Climate project methodology #0002

FLARE (OR VENT) REDUCTION AND UTILIZATION OF ASSOCIATED PETROLEUM GAS FROM OIL WELLS AS A FEEDSTOCK

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1. Terms and definitions

1. For the purpose of this methodology, the following definitions apply:

   (i) Associated petroleum gas (APG) – natural hydrocarbon gas dissolved in oil or found in the gas cap of a field, produced in association with oil and extracted from it when thermobaric conditions change;

   (ii) End-use facility – the industrial facility where the APG is used as feedstock under the project activity;

   (iii) Existing facility – an end-use facility that has been operational for at least three years prior to implementation of the project activity;

   (iv) New facility – a greenfield end-use facility that is constructed with the implementation of the project activity;

   (v) Useful chemical product – chemical substance produced using the APG in the end-use facility, e.g., methanol, ethylene, or ammonia, which has a market value;

   (vi) Greenhouse Gas (GHG) – A greenhouse gas listed in Annex A to the Kyoto Protocol, unless otherwise specified in a particular methodology;

   (vii) Crediting period – The period in which verified and certified GHG emission reductions or increases in net anthropogenic GHG removals by sinks attributable to a climate project activity, as applicable, can result in the issuance of carbon units. The time period that applies to a crediting period for a climate project activity, and whether the crediting period is renewable or fixed, is determined in accordance with Section 4. Project crediting period of this methodology.

2. All data for gas volumes in all equations should be converted to common standard temperature and pressure values. The default density of methane at 0 degree Celsius and 1 atm is 0.0007170 t CH_4 / m^3.

2. Scope and applicability

2.1. Scope

3. The methodology is applicable to project activities, which recover APG from oil wells that was previously flared, and utilize it in an existing or a new end-use facility, to produce a useful chemical product.

4. If the field has been in operation for less than three years, and consequently no data on associated gas flaring or venting is available for 3 years, one of the alternative approaches described in section "0 If the facilities within the project boundary as specified in this methodology are owned by different legal entities (or are under the operational management of different legal entities), then the project documentation should include a description of procedures for eliminating the possibility of double counting in GHG emission reductions potentially achieved as a result of project activities, enshrined in contractual agreements

5. Baseline methodology" should be used to establish the baseline.

2.2. Applicability

6. The following conditions apply to the methodology:

   (i) The APG from the oil well, which is used by the project activity, was flared or vented for the last three years prior to the start of the project activity;

   (ii) Under the project activity, the previously flared APG is used as feedstock and, where applicable, partly as energy source in a chemical process to produce a useful product (e.g. methanol, ethylene, or ammonia).

7. The following table describes the key elements of the methodology:

Table 1. Methodology key elements

Typical projects	APG from oil wells that was previously flared or vented is recovered and utilized as a feedstock to produce a chemical product
Type of GHG emissions mitigation action	Feedstock switch: Avoidance of GHG emissions that would have occurred by flaring/venting the APG

8. In case of changes in the GHG regulatory legal framework of the Russian Federation, this methodology is subject to revision in order to take into account the relevant changes.

9. The methodology is neutral towards GHG programmes[1]. If a GHG programme is applied, the requirements of that programme will complement the requirements of the methodology[2]. This methodology is based on the existing methodology developed under the Clean Development Mechanism (AM0037) [168] and includes its adaptation to current Russian regulations and standards.

2.3. Project boundary

10. The project boundary for this methodology includes:

    (i) The site where the APG would be flared in the absence of the project activity;

    (ii) The pipeline from the site of the previous APG flaring to the end-use facility;

    (iii) The end-use facility using the APG in the project activity;

    (iv) The facility(ies) where the useful product would be produced in the absence of the project activity.

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[1] Greenhouse gas programme, GHG programme – voluntary or mandatory international, national or sub-national system or scheme that records, accounts for or manages GHG emissions, removals, reductions or enhancements of GHG emissions outside the organisation or GHG project (ISO 14064-2:2019 | Greenhouse gases, Part 2);

[2] Examples of GHG programmes in Russia - GOST R ISO 14064-1-2021 (accounting and management of GHG emissions at the level of organisations), GOST R ISO 14064-2-2021 (accounting and management of GHG emissions at the level of projects), GOST R ISO 14067-2021 (carbon footprint of products); at the international level – European Union Emission Trading System (EU ETS), Clean Development Mechanism (CDM), GHG Protocol for companies/projects/products and for Scope 3 accounting, Verified Carbon Standard (VCS), Gold Standard, etc.

Table 2. Summary of gases and sources included in the project boundary, and justification / explanation where gases and sources are not included

Source		Gas	Included?	Justification/Explanation
Baseline	Flaring	CO_2	Yes	Main source of emissions in the baseline
		CH_4	Yes	Methane from APG combustion is also released into the atmosphere through underburning of the gas.
		N_2O	No	Assumed negligible
	Fuel consumption for APG transport	CO_2	Yes	If fossil fuels (other than APG) or electricity are used (e.g., in pipeline compressors)
		CH_4	No	Assumed negligible
		N_2O	No	Assumed negligible
	Fugitives emissions resulting from APG transport	CO_2	No	Assumed negligible
		CH_4	Yes	Methane emissions may occur if APG is transported to a flare in the baseline scenario
		N_2O	No	Assumed negligible
	Emissions associated with the production of the useful product in the absence of the project activity	CO_2	Yes	Main emission source
		CH_4	No	Assumed negligible
		N_2O	No	Assumed negligible
Project activity	Fuel consumption for APG transport	CO_2	Yes	If fossil fuels (other than previously flared APG) or electricity are used (e.g., in pipeline compressors)
		CH_4	No	Assumed negligible
		N_2O	No	Assumed negligible
	Fugitive emissions resulting from APG transport	CO_2	No	Assumed negligible
		CH_4	Yes	Fugitive methane emissions may occur if APG is transported to the end use facility in the project scenario
		N_2O	No	Assumed negligible
	Fugitive emissions from accidents	CO_2	No	Assumed negligible
		CH_4	Yes	Fugitive methane emissions may occur if there is an equipment failure in equipment transporting APG to the end use facility in the project scenario
		N_2O	No	Assumed negligible
	(Additional) energy used by end-use facility	CO_2	Yes	This includes fossil fuel use and electricity consumption in the end use facility
		CH_4	No	Assumed negligible
		N_2O	No	Assumed negligible

If the facilities within the project boundary as specified in this methodology are owned by different legal entities (or are under the operational management of different legal entities), then the project documentation should include a description of procedures for eliminating the possibility of double counting in GHG emission reductions potentially achieved as a result of project activities, enshrined in contractual agreements

3. Baseline methodology

11. The baseline[3] is set conservatively[4] for a business-as-usual activity, taking into account all existing policies and measures, but not considering additional project activities (Business-as-usual model).

12. The project developer may use one of the following approaches to determine the baseline with justification for the appropriateness of the choices[5]:

(i) best available technologies that represent an economically feasible and environmentally sound course of action;

(ii) an ambitious benchmark approach where the baseline is set at least at the average emission level of the 20% best performing comparable activities providing similar outputs and services in a defined scope in similar social, economic, environmental and technological circumstances;

(iii) an approach based on existing actual or historical emissions, adjusted downwards by at least 5%, unless otherwise specified in the project methodology.

13. The approaches above provide a framework for general understanding of the ways in which baselines can be defined. A detailed approach to determining the baseline for this type of project is provided in section 0 "If the facilities within the project boundary as specified in this methodology are owned by different legal entities (or are under the operational management of different legal entities), then the project documentation should include a description of procedures for eliminating the possibility of double counting in GHG emission reductions potentially achieved as a result of project activities, enshrined in contractual agreements

14. Baseline methodology".

15.

3.1. Procedure for the selection of the most plausible baseline scenario

16. The most plausible baseline scenario is identified in three steps:

(i) Step 1: Identify all realistic and credible alternative scenarios to the proposed project activity and eliminate alternative that do not comply with legal or regulatory requirements;

(ii) Step 2: Assess the alternative scenarios to the proposed project activity and eliminate alternative scenarios that face prohibitive barriers;

(iii) Step 3: Determine the most likely alternative (baseline scenario).

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[3] Greenhouse gas baseline, GHG baseline - quantitative reference(s) of GHGemissions and/or GHGremovals that would have occurred in the absence of a GHG project and provides the baseline scenario for comparison with project GHG emissions and/or GHG removals (ISO 14064-2:2019 Greenhouse gases - Part 2)

[4] Calculation of the baseline is considered conservative if the final estimate of emission reductions resulting from project activities will not be overestimated. If there is any doubt, the project developer should better understate the baseline projection.

[5] Approaches to determining baselines are given in Action taken by the Conference of the Parties serving as the meeting of the Parties to the Paris Agreement at its third session (FCCC/PA/CMA/2021/10/Add.1, Article 6, paragraph 4, p. 34, para. 36). URL: https://unfccc.int/sites/default/files/resource/cma2021_10a01E.pdf.

17. The most plausible baseline scenario should be determined regarding:

(i) What would happen to the APG from the oil well in the absence of the project activity; and

(ii) How the useful chemical product produced with the APG would be produced in the absence of the project activity.

3.1.1. Step 1: Identify all realistic and credible alternative scenarios to the proposed project activity and eliminate alternative that do not comply with legal or regulatory requirements

18. Plausible alternative baseline scenarios for the use of the APG could include, inter alia:

(i) T1: The continuation of the current situation: Flaring of the APG at or nearby the oil well;

(ii) T2: On-site consumption of the APG for the purpose of energy generation;

(iii) T3: Injection of the APG into an oil or gas reservoir;

(iv) T4: Recovery, transportation, processing and distribution of the APG to end-users;

(v) T5: The proposed project activity without the project: The APG is used as a feedstock at an off-site facility;

(vi) T6: The APG is used and transported to other consumers for the purpose of energy generation.

19. For the use of the APG under the project activity as feedstock and, where applicable, partly as energy source in a chemical production process at a specific facility, plausible alternative scenarios for the production of the useful product (e.g. methanol, ethylene, or ammonia) may include, inter alia:

(i) P1: The proposed project activity without the project: the product is (partly) produced using the APG from the oil well;

(ii) P2: The product is produced in the same existing production facility and natural gas, as used historically during the last three years, is used as feedstock and energy source instead of the APG;

(iii) P3: The product is produced in the same existing production facility and another fuel (e.g. naphtha) as the one used historically during the last three years is used as feedstock and energy source instead of the APG;

(iv) P4: The product is produced in a new production facility that is established at the same site and that has the same or a larger production capacity as the project plant but that uses fossil fuel(s) (e.g. natural gas) instead of the APG as feedstock and, where applicable, as energy source (this may apply if a new production facility would also be established at the same site in the absence of the project activity);

(v) P5: The product is produced in existing and / or new production facilities at other sites (this may apply if the APG is used in a new production facility which is established as a result of the project activity and would not be established at the same site in the absence of the project activity).

20. Project participants should identify all realistic and credible **combinations** of baseline scenarios for the fate of the APG (T1 to T6) and the production of the useful product (P1 to P5). These combinations should be considered in applying the following steps of the tool.

21. All baseline alternatives shall be in compliance with all applicable legal and regulatory requirements, even if these laws have objectives other than GHG reductions.

22. If an alternative does not comply with all applicable legislation and regulations, eliminate this alternative unless it is demonstrated, based on an examination of current practice in the country or region in which the law or regulation applies, that applicable legal or regulatory requirements are systematically not enforced and that non-compliance is widespread.

3.1.2. Step 2: Assess the alternatives to the proposed project activity and eliminate alternatives that face prohibitive barriers

23. Establish a complete list of barriers that would prevent alternative scenarios. Since the "proposed project activity not being registered as a climate project activity" shall be one of the considered alternatives, any barrier that may prevent the project activity to occur shall be included in that list. Show which alternatives are prevented by at least one of the barriers previously identified and eliminate those alternatives from further consideration. All alternatives shall be evaluated for a common set of barriers.

24. If only one alternative remains, it shall be the baseline scenario.

3.1.3. Step 3: Determine the most likely alternative (baseline scenario)

25. Where more than one credible and plausible alternative remains after steps 1 and 2, the alternative that results in the lowest baseline emissions shall be the baseline scenario.

26. The methodology is only applicable if the procedure to select the baseline scenario results in that flaring of the APG is (T1) is the most plausible baseline scenario. Furthermore, the methodology is only applicable if one of the scenarios described in table 3 below results to be the most plausible baseline scenario. Explain in the project design document (PDD) the specific situation of the project activity and demonstrate that the project activity and the most plausible baseline scenario corresponds to the "description of the situation" in table 3 and to the relevant baseline scenarios for the production of the useful product (P1 to P5), as indicated under the respective scenario in table 3 below. In addition, project participants should check whether the procedures to calculate emission reductions work appropriately for the project specific context. If the equations do not fully fit with the context of the project, a revision or deviation to this methodology should be requested following the guidance provided by the Board in latest version of "Clarifications to project participants on when to request revision, clarification to an approved methodology or a deviation".

Table 3. **Combinations of project types and baseline scenarios applicable to this methodology**

Scenario	Baseline	Scenario
1	P2	Under the project activity, the previously flared APG is used as feedstock and, where applicable, partly as energy source in a chemical process to produce a useful product (e.g. methanol, ethylene, or ammonia) in an existing end-use facility. At the start of the project activity, the end-use facility has an operation history of at least three years. Prior to the implementation of the project activity the end-use facility has used natural gas as feedstock and energy source for the chemical process and would in the absence of the project activity continue to do so throughout the crediting period. The use of the APG instead of natural gas does not result in a different quality of the useful product and does not result in a lower efficiency in the process of producing the useful product (i.e. the quantity of feedstock and energy required per quantity of useful product produced is not increased), apart from energy required to treat the APG prior to its use in the process
2	P3	Under the project activity, the previously flared APG is used as feedstock and, where applicable, partly as energy source in a chemical process to produce a useful product (e.g. methanol, ethylene, or ammonia) in an existing end-use facility. At the start of the project activity, the end-use facility has an operation history of at least three years. Prior to the implementation of the project activity the end-use facility has used a fossil fuel (e.g., natural gas, naphtha) as feedstock and energy source for the chemical process and would in the absence of the project activity continue to do so throughout the crediting period. The use of the APG instead of the fossil fuel does not result in a different quality of the useful product but may result in a different efficiency in the process of producing the useful product (i.e. the quantity of feedstock and energy required per quantity of useful product produced is not the same as under the project activity). Moreover, additional energy may be required to treat the APG prior to its use in the process
3	P4	Under the project activity, the previously flared APG is used as feedstock and, where applicable, partly as energy source in a chemical process to produce a useful product (e.g. methanol, ethylene, or ammonia) in a newly established end-use facility. In the absence of the project activity, the useful product would be produced in a new production facility that would be established at the same site and that would have the same production capacity as the project plant but that would use fossil fuel(s) (e.g. natural gas) instead of the APG as feedstock and energy source
4	P5	Under the project activity, the previously flared APG is used as feedstock and, where applicable, partly as energy source in a chemical process to produce a useful product (e.g. methanol, ethylene, or ammonia) in a newly established end-use facility. The new end-use facility is established as a result of the project activity and would not be established in the absence of the project activity. Therefore, the useful product would in the absence of the project activity be produced in existing and/or new production facilities at other sites

3.2. Baseline emissions

27. In the absence of the project activity, the APG would be transported to a flare, and be flared, or vented.[6] Baseline emissions therefore include emissions associated with the transportation and flaring of the APG ($BE_{CO_2,flaring,y}$, $BE_{T,CO_2,y}$ and $BE_{T,CH_4,y}$). In the absence of the project activity, the useful product would be generated using other fossil-based feed stock. Hence, baseline emissions also include CO_2 emissions from the

6 Please note that in the situation where the associated gas was vented in the baseline, the baseline emissions are still estimated as under the assumption that the gas is flared.

production of the useful product in the absence of the project activity ($BE_{CO_2,product,y}$). Baseline emissions are calculated as follows:

$$BE_y = BE_{CO_2,flaring,y} + BE_{T,CO_2,\,y} + BE_{T,CH_4,y} + BE_{CO_2,product,y} \quad (1)$$

Where:

BE_y	=	Baseline emissions in year *y* (t CO_2/yr);
$BE_{CO_2,flaring,y}$	=	Baseline CO_2 emissions from flaring of the APG in year *y* (t CO_2/yr);
$BE_{T,CO_2,\,y}$	=	Baseline emissions of CO_2 from energy required for transportation of the APG to the flare in year *y* (t CO_2/yr);
$BE_{T,CH_4,y}$	=	Fugitive CH_4 baseline emissions from transportation of the APG to the flare in year *y* (t CO_2e/yr);
$BE_{CO_2,product,y}$	=	Baseline CO_2 emissions from production of the useful product in the absence of the project activity in year *y* (t CO_2/yr).

28. These emission sources are calculated in the following steps:

( ) Step 1: Calculation of CO_2 emissions from flaring;

(a) Step 2: Calculation of CO_2 emissions from fuel combustion for the transportation of the APG to the flare;

(b) Step 3: Calculation of fugitive CH_4 emissions from transportation of the APG to the flare;

(c) Step 4: Calculation of CO_2 emissions from the production of the useful product in the absence of the project activity.

3.2.1. Step 1: Calculation of CO_2 emissions from flaring ($BE_{CO_2,flaring,y}$)

29. The calculation of baseline emissions from flaring includes CO_2 and CH_4 emissions from the flaring of APG and other hydrocarbon mixtures from well blowdowns, emptying and purging of process equipment and pipelines. It also includes emissions from the combustion of fuel gases in flares for standby combustion. It does not include N_2O emissions that may result from the combustion of hydrocarbon mixtures in flares. . Baseline emissions from flaring are calculated as follows:

$$BE_{i,flaring,y} = \sum_{i=1}^{n} (E_{i,y} \times GWP_i) \quad (2)$$

Where:

$BE_{i,flaring,y}$	=	Baseline CO_2 emissions from flaring of the APG in year *y* (t CO_2/yr);
$E_{i,y}$	=	*i*-GHG emissions from the combustion of hydrocarbon mixtures in a flare during the period *y* (t);

GWP_i = Global Warming Potential for *i*-GHG;

i = CO_2, CH_4;

n = the number of types of GHG.

$$E_{i,y} = \sum_{j=1}^{n}(FC_{j,y} \times EF_{i,j,y}) \tag{3}$$

Where:

$E_{i,y}$ = *i*-GHG emissions from the combustion of hydrocarbon mixtures in a flare during the period *y* (t);

$FC_{j,y}$ = is the consumption of the *j*-hydrocarbon mixture at the flare unit during the period *y* (1000 m^3 or t);

$EF_{i,j,y}$ = is the *i*-GHG emission factor from the combustion of the *j*-hydrocarbon mixture at the flare unit for the period *y* (t/1000 m^3 or t/t);

i = CO_2, CH_4;

j = type of hydrocarbon mixture;

n = the number of types of hydrocarbon mixtures to be flared.

30. The consumption of the hydrocarbon mixture ($FC_{j,y}$) in flares in an organisation should include all types of hydrocarbon mixture combusted during the reporting period, as well as the consumption of the fuel used to sustain flare combustion.

31. The CO_2 and CH_4 emission factor from the combustion of the hydrocarbon mixture in the flare ($EF_{i,j,y}$) is calculated using equations (4-6).

32. Calculation of CO_2 emission factor:

$$EF_{CO2,j,y} = \left(W_{CO2,j,y} + \sum_{i=1}^{n}\left(W_{i,j,y} \times n_{C.i}\right) \times \left(1 - CF_{j,y}\right)\right) \times \rho_{CO2} \times 10^{-2} \tag{4}$$

Where:

$EF_{CO2,j,y}$ = CO_2 emission factor from the combustion of the j-hydrocarbon mixture in the flare unit over the period *y*, (t CO_2/1000 m^3);

$W_{CO2,j,y}$ = CO_2 content of the *j*-hydrocarbon mixture over the period *y* (% vol or % mol);

$W_{i,j,y}$ = Content of the *i*-component (except CO_2) in the *j*-hydrocarbon mixture (% vol or % mol);

$n_{C.i}$	=	the number of moles of carbon per mole of the *i*-component of the hydrocarbon mixture;
$CF_{j,y}$	=	the underburning factor of the *j*-hydrocarbon mixture in the flare unit over the period *y*, fraction;
ρ_{CO2}	=	Density of carbon dioxide (CO_2) (kg/m^3) (taken from Table 4).

33. Alternative way to calculate of CO_2 emission factor:

$$EF_{CO2,j,y} = \left(W_{CO2,j,y} + \sum_{i=1}^{n}\left(\frac{W_{i,j,y} \times n_{C.i} \times 44{,}011}{M_i}\right) \times \left(1 - CF_{j,y}\right)\right) \times \rho_{CO2} \times 10^{-2} \quad (5)$$

Where:

$EF_{CO2,j,y}$	=	CO_2 emission factor from the combustion of the j-hydrocarbon mixture in the flare unit over the period *y*, (t CO_2/1000 m^3);
$W_{CO2,j,y}$	=	CO_2 content of the *j*-hydrocarbon mixture over the period *y* (% wt);
$W_{i,j,y}$	=	Content of the *i*-component (except CO_2) in the *j*-hydrocarbon mixture (% wt);
$n_{C.i}$	=	the number of moles of carbon per mole of the *i*-component of the hydrocarbon mixture;
M_i		Molar mass of the *i*-component of the gaseous fuel (g/mol);
$CF_{j,y}$	=	the underburning factor of the *j*-hydrocarbon mixture in the flare unit over the period *y*, fraction;
ρ_{CO2}	=	Density of carbon dioxide (CO_2) (kg/m^3) (taken from Table 4);
44,011	=	Molar mass of the CO_2.

34. As a conservative simplification, project participants may assume the CH_4 emission factor as zero ($EF_{CH4,j,y}$ = 0). It is assumed that flaring results in complete oxidation of carbon in APG, resulting in a conservative baseline

35. Calculation of the CH_4 emission factor:

$$EF_{CH4,j,y} = W_{CH4,j,y} \times CF_{j,y} \times \rho_{CH4} \times 10^{-2} \quad (6)$$

Where:

$EF_{CH4,j,y}$	=	CH_4 emission factor from the combustion of the *j*-hydrocarbon mixture in the flare unit over the period *y* (t CH_4/1000 m^3);
$W_{CH4,j,y}$	=	CH_4 content of the *j*-hydrocarbon mixture over the period *y* (% vol or % mol);

$CF_{j,y}$ = the underburning factor of the *j*-hydrocarbon mixture in the flare unit over the period *y*, fraction;

ρ_{CH4} = Density of methane (CH_4) (kg/m^3) (taken from Table 4).

36. Alternative way to calculate of CH_4 emission factor:

$$EF_{CH4,j,y} = W_{CH4,j,y} \times CF_{j,y} \times 10^{-2} \quad (7)$$

Where:

$EF_{CH4,j,y}$ = CH_4 emission factor from the combustion of the *j*-hydrocarbon mixture in the flare unit over the period *y* (t CH_4/1000 m^3);

$W_{CH4,j,y}$ = CH_4 content of the *j*-hydrocarbon mixture over the period *y* (% wt);

$CF_{j,y}$ = the underburning factor of the *j*-hydrocarbon mixture in the flare unit over the period *y*, fraction;.

37. In the absence of representative actual data for the reporting period on the chemical composition of the hydrocarbon mixture burned in the flare, obtained by regular laboratory analysis using officially approved methods and laboratory equipment that is verified, calibrated and maintained in accordance with legal requirements, the emission factors given in Table 5 shall be used.

38. The underburning factor of the hydrocarbon mixture in the flare unit ($CF_{j,y}$) shall be determined experimentally or taken in accordance with No. 1, 2 of Table 6, depending on the conditions of combustion of the hydrocarbon mixture (sootless or sooty combustion). In the absence of actual data on the conditions of combustion of hydrocarbon mixtures in the flare (sootless or carbon black combustion), the values of the underburning factor ($CF_{j,y}$) for the fields shall be taken in accordance with No. 3 of Table 6.

Table 4. Carbon dioxide and methane densities for different measurement conditions

Measurement conditions	Density of carbon dioxide (CO_2), kg/m^3	Density of methane (CH_4), kg/m^3
273.15 K (0 °C); 101.325 kPa	1.9768	0.7170
288.15 K (15 °C); 101.325 kPa	1.8738	0.6797
293.15 K (20 °C); 101.325 kPa	1.8393	0.6680

Source: Order of the Ministry of Natural Resources and Environment of the Russian Federation of 27.05.2022 No. 371 “On approval of methods for quantitative determination of greenhouse gas emissions and greenhouse gas removals” (Registered 29.07.2022 No. 69451)e Russian Federation" (registered with the Russian Ministry of Justice on 15.12.2015 N 40098), Table 1.2, page 8.

Table 5. GHG emission factors for APG burned in flares used in the absence of actual data on the chemical composition of the components of the hydrocarbon mixture burned

Type of GHG	Emission factor ($EF_{i,j,y}$), t/t	Emission factor ($EF_{i,j,y}$), t/ 1000 m^3
Carbon dioxide (CO_2)	2.6121	3.3689
Methane (CH_4)	0.0041	0.0053

Source: Order of the Ministry of Natural Resources and Environment of the Russian Federation of 27.05.2022 No. 371 “On approval of methods for quantitative determination of greenhouse gas emissions and greenhouse gas removals” (Registered 29.07.2022 No. 69451)e Russian Federation" (registered with the Russian Ministry of Justice on 15.12.2015 N 40098), Table 2.1, pages 10-11.

Table 6. Underburning factors of the hydrocarbon mixture in the flare unit

No.	Combustion conditions in the flare unit	The underburning factor ($CF_{j,y}$)
1.	Sootless flaring	0.0006
2.	Sooty flaring	0.035
3.	Oil, gas condensate and gas fields	0.02

Source: Order of the Ministry of Natural Resources and Environment of the Russian Federation of 27.05.2022 No. 371 “On approval of methods for quantitative determination of greenhouse gas emissions and greenhouse gas removals” (Registered 29.07.2022 No. 69451)e Russian Federation" (registered with the Russian Ministry of Justice on 15.12.2015 N 40098), Table 2.2, page 11.

3.2.2. Step 2: Calculation of CO_2 emissions from fuel combustion for the transportation of the APG to the flare ($BE_{T,CO_2,y}$)

39. As a conservative simplification, project participants may assume this emission source as zero ($BE_{T,CO_2,y}$ = 0).

40. If project participants wish to estimate this emission source, it is calculated based on the actual monitored quantity of APG supplied under the project activity for production of useful chemical product and an emission factor for the transportation of this APG to the flare, as follows:

$$BE_{T,CO_2,y} = V_y \times EF_{T,CO_2} \tag{8}$$

Where:

$BE_{T,CO_2,y}$	=	Baseline emissions of CO_2 from energy required for transportation of the APG to the flare in year y (t CO_2/yr);
V_y	=	Quantity of associated gas utilized in year y as feedstock. This is equal to the quantity of associated gas that enters the pipeline for transport to the end use facility less the quantity of associated gas used for energy purpose, if any, in the project activity, less any quantity of associated gas that is flared or vented at the end-use facility[7] (m^3/yr);
EF_{T,CO_2}	=	CO_2 emission factor for energy required for transportation of the APG to the flare (t CO_2/m^3).

[7] The reason this component of gas is omitted because the baseline emissions for associated gas used as energy in project activity is estimated as the fossil fuel used for energy purpose in baseline using step 4.

41. The emission factor for energy required for transportation of the APG to the flare is calculated based on CO_2 emissions from fuel consumption and electricity in the historical year *x* prior to the start of the project activity, as follows:

$$EF_{T,CO_2} = \frac{\left[\sum_i FC_{BL,T,flare,i,x} \times NCV_{i,x} \times EF_{CO2,i,x}\right] + EC_{T,flare,x} \times EF_{EL,T,x}}{V_x} \quad (9)$$

Where:

EF_{T,CO_2}	=	CO_2 emission factor for energy required for transportation of the APG to the flare (t CO_2/m^3);
$FC_{BL,T,flare,i,x}$	=	Quantity of fossil fuel type *i* combusted in year *x* for transportation of the APG to the flare (mass or volume unit);
$NCV_{i,x}$	=	Average net calorific value of fossil fuel type *i* in year *x* (GJ / mass or volume unit);
$EF_{CO_2,i,x}$	=	Average CO_2 emission factor of fossil fuel type *i* in year *x* (t CO_2/GJ);
$EC_{T,flare,x}$	=	Quantity of electricity consumed in year *x* for transportation of the APG to the flare (MWh);
$EF_{EL,T,x}$	=	Average CO_2 emission factor for electricity consumed for transportation of the APG to the flare in year *x* (t CO_2/MWh), estimated as per procedure defined in the monitoring table;
V_x	=	Quantity of APG flared in year *x* (m^3);
x	=	Year prior to the start of the project activity;
i	=	Fossil fuel types combusted for transportation of the APG to the flare in year *x*.

42. In equation (9) $\left[\sum_i FC_{BL,T,flare,i,x} \times NCV_{i,x} \times EF_{CO2,i,x}\right]$ is used if part of the energy is generated at the site (t CO_2), otherwise take it as 0.

3.2.3. Step 3: Calculation of fugitive CH_4 emissions from transportation of the APG to the point of flaring (BE_{T,CH_4y})

43. Fugitive CH_4 emissions occurring during the transport of the APG to the flare can be expected to be small. As a conservative simplification, project participants may assume this emission source as zero (BE_{T,CH_4y}= 0).

44. Emission factors are taken from the 1995 Protocol for Equipment Leak Emission Estimates, published by U.S. EPA. Emissions should be determined for all relevant activities and all equipment (such as valves, pump seals, connectors, flanges, open-ended lines, etc.).

45. The U.S. EPA approach is based on average emission factors for total organic compounds (TOC). Methane emissions from onshore oil and gas operations are calculated by multiplying the methane fraction in the in the APG with the appropriate emission factors from table 7 and then summing across all pieces of equipment, as follows:

$$BE_{T,CH_4y} = GWP_{CH_4} \times {}^{1}/_{1000} \times w_{CH_4,y} \times \sum_{equipment} \left[EF_{equipment} \times t_{equipment}\right] \quad (10)$$

Where:

BE_{T,CH_4y}	=	Fugitive CH_4 baseline emissions from transportation of the APG to the flare in year *y* (t CO_2e/yr);
GWP_{CH_4}	=	Global Warming Potential for methane;
$w_{CH_4,y}$	=	Average mass fraction of methane in the APG in year *y* (t CH_4/t APG);
$EF_{equipment}$	=	The emission factor for the relevant equipment type, taken from table 7 or the 2006 IPCC Guidelines (kg CH_4 / hour / equipment);
$t_{equipment}$	=	The operation time of the equipment (hours).

46. All data for gas volumes in all equations should be converted to common standard temperature and pressure values. The default density of methane at 0 degree Celsius and 1 atm is 0.0007170 t CH_4 / m^3.

47. It is recommended to group the equipment according to the different types listed in the table 7.

Table 7. Oil and natural gas production average emission factors

Equipment Type	Service	Emission Factor (kg / hour / equipment item) for TOC[a]
Valves	Gas	4.5E-03
Pump seals	Gas	2.4E-03
Others[b]	Gas	8.8E-03
Connectors	Gas	2.0E-04
Flanges	Gas	3.9E-04
Open-ended lines	Gas	2.0E-03

Source: US EPA-453/R-95-017, table 2.4, page 2-15

(a) TOC: Total organic compounds.

(b) "Other" equipment type was derived from compressors, diaphragms, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, relief valves and vents. This "other" equipment type should be applied for any equipment type other than connectors, flanges, open-ended lines, pumps or valves.

48. The U.S. EPA approach is based on average emission factors for total hydrocarbons (THC). Methane emissions from offshore oil and gas operations are calculated by multiplying the methane fraction in the in the APG with the appropriate emission factors from table 8 and then summing across all pieces of equipment, as follows:

$$BE_{T,CH_4 y} = GWP_{CH_4} \times \sum_{equipment} F_a \times WF_{CH_4} \times N \times t_{equipment} \quad (11)$$

Where:

$BE_{T,CH_4 y}$	=	Fugitive CH_4 baseline emissions from transportation of the APG to the flare in year *y* (t CO_2e/yr);
GWP_{CH_4}	=	Global Warming Potential for methane;
F_a	=	average THC emission factor for the component type A from the applicable table 8 (tonne THC/equipment/hr);
WF_{CH_4}	=	average weight fraction of CH_4;
N		number of components of the given type in the stream;
$t_{equipment}$	=	The operation time of the equipment (hours).

49. All data for gas volumes in all equations should be converted to common standard temperature and pressure values. The default density of methane at 0 degree Celsius and 1 atm is 0.0007170 t CH_4 / m^3.

50. It is recommended to group the equipment according to the different types listed in the table 8.

Table 8. Offshore THC[a] Equipment Leak Emission Factors

Equipment Type	Service	Emission Factor (tonne THC / equipment / hr)
Connector	Gas	2.08E-07
Flange	Gas	3.97E-07
Open ended line	Gas	2.08E-06
Otherb	Gas	8.88E-06
Pump	Gas	2.46E-06
Valve	Gas	4.54E-06

Source: Norwegian Environment Agency. Cold Venting and Fugitive Emissions from Norwegian Offshore Oil and Gas Activities: Module 2 – Emission Estimates and Quantification Methods, Sub-report 2, 15 March 2016, Table 49.

(a) THC: Total hydrocarbon.

(b) "Other" equipment type was derived from compressors, diaphragms, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, relief valves and vents. This "other" equipment type should be applied for any equipment type other than connectors, flanges, open-ended lines, pumps or valves. Norwegian Environment Agency notes that compressor seals are included in the definition of "Other".

3.2.4. Step 4: Calculation of CO_2 emissions from the production of the useful product in the absence of the project activity ($BE_{CO_2,product,y}$)

51. The calculation of CO_2 emissions from the production of the useful chemical product in the absence of the project activity depends on the scenario listed in table 3 that is applicable to the specific project activity.

3.2.4.1. Scenario 1

52. In case of scenario 1, the emissions associated with the production of the useful product are the same in the project situation and the baseline situation because the production occurs in the same plant, the same quality of product is produced and the efficiency of the production process is not affected by the project activity – apart from energy required to treat the APG prior to its use in the process. Therefore, baseline ($BE_{CO_2,product,y}$ = 0) and project emissions from electricity and fossil fuel energy used for production of the useful chemical product are not considered. Additional energy required to treat the APG, to enable its use as feedstock, is considered as part of project emissions. If no additional energy is used to treat the APG then $PE_{CO_2,facility,y}$ = 0.

3.2.4.2. Scenarios 2 and 3

53. In case of scenarios 2 and 3, in the absence of the project activity, the useful product would be produced in an existing (scenario 2) or a new (scenario 3) production facility at the same site but possibly with a different efficiency. The baseline emissions from that production are calculated based on the monitored quantity of the useful product produced in the end-use project facility (P_y) and an emission factor for the baseline CO_2 emissions associated with the production of the useful product in the baseline situation ($EF_{CO_2,BL,p}$), as follows:

$$BE_{CO_2,product,y} = P_y \times EF_{CO_2,BL,product} \quad (12)$$

Where:

$BE_{CO_2,product,y}$	=	Baseline CO_2 emissions from production of the useful product in the absence of the project activity in year *y* (t CO_2/yr);
P_y	=	Quantity of useful product produced in the end-use facility in year *y* (t useful product);
$EF_{CO_2,BL,product}$	=	CO_2 emission factor for the production of the useful product in the baseline situation (t CO_2 / t useful product).

3.2.4.3. Scenario 2

54. Where scenario 2 is applicable to the proposed project activity, $EF_{CO_2,BL,product}$ is calculated based on the historical performance of the existing facility to produce the useful product during the most recent three years prior to the start of the project activity. As a conservative approach, the lowest emission factor from the most recent three historical years prior to the start of the project activity should be chosen, as follows:

$$EF_{CO_2,BL,product} = MIN\left(EF_{CO_2,BL,product,x};\ EF_{CO_2,BL,product,x-1};\ EF_{CO_2,BL,product,x-2}\right) \quad (13)$$

55. Where the $EF_{CO_2,BL,product,x}$ is estimated as follows:

$$EF_{CO_2,BL,product,x} = \frac{\left[\sum_{k=1}^{n}\left(RMC_{k,i,x} \times W_{C,k,x}\right) - \left(\sum_{i=q}^{n}\left(PP_{i,x} \times W_{C,i,x}\right) + \sum_{j=1}^{l}\left(SP_{j,i,x} \times W_{C,i,x}\right)\right)\right] \times 3.664}{P_x} \quad (14)$$

Where:

$EF_{CO_2,BL,product}$	=	CO_2 emission factor for the production of the useful chemical product in the baseline situation (t CO_2 / t useful product);
$RMC_{k,i,x}$	=	The consumption of carbon-containing feedstock *k* for combustion for the production of the useful chemical product *i* in year *x* (tons);
$W_{C,k,x}$	=	Mass fraction of carbon in fossil fuel / feedstock type *k* (t C / unit);
$PP_{i,x}$	=	The production of the useful chemical product *i* in year *x* (t);
$W_{C,i,x}$	=	Mass fraction of carbon of the useful chemical product *i* in year *x* (t C / unit);
$SP_{j,i,x}$	=	Production of secondary (by-product) product *j* in the production process of useful chemical product *i* in year *x* (t);
$W_{C,j,x}$	=	Mass fraction of carbon of secondary (by-product) product *j* in year *x* (t C / unit);
P_x	=	Quantity of useful product produced in year *x* (t useful product);
i	=	The type of useful chemical product produced;
k	=	The type of carbon-containing feedstock used to produce useful chemical products;
j	=	The type of secondary (by-product) product produced;
n	=	The number of useful chemical products;
m	=	The number of carbon-containing feedstock types used to produce useful chemical products;
l	=	The number of secondary (by-product) product used to produce useful chemical products;
x	=	Year prior to the start of the project activity.

56. Production of the useful chemical product ($PP_{i,x}$), consumption of carbon-containing feedstock for the production of useful chemical products ($RMC_{k,i,x}$), Production of secondary (by-product) product in the production of useful chemical products ($SP_{j,i,x}$) are taken from the actual data of the existing facility in year x. The quantity of secondary (by-product) useful chemical products in the production of methanol, ethylene dichloride, ethylene oxide and soot is assumed to be zero because they are not produced in the production process.

57. The carbon content of carbon-containing feedstocks ($W_{C,k,x}$), primary and secondary (by-products) of useful chemical production ($W_{C,i,x}$, $W_{C,j,x}$) is determined by the existing organization's actual data for the year x, or in the absence of necessary data is taken from Table 9.

Table 9. The carbon content of carbon-containing feedstocks and useful chemical production.

Type of fossil fuel	Carbon content (W_C), tons C / tons
Acetonitrile	0.5852
Acrylonitrile	0.6664
Butadiene	0.888
Carbon black	0.970
Carbon black feedstock	0.900
Ethane	0.856
Ethylene	0.856
Ethylene dichloride	0.245
Ethylene glycol	0.387
Ethylene oxide	0.545
Cyanogen hydrogen	0.4444
Methanol	0.375
Methane	0.749
Propane	0.817
Propylene	0.8563
Vinyl chloride monomer	0.384

Source: Order of the Ministry of Natural Resources and Environment of the Russian Federation of 27.05.2022 No. 371 "On approval of methods for quantitative determination of greenhouse gas emissions and greenhouse gas removals" (Registered 29.07.2022 No. 69451)e Russian Federation" (registered with the Russian Ministry of Justice on 15.12.2015 N 40098), Table 12.1, pages 28-29.

3.2.4.4. Scenario 3

58. Where scenario 3 is applicable to proposed project activity, $EF_{CO_2,BL,product}$ is the emission factor of the new facility that would be constructed in the absence of the project activity. $EF_{CO_2,BL,product}$ should be calculated according to the alternative design that would be chosen by the project participant in the absence of the project activity as described in the baseline selection section.

59. The project participant shall demonstrate that the level of $EF_{CO_2,BL,product}$ is consistent or lower compared with the emissions intensity of commonly installed modern state-of-the-art plants. The emission factor should be chosen in a conservative manner, in case of several plausible design options or fuel types the least carbon intensive design option or fuel should be chosen to estimate as baseline scenario.

3.2.4.5. Scenario 4

60. In case of scenario 4, in the absence of the project activity, the useful product would be produced in existing and / or new production facilities at other sites. The baseline emissions

from that production are calculated based on the monitored quantity of the useful product produced in the end-use facility (P_y) and an emission factor for the baseline CO_2 emissions associated with the production of the useful product in other facilities ($EF_{CO_2,BL,product}$), as follows:

$$BE_{CO_2,product,y} = P_y \times EF_{CO_2,BL,product} \quad (15)$$

Where:

$BE_{CO_2,product,y}$	=	Baseline CO_2 emissions from production of the useful product in the absence of the project activity in year *y* (t CO_2/yr);
P_y	=	Quantity of useful product produced in the end-use facility in year *y* (t useful product);
$EF_{CO_2,BL,product}$	=	CO_2 emission factor for the production of the useful product in the baseline situation (t CO_2 / t useful product).

61. Project participants can estimate $EF_{CO_2,BL,product}$ based on either conservative default values from table 10 below or the emissions intensity of the top 20% performing plants established in the most recent five years prior to the start of the project activity in the defined geographical region, as per the following procedure:

3.2.4.5.1. Step 1: Determination of the geographical area

62. The geographical area should be chosen in a manner that it includes at least five plants that produce the same useful chemical product and that have been established in the most recent five years prior to the start of the project activity. If there are less than five plants in the host country, the geographical area should be extended to all neighbouring countries. If the number remains to be less than five, all countries should be considered as the appropriate geographical area. If the useful chemical product is regionally traded,[8] the host country may be used as a default area. If the product is globally traded then geographical area is considered to be all countries.

3.2.4.5.2. Step 2: Determination of the production capacity in non-Annex I countries[9]

63. Determine the fraction of the production capacity for producing the useful product within the geographical area, as identified in step 1, located in non-Annex I countries (x_{NAI}). If the geographical area, as identified in step 1, only includes non-Annex I countries, x_{NAI} = 1. If the geographical area includes Annex I countries, identify all plants within the geographical area that produce the same useful chemical product and started commercial production in the most recent five years prior to the start of the project activity. Use the following procedure to estimate the fraction of the production capacity that is located in non-Annex I countries (x_{NAI}):

[8] A globally traded product is defined as follows: (i) a significant portion of the production in host country is exported or its consumption is imported; and (ii) import/export is not limited to the neighbouring countries in the region.

[9] This step is necessary because in case of globally traded products the displacement of production in Annex I countries cannot be accounted towards emission reductions.

$$x_{NAI} = \frac{\sum_i P_{NAI,i}}{\sum_i P_{NAI,i} + \sum_j P_{AI,j}} \tag{16}$$

Where:

x_{NAI}	=	Fraction of production capacity for the production of the useful product that is located in non-Annex I countries within the defined geographical area (estimated in step 2 above);
$P_{NAI,i}$	=	Production capacity of plant *i* located in non-Annex I country (t useful product);
$P_{AI,j}$	=	Production capacity of plant *j* located in Annex I country (t useful product);
i	=	Plants located in non-Annex I countries that started commercial production in the most recent five years prior to the start of the project activity;
j	=	Plants located in Annex I countries that started commercial production in the most recent five years prior to the start of the project activity;
$P_{NAI,i}$	=	Production capacity of ith plant located in non-Annex I country (t useful product);
$P_{AI,j}$	=	Production capacity of j^{th} plant located in Annex I country (t useful product)

3.2.4.5.3. Step 3: Determination of $EF_{CO_2,BL\,product}$

64. The emission factor can be estimated using either one of the following two options:

65. **Option 1**: $EF_{CO_2,BL\,product}$ is calculated by multiplying the fraction of production capacity in non-Annex I countries (X_{NAI}) and the applicable default value from table 5, as follows:

$$EF_{CO_2,BL,product} = X_{NAI} \times EF_{CO_2,BL,default} \tag{17}$$

Where:

$EF_{CO_2,BL,product}$	=	CO_2 emission factor for the production of the useful product in the baseline situation (t CO_2 / t useful product);
X_{NAI}	=	Fraction of production capacity for the production of the useful product that is located in non-Annex I countries within the defined geographical area (estimated in step 2 above);
$EF_{CO_2,BL,default}$	=	CO_2 default emission factor for the production of the useful product (t CO_2 / t useful product), as provided in table 10 below.

Table 10. Conservative default values for the production of useful products in the baseline in cases where scenario 4 applies[10]

Useful product	Geographical applicability	Value to be applied	Source
Ammonia	Global	1.666 t CO_2 / t NH_3	2006 IPCC Guidelines, Vol. 3, Ch. 3, table 3.1, page 3.15

66. **Option 2**: For each plant *j* (*j* belongs to set J, where J is all the Non-Annex I plants identified in step 2) collect the necessary data to determine the emission factor of the plant. This includes data on the quantities and types of fuels used, the quantity of electricity consumed and the quantity of useful chemical product produced during the most year for which data is available. As a simplification, project participants may neglect electricity consumption. Calculate for each plan an emission factor $EF_{CO_2,BL,n}$, applying equation 8 above.

67. Sort all plants *j* from the plants with the lowest to the highest emission factor. Identify the first plants *j* starting from lowest efficiency such that the total capacity of these plants is at least 20% of the total capacity of all plants (J).

68. The baseline emission factor $EF_{CO_2,BL,product}$ is then calculated as follows:

$$EF_{CO_2,BL,product} = x_{NAI} \times \frac{\sum_j P_{j,x} \times EF_{CO2,BL,j,x}}{\sum_j P_{j,x}} \tag{18}$$

Where:

$EF_{CO_2,BL,product}$	=	CO_2 emission factor for the production of the useful product in the baseline situation (t CO_2 / t useful product);
x_{NAI}	=	Fraction of production capacity for the production of the useful product that is located in non-Annex I countries within the defined geographical area;
$P_{j,x}$	=	Quantity of useful product produced in plant *j* in year *x* (t useful product);
$EF_{CO_2,BL,j,x}$	=	CO_2 emission factor for the production of the useful product in plant *j* in year *x* (t CO_2 / t useful product);
j	=	Top 20% performer plants;
x	=	Year prior to the start of the project activity.

69. All steps should be documented transparently, including a list of the plants identified in steps 2 and 3, as well as relevant data on fuel consumption, electricity consumption and

[10] Project participants may propose amendments to this table by requesting for a revision to this methodology. The proposed default values should be estimated in a conservative manner. The proposed revision/deviation should provide detailed information on source of data used in estimating the default value and also the geographical applicability of the default value.

production for all identified plants. Reference to all the sources used in collecting all the data should be provided.

4. Project crediting period

70. The crediting period is a maximum of 5 years with a maximum of two renewable periods of 5 years each, or a maximum of 10 years without the possibility of renewal.

71. For project validation until 31 December 2025, projects may be submitted to the Validation and Verification Body for validation if they were started no earlier than 5 years prior to submission of the validation documents. From 1 January 2026 - no earlier than 2 years prior to submission of validation documents.

72. The crediting period starts no earlier than 5 years before submission of the validation documents for projects validated before 31 December 2025 and no earlier than 2 years before submission of the validation documents for projects validated after 1 January 2026.

73. Complementarity and baseline must be assessed at the start of the crediting period and confirmed or revised at the start of the next 5-year phase if the project is implemented in 3 5-year phases.

5. Additionality

74. Additionality shall be demonstrated using Guidelines #1 Demonstration of the additionality of the project activity.

75. Step 1. Describe the alternative development scenario in the absence of project activities, in accordance with the legislation of the Russian Federation:

    (i) If the proposed project activity is implemented without registration as a project activity;

    (ii) whether another realistic and credible alternative scenario(s) would have been implemented, producing a useful product (e.g. methanol, ethylene, or ammonia) of comparable quality, characteristics and applications, taking into account, as appropriate, examples of scenarios defined in the basic methodology.

    (iii) where appropriate, a continuation of the current situation (no project activities or other alternatives are implemented).

76. The alternatives presented must be shown to comply with applicable laws and regulations. If the proposed climate project activity is the only alternative that meets the mandatory requirements of the applicable legislation and regulations, the proposed project activity is not additional. All the scenarios identified in step 1 of the baseline scenario selection procedure, described in previous section, shall be used for evaluating the additionality of the project activity.

77. If step 2 of the Guidelines (Investment Analysis) is used, then an IRR analysis of the entire project is required, i.e. it should not be limited to use of APG but include both any investment in the infrastructure and operation costs to use the APG instead of flaring as well as the costs and revenues for the scenarios for production processes (P1 to P5). IRR analysis shall be performed if step 2 (substep 2b – option 2, Investment Comparison Analysis) is chosen.

78. Steps 3 and 4 of the Guidelines should be completed as specified in the latest approved version of the Guidelines № 001 "Demonstration Of The Additionality Of The Project Activity".

6. Monitoring plan requirements

6.1. Monitoring procedures

79. The monitoring methodology involves monitoring of the following:

(a) The composition and quantity of APG produced by oil and natural gas processing facility;

(b) The quantity and carbon intensity of any additional energy consumed for transportation purposes or for the processing of the APG as a feedstock material by the end use facility;

(c) Any fugitive emissions of methane along the APG transport pipeline (including from accident events).

80. Baseline emissions from flaring are calculated ex post using measured data on APG end use facility (versus to flare). Baseline emissions from energy use and fugitive releases of methane are calculated using ex ante data on energy use for transport (e.g., for compressors) and fugitive methane emissions along the pipeline.

81. Project emissions are all calculated ex post based on actual energy use and fugitive emissions data.

82. All data collected as part of monitoring should be archived electronically and be kept at least for two years after the end of the last crediting period. 100% of the data should be monitored.

7. Project Scenario

83. Project emissions include CO_2 emissions from energy required for transporting the APG to the end-use facility ($PE_{CO_2,T,y}$), fugitive CH_4 emissions from transportation of the APG to the end-use facility ($PE_{CH_4,T,y}$), including any accidental release, and CO_2 emissions at the end-use facility as a result of the project activity ($PE_{CO_2,facility,y}$). These are estimated as follows:

$$PE_y = PE_{CO_2,T,y} + PE_{CH_4,T,y} + PE_{CO_2,facility,y} \quad (19)$$

Where:

PE_y	=	Project emissions in year y (t CO_2/yr);
$PE_{CO_2,T,y}$	=	Project CO_2 emissions from energy required for transportation of the APG to the end-use facility (t CO_2);
$PE_{CH_4,T,y}$	=	Fugitive CH_4 emissions from transportation of the APG to the end-use facility (t CO_2e);

$PE_{CO_2,facility,y}$	=	Project CO_2 emissions that occur at the end-use facility as a result of the project activity (t CO_2).

7.1. CO_2 emissions from energy required for transportation of the APG to the end-use facility

84. To estimate CO_2 emissions from energy required for transportation of the APG to the end-use facility, project participants should monitor the quantity of fossil fuels and / or electricity that are required in year y for that purpose ($FC_{PJ,T,facility,i,y}$ and $EC_{PJ,T,facility,y}$). CO_2 emissions from energy required for transportation of the APG to the end-use facility are calculated as follows:

$$PE_{CO_2,T,y} = PE_{CO_2,T,FC,y} + PE_{CO_2,T,EC,y} \quad (20)$$

Where:

$PE_{CO_2,T,y}$	=	Project CO_2 emissions from energy required for transportation of the APG to the end-use facility (t CO_2);
$PE_{CO_2,T,FC,y}$	=	Project CO_2 emissions from fossil fuel combustion required for transportation of the APG to the end-use facility (t CO_2);
$PE_{CO_2,T,EC,y}$		Project CO_2 emissions from electricity consumption required for transportation of the APG to the end-use facility (t CO_2).

7.1.1. Calculation project CO_2 emissions from fossil fuel combustion

85. CO_2 emissions from fossil fuel combustion in process *j* are calculated based on the quantity of fuels combusted and the CO_2 emission coefficient of those fuels, as follows:

$$PE_{CO_2,T,FC,y} = \sum_i FC_{PJ,T,facility,i,y} \times COEF_{i,y} \quad (21)$$

Where:

$PE_{CO_2,T,FC,y}$	=	Project CO_2 emissions from fossil fuel combustion required for transportation of the APG to the end-use facility (t CO_2);
$FC_{PJ,T,facility,i,y}$	=	Is the quantity of fuel type *i* combusted for transportation of the APG to the end-use facility during the year *y* (mass or volume unit/yr);
$COEF_{i,y}$	=	Is the CO_2 emission coefficient of fuel type *i* in year *y* (t CO_2/mass or volume unit);
i	=	Are the fuel types combusted for transportation of the APG to the end-use facility during the year *y*.

87. The CO_2 emission coefficient $COEF_{i,y}$ can be calculated using one of the following two Options, depending on the availability of data on the fossil fuel type *i*, as follows:

(d) Option A: The CO_2 emission coefficient $COEF_{i,y}$ is calculated based on the chemical composition of the fossil fuel type *i*, using the following approach:

If $FC_{PJ,T,facility,i,y}$ is measured in a mass unit:

$$COEF_{i,y} = w_{C,i,y} \times 3.664 \quad (22)$$

If $FC_{PJ,T,facility,i,y}$ is measured in a volume unit:

$$COEF_{i,y} = w_{C,i,y} \times \rho_{i,y} \times 3.664 \quad (23)$$

Where:

$COEF_{i,y}$	=	Is the CO_2 emission coefficient of fuel type *i* in year *y* (t CO_2/mass or volume unit);
$w_{C,i,y}$	=	Is the weighted average mass fraction of carbon in fuel type *i* in year *y* (tC/mass unit of the fuel)
$\rho_{i,y}$	=	Is the weighted average density of fuel type *i* in year *y* (mass unit/volume unit of the fuel)
i	=	Are the fuel types combusted for transportation of the APG to the end-use facility during the year *y*.

(e) Option B: The CO_2 emission coefficient $COEF_{i,y}$ is calculated based on net calorific value and CO_2 emission factor of the fuel type *i*, as follows:

$$COEF_{i,y} = NCV_{i,y} \times EF_{CO2,i,y} \quad (24)$$

Where:

$COEF_{i,y}$	=	Is the CO_2 emission coefficient of fuel type *i* in year *y* (t CO_2/mass or volume unit);
$NCV_{i,y}$	=	Is the weighted average net calorific value of the fuel type *i* in year *y* (GJ/mass or volume unit)
$EF_{CO2,i,y}$	=	Is the weighted average CO_2 emission factor of fuel type *i* in year *y* (t CO_2/GJ)
i	=	Are the fuel types combusted for transportation of the APG to the end-use facility during the year *y*.

91. Option A should be the preferred approach, if the necessary data is available.

7.1.2. Calculation project emissions from electricity consumption

92. If emissions are calculated for electricity consumption, the calculation is only applicable if one out of the following three scenarios applies to the sources of electricity consumption:

(a) Scenario A: Electricity consumption from the grid. The electricity is purchased from the grid only, and either no captive power plant(s) is/are installed at the site of electricity consumption or, if any captive power plant exists on site, it is either not operating or it is not physically able to provide electricity to the electricity consumer;

(b) Scenario B: Electricity consumption from (an) off-grid fossil fuel fired captive power plant(s). One or more fossil fuel fired captive power plants are installed at the site of the electricity consumer and supply the consumer with electricity. The captive power plant(s) is/are not connected to the electricity grid; or

(c) Scenario C: Electricity consumption from the grid and (a) fossil fuel fired captive power plant(s). One or more fossil fuel fired captive power plants operate at the site of the electricity consumer. The captive power plant(s) can provide electricity to the electricity consumer. The captive power plant(s) is/are also connected to the electricity grid. Hence, the electricity consumer can be provided with electricity from the captive power plant(s) and the grid.

93. The followed calculations are not applicable in cases where captive renewable power generation technologies are installed to provide electricity in the project activity, in the baseline scenario or to sources of leakage. The calculations only accounts for CO_2 emissions.

94. Emissions from electricity consumption include CO_2 emissions from the combustion of fossil fuels at any power plants at the site(s) of electricity consumption and, if applicable, at power plants connected physically to the electricity system (grid) from which electricity is consumed.

$$PE_{CO_2,T,EC,y} = EC_{PJ,T,facility,y} \times EF_{EF,T,y} \times \left(1 \times TDL_{T,y}\right) \tag{25}$$

Where:

$PE_{CO_2,T,EC,y}$	=	Project CO_2 emissions from electricity consumption required for transportation of the APG to the end-use facility (t CO_2);
$EC_{PJ,T,facility,y}$	=	Quantity of electricity consumed by the project electricity consumption to transport of the APG to the end-use facility in year *y* (MWh/yr);
$EF_{EF,T,y}$	=	Emission factor for electricity generation for transportation of the APG to the end-use facility in year *y* (t CO_2/MWh);
$TDL_{T,y}$	=	Average technical transmission and distribution losses for providing electricity to transport of the APG to the end-use facility in year *y*.

96. The determination of the emission factors for electricity generation ($EF_{EF,j,y}$) in the project scenario depends on which scenario (A, B or C), as described in Section 7.1.2, paragraph 92 that applies to the source of electricity consumption that would be displaced in the baseline by electricity generated in the project:

7.1.2.1. Scenario A: Electricity consumption from the grid

97. Use the following conservative default values:

(a) A value of 1.3 t CO_2/MWh if:

(i) Scenario A applies only to project and/or leakage electricity consumption sources but not to baseline electricity consumption sources; or

(ii) Scenario A applies to: both baseline and project (and/or leakage) electricity consumption sources; and the electricity consumption of the project and leakage sources is greater than the electricity consumption of the baseline sources;

(b) A value of 0.4 t CO_2/MWh for electricity grids where hydro power plants constitute less than 50% of total grid generation in 1) average of the five most recent years, or 2) based on long-term averages for hydroelectricity production, and a value of 0.25 t CO_2/MWh for other electricity grids. These values can be used if:

(i) Scenario A applies only to baseline electricity consumption sources but not to project or leakage electricity consumption sources; or

(ii) Scenario A applies to: both baseline and project (and/or leakage) electricity consumption sources; and the electricity consumption of the baseline sources is greater than the electricity consumption of the project and leakage sources.

7.1.2.2. Scenario B: Electricity consumption from an off-grid captive power plant[11]

98. Use the following conservative default values:

(a) A value of 1.3 t CO_2/MWh if:

(i) The electricity consumption source is a project or leakage electricity consumption source; or

(ii) The electricity consumption source is a baseline electricity consumption source; and the electricity consumption of all baseline electricity consumptions sources at the site of the captive power plant(s) is less than the electricity consumption of all project electricity consumption sources at the site of the captive power plant(s);

(b) A value of 0.4 t CO_2/MWh if:

(i) The electricity consumption source is a baseline electricity consumption source; or

(ii) The electricity consumption source is a project electricity consumption source and the electricity consumption of all baseline electricity consumptions sources at the site of the captive power plant(s) is greater than the electricity consumption of all project electricity consumption sources at the site of the captive power plant(s).

7.1.2.3. Scenario C: Electricity consumption from the grid and (a) fossil fuel fired captive power plant(s)

99. Under this scenario, the consumption of electricity in the project, the baseline or as a source of leakage may result in different emission levels, depending on the situation of theproject activity. The following three cases can be differentiated:

(a) Case C.I: Grid electricity. The implementation of the project activity only affects the quantity of electricity that is supplied from the grid and not the operationof the captive power plant. This applies, for example:

(i) If at all times during the monitored period the total electricity demand at the site of the captive power plant(s) is, both with the project activity and in the absence of the project activity, larger than the electricity generation capacity of the captive power plant(s); or

(ii) If the captive power plant is operated continuously (apart from maintenance) and feeds any excess electricity into the grid, because the revenues for feeding electricity into the grid are above the plant operation costs; or

(iii) If the captive power plant is centrally dispatched and the dispatch of the captive power plant is thus outside the control of the project participants;

[11]Off-grid captive power plant – a power plant designed to supply electricity and heat to a specific technological installation without being connected to the electricity grid. VRD 39-1.10-071-2003

(b) Case C.II: Electricity from captive power plant(s). The implementation of the project activity is clearly demonstrated to only affect the quantity of electricity that is generated in the captive power plant(s) and does not affect the quantity of electricity supplied from the grid. This applies, for example, in the following situation: A fixed quantity of electricity is purchased from the grid due to physical transmission constraints, such as a limited capacity of the transformer that provides electricity to the relevant source. In this situation, case C.II would apply ifthe total electricity demand at the site of the captive power plant(s) is at all times during the monitored period, both with the project activity and in the absence of theproject activity, larger than the quantity of the electricity that can physically be supplied by the grid;

(c) Case C.III: Electricity from both the grid and captive power plant(s). The implementation of the project activity may affect both the quantity of electricity that is generated in the captive power plant(s) and the quantity of electricity supplied from the grid. This applies, for example:

(i) If the captive power plant(s) is/are not operating continuously; or

(ii) If grid electricity is purchased during a part of the monitored period; or

(iii) If electricity from the captive power plant is fed into the grid during a part ofthe monitored period.

100. Where case C.I has been identified, the guidance for scenario A above should be applied (use option A1 or option A2). Where case C.II has been identified, the guidance for scenario B above should be applied (use option B1 or B2). Where case C.III has been identified, as a conservative simple approach, the emission factor for electricity generation should be the more conservative5 value between the emission factor determined as per guidance for scenario A and B, respectively. This means that the more conservative value should be chosen between a) the result of applying either option A1 or A2 and b) the result of applying either option B1 or B2.

7.2. Fugitive CH_4 emissions from transportation of the APG to the end-use facility ($PE_{CH_4,T,y}$)

101. Note: Project participants may ignore this emission source if the pipeline transporting the APG to the end-use facility is identical (in terms of length, design, and other characteristics likely to affect fugitive emissions and energy demands for compressors) to the pipeline used to transport the APG to the flare in the baseline scenario or if fugitive CH_4 emissions can clearly be expected to be lower in the project case. In this case, both baseline ($BET_{CH_4,y}$) and project ($PE_{CH_4,T,y}$) emissions should be ignored.

102. If transport of the APG to the end use facility only requires an extension of the pipeline to the flare in the baseline scenario, then baseline emissions along the existing pipeline[12] can be ignored and project emissions only need to be estimated for the pipeline extension.

103. The fugitive CH_4 emissions will be estimated using the same procedure as provided in the baseline emissions section for $BET_{CH_4,y}$.

104. In addition, in case of accidents, the relevant fugitive CH_4 emissions should be calculated. When an accident causes gas leakage from the pipeline, the gas volume is calculated as the

[12] In other words, emissions from $\left(FCT_{flare,x} \times V_y \times EFFCT_{flare,x}\right) + FE$.

sum of (1) the total amount of gas flow from the time the accident occurred until gas flow was shut off, and (2) the total amount of gas remaining in the pipeline at time of shut off. Accidental release of methane from the pipeline should be calculated as:

$$PE_{CH_4,T,y} = GWP_{CH_4} \times \frac{1}{1000}\left(V_{accident} + V_{remain,accident}\right) \times w_{CH_4,pipeline,accident} \tag{26}$$

with

$$V_{accident} = t_{accident} \times F = (t_2 - t_1) \times F \text{ and} \tag{27}$$

$$V_{remain,accident} = d^2 \times \pi \times L \times \frac{P_p}{P_s} \times \frac{T_s}{T_p} \times \frac{V_{d,accident}}{\sum_i V_{Xi,d,accident} + V_{d,accident}} \tag{28}$$

Where:

EFA_y	=	Methane emissions from the transport pipeline due to an accidental event (t CO_2-e);
$V_{accident}$	=	The volume of APG supplied to the pipeline from the oil and natural gas processing plant from the time the gas leakage started until the shutdown valves were closed (m^3);
$V_{remain,accident}$	=	The volume of APG remaining in the pipeline after the shutdown valves have been closed (m^3);
$w_{CH_4,pipeline,accident}$	=	The fraction of methane in the APG on a mass basis (kg CH_4/m^3);
$t_{accident}$		Duration of accident (sec);
t_i		The time the gas leakage caused by the accident occurred (in the hour of incident occurred);
t_2	=	The time that the shutdown valves closed both the upstream and downstream pipeline (the hour when the pipe was shut);
F	=	The flow rate of APG supplied from the oil and natural gas processing plant (m^3/sec);
d	=	The radius of the pipeline (meters);
π	=	The ratio of the circumference of a circle to its diameter (unitless);
L	=	The length of the pipeline (meters);
P_P	=	The pressure in the pipeline when the shutdown valves close both the upstream and downstream of the pipeline (atm);
P_S	=	Standard pressure (atm);
T_P	=	The temperature in the pipeline when the shutdown valves close both the upstream and downstream of the pipeline (ºC);
T_S	=	Standard temperature (ºK);
$V_{d,accident}$	=	The volume of APG supplied to the pipeline from the oil and natural gas processing plant before the accident occurs during the period (m^3);
$V_{xi,d,accident}$	=	The volume of gas supplied to the pipeline from other sources, if any, before the accident occurs during the period (m^3).

7.3. CO_2 emissions occurring at the end-use facility as a result of the project activity ($PE_{CO_2,facility,y}$)

105. The calculation of this emission source depends on the applicable scenario.

7.3.1. Scenario 1

106. The use of the APG in the end-use facility instead of natural gas may be associated with an increased combustion of fossil fuels or electricity, for example, for cleaning the APG. Therefore, only emissions from such use of additional energy in the project activity is accounted for. The respective fossil fuel and electricity consumption should be monitored and project emissions from such energy requirements ($PE_{CO_2,facility,y}$) should be calculated as follows:

7.3.1.1. CO_2 emissions from fossil fuel combustion

107. CO_2 emissions from fossil fuel combustion in process j are calculated based on the quantity of fuels combusted and the CO_2 emission coefficient of those fuels, as follows:

$$PE_{CO_2,facility,y} = \sum_i FC_{PJ,P,facility,i,y} \times COEF_{i,y} \tag{29}$$

Where:

$PE_{CO_2,facility,y}$	=	Project CO_2 emissions that occur at the end-use facility as a result of the project activity (t CO_2);
$FC_{PJ,P,facility,i,y}$	=	Is the quantity of fuel type i combusted for processing of the APG, for example, for cleaning the APG during the year y (mass or volume unit/yr);
$COEF_{i,y}$	=	Is the CO_2 emission coefficient of fuel type i in year y (t CO_2/mass or volume unit);
i	=	Are the fuel types combusted for processing of the APG, for example, for cleaning the APG during the year y.

109. The CO_2 emission coefficient $COEF_{i,y}$ can be calculated using one of the following two Options, depending on the availability of data on the fossil fuel type i, as follows:

(a) Option A: The CO_2 emission coefficient $COEF_{i,y}$ is calculated based on the chemical composition of the fossil fuel type i, using the following approach:

110. If $FC_{PJ,P,facility,i,y}$ is measured in a mass unit:

$$COEF_{i,y} = w_{C,i,y} \times 3.664 \tag{30}$$

112. If $FC_{PJ,P,facility,i,y}$ is measured in a volume unit:

$$COEF_{i,y} = w_{C,i,y} \times \rho_{i,y} \times 3.664 \tag{31}$$

Where:

$COEF_{i,y}$	=	Is the CO_2 emission coefficient of fuel type i in year y (t CO_2/mass or volume unit);
$w_{C,i,y}$	=	Is the weighted average mass fraction of carbon in fuel type i in year y (t C/mass unit of the fuel);

$\rho_{i,y}$	=	Is the weighted average density of fuel type *i* in year *y* (mass unit/volume unit of the fuel);
i	=	Are the fuel types combusted for processing of the APG, for example, for cleaning the APG during the year *y*.

(b) Option B: The CO_2 emission coefficient $COEF_{i,y}$ is calculated based on net calorific value and CO_2 emission factor of the fuel type *i*, as follows:

$$COEF_{i,y} = NCV_{i,y} \times EF_{CO2,i,y} \quad (32)$$

Where:

$COEF_{i,y}$	=	Is the CO_2 emission coefficient of fuel type *i* in year *y* (t CO_2/mass or volume unit);
$NCV_{i,y}$	=	Is the weighted average net calorific value of the fuel type *i* in year *y* (GJ/mass or volume unit);
$EF_{CO2,i,y}$	=	Is the weighted average CO_2 emission factor of fuel type *i* in year *y* (t CO_2/GJ);
i	=	Are the fuel types combusted for processing of the APG, for example, for cleaning the APG during the year *y*.

115. Option A should be the preferred approach, if the necessary data is available.

7.3.1.2. Calculation project emissions from electricity consumption

116. In the generic approach, project emissions from consumption of electricity are calculated based on the quantity of electricity consumed, an emission factor for electricity generation and a factor to account for transmission losses, as follows:

$$PE_{CO_2,facility,y} = EC_{PJ,P,facility,y} \times EF_{EF,j,y} \times \left(1 \times TDL_{j,y}\right) \quad (33)$$

Where:

$PE_{CO_2,facility,y}$	=	Project CO_2 emissions that occur at the end-use facility as a result of the project activity (t CO_2);
$EC_{PJ,P,facility,y}$	=	Quantity of electricity consumed by the project electricity consumption to process of the APG, for example, for cleaning the APG during the year *y* (MWh/yr);
$EF_{EF,j,y}$	=	Emission factor for electricity generation to process of the APG, for example, for cleaning the APG during the year *y* (t CO_2/MWh);
$TDL_{j,y}$	=	Average technical transmission and distribution losses for providing electricity to process of the APG, for example, for cleaning the APG during the year y;

118. The determination of the emission factors for electricity generation ($EF_{EF,j,y}$) in the project scenario depends on which scenario (A, B or C), as described in Section 7.1.2, paragraph 92 that applies to the source of electricity consumption that would be displaced in the baseline by electricity generated in the project:

Scenario A: Electricity consumption from the grid

119. Use the following conservative default values:

(d) A value of 1.3 t CO_2/MWh if:

(i) Scenario A applies only to project and/or leakage electricity consumption sources but not to baseline electricity consumption sources; or

(ii) Scenario A applies to: both baseline and project (and/or leakage) electricity consumption sources; and the electricity consumption of the project and leakage sources is greater than the electricity consumption of the baseline sources;

(e) A value of 0.4 t CO_2/MWh for electricity grids where hydro power plants constitute less than 50% of total grid generation in 1) average of the five most recent years, or 2) based on long-term averages for hydroelectricity production, and a value of 0.25 t CO_2/MWh for other electricity grids. These values can be used if:

Scenario A applies only to baseline electricity consumption sources but not to project or leakage electricity consumption sources; or

(ii) Scenario A applies to: both baseline and project (and/or leakage) electricity consumption sources; and the electricity consumption of the baseline sources is greater than the electricity consumption of the project and leakage sources.

Scenario B: Electricity consumption from an off-grid captive power plant

120. Use the following conservative default values:

(a) A value of 1.3 t CO_2/MWh if:

The electricity consumption source is a project or leakage electricity consumption source; or

(ii) The electricity consumption source is a baseline electricity consumption source; and the electricity consumption of all baseline electricity consumptions sources at the site of the captive power plant(s) is less than the electricity consumption of all project electricity consumption sources at the site of the captive power plant(s);

(b) A value of 0.4 t CO_2/MWh if:

(i) The electricity consumption source is a baseline electricity consumption source; or

(ii) The electricity consumption source is a project electricity consumption source and the electricity consumption of all baseline electricity consumptions sources at the site of the captive power plant(s) is greater than the electricity consumption of all project electricity consumption sources at the site of the captive power plant(s).

Scenario C: Electricity consumption from the grid and (a) fossil fuel fired captive power plant(s)

121. Under this scenario, the consumption of electricity in the project, the baseline or as a source of leakage may result in different emission levels, depending on the situation of theproject activity. The following three cases can be differentiated:

(a) Case C.I: Grid electricity. The implementation of the project activity only affects the quantity of electricity that is supplied from the grid and not the operationof the captive power plant. This applies, for example:

(i) If at all times during the monitored period the total electricity demand at the site of the captive power plant(s) is, both with the project activity and in the absence of the project activity, larger than the electricity generation capacity of the captive power plant(s); or

(ii) If the captive power plant is operated continuously (apart from maintenance) and feeds any excess electricity into the grid, because the revenues for feeding electricity into the grid are above the plant operation costs; or

(iii) If the captive power plant is centrally dispatched and the dispatch of the captive power plant is thus outside the control of the project participants;

(b) Case C.II: Electricity from captive power plant(s). The implementation of the project activity is clearly demonstrated to only affect the quantity of electricity that is generated in the captive power plant(s) and does not affect the quantity of electricity supplied from the grid. This applies, for example, in the following situation: A fixed quantity of electricity is purchased from the grid due to physical transmission constraints, such as a limited capacity of the transformer that provides electricity to the relevant source. In this situation, case C.II would apply ifthe total electricity demand at the site of the captive power plant(s) is at all times during the monitored period, both with the project activity and in the absence of theproject activity, larger than the quantity of the electricity that can physically be supplied by the grid;

(c) Case C.III: Electricity from both the grid and captive power plant(s). The implementation of the project activity may affect both the quantity of electricity that is generated in the captive power plant(s) and the quantity of electricity supplied from the grid. This applies, for example:

(i) If the captive power plant(s) is/are not operating continuously; or

(ii) If grid electricity is purchased during a part of the monitored period; or

(iii) If electricity from the captive power plant is fed into the grid during a part of the monitored period.

122. Where case C.I has been identified, the guidance for scenario A above should be applied (use option A1 or option A2). Where case C.II has been identified, the guidance for scenario B above should be applied (use option B1 or B2). Where case C.III has been identified, as a conservative simple approach, the emission factor for electricity generation should be the more conservative5 value between the emission factor determined as per guidance for scenario A and B, respectively. This means that the more conservative value should be chosen between a) the result of applying either option A1 or A2 and b) the result of applying either option B1 or B2.

7.3.2. Scenarios 2, 3 and 4

123. In these scenarios, the end-use facility is established as a result of the project activity and the useful product would be produced in other facilities in the absence of the project activity. Emissions from fossil fuel use should be determined as follows:

$$PE_{CO_2,facility,y} = PE_{FC,j,y} + PE_{EC,y} \quad (3$$

Where:

$PE_{CO_2,facility,y}$	=	Project CO_2 emissions that occur at the end-use facility as a result of the project activity in year *y* (t CO_2/yr);
$PE_{FC,j,y}$	=	CO_2 emissions from fossil fuel combustion in process *j* during the year *y* (t CO_2/yr);
$PE_{EC,y}$	=	Project emissions from electricity consumption in year *y* (t CO_2/yr).

7.3.3. CO_2 emissions from fossil fuel combustion

124. CO_2 emissions from fossil fuel combustion in process *j* are calculated based on the quantity of fuels combusted and the CO_2 emission coefficient of those fuels, as follows:

$$PE_{FC,j,y} = \sum_i FC_{i,j,y} \times COEF_{i,y} \tag{35}$$

Where:

$PE_{FC,j,y}$	=	CO_2 emissions from fossil fuel combustion in process *j* during the year *y* (t CO_2/yr);
$FC_{i,j,y}$	=	Is the quantity of fuel type *i* combusted in process *j* during the year *y* (mass or volume unit/yr);
$COEF_{i,y}$	=	Is the CO_2 emission coefficient of fuel type *i* in year *y* (t CO_2/mass or volume unit);
i	=	Are the fuel types combusted in process *j* during the year *y*.

126. The CO_2 emission coefficient $COEF_{i,y}$ can be calculated using one of the following two Options, depending on the availability of data on the fossil fuel type *i*, as follows:

(a) Option A: The CO_2 emission coefficient $COEF_{i,y}$ is calculated based on the chemical composition of the fossil fuel type *i*, using the following approach:

127. If $FC_{i,j,y}$ is measured in a mass unit:

$$COEF_{i,y} = w_{C,i,y} \times 3.664 \tag{36}$$

129. If $FC_{i,j,y}$ is measured in a volume unit:

$$COEF_{i,y} = w_{C,i,y} \times \rho_{i,y} \times 3.664 \tag{37}$$

Where:

$COEF_{i,y}$	=	Is the CO_2 emission coefficient of fuel type *i* in year *y* (t CO_2/mass or volume unit);
$w_{C,i,y}$	=	Is the weighted average mass fraction of carbon in fuel type *i* in year *y* (tC/mass unit of the fuel)
$\rho_{i,y}$	=	Is the weighted average density of fuel type *i* in year *y* (mass unit/volume unit of the fuel)
i	=	Are the fuel types combusted in process *j* during the year *y*.

(b) Option B: The CO_2 emission coefficient $COEF_{i,y}$ is calculated based on net calorific value and CO_2 emission factor of the fuel type *i*, as follows:

$$COEF_{i,y} = NCV_{i,y} \times EF_{CO2,i,y} \tag{38}$$

Where:

$COEF_{i,y}$	=	Is the CO_2 emission coefficient of fuel type *i* in year *y* (t CO_2/mass or volume unit);
$NCV_{i,y}$	=	Is the weighted average net calorific value of the fuel type *i* in year *y* (GJ/mass or volume unit)
$EF_{CO2,i,y}$	=	Is the weighted average CO_2 emission factor of fuel type *i* in year *y* (t CO_2/GJ)
i	=	Are the fuel types combusted in process *j* during the year *y*.

132. Option A should be the preferred approach, if the necessary data is available.

7.3.4. Calculation project emissions from electricity consumption

133. In the generic approach, project emissions from consumption of electricity are calculated based on the quantity of electricity consumed, an emission factor for electricity generation and a factor to account for transmission losses, as follows:

$$PE_{EC,y} = \sum_j EC_{PJ,j,y} \times EF_{EF,j,y} \times \left(1 \times TDL_{j,y}\right) \tag{39}$$

Where:

$PE_{EC,y}$	=	Project emissions from electricity consumption in year *y* (t CO_2/yr);
$EC_{PJ,j,y}$	=	Quantity of electricity consumed by the project electricity consumption source *j* in year *y* (MWh/yr);
$EF_{EF,j,y}$	=	Emission factor for electricity generation for source *j* in year *y* (t CO_2/MWh);
$TDL_{j,y}$	=	Average technical transmission and distribution losses for providing electricity to source *j* in year *y*;
j	=	Sources of electricity consumption in the project.

135. The determination of the emission factors for electricity generation ($EF_{EF,j,y}$) in the project scenario depends on which scenario (A, B or C), as described in Section 7.1.2, paragraph 92 that applies to the source of electricity consumption that would be displaced in the baseline by electricity generated in the project:

Scenario A: Electricity consumption from the grid

136. Use the following conservative default values:

(a) A value of 1.3 t CO_2/MWh if:

(i) Scenario A applies only to project and/or leakage electricity consumption sources but not to baseline electricity consumption sources; or

(ii) Scenario A applies to: both baseline and project (and/or leakage) electricity consumption sources; and the electricity consumption of the project and leakage sources is greater than the electricity consumption of the baseline sources;

(b) A value of 0.4 t CO_2/MWh for electricity grids where hydro power plants constitute less than 50% of total grid generation in 1) average of the five most recent years, or

2) based on long-term averages for hydroelectricity production, and a value of 0.25 t CO_2/MWh for other electricity grids. These values can be used if:

(i) Scenario A applies only to baseline electricity consumption sources but not to project or leakage electricity consumption sources; or

(ii) Scenario A applies to: both baseline and project (and/or leakage) electricity consumption sources; and the electricity consumption of the baseline sources is greater than the electricity consumption of the project and leakage sources.

Scenario B: Electricity consumption from an off-grid captive power plant

137. Use the following conservative default values:

(a) A value of 1.3 t CO_2/MWh if:

(i) The electricity consumption source is a project or leakage electricity consumption source; or

(ii) The electricity consumption source is a baseline electricity consumption source; and the electricity consumption of all baseline electricity consumptions sources at the site of the captive power plant(s) is less than the electricity consumption of all project electricity consumption sources at the site of the captive power plant(s);

(b) A value of 0.4 t CO_2/MWh if:

(i) The electricity consumption source is a baseline electricity consumption source; or

(ii) The electricity consumption source is a project electricity consumption source and the electricity consumption of all baseline electricity consumptions sources at the site of the captive power plant(s) is greater than the electricity consumption of all project electricity consumption sources at the site of the captive power plant(s).

Scenario C: Electricity consumption from the grid and (a) fossil fuel fired captive power plant(s)

138. Under this scenario, the consumption of electricity in the project, the baseline or as a source of leakage may result in different emission levels, depending on the situation of theproject activity. The following three cases can be differentiated:

(a) Case C.I: Grid electricity. The implementation of the project activity only affects the quantity of electricity that is supplied from the grid and not the operationof the captive power plant. This applies, for example:

(i) If at all times during the monitored period the total electricity demand at the site of the captive power plant(s) is, both with the project activity and in the absence of the project activity, larger than the electricity generation capacity of the captive power plant(s); or

(ii) If the captive power plant is operated continuously (apart from maintenance) and feeds any excess electricity into the grid, because the revenues for feeding electricity into the grid are above the plant operation costs; or

(iii) If the captive power plant is centrally dispatched and the dispatch of the captive power plant is thus outside the control of the project participants;

(b) Case C.II: Electricity from captive power plant(s). The implementation of the project activity is clearly demonstrated to only affect the quantity of electricity that is generated in the captive power plant(s) and does not affect the quantity of electricity supplied from the grid. This applies, for example, in the following situation: A fixed quantity of electricity is purchased from the grid due to physical transmission constraints, such as a limited capacity of the transformer that provides electricity to the relevant source. In this situation, case C.II would apply ifthe total electricity demand at the site of the captive power plant(s) is at all times during the monitored period, both with the project activity and in the absence of theproject activity, larger than the quantity of the electricity that can physically be supplied by the grid;

(c) Case C.III: Electricity from both the grid and captive power plant(s). The implementation of the project activity may affect both the quantity of electricity that is generated in the captive power plant(s) and the quantity of electricity supplied from the grid. This applies, for example:

(i) If the captive power plant(s) is/are not operating continuously; or

(ii) If grid electricity is purchased during a part of the monitored period; or

(iii) If electricity from the captive power plant is fed into the grid during a part ofthe monitored period.

139. Where case C.I has been identified, the guidance for scenario A above should be applied (use option A1 or option A2). Where case C.II has been identified, the guidance for scenario B above should be applied (use option B1 or B2). Where case C.III has been identified, as a conservative simple approach, the emission factor for electricity generation should be the more conservative5 value between the emission factor determined as per guidance for scenario A and B, respectively. This means that the more conservative value should be chosen between a) the result of applying either option A1 or A2 and b) the result of applying either option B1 or B2.

7.4. Emission reductions

140. Emission reductions are calculated as the difference between baseline and project emissions, taking into account any adjustments for leakage:

$$ER_y = BE_y - PE_y \tag{40}$$

Where:

ER_y	=	Emission reductions during the year *y* (t CO_2/yr);
BE_y	=	Baseline emissions in year *y* (t CO_2/yr);
PE_y	=	Project emissions in year *y* (t CO_2/yr).

7.5. Risk management

141. As part of the project implementation, it is recommended to develop a risk assessment system with a description of the most likely risks that may arise at all stages of the climate project (Table 11). For such an assessment, the project developer should develop a detailed matrix with the following information, as a minimum:

(i) The main stages of the implementation of the climate project;

(ii) Description of the risks that may arise at each stage of the climate project;

(iii) Description of the probability of occurrence of risks. For this, the rating options "low, medium, high" or any other understandable numerical scales can be used;

(iv) Description of the impact of each risk on the results of the entire project. This can also be done using "low, medium, high" or any other understandable numerical scale;

(v) Description of the period of influence of each risk on the entire climate project;

(vi) Development of measures to minimize or avoid each type of risks;

(vii) The time for the implementation of each measure that reduces or prevents the occurrence of risks is indicated.

Table 11. Risk management

Stage of climate project implementation	Description of risks	Probability of occurrence	Impact on the project	Impact period	Risk minimization methods	Implementation period
		low medium high	low medium high	Preparation period 1-2 years after the implementation The entire period of the climate project	Detailed description of mitigation measures for each risk	Description of the time frame for the implementation of these activities
		Scale from 1 to 5 or others	Scale from 1 to 5 or others			

8. Leakage assessment

142. According to the Order of the Ministry of Economic Development of Russia dated May 11, 2022 N 248[13] project activities should not lead to an aggregate increase in greenhouse gas emissions or reduce their absorption levels outside the scope of such activities.

[13] Appendix № 1 to the order of the Ministry of Economic Development of Russia of May 11, 2022 № 248, paragraph "в";

143. At the same time, it is necessary to consider and fully account for if project leaks[14] exist in accordance with the methodology below.

9. Non-permanence risk analysis

144. Not applicable.

10. Methods to prevent double counting, negative impacts on the environment and society

145. In order to prevent double counting[15] the developer of the climate project in the PDT should set out a system of approaches and develop technical solutions that will ensure the absence of double counting in accordance with GOST R ISO 14080-2021. National Standard of the Russian Federation. Greenhouse Gas Management and Related Activities. System of approaches and methodological support for the implementation of climate projects. At the same time, it is necessary to:

(i) avoid boundary-crossing (overlap) in setting them;

(ii) ensure that consistent methodologies are used for each type of GHG emission source;

(iii) establish a principle of disclosure of information on climate change projects;

(iv) analyse any areas of potential overlap and communicate the potential for conflict.

146. The climate project should demonstrate that it complies with all legal requirements in the jurisdiction where it is located. Project proponents should consider whether there is a risk that their project will have a negative impact on local communities, biodiversity and the environment. Such projects should not lead to increased air, soil, surface and groundwater pollution, community conflict, land tenure issues, forced evictions, human rights violations, or reduced health and well-being due to restricted access to a forest or natural area.

147. Human Rights

(i) The project respects internationally proclaimed human rights, including the dignity, cultural values and uniqueness of indigenous peoples. The Project shall not be complicit in or involved in violating human rights.

(ii) The project shall not engage in or be complicit in involuntary resettlement.

(iii) The project shall not involve or be complicit in the alteration, damage or removal of significant cultural heritage.

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[14] Leakage for a project activity – the net change of anthropogenic emissions by sources of GHGs which occurs outside the project boundary, and which is measurable and attributable to the climate project activity, as applicable (CDM-EB07-A04-GLOS Glossary CDM terms. Version 08.0)

[15] Double counting: accounting for GHG emissions or removals more than once. Double counting can occur between organizations, i.e. two or more reporting organizations take ownership of the same GHG emissions or removals. Double counting can also occur inside an organization when GHG emissions or removals are taken into account in different categories (this type of double counting should not occur). (ISO/TR 14069:2013 Greenhouse gases - Quantification and reporting of greenhouse gas emissions for organizations - Guidance for the application of ISO 14064-1).

148. Labour Standards

(i) The project shall respect the freedom of association and the right to collective bargaining of workers and shall not be complicit in restricting these freedoms and rights.

(ii) The project shall not be complicit or associated with forced or compulsory labour.

(iii) The project shall not use or be complicit in the use of any form of child labour.

(iv) The project shall not use or be complicit in the use of or be associated with any form of discrimination.

(v) The project provides a safe and healthy working environment and is not complicit in exposing workers to unsafe or unhealthy conditions.

149. Environmental Protection

(i) The project shall neither involve nor contribute to the significant conversion or degradation of critical natural areas, including those that are (a) legally protected, (b) officially proposed for protection, (c) identified by authoritative sources as being of high conservation value, or (d) recognised as being protected by traditional local communities.

150. Anti-corruption

(i) The project shall respect the freedom of association and the right to collective bargaining of workers and shall not be complicit in the restriction of these freedoms and rights.

(ii) The project shall not be a party to, and shall not be complicit in, corruption..

11. Update of the baseline at the renewal of the crediting period

151. At the renewal of crediting period the project is subject to verification with elements of validation and a technical assessment by a validation and verification body to determine necessary updates to the baseline, the additionality and the quantification of emission reductions.

152. In order to update the baseline, the approach to its definition, the main parameters and assumptions used in the analysis are revised and updated. The baseline shall be representative of the conditions for the beginning of a new crediting period and be valid for that period.

153. The additionality at the renewal of the crediting period is checked for compliance to the criteria under Guidelines №001 #1 at the date of the beginning of the new crediting period.

12. Normative References

154. Order of the Ministry of Economic Development of Russia dated 11.05.2022 № 248 "On approval of the criteria and procedure for attributing projects implemented by legal entities, individual entrepreneurs or individuals to climate projects, the form and procedure for reporting on the implementation of a climate project" (registered with the Ministry of Justice of Russia on 30.05.2022, № 68642)

155. GOST R ISO 14064-1-2021. National standard of Russian Federation. Greenhouse gases. Part 1. Requirements and Guidance for Quantification and Reporting of Greenhouse Gas Emissions and Absorption at Organization Level (approved and enacted by Order No. 1029-st of Rosstandart dated 30.09.2021);

156. GOST R ISO 14064-2-2021. National standard of the Russian Federation. Greenhouse gases. Part 2. Requirements and Guidance on Quantification, Monitoring and Reporting Documentation for Projects to Reduce Greenhouse Gas Emissions or to Increase Their Absorption at the Project Level (approved and enacted by Order No. 1030-st of Rosstandart dated 30.09.2021);

157. GOST R ISO 14064-3-2021. National Standard of the Russian Federation. Greenhouse gases. Part 3. Requirements and Guidance for Validation and Verification of Declarations on Greenhouse Gases (approved and enacted by Order of Rosstandart, 30.09.2021, № 1031-st);

158. GOST R ISO 14065-2014 National Standard of the Russian Federation. Greenhouse gases. Requirements for greenhouse gas validation and verification bodies for their application in accreditation or other forms of recognition (approved and enacted by Rosstandart Order of 26.11.2014 No. 1869-st);

159. GOST R ISO 14080-2021. National Standard of the Russian Federation. Management of greenhouse gases and related activities. System of approaches and methodological support for the implementation of climate projects (approved and enacted by Order of Rosstandart dated 30.09.2021, No. 1033-st);

160. GOST R ISO 14066-2013. National standard of the Russian Federation. Greenhouse gases. Requirements for competence of greenhouse gas validation and verification groups (approved and enacted by Order of Rosstandart from 17.12.2013 № 2274-st);

161. Order No. 371 of the Ministry of Natural Resources of Russia dated May 27, 2022 "On approval of methods for quantitative determination of greenhouse gas emissions and greenhouse gas removals" (with effect from March 1, 2023, except for certain provisions effective from March 1, 2024);

162. Order of the Ministry of Natural Resources of the Russian Federation dated 30.06.2015 No. 300 "On approval of methodological guidelines and guidelines for quantitative determination of greenhouse gas emissions by organisations carrying out economic and other activities in the Russian Federation" (until 01.03.2023);

163. IPCC 2006. Guidelines for National Greenhouse Gas Inventories of the Intergovernmental Panel on Climate Change, 2006. Iggleston, L. Buendia, K. Miwa, T. Ngara and K. Tanabe. // T.1-5. - IGES// Hayyam. 2006.

164. ISO 6707-1:2020 Buildings and civil engineering works - Vocabulary - Part 1: General terms. IDT. Publication date: 2020-08;

165. GOST R ISO 6707-1-2020. National Standard of the Russian Federation. Buildings and structures. General terms (approved and enacted by Rosstandart Order No. 1388-st dated 24.12.2020);

166. U.S. Environmental Protection Agency (EPA, 1995b), 1995. Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, Nov 1995.

167. Norwegian Environment Agency. Cold Venting and Fugitive Emissions from Norwegian Offshore Oil and Gas Activities: Module 2 – Emission Estimates and Quantification Methods, Sub-report 2, 15 March 2016.

168. AM0037: Flare (or vent) reduction and utilization of gas from oil wells as a feedstock --- Version 3.0. Large-scale Methodology. https://cdm.unfccc.int/UserManagement/FileStorage/PST6IGNEQUK5WMRA2OF4BVX308DHZJ