Climate project methodology № 0004

Fuel switching from coal or petroleum fuel to natural gas

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Table of contents

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 applies to project activities switching from coal or petroleum fuel to natural gas in the generation of heat in industrial installations.

2.2. 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.

2.3. This methodology is applicable to project activities that switch one or more industrial installations from coal or petroleum fuel to natural gas.

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), these boilers that provide thermal energy for their own production (decentralized heat supply) and/or provide heat supply to a centralized network (centralized heat supply) cannot be taken into account for the purposes of implementation climate project. For example, iron and steel plant owns several hot-water boilers that provide heat energy for its own production. These industrial installations cannot be taken into account for the purposes of implementing a climate project, since these installations do not belong to the main type of activity.

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 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 determine and document the typical average technical lifetime of boilers in the country/region/industry in a conservative manner, taking into account special knowledge in this area. This may be done based on industry surveys, statistics, technical literature, historical replacement

records of boilers in the company, etc. The age of the existing boiler(s) and the average technical lifetime of boilers in the country and sector should be documented 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;

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

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

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

3.Baseline methodology

3.1. 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.

3.2. The baseline for the established baseline scenario (continuation of the use of coal or petroleum fuel) shall be set in a conservative way and below 'business as usual' emission projections (including by taking into account all existing policies). Each project developer shall apply of one of the approaches below to setting the baseline with justification for the appropriateness of the choices:

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

3.2.2. 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;

3.2.3. An approach based on existing actual or historical emissions, adjusted downwards;

3.3. For the approach defined by the project developer, the calculation of baseline emissions corresponds to the following 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 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[1] for industrial installation, operating in corresponding industry/sector. Activity data (A) of industrial installation(s) must comply with the applicable dimension of the EF.

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

3.8. For an operating industrial installation running on coal/petroleum fuel, the net efficiency should correspond to the best available technologies and practices.

3.9. 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 (FCbaseline,i,y) is calculated based on the actual monitored quantity of natural gas combusted in this industrial installation (FCproject,i,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 m³;

$NCV_{NG,y}$ - Average net calorific value of the natural gas combusted during the year y in GJ/m³;

$NCV_{FF,y}$ - 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;

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

3.10. In the process of verification of climate project, the baseline fuel consumption (FCbaseline,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 (FCproject,i,y).

3.11. 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).

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

3.13. 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.

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

4.Project crediting period

4.1. A crediting period is a maximum of 5 years renewable a maximum of twice (5+5+5=15 years), or a maximum of 10 years with no option of renewal, that is appropriate to the activity.

4.2. For validation process, 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. The crediting period shall not start before the registration of the project in the Register of Carbon Units.

5.Additionality

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

5.2. Additional explanations to Tool #1 for this type of project:

5.2.1. Step 1 «Identification of alternatives to the project activity consistent with current laws and regulations», point b: For this case is switching from coal or petroleum fuel to a different fuel than natural gas (such as biomass);

5.2.2. Step 1 «Identification of alternatives to the project activity consistent with current laws and regulations», point c: For this case is continuation of the current practice of using coal or petroleum fuel;

5.2.3. Step 4 «Common practice analysis»: For example, for the regions of Siberia and the Far East, coal generation has historically been crucial. The main obstacles of switching to other types of fuel are associated with the lack of a centralized energy infrastructure in most of the macroregion and state regulation of electricity prices. It is necessary to identify the main sectors that are characterized by coal consumption, outdated equipment, high capital costs. These sectors may include: energy, mining industry, construction industry, etc.

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 2 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 2-5.

Table 2. Data / Parameter monitored

Data / Parameter:	**$FC_{project,i,y}$**
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 3. 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 4. 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 5. 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:	-

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.

8. Leakage assessment

8.1. According to the Order of the Ministry of Economic Development of Russia dated May 11, 2022 № 248[2] 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.

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 national special studies or available specialized fact-based, transparent life cycle assessment (LCA) database[3]. The project developer should strive to provide the most complete information and description of all considered upstream emissions.

8.4. 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 CO2e/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;

8.5. 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.

[2] Appendix 1, point «в».

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

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. 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.

10.2. 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.

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 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.

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.