individual components. Flow rates typically have errors of ± 3 percent or less for sales volumes and ± 15 percent or more for other volumes. Production statistics or disposition analyses² may not agree between different

² A disposition analysis provides a reconciled accounting of produced hydrocarbons from the wellhead, or point of receipt, through to the final sales point or point of export. Typical disposition categories include flared/vented volumes, fuel usage, system losses, volumes added to/removed from inventory/storage, imports, exports, etc.

reporting agencies even though they are based on the same original measurement results (e.g. due to possible differences in terminology and potential errors in summarising these data). These discrepancies may be used as an indication of the uncertainty in the data. Additional uncertainty will exist if there is any inherent bias in the original measurement results (for example, sales meters are often designed to err in favour of the customer, and liquid handling systems will have a negative bias due to evaporation losses). Random metering and accounting errors may be assumed to be negligible when aggregated over the industry.

Counts of major facilities (e.g., gas plants, refineries and transmission compressor stations) will usually be known with little if any error (e.g., less than 5 percent). Where errors in these counts occur it is usually due to some uncertainties regarding the number of new facilities built and old facilities decommissioned during the time period.

Counts of well site facilities, minor field installations and gas gathering compressor stations, as well as the type and amount of equipment at each site, will be much less accurately known, if known at all (e.g., at least ± 25 percent uncertainty or more).

Estimates of emission reductions from individual control actions may be accurate to within a few percent to ± 25 percent depending on the number of subsystems or sources considered.

4.2.3 Inventory Quality Assurance/Quality Control (QA/QC)

It is *good practice* to conduct quality control checks as outlined in Volume 1 Chapter 6 of the 2006 IPCC Guidelines, Tier 1 General Inventory Level QC Procedures, and expert review of the emission estimates. Additional quality control checks, as outlined in Volume 1 Chapter 5 of the 2006 IPCC Guidelines, and quality assurance procedures may also be applicable, particularly if higher tier methods are used to determine emissions from this source category. Inventory compilers are encouraged to use higher tier QA/QC for *key categories* as identified in Volume 1 Chapter 4 of the 2006 IPCC Guidelines.

In addition to the guidance in Volume 1 Chapter 6 of the 2006 IPCC Guidelines, specific procedures of relevance to this source category are outlined below.

INDUSTRY INVOLVEMENT

Emission inventories for large, complex oil and gas industries will be susceptible to significant errors due to missed or unaccounted for sources. To minimise such errors, it is important to obtain active industry involvement in the preparation and refinement of these inventories.

REVIEW OF DIRECT EMISSION MEASUREMENTS

If direct measurements are used to develop country-specific emission factors, the inventory compiler should establish whether measurements at the sites were made according to recognised standard methods. If the measurement practices fail this criterion, then the use of these emissions data should be carefully evaluated, estimates reconsidered and qualifications documented.

EMISSION FACTORS CHECK

The inventory compiler should compare measurement-based factors to IPCC default factors and factors developed by other countries with similar industry characteristics. If IPCC default factors are used, the inventory compiler should ensure that they are applicable and relevant to the category. If possible, the IPCC default factors should be compared to national or local data to provide further indication that the factors are applicable.

ACTIVITY DATA CHECK

Several different types of activity data may be required for this source category, depending on which methodological tier is used to estimate the emissions. Where activity data are available from multiple sources (i.e. from national statistics and industry organisations) these data sets should be checked against each other to assess reasonableness. Significant differences in data should be explained and documented. Trends in the main emission drivers and activity data over time should be checked and any anomalies investigated.

EXTERNAL REVIEW

Emission inventories for large, complex oil and gas industries will be susceptible to significant errors due to missed or unaccounted for sources, or due to customization of average emission factors taken from a data source

that represents estimates from another country or region with operating characteristics different from those in the country where the emission factor is being applied. To minimise such errors, it is important to obtain active industry involvement in the preparation and refinement of these inventories.

4.2.4 Reporting and Documentation

It is *good practice* to document and archive all information required to produce the national emissions inventory estimates, as outlined in Volume 1 Chapter 8 of the 2006 Guidelines.

It may not be practical to include all supporting documentation in the inventory report. However, at a minimum, the inventory report should include summaries of the methods used and references to source data such that the reported emissions estimates are transparent and the steps in their calculation may be retraced. It is expected that many countries will use a combination of methodological tiers to evaluate the amount of fugitive greenhouse gas emissions from the different parts of their oil and natural gas systems. The specific choices should reflect the relative importance of the different subcategories and the availability of the data and resources needed to support the corresponding calculations. Table 4.2.9 is a sample template, with some example data entries, that may be used to conveniently summarize the applied methodologies and sources of emission factors and activity data.

Since emission factors and estimation procedures are continually being improved and refined, it is possible for changes in reported emissions to occur without any real changes in actual emissions. Accordingly, the basis for any changes in results between inventory recalculations should be clearly discussed and those due strictly to changes in methods and factors should be highlighted.

The issue of confidential business information will vary from region to region depending on the number of firms in the market and the nature of the business. The significance of this issue tends to increase in progressing downstream through the oil and gas industry. A common means to address such issues where they do arise is to aggregate the data using a reputable independent third party.

The above reporting and documentation guidance is applicable to all methodological choices. Where Tier 3 approaches are employed, it is important to ensure that either the applied procedures are detailed in the inventory report or that available references for these procedures are cited since the IPCC Guidelines do not describe a standard Tier 3 approach for the oil and gas sector. There is a wide range in what potentially may be classified as a Tier 3 approach, and correspondingly, in the amount of uncertainty in the results. If available, summary performance and activity indicators should be reported to help put the results in perspective (e.g. total production levels and transportation distances, net imports and exports, and specific energy, carbon and emission intensities). Reported emission results should also include a trend analysis to show changes in emissions, activity data and emission intensities (i.e., average emissions per unit of activity indicator) over time. 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.

The current trend by some government agencies and industry associations is to develop detailed methodology manuals and reporting formats for specific segments and subcategories of the industry. This is perhaps the most practical means of maintaining, documenting and disseminating the subject information. However, all such initiatives must conform to the common framework established in the IPCC Guidelines so that the emission results can be compared across countries.

TABLE 4.2.9

FORMAT FOR SUMMARIZING THE APPLIED METHODOLOGY AND BASIS FOR ESTIMATED EMISSIONS FROM OIL AND NATURAL GAS SYSTEMS SHOWING SAMPLE ENTRIES

IPCC Code	Sector Name	Subcategory	Source Category	Method	Activity Data			Emission Factors			Date Country Specific Values Updated
					Type	Basis	Year	Basis/Reference			
								CH ₄	CO ₂	N ₂ O	
1.B2	Oil and Natural Gas										
1.B2.a	Oil										
1.B2.ai	Venting										
1.B2.a.ii	Flaring										
1.B2.a.iii	All Other										
1.B2.a.iii.1	Exploration										
1.B2.a.iii.2	Production and Upgrading										
1.B2.a.iii.3	Transport										
1.B2.a.iii.4	Refining										
1.B2.a.iii.5	Distribution of oil products										
1.B2.a.iii.6	Other										
1.B2.b	Natural Gas										
1.B2.bi	Venting										

TABLE 4.2.9 (CONTINUED)
FORMAT FOR SUMMARIZING THE APPLIED METHODOLOGY AND BASIS FOR ESTIMATED EMISSIONS FROM OIL AND NATURAL GAS SYSTEMS SHOWING SAMPLE ENTRIES

IPCC Code	Sector Name	Subcategory	Source Category	Method	Activity Data			Emission Factors				Date Country Specific Values Updated
					Type	Basis	Year	Basis/Reference				
								CH ₄	CO ₂	N ₂ O		
1.B.2.b.ii	Flaring											
1.B.2.b.iii	All Other											
1.B.2.b.iii.1	Exploration											
1.B.2.b.iii.2	Production	Well Servicing	All	Tier 1	Number of Active Wells	National Statistics	2005	D	D	D		---
		Gas Production	Equipment Leaks	Tier 1	Throughput	National Statistics	2005	EFDB	EFDB	EFDB		---
1.B.2.b.iii.3	Processing	All	Equipment Leaks	Tier 1	Throughput	National Statistics	2005	D	EFDB	EFDB		---
1.B.2.b.iii.4	Transmission and Storage	Gas Transmission	Equipment Leaks	Tier 2	Number of facilities	Industry Survey	2005	CS	CS	----		2005
1.B.2.b.iii.5	Distribution											
1.B.2.b.iii.6	Other											
1.B.3	Other emissions from Energy Production											
AP	– API Compendium											
D	– IPCC Default Emission Factors											
CS	– Country-Specific Emission Factors											
EFDB	– IPCC Emission Factor Database											

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