DRAFT. FOR PUBLIC STAKEHOLDER CONSULTATION

Climate project methodology № 0001

Recovery of gas from oil wells that would otherwise be vented or flared and its use in heat and/or power generation on site

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I. TERMS AND DEFINITIONS

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

Associated gas. Natural gas found in association with the oil, either dissolved in the oil or as a cap of free gas above the oil.

Associated gas treatment plant is a plant designed to remove oil, moisture, mechanical impurities and condensate.

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.

Gas-lift - an artificial lift method for oil wells exploitation in which gas is injected into the production tubing to reduce the hydrostatic pressure of the fluid column. The resulting reduction in bottomhole pressure allows the reservoir liquids to enter the wellbore at a higher flow rate.

Gas-lift gas - high-pressure gas used for gas-lift in the oil wells.

Processed gas. The gas that is produced in an associated gas treatment plant.

Oil field – an area of land or seabed containing reserves of petroleum deposits, secured under concession for the purpose of extracting oil.

II. SCOPE AND APPLICABILITY

The methodology is applicable to project activities that recover associated gas from oil wells that would otherwise be flared or vented. A new associated gas treatment plant is installed in which the associated gas is processed. The processed gas is supplied to the heat and/or power generation facility on-site to meet on-site heat and/or power demands.

The methodology is applicable under the following conditions:

- All recovered associated gas comes from existing oil wells that are in operation and are producing oil at the time of the recovery of the associated gas;
- The project oil wells have the records of flaring or venting of the associated gas for at least three years. These records should be presented to a legal entity or an individual

entrepreneur accredited in the national accreditation system as a greenhouse gas validation and verification body and which is not affiliated with the project executor during the validation;

- Data (quantity and fraction of carbon) are accessible on the associated gas;
- If the project oil wells include gas-lift systems, the gas-lift gas has to be associated gas from the oil wells within the project boundary.

Under this methodology no carbon credits can be claimed for displacement of fossil fuels by the associated.[1]

Finally, this methodology is only applicable if the application of the procedure to identify the baseline scenario and demonstrate additionality results in the venting and/or flaring of the associated gas and/or gas-lift gas at the oil production facility as the most plausible baseline scenario.

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.

Projection and adjustment of project and baseline emissions on the basis of oil production

Project as well as baseline emissions depend on the quantity of the associated gas recovered, which is linked to the oil production. Oil production may be projected with the help of a reservoir simulator, reflecting the rock and fluid properties in the oil reservoir. As projections of the oil production, the methane content of the gas and other parameters involve a considerable degree of uncertainty, the quantity and composition of the recovered gas are monitored ex post and baseline and project emissions are adjusted respectively during monitoring.

The greenhouse gas validation and verification body shall confirm that estimated emission reductions reported in the information about the climate project are based on estimates provided in project documentation materials that have received positive conclusions from state reviews necessary to start underlying oil production project.

At verification the greenhouse gas validation and verification body shall check the production data for oil and associated gas and compare them with the initial production target as

[1] If an end-user wishes to claim carbon credits for the fuel switch, the associated or combined gas shall be considered as natural gas and relevant methodologies for fuel switch shall be applied.

per the information provided in survey used for defining the terms of the underlying oil production project. If the oil production differs significantly from the initial production target, then it should be checked that this is not intentional, and that such a scenario is consistent with the subsoil use license.

Project boundary

The project boundary encompasses:

- The project oil field and oil wells where the associated gas and/or gas-lift gas is collected.
- The site where the associated gas and/or gas-lift gas would have been flared or vented in the absence of the project activity.
- The gas recovery, pre-treatment and utilization infrastructure.
- The source of gas-lift gas.

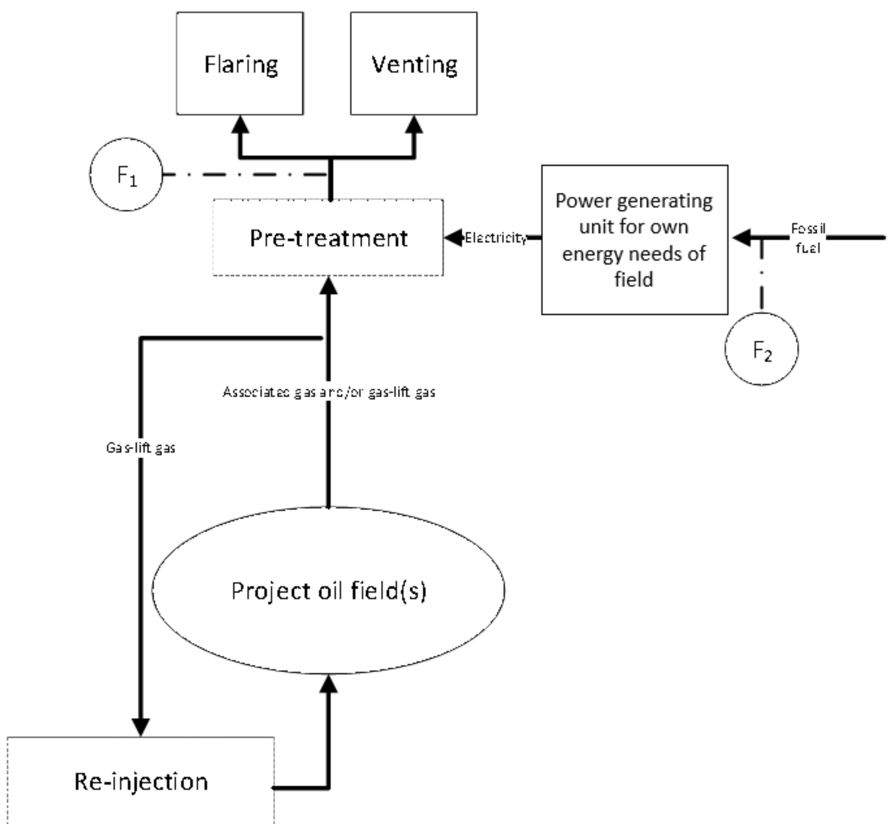
The greenhouse gases included in or excluded from the project boundary are shown in Table 1.

Table 1: Emissions sources included in or excluded from the project boundary

	Source	Gas	Included?	Justification / Explanation
Baseline	Venting of associated gas	CO_2	Yes	For conservativeness it is assumed that the associated gas was flared in the baseline scenario even if it was actually vented prior to the start of the project activity
		CH_4	Yes	For conservativeness it is assumed that the associated gas was flared in the baseline scenario even if it was actually vented prior to the start of the project activity
		N_2O	No	Assumed negligible
	Flaring of associated gas	CO_2	Yes	Main source of emissions in the baseline
		CH_4	Yes	It is assumed that flaring leads to incomplete oxidation of carbon in associated gas
		N_2O	No	Assumed negligible
	Energy use for recovery, pre-treatment, transportation of associated gas	CO_2	Yes	Energy is produced from the fossil fuel
		CH_4	No	Assumed negligible
		N_2O	No	Assumed negligible
	Flaring of	CO_2	Yes	Main source of emissions in the project activity

	associated gas	CH_4	Yes	It is assumed that flaring leads to incomplete oxidation of carbon in associated gas
		N_2O	No	Assumed negligible
	Fugitive emissions during treatment and transportation of the associated gas or processed gas	CO_2	No	Assumed negligible
		CH_4	Yes	Assumed negligible
		N_2O	No	Assumed negligible
	Energy use for recovery, pre-treatment, transportation of associated gas and heat and/or power generation facility	CO_2	Yes	Energy is produced from the processed gas
		CH_4	No	Assumed negligible
		N_2O	No	Assumed negligible

Figure 1. Schematic illustration of the baseline activity

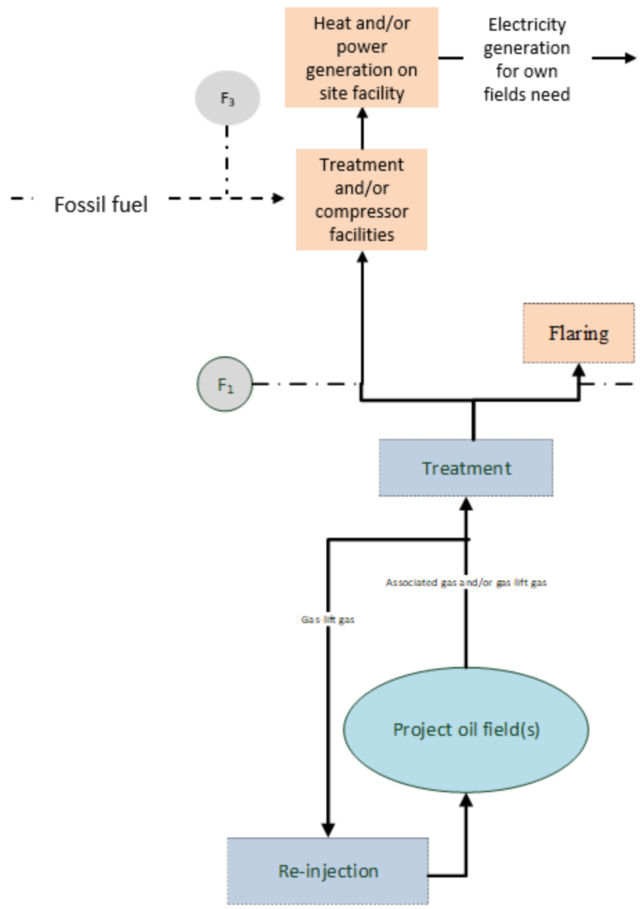


The points in Figure correspond to the following:

Point F_1 – Measurement point of recovered associated gas.

Point F_2 – Measurement point of fossil fuel at the inlet to the power generating unit.

Figure 2. Schematic illustration of the project activity



The points in Figure correspond to the following:

Point F_1 – Measurement point at the inlet of the on-site heat and/or power generation facility using the associated gas.

Point F_2 – Measurement point of the associated gas sent for flaring when the pumps are released and purged.

Point F_3 – Measurement point of fossil fuel used to generate the electricity required to operate the associated gas treatment plant (if the plant does not receive electricity from the grid or as a result of associated gas utilization).

III. BASELINE METHODOLOGY

Baselines shell be set in a conservative way and below ‘business as usual’ emission projections (including by taking into account all existing policies).

Each project shall apply of one of the approaches below to setting the baseline with justification for the appropriateness of the choices:

- Best available technologies that represent an economically feasible and environmentally sound course of action;
- 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;
- An approach based on existing actual or historical emissions, adjusted downwards

Standardized baselines shall be established at the highest possible level of aggregation in the relevant sector.

Baseline emissions

The baseline shall be determined taking into account the projected level of production activities and information on actual greenhouse gas emissions and removals for a period of at least 3 (three) years prior to project implementation.

It is assumed that all associated gas is flared (and not vented) in the baseline scenario and carbon is converted into carbon dioxide. It is assumed that flaring leads to incomplete oxidation of carbon in associated gas.

Also, the baseline takes into account the emissions from generating energy and/or heat on the power generating unit on site, in case the electricity supply for own needs of the field is not from the grid.

The baseline emissions are calculated as follows:

$$BE_{i,y} = BE_{CO_2,CH_4,\, flaring,\, y} + BE_{generating,\, y} \quad \textbf{(1)}$$

Where:

PE_y = Baseline emissions in year *y* (tCO_2/year)

$BE_{CO_2,CH_4, flaring, y}$ = CO_2 and CH_4 emissions from flaring of associated gas in year *y* (tCO_2e/year).

$BE_{generating ,y}$ = CO_2 emissions due to fossil fuel combustion for generating electricity on-site in year *y* (tCO_2/year).

Baseline emissions from flaring

$$BE_{CO2,CH4,flaring,y} = \sum_{j=1}^{n}(FC_{j,y} \times EF_{i,j,y}) \quad \textbf{(2)}$$

Where:

$BE_{CO_2,CH_4, flaring, y}$ = CO_2 and CH_4 emissions from flaring of associated gas in year *y* (tCO_2e/year).

$FC_{j,y}$ = Volume of the of j-hydrocarbon mixture measured at point F_1 in Figure 1 in period *y* (thousand m^3)

$EF_{i,j,y}$ = i-GHG emission factor from combustion of j-hydrocarbon mixture at a flare plant for period *y* (t/thousand m^3)

i = CO_2, CH_4

j = type of hydrocarbon mixture

n = the number of types of hydrocarbon mixtures combusted in the flare unit

GHG emission factors from combustion of j-hydrocarbon mixture at a flare plant are calculated in accordance with Part 2 of Appendix No. 2 to the methodology for quantifying greenhouse gas emissions, approved by Order of the Ministry of Natural Resources of Russia dated May 27, 2022 № 371.

Baseline emissions from the generating on site for fields own needs

$$BE_{generating,y} = \sum_{j=1}^{n}(FC_{j,y} \times EF_{CO2,j,y} \times OF_{j,y}) \quad \textbf{(3)}$$

Where:

$BE_{generating, y}$ = CO_2 emissions due to fossil fuel combustion for generating electricity on-site in year *y* (tCO_2/year).

$FC_{j,y}$ = Volume of the of j-hydrocarbon mixture measured at point F_2 in Figure 1 in period *y* (thousand m^3)

$EF_{CO_2,j,y}$ = CO_2 emission factor from combustion of j-hydrocarbon mixture for period *y* (t/thousand m^3)

$OF_{j,y}$ = oxidation factor for fuel j (fraction);

j = type of fuel used for combustion;

n = number of fuels used during the period *y*

Factors are taken in accordance with Part 1 of Appendix No. 2 to the methodology for quantifying greenhouse gas emissions, approved by Order of the Ministry of Natural Resources of Russia dated May 27, 2022 № 371.

IV. PROJECT CREDITING PERIOD

For validation, projects can be submitted to the validation and verification body, the implementation of which was started no earlier than 2 years before submission for validation.

Project timeline consists of separate crediting periods. A crediting period is a maximum of 5 years renewable a maximum of twice, or a maximum of 10 years with no option of renewal, that is appropriate to the activity.

The crediting period shall not start before the registration of the project in the Register of Carbon Units.

V. ADDITIONALITY

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

It is also necessary to take into account the following factors:

- The value of the indicator of venting or flaring of associated gas should not exceed 5%. The exception is cases of development of subsoil plots with the degree of depletion of oil reserves in the subsoil plot less than or equal to 0.01, as well as within 3 years from the moment the specified indicator is exceeded or until the degree of depletion of oil reserves in the subsoil plot is equal to 0.05, if this will come earlier;
- The volume of greenhouse gas emissions per ton of associated gas under the project scenario should be much lower than those specified in the applicable best available technologies (Table 5.4 and Table 5.5 of the Best Available Technologies reference document 28-2021 «Oil Production»);
- In the event of an increase in local demand for heat and/or electricity, the project scenario should provide for a proportional increase in associated gas production by no more than 5%. The lack of heat and/or electricity must be generated by renewable sources of electricity.

VI. MONITORING PLAN REQUIREMENTS

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. One hundred per cent of the data should be monitored if not indicated otherwise in the tables below. All measurements should be conducted with calibrated measurement equipment according to relevant industry standards.

Uncertainty assessment

'Permissible uncertainty' shall be expressed as the 95% confidence interval around the measured value, for normally distributed measurements. The uncertainty associated with each parameter should be assessed, for example, by calculating the probable uncertainty as the mean deviation divided by the square root of the number of measurements. If this uncertainty is within the 95% confidence interval, than it is considered permissible uncertainty, and no action must be taken.

If not, then the uncertainty should be assessed as low (<10%), medium (10-60%) or high (>60%). Percent uncertainty may be calculated by dividing the mean of the parameter by the probable uncertainty and multiply by 100% to get percent uncertainty. If percent uncertainty is <10%, the uncertainty is considered low. A detailed explanation of quality assurance and quality control procedures must be described for parameters with medium or high uncertainty in an attempt to decrease uncertainty, and to ensure that emissions reductions calculations are not compromised. In the case of a parameter with medium or high uncertainty, a sensitivity analysis should be performed to determine the potential of the uncertainty of the parameter to affect the emissions reduction calculation. The authenticity of the uncertainty levels should be verified by the verification body at the project verification stage.

For gas volume or mass measurement, the metering systems will be designed, installed and maintained to the requirements of the appropriate metering reference standards for the installed technology such that the uncertainty in measurement can be calculated in a fully traceable manner with reference to such standards.

For gas sampling, the sampling equipment and sampling procedure will comply with appropriate reference standards such that uncertainty in sample extraction can be calculated with reference to such standards.

For gas analysis, the gas analyser and analysis procedures shall also comply with appropriate reference standards and where laboratory analysis is used the laboratory shall comply with national accreditation standards.

Uncertainty associated with each parameter will be maintained through a calibration program designed to ensure individual parameter uncertainties are maintained at a level ensuring the combined overall uncertainty in emission reductions can be shown to be within a commonly acknowledged 5% verification materiality threshold.

In addition, the monitoring provisions in the tools referred to in this methodology apply.

Data and parameters monitored

Data / Parameter:	$FC_{j,y}$
Data unit:	m^3
Description:	Volume of the of j-hydrocarbon mixture measured at points during the period *y*: – F_1 in Figure 1; – F_2 in Figure 1 (if applicable); – F_1 in Figure 2; – F_2 in Figure 2; – F_3 in Figure 2 (if applicable);
Source of data:	Flow meter
Measurement procedures (if any):	The metering system shall be designed, installed and maintained to the requirements of the relevant metering technology reference standards. Metering instrumentation shall be calibrated at an appropriate frequency to ensure performance is maintained within design accuracy.
Monitoring frequency:	Continuously
QA/QC procedures:	Calibration and maintenance of metering instrumentation will be carried out to manufacturer and reference standard requirements. Internal audit of metering system calibrations prior to each monitoring report Data trend and production cross checks prior to each monitoring report

Data / Parameter:	Chemical composition of gas
Data unit:	Volume fraction, %
Description:	Average content of components in the j-hydrocarbon mixture at points during the period *y*: – F_1 in Figure 1; – F_2 in Figure 1 (if applicable); – F_1 in Figure 2; – F_2 in Figure 2; – F_3 in Figure 2 (if applicable);
Source of data	Analysis by either on-line analyser or by manual sample extraction and laboratory analysis using laboratory analyser.
Measurement procedures (if any):	Sampling equipment, sampling procedure, gas analyser and analysis procedures shall comply with appropriate reference standards and where laboratory analysis is used the laboratory shall comply with national accreditation standards. Calibration
Monitoring frequency:	Monthly
QA/QC procedures:	Calibration and maintenance of analyser shall be carried out to manufacturer and reference standard requirements. Internal audit of analyser calibrations shall be carried out prior to each monitoring report Data trend and production cross checks shall be carried out prior to each monitoring report

VII. PROJECT SCENARIO

The following sources of project emissions are accounted for in this methodology:

- CO_2 emissions due to processed gas combustion for generating heat and/or electricity on-site;
- CO_2, CH_4 emissions from flaring of processed gas during release and blowdown of heat and/or power generating facility pumps;
- CO2 emissions from combustion of fossil fuels to generate electricity required to operate the associated gas treatment plant (if the plant is not drawing electricity from the grid or associated gas utilization).

Project emissions are calculated as follows:

$$PE_y = PE_{generating,\,y} + PE_{CO_2,CH_4,\,flaring,\,y} + PE_{treatment\ plant,\,y} \quad \textbf{(4)}$$

Where:

PE_y	=	Project emissions in year *y* (tCO_2/year)
$PE_{generating\ ,y}$	=	CO_2 emissions due to processed gas combustion for generating heat and/or electricity on-site in year *y* (tCO_2/year).
$PE_{CO_2,CH_4,\,flaring,\,y}$	=	CO_2 and CH_4 emissions from flaring of processed gas during release and blowdown of heat and/or power generating facility pumps in year *y* (tCO_2e/year).
$PE_{treatment\ plant,\,y}$	=	CO_2 emissions due to fossil fuel combustion to generate electricity required to operate the associated gas treatment plant in year *y* (tCO_2/year).

Project emissions from the generating heat and/or electricity on site for fields own needs

Scenario 1

If electricity, required to operate the associated gas treatment plant for need is produced from fuel onsite.

$$PE_{generating,y} = \sum_{j=1}^{n}(FC_{j,y} \times EF_{CO2,j,y} \times OF_{j,y}) \quad \textbf{(5)}$$

Where:

$PE_{generating,y}$	=	CO_2 emissions due to processed gas combustion for generating heat and/or electricity on-site in year *y* (tCO_2/year).
$FC_{j,y}$	=	Volume of the of j-hydrocarbon mixture measured at point F_1 in Figure 2 in period *y* (thousand m^3)
$EF_{CO_2,j,y}$	=	CO_2 emission factor from combustion of j-hydrocarbon mixture for period *y* (t/thousand m^3)
$OF_{j,y}$	=	oxidation factor for fuel j (fraction);
j	=	type of fuel used for combustion;
n	=	number of fuels used during the period *y*

Factors are taken in accordance with Part 1 of Appendix No. 2 to the methodology for quantifying greenhouse gas emissions, approved by Order of the Ministry of Natural Resources of Russia dated May 27, 2022 № 371.

Project emissions from flaring

$$PE_{CO_2,CH_4,flaring,y} = \sum_{j=1}^{n}(FC_{j,y} \times EF_{i,j,y}) \quad \textbf{(6)}$$

Where:

$PE_{CO_2,CH_4,flaring,y}$	=	CO_2 and CH_4 emissions from flaring of associated gas during release and blowdown of heat and/or power generating facility pumps in year *y* (tCO_2e/year).
$FC_{j,y}$	=	Volume of the of j-hydrocarbon mixture measured at point F_2 in Figure 2 in period *y* (thousand m^3)
$EF_{i,j,y}$	=	i-GHG emission factor from combustion of j-hydrocarbon mixture at a flare plant for period *y* (t/thousand m^3)
i	=	CO_2, CH_4
j	=	type of hydrocarbon mixture
n	=	the number of types of hydrocarbon mixtures combusted in the flare unit

GHG emission factors from combustion of j-hydrocarbon mixture at a flare plant are calculated in accordance with Part 2 of Appendix No. 2 to the methodology for quantifying greenhouse gas emissions, approved by Order of the Ministry of Natural Resources of Russia dated May 27, 2022 № 371.

Project emissions from the generating electricity required to operate the associated gas treatment plant (if applicable)

Scenario 1

If electricity, required to operate the associated gas treatment plant for need is produced from fuel onsite.

$$PE_{treatment\ plant,y} = \sum_{j=1}^{n}(FC_{j,y} \times EF_{CO2,j,y} \times OF_{j,y}) \quad \textbf{(7)}$$

Where:

$PE_{treatment\ plant,\ y}$	=	CO_2 emissions due to fossil fuel combustion to generate electricity required to operate the associated gas treatment plant in year *y* (tCO_2/year).
$FC_{j,y}$	=	Volume of the of j-hydrocarbon mixture measured at point F_3 in Figure 2 in period *y* (thousand m^3)
$EF_{CO_2,j,y}$	=	CO_2 emission factor from combustion of j-hydrocarbon mixture for period *y* (t/thousand m^3)
$OF_{j,y}$	=	oxidation factor for fuel j (fraction);
j	=	type of fuel used for combustion;
n	=	number of fuels used during the period *y*

Factors are taken in accordance with Part 1 of Appendix No. 2 to the methodology for quantifying greenhouse gas emissions, approved by Order of the Ministry of Natural Resources of Russia dated May 27, 2022 № 371.

Scenario 2

If electricity, required to operate the associated gas treatment plant is imported from electricity grid, emissions could be accounted with methodology provided in Order of the Ministry of Natural Resources and Ecology of the Russian Federation dated June 29, 2017 N330 "On approval of methodological guidelines for quantifying the volume of indirect energy emissions of greenhouse gases" or emissions could be accounted from other relevant national data.

Emission reductions

$$ER_y = BE_y - PE_y \quad \textbf{(8)}$$

Where:

ER_y	=	Emission reductions in year *y* (t CO_2e/year)
BE_y	=	Baseline emissions in year *y* (t CO_2e/year)
PE_y	=	Project emissions in year *y* (t CO_2/year)

VIII. LEAKAGE ASSESSMENT

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

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

Leakage is the phenomenon through which efforts to reduce emissions in one place simply shift emissions to another location or sector where they remain uncontrolled or uncounted. Leakage is an inherent risk in carbon projects and programs. The level of leakage risk depends on what causes the baseline emissions and on the design of the carbon projects or programs, i.e. on how well they mitigate risks. The leakage management approach should include identifying, elimination, monitoring and quantifying carbon leakage throughout the whole cycle of the project, and subtracting that leakage from the estimated number of GHG emission reductions or removals that can be issued as carbon credits.

There are three types of leakage:

1) Market leakage occurs when projects significantly reduce the production of a commodity causing a change in the supply and market demand equilibrium that results in a shift of production elsewhere to make up for the lost supply.

2) Activity Shifting leakage is related to activities that directly cause carbon-emitting activities to be shifted to another location outside of the project boundaries, cancelling out some or all of the project's carbon benefits.

3) Ecological leakage occurs when the project activity causes changes in GHG emissions or fluxes of GHG emissions from ecosystems that are hydrologically connected to the project area.

GHG emissions from leakage may be determined either directly from monitoring, or indirectly when leakage is difficult to monitor directly but where scientific knowledge provides credible estimates of likely impacts. Leakage occurring outside the host country (international leakage) does not need to be quantified. Projects should not consider positive leakage (i.e., where GHG emissions decrease or removals increase outside the project area due to project activities).

When assessing leakage as a result of project activities under this methodology, consideration should be given to whether lower efficiency equipment was selected as a result of project activities.

If such leakage effects result from the project activity, emission reductions should be adjusted respectively in a conservative manner.

Where the fuels of the project activity substitute fuels with higher carbon intensity, emission reductions should as a conservative assumption not be adjusted.

IX. NON-PERMANENCE RISK ANALYSIS

Not applicable to the project activity.

X. METHODS TO PREVENT DOUBLE COUNTING, NEGATIVE IMPACTS ON THE ENVIRONMENT AND SOCIETY

Climate project should demonstrate its compliance with all legal requirements in the jurisdiction where it is located. Project proponent should question whether there is a risk that their project might result in negative impacts for local communities, biodiversity and the environment. Such projects should not cause an increase in atmosphere, soil, surface and ground water pollution as well as lead to any community conflicts, land tenure issues, forceful evictions, human rights violations, or worsened health and wellbeing due to restricted access to a forest or nature area.

Efforts should be made to avoid double counting between project areas (project boundaries), between company reporting and reporting on the project, between the reporting of different companies, between the subjects of the Russian Federation and different countries in the case of international transfer of carbon credits. In the latter case, it is necessary to demonstrate that the carbon credits transferred at the international level are excluded from the accounting of the quantitative goals of the defined at the national level contribution of the Russian Federation.

XI. UPDATE OF THE BASELINE AT THE RENEWAL OF THE CREDITING PERIOD

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.

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.

The additionality at the renewal of the crediting period is checked for compliance to the criteria under Tool #1 at the date of the beginning of the new crediting period.

XII. NORMATIVE REFERENCES

1 Order of the Ministry of Economic Development of Russia dated May 11, 2022 № 248 "On approval of the criteria and procedure for classifying projects implemented by legal entities, individual entrepreneurs or individuals, as climate projects, the form and procedure for reporting on the implementation of a climate project" (Registered with the Ministry of Justice of Russia on May 30, 2022 № 68642).

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

3 GOST R ISO 14064-2-2021. National Standard of the Russian Federation. Greenhouse gases. Part 2. Requirements and Guidelines for Quantification, Monitoring and Reporting Documents for Projects to Reduce Greenhouse Gas Emissions or Increase Their Absorption at the Project Level (approved and enacted by Order No. 1030-st of Rosstandart dated September 30, 2021).

4 GOST R ISO 14064-3-2021. National Standard of the Russian Federation. Greenhouse gases. Part 3. Requirements and Guidance for Validation and Verification of Greenhouse Gas Statements (approved and enacted by Rosstandart Order No. 1031-st of 30.09.2021).

5 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 Order of Rosstandart of 26.11.2014 № 1869-st).

6 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 of 17.12.2013 № 2274-st).

7 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 (approved and enacted by Order of Rosstandart No. 1033-st dated 30.09.2021).

8 Order of the Ministry of Natural Resources of Russia dated May 27, 2022 № 371 "On approval of methods for quantitative determination of greenhouse gas emissions and greenhouse gas removals" (from March 1, 2023, except for certain provisions, coming into force on March 1, 2024).

9 Order of the Ministry of Natural Resources of the Russian Federation dated June 30, 2015 №300 "On approval of methodological guidelines and guidelines for quantitative determination of greenhouse gas emissions by organizations engaged in economic and other activities in the Russian Federation" (until March 1, 2023).

10 Order of the Ministry of Natural Resources and Environment of Russia dated June 29, 2017 "On approval of methodological guidelines for quantification of indirect energy emissions of greenhouse gases"

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

12 Decree of the Government of the Russian Federation of 08.11.2012 № 1148 "On peculiarities of the calculation of payment for emissions of pollutants generated by flaring and (or) dispersion of associated petroleum gas" (As amended by the Government of the Russian Federation of 17.12.2016 № 1381, from 28.12.2017 № 1676, from 13.12.2019 № 1667).