National Greenhouse and Energy Reporting (Measurement) Amendment (2021 Update) Determination 2021

I, Angus Taylor, Minister for Energy and Emissions Reduction, make the following instrument.

Dated: 15 June 2021

Angus Taylor
Minister for Energy and Emissions Reduction

Contents

1 Name

This is the *National Greenhouse and Energy Reporting (Measurement) Amendment (2021 Update) Determination 2021*.

2 Commencement

(1) Each provision of this instrument specified in column 1 of the table commences, or is taken to have commenced, in accordance with column 2 of the table. Any other statement in column 2 has effect according to its terms.

Commencement information		
Column 1	**Column 2**	**Column 3**
Provisions	**Commencement**	**Date/Details**
1. The whole of this instrument	1 July 2021.	1 July 2021

Note: This table relates only to the provisions of this instrument as originally made. It will not be amended to deal with any later amendments of this instrument.

(2) Any information in column 3 of the table is not part of this instrument. Information may be inserted in this column, or information in it may be edited, in any published version of this instrument.

3 Authority

This instrument is made under subsection 10(3) of the *National Greenhouse and Energy Reporting Act 2007.*

4 Schedules

Each instrument that is specified in a Schedule to this instrument is amended or repealed as set out in the applicable items in the Schedule concerned, and any other item in a Schedule to this instrument has effect according to its terms.

Schedule 1—Amendments

National Greenhouse and Energy Reporting (Measurement) Determination 2008

[1] At the end of section 1.4

Add:

(3) Data points relevant to the implementation of particular methods are set out in column 3 of the tables in Schedule 4 as 'matters to be identified'.

Note: Regulations 4.10, 4.11, 4.13, 4.14, 4.15 and 4.17 of the Regulations require these matters to be identified to be included in reports under the Act.

[2] Section 1.8 (subparagraph (d)(i) of the definition of *appropriate unit*)

Omit "including crude oil condensates,", substitute "plant condensate".

[3] Section 1.8

Insert in the appropriate alphabetical position:

captured for enhanced oil recovery: a greenhouse gas is captured for enhanced oil recovery if it is captured and transferred to the holder of an enhanced oil recovery authority for injection into a geological formation, such as a natural reservoir, to further oil or gas production activities and is not captured for permanent storage.

city gate means a distribution hub where gas is reduced in pressure before it enters the lower pressure, smaller diameter, distribution pipeline network.

CO_2 stimulation means using carbon dioxide as a fluid in well stimulation treatment which enhances oil and gas production or recovery by increasing the permeability of the formation.

crude oil has the meaning given by the Regulations.

enhanced oil recovery authority means a licence, lease or approval by or under a law of the Commonwealth, State or Territory which authorises the injection of one or more greenhouse gases into one or more geological formations, such as a natural reservoirs, to further oil or gas production activities.

equivalent leak detection standard, means a standard or documented approach that:

(a) has equivalent or higher integrity than the method outlined in USEPA Method 21—*Determination of organic volatile compound leaks*, as set out in Appendix A-7 of Title 40, Part 60 of the Code of Federal Regulations, United States of America or optical gas imaging in accordance with paragraph 98.234(a)(1) of Title 40, Part 98 of the Code of Federal Regulations, United States of America; and

(b) has equivalent or higher sensitivity for detecting leaks than:

(i) 60 grams per hour in accordance with paragraph 98.234(a)(1) of Title 40, Part 98 of the Code of Federal Regulations, United States of America; or

(ii) 10,000 parts per million or greater in accordance with the method outlined in USEPA Method 21—*Determination of organic volatile compound leaks*, as set out in Appendix A-7 of Title 40, Part 60 of the Code of Federal Regulations, United States of America.

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Leak Detection and Repair Program or ***LDAR program*** means a system of procedures used at a facility to monitor, locate and repair leaking components in order to minimize emissions.

leaker, in relation to a component subject to an LDAR program, means:

(a) if optical gas imaging is used, a leaker is detected at a sensitivity of 60 grams per hour in accordance with paragraph 98.234(a)(1) of Title 40, Part 98 of the Code of Federal Regulations, United States of America; and

(b) if the method outlined in USEPA Method 21—*Determination of organic volatile compound leaks*, as set out in Appendix A-7 of Title 40, Part 60 of the Code of Federal Regulations, United States of America is used, a leaker is detected if 10,000 parts per million or greater is measured consistent with that method; and

(c) if an equivalent leak detection standard is used, a leaker is detected at the sensitivity set for that standard.

Note: Under the definition of equivalent leak detection standard, the sensitivity must be equivalent or higher than the approaches in paragraph (a) or (b).

liquefied natural gas station means the plant and equipment used in the natural gas liquefaction, storage and transfer of liquefied natural gas, and includes:

(a) all onshore or offshore equipment that receives natural gas, liquefies and stores liquefied natural gas, and transfers the liquefied natural gas to a transportation system; and

(b) equipment that receives imported or transported liquefied natural gas, stores liquefied natural gas, re-gasifies liquefied natural gas, and delivers re-gasified natural gas to a natural gas transmission or distribution system.

natural gas distribution pipelines mean pipelines for the conveyance of pipeline natural gas that:

(a) are identified as a distribution pipeline in an access arrangement applicable to the pipeline; or

(b) meet both of the following:

  (i) have a maximum design pressure of 1,050 kPa or less; and

  (ii) are not natural gas gathering and boosting pipelines.

natural gas liquefaction, storage and transfer means the activity to collect and liquefy natural gas and to store and transfer liquefied natural gas to a transportation system.

natural gas production includes offshore natural gas production and onshore natural gas production.

natural gas processing means one or both of the following activities:

(a) the separation of natural gas liquids or non-methane gases from unprocessed natural gas or coal seam methane;

(b) the separation of natural gas liquids into one or more component mixtures.

Note: The separation includes one or more of the following: forced extraction of natural gas liquids, sulphur and carbon dioxide removal, fractionation of natural gas liquids, or the capture of CO_2 separated from natural gas streams.

natural gas storage means the activity to store unprocessed natural gas, coal seam methane or natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas).

natural gas storage station means the plant and equipment used in natural gas storage, and includes:

(a) subsurface storage, such as depleted gas or oil reservoirs that store gas; and
(b) the equipment to undertake natural gas underground storage processes and operations (including compression, dehydration and flow measurement, but excluding natural gas transmission pipelines); and
(c) all the wellheads connected to the compression units located at the station that inject and recover natural gas into and from the underground reservoirs.

natural gas transmission pipeline means a pipeline for the conveyance of pipeline natural gas or plant condensate that:
(a) is licensed as a transmission pipeline under a Commonwealth, State or Territory law; and
(b) has a maximum design pressure exceeding 1,050 kPa; and
(c) is not a natural gas distribution pipeline or a natural gas gathering and boosting pipeline.

oil or gas exploration and development means the activity to explore for oil and gas resources and test, appraise, drill, develop and complete wells for oil and gas resources and includes the following actions:
(a) oil well drilling;
(b) gas well drilling;
(c) drill stem testing;
(e) well appraisals;
(f) development drilling;
(g) well completions;
(h) well workovers associated with the actions in the paragraphs above.

offshore natural gas production means the activity to produce, extract, recover, lift, stabilise, separate or treat unprocessed natural gas, condensate or coal seam methane on offshore submerged lands, including well workovers.

offshore platform includes:
(a) any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses plant and equipment to do either or both of the following:
   (i) extract unprocessed natural gas and condensate from the ocean or lake floor;
   (ii) transfers such unprocessed natural gas and condensate to storage, transport vessels, or onshore; and
(b) secondary platform structures connected to the platform structure via walkways, and
(c) storage tanks associated with the platform structure; and
(d) floating production and storage offloading equipment; and
(e) submerged wellhead production structures.

offshore platform (shallow water) means an offshore platform standing in less than 200 metres of water.

offshore platform (deep water) means an offshore platform standing in at least 200 metres of water.

onshore natural gas production means the activity to produce, extract, recover, lift, stabilise, separate or treat unprocessed natural gas, condensate or coal seam methane on land, including well workovers.

onshore natural gas wellhead means the gas wellhead.

plant condensate has the meaning given by the Regulations**.**

pipeline natural gas means natural gas that is suitable for market consumption.

[4] Section 1.8

Repeal the following definitions:

(a) definition of ***crude oil condensates***;

(b) definition of ***technical guidelines***.

[5] Section 1.8 (definition of *fugitive emissions*)

Repeal the definition, substitute:

fugitive emissions means greenhouse gas emissions that are:

(a) released in connection with, or as a consequence of, the extraction, processing, storage or delivery of fossil fuel; and

(b) not released from the combustion of fuel for the production of useable heat or electricity.

[6] Section 1.8 (definition of *natural gas distribution*)

Repeal the definition, substitute:

natural gas distribution means the transport of pipeline natural gas over a combination of natural gas distribution pipelines from a city gate to customer delivery points.

[7] Section 1.8 (definition of *natural gas transmission*)

Repeal the definition, substitute:

natural gas transmission means transmission of natural gas or plant condensate through one or more natural gas transmission pipelines from a natural gas processing station or a natural gas gathering and boosting network to any of the following:

(a) a natural gas distribution network;

(b) another natural gas processing station;

(c) a liquefied natural gas station;

(d) a large industrial facility, such as a power station.

[8] Section 1.8 (definition of *well workover*)

Repeal the definition, substitute:

well workover means activities performed to restore or increase production which can include any or all of the following processes:

(a) well venting;

(b) tubing maintenance;

(c) air clean out;

(d) hydraulic fracturing and recovery;

(e) well unloading.

[9] Subsection 1.9(4)

Omit "1 July 2014", substitute "1 January 2020".

[10] Subsection 1.10(1)

Repeal the subsection, substitute:

(1) A thing mentioned in the column headed 'Source of emissions' of the following table is a ***source***.

Item	Category of source	Source of emissions
1	Fuel combustion	
1A		Fuel combustion
2	Fugitive emissions	
2A		Underground mines
2B		Open cut mines
2C		Decommissioned underground mines
2D		Oil or gas exploration and development—flaring
2E		Oil or gas exploration and development (other than flaring)
2F		Crude oil production
2G		Crude oil transport
2H		Crude oil refining
2I		Onshore natural gas production (other than emissions that are vented or flared)
2J		Offshore natural gas production (other than emissions that are vented or flared)
2K		Natural gas gathering and boosting (other than emissions that are vented or flared)
2L		Produced water from oil and gas exploration and development, crude oil production, natural gas production or natural gas gathering and boosting (other than emissions that are vented or flared)
2M		Natural gas processing (other than emissions that are vented or flared)
2N		Natural gas transmission (other than flaring)
2O		Natural gas storage (other than emissions that are vented or flared)
2P		Natural gas liquefaction, storage and transfer (other than emissions that are vented or flared)
2Q		Natural gas distribution (other than flaring)
2R		Onshore natural gas production—venting
2S		Offshore natural gas production—venting
2T		Onshore natural gas production—flaring
2U		Offshore natural gas production—flaring
2V		Natural gas gathering and boosting—venting
2W		Natural gas gathering and boosting—flaring
2X		Natural gas processing—venting
2Y		Natural gas processing—flaring
2Z		Natural gas transmission—flaring
2ZA		Natural gas storage—venting
2ZB		Natural gas storage—flaring
2ZC		Natural gas liquefaction, storage and transfer—venting

Item	Category of source	Source of emissions
2ZE		Natural gas liquefaction, storage and transfer—flaring
2ZF		Natural gas distribution—flaring
2ZG		Carbon capture and storage
2ZH		Enhanced oil recovery
3	Industrial processes	
3A		Cement clinker production
3B		Lime production
3C		Use of carbonates for the production of a product other than cement clinker, lime or soda ash
3D		Soda ash use
3E		Soda ash production
3F		Ammonia production
3G		Nitric acid production
3H		Adipic acid production
3I		Carbide production
3J		Chemical or mineral production, other than carbide production, using a carbon reductant or carbon anode
3JA		Sodium cyanide production
3JB		Hydrogen production
3K		Iron, steel or other metal production using an integrated metalworks
3L		Ferroalloys production
3M		Aluminium production
3N		Other metals production
3O		Emissions of hydrofluorocarbons and sulphur hexafluoride gases
4	Waste	
4A		Solid waste disposal on land
4AA		Biological treatment of solid waste
4B		Wastewater handling (industrial)
4C		Wastewater handling (domestic or commercial)
4D		Waste incineration

[11] Subsection 2.27(1)

After “subsection (2)”, insert “and (3)”.

[12] Subsection 2.27(2)

Repeal the subsection, substitute:

(2) In applying method 1 under section 2.20, the emission factor $\boldsymbol{EF_{ijoxec}}$ is to be one of the following:

(a) obtained by using the equipment type emission factors set out in Volume 2, section 2.3.2.3 of the 2006 IPCC Guidelines corrected to gross calorific values;

(b) estimated based on the manufacturer’s specification for the specific equipment type under relevant operational conditions, including the effect of any supplementary equipment technologies that modify methane emitted to the atmosphere;

(c) if an equipment type (k) in column 2 of the following table is used—the factor in column 3 of the following table for the equipment type in column 2 of the table:

Item	Equipment type (k)	Emission factor for gas type (j)	
		CH_4	Units
1	Gas-fired reciprocating engines – 4-stroke lean burn	13.8	kg CO_2-e /GJ
2	Gas-fired reciprocating engines – 4-stroke rich burn	1.2	kg CO_2-e /GJ
3	Gas-fired reciprocating engines – 2-stroke lean burn	17.5	kg CO_2-e /GJ
4	Gas turbines	0.1	kg CO_2-e /GJ

(3) If applicable to the facility, the method described in section A.2.2 of Appendix A of the API Compendium may be used as method 2.

Note: In 2021, the API Compendium could be accessed at www.api.org.

[13] Subsection 2.45(1) (table items 3 and 4)

Repeal the items, substitute:

3	Crude oil	ASTM D 240-02 (2007) ASTM D 4809-06	ASTM D 5291-02 (2007)	ASTM D 1298 – 99 (2005) ASTM D 5002 – 99 (2005)
4	Plant condensates and other natural gas liquids not covered by another item in this table	ASTM D 240-02 (2007) ASTM D 4809-06	ASTM D 5291-02 (2007)	ASTM D 1298 – 99 (2005)

[14] Subsection 2.47(3) (table items 3 and 4)

Repeal the items, substitute:

3	Crude oil	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)
4	Plant condensates and other natural gas liquids not covered by another item in this table	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005) ASTM D1265 – 05

[15] Part 3.3

Repeal the Part, substitute:

Part 3.3—Oil and natural gas—fugitive emissions

Division 3.3.1—Preliminary

3.41 Outline of Part

(1) This Part provides for fugitive emissions from the following:

(a) oil or gas exploration and development (see Division 3.3.2);

(b) crude oil production (see Division 3.3.3);

(c) crude oil transport (see Division 3.3.4);

(d) crude oil refining (see Division 3.3.5);

(e) onshore natural gas production, other than emissions that are vented or flared (see Division 3.3.6A);

(f) offshore natural gas production, other than emissions that are vented or flared (see Division 3.3.6B);

(g) natural gas gathering and boosting, other than emissions that are vented or flared (see Division 3.3.6C);

(h) produced water from oil and gas exploration and development, crude oil production, natural gas production or natural gas gathering and boosting, other than emissions that are vented or flared (see Division 3.3.6D);

(i) natural gas processing, other than emissions that are vented or flared (see Division 3.3.6E);

(j) natural gas transmission, other than emissions that are flared (see Division 3.3.7);

(k) natural gas storage, other than emissions that are vented or flared (see Division 3.3.7A);

(l) natural gas liquefaction, storage and transfer, other than emissions that are vented or flared (see Division 3.3.7B);

(m) natural gas distribution, other than emissions that are flared (see Division 3.3.8);

(n) natural gas production (emissions that are vented or flared) (see Division 3.3.9A);

(o) natural gas gathering and boosting (emissions that are vented or flared) (see Division 3.3.9B);

(p) natural gas processing (emissions that are vented or flared) (see Division 3.3.9C);

(q) natural gas transmission (emissions that are flared) (see Division 3.3.9D);

(r) natural gas storage (emissions that are vented or flared) (see Division 3.3.9E);

(s) natural gas liquefaction, storage or transfer (emissions that are vented or flared) (see Division 3.3.9F);

(t) natural gas distribution (emissions that are flared) (see Division 3.3.9G).

(2) The activities at a facility should be classified in accordance with the relevant definitions to apply the calculations in this Part to comprehensively cover the emissions from the facility, but not count the emissions more than once.

3.41A Interpretation

(1) Terms relating to the oil and gas industry in this Part are to be interpreted:

(a) consistently with their accepted meaning in the oil and gas industry; and

(b) where the term is relevant to methods in the API Compendium—taking into account the meaning and scope of the term in that compendium.

Note: In 2021, the API Compendium could be accessed at www.api.org.

(2) If a method in this Part allows for the use of component or equipment emissions factors from the manufacturer of the component or equipment, those factors must not be used if they are likely to result in estimates of emissions inconsistent with the principles in section 1.13.

Division 3.3.2—Oil or gas exploration and development

Subdivision 3.3.2.1—Preliminary

3.42 Application

This Division applies to fugitive emissions from venting or flaring from oil or gas exploration and development activities, including emissions from:

(a) oil well drilling; and
(b) gas well drilling; and
(c) oil well completions; and
(d) gas well completions; and
(e) well workovers; and
(f) well blowouts; and
(g) cold process vents.

Subdivision 3.3.2.2—Oil or gas exploration and development (emissions that are flared)

3.43 Available methods

(1) Subject to section 1.18, for estimating emissions released by oil or gas flaring during the year from the operation of a facility that is constituted by oil or gas exploration and development:

(a) if estimating emissions of carbon dioxide released—one of the following methods must be used:
  (i) method 1 under section 3.44;
  (ii) method 2 under section 3.45;
  (iii) method 3 under section 3.46; and
(b) if estimating emissions of methane released—one of the following methods must be used:
  (i) method 1 under section 3.44;
  (ii) method 2A under section 3.45A; and
(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:
  (i) method 1 under section 3.44;
  (ii) method 2A under section 3.45A.

Note: There is no method 4 under paragraph (a) and no method 2, 3 or 4 under paragraph (b) or (c).

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.44 Method 1—oil or gas exploration and development

(1) Method 1 is:

$$E_{ij} = Q_i \times EF_{ij}$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions of gas type (***j***) from a fuel type (***i***) flared in the oil or gas exploration and development during the year measured in CO_2-e tonnes.

Q_i is the quantity of fuel type (***i***) flared in the oil or gas exploration and development during the year measured in tonnes.

Note: This quantity includes all of the fuel type, not just hydrocarbons within the fuel type.

EF_{ij} is the emission factor for gas type (***j***) measured in tonnes of CO_2-e emissions per tonne of the fuel type (***i***) flared.

(2) For EF_{ij} in subsection (1), columns 3, 4 and 5 of an item in the following table specify the emission factor, for gas type (***j***), for each fuel type (***i***) specified in column 2 of that item.

Item	Fuel type (*i*)	Emission factor for gas type (*j*) (tonnes CO_2-e/tonnes of fuel flared)		
		CO_2	CH_4	N_2O
1	Gas	2.80	0.933	0.026
2	Crude oil and liquids	3.20	0.009	0.06

3.45 Method 2—oil or gas exploration and development (flared carbon dioxide emissions)

Combustion of gaseous fuels (flared) emissions

(1) For subparagraph 3.43(1)(a)(ii), method 2 for combustion of gaseous fuels is:

$$E_{ico_2} = Q_h \times EF_h \times OF_i + QCO_2$$

where:

E_{iCO_2} is the fugitive emissions of CO_2 from fuel type (***i***) flared in oil or gas exploration and development during the year, measured in CO_2-e tonnes.

Q_h is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in oil or gas exploration and development during the year, measured in tonnes in accordance with Division 2.3.3.

EF_h is the emission factor for the total hydrocarbons (***h***) within the fuel type (***i***) in oil or gas exploration and development during the year, measured in CO_2-e tonnes per tonne of the fuel type (***i***) flared*,* estimated in accordance with Division 2.3.3.

OF_i is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

QCO_2 is the quantity of CO_2 within fuel type (***i***) in oil or gas exploration and development during the year, measured in CO_2-e tonnes in accordance with Division 2.3.3.

Combustion of liquid fuels (flared) emissions

(2) For subparagraph 3.43(1)(a)(ii), method 2 for combustion of liquid fuels is the same as method 1 under section 3.44, but the carbon dioxide emissions factor EF_{ij} must be determined in accordance with method 2 in Division 2.4.3.

3.45A Method 2A—oil or gas exploration and development (flared methane or nitrous oxide emissions)

For subparagraphs 3.43(1)(b)(ii) and (c)(ii), method 2A is:

$$E_{ij} = Q_h \times EF_{hij} \times OF_i$$

where:

$\boldsymbol{EF_{hij}}$ is the emission factor of gas type (***j***), being methane or nitrous oxide, for the total hydrocarbons (***h***) within the fuel type (***i***) in oil or gas exploration and development during the year, mentioned for the fuel type in the table in subsection 3.44(2) and measured in CO_2-e tonnes per tonne of the fuel type (***i***) flared.

$\boldsymbol{E_{ij}}$ is the fugitive emissions of gas type (***j***), being methane or nitrous oxide, from fuel type (***i***) flared from oil or gas exploration and development during the year, measured in CO_2-e tonnes.

$\boldsymbol{OF_i}$ is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

$\boldsymbol{Q_h}$ is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in oil or gas exploration and development during the year, measured in tonnes in accordance with Division 2.3.3 for gaseous fuels or Division 2.4.3 for liquid fuels.

3.46 Method 3—oil or gas exploration and development

Combustion of gaseous fuels (flared) emissions

(1) For subparagraph 3.43(1)(a)(iii), method 3 for the combustion of gaseous fuels is the same as method 2, but the carbon dioxide emissions factor $\boldsymbol{EF_h}$ must be determined in accordance with method 3 in Division 2.3.4.

Combustion of liquid fuels (flared) emissions

(2) For subparagraph 3.43(1)(a)(iii), method 3 for the combustion of liquid fuels is the same as method 2, but the carbon dioxide emissions factor $\boldsymbol{EF_h}$ must be determined in accordance with method 3 in Division 2.4.4.

Subdivision 3.3.2.3—Oil or gas exploration and development—fugitive emissions from system upsets, accidents and deliberate releases

3.46A Available methods

(1) Subject to section 1.18, the methods mentioned in subsections (2) and (3) must be used for estimating fugitive emissions that result from system upsets, accidents and deliberate releases during a reporting year from the operation of a facility that is constituted by oil or gas exploration and development.

(2) To estimate emissions for methane and carbon dioxide that result from deliberate releases from process vents, systems upsets and accidents at a facility during a year, for each oil or gas exploration and development activity one of the following methods must be used:

(a) method 1 under:

(i) section 3.46AB (natural gas well completions); and

(ii) section 3.56B (emissions from system upsets, accidents and deliberate releases from process vents); and

(iii) section 3.85B (cold process vents); and

(iv) section 3.85P (well workovers);

(b) method 4 under:

(i) for emissions of methane and carbon dioxide from natural gas well completions activities, well workovers, cold process vents and well blowouts—section 3.46B; and

(ii) for emissions and activities not mentioned in subparagraph (i)—Part 1.3.

(3) For estimating incidental emissions that result from deliberate releases from process vents, system upsets and accidents during a year from the operation of the facility, another method may be used that is consistent with the principles mentioned in section 1.13.

Note: There is no method 2 or 3 for this Subdivision.

Subdivision 3.3.2.3.1—Fugitive emissions that result from deliberate releases from process vents, system upsets and accidents–well completions

3.46AB Method 1—vented emissions from natural gas well completions

(1) Method 1 is:

$$E_{ij} = \Sigma_k \; Q_{ik} \times EF_{ijk} \times S_{ij} / SD_{ij}$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions of gas type (***j***), being methane or carbon dioxide, vented from the natural gas exploration and development during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e and estimated by summing up the emissions released from all of the equipment of type (***k***) specified in column 2 of the table in subsection (2), if the equipment is used in the natural gas exploration and development.

$\boldsymbol{Q_{ik}}$ is the total of the number of well completion events for equipment of type (***k***) specified in column 2 of the table in subsection (2) during the year, if the equipment is used in the natural gas exploration and development.

Note: Consistent with subsection 3.41(2), a well completion event should be reported for a single reporting year and not separately in two consecutive years.

$\boldsymbol{EF_{ijk}}$ is the emission factor for gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e per well completion event using equipment type (***k***) specified in column 2 of the table in subsection (2) during the year, if the equipment is used in the natural gas exploration and development.

$\boldsymbol{S_{ij}}$ is the measured share of gas type (***j***), being methane or carbon dioxide, in the unprocessed natural gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

$\boldsymbol{SD_{ij}}$ is the default share of gas type (***j***) in the unprocessed natural gas (***i***), for methane SD is 0.832 and for carbon dioxide SD is 0.0345.

(2) For $\boldsymbol{EF_{ijk}}$ mentioned in subsection (1), column 3 of an item in the following table specifies the emission factor for methane for an equipment of type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide for an equipment of type (***k***) specified in column 2 of that item:

Item	Equipment type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	
1	Well completion without hydraulic fracturing	5.5	1.1×10^{-2}	tonnes CO_2-e per well completion event

Item	Equipment type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	
2	Well completion with hydraulic fracturing and venting (no flaring)	1031	4.2	tonnes CO_2-e per well completion event
3	Well completion with hydraulic fracturing with capture (no flaring)	90.8	0.37	tonnes CO_2-e per well completion event
4	Well completion with hydraulic fracturing and flaring	136.6	0.56	tonnes CO_2-e per well completion event

3.46B Method 4—vented emissions from natural gas well completions, well workovers, cold process vents and well blowouts

Method 4 is, for natural gas well completion activities, well workovers, cold process vents and well blowouts, as described in section 5.7.1 of the API Compendium.

Division 3.3.3—Crude oil production

Subdivision 3.3.3.1—Preliminary

3.47 Application

(1) This Division applies to fugitive emissions from crude oil production activities, including emissions from flaring, from:

(a) an oil wellhead; and

(b) well servicing; and

(c) oil sands mining; and

(d) shale oil mining; and

(e) the transportation of untreated production to treating or extraction plants; and

(f) activities at extraction plants or heavy oil upgrading plants, and gas reinjection systems; and

(g) activities at upgrading plants and associated gas reinjection systems.

(2) For paragraph (1)(e), ***untreated production*** includes:

(a) well effluent; and

(b) emulsion; and

(c) oil shale; and

(d) oil sands.

Subdivision 3.3.3.2—Crude oil production (non-flared)—fugitive leak emissions of methane

3.48 Available methods

(1) Subject to section 1.18, for estimating fugitive emissions of methane, other than fugitive emissions of methane specified in subsection (1A), during a year from the operation of a facility that is constituted by crude oil production, one of the following methods must be used:

(a) method 1 under section 3.49;

(b) method 2 under section 3.50;

(c) method 3 under section 3.51.

Note: There is no method 4 for this Division.

(1A) For subsection (1), the following fugitive emissions of methane are specified:

(a) fugitive emissions from oil or gas flaring;

(b) fugitive emissions that result from system upsets, accidents or deliberate releases from process vents.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.49 Method 1—crude oil production (non-flared) emissions of methane

(1) Method 1 is:

$$E_{ij} = \Sigma_k (Q_{ik} \times EF_{ijk}) + Q_i \times EF_{(l)\ ij}$$

where:

E_{ij} is the fugitive emissions of methane (*j*) from the crude oil production during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of methane (*j*) measured in tonnes of CO_2-e and estimated by summing up the emissions released from all of the equipment of type (*k*) specified in column 2 of the table in subsection (2), if the equipment is used in the crude oil production.

Q_{ik} is the total of the quantities of crude oil measured in tonnes that pass through each equipment of type (*k*) specified in column 2 of the table in subsection (2) during the year, if the equipment is used in the crude oil production.

EF_{ijk} is the emission factor for methane (*j*) measured in tonnes of CO_2-e per tonne of crude oil that passes through each equipment of type (*k*) specified in column 2 of the table in subsection (2) during the year, if the equipment is used in the crude oil production.

Q_i is the total quantity of crude oil (*i*) measured in tonnes that passes through the crude oil production.

$EF_{(l)\,ij}$ is 1.6×10^{-3}, which is the emission factor for methane (*j*) from general leaks in the crude oil production, measured in CO_2-e tonnes per tonne of crude oil that passes through the crude oil production.

(2) For EF_{ijk} mentioned in subsection (1), column 3 of an item in the following table specifies the emission factor for an equipment of type (*k*) specified in column 2 of that item:

Item	Equipment type (k)	Emission factor for gas type (j) (tonnes CO_2-e/tonnes fuel throughput)
		CH_4
1	Internal floating tank	1.12×10^{-6}
2	Fixed roof tank	5.60×10^{-6}
3	Floating tank	4.27×10^{-6}

(3) For $EF_{(l)\,ij}$ in subsection (1), general leaks in the crude oil production comprise the emissions (other than vent emissions) from equipment listed in sections 5.4.3, 5.6.4, 5.6.5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil production.

3.50 Method 2—crude oil production (non-flared) emissions of methane

(1) Method 2 is:

$$E_{ij} = \Sigma_k (Q_{ik} \times EF_{ijk})$$

where:

E_{ij} is the fugitive emissions of methane (*j*) from the crude oil production during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of methane (*j*) measured in tonnes of CO_2-e and estimated by summing up the emissions released from each equipment type (*k*) listed in sections 5.4.1, 5.4.2, 5.4.3, 5.6.4, 5.6.5 and 6.1.2 of the API Compendium, if the equipment type is used in the crude oil production.

Q_{ik} is the total of the quantities of crude oil that pass through each equipment type (*k*), or the number of equipment units of type (*k*), listed in sections 5.4.1, 5.4.2, 5.4.3, 5.6.4, 5.6.5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil production, measured in tonnes.

EF*ijk*** is the emission factor of methane (***j***) measured in tonnes of CO_2-e per tonne of crude oil that passes through each equipment type (***k***) listed in sections 5.4.1, 5.4.2, 5.4.3, 5.6.4, 5.6.5 and 6.1.2 of the API Compendium as determined under subsection (2), if the equipment is used in the crude oil production.

(2) For ***EF****ijk***, the emission factors for methane (***j***), as crude oil passes through an equipment type (***k***), are:

(a) as listed in sections 5.4.1, 5.4.2, 5.4.3, 5.6.4, 5.6.5 and 6.1.2 of the API Compendium, for the equipment type; or

(b) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type—those factors.

3.51 Method 3—crude oil production (non-flared) emissions of methane

(1) Method 3 is:

$$E_{ij} = \sum_k (EF_{ijk} \times T_{ik} \times N_k)$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions of methane (***j***) from the crude oil production during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of methane (***j***) measured in tonnes of CO_2-e and estimated by summing up the emissions released from each component type (***k***) listed in section 6.1.3 of the API Compendium, if the component type is used in the crude oil production.

$\boldsymbol{EF_{ijk}}$ is the emission factor of methane (***j***) measured in tonnes of CO_2-e per component-hour that passes through each component type (***k***) listed in section 6.1.3 of the API Compendium as determined under subsection (2), if the component is used in the crude oil production.

$\boldsymbol{T_{ik}}$ is the average hours of operation during the year of the components of each component type (***k***) listed in section 6.1.3 of the API Compendium, if the component type is used in the crude oil production, measured in hours per year.

$\boldsymbol{N_k}$ is the total number of each component type (***k***) listed in section 6.1.3 of the API Compendium, if the component type is used in the crude oil production, measured in components.

(2) For $\boldsymbol{EF_{ijk}}$, the emission factors for methane (***j***), as crude oil passes through a component type (***k***), are:

(a) column 3 of an item in the following table, which specifies the emission factor for a component of type (***k***) specified in column 2 of that item:

Item	Component type (k)	Emission factor for gas type (j) (tonnes CO_2-e/component-hour)
		CH_4
1	Valves – heavy crude production	3.64×10^{-7}
2	Valves – light crude production	3.70×10^{-5}

Item	Component type (k)	Emission factor for gas type (j) (tonnes CO_2-e/component-hour)
		CH_4
3	Connectors – heavy crude production	2.23×10^{-7}
4	Connectors – light crude production	4.59×10^{-6}
5	Flanges – heavy crude production	6.13×10^{-7}
6	Flanges – light crude production	2.15×10^{-6}
7	Open-ended lines – heavy crude production	4.34×10^{-6}
8	Open-ended lines – light crude production	3.39×10^{-5}
9	Pump Seals – light crude production	8.90×10^{-6}
10	Others – heavy crude production	1.96×10^{-6}
11	Others – light crude production	2.10×10^{-4}

Note: API Publication 4615 defines light crude as oil with an API gravity of 20 or more, and heavy crude as oil with an API gravity of less than 20.

(b) if the manufacturer of the component supplies component-specific emission factors for the component type—those factors.

Subdivision 3.3.3.3—Crude oil production (flared)—fugitive emissions of carbon dioxide, methane and nitrous oxide

3.52 Available methods

(1) Subject to section 1.18, for estimating emissions released by oil or gas flaring during a year from the operation of a facility that is constituted by crude oil production:

(a) if estimating emissions of carbon dioxide released—one of the following methods must be used:

(i) method 1 under section 3.53;

(ii) method 2 under section 3.54;

(iii) method 3 under section 3.55; and

(b) if estimating emissions of methane released—one of the following methods must be used:

(i) method 1 under section 3.53;

(ii) method 2A under section 3.54A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:

(i) method 1 under section 3.53;

(ii) method 2A under section 3.54A.

Note: There is no method 4 under paragraph (a) and no method 2, 3 or 4 under paragraph (b) or (c).

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.53 Method 1—crude oil production (flared) emissions

(1) For subparagraph 3.52(a)(i), method 1 is:

$$E_{ij} = Q_i \times EF_{ij}$$

where:

$\boldsymbol{E_{ij}}$ is the emissions of gas type (***j***) measured in CO_2-e tonnes from a fuel type (***i***) flared in crude oil production during the year.

$\boldsymbol{Q_i}$ is the quantity of fuel type (***i***) measured in tonnes flared in crude oil production during the year.

Note: This quantity includes all of the fuel type, not just hydrocarbons within the fuel type.

$\boldsymbol{EF_{ij}}$ is the emission factor for gas type (***j***) measured in tonnes of CO_2-e emissions per tonne of the fuel type (***i***) flared.

(2) For $\boldsymbol{EF_{ij}}$ mentioned in subsection (1), columns 3, 4 and 5 of an item in following table specify the emission factor for each fuel type (***i***) specified in column 2 of that item.

Item	**Fuel type (*i*)**	**Emission factor for gas type (*j*) (tonnes CO_2-e/tonnes of fuel flared)**		
		CO_2	**CH_4**	**N_2O**
1	Gas	2.80	0.933	0.026
2	Crude oil and liquids	3.20	0.009	0.06

3.54 Method 2—crude oil production

Combustion of gaseous fuels (flared) emissions of carbon dioxide

(1) For subparagraph 3.52(1)(a)(ii), method 2 for combustion of gaseous fuels is:

$$E_{ico_2} = Q_h \times EF_h \times OF_i + QCO_2$$

where:

$\boldsymbol{E_{iCO_2}}$ is the fugitive emissions of CO_2 from fuel type (***i***) flared in crude oil production during the year, measured in CO_2-e tonnes.

$\boldsymbol{Q_h}$ is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in crude oil production during the year, measured in tonnes in accordance with Division 2.3.3.

$\boldsymbol{EF_h}$ is the emission factor for the total hydrocarbons (***h***) within the fuel type (***i***) in crude oil production during the year, measured in CO_2-e tonnes per tonne of fuel type (***i***) flared, estimated in accordance with method 2 in Division 2.3.3.

$\boldsymbol{OF_i}$ is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

$\boldsymbol{QCO_2}$ is the quantity of CO_2 within the fuel type (***i***) in crude oil production during the year, measured in CO_2-e tonnes in accordance with Division 2.3.3.

Combustion of liquid fuels (flared) emissions of carbon dioxide

(2) For subparagraph 3.51(1)(a)(ii), method 2 for combustion of liquid fuels is the same as method 1, but the carbon dioxide emissions factor $\boldsymbol{EF_h}$ must be determined in accordance with method 2 in Division 2.4.3.

3.54A Method 2A—crude oil production (flared methane or nitrous oxide emissions)

For subparagraphs 3.52(1)(b)(ii) and (c)(ii), method 2A is:

$$E_{ij} = Q_h \times EF_{hij} \times OF_i$$

where:

$\boldsymbol{EF_{hij}}$ is the emission factor of gas type (***j***), being methane or nitrous oxide, for the total hydrocarbons (***h***) within the fuel type (***i***) in crude oil production during the year, mentioned for the fuel type in the table in subsection 3.53(2) and measured in CO_2-e tonnes per tonne of the fuel type (***i***) flared.

$\boldsymbol{E_{ij}}$ is the fugitive emissions of gas type (***j***), being methane or nitrous oxide, from fuel type (***i***) flared from crude oil production during the year, measured in CO_2-e tonnes.

$\boldsymbol{OF_i}$ is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

$\boldsymbol{Q_h}$ is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in crude oil production during the year, measured in tonnes in accordance with Division 2.3.3 for gaseous fuels or Division 2.4.3 for liquid fuels.

3.55 Method 3—crude oil production

Combustion of gaseous fuels (flared) emissions of carbon dioxide

(1) For subparagraph 3.52(1)(a)(iii), method 3 for the combustion of gaseous fuels is the same as method 2, but the carbon dioxide emissions factor $\boldsymbol{EF_h}$ must be determined in accordance with method 3 in Division 2.3.4.

Combustion of liquid fuels (flared) emissions of carbon dioxide

(2) For subparagraph 3.52(1)(a)(iii), method 3 for the combustion of liquid fuels is the same as method 2, but the carbon dioxide emissions factor $\boldsymbol{EF_h}$ must be determined in accordance with method 3 in Division 2.4.4.

Subdivision 3.3.3.4—Crude oil production (non-flared)—fugitive vent emissions of methane and carbon dioxide

3.56A Available methods

(1) Subject to section 1.18, the methods mentioned in subsections (2) and (3) must be used for estimating fugitive emissions that result from system upsets, accidents and deliberate releases from process vents during a year from the operation of a facility that is constituted by crude oil production.

(2) To estimate emissions that result from deliberate releases from process vents, system upsets and accidents during a year from the operation of the facility, one of the following methods must be used:

(a) method 1 under section 3.56B;

(b) method 4 under Part 1.3.

(3) For estimating incidental emissions that result from deliberate releases from process vents, system upsets and accidents during a year from the operation of the facility, another method may be used that is consistent with the principles mentioned in section 1.13.

Note: There is no method 2 or 3 for this Subdivision.

Note: Methods to estimate vented emissions from condensate storage tanks are available at section 3.85D.

3.56B Method 1—emissions from system upsets, accidents and deliberate releases from process vents

(1) Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Gas treatment processes	Section 5.1
2	Cold process vents	Section 5.3
3	Storage tanks - vented emissions	Section 5.4
4	Other venting sources—gas driven pneumatic devices	Section 5.6.1
5	Other venting sources—gas driven chemical injection pumps	Section 5.6.2
6	Non-routine activities—production related non-routine emissions	Section 5.7.1 and 5.7.2

(2) However, emissions from well workovers may use method 1 under section 3.85P (as if that method referred to crude oil production instead of natural gas production).

Division 3.3.4—Crude oil transport

3.57 Application

This Division applies to fugitive emissions from crude oil transport activities, other than emissions that are flared.

3.58 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating fugitive emissions of methane released during a year from the operation of a facility that is constituted by crude oil transport:

(a) method 1 under section 3.59;

(b) method 2 under section 3.60.

Note: There is no method 3 or 4 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.59 Method 1—crude oil transport

Method 1 is:

$$E_{ij} = Q_i \times EF_{ij}$$

where:

E_{ij} is the fugitive emissions of methane (***j***) from the crude oil transport during the year measured in CO_2-e tonnes.

Q_i is the quantity of crude oil (***i***) measured in tonnes and transported during the year.

EF_{ij} is the emission factor for gas type (***j***), being methane, which is 9.74×10^{-4} tonnes CO_2-e per tonnes of crude oil transported during the year.

3.60 Method 2—fugitive emissions from crude oil transport

(1) Method 2 is:

$$E_{ij} = \sum_k (Q_{ik} \times EF_{ijk})$$

where:

E_{ij} is the fugitive emissions of gas type (***j***), being methane, from the crude oil transport during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (***j***), being methane, measured in tonnes of CO_2-e and estimated by summing up the emissions from each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil transport.

Q_{ik} is the total of the quantities of crude oil measured in tonnes that pass through each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil transport.

EF_{ijk} is the emission factor of gas type (***j***), being methane, measured in tonnes of CO_2-e per tonne of crude oil that passes through each equipment type (***k***) listed in sections 5 and

6.1.2 of the API Compendium as determined under subsection (2), if the equipment is used in the crude oil transport.

(2) For $\boldsymbol{EF_{ijk}}$**,** the emission factors for gas type (***j***), being methane, as crude oil passes through equipment type (***k***), are:

(a) as listed in sections 5 and 6.1.2 of the API Compendium, for the equipment type; or

(b) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type—those factors.

Division 3.3.5—Crude oil refining

3.62 Application

This Division applies to fugitive emissions from crude oil refining activities, including emissions from flaring at petroleum refineries.

3.63 Available methods

(1) Subject to section 1.18, for estimating emissions released during a year from the operation of a facility that is constituted by crude oil refining the methods as set out in this section must be used.

Crude oil refining and storage tanks

(2) One of the following methods must be used for estimating fugitive emissions of methane that result from crude oil refining and from storage tanks for crude oil:

(a) method 1 under section 3.64;

(b) method 2 under section 3.65;

(c) method 3 under section 3.66.

Note: There is no method 4 for subsection (2).

Process vents, system upsets and accidents

(3) One of the following methods must be used for estimating fugitive emissions of each type of gas, being carbon dioxide, methane and nitrous oxide, that result from deliberate releases from process vents, system upsets and accidents:

(a) method 1 under section 3.67;

(b) method 4 under section 3.68.

Note: There is no method 2 or 3 for subsection (3).

Flaring

(4) For estimating emissions released from gas flared from crude oil refining:

(a) one of the following methods must be used for estimating emissions of carbon dioxide released:

(i) method 1 under section 3.69;

(ii) method 2 under section 3.70;

(iii) method 3 under section 3.71; and

(b) if estimating emissions of methane released—one of the following methods must be used:

(i) method 1 under section 3.69;

(ii) method 2A under section 3.70A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:

(i) method 1 under section 3.69;

(ii) method 2A under section 3.70A.

Note: The flaring of gas from crude oil refining releases emissions of carbon dioxide, methane and nitrous oxide. The reference to gas type (***j***) in method 1 under section 3.69 is a reference to these gases. The same formula is used to estimate emissions of each of these gases. There is no method 4 for emissions of carbon dioxide and no method 2, 3 or 4 for emissions of nitrous oxide or methane.

(5) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

Subdivision 3.3.5.1—Fugitive emissions from crude oil refining and from storage tanks for crude oil

3.64 Method 1—crude oil refining and storage tanks for crude oil

Method 1 is:

$$E_{ij} = \Sigma_i\ Q_i \times EF_{ij}$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions of gas type (***j***), being methane or carbon dioxide, from fuel type (***i***) being crude oil refined or stored in tanks during the year measured in CO_2-e tonnes.

$\boldsymbol{\sum_i}$ is the sum of emissions of gas type (***j***), being methane or carbon dioxide, released during refining and from storage tanks during the year.

$\boldsymbol{Q_i}$ is the quantity of crude oil (***i***) refined or stored in tanks during the year measured in tonnes.

$\boldsymbol{EF_{ij}}$ is the emission factor for gas type (***j***), being methane or carbon dioxide, being 9.47×10^{-4} tonnes CO_2-e per tonne of crude oil refined and 1.73×10^{-4} tonnes CO_2-e per tonne of crude oil stored in tanks.

3.65 Method 2—crude oil refining and storage tanks for crude oil

(1) Method 2 is:

$$E_{ij} = \Sigma_k\ (Q_{ik} \times EF_{ijk})$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions of gas type (***j***), being methane, from the crude oil refining and from storage tanks during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***), being methane, measured in tonnes of CO_2-e estimated by summing up the emissions released from each equipment types (***k***) listed in sections 5 and 6.1.2 of the API Compendium as determined under subsection (2), if the equipment is used in the crude oil refining and in the storage tanks.

$\boldsymbol{Q_{ik}}$ is the total of the quantities of crude oil (***i***) measured in tonnes that pass through each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil refining and in the storage tanks.

$\boldsymbol{EF_{ijk}}$ is the emission factor for gas type (***j***), being methane, measured in tonnes of CO_2-e per tonne of crude oil that passes through each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil refining and in the storage tanks.

(2) For $\boldsymbol{EF_{ijk}}$, the emission factors for gas type (***j***), being methane, as the crude oil passes through an equipment type (***k***) are:

(a) as listed in sections 5 and 6.1.2 of the API Compendium, for the equipment type; or

(b) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type—those factors.

3.66 Method 3—crude oil refining and storage tanks for crude oil

(1) Method 3 is:

$$E_{ij} = \sum_k (Q_{ik} \times EF_{ijk})$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions of gas type (***j***), being methane, from the crude oil refining and from storage tanks during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***), being methane, measured in tonnes of CO_2-e and estimated by summing up the emissions released from each component type (***k***) listed in section 6.1.3 of the API Compendium, if the component type is used in the crude oil refining and from storage tanks.

$\boldsymbol{Q_{ik}}$ is the total of the quantities of crude oil (***i***) that pass through each component type (***k***), or the number of components of each component type (***k***), listed in section 6.1.3 of the API Compendium , if the component is used in the crude oil refining and from storage tanks, measured in tonnes.

$\boldsymbol{EF_{ijk}}$ is the emission factor of gas type (***j***), being methane, measured in tonnes of CO_2-e per tonne of crude oil that passes through each component type (***k***) listed in section 6.1.3 of the API Compendium as determined under subsection (2), if the component is used in the crude oil refining and from storage tanks.

(2) For $\boldsymbol{EF_{ijk}}$, the emission factors for gas type (***j***), being methane or carbon dioxide, as crude oil passes through a component type (***k***), are:

(a) as listed in section 6.1.3 of the API Compendium, for the component type; or

(b) if the manufacturer of the component supplies component-specific emission factors for the component type—those factors.

Subdivision 3.3.5.2—Fugitive emissions from deliberate releases from process vents, system upsets and accidents

3.67 Method 1—fugitive emissions from deliberate releases from process vents, system upsets and accidents

Method 1 is:

$$E_i = Q_i \times CCF_i \times 3.664$$

where:

$\boldsymbol{E_i}$ is the fugitive emissions of carbon dioxide during the year from deliberate releases from process vents, system upsets and accidents in the crude oil refining measured in CO_2-e tonnes.

$\boldsymbol{Q_i}$ is the quantity of refinery coke (***i***) burnt to restore the activity of the catalyst of the crude oil refinery (and not used for energy) during the year measured in tonnes.

$\boldsymbol{CCF_i}$ is the carbon content factor for refinery coke (***i***) as mentioned in Schedule 3.

3.664 is the conversion factor to convert an amount of carbon in tonnes to an amount of carbon dioxide in tonnes.

3.68 Method 4—deliberate releases from process vents, system upsets and accidents

(1) Method 4 is:

(a) is as set out in Part 1.3; or

(b) uses the process calculation approach in section 5.2 of the API Compendium.

(2) For paragraph (1)(b), all carbon monoxide is taken to fully oxidise to carbon dioxide and must be included in the calculation.

Subdivision 3.3.5.3—Fugitive emissions released from gas flared from the oil refinery

3.69 Method 1—gas flared from crude oil refining

(1) Method 1 is:

$$E_{ij} = Q_i \times EF_{ij}$$

where:

$\boldsymbol{E_{ij}}$ is the emissions of gas type (***j***) released from the gas flared in the crude oil refining during the year measured in CO_2-e tonnes.

$\boldsymbol{Q_i}$ is the quantity of gas for the fuel type (***i***) flared during the year measured in tonnes.

Note: This quantity includes all of the fuel type, not just hydrocarbons within the fuel type.

$\boldsymbol{EF_{ij}}$ is the emission factor for gas type (***j***) measured in tonnes of CO_2-e emissions per tonne of gas type (***j***) flared in the crude oil refining during the year.

(2) For $\boldsymbol{EF_{ij}}$ in subsection (1), columns 3, 4 and 5 of an item in the following table specify the emission factor for gas type (***j***) for the fuel type (***i***) specified in column 2 of that item:

Item	fuel type (i)	Emission factor of gas type (j) (tonnes CO_2-e/tonnes fuel flared)		
		CO_2	CH_4	N_2O
1	Gas	2.7	0.133	0.026
2	Crude oil and liquids	3.2	0.009	0.06

3.70 Method 2—gas flared from crude oil refining

For subparagraph 3.63(4)(a)(ii), method 2 is:

$$E_{ico_2} = Q_h \times EF_h \times OF_i + QCO_2$$

where:

$\boldsymbol{E_{iCO_2}}$ is the fugitive emissions of CO_2 from fuel type (***i***) flared in crude oil refining during the year, measured in CO_2-e tonnes.

$\boldsymbol{Q_h}$ is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in crude oil refining during the year, measured in tonnes in accordance with Division 2.3.3.

$\boldsymbol{EF_h}$ is the emission factor for the total hydrocarbons (***h***) within the fuel type (***i***) in the crude oil refining during the year, measured in CO_2-e tonnes per tonne of fuel type (***i***) flared, estimated in accordance with method 2 in Division 2.3.3.

$\boldsymbol{OF_i}$ is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

$\boldsymbol{QCO_2}$ is the quantity of CO_2 within the fuel type (***i***) in the crude oil refining during the year, measured in CO_2-e tonnes in accordance with Division 2.3.3.

3.70A Method 2A—crude oil refining (flared methane or nitrous oxide emissions)

For subparagraphs 3.63(4)(b)(ii) and (c)(ii), method 2A is:

$$E_{ij} = Q_h \times EF_{hij} \times OF_i$$

where:

$\boldsymbol{EF_{hij}}$ is the emission factor of gas type (***j***), being methane or nitrous oxide, for the total hydrocarbons (***h***) within the fuel type (***i***) in crude oil refining during the year, mentioned for the fuel type in the table in subsection 3.69(2) and measured in CO_2-e tonnes per tonne of the fuel type (***i***) flared.

$\boldsymbol{E_{ij}}$ is the fugitive emissions of gas type (***j***), being methane or nitrous oxide, from fuel type (***i***) flared from crude oil refining during the year, measured in CO_2-e tonnes.

$\boldsymbol{OF_i}$ is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

$\boldsymbol{Q_h}$ is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in crude oil refining during the year, measured in tonnes in accordance with Division 2.3.3.

3.71 Method 3—gas flared from crude oil refining

For subparagraph 3.63(4)(a)(iii), method 3 is the same as method 2 under section 3.70, but the emission factor $\boldsymbol{EF_{ij}}$ must be determined in accordance with method 3 for the consumption of gaseous fuels as specified in Division 2.3.4.

Division 3.3.6A—Onshore natural gas production (other than emissions that are vented or flared)

3.72 Application

This Division applies to fugitive emissions from onshore natural gas production activities, other than emissions that are vented or flared, including emissions from onshore natural gas wellheads.

Subdivision 3.3.6A.1—Onshore natural gas production, other than emissions that are vented or flared—wellheads

3.73 Available methods

(1) Subject to section 1.18 and subsections (3) and (4), one of the following methods must be used for estimating fugitive emissions of methane and carbon dioxide (other than emissions that are vented or flared) released during a year from the operation of a facility that is constituted by onshore natural gas production:

(a) method 1 under section 3.73A;

(b) method 2 under section 3.73B;

(c) method 3 under section 3.73C.

Note: There is no method 4 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

(3) If method 2 is used for a facility, all other available methods 2 must be used in Divisions 3.3.6B, 3.3.6C, 3.3.6E, 3.3.7A and 3.3.7B if those Divisions are applicable to the facility.

(4) If method 3 is used for a facility, all other available methods 3 must be used in Divisions 3.3.6B, 3.3.6C, 3.3.6E, 3.3.7A and 3.3.7B if those Divisions are applicable to the facility.

3.73A Method 1—onshore natural gas production, other than emissions that are vented or flared—wellheads

(1) Method 1 is:

$$E_{ij} = \Sigma_k (Q_{ik} \times EF_{ijk} \times S_{ij} / SD_{ij})$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the onshore natural gas production during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) specified in column 2 of an item in the table in subsection (2), if the equipment is used in the onshore natural gas production.

$\boldsymbol{Q_{ik}}$ is the total of the quantities of unprocessed natural gas (***i***) that pass through each equipment type (***k***) specified in column 2 of the table in subsection (2), during the year measured in tonnes in accordance with Division 2.3.6.

$\boldsymbol{EF_{ijk}}$ is the emission factor for gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes per tonne of unprocessed natural gas (***i***) that passes through each equipment type (***k***), if the equipment is used in the onshore natural gas production during the year.

Note: Consistent with subsection 3.41(2), emissions associated with any piece of equipment included in this definition should not be counted under this section if those emissions are also counted as equipment emissions under another section within this Part.

$\boldsymbol{S_{ij}}$ is the measured share of each gas type (***j***), being methane or carbon dioxide, in the unprocessed gas ***(i),*** by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

$\boldsymbol{SD_{ij}}$ is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.98 and for carbon dioxide SD is 0.02.

(2) For $\boldsymbol{EF_{ijk}}$ in subsection (1), column 3 of an item in the following table specifies the emission factor for gas type (***j***) being methane for an equipment type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item:

Item	**Equipment type (k)**	**Emission factor for gas type (j)**		
		CH_4	CO_2	Units
1	Onshore natural gas wellheads	1.32×10^{-3}	2.60×10^{-6}	tonnes CO_2-e/t gas throughput

3.73B Method 2—onshore natural gas production, other than emissions that are vented or flared—wellheads

(1) Method 2 is:

$$E_{ij} = \Sigma_k (T_{ik} \times N_{ik} \times EF_{ijk}) \times S_{ij}/SD_{ij}$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the onshore natural gas production during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) specified in column 2 of an item in the table in subsection (2), if the equipment is used in the onshore natural gas production.

$\boldsymbol{T_{ik}}$ is the average hours of operation during the year of the equipment of each equipment type (***k***), if the equipment is used in the onshore natural gas production during the year.

$\boldsymbol{N_{ik}}$ is the total number of equipment units of each equipment type (***k***), if the equipment type is used in the onshore natural gas production during the year.

$\boldsymbol{EF_{ijk}}$ is the emission factor of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e per equipment type (***k***) – hour as determined under subsection (2), if the equipment is used in the onshore natural gas production.

Note: Consistent with subsection 3.41(2), emissions associated with any piece of equipment included in this definition should not be counted under this section if those emissions are also counted as equipment emissions under another section within this Part.

S_{ij} is the measured share of each gas type (***j***), being methane or carbon dioxide, in the unprocessed gas ***(i),*** by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.788 and for carbon dioxide SD is 0.02.

(2) For EF_{ijk} in subsection (1):

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for an equipment type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item:

Item	**Equipment type (k)**	**Emission factor for gas type (j)**		
		CH_4	CO_2	Units
1	Gas wellheads	5.04×10^{-4}	1.25×10^{-6}	tonnes CO_2-e /equipment - hour
2	Gas separators	1.24×10^{-3}	3.08×10^{-6}	tonnes CO_2-e /equipment - hour
3	Gas heaters	1.29×10^{-3}	3.20×10^{-6}	tonnes CO_2-e /equipment - hour
4	Reciprocating compressor	4.60×10^{-2}	1.14×10^{-4}	tonnes CO_2-e /equipment - hour
5	Screw compressor	2.88×10^{-2}	7.15×10^{-5}	tonnes CO_2-e /equipment - hour
6	Metering installation and associated piping	9.86×10^{-4}	2.45×10^{-6}	tonnes CO_2-e /equipment - hour
7	Dehydrators	2.00×10^{-3}	4.96×10^{-6}	tonnes CO_2-e /equipment - hour

(b) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type—those factors are the relevant emissions factors.

3.73C Method 3—onshore natural gas production, other than emissions that are vented or flared—wellheads

(1) Method 3 is:

$$E_{ij} = \sum_k (T_{ik} \times N_{ik} \times EF_{ijk}) \times S_{ij} / SD_{ij}$$

where:

E_{ij} is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the onshore natural gas production during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e and estimated by summing up the emissions released from each component type (***k***), if the component type is used in the onshore natural gas production during the year.

EF_{ijk} is the emission factor of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e per component-hour for each component type (***k***) as determined under subsection (2) or (3), if the component is used in the onshore natural gas production during the year.

Note: Consistent with subsection 3.41(2), emissions associated with any components included in this definition should not be counted under this section if those emissions are also counted as component emissions under another section within this Part.

N_{ik} is the total number of components of each component type (***k***) if the component type is used in the onshore natural gas production during the year.

T_{ik} is:

(a) if subsection (2) applies—the average hours of operation during the year of the component of each component type (***k***), if the component is used in the onshore natural gas production;

(b) if subsection (3) applies—an engineering estimate of the number of hours in the year the component type (***k***) was operational as a leaker or non leaker based on the best available data and subsection (4).

S_{ij} is the measured share of gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.788 and for carbon dioxide SD is 0.02.

(2) Unless subsection (3) is elected and used for all components under this method, EF_{ijk}, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for a component type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for a component type (***k***) specified in column 2 of that item:

Item	Component type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Valves – gas production	7.36×10^{-5}	1.83×10^{-7}	tonnes CO_2-e /component - hour
2	Connectors – gas production	8.99×10^{-6}	2.23×10^{-8}	tonnes CO_2-e / component - hour
3	Flanges – gas production	3.30×10^{-6}	8.22×10^{-9}	tonnes CO_2-e / component - hour
4	Open-ended lines – gas production	1.92×10^{-5}	4.78×10^{-8}	tonnes CO_2-e / component - hour
5	Pump Seals – gas production	5.46×10^{-6}	1.36×10^{-8}	tonnes CO_2-e / component - hour
6	Others – gas production	2.57×10^{-4}	6.40×10^{-7}	tonnes CO_2-e / component - hour

Note: These component types are listed in section 6.1.3 of the API Compendium.

(b) if the manufacturer of the component supplies component-specific emission factors for the component type—those factors.

(3) If an LDAR program has been carried out at the facility in relation to onshore natural gas production components in accordance with subsection (4) and this subsection elected for all components under this method, EF_{ijk}, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item; and

(b) column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item:

Item	Component and leaker/non leaker type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Valves—non leaker	7.56×10^{-6}	1.88×10^{-8}	tonnes CO_2-e /component - hour
2	Values—leaker	5.60×10^{-3}	1.39×10^{-5}	tonnes CO_2-e / component - hour
3	Pumps—non leaker	4.20×10^{-6}	1.04×10^{-8}	tonnes CO_2-e / component - hour
4	Pumps—leaker	9.80×10^{-3}	2.44×10^{-5}	tonnes CO_2-e / component - hour
5	Flanges—non leaker	3.92×10^{-7}	9.75×10^{-10}	tonnes CO_2-e / component - hour
6	Flanges—leaker	3.36×10^{-3}	8.36×10^{-6}	tonnes CO_2-e / component - hour
7	Other—non leaker	2.27×10^{-6}	5.64×10^{-9}	tonnes CO_2-e / component - hour
8	Other—leaker	5.88×10^{-3}	1.46×10^{-5}	tonnes CO_2-e / component - hour

(4) For subsection (3), the LDAR program must survey each component used in onshore gas production at the facility at least once in a reporting year in accordance with:

(a) paragraph 98.234(a)(1) of Title 40, Part 98 of the Code of Federal Regulations, United States of America using optical gas imaging with a sensitivity of 60 grams per hour; or

(b) the method outlined in USEPA Method 21—*Determination of organic volatile compound leaks*, as set out in Appendix A-7 of Title 40, Part 60 of the Code of Federal Regulations, United States of America where a leaker is detected if 10,000 parts per million or greater is measured consistent with that method; or

(c) an equivalent leak detection standard.

(5) To determine whether a component is a leaker or non leaker at a period of time:

(a) if a leak is detected in a survey the component is assumed to leak from the later of the beginning of the reporting year or last survey where it was a non leaker; and

(b) after a leak is detected in a survey the component is assumed to leak until the earlier of the end of the reporting year or the next survey where it is a non leaker.

Division 3.3.6B—Offshore natural gas production (other than emissions that are vented or flared)

3.73D Application

This Division applies to fugitive emissions from offshore natural gas production activities, other than emissions that are vented or flared, including emissions from:

(a) a gas wellhead through to the inlet of gas processing plants; and

(b) a gas wellhead through to the tie-in points on gas transmission systems, if processing of natural gas is not required.

Subdivision 3.3.6B.1—Offshore natural gas production, other than emissions that are vented or flared—offshore platforms

3.73E Available methods

(1) Subject to section 1.18 and subsections (3) and (4), one of the following methods must be used for estimating fugitive emissions of methane and carbon dioxide (other than emissions that are vented or flared) released during a year from the operation of a facility that is constituted by offshore natural gas production:

(a) method 1 under section 3.73F;

(b) method 2 under section 3.73G;

(c) method 3 under section 3.73H.

Note: There is no method 4 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

(3) If method 2 is used for a facility, all other available methods 2 must be used in Divisions 3.3.6A, 3.3.6C, 3.3.6E, 3.3.7A and 3.3.7B if those Divisions are applicable to the facility.

(4) If method 3 is used for a facility all other available methods 3 must be used in Divisions 3.3.6A, 3.3.6C, 3.3.6E, 3.3.7A and 3.3.7B if those Divisions are applicable to the facility.

3.73F Method 1—offshore natural gas production (other than emissions that are vented or flared)

(1) Method 1 is:

$$E_{ij} = \sum_k (Q_{ik} \times EF_{ijk}) \times S_{ij/}SD_{ij}$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the offshore natural gas production during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) specified in column 2 of an item in the table in subsection (2), if the equipment is used in the offshore natural gas production.

$\boldsymbol{Q_{ik}}$ is the number of platforms of each equipment type (***k***) specified in column 2 of the table in subsection (2), during the year.

EF_{ijk} is the emission factor for gas type (*j*) measured in CO_2-e tonnes per platform during the year as determined under subsection (2), if the equipment is used in the offshore natural gas production.

Note: Consistent with subsection 3.41(2), emissions associated with any piece of equipment included in this definition should not be counted under this section if those emissions are also counted as equipment emissions under another section within this Part.

S_{ij} is the measured share of gas type (*j*), being methane or carbon dioxide, in the unprocessed gas (*i*), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (*j*) in the unprocessed gas (*i*) where methane SD is 0.832 and carbon dioxide SD is 0.035.

(2) For EF_{ijk} in subsection (1), column 3 of an item in the following table specifies the emission factor for methane (*j*) for an equipment type (*k*) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (j) for an equipment type (*k*) specified in column 2 of that item:

Item	Equipment type (k)	emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Offshore platforms (shallow water)	1,747.1	7.10	tonnes CO_2-e /platform
2	Offshore platforms (deep water)	18,422.6	75.0	tonnes CO_2-e/ platform

3.73G Method 2—offshore natural gas production (other than venting and flaring)

(1) Method 2 is:

$$E_{ij} = \sum_k (T_{ik} \times N_{ik} \times EF_{ijk}) \times S_{ij}/SD_{ij}$$

where:

E_{ij} is the fugitive emissions (other than emissions that are vented or flared) of gas type (*j*), being methane or carbon dioxide, from the offshore natural gas production during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (*j*), being methane or carbon dioxide, measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (*k*), if the equipment is used in the offshore natural gas production.

T_{ik} is the average hours of operation during the year of the equipment of each equipment type (*k*), if the equipment is used in the offshore natural gas production during the year.

N_{ik} is the total number of equipment units of each equipment type (*k*), if the equipment type is used in the offshore natural gas production during the year.

EF_{ijk} is the emission factor of gas type (*j*), being methane or carbon dioxide, measured in tonnes of CO_2-e per equipment type (*k*) – hour as determined under subsection (2), if the equipment is used in the offshore natural gas production.

Note: Consistent with subsection 3.41(2), emissions associated with any piece of equipment included in this definition should not be counted under this section if those emissions are also counted as equipment emissions under another section within this Part.

S_{ij} is the measured share of gas type (*j*), being methane or carbon dioxide, in the unprocessed gas (*i*), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.788 and for carbon dioxide SD is 0.02.

(2) For ***EF_{ijk}*** in subsection (1), column 3 of an item in the following table specifies the emission factor for methane (***j***) for an equipment type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item:

Item	**Equipment type (k)**	**Emission factor for gas type (j)**		
		CH_4	CO_2	Units
1	Gas wellheads	5.04×10^{-4}	1.25×10^{-6}	tonnes CO_2-e /equipment - hour
2	Gas separators	1.24×10^{-3}	3.08×10^{-6}	tonnes CO_2-e /equipment - hour
3	Gas heaters	1.29×10^{-3}	3.20×10^{-6}	tonnes CO_2-e /equipment - hour
4	Reciprocating compressor	4.60×10^{-2}	1.14×10^{-4}	tonnes CO_2-e /equipment - hour
5	Screw compressor	2.88×10^{-2}	7.15×10^{-5}	tonnes CO_2-e /equipment - hour
6	Metering installation and associated piping	9.86×10^{-4}	2.45×10^{-6}	tonnes CO_2-e /equipment - hour
7	Dehydrators	2.00×10^{-3}	4.96×10^{-6}	tonnes CO_2-e /equipment - hour
8	Gathering pipelines	7.45×10^{-4}	1.85×10^{-6}	tonnes CO_2-e /kilometre - hour

3.73H Method 3—offshore natural gas production (other than emissions that are vented or flared)

(1) Method 3 is:

$$E_{ij} = \sum_k (T_{ik} \times N_{ik} \times EF_{ijk}) \times S_{ij} / SD_{ij}$$

where:

E_{ij} is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the offshore natural gas production during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e and estimated by summing up the emissions released from each component type (***k***), if the component type is used in the offshore natural gas production.

EF_{ijk} is the emission factor of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e per component-hour for each component type (***k***) as determined under subsection (2) or (3), if the component is used in the offshore natural gas production.

Note: Consistent with subsection 3.41(2), emissions associated with any components included in this definition should not be counted under this section if those emissions are also counted as component emissions under another section within this Part.

T_{ik} is:

(a) if subsection (2) applies—the average hours of operation during the year of the component of each component type (***k***), if the component is used in the offshore natural gas production; and

(b) if subsection (3) applies—an engineering estimate of the number of hours in the year the component type (***k***) was operational as a leaker or non leaker based on the best available data and subsection (4).

N_{ik} is the total number of components of each component type (***k***) listed if the component type is used in the offshore natural gas production during the year.

S_{ij} is the measured share of gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.788 and for carbon dioxide SD is 0.02.

(2) Unless subsection (3) is elected and used for all components under this method, EF_{ijk}, the emission factors for methane (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for a component type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for a component type (***k***) specified in column 2 of that item:

Item	Component type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Valves	1.44×10^{-5}	3.58×10^{-8}	tonnes CO_2-e /component - hour
2	Pump Seals	5.46×10^{-6}	1.36×10^{-8}	tonnes CO_2-e / component - hour
3	Others	1.94×10^{-4}	4.83×10^{-7}	tonnes CO_2-e / component - hour
4	Connectors	3.02×10^{-6}	7.52×10^{-9}	tonnes CO_2-e / component - hour
5	Flanges	5.52×10^{-6}	1.37×10^{-8}	tonnes CO_2-e / component - hour
6	Open-ended lines	2.83×10^{-5}	7.03×10^{-8}	tonnes CO_2-e / component - hour

Note: These component types are listed in section 6.1.3 of the API Compendium.

(b) if the manufacturer of the component supplies component-specific emission factors for the component type—those factors.

(3) If an LDAR program has been carried out at the facility in relation to offshore natural gas production components in accordance with subsection (4) and this subsection elected for all components under this method, EF_{ijk}, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item; and

(b) column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item:

Item	Component and leaker/non leaker type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Valves—non leaker	7.56×10^{-6}	1.88×10^{-8}	tonnes CO_2-e

				/component - hour
2	Values—leaker	5.60×10^{-3}	1.39×10^{-5}	tonnes CO_2-e / component - hour
3	Pumps—non leaker	2.10×10^{-5}	5.22×10^{-8}	tonnes CO_2-e / component - hour
4	Pumps—leaker	9.80×10^{-3}	2.44×10^{-5}	tonnes CO_2-e / component - hour
5	Flanges—non leaker	3.92×10^{-7}	9.75×10^{-10}	tonnes CO_2-e / component - hour
6	Flanges—leaker	3.36×10^{-3}	8.36×10^{-6}	tonnes CO_2-e / component - hour
7	Other—non leaker	2.27×10^{-6}	5.64×10^{-9}	tonnes CO_2-e / component - hour
8	Other—leaker	5.88×10^{-3}	1.46×10^{-5}	tonnes CO_2-e / component - hour

(4) For subsection (3), the LDAR program must survey each component used in offshore gas production at the facility at least once in a reporting year in accordance with:

(a) paragraph 98.234(a)(1) of Title 40, Part 98 of the Code of Federal Regulations, United States of America using optical gas imaging with a sensitivity of 60 grams per hour; or

(b) the method outlined in USEPA Method 21—*Determination of organic volatile compound leaks*, as set out in Appendix A-7 of Title 40, Part 60 of the Code of Federal Regulations, United States of America where a leaker is detected if 10,000 parts per million or greater is measured consistent with that method; or

(c) an equivalent leak detection standard.

(5) To determine whether a component is a leaker or non leaker at a period of time:

(a) if a leak is detected in a survey the component is assumed to leak from the later of the beginning of the reporting year or last survey where it was a non leaker; and

(b) after a leak is detected in a survey the component is assumed to leak until the earlier of the end of the reporting year or the next survey where it is a non leaker.

Division 3.3.6C—Natural gas gathering and boosting (other than emissions that are vented or flared)

3.73I Application

This Division applies to fugitive emissions from natural gas gathering and boosting, other than emissions that are vented or flared, including emissions from natural gas gathering and boosting stations and pipelines.

Note: Division 3.3.6A applies to fugitive emissions from onshore natural gas production activities, other than emissions that are vented or flared, including emissions from wellheads.

3.73J Available methods

(1) Subject to section 1.18 and subsections (3) and (4), one of the following methods must be used for estimating fugitive emissions of methane and carbon dioxide (other than emissions that are vented or flared) released during a year from the operation of a facility that is constituted by natural gas gathering and boosting:

(a) method 1 under section 3.73K;

(b) method 2 under section 3.73L;

(c) method 3 under section 3.73M.

Note: There is no method 4 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

(3) If method 2 is used for a facility, all other available methods 2 must be used in Divisions 3.3.6A, 3.3.6B, 3.3.6E, 3.3.7A and 3.3.7B if those Divisions are applicable to the facility.

(4) If method 3 is used for a facility, all other available methods 3 must be used in Divisions 3.3.6A, 3.3.6B, 3.3.6E, 3.3.7A and 3.3.7B if those Divisions are applicable to the facility.

3.73K Method 1—natural gas gathering and boosting (other than venting and flaring)

Method 1 is:

$$E_{ij} = E_{ijs} + E_{ijp}$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting during the year measured in CO_2-e tonnes.

$\boldsymbol{E_{ijs}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting stations (***s***) during the year measured in CO_2-e tonnes, given by section 3.73KA.

$\boldsymbol{E_{ijp}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting pipelines (***p***) during the year measured in CO_2-e tonnes, given by section 3.73KB.

3.73KA Method 1—natural gas gathering and boosting, other than emissions that are vented or flared—natural gas gathering and boosting stations

(1) For section 3.73K, E_{ijs} is given by the following formula:

$$E_{ijs} = \Sigma_{js}(Q_{is} \times EF_j) \times S_{ij} / SD_{ij}$$

where:

$\boldsymbol{E_{ijs}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting stations during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_{js}}$ is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes and estimated by summing up the emissions released from each natural gas gathering and boosting station (***s***).

$\boldsymbol{Q_{is}}$ is the quantity of unprocessed natural gas (***i***) that passes through the natural gas gathering and boosting station (***s***) during the year, measured in tonnes in accordance with Division 2.3.6.

$\boldsymbol{EF_j}$ is the emission factor for gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes per tonne of unprocessed natural gas that passes through each natural gas gathering and boosting station (***s***) given by subsection (2) or (3).

$\boldsymbol{S_{ij}}$ is the measured share of each gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

$\boldsymbol{SD_{ij}}$ is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.832 and for carbon dioxide SD is 0.0345.

(2) For $\boldsymbol{EF_j}$ in subsection (1), $\boldsymbol{EF_j}$ for methane is given by the following formula:

$$EF_j = GWP_{methane} \times 2.386 \times Q_i^{-0.761}$$

where:

$\boldsymbol{EF_j}$ is the emission factor for methane (j) measured in CO_2-e tonnes per tonne of natural gas that passes through the natural gas gathering and boosting station during the year.

$\boldsymbol{Q_i}$ is the quantity of unprocessed natural gas that passes through the natural gas gathering and boosting station during the year, measured in tonnes in accordance with Division 2.3.6.

(3) For $\boldsymbol{EF_j}$ in subsection (1), $\boldsymbol{EF_j}$ for carbon dioxide is given by the following formula:

$$EF_j = 2.386 \times Q_i^{-0.761} \times SD_{ij=carbon\ dioxide} / SD_{ij=methane}$$

where:

$\boldsymbol{EF_j}$ is the emission factor for carbon dioxide (j) measured in CO_2-e tonnes per tonne of natural gas that passes through the natural gas gathering and boosting station during the year.

$\boldsymbol{Q_i}$ is the quantity of unprocessed natural gas that passes through the natural gas gathering and boosting station during the year, measured in tonnes in accordance with Division 2.3.6.

$\boldsymbol{SD_{ij=carbon\ dioxide}}$ is the default share of carbon dioxide (***j***) in the unprocessed gas (***i***), which is 0.0345.

$\boldsymbol{SD_{ij=methane}}$ is the default share of methane (***j***) in the unprocessed gas (***i***), which is 0.832.

3.73KB Method 1—natural gas gathering and boosting, other than emissions that are vented or flared—natural gas gathering and boosting pipelines

(1) For section 3.73K, subject to subsection (3), E_{ijp} is given by the following formula:

$$E_{ijp} = P_k \times EF_{ijk} \times S_{ij} / SD_{ij}$$

where:

$\boldsymbol{E_{ijp}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting pipelines during the year measured in CO_2-e tonnes.

$\boldsymbol{P_k}$ is the length of the system of gathering and boosting pipelines of type (***k)*** during the year measured in kilometres and used in the natural gas gathering and boosting.

$\boldsymbol{EF_{ijk}}$ is the emission factor for gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes per tonne of natural gas that passes through each equipment type (***k***), or CO_2-e tonnes per kilometre of pipeline if the equipment is used in the natural gas gathering and boosting pipelines during the year.

$\boldsymbol{S_{ij}}$ is the measured share of each gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

$\boldsymbol{SD_{ij}}$ is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.832 and for carbon dioxide SD is 0.0345.

(2) For $\boldsymbol{EF_{ijk}}$ in subsection (1), column 3 of an item in the following table specifies the emission factor for methane (***j***) for an equipment type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item:

Item	Equipment type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Onshore gas gathering and boosting pipelines	6.52	2.65×10^{-2}	tonnes CO_2-e /kilometres of pipeline

(3) However, $\boldsymbol{E_{ijp}}$ may also be calculated by the method in section 3.73LB.

Note: Calculating this parameter for method 1 under section 3.73LB does not trigger the requirements in subsection 3.73J(3) to use method 2 for other emissions sources.

3.73L Method 2—natural gas gathering and boosting (other than venting and flaring)

Method 2 is:

$$E_{ij} = E_{ijs} + E_{ijp}$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting during the year measured in CO_2-e tonnes.

$\boldsymbol{E_{ijs}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting stations (***s***) during the year measured in CO_2-e tonnes given by section 3.73LA.

$\boldsymbol{E_{ijp}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting pipelines (***p***) during the year measured in CO_2-e tonnes, given by section 3.73LB.

3.73LA Method 2—natural gas gathering and boosting, other than emissions that are vented or flared—natural gas gathering and boosting stations

(1) For section 3.73L, E_{ijs} is given by the following formula:

$$E_{ijs} = \sum_k (T_{ik} \times N_{ik} \times EF_{ijk}) \times S_{ij} / SD_{ij}$$

where:

$\boldsymbol{E_{ijs}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting stations during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***), if the equipment is used in the natural gas gathering and boosting station.

$\boldsymbol{T_{ik}}$ is the average hours of operation during the year of the equipment of each equipment type (***k***), if the equipment is used in the natural gas gathering and boosting station during the year.

$\boldsymbol{N_{ik}}$ is the total number of equipment units of each equipment type (***k***), if the equipment type is used in the natural gas gathering and boosting station during the year.

Note: Consistent with subsection 3.41(2), emissions associated with any piece of equipment included in this definition should not be counted under this section if those emissions are also counted as equipment emissions under another section within this Part.

$\boldsymbol{EF_{ijk}}$ is the emission factor for gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes per equipment type (***k***) – hour as determined under subsection (2), if the equipment is used in the natural gas gathering and boosting station.

$\boldsymbol{S_{ij}}$ is the measured share of each gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, passing through the gathering and boosting station measured in accordance Division 2.3.3 and the principles in section 1.13.

$\boldsymbol{SD_{ij}}$ is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.788 and for carbon dioxide SD is 0.02.

(2) For $\boldsymbol{EF_{ijk}}$ in subsection (1):

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for an equipment type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item:

Item	Equipment type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Gas separators	1.24×10^{-3}	3.08×10^{-6}	tonnes CO_2-e /equipment - hour
2	Gas heaters	1.29×10^{-3}	3.20×10^{-6}	tonnes CO_2-e

				/equipment - hour
3	Reciprocating compressor	4.60×10^{-2}	1.14×10^{-4}	tonnes CO_2-e /equipment - hour
4	Screw compressor	2.88×10^{-2}	7.15×10^{-5}	tonnes CO_2-e /equipment - hour
5	Metering installation and associated piping	9.86×10^{-4}	2.45×10^{-6}	tonnes CO_2-e /equipment - hour
6	Dehydrators	2.00×10^{-3}	4.96×10^{-6}	tonnes CO_2-e /equipment - hour

(b) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type—those factors are the relevant emissions factors.

3.73LB Method 2—onshore natural gas production, other than emissions that are vented or flared—onshore gas gathering and boosting pipelines

(1) For section 3.73L and subsection 3.73M(1), E_{ijp} is given by the following formula:

$$E_{ijp} = \sum_k T_{ik} \times P_k \times EF_{ijk} \times S_{ij} / SD_{ij}$$

where:

$\boldsymbol{E_{ijp}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting pipelines during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) specified in column 2 of an item in the table in subsection (2), if the equipment is used in natural gas gathering and boosting.

$\boldsymbol{T_{ik}}$ is the average hours of operation during the year of the equipment of each equipment type (***k***) specified in column 2 of the table in subsection (2), if the equipment is used in natural gas gathering and boosting during the year.

$\boldsymbol{P_k}$ is the length of the system of gathering and boosting pipelines of type (***k)*** during the year measured in kilometres and used in natural gas gathering and boosting.

$\boldsymbol{EF_{ijk}}$ is the emission factor for gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes per kilometre-hour of pipeline type (***k***), if the equipment is used in natural gas gathering and boosting.

$\boldsymbol{S_{ij}}$ is the measured share of each gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, that passes though the equipment measured in accordance with Division 2.3.3 and the principles in section 1.13.

$\boldsymbol{SD_{ij}}$ is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.788 and for carbon dioxide SD is 0.02.

(2) For $\boldsymbol{EF_{ijk}}$ in subsection (1), column 3 of an item in the following table specifies the emission factor for methane (***j***) for an equipment type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item:

Item	Equipment type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Onshore gas gathering and	7.72×10^{-3}	3.14×10^{-5}	tonnes CO_2-e

	boosting pipelines (cast iron)			/kilometres of pipeline hour
2	Onshore gas gathering and boosting pipelines (plastic)	6.99×10^{-4}	2.85×10^{-6}	tonnes CO_2-e /kilometres of pipeline hour
3	Onshore gas gathering and boosting pipelines (protected steel)	1.31×10^{-4}	5.34×10^{-7}	tonnes CO_2-e /kilometres of pipeline hour
4	Onshore gas gathering and boosting pipelines (unprotected steel)	4.64×10^{-3}	1.89×10^{-5}	tonnes CO_2-e /kilometres of pipeline hour

3.73M Method 3—natural gas gathering and boosting (other than venting and flaring)

(1) Method 3 is:

$$E_{ij} = E_{ijs} + E_{ijp}$$

where:

E

$\boldsymbol{E_{ij}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting during the year measured in CO_2-e tonnes.

$\boldsymbol{E_{ijs}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting stations (***s***) during the year measured in CO_2-e tonnes, given by subsection (2).

$\boldsymbol{E_{ijp}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting pipelines (***p***) during the year measured in CO_2-e tonnes, given by section 3.73LB.

(2) For subsection (1), E_{ijs} is given by the following formula:

$$E_{ijs} = \sum_k (T_{ik} \times N_{ik} \times EF_{ijk}) \times S_{ij} / SD_{ij}$$

where:

$\boldsymbol{E_{ijs}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting station during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e and estimated by summing up the emissions released from each component type (***k***), if the component type is used in the natural gas gathering and boosting stations (***s***).

$\boldsymbol{EF_{ijk}}$ is the emission factor of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e per component-hour for each component type (***k***) as determined under subsection (3) or (4), if the component is used in the natural gas gathering and boosting station.

$\boldsymbol{T_{ik}}$ is:

(a) if subsection (3) applies—the average hours of operation during the year of the component of each component type (***k***), if the component is used in natural gas gathering and boosting;

(b) if subsection (4) applies—an engineering estimate of the number of hours in the year the component type (***k***) was operational as a leaker or non leaker based on the best available data and subsection (4).

N_{ik} is the total number of components of each component type (***k***), if the component type is used in natural gas gathering and boosting.

Note: Consistent with subsection 3.41(2), emissions associated with any components included in this definition should not be counted under this section if those emissions are also counted as component emissions under another section within this Part.

S_{ij} is the measured share of gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.788 and for carbon dioxide SD is 0.02.

(3) Unless subsection (4) is elected and used for all components under this method, ***EF_{ijk}***, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for a component type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for a component type (***k***) specified in column 2 of that item:

Item	Component type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Valves – gas production	7.36×10^{-5}	1.83×10^{-7}	tonnes CO_2-e /component - hour
2	Connectors – gas production	8.99×10^{-6}	2.23×10^{-8}	tonnes CO_2-e / component - hour
3	Flanges – gas production	3.30×10^{-6}	8.22×10^{-9}	tonnes CO_2-e / component - hour
4	Open-ended lines – gas production	1.92×10^{-5}	4.78×10^{-8}	tonnes CO_2-e / component - hour
5	Pump Seals – gas production	5.46×10^{-6}	1.36×10^{-8}	tonnes CO_2-e / component - hour
6	Others – gas production	2.57×10^{-4}	6.40×10^{-7}	tonnes CO_2-e / component - hour

Note: These component types are listed in section 6.1.3 of the API Compendium.

(b) if the manufacturer of the component supplies component-specific emission factors for the component type—those factors.

(4) If an LDAR program has been carried out at the facility in relation to natural gas gathering and boosting components in accordance with subsection (5) and this subsection elected for all components under this method, ***EF_{ijk}***, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item; and

(b) column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item:

Item	Component and leaker/non leaker type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Valves—non leaker	7.56×10^{-6}	1.88×10^{-8}	tonnes CO_2-e /component - hour
2	Values—leaker	5.60×10^{-3}	1.39×10^{-5}	tonnes CO_2-e / component - hour
3	Pumps—non leaker	4.20×10^{-6}	1.04×10^{-8}	tonnes CO_2-e / component - hour
4	Pumps—leaker	9.80×10^{-3}	2.44×10^{-5}	tonnes CO_2-e / component - hour
5	Flanges—non leaker	3.92×10^{-7}	9.75×10^{-10}	tonnes CO_2-e / component - hour
6	Flanges—leaker	3.36×10^{-3}	8.36×10^{-6}	tonnes CO_2-e / component - hour
7	Other—non leaker	2.27×10^{-6}	5.64×10^{-9}	tonnes CO_2-e / component - hour
8	Other—leaker	5.88×10^{-3}	1.46×10^{-5}	tonnes CO_2-e / component - hour

(5) For subsection (4) the LDAR program must survey each component used in natural gas gathering and boosting at the facility at least once in a reporting year in accordance with:

(a) paragraph 98.234(a)(1) of Title 40, Part 98 of the Code of Federal Regulations, United States of America using optical gas imaging with a sensitivity of 60 grams per hour; or

(b) the method outlined in USEPA Method 21—*Determination of organic volatile compound leaks*, as set out in Appendix A-7 of Title 40, Part 60 of the Code of Federal Regulations, United States of America where a leaker is detected if 10,000 parts per million or greater is measured consistent with that method; or

(c) an equivalent leak detection standard.

(6) To determine whether a component is a leaker or non leaker at a period of time:

(a) if a leak is detected in a survey the component is assumed to leak from the later of the beginning of the reporting year or last survey where it was a non leaker; and

(b) after a leak is detected in a survey the component is assumed to leak until the earlier of the end of the reporting year or the next survey where it is a non leaker.

Division 3.3.6D—Produced water from oil and gas exploration and development, crude oil production, natural gas production or natural gas gathering and boosting (other than emissions that are vented or flared)

3.73N Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating fugitive emissions of methane (other than emissions that are vented or flared) released during a year from produced water relating to the operation of a facility that is constituted by a relevant activity:

(a) method 1 under section 3.73NA;

(b) method 2 under section 3.73NB.

Note: There is no method 3 or 4 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

(3) In this Division, a ***relevant activity*** is oil or gas exploration and development, crude oil production, natural gas gathering and boosting and onshore or offshore natural gas production.

3.73NA Method 1—produced water (other than emissions that are vented or flared)

Method 1 is:

$$E_{ij} = W_{\mathbf{i}} \times EF_{ijw} \times S_{ij} / SD_{ij}$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***) being methane from the produced water during the year measured in CO_2-e tonnes.

$\boldsymbol{W_i}$ is the total quantity of produced water during the year associated with the relevant activity measured in megalitres of produced water.

$\boldsymbol{EF_{ijw}}$ is the emission factor for gas type (***j***), being methane, of 7.99 tonnes of CO_2-e per megalitre of produced water associated with relevant activity during the year.

$\boldsymbol{S_{ij}}$ is the measured share of gas type (***j***) being methane in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

$\boldsymbol{SD_{ij}}$ is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.832.

3.73NB Method 2—produced water (other than emissions that are vented or flared)

(1) Method 2 is:

$$E_{ij} = W_{\mathbf{i}} \times EF_{ijw} \times S_{ij} / SD_{ij}$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***) being methane from the produced water from the relevant activity during the year measured in CO_2-e tonnes.

W_i is the total quantity of produced water during the year associated with the relevant activity measured in megalitres of produced water.

EF_{ijw} is the emission factor for gas type (***j***), being methane, measured in CO_2-e tonnes per megalitre of produced water associated with the relevant activity during the year as determined under subsection (2).

S_{ij} is the measured share of gas type (***j***) being methane in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.832.

(2) For EF_{ijw}, in subsection (1):

(a) if the average pressure for a water stream entering the separator during the year (***WP***) is less than 345 kilopascals and:

(i) the average salinity content of the water is less than or equal to 20,000 milligrams per litre during the year—0.8707 tonnes of CO_2-e tonnes per megalitre of produced water associated with the relevant activity; or

(ii) the average salinity content of the water is less than or equal to 100,000 milligrams per litre and greater than or equal to 20,000 milligrams per litre during the year—0.7439 tonnes of CO_2-e tonnes per megalitre of produced water associated with the relevant activity; or

(iii) the average salinity content of the water is greater than 100,000 milligrams per litre during the year—0.3212 tonnes of CO_2-e tonnes per megalitre of produced water associated with the relevant activity; or

(b) if the average pressure for a water stream entering the separator during the year (***WP***) is equal to or greater than 345 kilopascals—is calculated under subsection (3); and

(3) For paragraph (2)(b):

(a) if the average salinity content of the water is less than or equal to 20,000 milligrams per litre during the year—EF_{ijw}, is given by the following formula:

$$E_{ijw} = WP \times 0.0016 + 0.4342$$

(b) if the average salinity content of the water is less than or equal to 100 000 milligrams per litre and greater than or equal to 20,000 milligrams per litre during the year—EF_{ijw}, is given by the following formula:

$$E_{ijw} = WP \times 0.0013 + 0.3695$$

(c) if the average salinity content of the water is greater than 100,000 milligrams per litre during the year—EF_{ijw}, is given by the following formula:

$$E_{ijw} = WP \times 0.0009 + 0.0507$$

where:

EF_{ijw} is the emission factor for gas type (***j***), being methane, measured in CO_2-e tonnes per megalitre of produced water associated with the relevant activity during the year.

WP is the average pressure for a water stream entering the separator during the year measured in kilopascals.

(4) For subsection (2) and (3), if there is no separator the water pressure must be measured at an equivalent point in the process.

Division 3.3.6E—Natural gas processing (other than emissions that are vented or flared)

3.73O Application

This Division applies to fugitive emissions from natural gas processing activities, other than emissions that are vented or flared, including emissions from gas processing.

3.73P Available methods

(1) Subject to section 1.18 and subsections (3) and (4), one of the following methods must be used for estimating fugitive emissions of methane and carbon dioxide (other than emissions that are vented or flared) released during a year from the operation of a facility that is constituted by natural gas processing:

(a) method 1 under section 3.73Q;

(b) method 2 under section 3.73R;

(c) method 3 under section 3.73S.

Note: There is no method 4 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

(3) If method 2 is used for a facility, all other available methods 2 must be used in Divisions 3.3.6A, 3.3.6B, 3.3.6C, 3.3.7A and 3.3.7B if those Divisions are applicable to the facility.

(4) If method 3 is used for a facility, all other available methods 3 must be used in Divisions 3.3.6A, 3.3.6B, 3.3.6C, 3.3.7A and 3.3.7B if those Divisions are applicable to the facility.

3.73Q Method 1—natural gas processing (other than emissions that are vented or flared)

(1) Method 1 is:

$$E_{ij} = \Sigma_{js}(Q_{is} \times EF_{ijs}) \times S_{ij}/SD_{ij}$$

where:

E_{ij} is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas processing during the year, measured in CO_2-e tonnes.

Σ_{js} is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes and estimated by summing up the emissions released from each natural gas processing station (***s***).

Q_{is} is the quantity of unprocessed natural gas (***i***) that passes through the natural gas processing station (***s***) during the year, measured in tonnes, in accordance with Division 2.3.6.

EF_{ijs} is the emission factor for gas type (***j***), being methane or carbon dioxide, for the unprocessed natural gas (***i***) that passes through the natural gas processing station (***s***) during the year as determined under subsection (2) or (3), measured in tonnes of gas (leakage) per tonne of gas throughput.

S_{ij} is the measured share of gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.832 and for carbon dioxide SD is 0.0345.

(2) For EF_{ijs} in subsection (1), EF_{ijs} for methane is given by the following formula:

$$EF_{ijs} = GWP_{methane} \times 0.6369 \times Q_i^{-0.4801}$$

where:

EF_{ijs} is the emission factor for methane (***j***) measured in CO_2-e tonnes per tonne of natural gas that passes through the natural gas processing station (***s***) during the year.

Q_i is the quantity of unprocessed natural gas that passes through the natural gas processing station during the year, measured in tonnes in accordance with Division 2.3.6.

(3) For EF_{ijs} in subsection (1), EF_{ijs} for carbon dioxide is given by the following formula:

$$EF_{ijs} = 0.6369 \times Q_i^{-0.4801} \times SD_{ij=\text{carbon dioxide}} / SD_{ij=\text{methane}}$$

where:

EF_{ijs} is the emission factor for carbon dioxide (***j***) measured in CO_2-e tonnes per tonne of natural gas that passes through the natural gas gathering and boosting station (***s***) during the year.

Q_i is the quantity of unprocessed natural gas that passes through the natural gas gathering and boosting station during the year, measured in tonnes in accordance with Division 2.3.6.

$SD_{ij=\text{carbon dioxide}}$ is the default share of carbon dioxide (***j***) in the unprocessed gas (***i***), which is 0.0345.

$SD_{ij=\text{methane}}$ is the default share of methane (***j***) in the unprocessed gas (***i***), which is 0.832.

3.73R Method 2—natural gas processing (other than venting and flaring)

(1) Method 2 is:

$$E_{ij} = [\sum_k (T_{ik} \times N_{ik} \times EF_{ijk}) \times S_{ij}/SD_{ij}]$$

where:

E_{ij} is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas processing during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***), if the equipment is used in the natural gas processing.

T_{ik} is the average hours of operation during the year of the equipment of each equipment type (***k***), if the equipment is used in the natural gas processing during the year.

N_{ik} is the total number of equipment units of each equipment type (***k***), if the equipment type is used in the natural gas processing during the year.

EF_{ijk} is the emission factor (***A***) of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e per equipment type (***k***) – hour as determined under subsection (2), if the equipment is used in the natural gas processing.

S_{ij} is the measured share of gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.868 and for carbon dioxide SD is 0.0345.

(2) For ***EF_{ijk}*** in subsection (1), column 3 of an item in the following table specifies the emission factor for methane (***j***) for an equipment type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item:

Item	**Equipment type (k)**	**Emission factor for gas type (j)**		
		CH_4	CO_2	Units
1	Reciprocating compressors	7.66×10^{-2}	1.91×10^{-4}	tonnes CO_2-e /equipment - hour
2	Centrifugal compressors (wet seals)	1.54	5.99×10^{-3}	tonnes CO_2-e /equipment - hour
3	Centrifugal compressors (dry seals)	0.194	7.54×10^{-4}	tonnes CO_2-e /equipment - hour
4	Screw compressors	2.97×10^{-2}	1.16×10^{-4}	tonnes CO_2-e /equipment - hour

3.73S Method 3—natural gas processing (other than venting and flaring)

(1) Method 3 is:

$$E_{ij} = \sum_k (T_{ik} \times N_{ik} \times EF_{ijk}) \times S_{ij} / SD_{ij}$$

where:

E_{ij} is the fugitive emissions (other than venting and flaring) of gas type (***j***), being methane or carbon dioxide, from the natural gas processing during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e and estimated by summing up the emissions released from each component type (***k***), if the component type is used in the natural gas processing.

T_{ik} is:

(a) if subsection (2) applies—the average hours of operation during the year of the component of each component type (***k***), if the component is used in natural gas processing; or

(b) if subsection (3) applies—an engineering estimate of the number of hours in the year the component type (***k***) was operational as a leaker or non leaker based on the best available data and subsection (4).

N_{ik} is the total number of components of each component type (***k***) if the component type is used in the natural gas processing during the year.

EF_{ijk} is the emission factor of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e per component-hour for each component type (***k***) as determined under subsection (2) or (3), if the component is used in the natural gas processing.

S_{ij} is the measured share of gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***) for methane SD is 0.868 and for carbon dioxide SD is 0.0345.

(2) Unless subsection (3) is elected and used for all components under this method, EF_{ijk}, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for a component type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for a component type (***k***) specified in column 2 of that item: or

Item	**Component type (k)**	**Emission factor for gas type (j)**		
		CH_4	**CO_2**	**Units**
1	Valves	1.08×10^{-4}	4.21×10^{-7}	tonnes CO_2-e /component - hour
2	Pump Seals	3.22×10^{-4}	1.25×10^{-6}	tonnes CO_2-e / component - hour
3	Others	1.36×10^{-4}	5.30×10^{-7}	tonnes CO_2-e / component - hour
4	Connectors	7.67×10^{-6}	2.99×10^{-8}	tonnes CO_2-e / component - hour
5	Flanges	1.23×10^{-5}	4.78×10^{-8}	tonnes CO_2-e / component - hour
6	Open-ended lines	2.88×10^{-5}	1.12×10^{-7}	tonnes CO_2-e / component - hour

(b) if the manufacturer of the component supplies component-specific emission factors for the component type—those factors.

(3) If an LDAR program has been carried out at the facility in relation to natural gas processing components in accordance with subsection (4) and this subsection elected for all components under this method, EF_{ijk}, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item; and

(b) column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item:

Item	**Component and leaker/non leaker type (k)**	**Emission factor for gas type (j)**		
		CH_4	**CO_2**	**Units**
1	Valves—non leaker	7.56×10^{-6}	2.94×10^{-08}	tonnes CO_2-e /component - hour
2	Values—leaker	5.60×10^{-3}	2.18×10^{-05}	tonnes CO_2-e / component - hour

3	Pumps—non leaker	2.10×10^{-5}	8.18×10^{-08}	tonnes CO_2-e / component - hour
4	Pumps—leaker	9.80×10^{-3}	3.82×10^{-05}	tonnes CO_2-e / component - hour
5	Flanges—non leaker	3.92×10^{-7}	1.53×10^{-09}	tonnes CO_2-e / component - hour
6	Flanges—leaker	3.36×10^{-3}	1.31×10^{-05}	tonnes CO_2-e / component - hour
7	Other—non leaker	2.27×10^{-6}	8.83×10^{-09}	tonnes CO_2-e / component - hour
8	Other—leaker	5.88×10^{-3}	2.29×10^{-05}	tonnes CO_2-e / component - hour

(4) For subsection (3), the LDAR program must survey each component used in natural gas processing at the facility at least once in a reporting year in accordance with:

(a) paragraph 98.234(a)(1) of Title 40, Part 98 of the Code of Federal Regulations, United States of America using optical gas imaging with a sensitivity of 60 grams per hour; or

(b) the method outlined in USEPA Method 21—*Determination of organic volatile compound leaks*, as set out in Appendix A-7 of Title 40, Part 60 of the Code of Federal Regulations, United States of America where a leaker is detected if 10,000 parts per million or greater is measured consistent with that method; or

(c) an equivalent leak detection standard.

(5) To determine whether a component is a leaker or non leaker at a period of time:

(a) if a leak is detected in a survey the component is assumed to leak from the later of the beginning of the reporting year or last survey where it was a non leaker; and

(b) after a leak is detected in a survey the component is assumed to leak until the earlier of the end of the reporting year or the next survey where it is a non leaker.

Division 3.3.7—Natural gas transmission (other than emissions that are flared)

3.74 Application

This Division applies to fugitive emissions from natural gas transmission activities.

3.75 Available methods

(1) Subject to section 1.18 and subsection (2), one of the following methods must be used for estimating fugitive emissions (other than flaring) of each gas type, being carbon dioxide and methane, released from the operation of a facility that is constituted by natural gas transmission through a system of pipelines during a year:

(a) method 1 under section 3.76;

(b) method 2 under section 3.77;

(c) method 3 under section 3.78.

Note: There is no method 4 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.76 Method 1—natural gas transmission (other than flaring)

Method 1 is:

$$E_{ij} = (L_i \times EF_{ij})$$

where:

E_{ij} is the fugitive emissions (other than flaring) of gas type (***j***) from natural gas transmission through a system of pipelines of length (***i***) during the year measured in CO_2-e tonnes.

L_i is the length of the system of pipelines (***i***) measured in kilometres.

EF_{ij} is the emission factor for gas type (***j***), which is 0.02 for carbon dioxide and 11.6 for methane, measured in tonnes of CO_2-e emissions per kilometre of pipeline (***i***).

3.77 Method 2—natural gas transmission (other than flaring)

(1) Method 2 is:

$$E_j = \sum_k (Q_k \times N_k \times EF_{jk})$$

where:

E_j is the fugitive emissions (other than flaring) of gas type (***j***) measured in CO_2-e tonnes from the natural gas transmission through the system of pipelines during the year.

Σ_k is the total emissions of gas type (***j***) measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas transmission.

Q_k is the total of the quantities of natural gas or plant condensate measured in tonnes that pass through each equipment type (***k***) or the number of equipment units of type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas transmission during the year.

N_k is the total number of equipment units of each equipment type (***k***) listed in section 6.1.2 of the API Compendium if the equipment type is used in the natural gas transmission during the year.

EF_{jk} is the emission factor of gas type (***j***) measured in CO_2-e tonnes for each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium as determined under subsection (2), where the equipment is used in the natural gas transmission.

(2) For EF_{jk}, the emission factors for a gas type (***j***) as the natural gas or plant condensate passes through the equipment type (***k***) are:

(a) as listed in sections 5 and 6.1.2 of the API Compendium, for the equipment type; or

(b) as listed in that Compendium for the equipment type with emission factors adjusted for variations in estimated gas composition, in accordance with that Compendium's sections 5 and 6.1.2, and the requirements of Division 2.3.3; or

(c) as listed in that Compendium for the equipment type with emission factors adjusted for variations in the type of equipment material estimated in accordance with the results of published research for the crude oil industry and the principles of section 1.13; or

(d) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type—those factors; or

(e) estimated using the engineering calculation approach in accordance with sections 5 and 6.1.2 of the API Compendium.

3.78 Method 3—natural gas transmission (other than flaring)

(1) Method 3 is:

$$E_j = \sum_k (T_k \times N_k \times EF_{jk})$$

where:

E_{ij} is the fugitive emissions (other than flaring) of gas type (***j***) measured in CO_2-e tonnes from the natural gas transmission through the system of pipelines during the year.

Σ_k is the total emissions of gas type (***j***) measured in CO_2-e tonnes and estimated by summing up the emissions released from each component type (***k***) listed in section 6.1.3 of the API Compendium, if the component is used in the natural gas transmission.

T_k is the average hours of operation during the year of the components of each component type (***k***) listed in section 6.1.3 of the API Compendium, if the component is used in the natural gas transmission during the year.

N_k is the total number of components of each component type (***k***) listed in section 6.1.3 of the API Compendium if the component type is used in the natural gas transmission during the year.

EF_{jk} is the emission factor of gas type (***j***) measured in CO_2-e tonnes for each component type (***k***) listed in 6.1.3 of the API Compendium as determined under subsection (2), where the component is used in the natural gas transmission.

(2) For EF_{jk}, the emission factors for gas type (***j***), as natural gas or plant condensate passes through a component type (***k***), are:

(a) as listed in Table 6-18 in section 6.1.3 of the API Compendium, for the component type; or

(b) as listed in that Compendium for the component type with emission factors adjusted for variations in estimated gas composition, in accordance with that Compendium's Table 6-18 in section 6.1.3, and the requirements of Division 2.3.3; or

(c) as listed in that Compendium for the component type with emission factors adjusted for variations in the type of component material estimated in accordance with the results of published research for the crude oil industry and the principles of section 1.13; or

(d) if the manufacturer of the component supplies component-specific emission factors for the component type—those factors; or

(e) estimated using the engineering calculation approach in accordance with section 6.1.3 of the API Compendium.

Division 3.3.7A—Natural gas storage (other than emissions that are vented or flared)

3.78A Application

This Division applies to fugitive emissions (other than emissions that are vented or flared) from natural gas storage.

3.78B Available methods

(1) Subject to section 1.18 and subsection (3) and (4), one of the following methods must be used for estimating fugitive emissions (other than emissions that are vented or flared) of each gas type, being carbon dioxide and methane, released from the operation of a facility that is constituted by natural gas storage during a year:

(a) method 1 under section 3.78C;

(b) method 2 under section 3.78D;

(c) method 3 under section 3.78E.

Note: There is no method 4 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

(3) If method 2 is used for a facility, all other available methods 2 must be used in Divisions 3.3.6A, 3.3.6B, 3.3.6C, 3.3.6E and 3.3.7B if those Divisions are applicable to the facility.

(4) If method 3 is used for a facility, all other available methods 3 must be used in Divisions 3.3.6A, 3.3.6B, 3.3.6C, 3.3.6E and 3.3.7B if those Divisions are applicable to the facility.

3.78C Method 1—natural gas storage (other than emissions that are vented or flared)

(1) Method 1 is:

$$E_{ij} = \sum_k (Q_{ik} \times EF_{ijk})$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas storage during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) specified in column 2 of an item in the table in subsection (2), if the equipment is used in the natural gas storage.

$\boldsymbol{Q_{ik}}$ is the total number of each equipment type (***k***) specified in column 2 of the table in subsection (2).

$\boldsymbol{EF_{ijk}}$ is the emission factor for gas type (***j***), being methane or carbon dioxide, measured in tonnes of gas type (***j***) per equipment type (***k***) during the year, as determined under subsection (2), if the equipment is used in the natural gas storage.

(2) For $\boldsymbol{EF_{ijk}}$ in subsection (1), column 3 of an item in the following table specifies the emission factor for methane (***j***) for an equipment type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item:

Item	Equipment type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Natural gas storage station	10,336	20.7	tonnes CO_2-e per station

3.78D Method 2—natural gas storage (other than emissions that are vented or flared)

(1) Method 2 is:

$$E_{ij} = \sum_k (T_{ik} \times N_{ik} \times EF_{ijk})$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions (other than emissions that are vented or flared) of methane or carbon dioxide (***j***) from the natural gas storage during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of methane or carbon dioxide (***j***) measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***), if the equipment is used in the natural gas storage.

$\boldsymbol{T_{ik}}$ is the average hours of operation during the year of each equipment type (***k***), if the equipment is used in the natural gas storage during the year.

$\boldsymbol{N_{ik}}$ is the total number of each equipment type (***k***), if the equipment type is used in the natural gas storage during the year.

$\boldsymbol{EF_{ijk}}$ is the emission factor of methane or carbon dioxide (***j***) measured in tonnes of CO_2-e per equipment type (***k***) – hour as determined under subsection (2), if the equipment is used in the natural gas storage.

(2) For $\boldsymbol{EF_{ijk}}$ in subsection (1), column 3 of an item in the following table specifies the emission factor for methane or carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item:

Item	Equipment type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Natural gas storage station	0.482	1.01×10^{-3}	tonnes CO_2-e per equipment – hour
2	Reciprocating compressor	0.473	9.93×10^{-4}	tonnes CO_2-e per equipment – hour
3	Centrifugal compressor	0.683	1.43×10^{-3}	tonnes CO_2-e per equipment – hour
4	Screw compressor	2.88×10^{-2}	6.03×10^{-5}	tonnes CO_2-e per equipment – hour

3.78E Method 3—natural gas storage (other than emissions that are vented or flared)

(1) Method 3 is:

$$E_j = \sum_k (T_k \times EF_{jk} \times N_k)$$

where:

E_j is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***) measured in CO_2-e tonnes from the natural gas storage during the year.

Σ_k is the total emissions of gas type (***j***) measured in CO_2-e tonnes and estimated by summing up the emissions released from each component type (***k***), if the component is used in the natural gas storage.

EF_{jk} is the emission factor of gas type (***j***) measured in tonnes of CO_2-e per component-hour that passes through each component type (***k***) as determined under subsection (2) or (3), if the component is used in the natural gas storage.

T_k is:

(a) if subsection (2) applies—the average hours of operation during the year of the component of each component type (***k***), if the component is used in the onshore natural gas storage; or

(b) if subsection (3) applies—an engineering estimate of the number of hours in the year the component type (***k***) was operational as a leaker or non leaker based on the best available data and subsection (4).

N_{ik} is the total number of each component type (***k***) listed in section 6.1.3 of the API Compendium if the component type is used in the natural gas storage during the year.

(2) Unless subsection (3) is elected and used for all components under this method, EF_{ijk}, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) as listed in Table 6-18 in section 6.1.3 of the API Compendium, for the component type; or

(b) as listed in that Compendium for the component type with emission factors adjusted for variations in estimated gas composition, in accordance with that Compendium's Table 6-18 in section 6.1.3, and the requirements of Division 2.3.3; or

(c) if the manufacturer of the component supplies component-specific emission factors for the component type—those factors.

(3) If an LDAR program has been carried out at the facility in relation to natural gas storage components in accordance with subsection (4) and this subsection elected for all components under this method, EF_{ijk}, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item; and

(b) column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item:

Item	Component and leaker/non leaker type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Valves—non leaker	7.56×10^{-6}	2.94×10^{-08}	tonnes CO_2-e /component - hour
2	Values—leaker	5.60×10^{-3}	2.18×10^{-05}	tonnes CO_2-e / component - hour
3	Pumps—non leaker	2.10×10^{-5}	8.18×10^{-08}	tonnes CO_2-e / component - hour
4	Pumps—leaker	9.80×10^{-3}	3.82×10^{-05}	tonnes CO_2-e / component - hour
5	Flanges—non leaker	3.92×10^{-7}	1.53×10^{-09}	tonnes CO_2-e / component - hour
6	Flanges—leaker	3.36×10^{-3}	1.31×10^{-05}	tonnes CO_2-e / component - hour
7	Other—non leaker	2.27×10^{-6}	8.83×10^{-09}	tonnes CO_2-e / component - hour
8	Other—leaker	5.88×10^{-3}	2.29×10^{-05}	tonnes CO_2-e / component - hour

(4) For subsection (3), the LDAR program must survey each component used in natural gas storage at the facility at least once in a reporting year in accordance with:

(a) paragraph 98.234(a)(1) of Title 40, Part 98 of the Code of Federal Regulations, United States of America using optical gas imaging with a sensitivity of 60 grams per hour; or

(b) the method outlined in USEPA Method 21—*Determination of organic volatile compound leaks*, as set out in Appendix A-7 of Title 40, Part 60 of the Code of Federal Regulations, United States of America where a leaker is detected if 10,000 parts per million or greater is measured consistent with that method; or

(c) an equivalent leak detection standard.

(5) To determine whether a component is a leaker or non leaker at a period of time:

(a) if a leak is detected in a survey the component is assumed to leak from the later of the beginning of the reporting year or last survey where it was a non leaker; and

(b) after a leak is detected in a survey the component is assumed to leak until the earlier of the end of the reporting year or the next survey where it is a non leaker.

Division 3.3.7B—Natural gas liquefaction, storage and transfer (other than emissions that are vented or flared)

3.78F Application

This Division applies to fugitive emissions from natural gas liquefaction, storage and transfer (other than emissions that are vented or flared).

3.78G Available methods

(1) Subject to section 1.18 and subsection (3) and (4), one of the following methods must be used for estimating fugitive emissions (other than emissions that are vented or flared), being methane, released from the operation of a facility that is constituted by natural gas liquefaction, storage and transfer during the year:

(a) method 1 under section 3.78H;

(b) method 2 under section 3.78I;

(b) method 3 under section 3.78J.

Note: There is no method 4 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

(3) If method 2 is used for a facility, all other available methods 2 must be used in Divisions 3.3.6A, 3.3.6B, 3.3.6C, 3.3.6E and 3.3.7A if those Divisions are applicable to the facility.

(4) If method 3 is used for a facility, all other available methods 3 must be used in Divisions 3.3.6A, 3.3.6B, 3.3.6C, 3.3.6E and 3.3.7A if those Divisions are applicable to the facility.

3.78H Method 1—natural gas liquefaction, storage and transfer (other than emissions that are vented or flared)

(1) Method 1 is:

$$E_{ij} = \Sigma_k \left(Q_{ik} \times EF_{ijk}\right)$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***) being methane (other than emissions that are vented or flared) from the natural gas liquefaction, storage and transfer during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***) being methane, measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) specified in column 2 of an item in the table in subsection (2), if the equipment is used in the natural gas liquefaction, storage and transfer.

$\boldsymbol{Q_{ik}}$ is the total of each equipment type (***k***) specified in column 2 of the table in subsection (2).

$\boldsymbol{EF_{ijk}}$ is the emission factor for gas type (***j***) measured in CO_2-e tonnes per equipment type (***k***) during the year if the equipment is used in the natural gas liquefaction, storage and transfer.

(2) For EF_{ijk} in subsection (1), column 3 of an item in the following table specifies the emission factor for methane (*j*) for an equipment type (*k*) specified in column 2 of that item:

Item	Equipment type (k)	Emission factor for gas type (j)	
		CH_4	Units
1	Liquefied natural gas station	25,700	tonnes CO_2-e per station

3.78I Method 2—natural gas liquefaction, storage and transfer (other than emissions that are vented or flared)

(1) Method 2 is:

$$E_{ij} = \sum_k (T_{ik} \times N_{ik} \times EF_{ijk})$$

where:

E_{ij} is the fugitive emissions (other than venting and flaring) of methane (*j*) from the natural gas liquefaction, storage and transfer during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of methane (*j*) measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (*k*) listed in section 6.1.2 of the API Compendium, if the equipment is used in the natural gas liquefaction, storage and transfer.

T_{ik} is the average hours of operation during the year of each equipment type (*k*) listed in section 6.1.2 of the API Compendium, if the equipment is used in the natural gas liquefaction, storage and transfer.

N_{ik} is the total number of equipment units of each equipment type (*k*) listed in section 6.1.2 of the API Compendium if the equipment type is used in the natural gas liquefaction, storage and transfer during the year.

EF_{ijk} is the emission factor of methane (*j*) measured in tonnes of CO_2-e per equipment type (*k*) – hour listed in section 6.1.2 of the API Compendium as determined under subsection (2), if the equipment is used in the natural gas liquefaction, storage and transfer.

(2) For EF_{ijk}, the emission factors for methane (*j*) as the natural gas passes through the equipment types (*k*) are:

(a) as listed in Table 6-6 of section 6.1.2 of the API Compendium, for the equipment type; or

(b) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type—those factors.

3.78J Method 3—natural gas liquefaction, storage and transfer (other than venting and flaring)

(1) Method 3 is:

$$E_{ij} = \sum_k (T_{ik} \times N_{ik} \times EF_{ijk})$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions (other than venting and flaring) of methane (***j***) from the natural gas liquefaction, storage and transfer during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of methane (***j***) measured in tonnes of CO_2-e and estimated by summing up the emissions released from each component type (***k***), if the component type is used in the natural gas liquefaction, storage and transfer.

$\boldsymbol{T_{ik}}$ is:

(a) if subsection (2) applies—the average hours of operation during the year of the components of each component type (***k***) listed in table 13 in section 4.3.1 of the *API LNG Operations Consistent Methodology for Estimating Greenhouse Gas Emissions* published by the American Petroleum Institute, if the component is used in the natural gas liquefaction, storage and transfer during the year; or

(b) if subsection (3) applies—an engineering estimate of the number of hours in the year the component type (***k***) was operational as a leaker or non leaker based on the best available data and subsection (4).

$\boldsymbol{N_{ik}}$ is the total number of components of each component type (***k***), if the component type is used in the natural gas liquefaction, storage and transfer during the year.

$\boldsymbol{EF_{ijk}}$ is the emission factor of methane (***j***) measured in tonnes of CO_2-e per component type (***k***) – hour, if the component is used in the natural gas liquefaction, storage and transfer.

(2) Unless subsection (3) is elected and used for all components under this method, $\boldsymbol{EF_{ijk}}$, the emission factors for methane (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table, which specifies the emission factor for a component of type (***k***) specified in column 2 of that item: or

Item	**Component type (k)**	**Emission factor for gas type (j)**	
		CH_4	**Units**
1	Valve	6.40×10^{-4}	tonnes CO_2-e /hour/component
2	Pump Seal	2.15×10^{-3}	tonnes CO_2-e /hour/component
3	Connectors (flanges and threaded fittings)	1.83×10^{-4}	tonnes CO_2-e /hour/component
4	Other	9.52×10^{-4}	tonnes CO_2-e /hour/compressor
5	Vapour Recovery Compressors	2.24×10^{-3}	tonnes CO_2-e /hour/compressor

(b) if the manufacturer of the component supplies component-specific emission factors for the component type—those factors.

(3) If an LDAR program has been carried out at the facility in relation to natural gas liquefaction, storage and transfer components in accordance with subsection (4) and this subsection elected for all components under this method, EF_{ijk}, the emission factors for methane (***j***), for component type (***k***), are set out in column 3 of an item in the following table for a component and leaker/non-leaker type (***k***) specified in column 2 of that item:

Item	Component and leaker/non leaker type (k)	Emission factor for gas type (j)	
		CH_4	Units
1	Valves—non leaker	7.56×10^{-6}	tonnes CO_2-e /component - hour
2	Values—leaker	5.60×10^{-3}	tonnes CO_2-e / component - hour
3	Pumps—non leaker	2.10×10^{-5}	tonnes CO_2-e / component - hour
4	Pumps—leaker	9.80×10^{-3}	tonnes CO_2-e / component - hour
5	Flanges—non leaker	3.92×10^{-7}	tonnes CO_2-e / component - hour
6	Flanges—leaker	3.36×10^{-3}	tonnes CO_2-e / component - hour
7	Other—non leaker	2.27×10^{-6}	tonnes CO_2-e / component - hour
8	Other—leaker	5.88×10^{-3}	tonnes CO_2-e / component - hour

(4) For subsection (3), the LDAR program must survey each component used in natural gas liquefaction, storage and transfer at the facility at least once in a reporting year in accordance with:

(a) paragraph 98.234(a)(1) of Title 40, Part 98 of the Code of Federal Regulations, United States of America using optical gas imaging with a sensitivity of 60 grams per hour; or

(b) the method outlined in USEPA Method 21—*Determination of organic volatile compound leaks*, as set out in Appendix A-7 of Title 40, Part 60 of the Code of Federal Regulations, United States of America where a leaker is detected if 10,000 parts per million or greater is measured consistent with that method; or

(c) an equivalent leak detection standard.

(5) To determine whether a component is a leaker or non leaker at a period of time:

(a) if a leak is detected in a survey the component is assumed to leak from the later of the beginning of the reporting year or last survey where it was a non leaker; and

(b) after a leak is detected in a survey the component is assumed to leak until the earlier of the end of the reporting year or the next survey where it is a non leaker.

Division 3.3.8—Natural gas distribution (other than emissions that are flared)

3.79 Application

This Division applies to fugitive emissions from natural gas distribution activities.

3.80 Available methods

(1) Subject to section 1.18 and subsections (2) and (3), one of the following methods must be used for estimating fugitive emissions (other than emissions that are flared) of each gas type, being carbon dioxide and methane, released during a year from the operation of a facility that is constituted by natural gas distribution through a system of pipelines:

(a) method 1 under section 3.81;

(b) method 2 under section 3.82;

(c) method 3 under section 3.82A.

Note: There is no method 4 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

(3) Method 3 may only be used if the percentage of unaccounted for gas for a facility is calculated or determined during a reporting year in accordance with gas market rules or procedures applicable to the facility.

Note: A percentage of unaccounted for gas is generally worked out under procedures made by the Australian Energy Market Operator and available on their website: www.aemo.com.au

3.81 Method 1—natural gas distribution

(1) Method 1 is:

$$E_{jp} = S_p \times \%UAG_p \times 0.55 \times C_{jp}$$

where:

$\boldsymbol{E_{jp}}$ is the fugitive emissions of gas type (***j***) that result from natural gas distribution through a system of pipelines with sales of gas in a State or Territory (***p***) during the year, measured in CO_2-e tonnes.

$\boldsymbol{S_p}$ is the total sales during the year from the pipeline system in a State or Territory (***p***), measured in terajoules.

$\boldsymbol{\%UAG_p}$ is the percentage of unaccounted for gas in the pipeline system in a State or Territory, relative to the amount of gas issued annually by gas utilities in that State or Territory.

Note: The value 0.55 following the variable %UAGp in method 1 represents the proportion of gas that is unaccounted for and released as emissions.

$\boldsymbol{C_{jp}}$ is the natural gas composition factor for gas type (***j***) for the natural gas supplied from the pipeline system in a State or Territory (***p***), measured in CO_2-e tonnes per terajoule.

(2) For %UAGp in subsection (1), column 3 of an item in the following table specifies the percentage of unaccounted for gas in the pipeline system in a State or Territory specified in column 2 of that item.

(3) For C_{jp} in subsection (1), columns 4 and 5 of an item in the following table specify the natural gas composition factor for carbon dioxide and methane for a pipeline system in a State or Territory specified in column 2.

Item	State	Unaccounted for gas (a)%	Natural gas composition factor (a)(tonnes $CO_{2\text{-}e}$/TJ)	
		UAGp	CO_2	CH_4
1	NSW and ACT	2.2	0.8	437
2	VIC	3.0	0.9	435
3	QLD	1.7	0.8	423
4	WA	2.9	1.1	408
5	SA	4.9	0.8	437
6	TAS	0.2	0.9	435
7	NT	2.2	0.0	352

3.82 Method 2—natural gas distribution

(1) Method 2 is:

$$E_j = \Sigma_k \ (Q_k \times EF_{jk})$$

where:

$\boldsymbol{E_j}$ is the fugitive emissions of gas type (***j***) that result from the natural gas distribution during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total of emissions of gas type (***j***) measured in CO_2-e tonnes and estimated by summing up the emissions from each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas distribution.

$\boldsymbol{Q_k}$ is the total of the quantities of natural gas measured in tonnes that pass through each equipment type (***k***) or the number of equipment units of type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas distribution.

$\boldsymbol{EF_{jk}}$ is the emission factor for gas type (***j***) measured in CO_2-e tonnes for each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium as determined under subsection (2), if the equipment is used in the natural gas distribution.

(2) For $\boldsymbol{EF_{jk}}$, the emission factors for gas type (***j***) as the natural gas passes through the equipment type (***k***) are:

(a) as listed in sections 5 and 6.1.2 of the API Compendium; or

(b) as listed in that Compendium for the equipment type with emission factors adjusted for variations in estimated gas composition, in accordance with that Compendium's Sections 5 and 6.1.2, and the requirements of Division 2.3.3; or

(c) as listed in that Compendium for the equipment type with emission factors adjusted for variations in the type of equipment material using adjusted factors; or

(d) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type—those factors.

(3) In paragraph 3.82(2)(c), a reference to ***factors adjusted*** is a reference to the factors in Table 5-3 of the publication entitled *Greenhouse Gas Emission Estimation Methodologies, Procedures and Guidelines for the Natural Gas Distribution Sector*, American Gas Association, April 2008, that are adjusted for variations in estimated gas composition in accordance with:

(a) section 5.2.1 of that publication; and

(b) Division 2.3.3.

3.82A Method 3—natural gas distribution

(1) Method 3 is:

$$E_{jp} = S_p \times \%UAG_p \times 0.55 \times C_{jp}$$

where:

E_{jp} is the fugitive emissions (other than emissions that are flared) of gas type (***j***) that result from natural gas distribution through a system of pipelines with sales of gas in a State or Territory (***p***) during the year, measured in CO_2-e tonnes.

S_p is the total sales during the year from the pipeline system in a State or Territory (***p***), measured in terajoules.

$\%UAG_p$ is the percentage of unaccounted for gas in the pipeline system in a State or Territory (***p***), relative to the amount of gas issued annually by gas utilities to that system.

C_{jp} is the natural gas composition factor for gas type (***j***) for the natural gas supplied from the pipeline system in a State or Territory (***p***), measured in CO_2-e tonnes per terajoule.

(2) For ***$\%UAG_p$*** in subsection (1):

(a) if at the time of reporting the percentage of unaccounted for gas for the reporting year has been calculated or determined in accordance with gas market rules or procedures applicable to the facility—the percentage calculated or determined in accordance with those rules or procedures; or

(b) if at the time of reporting the percentage of unaccounted for gas for the reporting year has not been calculated or determined in accordance with gas market rules or procedures applicable to the facility—the percentage applicable to the most recent 12 month period for which the percentage of unaccounted for gas has been calculated or determined.

(3) For ***C_{jp}*** in subsection (1), columns 3 and 4 of an item in the following table specify the natural gas composition factor for carbon dioxide and methane for a pipeline system in a State or Territory specified in column 2.

Item	**State**	**Natural gas composition factor (a)(tonnes $CO_{2\text{-}e}$/TJ)**	
		CO_2	**CH_4**
1	NSW and ACT	0.8	437
2	VIC	0.9	435
3	QLD	0.8	423
4	WA	1.1	408
5	SA	0.8	437
6	TAS	0.9	435
7	NT	0.0	352

Division 3.3.9A—Natural gas production (emissions that are vented or flared)

3.83 Application

This Division applies to fugitive emissions from venting or flaring from natural gas production activities, including emissions from:

(a) the venting of natural gas; and

(b) the venting of waste gas and vapour streams at facilities that are constituted by natural gas production; and

(c) the flaring of natural gas, waste gas and waste vapour streams at those facilities.

Note: This Division covers the four sources of offshore natural gas production—venting, onshore natural gas production—venting, offshore natural gas production—flaring and onshore natural gas production—flaring.

Subdivision 3.3.9A.1—Natural gas production—emissions that are vented—gas treatment processes

3.84 Available methods

(1) Subject to section 1.18, for estimating emissions relating to gas treatment processes (emissions that are vented) released during a year from the operation of a facility that is constituted by natural gas production the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions that result from deliberate releases from process vents, system upsets and accidents:

(a) method 1 under section 3.85;

(b) method 4 under Part 1.3.

Note: There is no method 2 or 3 for subsection (2).

(3) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.85 Method 1—emissions from system upsets, accidents and deliberate releases from process vents—gas treatment processes

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Gas treatment processes	Section 5.1

Subdivision 3.3.9A.2—Natural gas production—emissions that are vented—cold process vents

3.85A Available methods

(1) Subject to section 1.18, for estimating emissions relating to cold process vents (emissions that are vented) released during a year from the operation of a facility that is constituted by natural gas production the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions that result from deliberate releases from process vents, system upsets and accidents:

(a) method 1 under section 3.85B;

(b) method 4 under Part 1.3.

Note: There is no method 2 or 3 for subsection (2).

(3) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.85B Method 1—emissions from system upsets, accidents and deliberate releases from process vents

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Cold process vents	Section 5.3

Subdivision 3.3.9A.3—Natural gas production—emissions that are vented—natural gas blanketed tanks and condensate storage tanks

3.85C Available methods

(1) Subject to section 1.18, for estimating emissions relating to natural gas blanketed tanks and condensate storage tanks (emissions that are vented) released during a year from the operation of a facility that is constituted by natural gas production the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions that result from deliberate releases from process vents, system upsets and accidents:

(a) method 1 under section 3.85D;

(b) method 4 under Part 1.3.

Note: There is no method 2 or 3 for subsection (2).

(3) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.85D Method 1—emissions from system upsets, accidents and deliberate releases from process vents—natural gas blanketed tanks and condensate storage tanks

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Natural gas blanketed tanks	Section 5.4.4
2	Condensate storage tanks	Section 5.4.1

Subdivision 3.3.9A.4—Natural gas production—emissions that are vented—gas driven pneumatic devices

3.85E Available methods

(1) Subject to section 1.18, for estimating emissions relating to gas driven pneumatic devices (emissions that are vented) released during a year from the operation of a facility that is constituted by natural gas production the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions that result from deliberate releases from process vents, system upsets and accidents:

(a) method 1 under section 3.85F;

(b) method 4 under Part 1.3.

Note: There is no method 2 or 3 for subsection (2).

(3) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.85F Method 1—emissions from system upsets, accidents and deliberate releases from process vents—gas driven pneumatic devices

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Other venting sources—gas driven pneumatic devices	Section 5.6.1

Subdivision 3.3.9A.5—Natural gas production—emissions that are vented—gas driven chemical injection pumps

3.85G Available methods

(1) Subject to section 1.18, for estimating emissions relating to gas driven chemical injection pumps (emissions that are vented) released during a year from the operation of a facility that is constituted by natural gas production the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions that result from deliberate releases from process vents, system upsets and accidents:

(a) method 1 under section 3.85H;

(b) method 4 under Part 1.3.

Note: There is no method 2 or 3 for subsection (2).

(3) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.85H Method 1—emissions from system upsets, accidents and deliberate releases from process vents—gas driven chemical injection pumps

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Other venting sources—gas driven chemical injection pumps	Section 5.6.2

Subdivision 3.3.9A.6—Natural gas production—emissions that are vented—well blowouts

3.85K Available methods

(1) Subject to section 1.18, for estimating emissions relating to well blowouts (emissions that are vented) released during a year from the operation of a facility that is constituted by natural gas production the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions that result from deliberate releases from process vents, system upsets and accidents:

(a) method 1 under section 3.85L;

(b) method 4 under Part 1.3.

Note: There is no method 2 or 3 for subsection (2).

(3) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.85L Method 1—emissions from system upsets, accidents and deliberate releases from process vents—production related non-routine emissions—well blowouts

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Non-routine activities—production related non-routine emissions	Section 5.7.1

Subdivision 3.3.9A.7—Natural gas production—emissions that are vented—CO_2 stimulation

3.85M Available methods

(1) Subject to section 1.18, for estimating emissions relating to CO_2 stimulation (emissions that are vented) released during a year from the operation of a facility that is constituted by natural gas production the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions that result from deliberate releases from process vents, system upsets and accidents:

(a) method 1 under section 3.85N;

(b) method 4 under Part 1.3.

Note: There is no method 2 or 3 for subsection (2).

(3) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.85N Method 1—emissions from system upsets, accidents and deliberate releases from process vents—production related non-routine emissions—CO_2 stimulation

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Non-routine activities—production related non-routine emissions	Section 5.7.1

Subdivision 3.3.9A.8—Natural gas production—emissions that are vented—well workovers

3.85O Available methods

(1) Subject to section 1.18, for estimating emissions relating to well workovers (emissions that are vented) released during a year from the operation of a facility that is constituted by natural gas production the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions that result from deliberate releases from process vents, system upsets and accidents:

(a) method 1 under section 3.85P;

(b) method 4 under Section 3.85Q.

Note: There is no method 2 or 3 for subsection (2).

(3) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.85P Method 1—vented emissions from well workovers

(1) Subject to subsection (3), Method 1 is:

$$E_{ij} = \Sigma_k \; (Q_{ik} \times EF_{ijk} \times S_{ij} / SD_{ij})$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive (vented) emissions of gas type (***j***), being methane or carbon dioxide, from the natural gas production during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e and estimated by summing up the emissions released from all of the equipment of type (***k***) specified in column 2 of the table in subsection (2), if the equipment is used in the natural gas production.

$\boldsymbol{Q_{ik}}$ is the total of the number of well workover events for equipment of type (***k***) specified in column 2 of the table in subsection (2) during the year, if the equipment is used in the natural gas production.

Note: Consistent with subsection 3.41(2), a well workover event should be reported for a single reporting year and not separately in two consecutive years.

$\boldsymbol{EF_{ijk}}$ is the emission factor for gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e per well workover event using equipment type (***k***) specified in column 2 of the table in subsection (2) during the year, if the equipment is used in the natural gas production.

S_{ij} is the measured share of gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.825 and for carbon dioxide SD is 0.0345.

(2) For EF_{ijk} mentioned in subsection (1), column 3 of an item in the following table specifies the emission factor for methane for an equipment of type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide for an equipment of type (***k***) specified in column 2 of that item:

Item	Equipment type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	
1	Well workover without hydraulic fracturing	5.5	1.1×10^{-2}	tonnes CO_2-e per well workover event
2	Well workover with hydraulic fracturing and venting (no flaring)	1,031	4.2	tonnes CO_2-e per well workover event
3	Well workover with hydraulic fracturing with capture (no flaring)	90.8	0.37	tonnes CO_2-e per well workover event
4	Well workover with hydraulic fracturing with flaring	136.6	0.56	tonnes CO_2-e per well workover event

(3) If the well workover includes a well unloading, the fugitive (vented) emissions of gas type (***j***), being methane or carbon dioxide, for the well unloading must be calculated by applying section 5.7.1 of the API Compendium.

3.85Q Method 4—vented emissions from gas well workovers

Method 4 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Engineering calculation approach	Section 5.7.1

Subdivision 3.3.9A.9—Natural gas production—emissions that are vented—vessel blowdowns, compressor starts and compressor blowdowns

3.85R Available methods

(1) Subject to section 1.18, for estimating emissions relating to vessel blowdowns, compressor starts and compressor blowdowns (emissions that are vented) released during a year from the operation of a facility that is constituted by natural gas production the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions that result from deliberate releases from process vents, system upsets and accidents:

(a) method 1 under section 3.85S;

(b) method 4 under Part 1.3.

Note: There is no method 2 or 3 for subsection (2).

(3) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.85S Method 1—emissions from system upsets, accidents and deliberate releases from process vents—production related non-routine emissions—vessel blowdowns, compressor starts and compressor blowdowns

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Non-routine activities—production related non-routine emissions—vessel blowdowns	Section 5.7.1 and 5.7.2
2	Non-routine activities—production related non-routine emissions—compressor starts	Section 5.7.1 and 5.7.2
3	Non-routine activities—production related non-routine emissions—compressor blowdowns	Section 5.7.1 and 5.7.2

Subdivision 3.3.9A.10—Natural gas production (emissions that are flared)

3.85T Available methods

(1) For estimating emissions released from gas flared from natural gas production:

(a) one of the following methods must be used for estimating emissions of carbon dioxide released:

(i) method 1 under section 3.86;

(ii) method 2 under section 3.87;

(iii) method 3 under section 3.88; and

(b) if estimating emissions of methane released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A.

Note: The flaring of gas from natural gas production and processing releases emissions of carbon dioxide, methane and nitrous oxide. The reference to gas type (***j***) in method 1 in section 3.85 is a reference to these gases. The same formula is used to estimate emissions of each of these gases. There is no method 4 for emissions of carbon dioxide and no method 2, 3 or 4 for emissions of nitrous oxide or methane.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.86 Method 1—gas flared from natural gas production

(1) Method 1 is:

$$E_{ij} = Q_i \times EF_{ij}$$

where:

$\boldsymbol{E_{ij}}$ is the emissions of gas type (***j***) measured in CO_2-e tonnes that result from a fuel type (***i***) flared in the natural gas production during the year.

$\boldsymbol{Q_i}$ is the quantity of fuel type (***i***) measured in tonnes of gas flared during the year.

Note: This quantity includes all of the fuel type, not just hydrocarbons within the fuel type.

$\boldsymbol{EF_{ij}}$ is the emission factor for gas type (***j***) measured in CO_2-e tonnes of emissions per tonne of gas flared in the natural gas production during the year as determined under subsection (2).

(2) For $\boldsymbol{EF_{ij}}$ mentioned in subsection (1), columns 3, 4 and 5 of an item in the following table specify the emission factor for fuel type (***i***) specified in column 2 of that item.

Item	fuel type (i)	Emission factor of gas type (j) (tonnes CO_2-e/tonnes fuel flared)		
		CO_2	CH_4	N_2O
1	Gas	2.7	0.133	0.026
2	Crude oil and liquids	3.20	0.009	0.06

3.87 Method 2—gas flared from natural gas production

Method 2 is:

$$E_{ico_2} = Q_h \times EF_{hi} \times OF_i + QCO_2$$

where:

$\boldsymbol{E_{iCO_2}}$ is the fugitive emissions of CO_2 from fuel type (***i***) flared in the natural gas production during the year, measured in CO_2-e tonnes.

$\boldsymbol{Q_h}$ is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in the natural gas production during the year, measured in tonnes in accordance with Division 2.3.3.

$\boldsymbol{EF_{hi}}$ is the carbon dioxide emission factor for the total hydrocarbons (***h***) within the fuel type (***i***) in the natural gas production during the year, measured in CO_2-e tonnes per tonne of fuel type (***i***) flared, estimated in accordance with Division 2.3.3.

$\boldsymbol{OF_i}$ is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

$\boldsymbol{QCO_2}$ is the quantity of CO_2 within the fuel type (***i***) in the natural gas production and processing during the year, measured in CO_2-e tonnes in accordance with Division 2.3.3.

3.87A Method 2A—natural gas production (flared methane or nitrous oxide emissions)

Method 2A is:

$$E_{ij} = Q_h \times EF_{hij} \times OF_i$$

where:

$\boldsymbol{EF_{hij}}$ is the emission factor of gas type (***j***), being methane or nitrous oxide, for the total hydrocarbons (***h***) within the fuel type (***i***) in natural gas production during the year, mentioned for the fuel type in the table in subsection 3.85(2) and measured in CO_2-e tonnes per tonne of the fuel type (***i***) flared.

$\boldsymbol{E_{ij}}$ is the fugitive emissions of gas type (***j***), being methane or nitrous oxide, from fuel type (***i***) flared from natural gas production during the year, measured in CO_2-e tonnes.

$\boldsymbol{OF_i}$ is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

$\boldsymbol{Q_h}$ is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in natural gas production during the year, measured in tonnes in accordance with Division 2.3.3.

3.88 Method 3—gas flared from natural gas production

Method 3 is the same as method 2 under section 3.86, but the emission factor (EF_{ij}) must be determined in accordance with method 3 for the consumption of gaseous fuels as specified in Division 2.3.4.

Division 3.3.9B—Natural gas gathering and boosting (emissions that are vented or flared)

3.88A Application

This Division applies to fugitive emissions from venting or flaring from natural gas gathering and boosting, including emissions from:

(a) the venting of natural gas; and

(b) the venting of waste gas and vapour streams at facilities that are constituted by natural gas gathering and boosting; and

(c) the flaring of natural gas, waste gas and waste vapour streams at those facilities.

Subdivision 3.3.9B.1—Natural gas gathering and boosting (emissions that are vented)

3.88B Available methods

(1) Subject to section 1.18, method 1 under section 3.88C must be used for estimating fugitive emissions from gas vented during natural gas gathering and boosting.

Note: There is no method 2, 3 or 4 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.88C Method 1—emissions from system upsets, accidents and deliberate releases from process vents—gas gathering and boosting emissions

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Gas treatment processes	Section 5.1
2	Cold process vents	Section 5.3
3	Natural gas blanketed tanks	Section 5.4.4
4	Other venting sources—gas driven pneumatic devices	Section 5.6.1
5	Other venting sources—gas driven chemical injection pumps	Section 5.6.2
6	Non-routine activities—gas production related non-routine emissions – gas gathering pipeline blowdowns	Section 5.7.1 and 5.7.2
7	Condensate storage tanks	Section 5.4.1

Subdivision 3.3.9B.2—Natural gas gathering and boosting (emissions that are flared)

3.88D Available methods

(1) For estimating emissions released from gas flared from natural gas gathering and boosting:

(a) one of the following methods must be used for estimating emissions of carbon dioxide released:

(i) method 1 under section 3.86;

(ii) method 2 under section 3.87;

(iii) method 3 under section 3.88; and

(b) if estimating emissions of methane released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A.

Note: The flaring of gas from natural gas production and processing releases emissions of carbon dioxide, methane and nitrous oxide. The reference to gas type (***j***) in method 1 in section 3.86 is a reference to these gases. The same formula is used to estimate emissions of each of these gases. There is no method 4 for emissions of carbon dioxide and no method 2, 3 or 4 for emissions of nitrous oxide or methane.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

Division 3.3.9C—Natural gas processing (emissions that are vented or flared)

3.88E Application

This Division applies to fugitive emissions from venting or flaring from natural gas processing activities, including emissions from:

(a) the venting of natural gas; and

(b) the venting of waste gas and vapour streams at facilities that are constituted by natural gas processing; and

(c) the flaring of natural gas, waste gas and waste vapour streams at those facilities.

Subdivision 3.3.9C.1—Natural gas processing (emissions that are vented)

3.88F Available methods

(1) Subject to section 1.18, method 1 under section 3.88G must be used for estimating fugitive emissions from gas vented during natural gas processing.

Note: There is no method 2, 3 or 4 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.88G Method 1—emissions from system upsets, accidents and deliberate releases from process vents—gas processing

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Gas treatment processes	Section 5.1
2	Cold process vents	Section 5.3
3	Natural gas blanketed tanks	Section 5.4.4
4	Other venting sources—gas driven pneumatic devices	Section 5.6.1
5	Other venting sources—gas driven chemical injection pumps	Section 5.6.2
6	Non-routine activities—gas processing related non-routine emissions	Section 5.7.1 and 5.7.3
7	Condensate storage tanks	Section 5.4.1

Subdivision 3.3.9C.2—Natural gas processing (emissions that are flared)

3.88H Available methods

(1) For estimating emissions released from gas flared from natural gas processing:

(a) one of the following methods must be used for estimating emissions of carbon dioxide released:

(i) method 1 under section 3.86;

(ii) method 2 under section 3.87;

(iii) method 3 under section 3.88; and

(b) if estimating emissions of methane released—one of the following methods must be used:

   (i) method 1 under section 3.86;

   (ii) method 2A under section 3.87A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:

   (i) method 1 under section 3.86;

   (ii) method 2A under section 3.87A.

Note: The flaring of gas from natural gas production and processing releases emissions of carbon dioxide, methane and nitrous oxide. The reference to gas type (***j***) in method 1 in section 3.86 is a reference to these gases. The same formula is used to estimate emissions of each of these gases. There is no method 4 for emissions of carbon dioxide and no method 2, 3 or 4 for emissions of nitrous oxide or methane.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

Division 3.3.9D—Natural gas transmission (emissions that are flared)

3.88I Application

This Division applies to fugitive emissions from venting or flaring from natural gas transmission activities, including emissions from the flaring of natural gas, waste gas and waste vapour streams at those facilities.

Note: Vented emissions from Natural gas transmission are estimated under Division 3.3.7.

3.88J Available methods

(1) For estimating emissions released from gas flared from natural gas transmission:

(a) one of the following methods must be used for estimating emissions of carbon dioxide released:

(i) method 1 under section 3.86;

(ii) method 2 under section 3.87;

(iii) method 3 under section 3.88; and

(b) if estimating emissions of methane released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A.

Note: The flaring of gas releases emissions of carbon dioxide, methane and nitrous oxide. The reference to gas type (***j***) in method 1 in section 3.86 is a reference to these gases. The same formula is used to estimate emissions of each of these gases. There is no method 4 for emissions of carbon dioxide and no method 2, 3 or 4 for emissions of nitrous oxide or methane.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

Division 3.3.9E—Natural gas storage (emissions that are vented or flared)

3.88K Application

This Division applies to fugitive emissions from venting or flaring from natural gas storage, including emissions from:

(a) the venting of natural gas; and

(b) the venting of waste gas and vapour streams at facilities that are constituted by natural gas production or processing; and

(c) the flaring of natural gas, waste gas and waste vapour streams at those facilities.

Subdivision 3.3.9E.1——Natural gas storage (emissions that are vented)

3.88L Available methods

(1) Subject to section 1.18, method 1 under section 3.88M must be used for estimating fugitive emissions from gas vented during natural gas storage.

Note: There is no method 2, 3 or 4 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.88M Method 1—emissions from system upsets, accidents and deliberate releases from process vents—gas storage related non-routine emissions

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Gas treatment processes	Section 5.1
2	Cold process vents	Section 5.3
3	Natural gas blanketed tanks	Section 5.4.4
4	Other venting sources—gas driven pneumatic devices	Section 5.6.1
5	Other venting sources—gas driven chemical injection pumps	Section 5.6.2
6	Non-routine activities—gas storage related non-routine emissions	Section 5.7.1 and 5.7.4 a
7	Condensate storage tanks	Section 5.4.1

a The emission factor at Table 5-26 ‘Gas storage station venting’ must be used for each instance of a natural gas storage station if emissions are estimated according to section 5.7.4.

Subdivision 3.3.9E.2—Natural gas storage (emissions that are flared)

3.88N Available methods

(1) For estimating emissions released from gas flared from natural gas storage:

(a) one of the following methods must be used for estimating emissions of carbon dioxide released:

(i) method 1 under section 3.86;

(ii) method 2 under section 3.87;

(iii) method 3 under section 3.88; and

(b) if estimating emissions of methane released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.86A.

Note: The flaring of gas from natural gas storage releases emissions of carbon dioxide, methane and nitrous oxide. The reference to gas type (***j***) in method 1 in section 3.86 is a reference to these gases. The same formula is used to estimate emissions of each of these gases. There is no method 4 for emissions of carbon dioxide and no method 2, 3 or 4 for emissions of nitrous oxide or methane.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

Division 3.3.9F— Natural gas liquefaction, storage and transfer (emissions that are vented or flared)

3.88O Application

This Division applies to fugitive emissions from venting or flaring from natural gas liquefaction, storage and transfer activities, including emissions from:

(a) the venting of natural gas; and

(b) the venting of waste gas and vapour streams at facilities that are constituted by natural gas liquefaction, storage and transfer activities; and

(c) the flaring of natural gas, waste gas and waste vapour streams at those facilities.

Subdivision 3.3.9F.1—Natural gas liquefaction, storage and transfer (emissions that are vented)

3.88P Available methods

(1) Subject to section 1.18, method 1 under section 3.88Q must be used for estimating fugitive emissions from gas vented from natural gas liquefaction, storage and transfer (emissions that are vented) activities.

Note: There is no method 2, 3 or 4 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.88Q Method 1—emissions from system upsets, accidents and deliberate releases from process vents— natural gas liquefaction, storage and transfer

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Gas treatment processes	Section 5.1
2	Cold process vents	Section 5.3
3	Natural gas blanketed tanks	Section 5.4.4
4	Other venting sources—gas driven pneumatic devices	Section 5.6.1
5	Other venting sources—gas driven chemical injection pumps	Section 5.6.2
6	Non-routine activities— natural gas liquefaction, storage and transfer related non-routine emissions	Section 5.7.1 and 5.7.4 a
7	Condensate storage tanks	Section 5.4.1

a The emission factor at Table 5-26 ‘Gas storage station venting’ must be used for each instance of an LNG station if emissions are estimated according to section 5.7.4.

Subdivision 3.3.9F.2—Natural gas liquefaction, storage and transfer (emissions that are flared)

3.88R Available methods

(1) For estimating emissions released from gas flared from natural gas liquefaction, storage and transfer:

(a) one of the following methods must be used for estimating emissions of carbon dioxide released:

  (i) method 1 under section 3.86;

  (ii) method 2 under section 3.87;

  (iii) method 3 under section 3.88; and

(b) if estimating emissions of methane released—one of the following methods must be used:

  (i) method 1 under section 3.86;

  (ii) method 2A under section 3.87A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:

  (i) method 1 under section 3.86;

  (ii) method 2A under section 3.87A.

Note: The flaring of gas releases emissions of carbon dioxide, methane and nitrous oxide. The reference to gas type (***j***) in method 1 in section 3.86 is a reference to these gases. The same formula is used to estimate emissions of each of these gases. There is no method 4 for emissions of carbon dioxide and no method 2, 3 or 4 for emissions of nitrous oxide or methane.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

Division 3.3.9G—Natural gas distribution (emissions that are flared)

3.88S Application

This Division applies to fugitive emissions from flaring from natural gas distribution activities, including emissions from the flaring of natural gas, waste gas and waste vapour streams at those facilities.

3.88T Available methods

(1) For estimating emissions released from gas flared from natural gas distribution:

(a) one of the following methods must be used for estimating emissions of carbon dioxide released:

(i) method 1 under section 3.86;

(ii) method 2 under section 3.87;

(iii) method 3 under section 3.88; and

(b) if estimating emissions of methane released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A.

Note: The flaring of gas releases emissions of carbon dioxide, methane and nitrous oxide. The reference to gas type (***j***) in method 1 in section 3.86 is a reference to these gases. The same formula is used to estimate emissions of each of these gases. There is no method 4 for emissions of carbon dioxide and no method 2, 3 or 4 for emissions of nitrous oxide or methane.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

[16] Heading to Part 3.4

After "capture and storage", insert "and enhanced oil recovery".

[17] Section 3.88

After "capture and storage", insert "and enhanced oil recovery".

[18] Divisions 3.4.2 and 3.4.3

Repeal the Divisions, substitute:

Division 3.4.2—Transport of greenhouse gases

Subdivision 3.4.2.1—Preliminary

3.89 Application

This Division applies to fugitive emissions from the transport of a greenhouse gas captured for permanent storage or captured for enhanced oil recovery.

Note: Section 1.19A defines when a greenhouse gas is captured for permanent storage.

Note: Section 1.8 defines enhanced oil recovery.

3.90 Available methods

(1) Subject to section 1.18, for estimating emissions released during a year from the operation of a facility that is constituted by the transport of a greenhouse gas captured for permanent storage or for injection as part of enhanced oil recovery, the methods as set out in this section must be used.

Emissions from transport of a greenhouse gas involving transfer

(2) If the greenhouse gas is transferred to a relevant person for injection by the person in accordance with a licence, lease or approval mentioned in section 1.19A or an enhanced oil recovery authority, one of the following methods must be used for estimating fugitive emissions of the greenhouse gas that result from the transport of the greenhouse gas stream for that injection:

(a) method 1 under section 3.91 (which deals with injection);

(b) method 2 under section 3.77 (which deals with transport), applied in relation to the greenhouse gas as if it were a type of natural gas.

Note 1: There is no method 3 or 4 for subsection (2).

Note 2: The same emissions cannot be counted under both the method mentioned in paragraph (2)(a) (injection) and the method mentioned in paragraph (2)(b) (transport).

Emissions from transport of a greenhouse gas not involving transfer

(2A) Subsection (3) applies if:

(a) the greenhouse gas is captured by a relevant person for injection in accordance with a licence, lease or approval mentioned in section 1.19A or an enhanced oil recovery authority; and

(b) the greenhouse gas is not transferred to another person for the purpose of injection.

(3) One of the following methods must be used for estimating fugitive emissions of the greenhouse gases that result from the transport of the greenhouse gas stream for that injection:

(a) method 1 under section 3.92 (which deals with injection);

(b) method 2 under section 3.77 (which deals with transport), applied in relation to the greenhouse gas as if it were a type of natural gas.

Note 1: There is no method 3 or 4 for subsection (3).

Note 2: The same emissions cannot be counted under both the method mentioned in paragraph (3)(a) (injection) and the method mentioned in paragraph (3)(b) (transport).

(4) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

Subdivision 3.4.2.2—Emissions from transport of greenhouse gases involving transfer

3.91 Method 1—emissions from transport of greenhouse gases involving transfer

For subsection 3.90(2), method 1 is:

$$E_j = \gamma_j \left(RCCS_j - Q_{inj} \right) - E_{ij}$$

where:

$\boldsymbol{E_j}$ is the emissions of gas type (***j***), during the year from transportation of greenhouse gas captured for permanent storage, or captured for enhanced oil recovery, to the storage or injection site, measured in CO_2-e tonnes.

$\boldsymbol{\gamma_j}$ is the factor for converting a quantity of gas type (***j***) from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes, being:

(a) for methane—$6.784 \times 10^{-4} \times GWP_{methane}$; and

(b) for carbon dioxide—1.861×10^{-3}; and

(c) for any other gas type—the appropriate conversion factor for the gas type.

$\boldsymbol{Q_{inj}}$ is the quantity of greenhouse gas injected into the storage or injection site during the year and measured in cubic metres at standard conditions of pressure and temperature.

$\boldsymbol{RCCS_j}$ is the quantity of gas type (***j***) captured during the year worked out under Division 1.2.3 and measured in cubic metres at standard conditions of pressure and temperature. If the injection is part of enhanced oil recovery, Division 1.2.3 must be applied to enhanced oil recovery as if it was capture for permanent storage.

$\boldsymbol{E_{ij}}$ is the fugitive emissions (***j***) from the injection of a greenhouse gas into a geological formation during the reporting year, measured in CO_2-e tonnes and calculated in accordance with Subdivision 3.4.3.2.

Subdivision 3.4.2.3—Emissions from transport of greenhouse gases not involving transfer

3.92 Method 1—emissions from transport of greenhouse gases not involving transfer

For subsection 3.90(3), method 1 is:

$$E_j = \gamma_j \left(RCCS_j - Q_{inj} \right)$$

where:

$\boldsymbol{E_j}$ is the emissions of gas type (***j***), during the year from transportation of greenhouse gas captured for permanent storage, or captured for enhanced oil recovery, to the storage or injection site, measured in CO_2-e tonnes.

$\boldsymbol{\gamma_j}$ is the factor for converting a quantity of gas type (***j***) from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes, being:

(a) for methane—$6.784 \times 10^{-4} \times GWP_{methane}$; and

(b) for carbon dioxide—1.861×10^{-3}; and

(c) for any other gas type—the appropriate conversion factor for the gas type.

$\boldsymbol{Q_{inj}}$ is the quantity of greenhouse gas injected into the storage or injection site during the year and measured in cubic metres at standard conditions of pressure and temperature.

$RCCS_j$ is the quantity of gas type (***j***) captured during the year worked out under Division 1.2.3 and measured in cubic metres at standard conditions of pressure and temperature. If the injection is part of enhanced oil recovery, Division 1.2.3 must be applied to enhanced oil recovery as if it was capture for permanent storage.

Division 3.4.3—Injection of greenhouse gases

Subdivision 3.4.3.1—Preliminary

3.93 Application

This Division applies to fugitive emissions of greenhouse gases from the injection of a greenhouse gas captured for permanent storage, or captured for enhanced oil recovery, into a geological formation.

Note: A greenhouse gas is ***captured for permanent storage*** in a geological formation if the gas is captured by, or transferred to, the holder of a licence, lease or approval mentioned in section 1.19A, under a law mentioned in that section, for the purpose of being injected into a geological formation (however described) under the licence, lease or approval.

Note: Section 1.8 defines enhanced oil recovery.

3.94 Available methods

(1) For estimating fugitive emissions of greenhouse gases released during a year from the injection of a greenhouse gas captured for permanent storage, or captured for enhanced oil recovery, into a geological formation, the methods set out in this section must be used.

Process vents, system upsets and accidents

(2) Method 2 under section 3.95 must be used for estimating fugitive emissions of greenhouse gases that result from deliberate releases from process vents, system upsets and accidents.

Fugitive emissions of greenhouse gases other than from process vents, system upsets and accidents

(3) One of the following methods must be used for estimating fugitive emissions of greenhouse gases from the injection of a greenhouse gas captured for permanent storage, or captured for enhanced oil recovery, into a geological formation that are not the result of deliberate releases from process vents, system upsets and accidents:

(a) method 2 under section 3.96;

(b) method 3 under section 3.97.

Note: There is no method 1, 3 or 4 for subsection (2) and no method 1 or 4 for subsection (3).

Subdivision 3.4.3.2—Fugitive emissions from deliberate releases from process vents, system upsets and accidents

3.95 Method 2—fugitive emissions from deliberate releases from process vents, system upsets and accidents

Method 2 is the same as the approach mentioned in section 5.3 or 5.7.1 of the API Compendium.

Subdivision 3.4.3.3—Fugitive emissions from injection of greenhouse gases (other than emissions from deliberate releases from process vents, system upsets and accidents)

3.96 Method 2—fugitive emissions from injection of a greenhouse gas into a geological formation (other than deliberate releases from process vents, system upsets and accidents)

(1) Method 2 is:

$$E_{ij} = \sum_k \left(Q_{ik} \times EF_{ijk} \right)$$

where:

$\boldsymbol{EF_{ijk}}$ is the emission factor (***j***) measured in CO_2-e tonnes that passes through each equipment type (***k***) mentioned in section 6.1 of the API Compendium, if the equipment type was used in the injection of a greenhouse gas into the geological formation.

$\boldsymbol{E_{ij}}$ is the fugitive emissions (***j***) from the injection of a greenhouse gas into a geological formation during the reporting year, measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the emissions (***j***) measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) mentioned in section 6.1 of the API Compendium, if the equipment type was used in the injection of a greenhouse gas into the geological formation.

$\boldsymbol{Q_{ik}}$ is the total of the quantities of greenhouse gas measured in tonnes that pass through each equipment type (***k***) mentioned in section 6.1 of the API Compendium, if the equipment type was used in the injection of a greenhouse gas into the geological formation.

(2) For $\boldsymbol{EF_{ijk}}$ in subsection (1), the emission factors are:

(a) the emission factors listed for the equipment type in section 6.1 of the API Compendium; or

(b) if the manufacturer of the equipment supplies equipment specific emissions factors for the equipment type—those factors.

3.97 Method 3—fugitive emissions from injection of greenhouse gases (other than deliberate releases from process vents, system upsets and accidents)

Method 3 is the same as an approach mentioned in Appendix C to the API Compendium.

Note: For this method, any approach mentioned in Appendix C to the API Compendium may be used.

[19] At the end of paragraph 4.1(2)(b)

Add:

(vii) hydrogen production (see Division 4.3.7);

[20] At the end of Part 4.3

Add:

Division 4.3.7—Hydrogen production

4.60 Application

This Division applies to chemical industry hydrogen production if:

(a) hydrogen is the main product at the facility; and

(b) the hydrogen is for use outside the facility; and

(c) the facility does not involve the production of ammonia with emissions reported under Division 4.3.1; and

(d) the emissions from hydrogen production are not included under another method in this Determination applicable to one or more primary products from the facility.

4.61 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions released during a year from the operation of a facility that is constituted by the production of hydrogen:

(a) method 1 under section 4.62;

(b) method 2 under section 4.62A;

(c) method 3 under section 4.62B;

(d) method 4 under Part 1.3.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

4.62 Method 1—hydrogen production

(1) Method 1 is:

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ij}}{1000} - R$$

where:

$\boldsymbol{E_{ij}}$ is the emissions of carbon dioxide released from the production of hydrogen during the year measured in CO_2-e tonnes.

$\boldsymbol{Q_i}$ is the quantity of each type of feedstock or type of fuel (***i***) consumed from the production of hydrogen during the year, measured in the appropriate unit and estimated using a criterion in Division 2.3.6 for gaseous fuels or Division 2.2.5 for solid fuels.

Note: If more than one feedstock or type of fuel is used, the emissions of each feedstock or type of fuel are calculated and summed to determine the overall emissions.

$\boldsymbol{EC_i}$ is the energy content factor for fuel type ***(i)*** used as a feedstock in the production of hydrogen during the year, estimated under section 6.5.

$\boldsymbol{EF_{ij}}$ is the carbon dioxide emission factor for each type of feedstock or type of fuel (***i***) used in the production of hydrogen during the year, including the effects of oxidation, measured in kilograms for each gigajoule according to source as mentioned in Part 1 or 2 of Schedule 1.

R is the quantity of carbon dioxide measured in tonnes derived from the production of hydrogen during the year, captured and transferred for use in the operation of another facility, estimated using an applicable criterion in Division 2.3.6 for gaseous fuels or Division 2.2.5 for solid fuels and in accordance with any other requirements of those Divisions.

(2) For the purposes of calculating ***R*** in subsection (1), if:

(a) more than one fuel is consumed in the production of hydrogen; and

(b) the carbon dioxide generated from the production of hydrogen is captured and transferred for use in the operation of another facility or captured for permanent storage;

the total amount of carbon dioxide that may be deducted in relation to the production of hydrogen is to be attributed to each fuel consumed in proportion to the carbon content of the fuel relative to the total carbon content of all fuel consumed in the production of hydrogen.

(3) However, if no fuel is used as a feedstock in the production of hydrogen the emissions of carbon dioxide released from the production of hydrogen during the year under this Division is taken to be zero.

Note: Hydrogen can be produced by electrolysis without using fossil fuels as a feedstock. Other emissions from the combustion of fuels at the facility may need to be reported elsewhere under this Determination.

4.62A Method 2—hydrogen production

(1) Method 2 is:

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ij}}{1\ 000} - R - \gamma RCCS_{co_2}$$

where:

$\boldsymbol{E_{ij}}$ is the emissions of carbon dioxide released from the production of hydrogen during the year measured in CO_2-e tonnes.

$\boldsymbol{Q_i}$ is the quantity of each type of feedstock or type of fuel (***i***) consumed from the production of hydrogen during the year, measured in the appropriate unit and estimated using an applicable criterion in Division 2.3.6 for gaseous fuels or Division 2.2.5 for solid fuels.

Note: If more than one feedstock or type of fuel is used, the emissions of each feedstock or type of fuel are calculated and summed to determine the overall emissions.

$\boldsymbol{EC_i}$ is the energy content factor for fuel type ***(i)*** used as a feedstock in the production of hydrogen during the year, estimated under section 6.5.

$\boldsymbol{EF_{ij}}$ is the carbon dioxide emission factor for each type of feedstock or type of fuel (***i***) used in the production of hydrogen during the year, including the effects of oxidation, measured in kilograms for each gigajoule according to source in accordance with subsection (2).

R is the quantity of carbon dioxide measured in tonnes derived from the production of hydrogen during the year, captured and transferred for use in the operation of another facility, estimated using an applicable criterion in Division 2.3.6 for gaseous fuels or Division 2.2.5 for solid fuels and in accordance with any other requirements of those Divisions.

$\boldsymbol{\gamma}$ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$\boldsymbol{RCCS_{CO_2}}$ is carbon dioxide captured for permanent storage measured in cubic metres in accordance with Division 1.2.3.

(2) The method for estimating emission factors for gaseous fuels in Division 2.3.3, or for solid fuels in Division 2.2.3, apply for working out the factor $\boldsymbol{EF_{ij}}$.

(3) For the purposes of calculating ***R*** in subsection (1), if:

(a) more than one fuel is consumed in the production of hydrogen; and

(b) the carbon dioxide generated from the production of hydrogen is captured and transferred for use in the operation of another facility or captured for permanent storage;

the total amount of carbon dioxide that may be deducted in relation to the production of hydrogen is to be attributed to each fuel consumed in proportion to the carbon content of the fuel relative to the total carbon content of all fuel consumed in the production of hydrogen.

4.62B Method 3—hydrogen production

(1) Method 3 is the same as method 2 under section 4.62.

(2) In applying method 2 as method 3, the method for estimating emission factors for gaseous fuels in Division 2.3.4, or for solid fuels in Division 2.2.4, apply for working out the factor $\boldsymbol{EF_{ij}}$.

[21] Subsection 5.17(2)

Repeal the subsection, substitute:

(2) The site plan must:

(a) be consistent with the provisions relating to landfill site plans included in the document entitled *Landfill site plan and verification requirements (methods 2 and 3)*, published by the Clean Energy Regulator in June 2021; and

(b) if the landfill has more than one sub-facility zone—show the boundaries of each sub-facility zone.

Note: In 2021, the *Landfill site plan and verification requirements (methods 2 and 3)* were available at www.cleanenergyregulator.gov.au.

[22] Subsection 5.17B(3)

Repeal the subsection, substitute:

(3) The report must include the details specified in the *Landfill site plan and verification requirements (methods 2 and 3)*, published by the Clean Energy Regulator in June 2021, in relation to expert reports.

Note: In 2021, the *Landfill site plan and verification requirements (methods 2 and 3)* were available at www.cleanenergyregulator.gov.au.

[23] Subsection 8.6(1) (table items 33 and 34)

Repeal the items, substitute:

33	Crude oil	6	3
34	Plant condensate and other natural gas liquids not covered by another item in this table	7	9

[24] Subsection 8.8(1) (table items 4 to 11)

Repeal the items, substitute:

4	Oil or gas exploration and development—flaring	25
5	Oil or gas exploration and development (other than flaring)	50
6	Crude oil production	50
7	Crude oil transport	50
8	Crude oil refining	50
9	Onshore natural gas production (other than emissions that are vented or flared)	50
10	Offshore natural gas production (other than emissions that are vented or flared)	50
11	Natural gas gathering and boosting (other than emissions that are vented or flared)	50
12	Produced water from oil and gas exploration and development, crude oil production, natural gas production or natural gas gathering and boosting (other than emissions that are vented or flared)	50
13	Natural gas processing (other than emissions that are vented or flared)	50
14	Natural gas transmission (other than flaring)	50
15	Natural gas storage (other than emissions that are vented or flared)	50
16	Natural gas liquefaction, storage and transfer (other than emissions that are vented or flared)	50
17	Natural gas distribution (other than flaring)	50
18	Onshore natural gas production—venting	50
19	Offshore natural gas production—venting	50
20	Onshore natural gas production—flaring	25
21	Offshore natural gas production—flaring	25
22	Natural gas gathering and boosting—venting	50
23	Natural gas gathering and boosting—flaring	25
24	Natural gas processing—venting	50
25	Natural gas processing—flaring	25
26	Natural gas transmission—flaring	25
27	Natural gas storage—venting	50
28	Natural gas storage—flaring	25
29	Natural gas liquefaction, storage and transfer—venting	50
30	Natural gas liquefaction, storage and transfer—flaring	25
31	Natural gas distribution—flaring	25

[25] After section 9.13

Insert:

9.14 Amendments made by the *National Greenhouse and Energy Reporting (Measurement) Amendment (2021 Update) Determination 2021*

The amendments made by the *National Greenhouse and Energy Reporting (Measurement) Amendment (2021 Update) Determination 2021* apply in relation to:

(a) the financial year starting on 1 July 2021; and

(b) later financial years.

[26] Part 3 of Schedule 1 (table items 33 and 34)

Repeal the items, substitute:

33	Crude oil	45.3 GJ/t	69.6	0.08	0.2
34	Plant condensate and other natural gas liquids not covered by another item in this table	46.5 GJ/t	61.0	0.08	0.2

[27] Part 6 of Schedule 1

Repeal the Part, substitute:

Part 6—Indirect (scope 2) emission factors from consumption of electricity purchased or lost from grid

Indirect (scope 2) emissions factors from consumption of electricity purchased or lost from grid

Item	Column 1 State, Territory or grid description	Column 2 Emission factor kg CO_2-e/kWh
77	New South Wales and Australian Capital Territory	0.79
78	Victoria	0.96
79	Queensland	0.80
80	South Australia	0.35
81	South West Interconnected System in Western Australia	0.68
82	Tasmania	0.16
83	Northern Territory	0.57

[28] Part 3 of Schedule 3

Repeal the items, substitute:

33	Crude oil	0.861 tC/t fuel
34	Plant condensate and other natural gas liquids not covered by another item in this table	0.774 tC/t fuel

[29] After Schedule 3

Add:

Schedule 4—Matters to be identified for sources

(See subsection 1.4(3) and regulations 4.10, 4.11, 4.13, 4.14, 4.15 and 4.17 of the Regulations)

Part 1—Coal mining

Source 2A—Underground mine

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in sections 3.5 and 3.17	(a) the location of the mine by State or Territory (b) whether the mine is a gassy mine or a non-gassy mine (c) the tonnes of raw coal produced (d) the tonnes of coal mine waste gas (CO_2-e) flared
2	Method 4 for the source, as set out in section 3.6	(a) the location of the mine by State or Territory (b) the tonnes of raw coal produced (c) the tonnes of methane (CO_2-e) and the tonnes of carbon dioxide captured for energy production on site (d) the tonnes of methane (CO_2-e) and the tonnes of carbon dioxide captured and transferred off site (e) the tonnes of methane (CO_2-e) and the tonnes of carbon dioxide flared

Source 2B—Open cut mine

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 3.20	(a) the location of the mine by State or Territory (b) the tonnes of raw coal produced (c) the tonnes of coal mine waste gas flared
2	Methods 2 and 3 for the source, as set out in sections 3.21 and 3.26	(a) the location of the mine by State or Territory (b) the tonnes of raw coal produced (c) the tonnes of methane (CO_2-e) and the tonnes of carbon dioxide captured for energy production on site (d) the tonnes of methane (CO_2-e) and the tonnes of carbon dioxide captured and transferred off site (e) the tonnes of methane (CO_2-e) and the tonnes of carbon dioxide flared (f) the tonnes of methane (CO_2-e) and the tonnes of carbon dioxide vented

Source 2C—Decommissioned underground mine

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 3.32	(a) the location of the mine by State or Territory (b) whether the mine is a gassy mine or a non-gassy mine (c) the tonnes of methane emissions (CO_2-e) from the mine in the last 12 month period before the mine became a decommissioned underground coal mine (d) the date that the mine was decommissioned (e) the percentage of the mine void volume flooded

Item	Method	Matters to be identified
		(f) the tonnes of coal mine waste gas (CO_2-e) flared
2	Method 4 for the source, as set out in section 3.37	(a) the location of the mine by State or Territory (b) the tonnes of methane (CO_2-e) and the tonnes of carbon dioxide captured for energy production on site (c) the tonnes of methane (CO_2-e) and the tonnes of carbon dioxide captured and transferred off site (d) the tonnes of methane (CO_2-e) and the tonnes of carbon dioxide flared

Part 2—Oil or gas

Source 2D—Oil or gas exploration and development—flaring

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 3.44	(a) the tonnes of flared gas (b) the tonnes of flared crude oil and liquids
2	Methods 2, 2A and 3 for the source, as set out in sections 3.45, 3.45A and 3.46	(a) the tonnes and megajoules of flared gas (hydrocarbon component) (b) the tonnes and megajoules of flared crude oil and liquids (hydrocarbon component)

Source 2E—Oil or gas exploration and development (other than flaring)

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in sections 3.46AB, 3.56B, 3.85B and 3.85P	(a) the tonnes and megajoules of vented gas for each gas type (b) number of well completions of each type
	Method 4 for the source, as set out in section 3.46B and Part 1.3	(a) the tonnes and megajoules of vented gas for each gas type

Source 2F—Crude oil production

Item	Method	Matters to be identified
1	Methods 1 and 2 for the source (leak emissions), as set out in sections 3.49 and 3.50	(a) the tonnes of crude oil throughput
2	Method 3 for the source (leak emissions), as set out in section 3.51	(a) the tonnes of crude oil throughput (b) number of components of each component type (c) average hours of operation of each component type (d) total emissions of each gas type from each component type
3	Method 1 for the source (flaring), as set out in section 3.53	(a) the tonnes of flared gas (b) the tonnes of flared crude oil and liquids
4	Methods 2, 2A and 3 for the source (flaring), as set out sections 3.54, 3.54A and 3.55	(a) the tonnes and megajoules of flared gas (hydrocarbon component) (b) the tonnes and megajoules of flared crude oil and liquids (hydrocarbon component)
5	Method 1 for the source (venting), as set out in section 3.56B	(a) the tonnes and megajoules of vented gas for each gas type (b) number workovers of each event type
6	Method 4 for the source (venting), as set out in Part 1.3	(a) the tonnes and megajoules of vented gas for each gas type

Source 2G—Crude oil transport

Item	Method	Matters to be identified
1	Methods 1 and 2 for the source, as set out in section 3.59 and 3.60	the tonnes of indigenous crude oil transported to Australian refineries

Source 2H—Crude oil refining

Item	Method	Matters to be identified
1	Methods 1, 2, and 3 for the source (refining and storage tanks), as set out in sections 3.64, 3.65 and 3.66	(a) the tonnes of crude oil refined (b) the tonnes of crude oil stored
2	Method 4 for the source (vents, system upsets and accidents), as set out in section 3.68	(a) the quantity of refinery coke burnt
3	Method 1 for the source (flaring), as set out in section 3.69	(a) the tonnes of flared gas (b) the tonnes of flared crude oil and liquids
4	Methods 2, 2A and 3 for the source (flaring), as set out in sections 3.70, 3.70A and 3.71.	(a) the tonnes and megajoules of flared gas (hydrocarbon component) (b) the tonnes and megajoules of flared crude oil and liquids (hydrocarbon component)

Source 2I—Onshore natural gas production (other than emissions that are vented or flared)

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in the section 3.73A	(a) the tonnes of onshore natural gas production throughput (b) the total number of wells (including producing wells and suspended wells but not decommissioned wells)
2	Method 2 for the source, as set out in the section 3.73B	(a) the tonnes of onshore natural gas production throughput (b) number of equipment units of each equipment type (c) average hours of operation of each equipment type (d) total emissions for each gas type (CO_2-e) for each equipment type
3	Method 3 for the source, as set out in the section 3.73C	(a) the tonnes of onshore natural gas production throughput (b) the total number of wells (including producing wells and suspended wells but not decommissioned wells) (c) number of components of each component type (by leaker or non-leaker if LDAR factors are elected) (d) average hours of operation of each component type (by leaker or non-leaker if LDAR factors are elected) (e) total emissions for each gas type (CO_2-e) for each component type (by leaker or non-leaker if LDAR factors are elected) (f) if LDAR factors are elected—the standard used to detect leakers

Source 2J—Offshore natural gas production (other than emissions that are vented or flared)

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in the section 3.73F	(a) the tonnes of offshore natural gas production throughput (b) the total number of offshore platforms (shallow water) (c) the total number of offshore platforms (deep water)
2	Method 2 for the source, as set out in section 3.73G	(a) the tonnes of offshore natural gas production throughput (b) the total number of offshore platforms (shallow water) (c) the total number of offshore platforms (deep water) (d) number of equipment units of each equipment type (e) average hours of operation of each equipment type (f) total emissions for each gas type (CO2-e) for each equipment type
3	Method 3 for the source, as set out in section 3.73H	(a) the tonnes of offshore natural gas production throughput (b) the total number of offshore platforms (shallow water) (c) the total number of offshore platforms (deep water) (d) number of components of each component type (by leaker or non-leaker if LDAR factors are elected) (e) average hours of operation of each component type (by leaker or non-leaker if LDAR factors are elected) (f) total emissions for each gas type (CO_2-e) for each component type (by leaker or non-leaker if LDAR factors are elected) (g) if LDAR factors are elected—the standard used to detect leakers

Source 2K—Natural gas gathering and boosting (other than emissions that are vented or flared)

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 3.73K	(a) number of natural gas gathering and boosting stations (b) the tonnes of natural gas gathering and boosting throughput for each station (c) kilometres of pipeline length
2	Method 2 for the source, as set out in section 3.73L	*Stations* (a) number of natural gas gathering and boosting stations (b) the tonnes of natural gas gathering and boosting throughput for each station (c) number of equipment units of each equipment type (d) average hours of operation of each equipment type (e) total emissions for each gas type (CO_2-e) for each equipment type *Pipelines* (f) kilometres of pipeline length of each material (g) total emissions for each gas type (CO_2-e) for each material
3	Method 3 for the source, as set out in section 3.73M	*Stations* (a) number of natural gas gathering and boosting stations (b) the tonnes of natural gas gathering and boosting throughput for each station (c) number of components of each type (by leaker or non-leaker if LDAR factors are elected) (d) average hours of operation of each component type (by leaker or non-leaker if LDAR factors are elected) (e) total emissions for each gas type (CO_2-e) for each component type (by leaker or non-leaker if LDAR factors are elected)

Item	Method	Matters to be identified
		(f) if LDAR factors are elected—the standard used to detect leakers *Pipelines* (g) kilometres of pipeline length of each material (h) total emissions for each gas type (CO_2-e) for each material

Source 2L—Produced water from oil and gas exploration and development, crude oil production, natural gas production or natural gas gathering and boosting (other than emissions that are vented or flared)

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 3.73NA	megalitres of produced water
2	Method 2 for the source, as set out in section 3.73NB	(a) megalitres of produced water (b) average pressure in kilopascals for a water stream entering the separator during the year (or equivalent if no separator) (c) average salinity content of the water

Source 2M—Natural gas processing (other than emissions that are vented or flared)

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 3.73Q	(a) number of processing stations (b) the tonnes of throughput for each station
2	Method 2 for the source, as set out in section 3.73R	(a) number of processing stations (b) the tonnes of throughput for each station (c) number of equipment units of each equipment type (d) average hours of operation of each equipment type (e) total emissions for each gas type (CO_2-e) for each equipment type
3	Method 3 for the source, as set out in section 3.73S	(a) number of processing stations (b) the tonnes of throughput for each station (c) number of components of each type (by leaker or non-leaker if LDAR factors are elected) (d) average hours of operation of each component type (by leaker or non-leaker if LDAR factors are elected) (e) total emissions for each gas type (CO_2-e) for each component type (by leaker or non-leaker if LDAR factors are elected) (f) if LDAR factors are elected—the standard used to detect leakers

Source 2N—Natural gas transmission (other than flaring)

Item	Method	Matters to be identified
1	Method 1, 2 and 3 for the source, as set out in sections 3.76, 3.77 and 3.78	(a) the terajoules of natural gas transmission throughput (b) kilometres of pipeline length

Source 2O—Natural gas storage (other than emissions that are vented or flared)

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 3.78C	number of storage stations
2	Method 2 for the source, as set out in section 3.78D	(a) number of storage stations (b) number of equipment units of each equipment type (c) average hours of operation of each equipment type (d) total emissions for each gas type (CO_2-e) for each equipment type
3	Method 3 for the source, as set out in section 3.78E	(a) number of storage stations (b) number of components of each type (by leaker or non-leaker if LDAR factors are elected) (c) average hours of operation of each component type (by leaker or non-leaker if LDAR factors are elected) (d) total emissions for each gas type (CO_2-e) for each component type (by leaker or non-leaker if LDAR factors are elected) (e) if LDAR factors are elected—the standard used to detect leakers

Source 2P—Natural gas liquefaction, storage and transfer (other than emissions that are vented or flared)

Item	Method	Matters to be identified
1	Method 1, and 2 for the source, as set out in sections 3.78H and 3.78I	(a) the tonnes of natural gas liquefied (b) number of liquefied natural gas stations
3	Method 3 for the source, as set out in section 3.78J	(a) the tonnes of natural gas liquefied (b) number of liquefied natural gas stations (c) number of components of each type (by leaker or non-leaker if LDAR factors are elected) (d) average hours of operation of each component type (by leaker or non-leaker if LDAR factors are elected) (e) total emissions for each gas type (CO_2-e) for each component type (by leaker or non-leaker if LDAR factors are elected) (f) if LDAR factors are elected—the standard used to detect leakers

Source 2Q—Natural gas distribution (other than flaring)

Item	Method	Matters to be identified
1	Methods 1 and 2 for the source, as set out in sections 3.81 and 3.82	(a) terajoules of utility sales (b) location of the natural gas distribution
3	Method 3 for the source, as set out in section 3.82A	(a) terajoules of utility sales (b) location of the natural gas distribution (c) the facility specific unaccounted for gas factor as a percentage (d) whether the facility specific unaccounted for gas factor is the percentage calculated or determined for the reporting year or for a previous period

Source 2R—Onshore natural gas production—venting

Item	Method	Matters to be identified
1	Methods 1 and 4 for the source, as set out in section 3.85, 3.85B, 3.85D, 3.85F, 3.85H, 3.85L, 3.85N, 3.85P, 3.85Q, 3.85S and Part 1.3	(a) the tonnes and megajoules of vented gas related to gas treatment processes (b) the tonnes and megajoules of vented gas related to cold process vents (c) the tonnes and megajoules of vented gas related to gas blanketed tanks (d) the tonnes and megajoules of vented gas related to condensate storage tanks (e) the tonnes and megajoules of vented gas related to gas driven pneumatic devices (f) the tonnes and megajoules of vented gas related to gas driven chemical injection pumps (g) the tonnes and megajoules of vented gas related to well blowouts (h) the tonnes and megajoules of vented gas related to carbon dioxide stimulation (i) the tonnes and megajoules of vented gas related to well workovers (j) the tonnes and megajoules of vented gas related to vessel blowdowns, compressor starts and compressor blowdowns (k) number of well workovers without hydraulic fracturing (l) number of well workovers with hydraulic fracturing and venting (no flaring) (m) number of well workovers with hydraulic fracturing with capture (no flaring) (n) number of well workovers with hydraulic fracturing with flaring

Source 2S—Offshore natural gas production—venting

Item	Method	Matters to be identified
1	Methods 1 and 4 for the source, as set out in sections 3.85, 3.85B, 3.85D, 3.85F, 3.85H, 3.85L, 3.85N, 3.85P, 3.85Q, 3.85S and Part 1.3	(a) the tonnes and megajoules of vented gas related to gas treatment processes (b) the tonnes and megajoules of vented gas related to cold process vents (c) the tonnes and megajoules of vented gas related to gas blanketed tanks (d) the tonnes and megajoules of vented gas related to condensate storage tanks (e) the tonnes and megajoules of vented gas related to gas driven pneumatic devices (f) the tonnes and megajoules of vented gas related to gas driven chemical injection pumps (g) the tonnes and megajoules of vented gas related to well blowouts (h) the tonnes and megajoules of vented gas related to carbon dioxide stimulation (i) the tonnes and megajoules of vented gas related to well workovers (j) the tonnes and megajoules of vented gas related to vessel blowdowns, compressor starts and compressor blowdowns (k) number of well workovers without hydraulic fracturing (l) number of well workovers with hydraulic fracturing and venting (no flaring) (m) number of well workovers with hydraulic fracturing with capture (no flaring) (n) number of well workovers with hydraulic fracturing with flaring

Source 2T—Onshore natural gas production—flaring

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 3.86	(a) the tonnes of flared gas (b) the tonnes of flared crude oil and liquids
2	Methods 2, 2A and 3 for the source, as set out in sections 3.87, 3.87A and 3.88	(a) the tonnes and megajoules of flared gas (hydrocarbon component) (b) the tonnes and megajoules of flared crude oil and liquids (hydrocarbon component)

Source 2U—Offshore natural gas production—flaring

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 3.86	(a) the tonnes of flared gas (b) the tonnes of flared crude oil and liquids
2	Methods 2, 2A and 3 for the source, as set out in sections 3.87, 3.87A and 3.88	(a) the tonnes and megajoules of flared gas (hydrocarbon component) (b) the tonnes and megajoules of flared crude oil and liquids (hydrocarbon component)

Source 2V—Natural gas gathering and boosting—venting

Item	Method	Matters to be identified
1	Methods 1 for the source, as set out in section 3.88C	(a) the tonnes and megajoules of vented gas for each gas type

Source 2W—Natural gas gathering and boosting—flaring

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 3.86	(a) the tonnes of flared gas (b) the tonnes of flared crude oil and liquids
2	Methods 2, 2A and 3 for the source, as set out in sections 3.87, 3.87A and 3.88	(a) the tonnes and megajoules of flared gas (hydrocarbon component) (b) the tonnes and megajoules of flared crude oil and liquids (hydrocarbon component)

Source 2X—Natural gas processing—venting

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 3.88G	(a) the tonnes and megajoules of vented gas for each gas type

Source 2Y—Natural gas processing—flaring

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 3.86	(a) the tonnes of flared gas (b) the tonnes of flared crude oil and liquids
2	Methods 2, 2A and 3 for the source, as set out in sections 3.87, 3.87A and 3.88	(a) the tonnes and megajoules of flared gas (hydrocarbon component) (b) the tonnes and megajoules of flared crude oil and liquids (hydrocarbon component)

Source 2Z—Natural gas transmission—flaring

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 3.86	(a) the tonnes of flared gas (b) the tonnes of flared crude oil and liquids
2	Methods 2, 2A and 3 for the source, as set out in sections 3.87, 3.87A and 3.88	(a) the tonnes and megajoules of flared gas (hydrocarbon component) (b) the tonnes and megajoules of flared crude oil and liquids (hydrocarbon component)

Source 2ZA—Natural gas storage—venting

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 3.88M	(a) the tonnes and megajoules of vented gas for each gas type

Source 2ZB—Natural gas storage—flaring

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 3.86	(a) the tonnes of flared gas (b) the tonnes of flared crude oil and liquids
2	Methods 2, 2A and 3 for the source, as set out in sections 3.87, 3.87A and 3.88	(a) the tonnes and megajoules of flared gas (hydrocarbon component) (b) the tonnes and megajoules of flared crude oil and liquids (hydrocarbon component)

Source 2ZC—Natural gas liquefaction, storage and transfer—venting

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 3.88Q	(a) the tonnes and megajoules of vented gas for each gas type

Source 2ZE—Natural gas liquefaction, storage and transfer—flaring

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 3.86	(a) the tonnes of flared gas (b) the tonnes of flared crude oil and liquids
2	Methods 2, 2A and 3 for the source, as set out in sections 3.87, 3.87A and 3.88	(a) the tonnes and megajoules of flared gas (hydrocarbon component) (b) the tonnes and megajoules of flared crude oil and liquids (hydrocarbon component)

Source 2ZF—Natural gas distribution—flaring

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 3.86	(a) the tonnes of flared gas (b) the tonnes of flared crude oil and liquids
2	Methods 2, 2A and 3 for the source, as set out in sections 3.87, 3.87A and 3.88	(a) the tonnes and megajoules of flared gas (hydrocarbon component) (b) the tonnes and megajoules of flared crude oil and liquids (hydrocarbon component)

Source 2ZH—Enhanced oil recovery

Item	Method	Matters to be identified
1	Method 1, 2 or 3 for the source, as set out sections 3.77, 3.91, 3.92, 3.95, 3.96 and 3.97	(a) the amount of greenhouse gases captured for enhanced oil recovery (b) the amount of greenhouse gases imported for enhanced oil recovery (c) the amount of greenhouse gases injected at enhanced oil recovery sites (d) the amount of emissions that occurred during the transportation of greenhouse gases to the enhanced oil recovery site (e) the amount of emissions that occurred when greenhouse gases were being injected into the enhanced oil recovery site (f) the type of the source of the greenhouse gases captured for enhanced oil recovery

Part 3—Mineral products

Source 3A—Cement clinker production

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 4.4	(a) the tonnes of clinker produced (b) the tonnes of cement kiln dust produced (c) the degree of calcination of cement kiln dust produced
2	Methods 2 and 4 for the source, as set out in sections 4.5 and Part 1.3	(a) the tonnes of clinker produced (b) the tonnes of cement kiln dust produced (c) the facility specific emission factor or factors for clinker production, in tonnes of greenhouse gas emissions of each gas (CO_2-e) per tonne of clinker produced (d) the degree of calcination of cement kiln dust produced
3	Method 3 for the source, as set out in section 4.8	(a) the tonnes of pure calcium carbonate calcined (b) the tonnes of pure magnesium carbonate calcined (c) the tonnes of pure dolomite calcined (d) the tonnes of cement kiln dust not recycled or lost (e) the tonnes of organic matter or other carbon in specific non-fuel raw material (f) the emission factor for kerogen or other carbon-bearing non-fuel raw material, in tonnes of emissions (CO_2-e) per tonne of clinker produced (g) the degree of calcination of the carbonate in the production of cement clinker during the year (h) the tonnes of any other pure carbonate calcined (i) the degree of calcination of cement kiln dust produced

Source 3B—Lime production

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 4.13	(a) the tonnes of commercial lime produced (b) the tonnes of in-house lime produced (c) the tonnes of dolomitic lime produced (d) the tonnes of magnesian lime produced; (e) the tonnes of lime kiln dust produced (f) the degree of calcination of lime kiln dust produced
2	Method 2, 3 and 4 for the source, as set out in sections 4.14, 4.17 and Part 1.3	(a) the tonnes of lime produced (b) the tonnes of lime kiln dust produced (c) the degree of calcination of lime kiln dust produced (d) the emission factor for lime production at each facility, in tonnes of emissions (CO_2-e) per tonne of lime

Source 3C—Use of carbonate for production of mineral product (other than cement, clinker, lime or soda ash)

Item	Method	Matters to be identified
1	Methods 1 or 1A for the source, as set out in section 4.22 or 4.22A	(a) the tonnes of limestone calcined (b) the tonnes of dolomite calcined (c) the tonnes of magnesium carbonate calcined (d) the degree of calcination of the carbonate during the year (e) the tonnes of any other raw carbonate calcined
2	Methods 3 or 3A for the source, as set out in section 4.23 and 4.23A	(a) the tonnes of pure calcium carbonate calcined (b) the tonnes of pure dolomite calcined (c) the tonnes of pure magnesium carbonate calcined (d) the degree of calcination of the carbonate during the year (e) the tonnes of any other pure carbonate calcined
3	Method 4 for the source, as set out in Part 1.3	the tonnes of each pure carbonate calcined

Source 3D—Soda ash use

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 4.29	the tonnes of soda ash consumed

Source 3E—Soda ash production

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 4.31	(a) the tonnes of limestone consumed (b) the tonnes of dolomite consumed (c) the tonnes of magnesium carbonate consumed (d) the tonnes of soda ash produced (e) the tonnes of sodium bicarbonate produced (f) the tonnes of soda ash used for brine purification (g) the tonnes of solid waste by-product containing carbon produced (h) the average carbon content factor of solid waste by-products, in tonnes of carbon per tonne of solid waste by-product (i) the change in stock containing carbon, in tonnes (j) the carbon content factor of the change in stock, in tonnes of carbon per tonne of stock
2	Methods 2, 3 and 4 for the source, as set out in sections 4.32, 4.33 and Part 1.3	(a) the facility specific carbon content factor for soda ash production for each fuel type consumed, or each carbonaceous input material type consumed, in tonnes of carbon per: (i) tonne of fuel or carbonaceous input material; or (ii) cubic metre of fuel or carbonaceous input material; or (iii) kilolitre of fuel or carbonaceous input material (b) the tonnes of pure calcium carbonate consumed (c) the tonnes of pure dolomite consumed (d) the tonnes of pure magnesium carbonate consumed (e) the tonnes of soda ash produced

Item	Method	Matters to be identified
		(f) the tonnes of sodium bicarbonate produced (g) the tonnes of soda ash used for brine purification (h) the tonnes of solid waste by-product containing carbon produced (i) the average carbon content factor of solid waste by-products, in tonnes of carbon per tonne of solid waste by-product (j) the change in stock containing carbon, in tonnes (k) the carbon content factor of the change in stock, in tonnes of carbon per tonne of stock

Part 4—Chemical products

Source 3F—Ammonia production

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 4.42	(a) the tonnes of ammonia produced (b) the tonnes of carbon dioxide recovered and transferred from the facility (c) the tonnes of carbon dioxide recovered and used for urea production
2	Methods 2, 3 and 4 for the source, as set out in sections 4.43, 4.44 and Part 1.3	(a) the tonnes of ammonia produced (b) the tonnes of carbon dioxide recovered and transferred from the facility (c) the facility specific emission factor or factors for each fuel type consumed, in kilograms of CO_2-e per gigajoule (d) the tonnes of carbon dioxide recovered and used for urea production

Source 3G—Nitric acid production

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 4.47	(a) the tonnes of nitric acid production (b) the emission factor of the plant type, in tonnes of emissions (CO2-e) per tonne of nitric acid produced
2	Methods 2 and 4 for the source, as set out in section 4.48 and Part 1.3	(a) the tonnes of nitric acid produced (b) the facility specific emission factor or factors, in tonnes of emissions (CO_2-e) per tonne of nitric acid produced

Source 3H—Adipic acid production

Item	Method	Matters to be identified
1	The method set out in section 4.50	the tonnes of adipic acid produced

Source 3I—Carbide production

Item	Method	Matters to be identified
1	The method set out in section 4.52	the tonnes of carbide produced

Source 3J—Chemical or mineral production (other than carbide production) using carbon reductant or carbon anode

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 4.55	(a) the tonnes of chemical or mineral products containing carbon produced (b) the carbon content of the chemical or mineral products containing carbon produced, in tonnes of carbon per tonne of output

Item	Method	Matters to be identified
		(c) the tonnes of solid waste by-products containing carbon produced (d) the average carbon content factor of solid waste by-products, in tonnes of carbon per tonne of solid waste by-product (e) the change in stock containing carbon, in tonnes (f) the carbon content factor of the change in stock, in tonnes of carbon per tonne of stock (g) the tonnes of pure calcium carbonate consumed (h) the tonnes of pure dolomite consumed (i) the tonnes of pure magnesium carbonate consumed (j) the tonnes of any other pure carbonate consumed
2	Methods 2, 3 and 4 for the source, as set out in sections 4.56, 4.57 and Part 1.3	(a) the tonnes of chemical or mineral products containing carbon produced (b) the carbon content of the chemical or mineral products containing carbon produced, in tonnes of carbon per tonne of output (c) the tonnes of solid waste by-products containing carbon produced (d) the average carbon content factor of solid waste by-products, in tonnes of carbon per tonne of solid waste by-product (e) the change in stock containing carbon, in tonnes (f) the carbon content factor of the change in stock, in tonnes of carbon per tonne of stock (g) the facility specific carbon content factor for each fuel type consumed, or each carbonaceous input material consumed, in tonnes of carbon per: (i) tonne of fuel or carbonaceous input material; or (ii) cubic metre of fuel or carbonaceous input material; or (iii) kilolitre of fuel or carbonaceous input material (h) the tonnes of pure calcium carbonate consumed (i) the tonnes of pure dolomite consumed (j) the tonnes of pure magnesium carbonate consumed (k) the tonnes of any other pure carbonate consumed

Source 6—Hydrogen production

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 4.62	(a) the tonnes of hydrogen produced from fossil fuel feedstocks (b) the tonnes of hydrogen produced from electrolysers (c) the amount of electricity consumed for hydrogen production from electrolysers (d) the tonnes of carbon dioxide recovered and transferred from the facility
2	Methods 2, 3 and 4 for the source, as set out in sections 4.62A, 4.62B and Part 1.3	(a) the tonnes of hydrogen produced from fossil fuel feedstocks (b) the tonnes of hydrogen produced from electrolysers (c) the amount of electricity consumed for hydrogen production from electrolysers (d) the tonnes of carbon dioxide recovered and transferred from the facility

Part 5—Metal products

Source 3K—Iron, steel or other metal production using integrated metalworks

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 4.66	(a) the tonnes of iron produced for sale (b) the carbon content of the iron produced for sale, in tonnes of carbon per tonne of output (c) the tonnes of crude steel produced (d) the carbon content factor of the crude steel, in tonnes of carbon per tonne of output (e) the tonnes of solid waste by-product containing carbon produced (f) the average carbon content factor of solid waste by-products containing carbon, in tonnes of carbon per tonne of waste by-product (g) the change in stock containing carbon, in tonnes (h) the carbon content factor of the change in stock, in tonnes of carbon per tonne of stock (i) the tonnes of coke transferred beyond the boundary of the activity (j) the tonnes of coal tar transferred beyond the boundary of the activity (k) the tonnes of pure calcium carbonate consumed (l) the tonnes of pure dolomite consumed (m) the tonnes of pure magnesium carbonate consumed (n) the tonnes of any other pure carbonate consumed
2	Methods 2, 3 and 4 for the source, as set out in sections 4.67, 4.68 and Part 1.3	(a) the tonnes of iron produced for sale (b) the carbon content of the iron produced for sale, in tonnes of carbon per tonne of output (c) the tonnes of crude steel produced (d) the carbon content factor of the crude steel, in tonnes of carbon per tonne of output (e) the facility specific carbon content factor for each fuel type consumed, or each carbonaceous input material consumed, in tonnes of carbon per: (i) tonne of fuel or carbonaceous input material; or (ii) cubic metre of fuel or carbonaceous input material; or (iii) kilolitre of fuel or carbonaceous input material (f) tonnes of solid waste by-product containing carbon produced (g) the average carbon content factor of solid waste by-products containing carbon, in tonnes of carbon per tonne of waste by-product (h) the change in stock containing carbon, in tonnes (i) the carbon content factor of the change in stock, in tonnes of carbon per tonne of stock (j) the tonnes of coke transferred beyond the boundary of the activity (k) the tonnes of coal tar transferred beyond the boundary of the activity (l) the tonnes of pure calcium carbonate consumed (m) the tonnes of pure dolomite consumed

Item	Method	Matters to be identified
		(n) the tonnes of pure magnesium carbonate consumed (o) the tonnes of any other pure carbonate consumed

Source 3L—Ferroalloys production

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 4.71	(a) the tonnes of ferroalloys containing carbon produced (b) the carbon content factor of the ferroalloy produced, in tonnes of carbon per tonne of output (c) the tonnes of solid waste by-products containing carbon produced (d) the average carbon content factor of solid waste by-products, in tonnes of carbon per tonne of solid waste by-product (e) the change in stock containing carbon, in tonnes (f) the carbon content factor of the change in stock, in tonnes of carbon per tonne of stock (g) the tonnes of pure calcium carbonate consumed (h) the tonnes of pure dolomite consumed (i) the tonnes of pure magnesium carbonate consumed (j) the tonnes of any other pure carbonate consumed
2	Methods 2, 3 and 4 for the source, as set out in sections 4.72, 4.73 and Part 1.3	(a) the tonnes of ferroalloy containing carbon produced (b) the carbon content factor of the ferroalloy produced, in tonnes of carbon per tonne of output (c) the tonnes of solid waste by-products containing carbon produced (d) the average carbon content factor of solid waste by-products, in tonnes of carbon per tonne of solid waste by-product (e) the change in stock containing carbon, in tonnes (f) the carbon content factor of the change in stock, in tonnes of carbon per tonne of stock (g) the facility specific carbon content factor for each fuel type consumed, or each carbonaceous input material consumed, in tonnes of carbon per: (i) tonne of fuel or carbonaceous input material; or (ii) cubic metre of fuel or carbonaceous input material; or (iii) kilolitre of fuel or carbonaceous input material (h) the tonnes of pure calcium carbonate consumed (i) the tonnes of pure dolomite consumed (j) the tonnes of pure magnesium carbonate consumed (k) the tonnes of any other pure carbonate consumed

Source 3M—Aluminium production

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 4.76	the amount of primary aluminium produced, in tonnes
2	Methods 2, 3 and 4 for the source, as set out in sections 4.77, 4.78 and Part 1.3	(a) the facility specific emission factor or factors for each fuel type consumed, in kilograms of CO_2-e per gigajoule (b) the facility specific carbon tetrafluoride emission factor or factors, in tonnes of CO_2-e emitted per tonne of aluminium production
		(c) the facility specific hexafluoroethane emission factor or factors, in tonnes of CO_2-e emitted per tonne of aluminium production

Item	Method	Matters to be identified
		(d) the amount of primary aluminium produced, in tonnes

Source 3N—Production of other metals

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 4.94	(a) the tonnes of other metals produced (b) the carbon content of the other metals produced, in tonnes of carbon per tonne of output (c) the tonnes of solid waste by-products containing carbon produced (d) the average carbon content factor of solid waste by-products, in tonnes of carbon per tonne of solid waste by-product (e) the change in stock containing carbon, in tonnes (f) the carbon content factor of the change in stock, in tonnes of carbon per tonne of stock (g) the tonnes of pure calcium carbonate limestone consumed (h) the tonnes of pure dolomite consumed (i) the tonnes of pure magnesium carbonate consumed (j) the tonnes of any other pure carbonate consumed
2	Methods 2, 3 and 4 for the source, as set out in sections 4.95, 4.96 and Part 1.3	(a) the tonnes of other metal produced (b) the carbon content factor of the other metal, in tonnes of carbon per tonne of output (c) the tonnes of solid waste by-products containing carbon produced (d) the average carbon content factor of solid waste by-products, in tonnes of carbon per tonne of solid waste by-product (e) the change in stock containing carbon, in tonnes (f) the carbon content factor of the change in stock, in tonnes of carbon per tonne of stock (g) the facility specific carbon content factor for each fuel type consumed, or each carbonaceous input material consumed, in tonnes of carbon per: (i) tonne of fuel or carbonaceous input material; or (ii) cubic metre of fuel or carbonaceous input material; or (iii) kilolitre of fuel or carbonaceous input material (h) the tonnes of pure calcium carbonate consumed (i) the tonnes of pure dolomite consumed (j) the tonnes of pure magnesium carbonate consumed (k) the tonnes of any other pure carbonate consumed

Part 6—Waste

Source 4A—Solid waste disposal on land

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in sections 5.4 and 5.22	(a) the location of the landfill facility by State or Territory or by landfill classification specified in the Determination (b) the number of years in operation (c) the average annual amount (in tonnes) of disposal of solid waste over the lifetime of the landfill facility prior to the first year of reporting (d) the total tonnes of waste entering the landfill (e) the tonnes of waste entering the landfill from each of the following: (i) municipal sources; (ii) commercial and industrial sources; (iii) construction and demolition sources; (iv) alternative waste treatment facilities; (v) shredder flock; (vi) inert waste (f) the tonnes of waste received at the landfill facility for each of the following: (i) transfer to an external recycling or biological treatment facility; (ii) recycling or biological treatment onsite; (iii) construction purposes, daily cover purposes, intermediate cover purposes or final capping and cover purposes (inert waste only) (g) the percentages of each waste mix type entering the landfill in each of the following: (i) municipal solid waste; (ii) commercial and industrial waste; (iii) construction and demolition waste; (iv) shredder flock (h) the opening stock of degradable organic carbon, in tonnes (i) if the total amount of scope 1 emissions from the operation of the facility during the year is more than 100 000 tonnes CO_2-e—the following matters: (i) the legacy emissions from decomposition of waste; (ii) the emissions, other than legacy emissions, from decomposition of waste; (iii) the tonnes of methane (CO_2-e) captured for combustion that are legacy emissions; (iv) the tonnes of methane (CO_2-e) captured for combustion that are not legacy emissions; (v) the tonnes of methane (CO_2-e) captured and transferred offsite that are legacy emissions; (vi) the tonnes of methane (CO_2-e) captured and transferred offsite that are not legacy emissions; (vii) the tonnes of methane (CO_2-e) flared that are legacy emissions; (viii) the tonnes of methane (CO_2-e) flared that are not legacy emissions;

Item	Method	Matters to be identified
		(j) if the total amount of scope 1 emissions from the operation of the facility during the year is 100 000 tonnes CO_2-e or less—the following matters: (i) the emissions from decomposition of waste; (ii) the tonnes of methane (CO_2-e) captured for combustion; (iii) the tonnes of methane (CO_2-e) captured and transferred offsite; (iv) the tonnes of methane (CO_2-e) flared; (n) the tonnes of waste treated by each of the following methods: (i) composting; (ii) anaerobic digestion (o) the tonnes of methane (CO_2-e) captured from each of the following: (i) composting; (ii) anaerobic digestion
2	Methods 2, 3 and 4 for the source, as set out in sections 5.15, 5.18 and 5.22AA	(a) the location of the landfill facility by State or Territory (b) the number of years in operation (c) the average annual amount (in tonnes) of disposal of solid waste over the lifetime of the landfill facility prior to the first year of reporting (d) the total tonnes of waste entering the landfill (e) the opening stock of degradable organic carbon, in tonnes (f) the tonnes of waste entering the landfill from each of the following: (i) municipal sources; (ii) commercial and industrial sources; (iii) construction and demolition sources; (iv) alternative waste treatment facilities; (v) shredder flock; (vi) inert waste (g) the percentages of each waste mix type entering the landfill in each of the following: (i) municipal solid waste; (ii) commercial and industrial waste; (iii) construction and demolition waste (h) the tonnes of waste received at the landfill facility for each of the following: (i) transfer to an external recycling or biological treatment facility; (ii) recycling or biological treatment onsite; (iii) construction purposes, daily cover purposes, intermediate cover purposes or final capping and cover purposes (inert waste only) (i) the facility specific k value for each of the following waste mix types: (i) food; (ii) paper and cardboard; (iii) garden and green; (iv) wood; (v) textiles; (vi) sludge; (vii) nappies; (viii) rubber and leather; (ix) alternative waste treatment residues

Item	Method	Matters to be identified
		(j) if the total amount of scope 1 emissions from the operation of the facility during the year is more than 100 000 tonnes CO_2-e—the following matters: (i) the legacy emissions from decomposition of waste; (ii) the emissions, other than legacy emissions, from decomposition of waste; (iii) the tonnes of methane (CO_2-e) captured for combustion that are legacy emissions; (iv) the tonnes of methane (CO_2-e) captured for combustion that are not legacy emissions; (v) the tonnes of methane (CO_2-e) captured and transferred offsite that are legacy emissions; (vi) the tonnes of methane (CO_2-e) captured and transferred offsite that are not legacy emissions; (vii) the tonnes of methane (CO_2-e) flared that are legacy emissions; (viii) the tonnes of methane (CO_2-e) flared that are not legacy emissions; (k) if the total amount of scope 1 emissions from the operation of the facility during the year is 100 000 tonnes CO_2-e or less—the following matters: (i) the emissions from decomposition of waste; (ii) the tonnes of methane (CO_2-e) captured for combustion; (iii) the tonnes of methane (CO_2-e) captured and transferred offsite; (iv) the tonnes of methane (CO_2-e) flared; (o) the tonnes of waste treated by each of the following methods: (i) composting; (ii) anaerobic digestion (p) the tonnes of methane (CO_2-e) captured from each of the following: (i) composting; (ii) anaerobic digestion

Source 4B—Wastewater handling—industrial

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in sections 5.25 and 5.31	(a) the tonnes of commodity produced (b) the fraction of wastewater anaerobically treated (c) the fraction of COD removed as sludge (d) the fraction of COD in sludge anaerobically treated on site (e) the tonnes of COD in sludge transferred off site and disposed of at a landfill facility (f) the tonnes of COD in sludge transferred off site and disposed of at a site other than a landfill facility (g) the tonnes of COD in effluent leaving the site (h) the tonnes of methane (CO_2-e) captured for production of electricity on site (i) the tonnes of methane (CO_2-e) captured and transferred off site (j) the tonnes of methane (CO_2-e) flared
2	Methods 2 and 3 for the source, as set out in sections 5.26, 5.30, 5.32 and 5.36	(a) the tonnes of commodity produced (b) the tonnes of COD measured entering the treatment site (c) the fraction of wastewater anaerobically treated

Item	Method	Matters to be identified
		(d) the tonnes of COD removed as sludge (e) the fraction of COD in sludge anaerobically treated on site (f) the tonnes of COD in sludge transferred off site and disposed of at a landfill facility (g) the tonnes of COD in sludge transferred off site and disposed of at a site other than a landfill facility (h) the tonnes of COD in effluent leaving the site (i) the tonnes of emissions (CO_2-e) generated (j) the tonnes of methane (CO_2-e) captured for production of electricity on site (k) the tonnes of methane (CO_2-e) captured and transferred off site (l) the tonnes of methane (CO_2-e) flared

Source 4C—Wastewater handling—domestic or commercial

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in section 5.42	(a) the population served by the wastewater treatment plant (b) the fraction of COD in wastewater anaerobically treated (c) the tonnes of COD removed as sludge (d) the fraction of COD in sludge anaerobically treated on site (e) the tonnes of COD in sludge transferred off site and disposed of at a landfill facility (f) the tonnes of COD in sludge transferred off site and disposed of at a site other than a landfill facility (g) the tonnes of methane (CO_2-e) captured for combustion on site (h) the tonnes of methane (CO_2-e) captured and transferred off site (i) the tonnes of methane (CO_2-e) flared (j) the tonnes of COD in effluent leaving the site (k) the tonnes of nitrogen in sludge transferred out of the plant and disposed of at a landfill facility (l) the tonnes of nitrogen in sludge transferred out of the plant and disposed of at a site other than a landfill facility (m) the tonnes of nitrogen in effluent leaving the plant into enclosed waters (n) the tonnes of nitrogen in effluent leaving the plant into estuarine waters (o) the tonnes of nitrogen in effluent leaving the plant into open coastal waters
2	Methods 2 and 3 for the source, as set out in sections 5.43 and 5.47	(a) the population served by the wastewater treatment plant (b) the tonnes of COD measured entering treatment facility (c) the fraction of COD in wastewater anaerobically treated (d) the tonnes of COD removed as sludge (e) the fraction of COD in sludge anaerobically treated (f) the tonnes of methane (CO_2-e) generated from the decomposition of COD (g) the tonnes of methane (CO_2-e) captured for combustion on site (h) the tonnes of methane (CO_2-e) captured and transferred off site (i) the tonnes of methane (CO_2-e) flared (j) the tonnes of COD in effluent leaving the site

Item	Method	Matters to be identified
		(k) the tonnes of COD in sludge transferred offsite and disposed of at a landfill facility (l) the tonnes of COD in sludge transferred offsite to a site other than a landfill facility (m) the tonnes of nitrogen in influent entering the plant (n) the tonnes of nitrogen in sludge transferred out of the plant and disposed of at a landfill facility (o) the tonnes of nitrogen in sludge transferred out of the plant and disposed of at a site other than a landfill facility (p) the tonnes of nitrogen in effluent leaving the plant into enclosed waters (q) the tonnes of nitrogen in effluent leaving the plant into estuarine waters (r) the tonnes of nitrogen in effluent leaving the plant into open coastal waters

Source 4D—Waste incineration

Item	Method	Matters to be identified
1	Methods 1 and 4 for the source, as set out in section 5.53 and Part 1.3	the tonnes of waste incinerated