Climate project methodology № 0004

FUEL SWITCHING FROM COAL OR PETROLEUM FUEL TO NATURAL GAS

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1.Terms and definitions

1.1. The definitions and terms contained in Russian regulatory documents and national standards shall apply.

1.2. The climate project developer is encouraged to use the terms and definitions used in this methodology:

1.2.1. **Industrial installation –** stationary technical unit and/or a complex of interconnected equipment and structures on which one or more elemental processes are carried out. Examples of industrial installations: furnace, boiler, stationary boiler, boiler plant, steam boiler, hot-water boiler, waste fuel boiler.

1.2.2. **Element process –** is defined as fuel combustion in a single equipment at one point of an industrial facility or of a district heating system, for the purpose of providing thermal energy (the fuel is not combusted for the purpose of electricity generation or used as oxidant in chemical reactions or otherwise used as feedstock). Examples of an element process are steam generation by a boiler and hot air generation by a furnace. Each element process should generate a single output (such as steam or hot air) by using mainly a single fuel (not plural energy sources).

1.2.3. **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.

1.2.4. **Project Design Document (PDD)** – is the principal document used by project developers to demonstrate and describe information about the proposed climate project for submission to the validation/verification authorities and the carbon carbon register.

2.Scope and applicability

2.1. This methodology has been prepared on the basis of the existing methodology developed within the framework of the Clean Development Mechanism (ACM0009) and includes its adaptation to the current Russian regulations and standards.

2.2. This methodology applies to project activities switching from coal or petroleum fuel to natural gas in the generation of heat in industrial installations. The number of industrial installations is not limited by the climate project boundaries[1].

2.3. 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.

2.4. Industrial installations that fall within the scope of this methodology can be applied in the following sectors: utility, iron and steel industry, oil refining and petrochemical industry (natural gas as fuel), glass industry, cement production, machine-building industry, pulp and paper industry, food industry, construction sector, etc.

2.5. The methodology is not applicable for installations operating in the electric power sector, including cogeneration plants.

2.6. If an organization has an additional type of activity related to the production, transmission and distribution of steam and hot water (thermal energy), the project developer needs to determine the output energy flows according to the technological scheme of the thermal power plant. If a thermal power plant or a boiler house belonging to an industrial enterprise serves only its needs for thermal energy (decentralized heat supply), or releases all the energy produced to the side (centralized heat supply) – these industrial installations fall under the implementation of a climate project. If a thermal power plant or boiler house provides thermal energy to industrial enterprises at the same time and releases energy to the side, this thermal power plant cannot be taken into account for the purposes of implementing a climate project.

2.7. Furthermore, the following conditions shall be applied to project activities:

2.7.1 Prior to the implementation of the project activity, only coal or petroleum fuel (but not natural gas) have been used in the industrial installations.

2.7.2 No national, regional programs or specific technical regulations constrain the facility from using the fossil fuels being used prior to fuel switching.

2.7.3 National, regional programs or specific technical regulations do not require the use of natural gas or any other fuel in the industrial installations.

2.7.4 Design (installed) thermal capacity of industrial installations after switching to natural gas should not exceed the historical (actual) capacity by more than 5%.

2.7.5 The project activity does not contribute to increasing the technical lifetime of industrial installation (or its elements) during the crediting period. In case of project activities that involve the replacement or retrofit of existing boiler(s), all boiler(s) existing at the project

[1] In accordance with this methodology, the project boundaries include a list of facilities (industrial installations), the operation of which is accompanied by greenhouse gas emissions and (or) their absorption).

site prior to the implementation of the project activity should be able to operate until the end of the crediting period without any retrofitting or replacement. For the purpose of demonstrating this applicability condition, project participants should provide the appropriate technical documentation of the installation (passport) or a mode map, which reflects the list of parameters of the installation operation under various power modes (mode-setting tests). Additionally, with the involvement of Rostechnadzor, the project developer can demonstrate compliance with the actual service life of the installations with the regulatory one (indicated in the passport or the mode map), and confirm the remaining service life of the installations. The relevant information should be reflected in the PDD.

2.7.6 No increase in the thermal capacity of the industrial installation/facility is planned during the crediting period. In this case, the project developer should provide evidence that connected heat load of industrial installation it is not planned to increase. The evidence may be a written assurance or documentary confirmation, for example, development plans, etc.

2.7.7 The proposed project activity does not result in integrated process change[2];

2.8. The project boundary covers CO_2 emissions associated with fuel combustion in each industrial installation subject to the fuel switching. The same project boundaries are applicable to both baseline emissions and project emissions.

2.9. For the purpose of determining project activity emissions, project participants shall include carbon dioxide emissions from the combustion of natural gas in each industrial installation.

2.10. For the purpose of determining baseline emissions, project participants shall include carbon dioxide emissions from the combustion of the quantity of coal or petroleum fuel that would be used in each industrial installation in the absence of the project activity.

2.11. The spatial extent of the project boundary encompasses the physical, geographical site of the industrial facility or the district heating system.

2.12. Summary of GHGs and sources included in the project boundary, and justification/explanation where GHGs and sources are not included presented in table 1.

Table 1. Emission sources included in or excluded from the project boundary

[2] In accordance with this methodology, integrated process change – change of drawings, technological conditions, chart of the terms of delivery of blanks of parts, equipment, tooling, tools, technological route, the change is made when improving the technological process and tooling, when correcting errors in technology. In a broader sense, a complex process change is a change in the technological process in production, a change in the relationship between production units, a change in the loading of individual processing units, the introduction of innovative technologies, etc.

Source		Gas	Included	Justification/Explanation
Baseline	Baseline fuel burning	CO_2	Yes	Main emission source
		CH_4	No	Minor source. Accounting is not required
		N_2O	No	Minor source. Accounting is not required
Project activity	Natural gas burning	CO_2	Yes	Main emission source
		CH_4	No	Minor source. Accounting is not required
		N_2O	No	Minor source. Accounting is not required

2.13 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

3.1. The baseline[3] for the established baseline scenario (continuation of the use of coal or petroleum fuel) 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). The project developer may use one of the following approaches to determine the baseline with justification for the appropriateness of the choices[5]:

3.1.1. Best available technologies that represent an economically feasible and environmentally sound course of action.

[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.

3.1.2. 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.

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

3.2. 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 below.

3.3. For the approach defined by the project developer, the calculation of baseline emissions corresponds to the general equation:

$$BE_y = A_{baseline,y} \times EF_{CO2,baseline}$$

Where:

BE_y - Baseline emissions during the year y in t CO2;

$A_{baseline,y}$ - Data on any activity of the installation for the year y;

$EF_{CO2,baseline}$- CO2 emission factor;

3.4. For each of the approaches described in paragraphs 3.2.1-3.2.3, activity data (A) and emission factors (EF) are determined in accordance with the required conditions. For example, for existing actual emission approach, activity data (A) is the amount of solid/liquid fuel consumption in year y in tonn/TEF, (EF) - emission factor from fuel combustion in year y in ton CO2/tonn (TEF) fuel. The calculation of emissions must be carried out in accordance with the methodological guidelines of the Ministry of Natural Resources 371.

3.5. For ambitious benchmark approach, activity data (A) is the amount of products produced at industrial installation(s) (downstream products/ /TJ/ Gcal) in year y, (EF) - average GHG emissions intensity of the 20% most efficient installations according to national benchmark values or industry standards[6] in year y in ton CO2/ton products.

3.6. For best available technologies, emission factor (EF) is determined in accordance with Best Available Techniques Reference Documents[7] for industrial installation, operating in corresponding industry/sector. Activity data (A) of industrial installation(s) must comply with the applicable dimension of the EF.

[6] If the relevant regulatory documents have been developed and put into effect.

[7] See: https://www.rst.gov.ru/portal/gost/home/activity/NDT

3.7. This methodology provides a detailed calculation of baseline emissions for approach 3.1.3 (existing actual or historical emissions). For an approach based on existing actual or historical emissions, the project developer should use paragraphs 3.7-3.14 of this methodology to calculate baseline emissions.

3.8. Design (installed) thermal capacity of industrial installations after switching to natural gas should not exceed the previous figures by more than 5%.

3.9. Baseline emissions include BE_y CO_2 emissions from the combustion of the quantity of coal or petroleum fuel that would in the absence of the project activity be used in all element processes i. The determination of the corresponding values of the net calorific value of coal/petroleum fuel and CO_2 emission factors should be carried out in accordance with the methodological guidelines of the Ministry of Natural Resources No. 371. The calculation of baseline emissions BE_y is as follows:

$$BE_y = \sum_i FC_{baseline,i,y} \times NCV_{FF,i} \times EF_{FF,CO2,i}$$

где:

BE_y – Baseline emissions during the year y in t CO_2;

$FC_{baseline,i,y}$ – Quantity of coal or petroleum fuel that would be combusted in the absence of the project activity in industrial installation i during the year y in a volume or mass unit

$NCV_{FF,i}$ – Average net calorific value of the coal or petroleum fuel that would be combusted in the absence of the project activity in the industrial installation i during the year y in GJ per volume or mass unit;

$EF_{FF,CO2,i}$ – CO2 emission factor from the combustion of coal type that would be combusted in the absence of project activity in the element process i, t CO_2/GJ;

3.10. The quantity of coal or petroleum fuel (approach based on existing actual) that would be used in the absence of the project activity in an industrial installation i ($FC_{baseline,i,y}$) is calculated based on the actual monitored quantity of natural gas combusted in this industrial installation ($FC_{project,i,y}$ y), the relation of the energy efficiencies and the net calorific values between the project scenario (use of natural gas) and the baseline scenario (use of coal or petroleum fuel), as follows:

$$FC_{baseline,i,y} = FC_{project,i,y} \times \frac{NCV_{NG,y} \times \varepsilon_{project,i}}{NCV_{FF,y} \times \varepsilon_{baseline,i,y}}$$

Where:

$FC_{baseline,i,y}$ - Quantity of coal or petroleum fuel that would be combusted in the absence of the project activity in industrial installation i during the year y in a volume or mass unit;

$FC_{project,i,y}$ – Quantity of natural gas combusted in industrial installation i during the year y in m^3;

$NCV_{NG,y}$ - Average net calorific value of the natural gas combusted during the year y in GJ/m^3;

$NCV_{FF,y}$ - Average net calorific value of the coal or petroleum fuel that would be combusted in the absence of the project activity in the industrial installation i during the year y in GJ per volume or mass unit;

$\varepsilon_{project,i}$- Net energy efficiency of the industrial installation i if fired with natural gas;

$\varepsilon_{baseline,i,y}$- Net energy efficiency of the industrial installation i if fired with coal or petroleum fuel respectively;

3.11. In the process of verification of climate project, the baseline fuel consumption ($FC_{baseline,i,y}$) for industrial installatio(n) i must be reviewed for all years, depending on the actual consumption of natural gas in this industrial installation ($FC_{project,i,y}$).

3.12. Note that the most plausible baseline scenario may be that several fuel types would be used in the industrial installation(s). Where several fuel types have been used in industrial installation(s) prior to the implementation of the project activity (including cases where a start-up fuel is clearly defined) and where the continuation of this practice is the most plausible baseline scenario, project participants should exclude the start-up fuel from the list of multiple fuels and, as a conservative approach, select the fuel type with the lowest CO2 emission factor from the fuels used in that industrial installation(s) during the last three years and the baseline net calorific value (NCVFF,i). For example, cases of using brown coal and hard coal in an industrial installation(s).

3.13. For the determination of emission factors and net calorific values, guidance by the latest MNR № 371 should be followed where appropriate.

3.14. The net energy efficiencies have to be determined for each industrial installation(s) for the project activity (εproject,i) and the baseline scenario (εbaseline,i). The efficiencies should be determined by undertaking measurements at the element process firing the relevant fuels. Efficiencies for the project activity (εproject,i) should be measured monthly throughout the crediting period and annual averages should be used for emission calculations.

3.15.Baseline efficiency (εbaseline,i) is calculated as:

3.15.1. Option A: Use a default conservative value equal to 1;

3.15.2. Option B: Use a default conservative value obtained from the manufacture's databook, taking the highest possible efficiency under optimal operational conditions;

3.15.3. Option C: Measure efficiency monthly during 6 months before project implementation and the six months average should be used for emission calculations. All measurements should be conducted at a representative load factor (or operation mode), following national or international standards. Where a representative load factor (or operation mode) cannot be determined, measurements should be conducted for different load factors (or operation modes) and be weighted by the time these load factors (or operation modes) are typically operated. The same load factor(s) (or operation mode(s)) and weight factors should be used in the determination of εproject,i and εbaseline,i;

3.15.4. Option D: Where project developer can reasonably demonstrate that the efficiency of the element process does not change due to the fuel switch or that any changes are negligible (i.e. $0 < \varepsilon_{project,i} - \varepsilon_{baseline,i} < 1$ per cent) or that εproject,i can be expected to be higher than εbaseline,i, project participants can assume εbaseline,i = εproject,i as a simplification provided that εbaseline,i, and εproject,i can be established ex ante.

3.15.5. Option E: Use default baseline efficiency (see Table 2).

Table 2. Default baseline efficiency for different boilers[8]

Heat supply technology	**Default efficiency**
New oil fired boiler	90 %
New coal fired boiler	85 %
Old oil fired boiler	85 %
Old coal fired boiler	80 %

3.16.The values determined for εbaseline,i should be documented in the PDD and shall remain fixed throughout the crediting period.

[8] The default efficiency values are taken from the methodology developed within the framework of the Clean Development Mechanism (ACM0009).

4.Project crediting period

4.1. The starting date of project activities is not regulated. A crediting period for emission reduction projects is a maximum of 5 years renewable a maximum of twice, or a maximum of 10 years with no option of renewal. The crediting period begins no earlier than 5 years prior to applying for validation for projects validated until December 31, 2025, and no earlier than 2 years prior to applying for validation for projects validated after January 1, 2026.

4.2. The additionality and baseline shall be evaluated at the beginning of the crediting period and confirmed or reevaluated at the beginning of the next 5-year phase if the project is conducted 3 times 5 years each.

5.Additionality

5.1. Additionality shall be demonstrated using Guidelines №001 «Demonstration of the additionality of the project activity» to confirm this criterion.

5.2. The project developer should demonstrate the additionality of the project activity in the PDD. Paragraphs 5.3-5.4 provide explanatory information on this methodology and the Guidelines №001 «Demonstration of the additionality of the project activity».

5.3. In order to identify alternatives to project activities in accordance with legal and regulatory requirements, the project developer should consider the following alternatives:

5.3.1. Point a: «the proposed project activity undertaken without being registered as a project activity». In this case, the project developer should consider an alternative to switching industrial installations from coal to natural gas without registering a climate project and obtaining carbon units.

5.3.2. Point b: «other realistic and credible alternative scenario(s) …». Other alternatives for the project developer may be: switching from coal or petroleum fuel to another fuel other than natural gas (for example, biomass).

5.3.3. Point c: «continuation of the current situation …». The current situation for the project developer is the continuation of the existing practice of using coal or petroleum fuel.

5.4. To demonstrate that the proposed project activity is not considered as a «common practice», it is necessary to provide a special justification. Common practice may differ depending on the region of implementation of the climate project and the type of industry in which the climate project is implemented. In the case of regional specifics, index of use of local fuels are important. Depending on the industry, the «common practice» may vary greatly, for example, the energy, mining and construction industries may be characterized by coal consumption, the use of outdated equipment, high capital costs, etc. The project developer should demonstrate the main obstacles that are inherent in this climate project, for example, the lack of energy (centralized) infrastructure, state regulation of electricity prices in the region, the cost of equipment and its availability, etc. All these factors together need to be considered for the analysis of common practice.

5.5. This methodology is only applicable if the continuation of the use of coal or petroleum fuel throughout the crediting period is the most plausible baseline scenario, and he proposed project activity has passed the Additionality criterion.

6.Monitoring plan requirements

6.1. All data collected as part of monitoring of projects emissions should be archived electronically and be kept at least for two years after the end of the last crediting period. One hundred per cent (100%) 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. The list of parameters that need to be monitored is presented in the tables 3-6.

Table 3. Data / Parameter monitored

Data / Parameter:	$\mathbf{FC_{project,i,y}}$
Data unit:	m^3, TEF or TJ
Description:	Quantity of natural gas combusted in the industrial installation(s) *i* during the year *y*
Source of data:	On-site measurements
Measurement procedures (if any):	Use volume meters, Flow meters. 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

Any comment:	m^3 should be provided at norm conditions for pressure and temperature. 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

Table 4. Data / Parameter monitored

Data / Parameter:	**$EF_{NG,CO2,y}$**
Data unit:	t CO_2/GJ
Description:	CO_2 emission factor of the natural gas combusted in all industrial installations in the year *y*
Source of data:	The principle of calculating CO_2 emission factor from natural gas combustion is presented in the methodological guidelines of MNR № 371. Values provided by the fuel supplier in invoices is the preferred source. In the absence of such data, it is necessary to use measurements by the project participants. For more information, see the MNR № 371 manual.
Measurement procedures (if any):	-
Monitoring frequency:	Monthly
QA/QC procedures:	-
Any comment:	The invoices of natural gas should be issued on the basis of the results of measurements of physico-chemical parameters in accordance with GOST 5542.

Table 5. Data / Parameter monitored

Data / Parameter:	**$NCV_{NG,y}$**
Data unit:	GJ/m^3

Description:	Average net calorific value of the natural gas combusted during the year *y*
Source of data:	Values provided by the fuel supplier in invoices is the preferred source. In the absence of such data, it is necessary to use measurements by the project participants. For more information, see the MNR № 371 manual.
Measurement procedures (if any):	According to GOST 31369.
Monitoring frequency:	According to the monthly natural gas invoices.
Any comment:	Note that for the NCV the same basis (pressure and temperature) should be used as for the fuel consumption. The invoices of natural gas should be issued on the basis of the results of measurements of physico-chemical parameters in accordance with GOST 5542.

Table 6. Data / Parameter monitored

Data / Parameter:	$\varepsilon_{project,i,y}$
Data unit:	-
Description:	Net Energy efficiency of the industrial installation *i* if fired with natural gas
Source of data:	-
Measurement procedures (if any):	The efficiencies should be determined by undertaking measurements at the industrial installation firing the relevant fuels. All measurements should be conducted at a representative load factor (or operation mode), based on national standards or Standards of organizations (STO). For example, GOST R 56777-2015.
Monitoring frequency:	Monthly
QA/QC procedures:	-

Any comment:	-

6.2. Data and parameters that are not monitored should be calculated once and remain fixed throughout the crediting period. The list of not monitored parameters is presented in the tables 7-8.

Table 7. Data / Parameter not monitored

Data / Parameter:	$\boldsymbol{EF_{FF,CO2,i}}$
Data unit:	t CO2/GJ
Description:	CO2 emission factor from the combustion of coal type that would be combusted in the absence of project activity in the element process i, t CO2/GJ;
Source of data:	On-site measurements or reference value
Measurement procedures (if any):	-
Any comment:	See methodological guidelines of MNR № 371.

Table 8. Data / Parameter not monitored

Data / Parameter:	$\boldsymbol{NCV_{FF,i}}$
Data unit:	GJ per volume or mass unit
Description:	Average net calorific value of the coal or petroleum fuel that would be combusted in the absence of the project activity in the industrial installation i during the year y in GJ per volume or mass unit;
Source of data:	On-site measurements or reference value
Measurement procedures (if any):	-
Any comment:	See methodological guidelines of MNR № 371.

7. Project scenario

7.1. Project scenario include CO_2 emissions from the combustion of natural gas in all industrial installation(s). Project emissions are calculated based on the quantity of natural gas combusted in all industrial installation i and CO_2 emission factors for natural gas ($EF_{NG,CO2}$), as follows:

$$PE_y = \sum_i (FC_{project,i,y} \times EF_{CO2,,y} \times OF_y)$$

Where:

PEy - Project emissions during the year y in t CO2;

$FC_{project,i,y}$ – Natural gas consumption for the period y in industrial installation i, thousand m^3, TEF or TJ;

$EF_{CO2,y}$- CO2 emission factor from natural gas combustion for the period y, t /unit;

OF_y - fuel oxidation coefficient, fraction.

7.2. For the determination of emission factors, sources of information about natural gas consumption, guidance by the latest methodology for quantifying greenhouse gas emissions, approved by Order of the Ministry of Natural Resources of Russia dated May 27, 2022 № 371 (MNR, 371) should be followed. Where measurements are undertaken, project participants should document the measurement results after implementation of the project activity in their monitoring reports.

7.3. The emission reduction by the project activity during a given year y (ERy) is the difference between the baseline emissions (BEy) and project emissions (PEy) and leakage emissions (LEy), as follows:

$$ER_y = BE_y - PE_y - LE_y$$

where:

ERy – Emissions reductions of the project activity during the year y in t CO_2;

BE_y – Baseline emissions during the year y in t CO_2;

PEy – Project emissions during the year y in t CO_2;

LE_y – Leakage emissions in the year y in t CO_2;

7.4. In the process of implementing a climate project, project developers may face certain risks and barriers. To assess the risks, the project developer should develop a risk matrix. For more details, see Appendix 1.

8. Leakage assessment

8.1. According to the Order of the Ministry of Economic Development of Russia dated May 11, 2022 № 248[9] 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 leakage for a project activity[10] in accordance with the methodology below.

8.2. For this type of project activity, leakage upstream emissions (LEUS,y) from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary has to be considered. It is necessary to compare upstream leakage for the use of coal/petroleum fuel and natural gas.

8.3. Leakage upstream emissions in year y ($LE_{US,y} = LE_y$) shall be determined on the basis of coefficients available to the project developer, national special studies or available specialized fact-based, transparent life cycle assessment (LCA) database[11].

8.4. The project developer should refer in PDD to the data source that was used to estimate fuel leaks and describe the properties of the selected coefficients.

8.5. Leakage Upstream emissions are calculated as follows.

$$LE_{US,y} = (FC_{project,i,y} \times EF_{default,NG,y}) - (FC_{baseline,i,y} \times EF_{default,C(P),y})$$

Where:

$LE_{US,y}$ – Leakage upstream emissions in year y (t CO2/yr);

$FC_{project,i,y}$ – Quantity of Natural gas used in the project situation in year y, thousand m3, TEF or TJ;

$EF_{default,NG,y}$ – Default emission factor for upstream emissions associated with consumption of Natural gas in year y, t /unit.

$FC_{baseline,i,y}$ – Quantity of Coal or Petroleum fuel used in the baseline situation in year y, tonn, TEF or TJ;

$EF_{default,C(P),y}$- Default emission factor for upstream emissions associated with consumption of Coal or Petroleum fuel in year y, t /unit;

[9] Appendix 1, point «в».

[10] 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 11.0)

[11] Database sources example: DEFRA database, SimaPro life cycle assessment (LCA) software, Ecoinvent database, industry association reports, etc.

8.6. Where total net leakage effects from upstream emissions are negative (LEUS,y < 0), project participants should assume LEUS,y = 0.

9. Non-permanence risk analysis

9.1. Not applicable for this type of project.

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

10.1. Climate project should demonstrate its compliance with all legal requirements in the jurisdiction where it is located. The project developer needs to minimize the risk that his project might result in negative impacts for local communities, biodiversity and the environment. 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.

10.2. The project developer should make efforts to avoid double counting[12] 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.

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

11.1. 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, it is necessary to revise and update the main parameters and assumptions used in established baseline approach (point's 3.2.1-3.2.3). The baseline shall be representative of the conditions for the beginning of a new crediting period

[12] 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). See also GOST R ISO 14080-2021. National Standard of the Russian Federation. Greenhouse gas management and related activities. A system of approaches and methodological support for the implementation of climate projects.

and be valid for that period. The additionality at the renewal of the crediting period is checked for compliance to the criteria under Guidelines №001 at the date of the beginning of the new crediting period.

11.2. At the renewal of crediting period, it is impossible to change the established baseline approach earlier (Best available technologies; Ambitious benchmark; Existing actual or historical emissions).

12.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. 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.
10. ACM0009: Fuel switching from coal or petroleum fuel to natural gas. Version 5.0. CDM Methodology.

Appendix 1. Risk management

As a 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. 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.

An example of a template with a risk matrix is shown in Table 1.

Table 1. Risk matrix template

Stage of climate project implementation	Descriptio n 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			